Gas Inquiry 2017 – 2030

Interim update on east coast gas market

June 2023

Acknowledgement of country

The ACCC acknowledges the traditional owners and custodians of Country throughout Australia and recognises their continuing connection to the land, sea and community. We pay our respects to them and their cultures; and to their Elders past, present and future.

Australian Competition and Consumer Commission

23 Marcus Clarke Street, Canberra, Australian Capital Territory, 2601

ACCC June 2023

www.accc.gov.au

Contents

Acronyms

ACQ	Annual contract quantity
ADQ	Average daily quantity
C&I	commercial and industrial
CPI	Consumer Price Index
CSG	coal seam gas
DWGM	Declared Wholesale Gas Market
EOI	Expression of interest
GPG	gas powered generation/generator
GSA	gas supply agreement
GSOO	Gas Statement of Opportunities
JKM	Japan Korea Marker
LNG	liquefied natural gas
NGL	National Gas Law
NGR	National Gas Rules
SPAs	sale and purchase agreements
Organisation	
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIE	Australian Industrial Energy
APPEA	Australian Petroleum Production and Exploration Association
COAG	Council of Australian Governments (cessation in May 2020)
GBJV	Gippsland Basin Joint Venture

ICE	Intercontinental Exchange
RBA	Reserve Bank of Australia
Pipelines	
AGP	Amadeus Gas Pipeline
CGP	Carpentaria Gas Pipeline
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
PCA	Port Campbell to Adelaide Pipeline
QGP	Queensland Gas Pipeline
RBP	Roma to Brisbane Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
VTS	Victorian Transmission System
LNG plant	
GLNG	Gladstone LNG
APLNG	Asia Pacific LNG
QGC	Queensland Curtis LNG
Units	
MMBtu	Million British Thermal Units–see Glossary, Units of Energy
GJ	Gigajoule
PJ	Petajoule
TJ	Terajoule

Interim report findings

Overall surplus in 2024

- Overall east coast gas supply should be sufficient to meet forecast demand in 2024
- Based on anticipated production and exports, the surplus could be as large as 90 PJ

Elevated international oil and LNG prices

- Conditions in global markets improved but prices remain above their long-term averages
- International oil and gas prices fell from their record high peak in mid-2022, with average JKM and Brent Crude at USD$10.08/MMBtu and USD$75.52/barrel respectively as of 22 May 2023

Southern supply shortfall

- Forecast shortfall in southern states over 2024, but surplus in Queensland
- Storage and transport capacity required to transport gas from Queensland to the southern states appears sufficient, but there is limited uncontracted southern haul pipeline capacity

Demand uncertainty

- The supply demand outlook is dependent on significantly reduced GPG demand materialising and moderate weather conditions over 2023

Policy reform

- Unless exempt, $12/GJ Emergency Price Cap Order, introduced on 23 December 2022, applies to new contracts for 2023 supply
- A Mandatory Code of Conduct is expected to be implemented in June 2023 and is intended to address imbalances in bargaining power between producers and gas buyers
- The Code is expected to include a price requirement of $12/GJ, subject to exemptions, from 23 December 2023, after the expiration of the Emergency Price Cap Order

Fewer gas supply contracts

- Gas prices offered for 2023 and 2024 supply have fallen from their peak in 2022
- Overall levels of contracting have fallen significantly
- Lack of contracting may be influenced by market pariticipants' preference for holding off on contracting in response to the uncertainty of further regulatory changes

2023 prices

- Average prices payable for 2023 supply increased in a peak of $12.3/GJ for producers and $27.1/GJ for retailers in the period between September and December 2022
- The Emergency Price Cap Order applies only to contracts entered into between 23 December 2022 and 22 December 2023 for 2023 supply

2024 prices

- Most producer offers made after implementation of the Emergency Price Cap Order for 2024 were slightly above $12/GJ. These offers are not subject to the $12/GJ Emergency Price Cap Order
- Since the introduction of the Emergency Price Cap Order, retailer offers have decreased to around $20/GJ

Gas users face worsening market conditions

- Some gas users reported a reduction in prices following the introduction of the Emergency Price Cap Order up until April. However, some market participants have observed an uptick in prices in May.
- Some gas users have also reported fewer offers for supply in the 2023–25 period
- Gas users are facing worsening market conditions as they continue to report a deterioration in non-price terms such as contract flexibility and have expressed concerns about retail prices

Overview

This is the June 2023 interim report of the Australian Competition and Consumer Commission's (ACCC's) inquiry into gas supply in Australia (the Inquiry). It reports on the east coast domestic supply and price outlook and related matters including the experiences of commercial and industrial (C&I) users, and transportation and storage.

Recent policy reforms

When the Gas Inquiry January 2023 interim report was released, the Prime Minister had recently announced a suite of measures which were intended to reduce the economic impact of the global energy shock in Australia. These measures include:

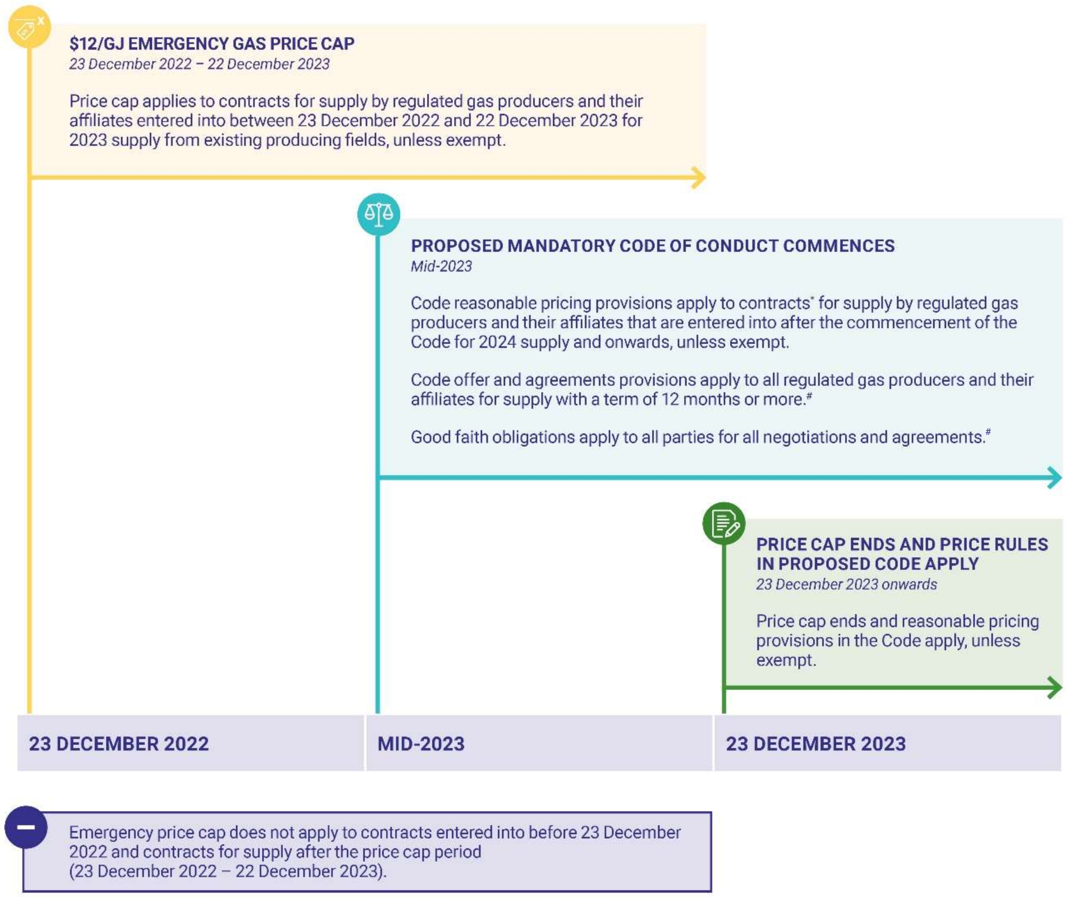
- An emergency, 12-month price cap of $12/GJ (the *Competition and Consumer (Gas Market Emergency price) Order 2022* (the price cap)). The price cap applies to offers and new contracts that provide for supply during the price cap period (23 December 2022–22 December 2023) from a field with an existing production licence in the east coast and Northern Territory by a non-exempt[1] producer or affiliate over the price cap period.
- The development of a mandatory code of conduct for the wholesale gas market (code) under Part IVBB of the *Competition and Consumer Act 2010* (CCA), which is expected to be implemented in mid-2023. The code includes conduct, price and transparency provisions, which are intended to:
  - improve selling practices and level the negotiating playing field between users and producers to deliver a better functioning and more transparent gas market
  - ensure sufficient supply of gas for east coast users at reasonable prices, and
  - give producers the certainty they need to invest in supply; and ensure Australia remains a reliable trading partner by allowing LNG producers to meet their export commitments.

The ACCC is responsible for monitoring and enforcing compliance with the price cap and has also been delegated a power by the Minister to grant exemptions. The ACCC will also be responsible for monitoring and enforcing compliance with the code and supporting Ministerial exemption decisions. These new functions and powers are in addition to the ACCC's existing functions and powers under the CCA, and its inquiry function under Part VII of the CCA.

The illustration below provides a high-level overview of these reforms. It does not capture all the exemptions, transitional and other arrangements provided by the price cap and the code.

[1] The Minister delegated the power to grant exemptions from the price cap Order to the ACCC. The ACCC can only grant an exemption from the Order when it is satisfied that it is appropriate, having regard to the matters mentioned in the Order.

Timeline of policy reforms



* Includes agreements entered into before the commencement of the Code but varied after that where the variation determines price.

\# This depends on when negotiations commenced.

There should be sufficient gas at an east coast level to meet forecast demand in 2024

There is forecast to be sufficient gas to meet 2024 demand in the east coast gas market. This is based on the information provided to us by producers in response to our compulsory information gathering powers and the Australian Energy Market Operator's (AEMO's) domestic demand forecasts.

The volumes of surplus gas will depend on how much is exported as LNG in 2024. Based on information reported by the LNG producers there will be between:

- a 27 PJ surplus in 2024 if LNG producers export all of their currently uncontracted gas, and
- a 90 PJ surplus in 2024 if the LNG producers export only the spot sales that are currently anticipated.

The forecast is also impacted by the demand outlook which remains uncertain. AEMO has forecast record low levels of domestic gas demand in 2024, 46 PJ lower in 2024 than in 2023. This is due primarily to reductions in demand for GPG. This is critically dependent on weather and electricity market conditions where deviations could lead to either increased or decreased GPG demand.

In our previous report, we forecast an additional 3 PJ of gas would be needed from LNG producers in Queensland to avert a potential shortfall in 2023. The current outlook for 2024 will see a significant improvement as there is expected to be sufficient gas to meet demand. This improvement can largely be attributed to the reduction in demand.

To avoid a shortfall in southern states significant volumes of gas will need to flow south in 2024

The southern states are expected to experience a 44 PJ shortfall in 2024 notwithstanding the overall surplus at the east coast level. This is due to declining gas reserves in the south and high levels of residential gas demand during winter.

In contrast, Queensland is expected to have surplus gas supply in 2024, with the surplus ranging from 71 PJ to 135 PJ, depending on whether LNG producers export all their uncontracted gas or just their anticipated LNG spot sales.

As highlighted above, variability in weather conditions impacting GPG demand, or unpredicted reductions in supply could impact the outlook for the southern states. As such, it is imperative to ensure a flow of gas from Queensland to the southern states via pipeline transportation, as well as adequate storage capacity. While there appears to be sufficient transportation capacity to transport the required volumes of gas south, there is limited uncontracted capacity.

Shortfalls are expected over the winter months in 2023 and 2024

There is forecast to be a shortfall of 14 PJ in quarter 3 of 2023 unless LNG producers commit additional gas to the domestic market via sales or swap contracts, an increase of 3 PJ from our March 2023 interim report. Quarter 4 of 2023, on the other hand, is unlikely to face a shortfall even if all uncontracted gas is exported as spot or additional LNG sales.

In the winter quarters of 2024, while an overall surplus is forecast for 2024, supply shortfalls are possible if the LNG producers export all of their uncontracted gas.

There are also growing concerns that the demand for GPG is shifting from summer to winter and so there will be coincidental peaks between residential and gas generation demand, particularly in the southern states. This is being driven by the changing role that GPG is expected to play in the electricity market, with GPG providing services to support renewable energy generation (the need for which is greater in winter), and to fill the gap that is being left by an ageing coal generation fleet.

Over recent years, LNG producers have committed additional gas to the domestic market to avoid predicted shortfalls. The volume of exports by LNG producers remain a big contributor to the forecast shortfall, despite the ability to mitigate the shortfall through gas swaps across the year and appropriate withdrawals of gas from storage.

Effective regulatory levers are imperative to bolster producer incentives to supply gas domestically during these times, including the updated Heads of Agreement (HoA), the new Australian Domestic Gas Security Mechanism (ADGSM) and the code.

Prices offered and agreed to in 2022 for 2023 supply remained high

Prices offered for 2023 supply on the east coast remained high through most of 2022, before the introduction of the price cap on 23 December 2022.

Prices reached a peak in August 2022 where producer offers reached over $70/GJ in line with LNG netback prices. This reflected the particularly tight international market at that time. During this peak period, retailer offers tracked below producer offers at around $30/GJ.

There was a marked decrease in November 2022 where producer offer prices fell to around $20/GJ. Short-term LNG netback prices also moderated from its peaks to just under $40/GJ. Retail offers remained around $30/GJ.

Volume-weighted average prices payable under gas supply agreements (GSAs) executed by producers and retailers for supply in 2023 increased over the reporting periods from September 2021. While producer GSAs agreed to between September and December 2022 increased only marginally (3%) from the previous period (March to August 2022), retailer GSAs increased significantly (41%) over the same time period.

Increases in short-term contracts for 2023 delivery

Since the introduction of the price cap we have observed an increase in the volume of gas sold under short-term Gas Supply Agreements and traded on facilitated markets. Most gas sold by producers under contracts has been below $12/GJ, however we have observed some contracts with prices that appear to be in excess of $12/GJ. The ACCC is continuing to monitor transactions and is collecting contracting data.

There has been a reduction in offers for supply in 2024 and prices are high

There was a reduction in offers for supply in 2024. Producers and retailers made fewer offers in 2022 for 2024 supply than in 2021 for 2023 supply. Similarly, contracting for 2024 slowed down considerably compared to previous years. Only 7 GSAs were executed between September 2022 and February 2023 for supply in 2024, representing a 46% decrease from January to August 2022 and a 22% decrease from September 2021 to February 2022.

For 2024 supply the majority of producer and retailer offers tracked between the medium-term oil-linked netback price and the short-term JKM netback price. Retailer prices are typically higher than producer prices reflecting different cost structures. However, LNG producer offers, linked to short-term LNG netback prices, for 2024 supply were higher than contemporaneous retailer and non-LNG producer offers.

Prices offered by producers for 2024 supply peaked at just under $50/GJ in August 2022 , before falling to around $12/GJ at the end of 2022. Retailer offers trended upwards in the first half of 2022 and remained high for 2022 (just under $30/GJ), before slowly trending down in the early part of 2023 to around $20/GJ.

Prices agreed under producer GSAs between September 2022 and February 2023 for 2024 supply averaged $16.2/GJ, a 30% increase from the previous period. The increase in retailer GSA prices was almost double this increase, at 67.6% over the same period, averaging $21.3/GJ.

Since the introduction of the price cap on 23 December 2022, most producer offers for 2024 supply settled at over $12/GJ. The $12/GJ price cap applies for 12 months from 23 December 2022 with no price provisions under the code applying to supply in 2024 in the contract periods considered.

Despite falling prices, C&I users continue to report deteriorated selling practices

A number of C&I users reported that prices offered for firm GSAs fell following the implementation of the price cap in December 2022. Prices quoted for supply in 2023-24 fell from around $65/GJ prior to the price cap, to around $19/GJ in April 2023.

Consistent with the observations above, C&I users received fewer offers for supply in the 2023-25 period, with some stating that they have not received any offers at all. Several C&I users suggested that suppliers may be withholding or delaying making offers for 2024 supply until there is greater clarity around the operation of the code.

In addition to fewer offers for supply, users have reported a deterioration in contract flexibility and selling practices since the ACCC's last survey in August 2022, with a number noting that suppliers are less willing to negotiate on non-price terms such as contract length, take-or-pay provisions and delivery points.

These experiences underscore the importance of the code, which is intended to improve selling practices and level the negotiating playing field through various conduct provisions, including a requirement for producers and buyers to negotiate in good faith.

Future work of the Inquiry

We expect to publish the next update to the supply-demand outlook in September 2023 and our next full interim report in December 2023. The December interim report will provide an update on the supply-demand outlook for 2024, the domestic price outlook for 2024 supply, and material transportation and storage prices, and C&I user experiences. It will also include an assessment of the longer-term supply-demand outlook and potential supply and infrastructure developments.

We will also continue to publish the LNG netback price series and make information available and policy recommendations as appropriate and necessary.

The ACCC is expected to take up new functions under the code in mid-2023. As noted above, these new functions include monitoring and enforcing compliance with the code and providing advice on exemptions. We intend to report on our work in this area and continue to assist the Minister for Resources with monitoring and reporting on LNG producer's compliance with the updated HoA.

In addition, the ACCC will monitor retailer behaviour and has commenced a review into retailer pricing. This review will consider, among other things, the impact of the code of conduct on prices faced by gas users. The ACCC will report on findings in our upcoming reports and advice will be provided to Government where issues are apparent.

1. Supply and demand

Key points

Supply and demand outlook for the remainder of 2023

- On 3 April 2023, the Minister for Resources announced that she would not trigger the newly reformed ADGSM for the upcoming quarter 3 of 2023.
- This decision was informed by the ACCC's March 2023 report which noted there was expected to be sufficient supply to meet forecast demand supply in the third quarter if the LNG producers commit 11 PJ of uncontacted gas to the domestic market in addition to their existing commitments. While this needed supply could come from the Queensland LNG producers, there was expected to be 18 PJ of surplus supply in quarter 4 of 2023, which could be brought forward to resolve a supply shortfall.
- Based on the latest information from gas producers, the supply situation has tightened slightly for the remainder of 2023. The anticipated supply shortfall in quarter 3 has increased to 14 PJ, and the expected surplus in quarter 4 has reduced to 14 PJ.
- This tightening of the outlook is primarily due to reductions in forecast supply and increased volumes of contracted exports. However, we note that LNG producers have also contracted an additional 9 PJ of gas to domestic buyers.

Supply and demand outlook for 2024

- The east coast gas market is likely to have sufficient supply to meet forecast demand in 2024, with information provided by gas producers indicating that supply may be up to 90 PJ higher than demand projections:
  - If the LNG producers export all of their currently uncontracted gas, supply is expected to be 27 PJ higher than demand.
  - If the LNG producers export only the spot sales that are currently anticipated, gas supply is expected to be 90 PJ higher than demand.
- This is a significant improvement on what is expected in 2023. However, policy reforms are being finalised at the time of writing this report. As such our report is based on supply and demand forecasts currently available and there may be further changes to the supply outlook throughout the year.
- The overall improvement in the outlook for 2024 can largely be attributed to a reduction in forecast gas powered generation (GPG) demand, which AEMO is projecting will occur as substantial new renewable energy generation projects enter the market in 2024. However, it is important to note that delays in the installation of new generation, outages in the electricity market and/or variations in anticipated weather conditions could potentially lead to a tighter outlook.
- While there is likely to be sufficient supply across the east coast, there is seasonable variability in gas demand. In the southern states in particular, colder winters and higher heating demands mean that supply is expected to be insufficient to meet demand. This will need to be made up with gas in storage or transported from Queensland. Additional gas placed into storage may need to transported from Queensland in the summer periods to avoid congesting pipelines in the winter.

1.1. Introduction

This chapter outlines the supply and demand outlook for 2024 for the east coast market as a whole and two regions within it: Queensland and the southern states.

In this report, we consider whether there is likely to be sufficient gas to meet forecast demand in the east coast market in 2024. This considers:

- **total forecast supply of gas on the east coast**, including net withdrawals from storage and expected gas flows from the Northern Territory into Queensland, and
- **total forecast demand**, including domestic demand and the quantities of gas required by the Liquified Natural Gas (LNG) producers to meet their long-term LNG Sale and Purchase Agreement (SPA) commitments and LNG spot sales.

The east coast LNG producers (APLNG, GLNG and QGC)[2] sell their gas to international LNG buyers, but are also a major source of supply in the east coast market. We report the difference between their incomings (their gas production and contracted purchases from other domestic producers) and outgoings (their contracted sales to the domestic market and to international LNG buyers) as their uncontracted gas. These uncontracted quantities of gas could be:

- sold to the domestic market, including through flexibility arrangements within existing contracts with domestic customers
- sold as LNG spot cargoes on the international market
- sold as additional volumes to long-term SPA customers, including through customers' ability to call on additional volumes above minimum take-or-pay volumes
- placed or sold into gas storage facilities
- sold to other producers, including as part of swap arrangements.[3]

The volumes of gas potentially sold as spot or additional cargoes are subject to Heads of Agreement requirements. These require that uncontracted gas is first offered with reasonable notice on competitive market terms to the Australian domestic market before being offered to the international market as LNG spot cargoes.

While this uncontracted gas must be offered to the domestic market, LNG producers have historically exported most of this gas as spot LNG sales or additional LNG sales.[4] It is for this reason that we report uncontracted gas as potential demand in our supply-demand outlook – it represents a quantity of gas that could be, and historically mostly has been, exported as additional or spot LNG sales.

Data collected for the 2024 outlook has occurred during a rapidly changing policy environment, and forecasts collected by the ACCC from gas producers may change to account for this. Future updates to the 2024 outlook will help the ACCC assess the impact of these interventions on expected gas production.

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2 Throughout this report, any reference to the LNG producers refers only to these three LNG producers in Queensland.

3 In this report, when we refer to uncontracted gas, we refer to an aggregated quantity calculated using the sum of inputs and outputs for each of the LNG producers. However, the amount of uncontracted gas individual producers may consider themselves to have varies for each of the LNG producers and may vary from our calculations for them individually. The amounts may vary due to, for example, swaps, customer flexibility, or buffers to account for contingencies.

4 ACCC Gas Inquiry July 2022 Interim Report Section 1.5.

Further information on actual gas supply and demand in 2022 can be found in **Appendix A.**

Sources of supply and demand data

Our supply and demand forecast is based on data obtained from east coast gas producers and the AEMO.

Supply data reflects east coast gas producers' forecasts of production from 2P (probable) developed and undeveloped reserves, net withdrawals from storage, and flows from the Northern Territory. This is based on information obtained directly from producers in response to compulsory information gathering notices issued in February and April 2023.

Demand data is based on:

- LNG producers' forecasts of gas that will be exported under long-term LNG Sale and Purchase Agreements (SPAs) with international buyers. We include volumes of LNG SPA demand based on 'expected commitments' under take-or-pay requirements in long term LNG supply contracts, which typically reflect minimum annual contracted quantities required under these long-term contracts.
- LNG producers' forecasts of gas that will be exported as spot or additional LNG cargoes. These are committed and anticipated (2023) and anticipated (2024) figures. The majority of spot and additional LNG cargoes in 2023 are committed.
- LNG producers' uncontracted gas, with further information on this figure provided by LNG producers' forecasts of gas that they anticipate exporting as LNG spot cargoes or additional LNG sales, in addition to their expected sales under SPAs.
- Forecasts of domestic gas demand obtained from AEMO, included in its March 2023 Gas Statement of Opportunities (GSOO) report.

AEMO annually produces 20-year forecasts for domestic gas demand for their GSOO. Forecasts are broken down by the source of demand, including residential and commercial demand, industrial demand, and gas power generation (GPG) demand. In this report, we have used AEMO's forecast of domestic gas under the 'Orchestrated Step Change' scenario from the 2023 GSOO. AEMO's 2023 GSOO states that this "scenario reflects observed trends impacting residential, commercial and industrial consumption and the likely near-term continuation of these trends". For further discussion on our choice of demand scenario from AEMO's 2023 GSOO, please see the ACCC's March 2023 Gas Inquiry interim report.

Demand forecasts that are more aimed at a short term outlook may become available (including by AEMO) and we will continue to consider what source of demand forecast information we will use in the future.

These information sources reflect a forecast of supply and demand at a point in time. There is an element of forecasting risk and actual supply or demand may differ. However, these reflect the best available estimates of the outlook for the east coast market in 2024.

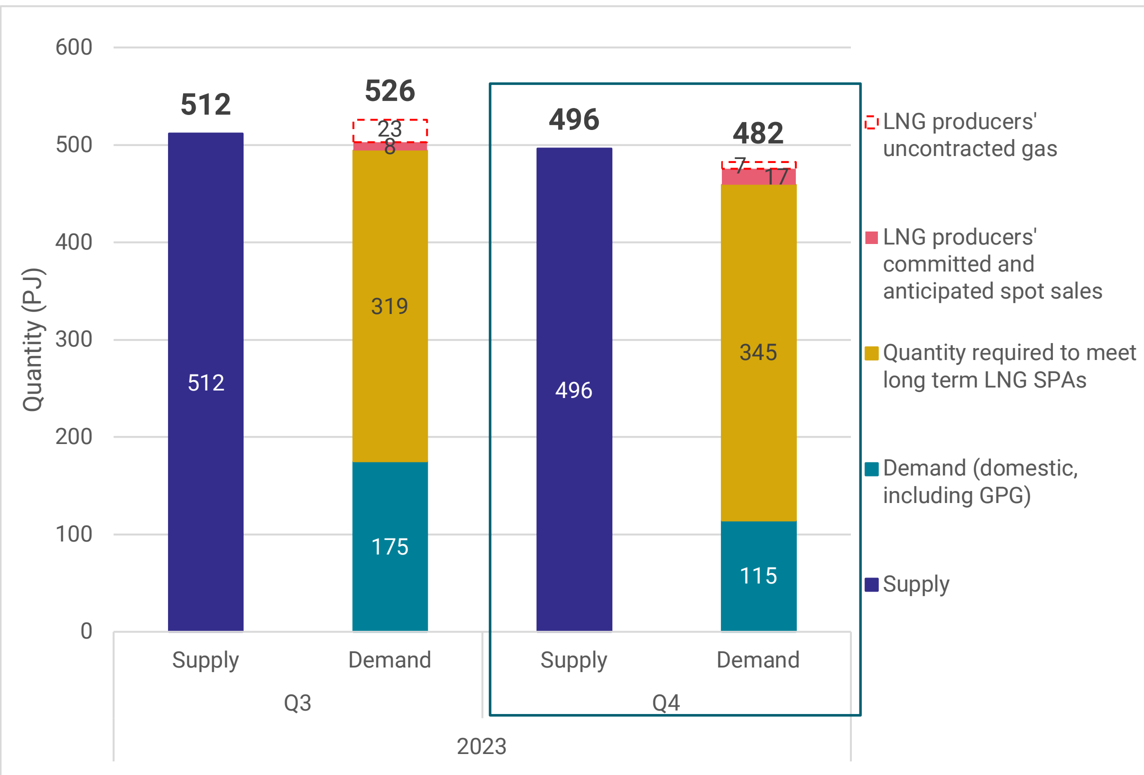
1.2. East coast supply and demand outlook for the remainder of 2023

This section examines the supply-demand outlook for the second half of the 2023 calendar year, with a particular focus on quarter 4 of 2023. This includes updated forecasts for the remainder of 2023 that the ACCC previously published in March 2023.

This quarterly outlook provides insights into the expected availability of gas throughout the year to meet forecast demand, including identifying whether there are specific seasons that are at risk of material supply shortfalls. This outlook provides information relevant to the Government in assessing whether there is likely to be a supply shortfall for the purposes of the ADGSM. [5] Under this mechanism, the Minister for Resources will make assessments on whether there is likely to be a shortfall of gas for domestic buyers in each quarter of the year.

Chart 1.1 shows the quarterly supply-demand outlooks for quarter 3 and quarter 4 of 2023. Note that these charts for 2023 show committed and anticipated spot LNG sales, with the majority of cargoes in 2023 being committed.

Chart 1.1: Quarterly Supply-Demand Outlooks for Q3 and Q4 2023 (PJ)



Source: ACCC analysis of data obtained from gas producers in April 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO's 2023 GSOO. As the upcoming ADGSM assessment quarter 4 has been highlighted. Note: Totals have been rounded.

5 Customs (Prohibited Exports) (Operation of the Australian Domestic Gas Security Mechanism) Guidelines 2023.

Our March 2023 interim report found that the seasonal outlook for 2023 was mixed, with 11 PJ of gas needed over currently contracted levels to ensure there is sufficient supply to meet demand in quarter 3 of 2023, but a surplus of 18 PJ in quarter 4.

Chart 1.1 shows that the seasonal outlook for 2023 remains mixed. A **2023 quarter 3 winter shortfall of 14 PJ is currently forecast** if the LNG producers export all of their uncontracted gas. This is an increase of 3 PJ on the previous forecast shortfall and is due to several factors including:

- a 9 PJ reduction in supply
- a 3 PJ increase in committed long term LNG SPAs
- a 10 PJ decrease in uncontracted gas.

The forecast shortfall can be prevented if the LNG producers export only their anticipated sales, withdraw gas from storage or engage in gas swaps.

Several risk factors may result in higher gas demand or lower gas supply over winter 2023. Declining gas production in the southern states means that winter demand will be reliant on gas from Queensland or from storage in Victoria. In addition, there is the potential for severe weather events and the risks of sudden unplanned outages of coal-fired power stations or unexpected restrictions on gas production.[6] All of these factors could deteriorate conditions across the east coast gas market.

However, AEMO has reported that overall, the energy market has lower risks for winter 2023 compared to winter 2022 which faced significant seasonable shortfalls (as explained in Appendix A). Reduced risks are a result of forecasts of warmer temperatures and less rainfall, higher than average winter gas storage levels, improved coal availability and new dispatchable generation capacity in the NEM.[7] These factors may contribute to lower demand from residential and commercial users of gas as well as for GPG.

Quarter 4 of 2023 is forecast to remain in surplus even if the LNG producers export all of their uncontracted gas. The surplus is forecast to be 14 PJ which is a reduction of 3 PJ on the previous forecast. This reduction in surplus is due to a number of factors including:

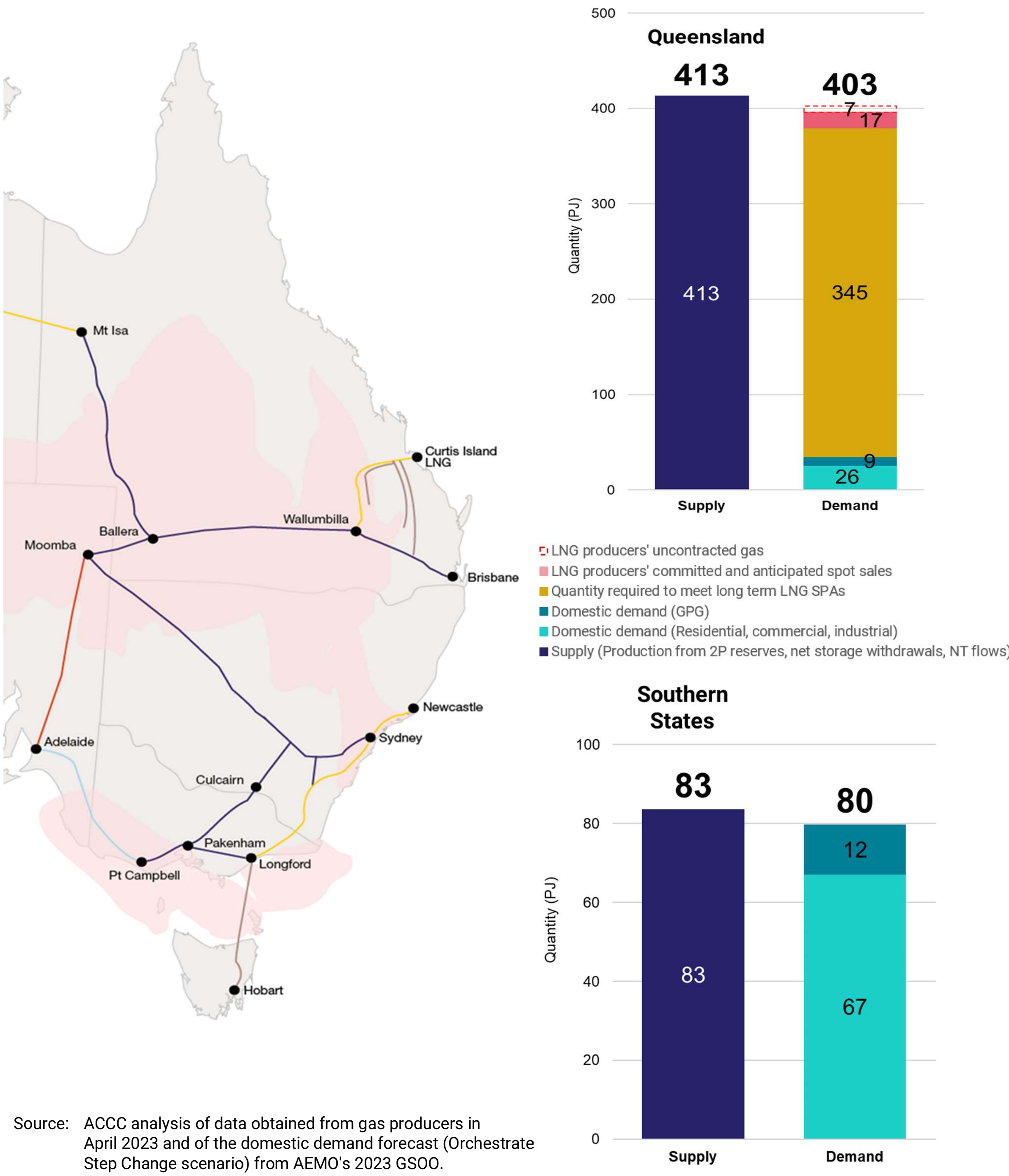
- a 13 PJ reduction in supply
- a 1 PJ decrease in committed long term LNG SPAs
- a 6 PJ increase in contracted and anticipated spot LNG sales
- a 13 PJ decrease in uncontracted gas.

Chart 1.2 shows the regional supply and demand outlook for quarter 4 of 2023. This shows that there is expected to be sufficient gas supply to meet demand in both Queensland and the southern states, even if LNG producers export all their uncontracted gas. However, we noted, it may be necessary for some of this gas to be brought forward in 2023 (e.g. through time swaps) to avert winter shortfalls.

6 AEMO, 'AEMO forecasts improved winter 2023 for Australia's energy system, risks remain', 1 June 2023, accessed 2 June 2023. See Appendix A for discussion on the declining production of gas in Longford.

7 AEMO, 'AEMO forecasts improved winter 2023 for Australia's energy system, risks remain', 1 June 2023, accessed 2 June 2023.

Chart 1.2: Regional supply outlooks in quarter 4 of 2023 (PJ)



Source: ACCC analysis of data obtained from gas producers in April 2023 and of the domestic demand forecast (Orchestrate Step Change scenario) from AEMO's 2023 GSOO.

Note: Totals may not sum due to rounding

Table 1.1 shows the forecast supply and demand breakdown for the LNG producers in the remaining quarters of 2023. Since our March 2023 report, the LNG producers have contracted for additional domestic supply and additional LNG spot or additional sales. This has reduced the remaining uncontracted gas available in both quarter 3 and 4.

Table 1.1: LNG producers' supply-demand outlook in 2023

	2023	
	Q3	Q4
Supply		
Production from 2P reserves and net storage withdrawals	357	361
3rd party purchases from suppliers other than LNG projects	44	47
Total supply available to LNG producers	401	408
Demand		
Quantity required to meet domestic GSAs	50	41
Quantity required to meet LNG SPAs	319	345
Committed and anticipated LNG spot cargoes and additional sales	8	17
Total contracted demand	378	403
Uncontracted gas (total supply – total demand)	23	7

Source: ACCC analysis of data obtained from LNG producers as at January 2023. Note: Totals may not add up due to rounding. The quantity required to meet the contractual obligations under the long-SPAs includes the feed gas required to produce LNG (such as fuel).

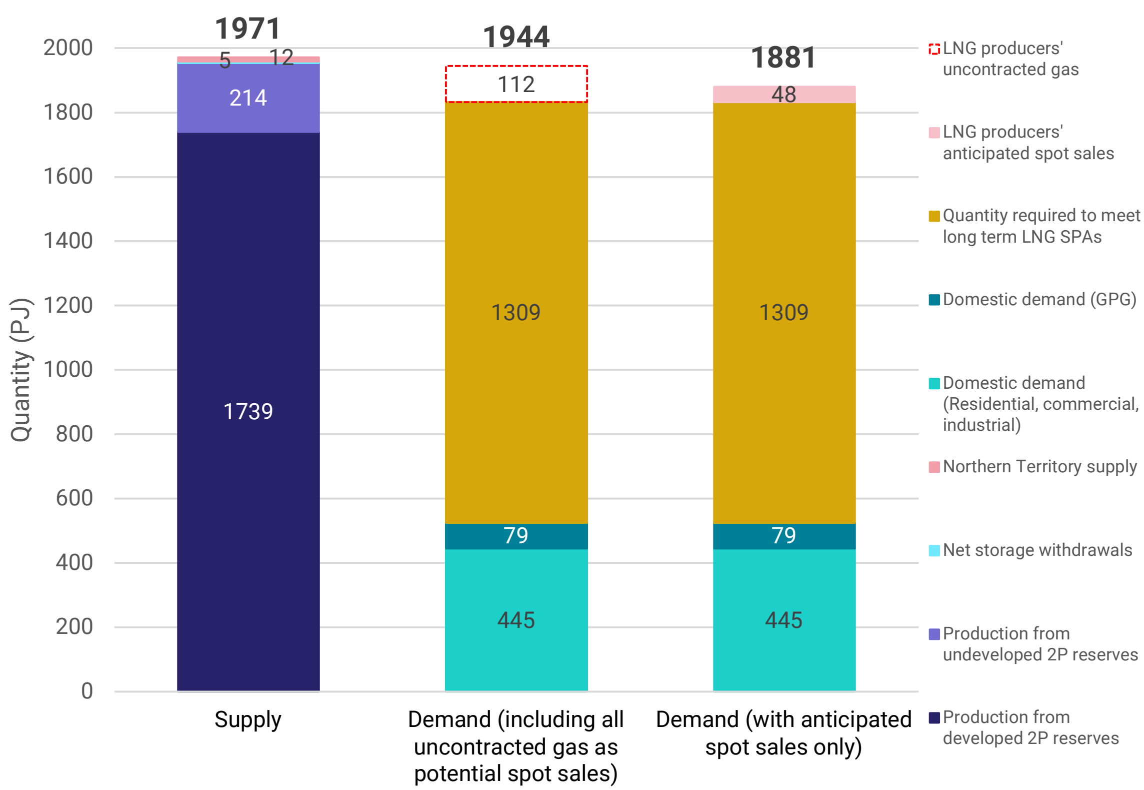
1.3. East coast supply-demand outlook for 2024

Chart 1.3 sets out the forecast supply-demand outlook in the east coast gas market for the 2024 supply year, based on the latest available information.

The east coast gas market is likely to have sufficient gas supply to meet forecast demand in 2024. There is forecast to be 27 PJ more gas produced, withdrawn from storage or flowed into the east coast gas market than forecast demand, even if the LNG producers export all of their uncontracted gas as spot or additional LNG cargoes.

If the LNG producers only export what they currently anticipate they will sell as LNG spot or additional sales, then there will be 90 PJ of gas available to the east coast market. The LNG producers' anticipated spot sales for 2024 are less than what has been exported in recent years.[8] However, we note that recent policy reforms — including those being finalised at the same time as this report — could change the volumes LNG producers sell to the domestic market. This includes the code and ADGSM.

Chart 1.3: Forecast east coast supply-demand balance in 2024 (PJ)



Source: ACCC analysis of data obtained from gas producers in February 2023 and the domestic demand forecast (Orchestrated Step Change scenario) from AEMO's 2023 GSOO. Note: Totals have been rounded.

Chart 1.4 sets out the forecast supply-demand outlook in the east coast gas market for each quarter of the calendar year. This quarterly outlook provides insights into the expected

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8 The LNG producers have exported LNG spot cargoes coming to 114 PJ in 2020, 75 PJ in 2021 and 86 PJ in 2022. They also exported additional LNG SPA sales in 2020 and 2021.

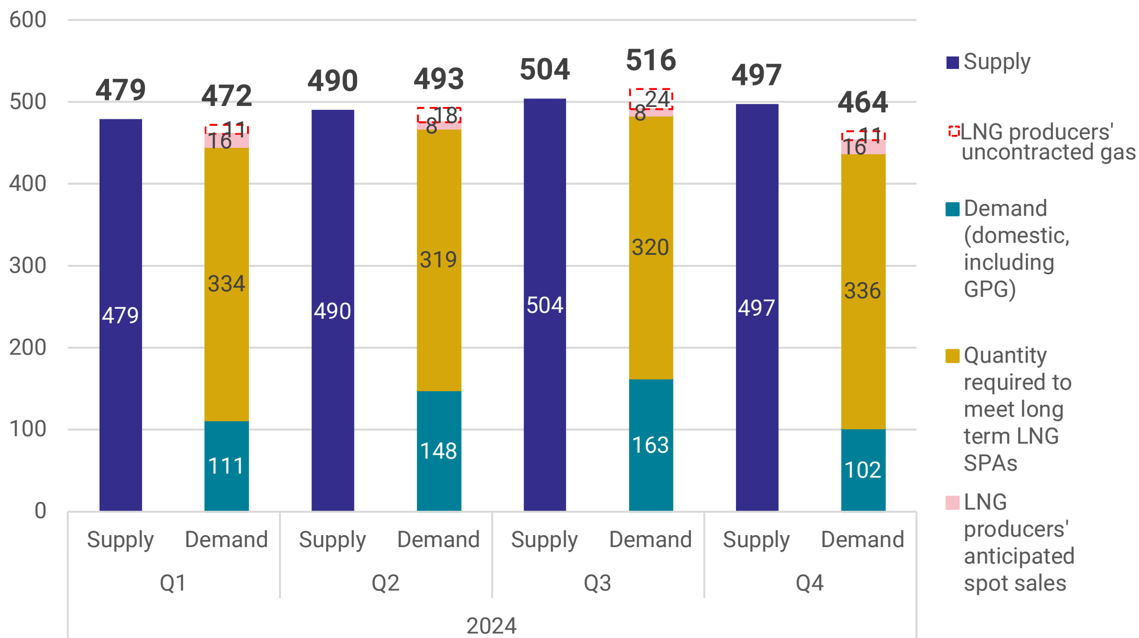
availability of gas throughout the year to meet forecast demand, including identifying whether there are specific seasons that are at risk of material supply shortfalls.

This chart shows that there is expected to be sufficient gas supply to meet demand in quarters 1 and 4 of 2024. However, for quarters 2 and 3, there will be sufficient supply to meet demand only if:

- the LNG producers commit additional uncontracted gas to the domestic market
- and/or producers bring forward supply (including through seasonal swaps).

Quarters 2 and 3 coincide with an increase in residential and GPG demand during the winter season, which is posing a risk to supply adequacy in both the gas and electricity markets.

Chart 1.4: Quarterly Supply-Demand Outlooks for 2024 (PJ)



Source: ACCC analysis of data obtained from gas producers in March 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO's 2023 GSOO. Note: Totals have been rounded.

While we are currently forecasting the east coast gas market is likely to have enough gas to meet forecast demand in 2024, there is uncertainty for both supply and demand across the east coast market. In particular:

- GPG demand could be higher than forecast if weather conditions differ from what is expected and/or there are generator outages. Delays to new renewable generation could also cause increase GPG demand. LNG demand could also be higher than forecast depending on international conditions. Conversely, these sources of demand could be lower than expected.
- Gas supply could fall short of the volumes forecast by producers due to production issues, investment choices or other factors, and flows from the Northern Territory could also be lower than forecast, as occurred in 2022. Conversely, supply could be higher than producers' forecast.
- The implementation of the code and changes to the ADGSM may affect the volume of gas supplied into the domestic market. For example, supply commitments made as part of the code could increase supply to the domestic market.

There has been an improvement in the outlook compared to 2023

The most recent forecast for 2023 anticipated a 3PJ shortfall if all uncontracted gas is exported. The current 2024 forecast anticipates a surplus of 27PJ, representing an improvement of 30 PJ. This variation is due in large part to a forecast reduction in demand.

Supply is estimated to fall from 2023 to 2024, with an increase in production from currently 2P undeveloped reserves (+112 PJ) not sufficiently covering the decline of production from 2P developed reserves (-133 PJ).

At a basin level, forecast production is down 49 PJ in the Gippsland basin, but up 16 PJ in Queensland and 16 PJ in the Otway basin. As the established basins in Victoria come to the end of their productive life, decreases or unexpected increases in production may become more common. Overall, accounting for all factors (such as flows from the NT and net withdrawals from storage) supply is down 24 PJ in 2024 compared to our latest 2023 forecast.[9]

The reduction in supply is expected to be more than offset by reduced demand for gas. Demand is forecast to reduce by 56 PJ between 2023 and 2024. This reduction is primarily due to AEMO projecting a 44 PJ reduction in GPG requirements. As noted further in this report, while this is a positive development for the demand-supply outlook, it is important to recognise that GPG demand is dependent on prevailing weather and conditions in the electricity market, making it difficult to forecast.

In addition to the forecast reduction in GPG demand, residential, commercial, and industrial demand is forecast to drop slightly by 2 PJ year on year. Such reductions are due to forecast assumptions around electrification, particularly for residential and commercial gas users. Non-GPG domestic consumption of gas is generally less volatile than demand for GPG and is not expected to fluctuate significantly.[10]

While there has been an increase in forecast demand under LNG SPAs (15 PJ), this has been more than offset by reduced total uncontracted gas, including committed spot and anticipated spot sales (24 PJ).

While supply appears to be sufficient, data from suppliers and feedback from gas users indicates there have been fewer offers for firm supply in 2024 (see Section 2.3.1 for further information).

1.3.1. The impact of the electricity market on the 2024 supply and demand for gas

The primary reason for the improvement in the forecast outlook for 2024 compared to 2023 is AEMO estimating a decrease in forecast demand for GPG. This decrease is driven by several renewable generation projects coming online, which is forecast to reduce gas usage in the National Electricity Market (NEM).

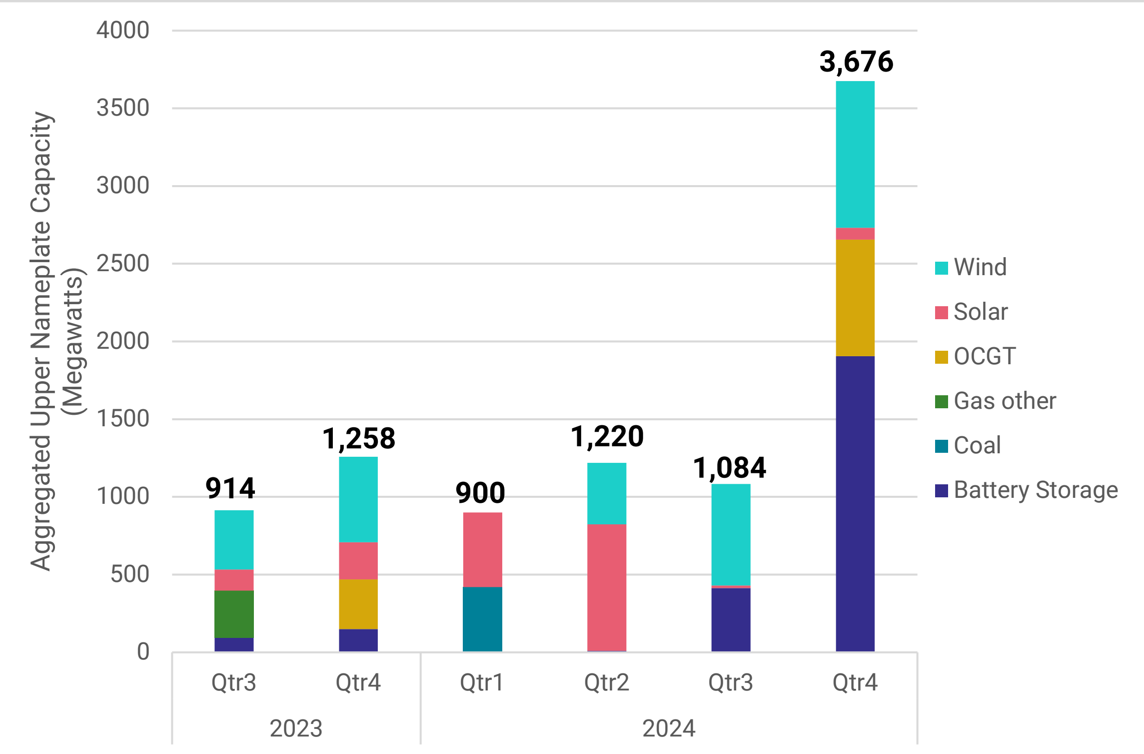
9 ACCC, Gas inquiry March 2023 interim report, March 2023.

10 Based on the Orchestrated Step Change Scenario from AEMO, Gas Statement of Opportunities, March 2023.

Renewable energy capacity installations in 2023 and 2024

Chart 1.5 shows the aggregated upper nameplate capacity of new generation[11] entering the NEM over the remainder of 2023 and all of 2024. This capacity is scheduled or expected only and may not eventuate. Using this measure, the vast majority (80%) of the new capacity entering into the market are renewables. Queensland and South Australia are the states expected to see the largest reductions in GPG demand due to several new sources of renewable energy entering the market.

Chart 1.5: Nameplate capacity entering the NEM Q3 2023 – Q4 2024



Source: ACCC analysis of AEMO, 'NEM Generation information publications', May 2023, accessed 13 June 2023.

Note: **This chart reports the upper nameplate capacity, not the actual expected generation.**

Each of these projects have their own risks. Chart 1.2 assumes that all projects are available for full commercial operation on expected dates. Delays to these projects may result in higher than forecast GPG demand. Additionally, only the aggregated upper nameplate capacity is reported here, and the ability of these projects to supply electricity will be less for intermittent sources of generation and vary based on a variety of factors including weather, infrastructure and outages.

However, GPG demand is difficult to forecast and sensitive to external events, including unanticipated coal plant closures, outages and weather. Historical events have shown demand lower than forecast (such as in 2018)[12] or higher than forecast (such as in 2017 and 2019–2022).[13] In recent years, issues impacting coal-fired power have generally led to underestimates of GPG demand.

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11 Nameplate capacity represents the maximum amount of electricity capable of being generated under ideal conditions.

12 Australian Energy Market Operator (AEMO), '2019 Gas Statement of Opportunities', accessed 19 April 2023. The installation of large-scale renewable energy capacity in the NEM saw decrease in GPG demand in 2018.

13 AEMO GSOO 2018, 2020, 2021, 2022. Key events leading to increased demand for GPG include the 2017 closure of Hazelwood Power Station and extended outage at Yallourn Power Station and Loy Yang A (continues next page…) (continuation of footnote 13) power stations; 2019 outages at Loy Yang A and Mortlake units and extended hot weather

AEMO's 2023 GSOO includes three short-term GPG sensitivities for the 2024 forecast:

- Dry year — the impact of drought conditions affecting rainfall inflows to hydro-electric schemes in the NEM, which will increase the demand for gas generation.
- Delayed Variable Renewable Energy — committed and anticipated renewable developments delay their full commissioning by one year.
- Improved coal availability — coal availability reserves recover to the level observed in 2019.

The impact of these sensitivities on GPG demand in 2024 is outlined in Table 1.2 below. It should be noted that it is possible for multiple events to occur at once, which could result in GPG demand increasing or decreasing depending on the degree and timing of events.

Table 1.2: Sensitivity scenarios for gas demand in 2024

Scenario	Annual consumption (PJ)	Change in demand (percentage)
Orchestrated Step Change Scenario	79	-
Weather Variability (Dry Year)	111	41%
Delayed Variable Renewable Energy	110	39%
Improved Coal Availability	50	-37%

Source: AEMO GSOO 2023

An emerging concern for GPG is that its winter peak is forecast to grow while its summer peak will trend flat according to AEMO. The growing coincidental peaks between residential heating demand in southern jurisdictions and GPG demand may create challenges, especially given GPG's role in firming capacity for variable renewable energy.

This is being driven by the changing role that GPG is expected to play in the electricity market. While increases in renewable energy generation is expected to reduce the annual demand for gas for electricity generation, GPG is expected to:

- provide firming services to support variable renewable energy generation, the need for which is greater in winter
- fill any gaps caused by the delayed development of new generation capacity (e.g. Snowy and Kurri Kurri have already been delayed)
- and also fill the gap left by an ageing coal generation fleet (e.g. some coal fired generators are also expected to permanently exit the NEM in the coming years, including Eraring Power Station which is scheduled to close in August 2025).[14]

and bushfires; 2020 coal outages affecting Tarong and Tarong North power stations and transmission outages affecting the Heywood interconnector; 2021 coal plant failures at Callide in Queensland and coal mine flooding at Yallourn in Victoria; and 2022 flooding across Australia and geopolitical turmoil resulted in high fuel costs. and supply chain issues, offset partially by a cooler than normal summer suppressing summer GPG demand.

[14] AEMO, 'Expected closure years', May 2023, accessed 1 June 2023.

The above factors create further risks for seasonal and peak day shortfalls. For instance, the Callide C Power Plant has been out of service since May 2021, with unit C3 recommencing operation in July 2021. However, unit C3 has faced other issues since the cooling tower collapse in October 2022. While Callide C was expected to be running in 2022, the return to service has since been delayed by several months.[15] AEMO's GSOO 2023 was estimated prior to this market update and as such did not factor in this delay which could potentially see an increase in GPG demand.

The above factors also pose a concern for seasonal and peak day shortfalls. AEMO's latest projections indicate that if extreme winter weather conditions in the southern jurisdictions coincide with a high need for GPG in the NEM then peak day supply shortfalls could arise, with gas supplied from storage potentially not enough to avert these shortfalls.

If these conditions do not eventuate in southern jurisdictions, AEMO predicts that peak day shortfalls could be narrowly averted. While in force, mechanisms such as the Gas Supply Guarantee can help to mitigate the risks to the market of a surge in GPG demand.[16] However, the demand-supply balance will remain very tight in winter (as shown in chart 1.2) and in the southern states (as shown in chart 1.4 below). In the face of falling gas production, there is a risk of production being unable to meet surges in demand at a given time.

1.3.2. Despite falling gas supply, some new supply is expected to come online in 2024

Total east coast gas production is forecast to decline between 2023 and 2024. This is led by the declining reserves in the Gippsland Basin, as well as some reduction in production from the LNG producers.

Despite the overall decrease in production and delays in some new projects, there are some new sources of supply expected to come online in 2024:

- Beach Energy's Enterprise project is expected to be completed by the middle of the 2024 financial year.[17]
- Senex's Atlas expansion may continue in 2024, however as at the time of reporting there has been a pause in investment.[18]
- Further construction as part of Arrow's Surat Gas Project is anticipated[19], however much of the increased production will not come online until 2025.[20]

Note that the above list is not intended to be comprehensive. Our end-of-year report for 2023 will investigate new options for supply in further detail, as has been the case in previous reports.[21]

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15 CS Energy 'UPDATED RETURN TO SERVICE DATES FOR CALLIDE C GENERATING UNITS', 30 May 2023, accessed 1 June 2023.

16 AEMO, 'Gas Supply Guarantee', accessed 19 April 2023.

17 Beach Energy, FY23 half year results, February 2023, accessed 21 April 2023.

18 Senex, 'Federal Government gas intervention puts $1 billion Atlas expansion in Queensland at risk', December 2022, accessed 21 April 2023; Senex, 'Senex calls on the Federal Government to re-think intervention plans to maintain gas investment for Australian businesses and homes', February 2022, accessed 21 April 2023.

19 Arrow Energy, 'Surat Gas Project', accessed 21 April, 2023.

20 ACCC, Gas Inquiry 2017-2030 interim report, January 2023, table 6.1.

21 ACCC, Gas Inquiry 2017-2030 interim report, January 2023, section 6.

We have also previously reported that a number of potential new sources of supply have been delayed in recent years. These include Port Kembla import terminal and Golden Beach (delayed until 2025).[22]

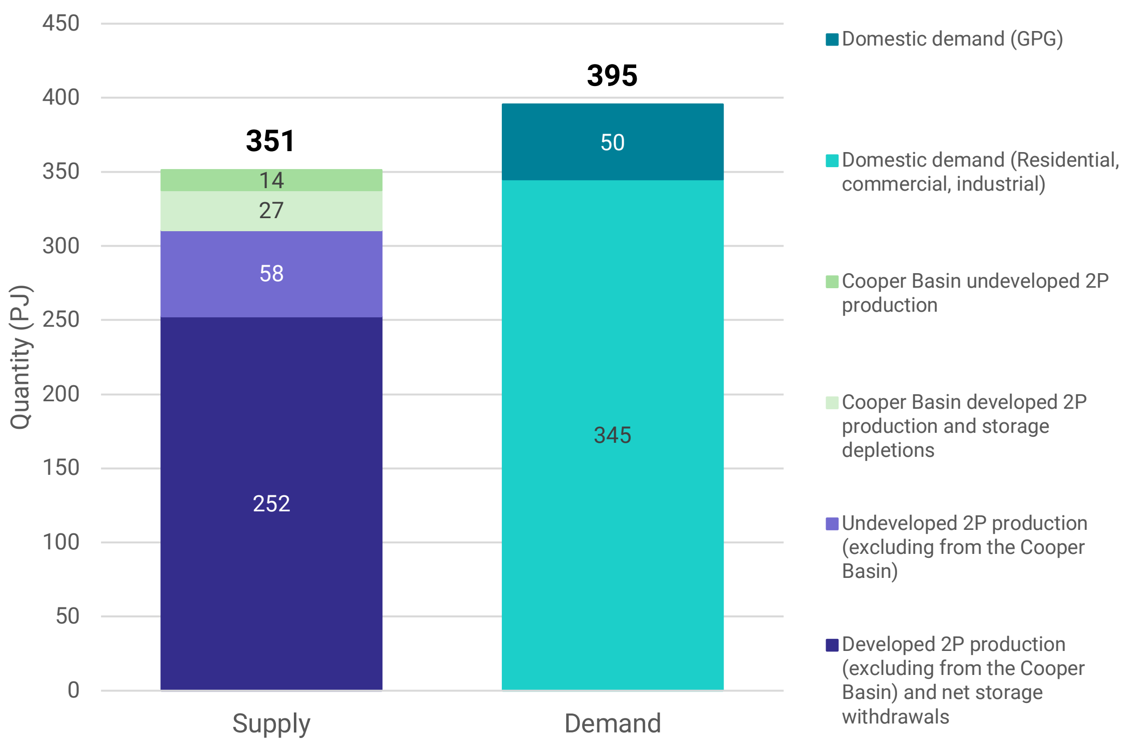
Other major projects include Santos' Narrabri project. The project is scheduled to undergo further development over the course of 2024. However, pending approvals, it is reported to be unlikely to supply gas in the market until 2025 at the earliest.[23]

1.3.3. Substantial volumes of gas will be required from Queensland to avoid a shortfall in the southern states in 2024

This section sets out the supply and demand outlook in two regions of the east coast gas market – the southern states (Victoria, NSW, Tasmania, South Australia and the ACT) and Queensland. This section shows that substantial volumes of gas will need to be transported from Queensland to the southern states in 2024, to avoid a southern shortfall.

Chart 1.6 shows the supply and demand balance for gas in the southern states. These states are the key source of domestic demand in the east coast, including substantial residential as well as commercial and industrial demand. The southern states are facing a 44 PJ shortfall in 2024.

Chart 1.6: Southern states outlook in 2024 (PJ)



Source: ACCC analysis of data obtained from gas producers in March 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO's 2023 GSOO. Note: Totals may not add up due to rounding.

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22 AEMO, Gas Statement of Opportunities, March 2023, page 6, accessed 19 April 2023.

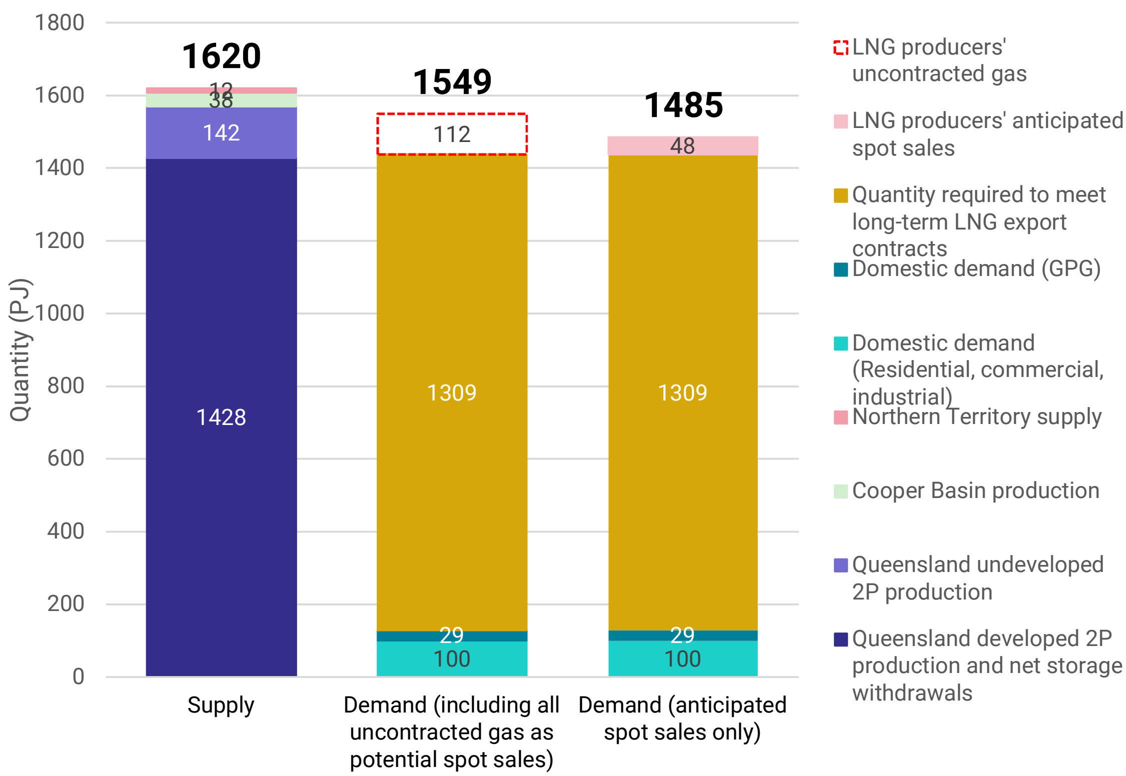
23 Max Maddison, 'Narrabri gas project hits legal roadblock' , 'The Australian', 16 January 2023, accessed 20 April 2023.

The 2024 outlook for the southern states is a slight improvement on the outlook for 2023. In our January 2023 report, we forecast a 52 PJ shortfall for 2023. This improvement is primarily driven by a forecast decrease in demand (- 26 PJ) primarily because of falling GPG consumption. Supply in the southern states is set to fall by 18 PJ. However, as mentioned above, if the forecast decrease in GPG demand does not eventuate, then this will cause the forecast shortfall to worsen.

The outlook for 2024 in Queensland is shown in chart 1.7. This includes gas supplied from the Northern Territory via the Northern Gas Pipeline (NGP) and those volumes of gas from the Cooper Basin that are forecast to flow into Queensland. Although there is some domestic demand in Queensland (mostly commercial and industrial), the primary source of demand comes from the 3 LNG export facilities in Gladstone. In contrast to the southern states, Queensland is expected to be in a substantial surplus, even if all the LNG producers' uncontracted gas is exported.

Similar to the southern states, forecast demand has decreased in Queensland (by 33 PJ) due to falling GPG. In 2024, AEMO's 2023 GSOO anticipates that Queensland will experience the biggest drop in GPG demand across all states, with GPG dropping by 21 PJ.

Chart 1.7: Queensland regional supply/demand outlook in 2024



Source: ACCC analysis of data obtained from gas producers in March 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO's 2023 GSOO. Note: Totals may not add up due to rounding.

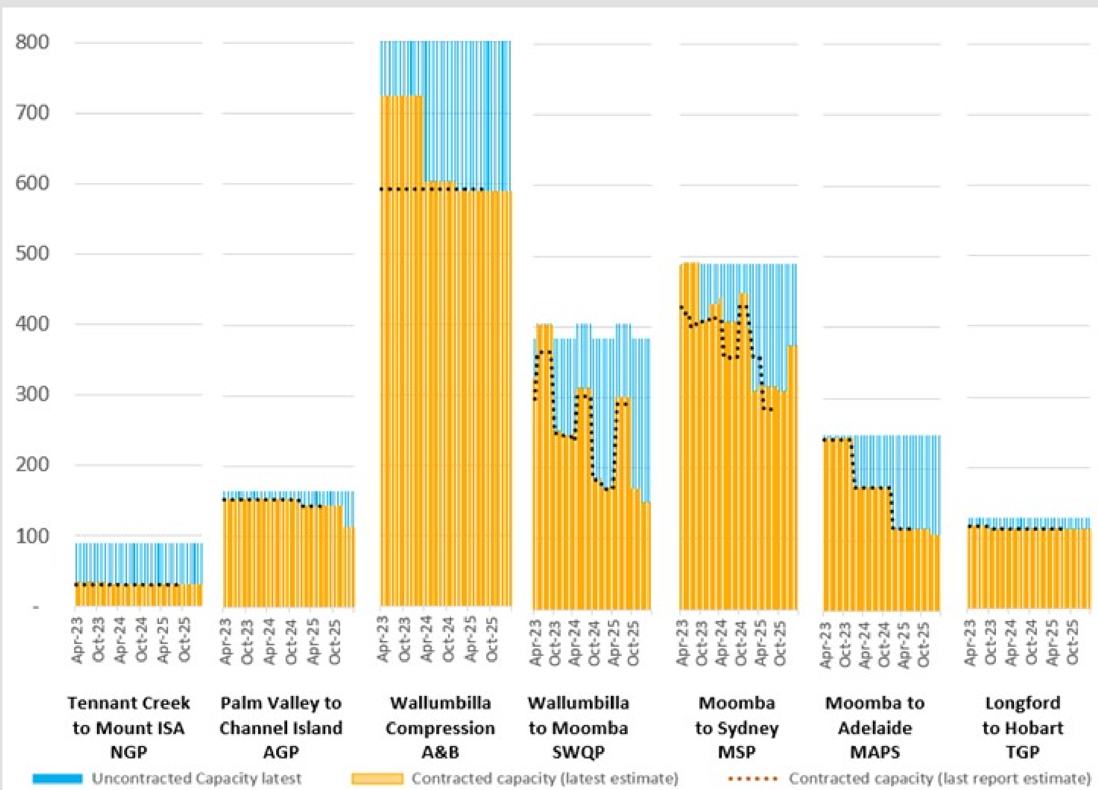
This shortfall in the southern states will need to be made up with gas transported from Queensland. This may also need to occur in the summer where gas can be placed in storage. There is not anticipated to be any substantial additional supply available in Victoria, such as from an LNG import terminal, in time for 2024.

Chart 1.8 shows the contracted capacity of pipelines that transport gas to the southern states from April 2023 to October 2025, compared to the outlook from our January 2023 interim report.

Chart 1.8 shows that uncontracted capacity on key pipelines required to transport gas south (including the SWQP, MSP and Moomba to Adelaide Pipeline System) and compression services remains limited. While there is likely to be sufficient pipeline capacity to meet shortfalls in the southern states, the lack of uncontracted capacity could affect the ability of some shippers to transport additional gas from the north.

The Dandenong LNG storage facility is used to store small volumes of gas to be injected quickly into the Victorian Transmission System (VTS). This gas is usually used to address short-term peaks and system security issues in Victoria. Low levels of storage at the Dandenong LNG facility have magnified risks to system security in Victoria's Declared Transmission System. Chart 1.9 shows the levels of contracted and uncontracted capacity at the Dandenong LNG facility from January 2019 to March 2026.

Chart 1.8: Contracted capacity of facilities that can transport gas to southern states (TJ/d)



Source: Contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (March 2023).

Many shippers prefer firm contracted pipeline capacity to ensure they can transport gas when needed. If pipelines do not have sufficient uncontracted capacity available, some shippers may not be able to access firm transport capacity and may need to rely instead on as available or interruptible services and the Day Ahead Auction to transport gas to the southern states during winter months. These services are inherently less certain.

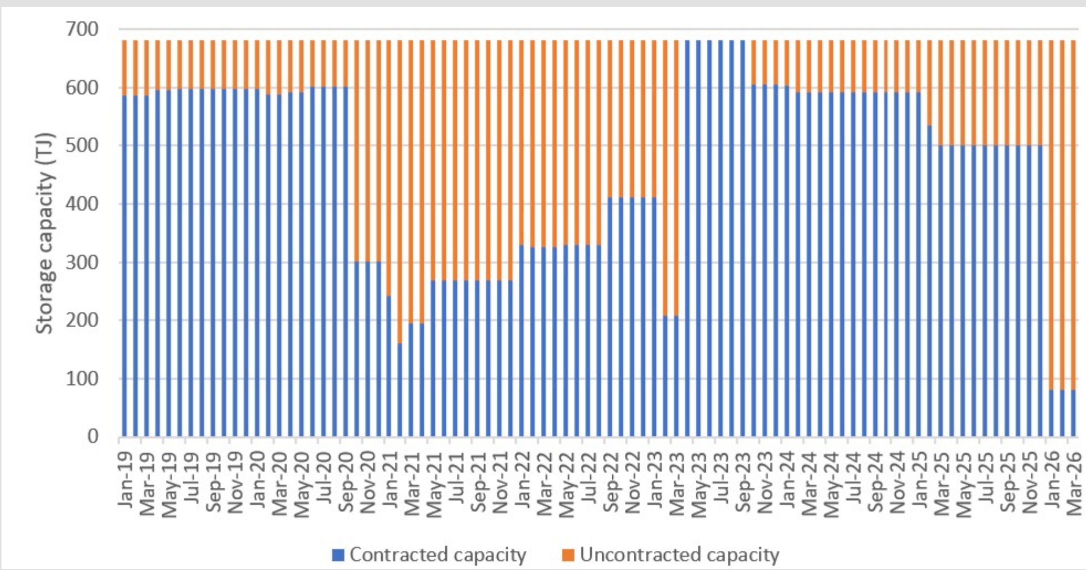
The outlook indicates that many of the southern haul pipelines have limited uncontracted capacity available over the period to October 2025. While there is likely to be sufficient pipeline capacity to meet the shortfall in the southern states, the lack of uncontracted capacity could affect the ability of some shippers to transport additional gas from the north.

The majority of the contracted capacity on these pipelines is held by a few shippers, which may prevent other shippers from contracting sufficient pipeline capacity. These other shippers are likely to experience an increasing risk of interruption, particularly on the South West Queensland Pipeline (SWQP) and Moomba to Adelaide Pipeline System (MAPS).

Chart 1.9 shows that the Dandenong LNG facility was contracted at near capacity until around late 2020, when contracted capacity declined steadily following the APA's adoption of its new contracting model until March 2023. After March 2023 the facility is almost nearly fully contracted until 2026.

This increase in contracted capacity coincides with the interim rule change to require AEMO to act as a buyer and supplier of last resort with respect to the Dandenong LNG facility from 2023 to 2025.

Chart 1.9: Dandenong LNG storage contracted capacity and gas held in storage (TJ), 2019 to 2026



Source: Publicly available data from AEMO's Gas Bulletin Board, March 2023.

For further information on physical flows on pipelines and the contracted capacity of key storage facilities and pipelines, please see Appendix C.

1.3.4. The LNG producers are forecast to have uncontracted gas that will help avert any shortfall that may arise

This section provides information about the east coast LNG producers’ supply and demand, including gas that has not yet been committed to the international market.

The LNG producers are the largest gas producers in the east coast, and LNG exports are the largest source of demand. LNG exports are forecast to reach 1357 PJ in 2024, including exports under LNG SPAs and anticipated additional and spot sales. This represents 69% of production from 2P reserves on the east coast. While the LNG projects were developed primarily to export gas to international customers and produce most of their own gas for this purpose, they source some of their gas for export from the domestic market. They also produce some gas that is sold to the domestic market.

The LNG producers and their associates influence close to 90% of 2P reserves in the east coast market.[24] This provides these producers with the available capacity to address shortfalls that may occur. They also have the ability and incentive to divert that gas into export markets where that is more profitable.

Table 1.3 shows the forecast supply and demand breakdown for the LNG producers in 2024.

Table 1.3: LNG Producers forecast supply and contracted sales in 2024 (PJ)

Supply	
Production from 2P reserves + net storage withdrawals	1398
3rd party purchases from suppliers other than LNG projects	179
Total supply available to LNG producers	**1577**
Domestic demand	
Contracted east coast market demand	157
Export demand	
Contracted LNG export demand	1309
Total contracted LNG demand	**1466**
Uncontracted gas supply	
LNG producers' uncontracted gas	112
LNG producers' anticipated LNG spot and additional sales (out of their uncontracted gas)	48

Source: ACCC analysis of data obtained from LNG producers as at March 2023. Note: Totals may not add up due to rounding. The quantity required to meet the contractual obligations under the long-SPAs includes the feed gas required to produce LNG (such as fuel)

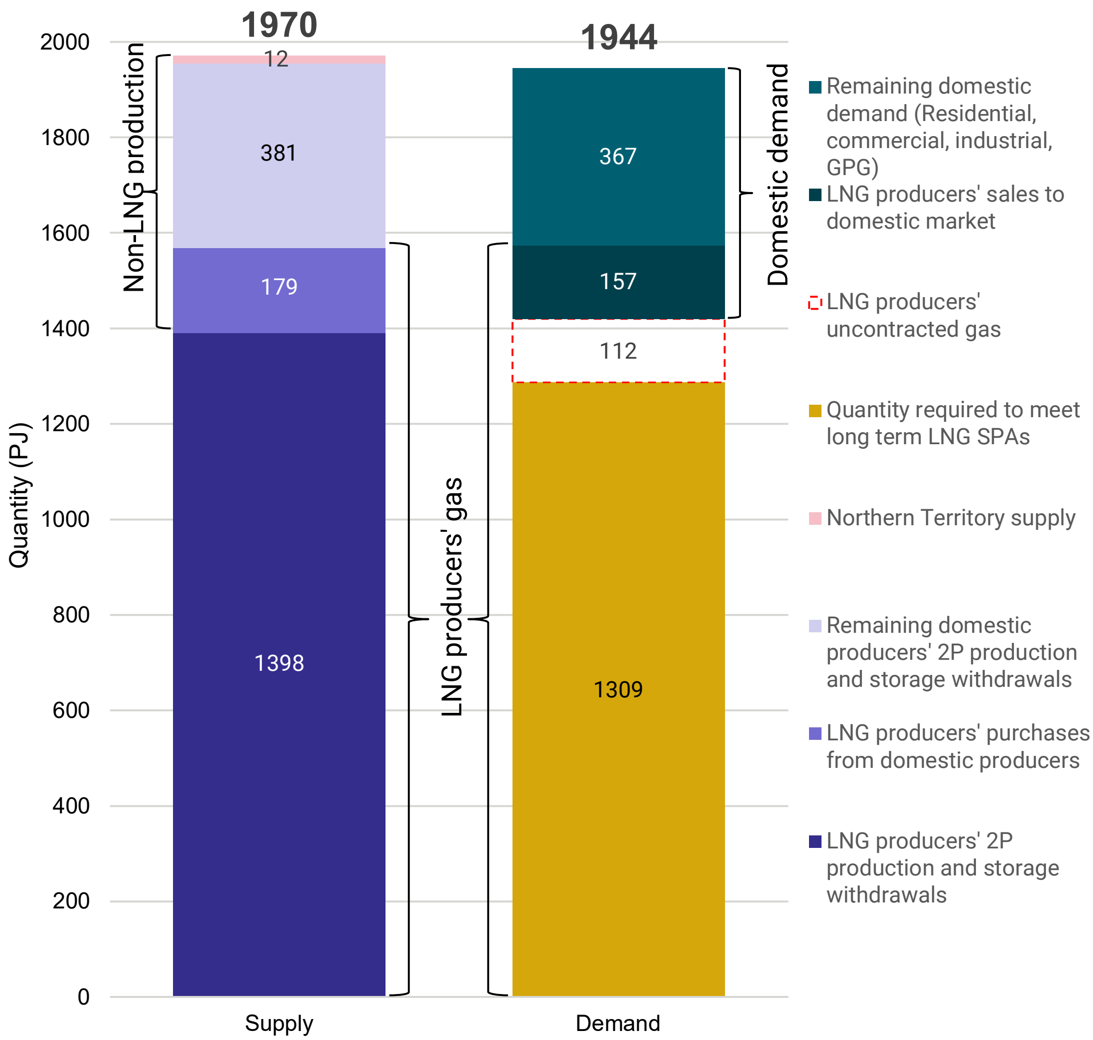
Chart 1.10 shows the impact of the LNG producers on the supply-demand outlook in 2024. It shows how much gas is forecast to be produced and bought by the LNG producers, and of that how much is forecast to be sold to the domestic market and exported as LNG. The remaining uncontracted gas is available to be exported as spot or additional LNG cargoes or sold to the domestic market.

The uncontracted gas figure in chart 1.7 represents uncontracted gas as potential LNG spot and additional sales. If the LNG producers sell their uncontracted gas as spot or additional LNG sales, the uncontracted gas portion of the demand chart will be 'filled in' and remain in the demand column. If the gas is sold domestically, then uncontracted gas, representing

24 ACCC July 2022 interim report, Chapter 5.

potential spot or additional LNG sales, will reduce as that gas has instead gone towards addressing domestic demand. As the chart shows, there should be sufficient domestic production that has not been sold to the LNG producers to fulfil the remaining domestic demand.

Chart 1.10: LNG producers' impact on the supply-demand balance in 2024



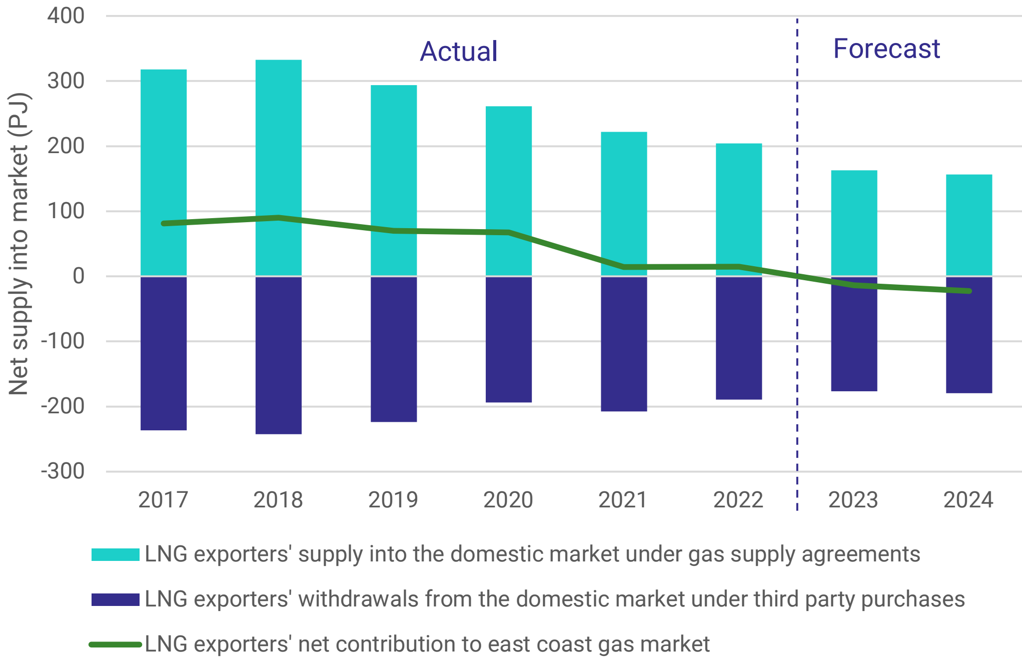
Source: ACCC analysis of data obtained from gas producers in March 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO's 2023 GSOO. Note: Totals may not add up due to rounding.

The LNG producers are expected to have 112 PJ of uncontracted gas in 2024, of which 48 PJ is anticipated to be exported as spot or additional LNG sales. As previously noted, the uncontracted quantities of gas produced by LNG producers can be:

- sold to the domestic market above that already committed, including through flexibility arrangements within existing contracts with domestic customers
- sold as LNG spot cargoes on the international market
- sold as additional volumes to long-term SPA customers, including through customers' ability to call on additional volumes above minimum take-or-pay volumes
- placed or sold into gas storage facilities
- sold to other producers, including as part of swap arrangements.

The LNG producers have committed 157 PJ of gas to the domestic market in 2024, but they are forecast to acquire 179 PJ of gas from the domestic market. This means the LNG producers are forecast to be net extractors from the domestic market as they purchase more gas for export to the international market than they sell to the domestic market.

Chart 1.11: The net contribution of LNG producers to the east coast gas market



Source: ACCC analysis of data obtained from gas producers in March 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO's 2023 GSOO.

Chart 1.11 shows that the LNG producers' supply into the domestic market has been decreasing over time. While the LNG producers have made a net contribution in aggregate terms for each year that has fully elapsed, this amount has also been decreasing over time.

2. Domestic price outlook

Key Points

- Prices for 2023 supply increased significantly in 2022, compared to 2021.
  - Prices *offered* for 2023 supply peaked at $71.52/GJ in August 2022.
  - Volume-weighted average prices *payable* under both producer and retailer GSAs for supply in 2023 increased over the reporting periods from September 2021.
  - Producer GSAs agreed to for 2023 supply between September and December 2022 averaged at $12.29/GJ increasing by 3% from the previous 6 months. Prices agreed by retailers averaged $27.12/GJ, an increase of 41% from the previous 6 months. Producers and retailers have different cost structures with retailer prices typically higher than producer prices as retailers offer bundled services.[25]
  - There were only 2 GSAs (with a contract term of at least 12 months and volumes above 0.5 PJ) executed in November and December 2022 for 2023 supply.
- There were fewer *offers* for supply in 2024.
  - The price cap does not apply for gas supplied in 2024.
  - Gas suppliers made fewer offers in 2022 for 2024 supply than in 2021 for 2023 supply. The number of producer offers fell 52% while the number of retail offers fell 7%. Fewer offers in the second half of 2022 may reflect a combination of factors including seasonal slowdown and industry's response to regulatory uncertainty.
  - Prices offered for 2024 supply peaked at $48.78/GJ in August 2022. Producer offers between September 2022 and February 2023 for 2024 supply averaged $17.73/GJ, a decline of 45% from the previous quarter. Average retailer prices over the same period increased by 18% from the previous quarter to reach $25.11/GJ.
  - Most producer and retailer offers to the east coast gas market tracked between the medium-term oil-linked netback price and short term JKM netback prices. Most prices offered by LNG producers were higher than retailer and non-LNG producer prices.
  - Most producer offers made after implementation of the price cap for 2024 supply were priced slightly above $12/GJ. Retailer offers were priced around $20/GJ.
  - C&I users observed a deterioration in the willingness of suppliers to make offers and noted the lack of liquidity for firm supply in the 2023-25 period. They reported that prices offered for firm contracts have decreased following the implementation of the price cap in December 2022.
- *Contracting* for 2024 supply slowed down considerably compared to previous years.
  - There was a decrease in GSAs executed for 2023 and 2024 supply compared to 2021 and 2022. Only 7 GSAs were executed between September 2022 and February 2023 for supply in 2024, representing a 46% decrease from January 2022 to August 2022 and a 22% decrease from September 2021 to February 2022.
  - Volume-weighted average prices payable under GSAs executed by producers from September 2022 to February 2023 for 2024 supply were $16.18/GJ. This is an increase of 27% from the January to August 2022 period. In comparison, average prices agreed by retailers were $21.31/GJ, an increase of 68% from the previous 6 months.
- Suppliers entered into an increased number of short-term contracts for 2023 delivery.

[25] The ACCC will be monitoring prices offered and contracted by retailers.

- There was an increase in the volume of gas sold under short-term contracts in December 2022 and January 2023.
- Gas sold under short-term producer GSAs from 23 December 2022 to 15 February 2023 for 2023 supply averaged under $11/GJ. Short-term contracts, reported to the AEMO Bulletin Board from 15 March to 30 April by LNG producers, averaged at $11.49/GJ while non-LNG producer short-term contracts averaged at $11.83/GJ. Short-term contracts by retailers averaged at $13.61/GJ.

- Spot prices continued a downward trend in early 2023 falling from their peak in July 2022. Spot prices across all markets in quarter 1 2023 averaged below $12/GJ.
- Between 18 November 2022 and 15 February 2023, the east coast LNG producers offered the Australian domestic market around 24 PJ for supply in 2022 and 2023. This is in addition to the previous offers made between 19 August and 18 November for 2023 supply of up to 250PJ.
  - LNG producers swapped approximately 27 PJ of gas with buyers in the Australian domestic market over the same period. While gas swaps do not provide a net increase in the volume of gas LNG producers supply to the Australian domestic market they can provide increased liquidity to the market, particularly over periods of peak gas demand.
  - In the same period, they sold 49.9 PJ of gas into the international market as spot or additional LNG cargoes.

2.1. Introduction

This chapter reports on domestic gas prices in the east coast gas market highlighting the trends since the last Gas Inquiry interim report in January 2023.[26]

It presents analysis and information on:

- historical and forward international prices
- key findings on prices for supply in 2023 under offers and contracts with a term length of at least 12 months
- prices for supply in 2024 under bids and offers for a term length of at least 12 months
- prices payable and flexibilities available for supply in 2024 under GSAs for a term length of at least 12 months
- short-term contracts (for a term length of less than 12 months) and prices
- spot market prices.

This chapter provides early insights on the impact of the price cap on wholesale pricing, short term contracts and spot markets.

It also provides a high-level assessment of LNG producers’ compliance with the renewed HoA for the reporting period from 18 November 2022 to 15 February 2023.

Further, where relevant, it presents C&I users views and experience in the east coast gas market, based on the information provided by a sample of users surveyed by ACCC in April 2023 (Box 2.1).

[26] The east coast gas market consists of Queensland, New South Wales, Victoria, South Australia, the Australian Capital Territory and Tasmania.

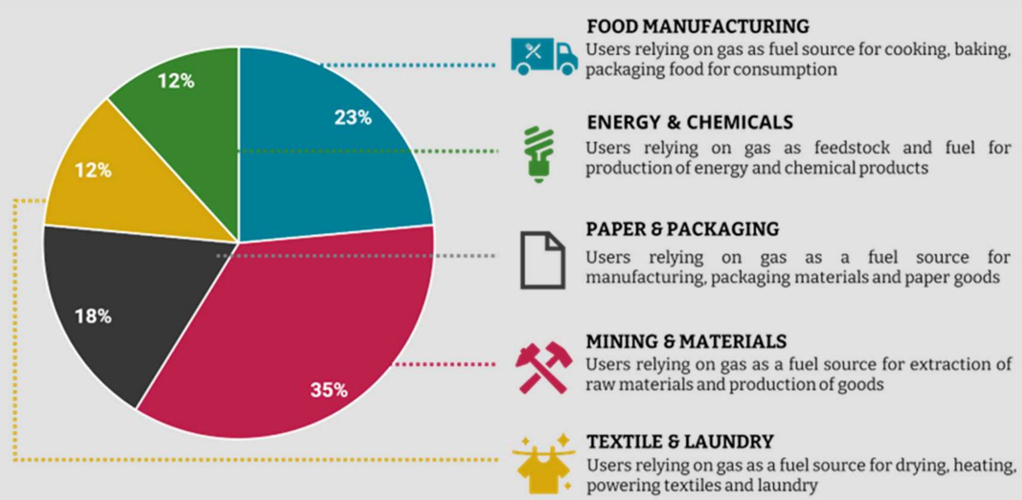
Box 2.1: The ACCC's engagement with gas users

The ACCC surveyed and met with gas users in early 2023 as part of our regular engagement program. This engagement, which involves bi-annual surveys, helps to inform our understanding of market developments and complements information obtained from gas suppliers.

[18] users responded to the ACCC's April 2023 survey, spanning a range of industries and including large and small users (figure 1). In aggregate, these users have an expected annual demand of around 45 PJ, representing about 11% of C&I user gas demand in 2023.[27]

Importantly, most survey responses were received prior to the release of the draft code consultation paper.

Figure 1: C&I user survey respondents



Source: ACCC analysis of information provided by users.

Appendix B presents a detailed update on the wholesale gas commodity prices in the east coast gas market for supply in 2023. In January 2023, we reported on offers and contract prices between 1 January 2021 and August 2022 for supply in 2023. For completeness, this Appendix extends the analysis of pricing for supply in 2023 offered up to December 2022.

Appendix C sets out the ACCC's approach to reporting on prices.

2.2. Trends in international oil and LNG prices

International prices for oil, natural gas and LNG have played a role in shaping domestic prices offered and agreed in GSAs. They reflect the opportunity cost of supplying gas to the east coast domestic gas market for some domestic suppliers.[28]

Chart 2.1 presents the historical monthly average prices for Brent Crude and international gas indices including the Japan/Korea Marker (JKM) and Dutch Title Transfer Facility (TTF).

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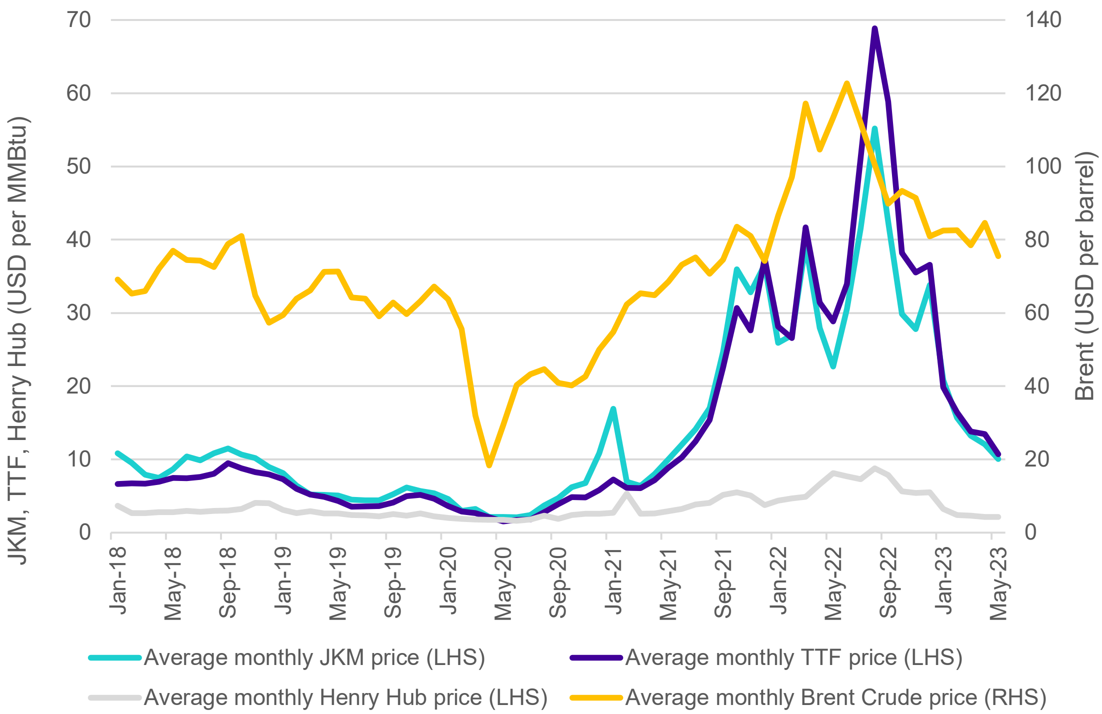
27 ACCC Analysis of GSOO Gas Statement of Opportunities – March 2023 – Table 17.

28 ACCC LNG netback price series: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series, accessed 22 May 2023.

Chart 2.1: Historical Brent Crude and international gas prices



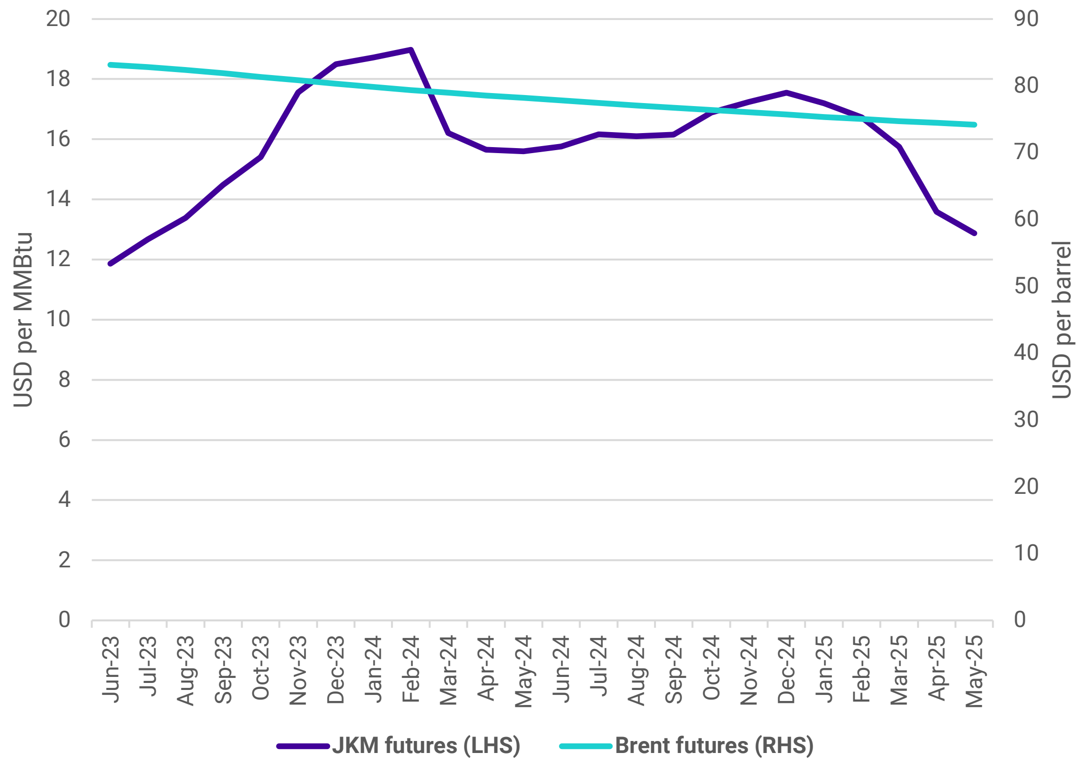
Source: ICE (JKM), Argus (TTF), EIA (Brent Crude), ACCC analysis.

Our January 2023 interim report noted that the JKM and Brent prices reached their peaks in the middle of 2022. The prices continued to fall since then. The JKM, TTF and Brent prices for May averaged USD$10.08/MMBtu, USD$10.73/MMBtu and USD$75.52/barrel as of 22 May 2023.

While prices have fallen from record highs in 2022, they were still above long-term historical averages. This means that domestic offers linked to international gas prices exceeded the prices historically seen in the east coast domestic gas market.

Chart 2.2 sets out the estimated forward prices for JKM and Brent crude traded on 19 April 2023.

Chart 2.2: Forward estimates of JKM and Brent Crude



Source: ICE, ACCC analysis.

Note: JKM and Brent futures are presented as monthly averages traded on 19 April 2023.

Estimated forward prices for JKM are forecast to fluctuate over the forecast period, beginning at a low of USD$11.87/MMBtu in June 2023 and reaching a high of USD$18.98/MMBtu in February 2024. Over the same period, Brent Crude prices are forecast to decrease from USD$83.12/barrel in June 2023 to USD$74.19/barrel by May 2025.

2.3. Key findings on 2023 prices for supply term length of at least 12 months

Price cap applies to contracts entered into after 23 December 2022 for supply during the price cap period (23 December 2022 to 22 December 2023)

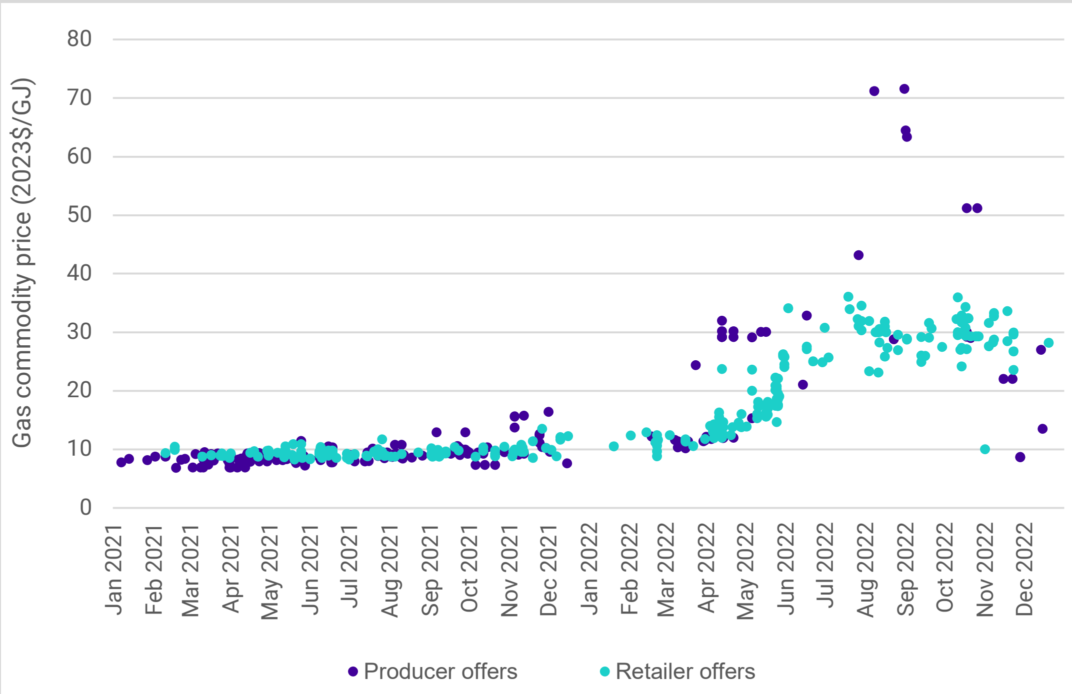
In January 2023, we reported on offers and contract prices between 1 January 2021 and 31 August 2022 for supply in 2023. This section provides an updated view on 2023 prices by extending the previous analysis to include data up to 31 December 2022.

This analysis relies on offers and contracts for supply quantities of at least 0.5 PJ per annum and a term length of minimum 12 months. Detailed assumptions, findings, analysis are available in Appendix B.

Box 2.2: Offer and Contract Prices for supply in 2023

Chart 2.3 shows prices offered by producers to all buyers, or retailers to C&I users and gas-powered generators, for 2023 supply over the period from 1 January 2021 to 31 December 2022.

Chart 2.3: Gas commodity prices (2023$/GJ) offered in the east coast gas market for 2023 supply



Source: ACCC analysis of bid and offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA.

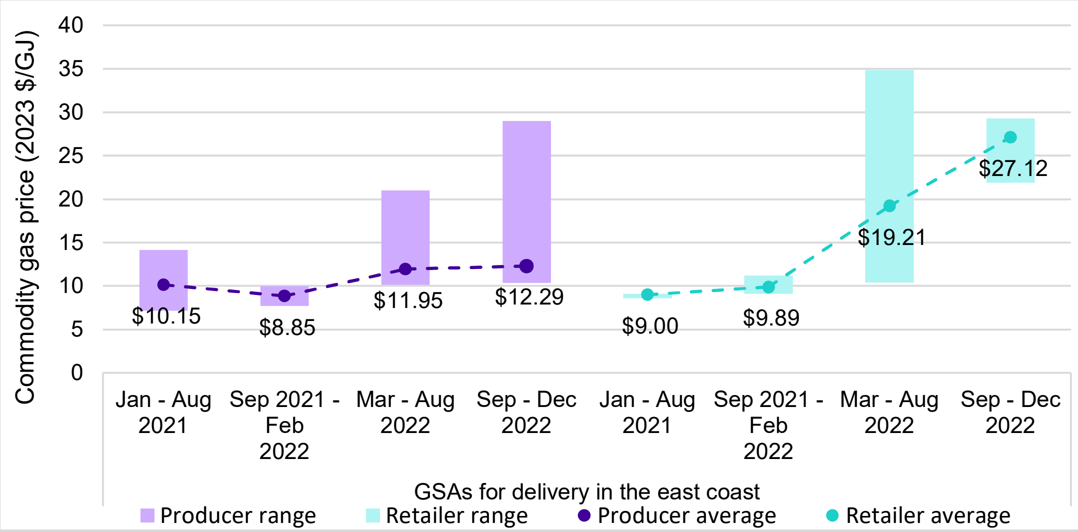
Prices offered for 2023 supply peaked at $71.52/GJ in August 2022. Prices offered in 2021 ranged between $6.79/GJ and $16.33/GJ. The corresponding price range offered in 2022 was $8.61/GJ - $71.54/GJ.

Both average prices and the spread of prices offered by producers from September 2022 to December 2022 were higher compared to retailer average prices and range, with high prices driven primarily by offers linked to LNG netback prices. Average producer prices offered from September 2022 to December 2022 for 2023 supply were $32.05/GJ, a decrease of 35% from the previous quarter. In comparison, average prices offered by retailers from September 2022 to December 2022 for 2023 supply were $29.68/GJ, an increase of 21% from the previous quarter.

Producer prices offered fell substantially in November and December 2022.

Chart 2.4 presents prices payable under producer and retailer GSAs for supply in 2023, which were executed between January 2021 and December 2022, for delivery in the east coast.

Chart 2.4: Expected gas commodity prices (2023$/GJ) payable under GSAs entered in the east coast gas market for 2023 supply



Source: ACCC analysis of information provided by suppliers.

Note: ACCC pricing model last updated on 14 April 2023.

Volume-weighted average prices payable under GSAs executed by both producers and retailers for supply in 2023 increased over the reporting periods from September 2021. The range in prices offered by producers also steadily increased over the period.

Producer GSAs between September 2022 and December 2022 averaged at $12.29/GJ, slightly increasing by 3% from the previous 6 months. Prices agreed by retailers between September 2022 and December 2022 averaged $27.12/GJ, an increase of 41% from the previous 6 months.

There were only 2 GSAs executed in November and December 2022 for 2023 supply possibly influenced by seasonality and industry's early response to speculated policy changes.

2.4. Prices for supply in 2024 under bids and offers for a term length of at least 12 months

Price cap does not apply to contracts for supply after the price cap period (23 December 2022 to 22 December 2023)

This section reports on the trends in prices, in offers made and bids received by suppliers, for 2024. Our analysis included offers and bids that contained clear indications of price, quantity, supply start and end dates and we estimated the price for each offer and bid using the approach outlined in appendix C.

Bids and offers in this analysis:

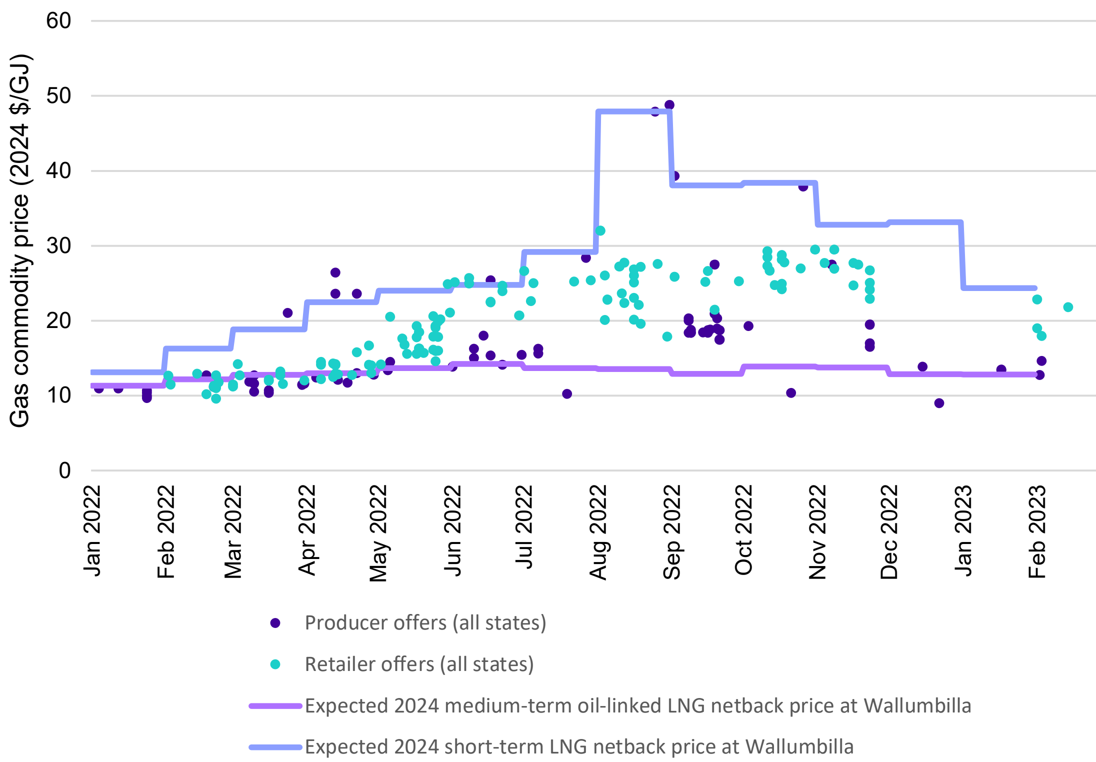
- were made by producers to all buyers or retailers, to C&I users and gas-powered generators for 2024 supply, over the period from 1 January 2021 to 15 February 2023
- had fixed prices or prices linked to a commodity price index, such as Brent Crude oil
- were for supply quantities of at least 0.5 PJ and a term length of at least 12 months.

As explained in Appendix C, the prices of individual offers and bids are not necessarily comparable as they can differ in non-price aspects, such as delivery location, quantity, contract term and contract flexibility. Offer and bid pricing in some instances may also reflect seasonal price fluctuations, linkages to prices of other commodities (such as oil), price expectations over the length of the contract (not only the supply year in discussion) or, in the case of GPG, conditions in the electricity market.

2.4.1. Fewer offers for supply in 2024 and prices eased since late 2022

Chart 2.5 shows offers made by producers and retailers, from January 2022 to February 2023, for 2024 supply. It compares domestic prices with LNG netback prices.

Chart 2.5: Gas commodity prices (2024$/GJ) offered in the east coast gas market for 2024 supply compared to LNG netback prices



Source: ACCC analysis of bid and offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA.

Producer prices offered in 2022 for supply in 2024 peaked at $48.78/GJ in August. Producer prices offered have eased since late 2022. Retailer offers trended upward in the first half of the year and remained high for the remainder of 2022 before trending downward in the early part of 2023.

The majority of producer and retailer offers for 2024 supply tracked between the medium-term oil-linked netback price and the short-term JKM netback price. Prices offered by LNG producers were higher than retailer and non-LNG producer prices and were priced in line with short-term JKM netback prices.

Gas suppliers made fewer offers in 2022 for 2024 supply than in 2021 for 2023 supply. In 2022, gas producers and retailers made 71 and 128 offers for 2024 supply, respectively. In comparison, there were 152 producer offers and 140 retailer offers in 2021 for 2023 supply.

We generally observe a decrease in the number of offers made by suppliers over December and January. For 2024 supply, this seasonal slowdown in offers began earlier, in late November. This may reflect market participants' early response to Government communication of implementation of a price cap and code.

Since the introduction of the price cap on 23 December 2022, there have only been 7 offers for 2024 supply. Most of the prices offered by producers were slightly above $12/GJ while retailer offers were approximately $20/GJ. The price cap does not apply to gas supplied in 2024, however producer offers around $12/GJ may reflect an anchoring of prices close to the cap.

Fewer offers in the second half of 2022 may reflect a combination of factors including seasonal slowdown, industry's response to the introduction of the price cap and preference to wait in the prospect of further regulatory changes.

The decline in offers reflects feedback from C&I users to the ACCC (Box 2.3).

Box 2.3: Gas users report fewer offers for supply

The majority of users surveyed had sought firm gas supply from producers, retailers or both in the period since the ACCC's August 2022 survey. These users indicated they rely on firm GSAs to secure reliable gas supply (which some users supplement with supply from the Gas Supply Hub and spot markets).

Most of these users reported fewer offers for supply in the 2023-25 period, with some users stating they have not been able to obtain any offers at all. For example, one user noted that retailers had advised that they were fully contracted for the remainder of 2023.

Another user, however, reported an improvement in the availability of offers for supply and in meetings or other correspondence with the ACCC other parties also noted that they had received offers for supply. Anecdotally, the ACCC has heard that buyers with existing relationships with suppliers may be better placed to receive firm offers for gas supply.

Similarly, some users noted a lack of offers for 2024 from both producers and retailers. Where one user explains:

> 'Informal testing/conversation with gas suppliers has indicated little to no gas for 2024 for the east coast.'

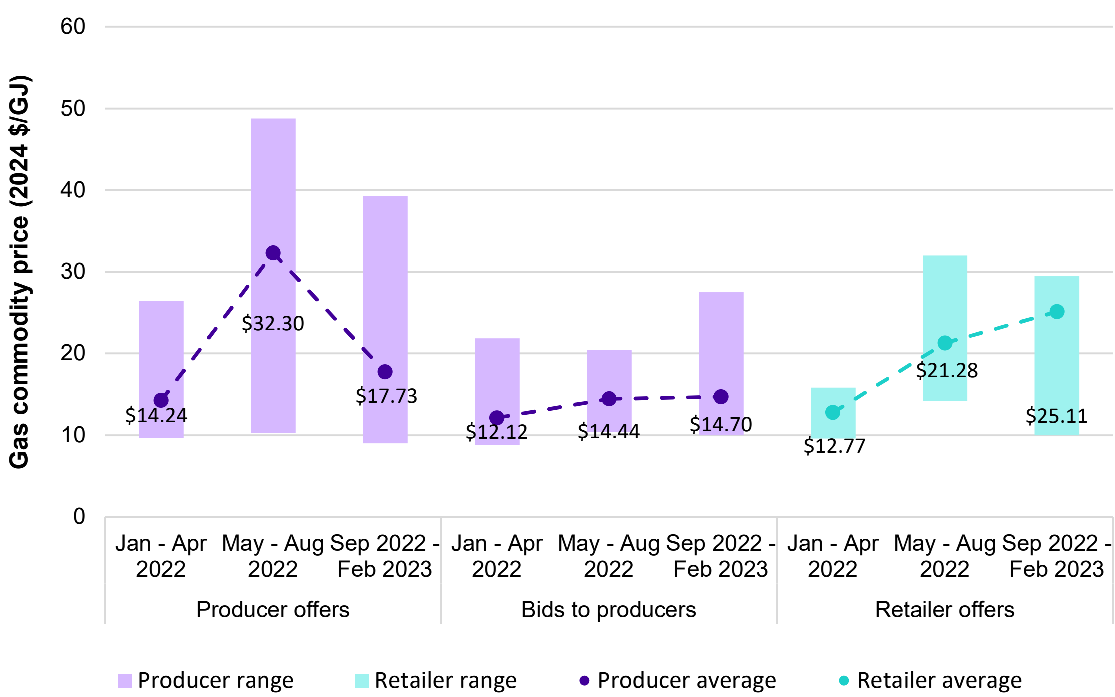
Another user observed that almost all 'gas [for supply in 2023 and 2024] was sold or in the process of being sold during 2022'.

Several gas users suggested that gas suppliers may be withholding or delaying gas offers for 2024 until there is greater clarity about the code.

Several users also suggested that suppliers may have responded to the price cap by supplying volumes of gas, that would have otherwise been offered under contracts, into the Gas Supply Hub and spot markets.

Chart 2.6 compares the volume-weighted average price of offers made or bids received by producers and retailers for gas supply in 2024.

Chart 2.6: Gas commodity prices (2024$/GJ) offered in the east coast gas market for 2024 supply



Source: ACCC analysis of bid and offer information provided by suppliers.

Note: Volume-weighted average prices are displayed next to the point, or below the price range. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA.

Between September 2022 and February 2023, the producer offers averaged $17.73/GJ with a range from $9.00/GJ to $39.30/GJ. The average prices offered by retailers reached $25.11/GJ with a spread of $10/GJ to $29.47/GJ. While average prices offered by retailers exceeded average prices offered by producers from September 2022 to February 2023, the range of prices offered by producers was larger, with a higher maximum price.

The average prices offered by producers during September 2022 to February 2023 decreased by 45% from the previous period. Higher prices and higher volumes offered by producers in September dominated the average with the rest of the months in the averaging period reporting fewer offers and lower than average prices. The average prices offered by retailers during September 2022 to February 2023 increased by 18% from the previous period.

Bids to producers increased over the reporting periods as they increased from $12.12/GJ in the January to April 2022 period to $14.70/GJ in the September 2022 to February 2023 period.

Gas users reported a decrease in prices from recent highs in recent data collected from the ACCC's April survey.

Box 2.4: Gas users report lower offer prices since the introduction of the price cap

In their responses to our survey and in meetings with the ACCC, some gas users reported that prices offered for firm GSAs fell following the implementation of the price cap in December 2022.

Generally, users reported that in the period since August 2022, they had received a higher spread of offers ranging up to $65/GJ for supply in 2023-24. This compares to the ACCC's August 2022 survey, where users observed a range between $25 and $47/GJ for supply in 2023 and approximately $20 to $32/GJ for supply in 2024.[29]

Following the introduction of the price cap, some users reported that prices quoted by suppliers fell from recent highs, with prices being offered (by retailers who are not subject to the price cap) appearing to be approximately in the range of $18 to $20/GJ by April 2023. One small user, however, reported receiving an offer as high as $25/GJ, after April 2023, and another market participant reported that gas prices for firm contracts increased to around $20 to $22/GJ by the end of May 2023. As noted earlier, some users also reported that they have been unable to source any offers following the introduction of the price cap.

One user noted that these prices remain above the level of the price cap and that this may reflect that retailers face gas procurement costs above the price cap (under GSAs entered into in 2022 at higher prices). One user further suggested that it will take time for the price cap to have an impact as retailers had already procured gas at higher prices.

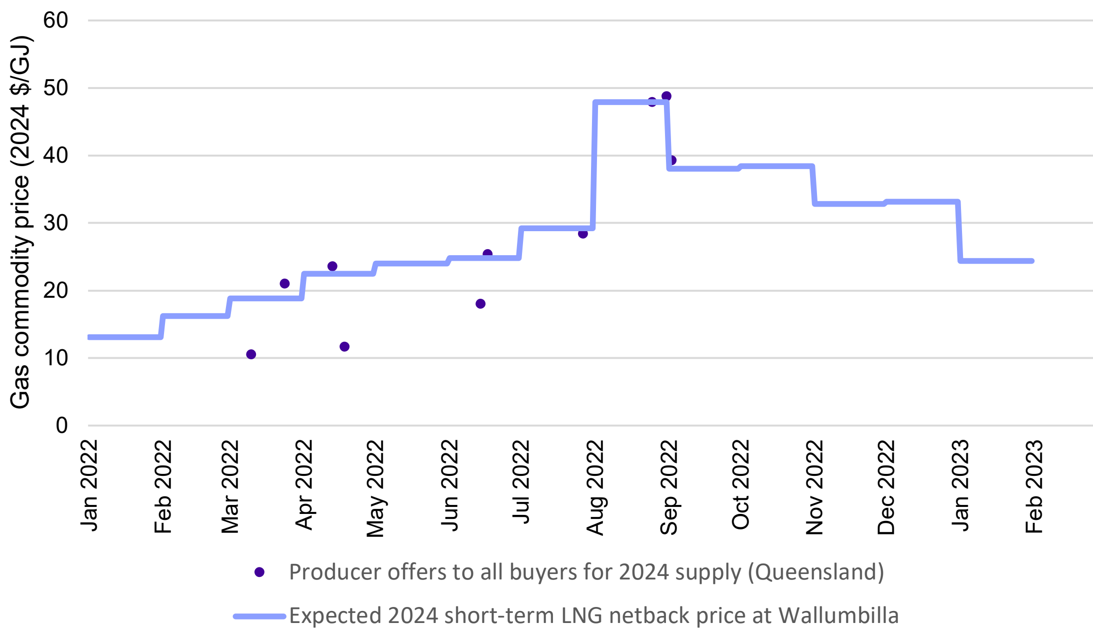
Another user noted that '[retailers] have advised in writing that they have no contracted gas from wholesalers at the $12/GJ price cap.' While this statement may have been correct at the time the statement was made, the ACCC notes that data obtained by the ACCC shows that some retailers have obtained gas at $12/GJ for 2023 supply under GSAs entered into in [late] March 2023.

2.4.2. Producer offers for supply in Queensland in 2024 tracked short-term LNG netback prices and ceased in September

Chart 2.7 compares offers made by producers between 1 January 2022 and 15 February 2023 for supply in Queensland in 2024 compared to the short-term LNG netback price expectations.

29 ACCC Gas Inquiry January 2023 Interim Report, p. 60.

Chart 2.7: Gas commodity prices (2024$/GJ) offered by producers to all buyers for 2024 supply (Queensland) and short-term LNG netback expectations



Source: ICE, Argus, ACCC analysis of offer information provided by suppliers.

Note: The above chart only includes offers that relate to contracts with a term of 1-3 years. Offers that specify pricing mechanisms linked to oil prices have been excluded.

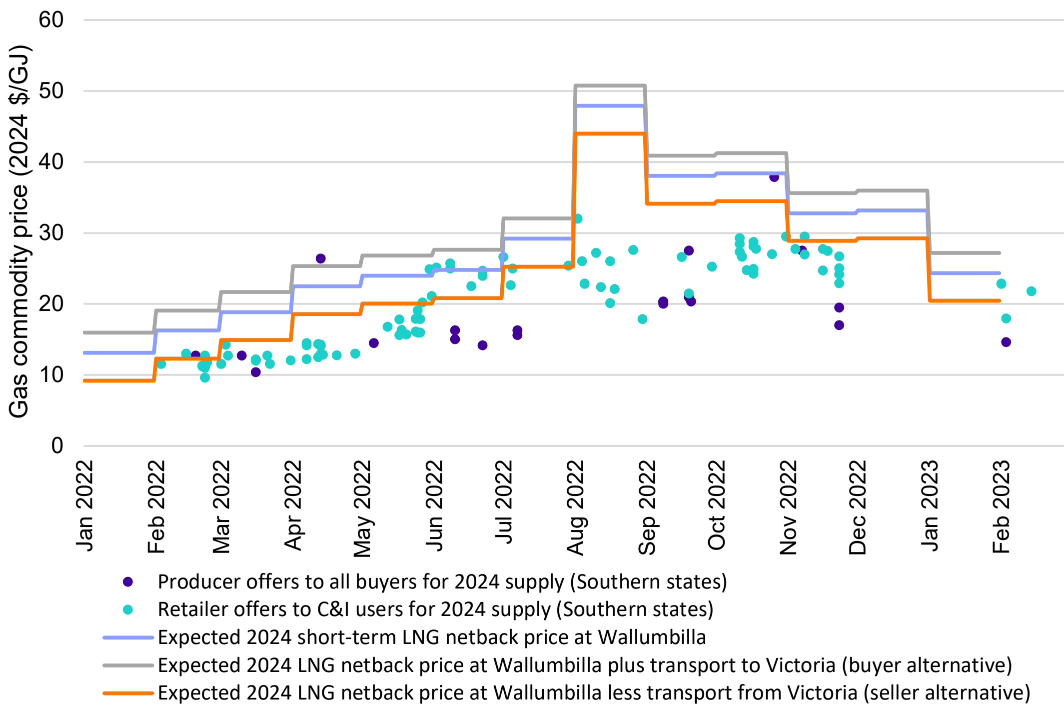
There were limited producer offers for supply in Queensland in 2024. Of the 10 offers made, most tracked short-term LNG netback prices. The 2 highest producer offers were JKM commodity linked and priced at $48/GJ.

2.4.3. Most retailer offers to the southern states for 2024 supply tracked below seller alternative (short-term LNG netback prices); Producer offers to the southern states were lower than retailer offers.

Chart 2.8 compares offers in the southern states for 2024 supply with short-term LNG netback prices and the buyer and seller alternative prices.[30]

[30] The buyer alternative reflects the LNG netback price at Wallumbilla plus the cost of transportation. The seller alternative is the LNG netback price at Wallumbilla less the cost of transportation gas to Wallumbilla from the south.

Chart 2.8: Gas commodity prices (2024$/GJ) offered by producers to all buyers, and retailers to C&I users for 2024 supply against short-term LNG netback expectations (southern states)



Source: ICE, Argus, ACCC analysis of offer information provided by suppliers.

Note: The above chart only includes offers that relate to contracts with a term of 1-3 years. Offers that specify pricing mechanisms linked to oil prices have been excluded.

Our January 2023 report noted that the seller alternative netback price increased in the first half of 2022 alongside netback prices. Netback prices have fallen since mid-2022, however remain above historical prices. The vast majority of producer offers to the southern states tracked below the seller alternative netback prices.

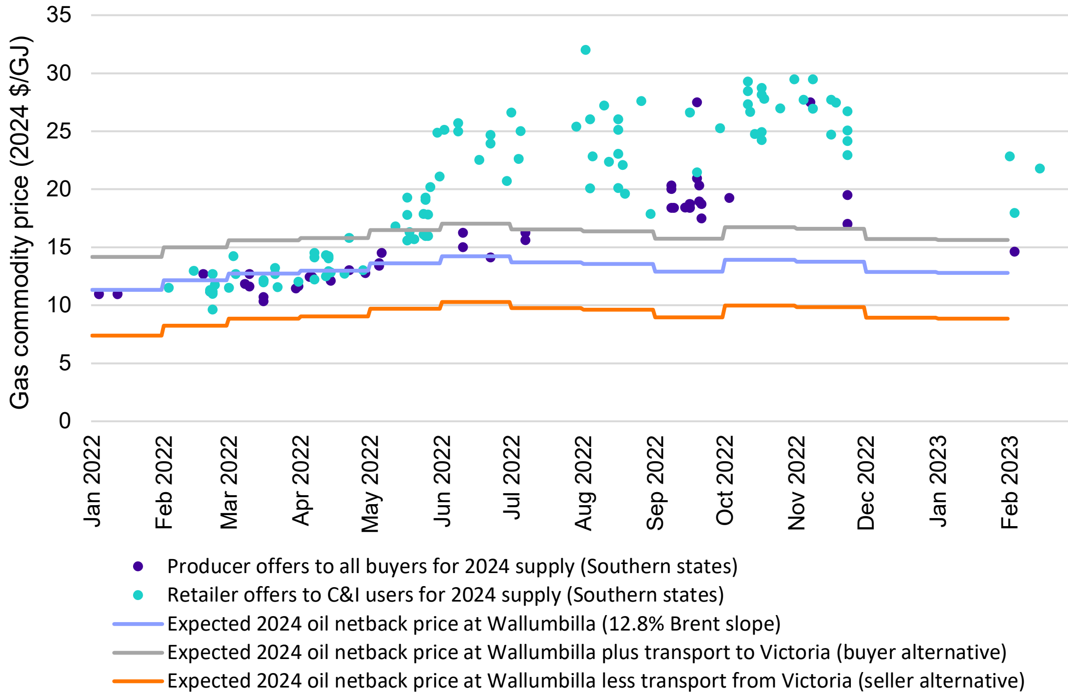
Retailer offers showed a similar trend with most offers to C&I users in southern states tracking below the seller alternative until November 2022, but to a lesser extent compared to producer offers. Following the netback price decreases from mid-2022, some retailer offers were priced at or above the seller alternative netback prices in November and February 2023.

2.4.4. Producer and retailer offers to the southern states in the second half of 2022 were higher than buyer alternative prices (oil-linked netback prices)

Chart 2.9 compares offers by producers and retailers in the southern states for 2024 supply, made between January 2022 and February 2023, with 2023 medium-term oil-linked LNG netback and the buyer and seller alternative prices.[31]

[31] The medium-term oil-linked LNG netback price is calculated with a Brent Crude slope of 12.8%. More information on the medium-term LNG netback can be found in our LNG netback price series review.

Chart 2.9: Gas commodity prices (2024$/GJ) offered by producers to all buyers, and retailers to C&I users for 2024 supply to the southern states, against expectations of medium-term oil-linked LNG netback



Source: ICE, Argus, ACCC analysis of offer information provided by suppliers.

Note: Offers that specify pricing mechanisms linked to JKM prices have been excluded.

Our January 2023 interim report noted that both producer and retailer offers to the southern states for 2023 supply tracked the medium-term oil-linked LNG netback price until May 2022. Similarly, most retailer and producer offers for 2024 supply were in line with the medium-term LNG netback price until around May 2022. Retail and producer offers increased sharply from May 2022 exceeding the medium-term oil-linked LNG netback for the remainder of the period.

Producer offers with Brent linkages from January 2022 to February 2023 had an average slope of 11%, with Brent linked slopes increasing in the second half of 2022.

2.5. Prices payable and flexibilities available for supply in 2024 under GSAs for a term length of at least 12 months

Price cap does not apply to contracts for supply after the price cap period (23 December 2022 to 22 December 2023)

This section reports on the prices that gas buyers on the east coast are expected to pay and receive for supply in 2024. It also reports on the levels of flexibilities agreed to in GSAs.

GSAs in this analysis:

- are entered into by producers with all buyers, or by retailers with C&I users and gas-powered generators between 1 January 2022 and 15 February 2023.
- have fixed prices or prices linked to a commodity price index, such as Brent Crude oil.
- have an ACQ of at least 0.5 PJ and a term length of at least 12 months.

As with the analysis of bids and offers, we estimate prices under GSAs using assumptions relating to several variables, including the AUD/USD exchange rate, the consumer price index, and the price of oil and LNG on international spot markets. However, while bids and offers are priced using expectations of these variables at the time the bid or offer was made, GSA prices payable are estimated based on current market expectations for the relevant supply year.

2.5.1. A marked reduction in the number of GSAs executed for 2024 supply

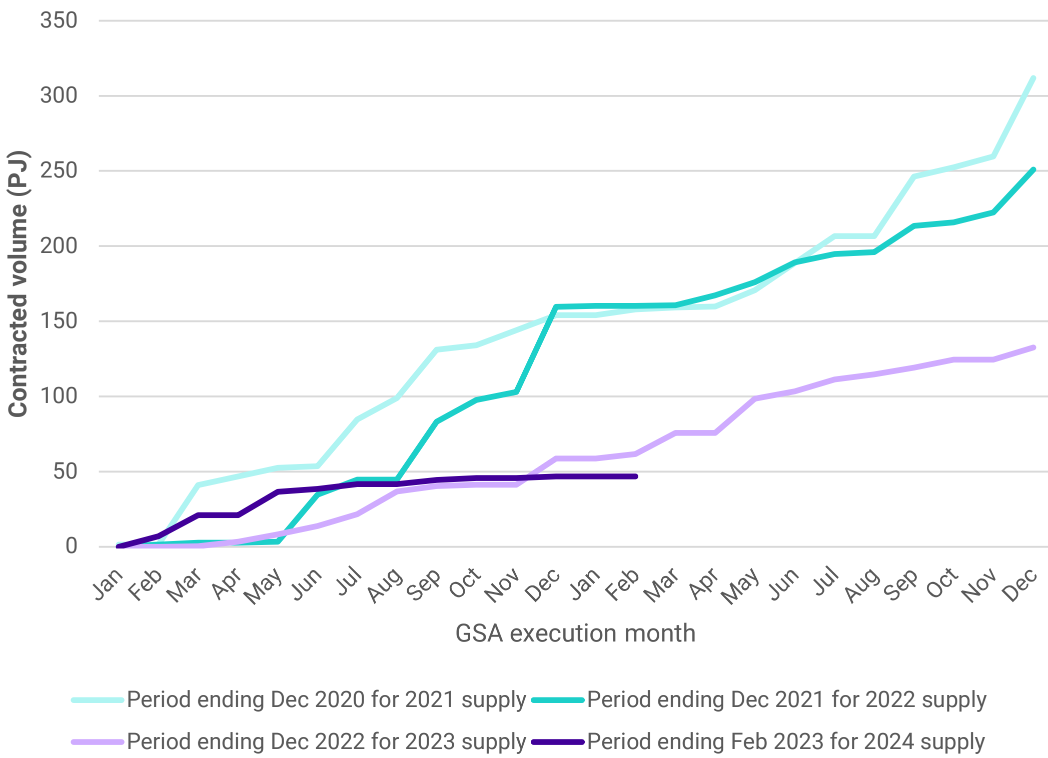
There was limited contracting activity between September 2022 and February 2023 for supply in 2024. Only 7 GSAs were executed by producers and retailers in this period, nearly 50% down from the January to August 2022 period. There was a total of 13 GSAs executed during the January to August 2022 period for 2024 supply.

Lack of contracting over this period may have been influenced by market participants' preference for holding off on contracting in response to the uncertainty of further regulatory changes.

A total of 20 GSAs were executed between January 2022 and February 2023 for 2024 supply, 8 by producers and 12 by retailers. Of this total, 15 GSAs were for delivery in the southern states compared to 5 for Queensland. From the 8 producer GSAs executed from January 2022 to February 2023, 6 were for delivery in the southern states and 2 were for Queensland. Of the 12 executed by retailers 3 were for delivery in Queensland and the remaining 9 GSAs for southern states.

Chart 2.10 displays the volumes of gas contracted for a given supply year in the 24 months before that supply period begins, noting that only data up to February 2023 is available for the 2024 supply year. The chart shows that there has been a decrease the volume of gas traded under GSAs executed for 2023 and 2024 supply, compared to GSAs executed for 2021 and 2022 supply over comparable time frames. Both retailer and producer GSAs are included.

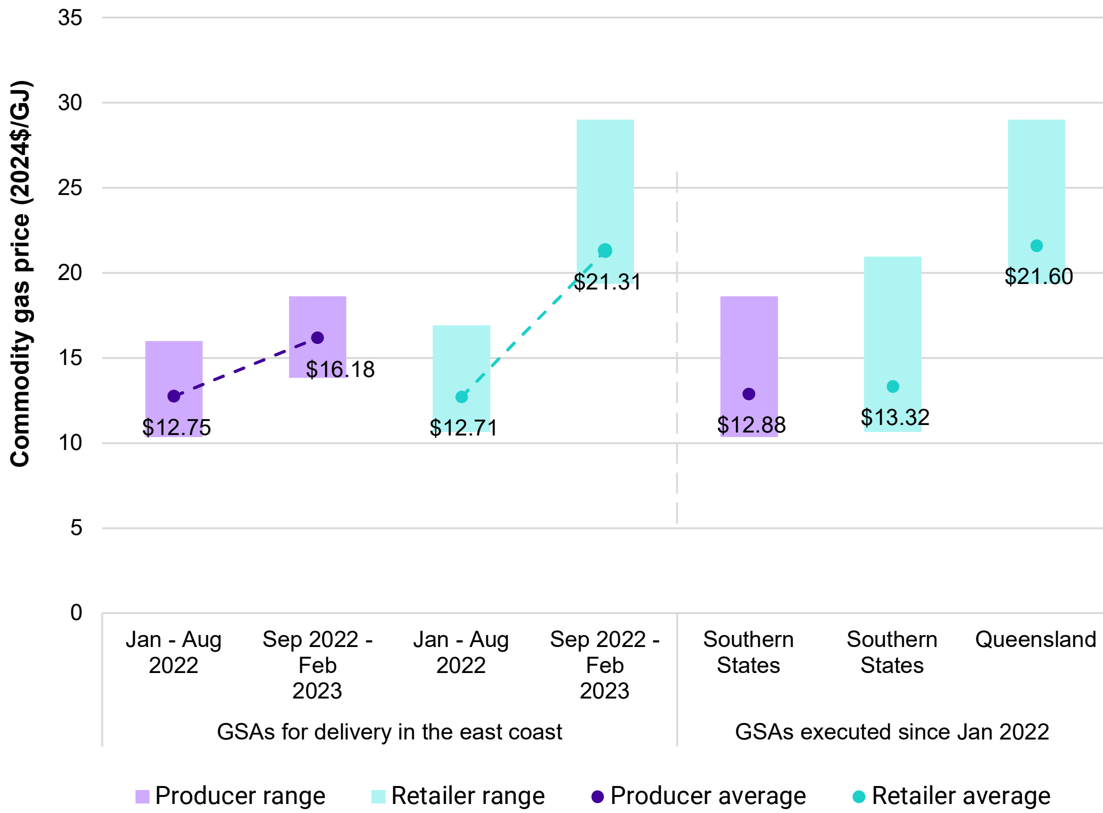
Chart 2.10: Cumulative volume of GSAs agreed for supply



Source: ACCC analysis of information provided by suppliers.

Chart 2.11 presents volume-weighted average wholesale gas commodity prices, expected to be paid under GSAs entered into by producers and retailers, for delivery in the east coast gas market in 2024. The left-hand side of the chart compares average prices payable under GSAs by producers and retailers in the east coast market between January 2022 and August 2022 with those entered into between September 2022 and February 2023. The right-hand side of the chart compares average prices payable under GSAs entered into between January 2022 and February 2023 by producers and retailers for delivery in the southern states.

Chart 2.11: Gas commodity prices (2024$/GJ) payable under GSAs in the east coast gas market for 2024 supply[32]



Source: ACCC analysis of GSA information provided by suppliers.

Note: Volume-weighted average prices are displayed next to the point, or below the price range. All contracts are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Prices are based on assumptions as at 14 April 2022.

The GSAs executed by producers and retailers from September 2022 to February 2023 were at higher prices compared to previous 6 months, however the lack of contracting in the current reporting period may skew the associated pricing inferences.

Average prices agreed under GSAs executed by producers between September 2022 and February 2023 for 2024 supply were $16.18/GJ. This is an increase of 26.96% from the January to August reporting period. In comparison average prices agreed by retailers for 2024 were $21.31/GJ, an increase of 67.63% from the previous reporting period.

All GSAs agreed to by retailers from January 2022 to February 2023 for delivery in the southern states were at slightly higher prices compared to producer GSAs. GSAs agreed to by retailers were significantly higher in Queensland than in southern states, with averages of $21.60/GJ and $13.32/GJ respectively.

Table 2.1 shows the proportion of contracts and quantity of gas supplied by pricing mechanism. Brent-linked contracts made up 30% of all contracts for 2024 supply and accounted for 61% of all gas supplied. This is a slight increase in volume of gas supplied

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[32] Due to a lack of contracting, we have departed from our usual practice of reporting GSAs by region (Queensland and southern states) and have instead grouped GSAs at the east coast level rather than by delivery region on the left-hand side of the chart. For the same reasons, producer GSAs are not presented on the right-hand side of the chart.

under Brent-linked contracts for 2022 supply, up from 43% as reported in the July 2022 interim report.[33]

Since January 2021, there have been no GSAs agreed to with a pricing mechanism linked to short-term LNG netback prices.

Table 2.1: GSAs by pricing mechanism for supply in 2024

Year/variable	Fixed Price	Brent	Total
Volume-weighted average price	$13.17/GJ	$13.58/GJ	
2024 % Count	70%	30%	100%
2024 % Quantity	39%	61%	100%

Source: ACCC analysis of information provided by suppliers

Note: Table 2.1 separates GSAs by pricing mechanism for contracts executed between 1 January 2022 to 15 February 2023 for supply in 2024. It does not include information from contracts executed prior to 2022 for supply in 2024. Additionally, contracts are only included which have an annual contract quantity of at least 0.5 PJ and a contract length of 12 months or more.

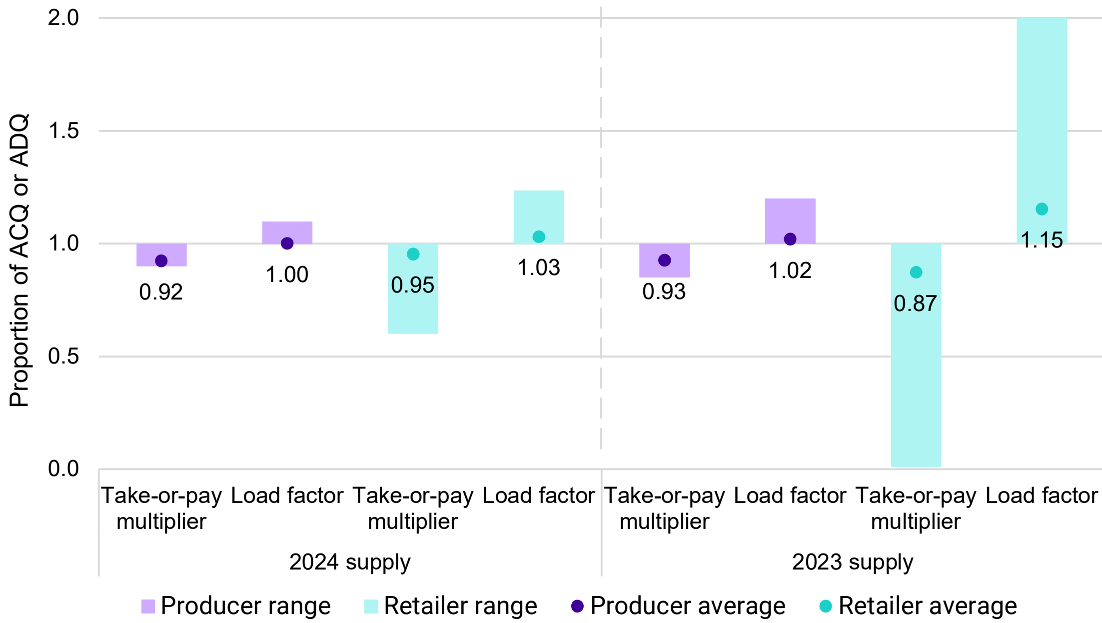
2.5.2. Flexibility under GSAs for supply in 2024

This section reports on volume-weighted average take-or-pay multipliers and load factors in GSAs. The take-or-pay multiplier and the load factor are key terms in GSAs that, in practice, provide buyers with flexibility in how they manage their gas usage.

Chart 2.12 shows average flexibility under GSAs for 2023 supply compared to the flexibility under GSAs for 2024 supply. GSAs for 2024 supply were executed between January 2022 and February 2023, while GSAs for 2023 supply were executed between January 2021 and December 2022.

33 ACCC, Gas Inquiry 2017-25 interim report, July 2022, p 46.

Chart 2.12: Average load factor and take-or-pay multiplier under GSAs entered into in the east coast gas market for 2024 and 2023 supply



Source: ACCC analysis of information provided by suppliers.

Producers provided similar levels of flexibilities under GSAs for delivery in the east coast between 2023 and 2024.

However, retailers have provided GSAs with significantly less flexibility in 2024 when compared to 2023. Average take-or-pay for retailer GSAs for supply in 2024 was 95% with a range between 60% and 100%. In 2023 the average was 87% with a range between 1% and 100%. Average load factor for retailer GSAs for supply in 2024 was 103% with a range between 100% and 124%. In comparison the 2023 load factor averaged at 115% with a range between 100% and 201%.

Retailers offered a greater level of flexibility than producers in both supply years. Better flexibility terms offered by retailers may reflect that they are in a better position to provide flexibility in GSAs to C&I gas users as retailers can manage changes in the demand for gas on a portfolio basis and may have greater access to underground or pipeline storage.

C&I gas users have reported on deterioration in the level of flexibility in non-price terms offered by suppliers, including producers and retailers, as expanded in Box 2.5.

Box 2.5: Some gas users report less flexibility and worsening selling practices

A number of users have reported to the ACCC a deterioration in both contract flexibility and selling practices since the ACCC's last survey in August 2022.

Specifically, about a quarter of users who responded to the ACCC's survey reported a worsening in the level of flexibility in firm GSA offers, with multiple respondents citing that suppliers are less willing to negotiate on non-price terms including contract length, take-or-pay provisions, and delivery points. Notably, no users reported any improvement in the level of flexibility or non-price terms offered by suppliers.

More generally, 50% of gas users who responded to the ACCC's survey observed a deterioration in selling practices since the ACCC's August 2022 survey and since the introduction of the price cap, with one additional user reporting a deterioration following the introduction of the price cap.

One user noted that suppliers were withdrawing or increasing prices prior to response dates. Another user stated that supplier-led EOI processes were vague and provided limited transparency to users.

The deterioration in selling practices since August 2022 compound worsening market conditions for gas buyers, which the ACCC has reported on extensively in recent years. It also highlights the critical need for policy measures to improve the conduct of gas suppliers in their negotiations with gas buyers.

2.6. Short term contract volumes and price

This section analyses and reports on the volume and price of gas sold under short-term contracts based on:

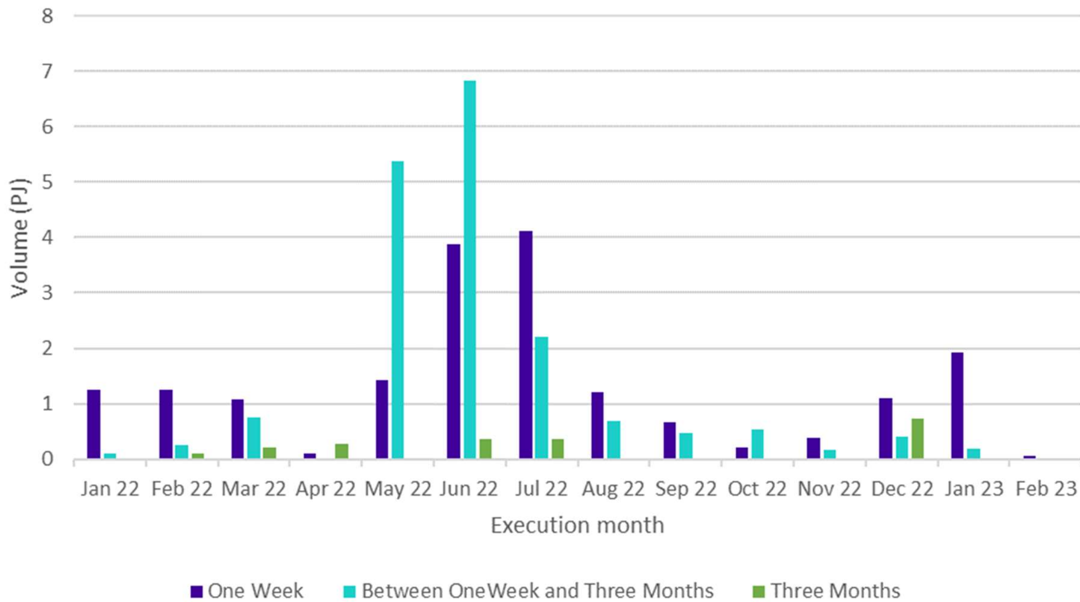
- GSAs executed by producers with a term length between one day and 12 months based on the data reported in response to the ACCC's 95ZK information requests.
- Short term transactions reported by producers and retailers on the AEMO's Gas Bulletin Board since 15 March 2023 to 30 April 2023 (accessed and provided by the AER).
- Short term transactions on the Wallumbilla Gas Supply Hub, DWGM and Short-term Trading Markets (provided by the AER).

The price cap limits the sale of gas under new contracts during the 12-month period that commenced on 23 December 2022 to $12/GJ. Our analysis in this section indicates that nearly all producer contracts have been agreed to at or below the $12/GJ price. However, we have observed some contracts with prices that appear to be in excess of $12/GJ. The ACCC is continuing to collect contracting data and monitor transactions. In the event we identify potential non-compliance, we will take appropriate action.

2.6.1. Producers entered into an increased number of short-term contracts

Chart 2.13 summarises trends in the volume of gas sold under producer GSAs for firm supply with a term length of one day to one week, one week up to 3 months and 3 months.

Chart 2.13: Contract volumes agreed to under Producer GSAs for delivery within 12 months of execution



Source: ACCC analysis of information provided by suppliers.

From our analysis based on 95ZK data, short-term GSAs have a seasonal profile with producers selling more gas to the market under short-term GSAs during high demand periods in the winter months.

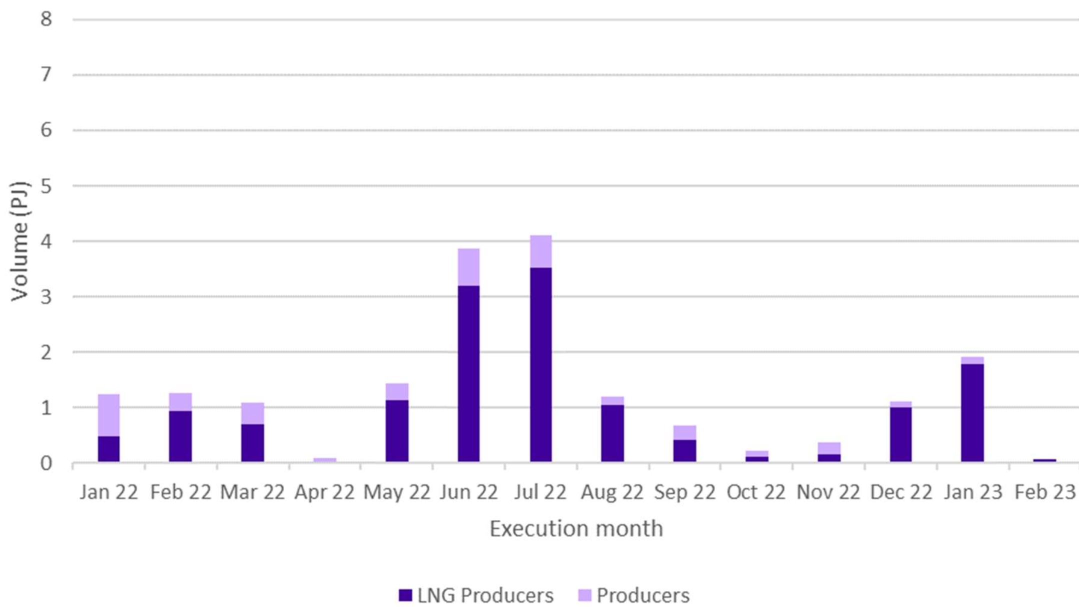
There has been an increase in the volumes of gas sold under short-term GSAs in December 2022 and January 2023, particularly for sales of gas with a term length between one day and one week. This increase in volume coincides with increased volumes traded in domestic short-term markets in quarter 1 of 2023.

Based on the AER's findings on spot markets and gas supply hub trades in quarter 1 of 2023:

- Exporters and producers offered record volumes of gas into the gas supply hub. Most gas sold was exempt from the $12/GJ price cap.
- Exporters sold more gas into domestic spot markets.
- Additional gas was available through spot markets resulting from several outages on the QGC export train.

Chart 2.14 presents short-term contract volumes by producer type. LNG producers are the primary supplier of gas under GSAs with a term of up to 1 week. The increase in volumes sold under short-term GSA in December 2022 and January 2023 was driven by LNG producers.

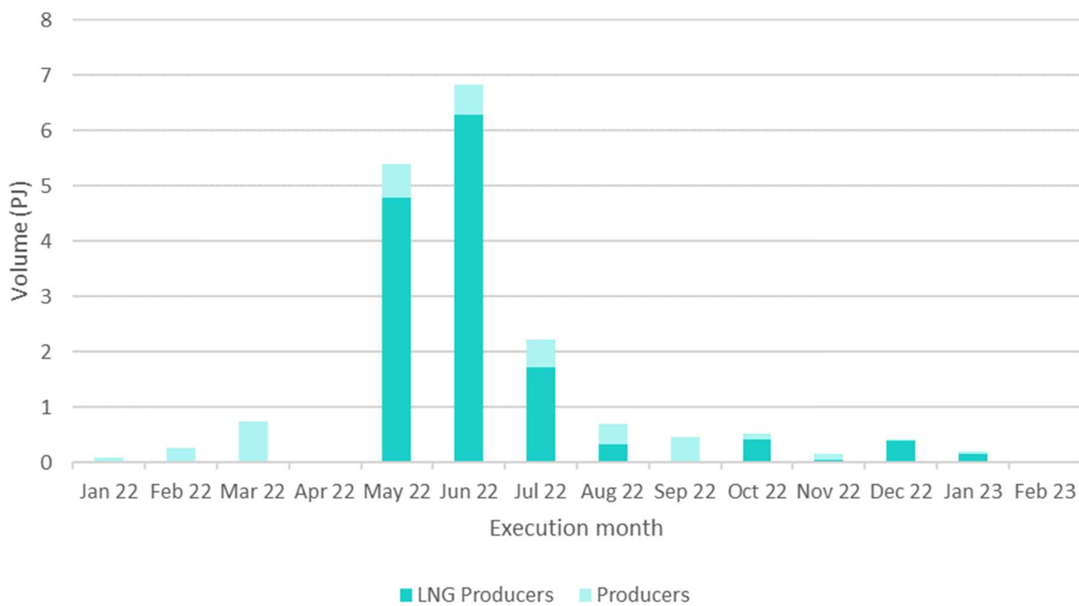
Chart 2.14: Contract volumes agreed to under Producer GSAs with a term length between one day and one week for delivery within 12 months of execution



Source: ACCC analysis of information provided by suppliers.

Similarly, LNG producers are the main providers of gas volumes sold under GSAs with a term length between one week and 3 months (chart 2.15).

Chart 2.15: Contract volumes agreed to under Producer GSAs with a term length between one week and 3 months for delivery within 12 months of execution



Source: ACCC analysis of information provided by suppliers.

The increase in volumes sold under short term GSAs and traded through domestic short-term markets in early 2023 appears to have been impacted by maintenance on QGC's LNG export facility. From December 2022 to March 2023, AEMO has reported QGC experiencing recurring maintenance impacting capacity on one of its LNG trains.[34]

Between December 2022 and March 2023, QGC has transported around 11.2 PJ on average less than total nameplate capacity to its export facilities.

2.6.2. Gas sold under short term GSAs from 23 December 2022 to 15 February 2023 for 2023 supply averaged under $11.00/GJ

Price cap applies to contracts entered into after 23 December 2022 for supply during the price cap period (23 December 2022 to 22 December 2023)

Table 2.2 displays short term GSAs reported by Producers from 23 December 2022 to 15 February 2023 in response to 95ZK Notices.

[34] AEMO, Energy Dynamics, LNG Maintenance.

Table 2.2: Short term Producer GSAs (23 December 2022 to 15 February 2023)

Seller	Average price (/GJ)	Volume-weighted average price (/GJ)	Minimum	Maximum	Volume (PJ)
LNG producers	$10.90	$10.78	$9.80	$12.00	2.63
Non-LNG producers	$10.97	$11.15	$9.75	$12.00	0.18
Total	$10.92	$10.81	$9.75	$12.00	2.81

Between 23 December 2022 and 15 February 2023 LNG producers sold 2.63 PJ of gas with non-LNG producers selling an additional 0.18 PJ. The maximum price agreed to under short term contracts was $12/GJ which was consistent with the price cap introduced by the Government on 23 December 2022.

The volume-weighted average price for contracts agreed to by LNG producers was $10.78 with non-LNG producers slightly higher at $11.15/GJ. Contemporaneous prices on facilitated markets ranged from an average of $12.78/GJ and $13.37/GJ on short-term markets, $12.15/GJ on the Declared Wholesale Gas Market and a volume-weighted average price of $10.85/GJ on the Wallumbilla Gas Supply Hub[35].

2.6.3. Gas sold under short term transactions between 15 March and 30 April for 2023 supply averaged around $12/GJ

Price cap applies to contracts entered into after 23 December 2022 for supply during the price cap period (23 December 2022 to 22 December 2023)

Table 2.3 displays short term transactions reported to the AEMO Gas Bulletin Board between 15 March and 30 April 2023 by seller categories.[36] This analysis includes LNG producers, non-LNG producers and retailers.

[35] Prices traded for short-term contracts and for delivery at WAL, SEQ.

[36] Under new obligations set out in the National Gas Amendment Market Transparency rule 2022 (Gas Transparency Measures), gas market participants have commenced reporting short-term transactions to the AEMO's Gas Bulletin Board effective from 15 March 2023. Table 2.3 summarises this data as reported to the AEMO's Gas Bulletin Board by these market participants.

Table 2.3: Gas short term trades for supply in 2023 (15 March to 30 April 2023)

Seller	Average price (/GJ)	Volume-weighted average price (/GJ)	Minimum	Maximum	Volume (PJ)
LNG producers	$11.49	$11.65	$8.00	$12.00	10.37
Non-LNG producers	$11.83	$12.47	$7.90	$20.13	2.42
Retailers	$13.61	$13.04	$8.80	$19.90	3.41
Total	$11.84	$12.07	$7.90	$20.13	16.20

Source: ACCC analysis of AER data.

Note: This analysis excludes swap contracts and supply for 2024-25. Retailer category includes both large (with generation assets) and smaller retailers. Data includes prices determined by pricing mechanisms referencing to spot markets. The AER notes that some transactions have been amended and/or cancelled after reporting to the Bulletin Board and some transactions appear to have been signed before 15 March 2023. AER intends to conduct further analysis on time of pricing (historic vs actual) and pricing mechanisms in its upcoming reports to bring further clarity to this data.

Between 15 March and 30 April LNG producers sold around 64% of short-term contracts reported to the AEMO Bulletin Board, with a max price of $12/GJ and a volume-weighted average price of $11.65/GJ.

Non-LNG producers sold 2.42 PJ of gas, with some contracts priced higher than the $12/GJ price cap. The ACCC will continue to monitor and review contract prices against the price cap. In the event we identify potential non-compliance, we will take appropriate action.

Retailers sold 3.41 PJ over the period, with a volume-weighted average price of $13.04/GJ.

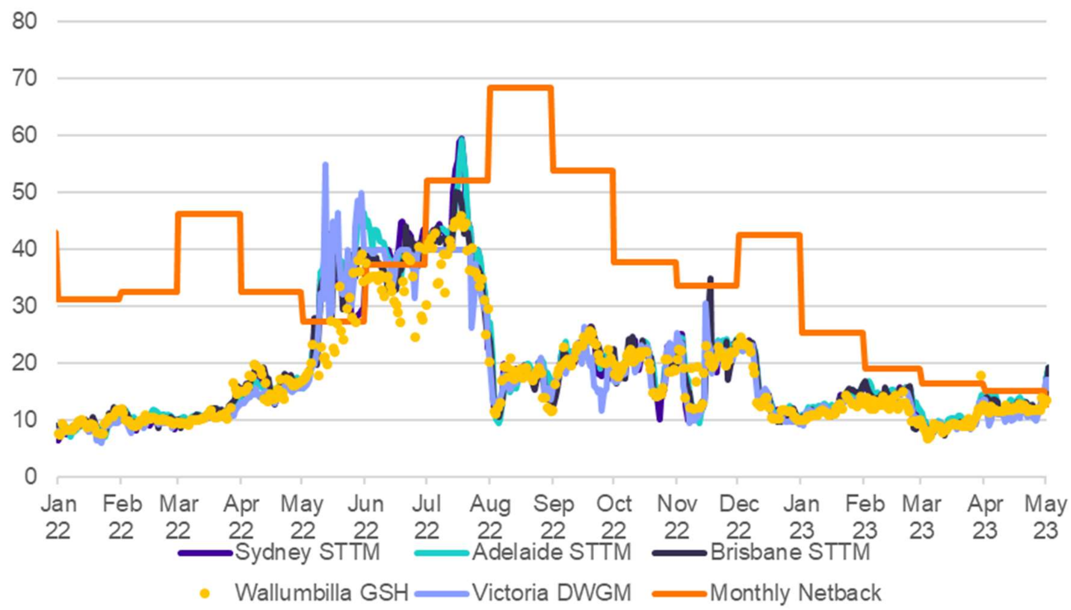
Contemporaneous prices on facilitated markets ranged from an average of $11.47/GJ and $12.10/GJ on short-term markets, $10.75/GJ on the Declared Wholesale Gas Market and a volume-weighted average price of $10.95/GJ on the Wallumbilla Gas Supply Hub.

2.6.4. Prices for gas sold on short-term markets in quarter 1 of 2023 have fallen from 2022

Price cap does not apply to short-term trading markets, and near term (next 3 days) trades and offers on the Wallumbilla Gas Supply Hub

Chart 2.16 shows daily prices in east coast domestic spot markets including the Short-Term Trading Market, the Victorian Domestic Wholesale Gas Market (DWGM) and the Wallumbilla Gas Supply Hub (GSH) compared to short-term LNG netback.

Chart 2.16: Domestic spot market prices



Source: AEMO, ACCC (LNG netback), S&P Global Platts.

Domestic spot prices that remained high in the middle of 2022 fell from their peak in July 2022. Prices fell further in December 2022 beginning 2023 around $10/GJ. Prices in early 2023 primarily traded below both prices that occurred in the second half of 2022 and LNG netback prices.

AEMO reported that the east coast wholesale gas spot prices eased in early 2023 and averaged $11.86/GJ across all markets in quarter 1 of 2023.[37] AEMO noted that the average price across all AEMO markets in March 2023 was $9.43/GJ and was the lowest since $8.81/GJ in January 2022.

As noted in section 2.6.1, the AER reported that exporters have sold more gas into domestic spot markets in quarter 1 of 2023. The additional volume available to domestic markets, primarily due to the LNG train outages experienced by QCLNG, alongside low gas generation in the NEM and falling international prices may have influenced the decrease in spot market prices.

More recent data suggests that spot prices trended upward in May possibly driven by a partial outage of the Longford gas plant, capacity constraints on the Moomba to Sydney pipeline (MSP) due to maintenance and likely ending of the LNG train outages experienced by QCLNG.

2.6.5. Producer sales on the Wallumbilla Gas Supply Hub averaged below $12/GJ in quarter 1 2023

Price cap does not apply near term (next 3 days) trades and offers on the Wallumbilla Gas Supply Hub

[37] AEMO (2024), Quarterly Energy Dynamics Q1 2023, April 2023.

In quarter 1 of 2023 LNG producers sold 6.5 PJ of gas on the GSH, with 67% of the gas sold being exempt from the price cap. Nearly all the gas sold was on a short-term basis (balance of day, day ahead or daily).

While there were some transactions of price cap exempt trades occurring above the cap, for the most part prices for gas sold that was exempt from the cap was comparable to prices sold where the cap applies. Over the quarter the volume-weighted average price for exempt trade averaged $10.29/GJ compared to $10.20/GJ for non-exempt trade.

Contemporaneous retail prices traded on the GSH, which are exempt from the price cap, were priced higher with a volume-weighted average of $13.56/GJ. Retail transactions contained a higher volume of weekly and monthly trades.

AER reports that gas covered by the price cap is being traded over winter months at $12/GJ, where exempt forward trade over the same period is trading at prices above the cap. The report further notes that holding other factors constant, this suggests that the cap is imposing downward pressure on the trade to which it applies.

2.7. Heads of Agreement

This section provides a high-level assessment of the LNG producers' compliance with the HoA for the reporting period between 18 November 2022 and 15 February 2023.

The Australian Government and the 3 east coast gas producers signed an updated HoA on 29 September 2022[38] with the objective of preventing a gas supply shortfall through access to secure and competitively priced gas for the east coast domestic market.

Under the terms of the HoA, excess gas produced by the LNG producers must be offered to the domestic market for reasonable supply periods, with reasonable notice, on competitive market terms and at prices no more than international customers will pay, before being offered to the international market.

The LNG producers have committed that prices offered to domestic buyers will be internationally competitive, and that:

- spot prices offered to the domestic market will have regard to the spot price LNG producers could reasonably expect to receive for uncontracted gas in overseas markets
- term prices offered to the domestic market will have regard to forward term prices LNG producers could reasonably expect to receive for uncontracted gas in overseas markets.

LNG producers have additionally committed to increased transparency measures, including publishing offers and EOIs on their website to make gas available more broadly to the Australian domestic market, and providing a quarterly report to the Minister for Resources outlining their respective actions and commitments in the HoA.

The ACCC will continue to monitor and report on the progress of the commitments LNG producers have made under the updated HoA as part of our ongoing gas inquiry reporting.

[38] Department of Industry, Science and Resources, Heads of Agreement - The Australian East Coast Domestic Gas Supply Commitment, September 2022.

2.7.1. LNG producer offers to the domestic market

For each cargo sold to the international market between 18 November 2022 and 15 February 2023, LNG producers were required to provide the ACCC with evidence that equivalent gas volumes were first offered to the domestic market.

During the reporting period, the east coast LNG producers sold 13 spot or additional LNG cargoes to the international market, totalling 49.9 PJ (8 PJ for supply in 2022, and 41.9 PJ for supply in 2023).

LNG producers primarily relied on EOIs and other offers to the domestic market made in 2021 and 2022 for delivery in late 2022 and 2023 to demonstrate compliance with the HoA. In our January 2023 report, we noted that LNG producers had offered up to 250 PJ of gas for 2023 supply between 19 August and 18 November 2022.[39]

Between 18 November 2022 and 15 February 2023, the east coast LNG producers made offers to the Australian domestic market of around 24 PJ for supply in late 2022 and 2023, in addition to previous offers for 2023 supply.

During this period, LNG producers sold 5.5 PJ of the gas to the Australian domestic market for supply in late 2022 and 2023, with all the gas supplied with a term length of less than one year. 2 PJ of gas was contracted to the domestic market as an outcome of LNG producer EOIs offered in late 2022.

LNG producers also traded gas via time and location swaps. Between 18 November 2022 and 15 February 2023 LNG producers swapped approximately 27 PJ of gas with buyers in the Australian domestic market for 2023 supply. Gas swaps do not provide a net increase in the volume of gas LNG producers supply to the Australian domestic market. However, gas swaps can provide increased liquidity to the market, particularly over periods of peak gas demand.

2.7.2. Equivalent volumes offered to the domestic market with reasonable notice

Under the HoA, LNG producers have committed to not offer uncontracted gas to the international market unless equivalent volumes of gas have first been offered with reasonable notice on competitive market terms to the Australian domestic gas market.

During the current reporting period, LNG producers primarily used EOI processes to demonstrate compliance with the HoA. They have also occasionally used brokers, short-term markets, and customer requests and bids to supply to the market.

In general, the EOIs used to demonstrate compliance with the HoA provided sufficient notice of around 2 or more weeks for gas buyers to consider the offer, and sufficient notice of around 2 or more months between the date of the offer and the supply start date.

2.7.3. International competitiveness of domestic offers

Under the HoA, LNG producers have committed to offer internationally competitive prices to the domestic market and will have regard to spot and term LNG prices they could reasonably expect to receive when making domestic offers.

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39 The total volume of gas offered by LNG producers may reflect gas that has been offered to a number of parties or offered multiple times. The total volume of gas offered may not reflect the volume of gas LNG producers have available for supply.

In our January 2023 interim report, we noted that LNG netback prices increased significantly during the corresponding reporting period and LNG producer offers to the domestic market had a strong regard to LNG netback.

Since the January 2023 report, LNG netback prices have fallen from their record highs while they remain well above the long-term averages. We have observed that LNG producer offers and EOI processes continued to have strong regard to LNG netback prices until the price cap came into effect on 23 December 2022. We note that while offers at LNG netback prices could be considered internationally competitive and meet the HoA commitments, very few domestic gas market buyers were willing or able to purchase gas at these high prices.

Following the implementation of the $12/GJ price cap, one LNG producer counter-offered the original EOI with price consideration to LNG netback at lower prices and volumes lower than the bid.

2.7.4. Transparency measures

The HoA requires LNG producers to publish on their websites information that provides domestic customers with visibility on uncontracted gas volumes and allow domestic customers to approach LNG producers to purchase these volumes. This information published every 6 months includes:

- Expression of interest and/or Annual Delivery Plans
- Volumes committed for sale in the previous period, by customer type (for example, Commercial and Industrial, Gas-Powered Generator, retailer, LNG producer), and
- Volumes offered because of extraordinary unplanned circumstances (see clause 2), and what the extraordinary unplanned circumstances were.

In general, all LNG producers published useful information on their websites demonstrating that they have the required web infrastructure available to publish relevant EOI information for transparency purposes.

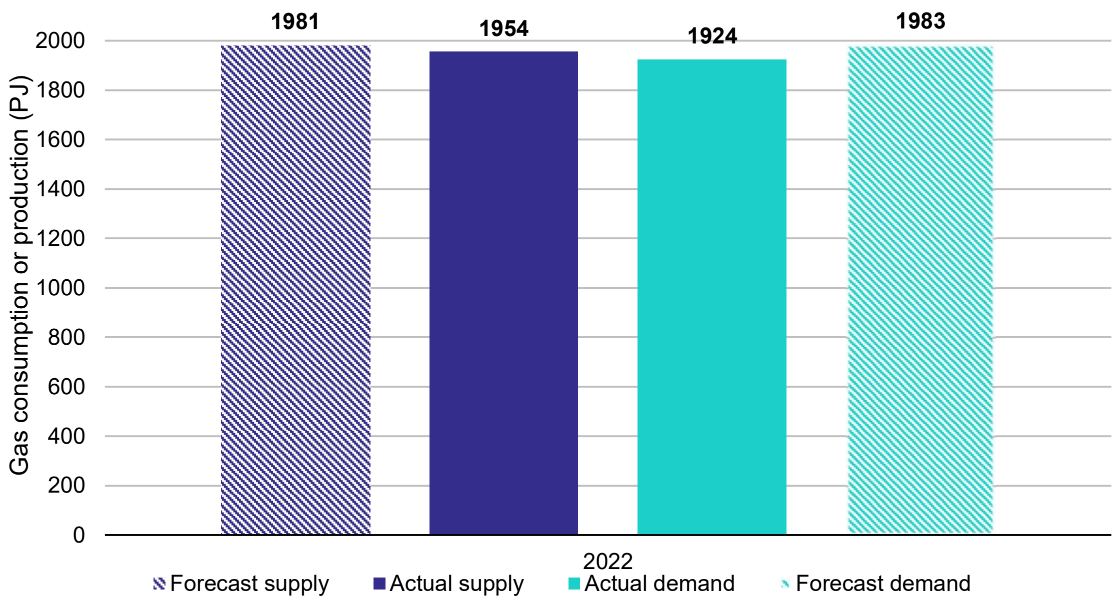
APLNG has published relevant EOIs on its website. The APLNG website provides information on the expired EOIs for further visibility on past terms and conditions. QGC and GLNG have also published key information in relation to their EOIs on their websites.

Appendix A – Supply and demand in 2022

This section compares the supply and demand for gas in 2022, including a comparison with previous forecasts of supply and demand and the supply shortfall that occurred in winter.

Chart compares the supply and demand forecasts made in July 2021 for 2022 with the actual production data for 2022 collected in March 2023. It shows that in 2022 supply was 27 PJ (~1.4%) lower than forecast, while demand was 59 PJ (~3.0%) lower than forecast. The 2022 actuals for demand do not account for gas losses throughout the pipelines.

Chart A.1: Supply and demand actuals for 2022 compared to the July 2021 forecast



Source: ACCC analysis of data obtained from gas producers as of March 2023 (actual) and May 2021 (forecast).

Note: Domestic demand actuals do not account for losses. Forecast demand is shown as reported in July 2021, which includes the LNG producers' uncontracted (or excess) gas as opposed to forecast additional/spot sales. Actual demand however shows realised spot/additional LNG sales, including the feedgas used to make the LNG for those sales.

While there was sufficient supply to meet demand on average across the year, between May and August 2022 the east coast gas market experienced an unexpected shortfall in supply. The shortfall that emerged over this period triggered a significant amount of volatility in the market, with spot prices more than doubling between the end of April and the end of May and reaching record highs of $50-$59/GJ in July. This, in turn, triggered a chain of events that had a range of adverse effects on gas users and the market more generally such as the higher prices in GSAs observed in this report.

This supply shortfall can be traced back to several coincidental events that occurred in international LNG markets, the NEM and on the supply side of the gas market, which resulted in the demand for gas exceeding supply in the first half of 2022. These include:

- Strong demand by LNG producers. The Russian-Ukraine conflict, in conjunction with some other events in international LNG markets, has resulted in higher demand for LNG and significantly higher LNG prices. Queensland LNG producers exported record volumes in the first half of 2022.
- Higher than forecast demand by GPG. In quarter 2 of 2022, the demand for gas by GPG increased substantially in some states. The increase over this period can largely be attributed to the significant unplanned outages and supply constraints experienced by a number of coal generation plants, lower renewable energy generation and higher electricity demand.
- Lower production from several sources. In the first half of 2022, rain, flooding and unplanned outages resulted in supply from a number of fields in the Cooper, Surat and Bowen basins (including a number operated by the LNG producers) being lower than at was at the same time in 2021. While the reduction in supply from these sources was more than offset by an increase in supply from the Gippsland and Otway basins, the increased supply was insufficient to meet the increased demand for gas by both LNG producers and GPG.

The coincidental events that occurred in the electricity market in May and June 2022 led to AEMO suspending the electricity market and AEMO introducing an administered price cap in gas wholesale markets. The price cap in the Victorian Declared Wholesale Gas Market remained in place until 1 August 2022.

Between June and August, AEMO took a number of steps to try and manage the supply shortfall. In particular:

- In Victoria, AEMO drew on the powers and tools it has as both the system and market operator in the DWGM, including issuing directions to GPG operators to curtail demand.
- Outside Victoria, AEMO relied upon the ‘gas supply guarantee’.[40] In June and July 2022, AEMO utilised the gas supply guarantee and LNG producers committed to bring additional gas to southern markets.

The remainder of this section examines supply and demand outcomes in more detail.

Actual gas production was lower than forecast due to LNG production issues and Northern Territory flows

In 2022, gas supply in was ~1.4% lower than forecast. As shown in Table A.1, this was mostly due to decreased production in Queensland, and was partially offset by increased production in the southern states.

40 This is a voluntary arrangement that was implemented in 2017 and can be triggered if AEMO identifies a shortfall in gas available to meet GPG demand in a peak NEM period. See AEMO, Gas Supply Guarantee Guidelines version 2, April 2020.

Table A.1: Supply forecast compared to actual production in 2022 (PJ)

Component	Forecast	Actual	Difference	Difference (%)
Queensland production	1533.2	1475.6	-57.6	-3.8%
Cooper Basin production	79.6	83.9	4.3	5.5%
Southern states production	341.6	373.9	32.3	9.4%
Storage withdrawals	11.9	12.9	1.0	8.7%
NT supply	14.9	7.6	-7.4	-49.2%
Supply total	1981.2	1953.9	-27.3	-1.4%

Source: ACCC analysis of data obtained from gas producers as at March 2023 (actual) and May 2021 (forecast).

Lowered Queensland production was driven primarily by the LNG producers, alongside some unplanned maintenance on LNG trains. This decrease in production was reported by LNG producers as being due to the impact of flooding during winter 2022, which reduced well performance and affected access to fields. This was noted in the annual reports of some of the firms with a stake in the LNG producers:

- Origin's half-year FY2023 report indicated that APLNG's production was down 5 per cent compared to the HY2022, 'reflecting the cumulative impact of the La Niña weather event which restricted access to fields for workovers, drilling and optimisation activities.' Planned maintenance at gas processing facilities and unplanned outages also impacted production during the period.[41]
- Santos' 2022 annual report noted that annual GLNG's LNG production was down compared to the previous year 'due to lower volumes of third-party gas supply, partially offset by the continued ramp-up in GLNG upstream equity gas supply'.[42]
- Shell's (majority owner of QGC) quarter 4 of 2022 report noted that its global integrated gas businesses segment's liquefaction volumes were lower than they may have been partially because of operational issues at QGC.[43]

This also coincided with maintenance on LNG trains:

- APLNG took one full LNG train off-line for maintenance between July and August 2022, and half of one train in later September 2022.[44]
- QCLNG took one half of an LNG train offline for maintenance between June to July and October to November 2022, and a full train offline in December 2022.[45]

Gas supply in Queensland was also affected by lower than forecast supply from the Northern Territory via the Northern Gas Pipeline. This was due to gas production issues in

41 Origin Energy, '2023 Half Year Report', Origin Energy Limited, February 2023, pp 7–9, accessed 12 April 2023.

42 Santos, 'Annual Report 2022', February 2023, page 23, accessed 12 April 2023.

43 Shell PLC, '4th quarter 2022 and full year unaudited results', Shell PLC, February 2023, page 3, accessed 12 April 2023.

44 AEMO, 'LNG maintenance', AEMO, March 2023, accessed 19 April 2023.

45 ibid.

the Blacktip gas field that resulted in no gas flowing along the Northern Gas Pipeline between early September and December 2022.[46]

In the southern states, production was higher than forecast, primarily in the Gippsland Basin. At the 2023 Australian Domestic Gas Outlook conference, the Commercial Director of Esso (one of the partners in the Gippsland Basin Joint Venture) stated:

> 'We stepped up in 2022 to fill the gap left by coal generator outages, coal supply disruptions and lower than expected renewable generation. Last year the Gippsland Basin Joint Venture increased gas production by 11% over the year before, which meant Longford produced more gas in 2022 than in any year since 2017.' [47]

However, it is also clear that the increase in exports in was aided by additional supply from Victoria, with material volumes of gas (~28 PJ)[48] transported from Victoria to Queensland to meet LNG producer and Queensland domestic demand, with gas continuing to flow north until May, which is when gas usually flows south to meet the winter demand.

Actual gas demand was lower than forecast, despite increased need for gas powered generation and international LNG prices

In 2022, gas demand was ~3.0% lower than forecast. A key reason for the reduction in demand in 2022 was due to lower than forecast exports by LNG producers. Demand for LNG exports is the largest component of demand on the east coast, and can have a material effect on the gas available for domestic buyers on the east coast.

As shown in table A.2, gas used to produce LNG sales under long-term supply and purchase agreement (SPAs) and LNG spot sales were 84 PJ lower than forecast in July 2021 (including all uncontracted/excess gas). This was largely due to LNG production issues in the second half of the year. However, during the first half of the year LNG producers responded to the increased international demand and high LNG spot prices by exporting record volumes of LNG over this period.[49]

Table A.2: Production by LNG producers in 2022 for domestic and international sales actuals vs forecast in July 2021 (PJ)

Component	Forecast	Actual	Difference	Difference (%)
Production of LNG for long-term SPA demand	1340.6	1271.6	-69.0	-5.2%
Production of LNG for spot and additional sales	100.8	86	-14.8	-14.7%
Sales to the domestic market	159.2	204.3	45.1	28.3%

Source: ACCC analysis of data collected from LNG producers.

46 D Fitzgerald, 'NT's Blacktip gas field production drops, forcing shutdown of Northern Gas Pipeline', Australian Broadcasting Corporation (ABC), 22 October 2022, accessed 18 April 2023.

47 ExxonMobil, 'The evolving role of Gippsland gas in Australia's east coast gas market', ExxonMobil, March 2023, accessed 13 April 2023.

48 AER, 'Wholesale Markets Quarterly, Q3 2022', 16 November 2023, p. 11.

49 Port of Gladstone, 'Port of Gladstone Cargo statistics', May 2023.

Despite increases in exports in the first half of 2022, LNG producers brought additional gas to southern markets.[50] This additional supply is evident in the increase in LNG producers' domestic sales (see table A.2), as well as reported flows on the pipelines from Queensland to the southern states.[51]

LNG producers were forecast to be net withdrawers from the domestic market, however they ended up as net contributors, albeit at lower levels than in previous years (chart 1.8).

While LNG exports were lower than forecast, demand from domestic buyers was higher than forecast. As shown in Table A.3, this was due in large part to higher than forecast GPG requirements in the electricity market (56% higher). Residential, commercial and industrial demand overall was marginally lower than forecast.

Table A.3: Domestic demand actuals in 2022 vs forecast in July 2021 (PJ)

Component	Forecast	Actual	Difference	Difference (%)
Residential & commercial	192.8	194.3	1.5	0.8%
Industrial	260.6	256.4	-4.2	-1.6%
GPG	73.9	115.5	41.7	56.4%
Total	**527.3**	**566.3**	**39.0**	**7.4%**

Source: Forecast data from AEMO's 2021 GSOO and actuals data from the 2023 GSOO.

Note: Actuals do not include losses.

The higher than forecast demand for gas generation reflects one of the key risks for gas supply and demand on the east coast. Gas generation was higher due to significant events that occurred within the electricity market over 2022, including unexpected outages in coal generation and low renewable generation. This led to substantially and unexpectedly increased demand for gas in winter 2022. According to the AER, GPG operators over this period purchased gas from the spot markets at record levels to cover the unplanned generation.[52]

50 AER, 'Wholesale Markets Quarterly Q2 2022', 6 September 2022, p 14.

51 AER, 'Wholesale Markets Quarterly Q3 2022', 16 November 2023, p 11.

52 AER, 'Significant price variation report', 30 September 2022, p 12.

Appendix B: Domestic prices in 2023

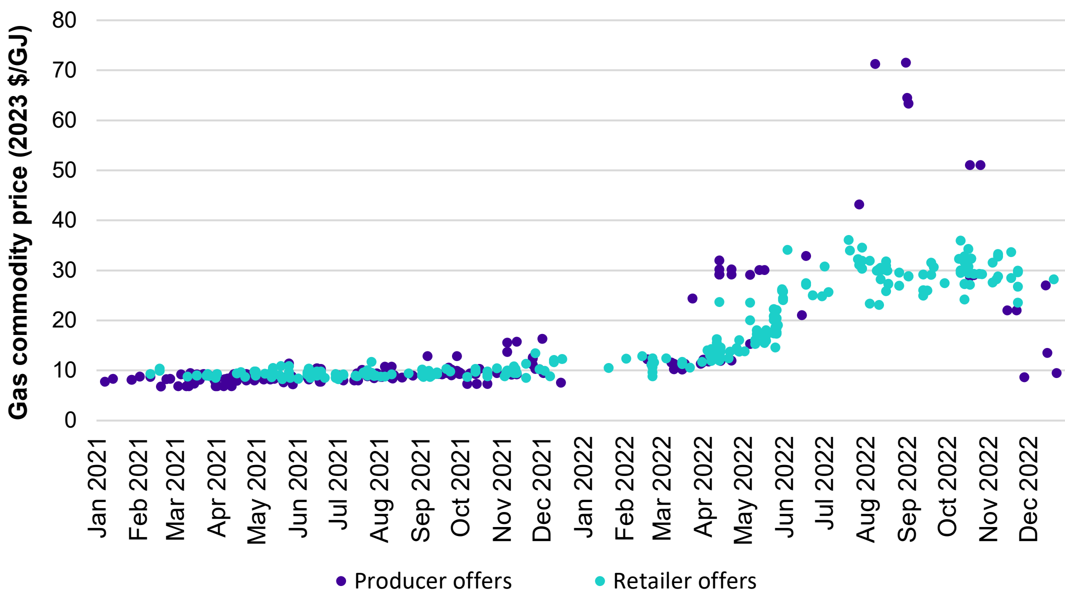
This appendix presents information on wholesale gas commodity prices in the east coast gas market for supply in 2023. In January 2023, we reported on offer and contract prices between 1 January 2021 and August 2022 for supply in 2023. For completeness, this report extends the analysis of pricing for supply in 2023 offered up to December 2022.

Our analysis is based on offers and contracts for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months.

B.1 Offers and bids

Chart B.1 shows prices offered by producers to all buyers or retailers to C&I users and gas-powered generators for 2023 supply over the period from 1 January 2021 to 31 December 2022.

Chart B.1: Gas commodity prices (2023$/GJ) offered in the east coast gas market for 2023 supply



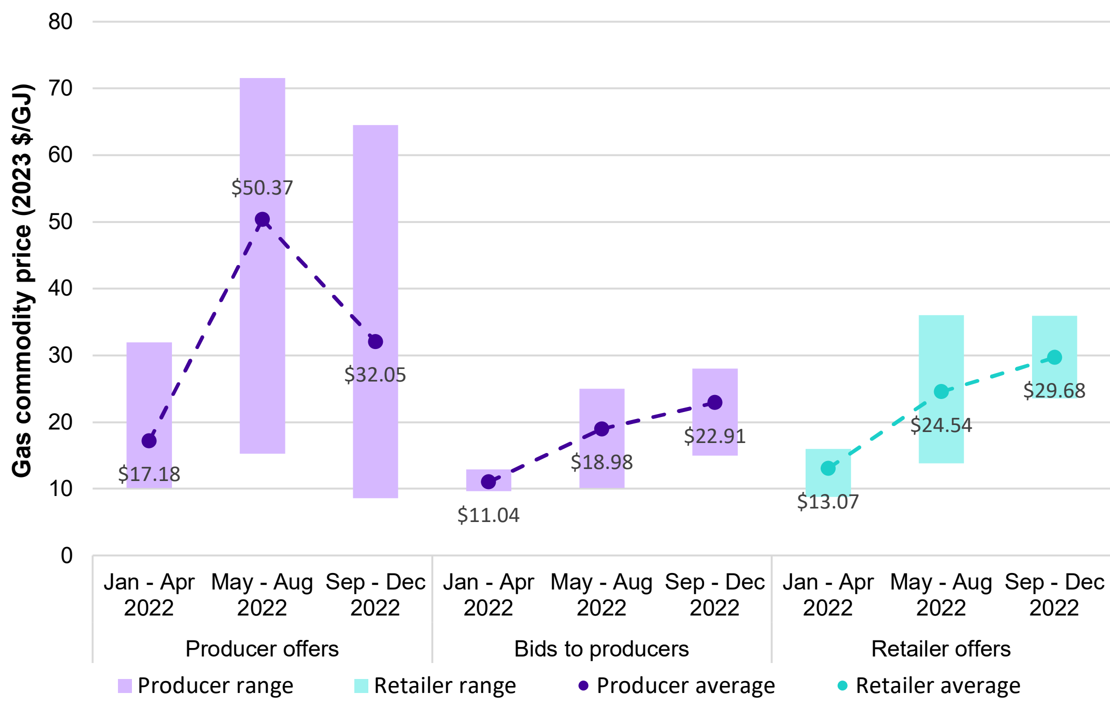
Source: ACCC analysis of bid and offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA.

Prices offered for 2023 supply increased until August 2022. Prices offered by producers in 2022 were higher than retail prices. There were instances when producer offers (i.e., $70/GJ) were significantly higher than retail offers.

The majority of producer offers in the second half of 2022 were at or around short term JKM netback prices. While retail prices increased in 2022, most offers tracked well below short term netback prices.

Chart B.2: Gas commodity prices (2023$/GJ) offered in the east coast gas market for 2023 supply



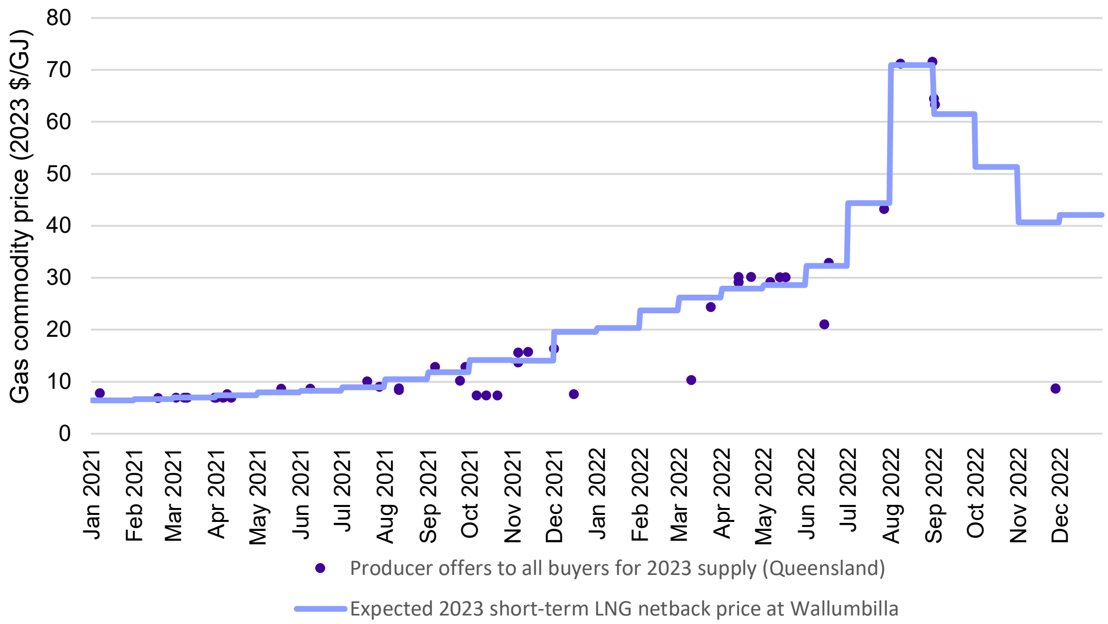
Source: ACCC analysis of bid and offer information provided by suppliers.

Note: Volume-weighted average prices are displayed next to the point, or below the price range. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA.

Average prices and the spread of prices offered by producers from September to December 2022 were higher compared to retailer average and price range. Average producer prices offered from September to December 2022 were $32.05/GJ, a decrease of 35% from the previous quarter. In comparison, average prices offered by retailers in from September to December 2022 for 2023 supply were $29.68/GJ, an increase of 21% from the previous quarter.

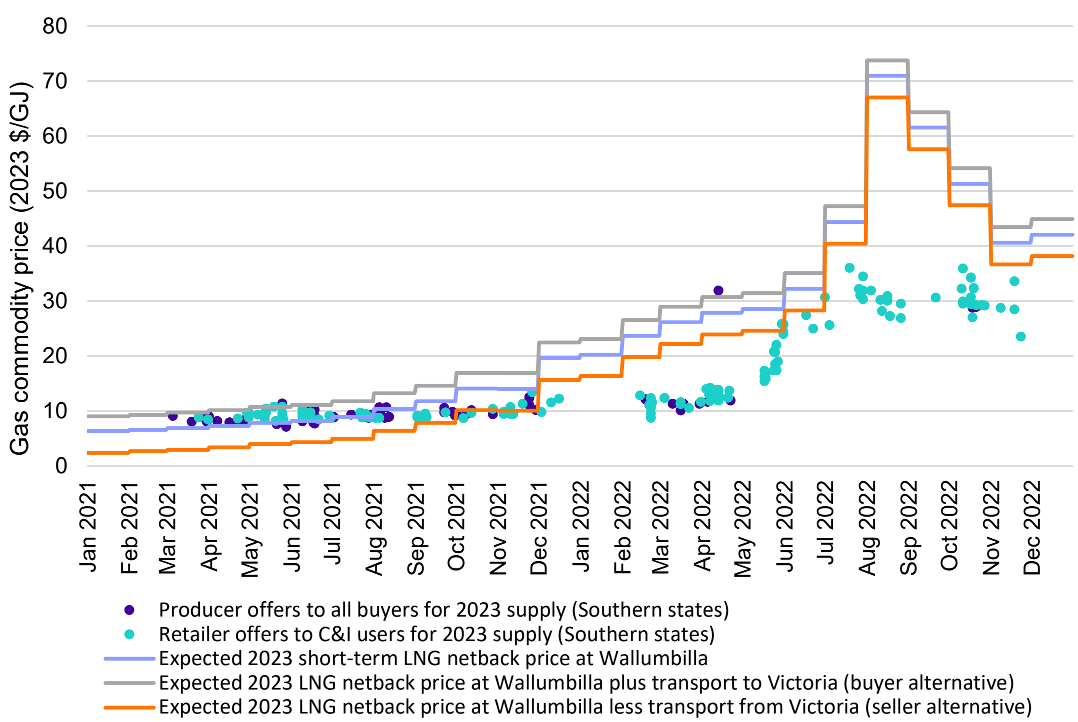
Chart B.3 shows offers made by producers between 1 January 2021 and 31 December 2022 for supply in Queensland in 2023 against expectations of 2022 LNG netback prices.

Chart B.3: Gas commodity prices offered by producers to all buyers for 2023 supply in Queensland (2023$/GJ



Our January report observed that the expected LNG netback prices increased throughout the reporting period. LNG netback price expectations increased further in the second half of 2022 and the majority of producer offers to Queensland tracked LNG netback prices.

Chart B.4: Gas commodity prices offered by producers to all buyers, and retailers to C&I users for 2023 supply in the southern states (2023$/GJ)



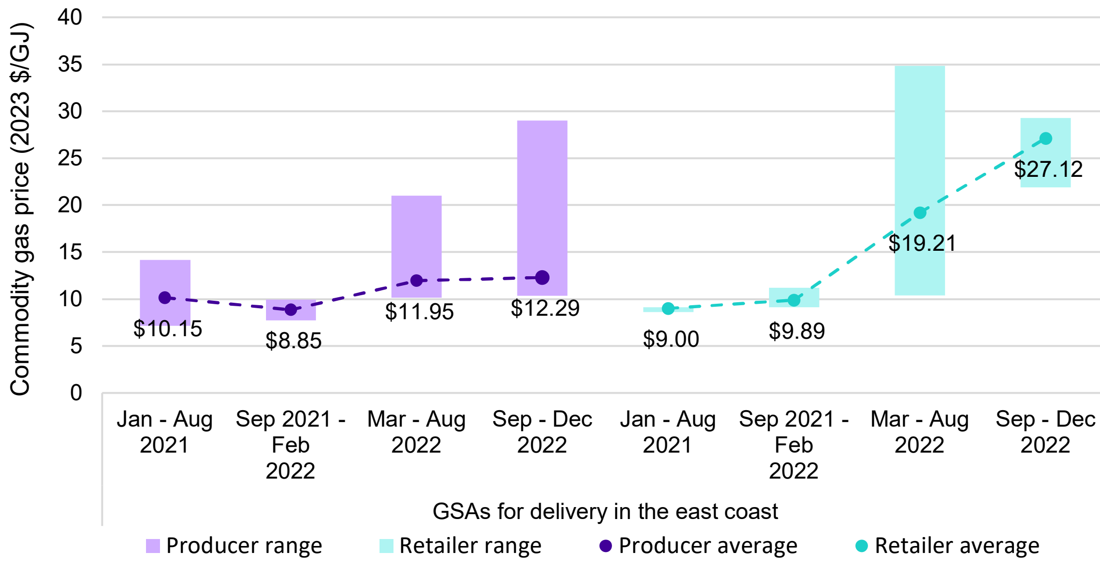
B.2 Prices payable for supply in 2023

This section presents prices payable and volume flexibility agreed under GSAs for supply in 2023 that were entered into between 1 January 2021 and 31 December 2022. Our approach to GSA analysis is described in appendix C.

B.2.1 Prices payable under GSAs for supply in 2023

Chart B.5 presents prices payable under producer and retailer GSAs for supply in 2023 which were executed between January 2021 and December 2022.

Chart B.5: Expected gas commodity prices (2023 $/GJ) payable under GSAs entered in the east coast gas market for 2022 supply



Source: ACCC analysis of information provided by suppliers.

Note: ACCC pricing model last updated on 14 April 2023.

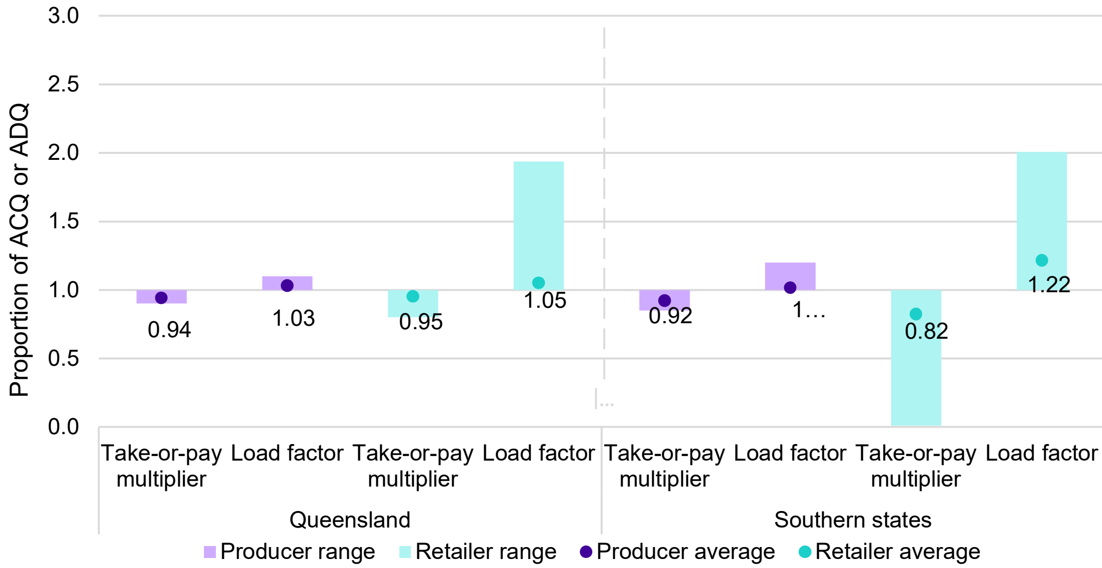
Prices agreed by producers between September 2022 and February 2023 for 2023 supply averaged $12.29/GJ, a 3% increase from the March-August period. Both the average price and price spread under producer GSAs between September 2022 and February 2023 for 2023 supply were higher compared to the previous period. Prices agreed by retailers between September 2022 and February 2023 averaged $27.12/GJ, an increase of 41% from the previous quarter.

There were no GSAs executed after 22 December 2022 for supply in 2023 and only 2 GSAs executed between November and December 2022. This may reflect both an anticipation and the impact of the price cap on contracting behaviour.

B.2.2 Flexibility under GSAs for supply in 2022

Chart B.6 presents volume-weighted average take-or-pay multipliers and load factors under GSAs for supply in 2023 which were executed between January 2021 and December 2022.

Chart B.6: Average load factor and take-or-pay multiplier under GSAs entered in the east coast gas market for 2023 supply



Source: ACCC analysis of information provided by suppliers.

Producers provided similar levels of flexibilities for Queensland and the southern states. In comparison, retailers provided greater flexibility for supply in the southern states.

On average, both retailers and producers provided similar levels of take-or-pay flexibility for supply in Queensland. However, retailers have provided a large range of load factor for the Queensland supply. In the southern states, retailers provided a lower average take-or-pay multiplier and a large range compared to producers.

Appendix C: Approach to reporting on gas prices

This appendix sets out the ACCC's approach to reporting on prices offered, bid and agreed to under GSAs, as presented in chapter 2 and Appendix B.

C.1 Parameters of reported prices

The following apply to our analysis of prices reported in chapter 2 and Appendix B:

- Prices reported are GST exclusive.
- Prices reported are wholesale gas commodity prices and do not include separate charges for transporting gas to the user's location or other ancillary charges (although delivery charges may, in some cases, be bundled with commodity gas prices). The prices charged for transportation have been excluded from our analysis to enable a more direct comparison between the prices paid by buyers in different locations and with differing transportation requirements.
- Only arm's length transactions are included. Related party transactions are excluded to ensure that the prices reported are reflective of market conditions.
- Transactions with a term of at least one year and an annual contract quantity of at least 0.5 PJ are included in sections 2.3, 2.4 and 2.5. Section 2.6 reports on short term contracts (with a term length of less than 12 months) and prices
- Where average prices are reported, these are volume-weighted average prices unless otherwise mentioned. Where average prices are reported for a region, these are based on the location at which the gas is to be delivered rather than the location at which the gas is produced.
- Retailer category is defined to include aggregators and other parties selling wholesale gas who are not primarily engaged in the production of gas. The following entities were classified as 'retailers' in sections 2.3, 2.4 and 2.5 where the 95ZK data is used: Origin Energy, AGL, EnergyAustralia, ENGIE, Alinta Energy, Shell Energy Australia, Macquarie Bank and Weston Energy.

We note that prices of individual transactions are not necessarily directly comparable due to differences in non-price aspects such as flexibility, quantity, contract term and delivery point. These non-price terms and the flexibility they can provide may be valued differently depending on the customer and may influence the gas prices that are ultimately agreed. The ACCC has not sought to adjust for these factors in the analysis presented in chapter 2 and Appendix A, but rather reports on GSA flexibilities separately in these sections.

C.2 Reporting on offers and bids

The information in this section describes our approach to reporting on offers and bids, as presented in sections 2.3 and 2.4, and should be read in conjunction with information above in section C.1.

The following also applies to our analysis of offers and bids.

- The analysis only includes those offers and bids that contain clear indications of price, quantity, supply start and supply end dates.
- The commodity gas price for each offer and bid has been estimated using the pricing mechanisms specified in each offer or bid along with assumptions relating to key variables (for example, oil and LNG prices, foreign exchange rates and inflation) based on the expectations for those variables at the time of the offer or bid.[53]
- Some producer and retailer offers specify a pricing mechanism linked to Brent crude oil prices. We calculated an indicative price in such offers using the following approach:
  - For each day in the month in which an offer was made, we calculated the expected price of Brent crude oil for the year of supply (for example, 2022) by taking a simple average of Brent crude oil prices expected in each month of that year.
  - We then averaged these daily estimates to derive a monthly estimate for the year of supply.
  - We then applied this monthly estimate to the pricing mechanism specified in the offer to arrive at an indicative price.
- A similar approach is used to calculate an indicative price for offers and bids that specify a pricing mechanism linked to JKM (LNG) prices.

C.3. Comparing domestic price offers with expectations of future LNG netback prices

In section 2.4 of this report, we compare prices offered (for those offers with fixed or JKM-linked pricing and a term of 1–3 years):

- for delivery in Queensland to expectations of LNG netback prices in Queensland in the month the offer or bid occurred
- for delivery in the southern states to the range of prices expected under a bargaining framework, outlined in previous ACCC reports in the month the offer or bid occurred.

C.3.1 Approach to comparing offers in Queensland

We calculate LNG netback prices, based on JKM= spot prices, to compare against prices offered in Queensland (which is where the east coast gas market's LNG export facilities are located).

Asian LNG spot markets provide an alternative for LNG producers to selling gas in the domestic market. As such, Asian LNG spot prices are likely to influence domestic gas prices under current market conditions. While LNG netback prices likely play an important role in

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[53] In all estimates of offer and bid prices in this report, the following assumptions were made, where relevant:

- The expected AUD/USD exchange rate is equal to the average rate prevailing during the month in which the offer or bid occurred (source: RBA).
- The expected Brent Crude oil price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: Bloomberg).
- The expected Japan Korea Marker (JKM) LNG price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: ICE).
- The applicable CPI is based on actual CPI where available at the time the bid or offer occurred (up to the most recent available quarter, source: ABS), and 2.5% thereafter.

the east coast gas market, they are not likely to be the sole factor influencing domestic prices.

The gas prices received by producers will also depend on the location of gas fields, the marginal cost of supply, the buyer's maximum willingness to pay and the demand-supply balance, the importance of which will differ over time.

To calculate an LNG netback price to compare against offers for future supply, we have:

- calculated a forward-looking LNG netback price as at the date of the offer – based on market expectations of future LNG spot prices during the period of supply – as this gives the best indication of the likely opportunity cost of supplying gas to the domestic market[54]
- used short-run incremental costs of LNG production and transport, since LNG producers are making decisions about the sale of uncontracted gas over the short-run.

We have calculated LNG netback prices using the method and assumptions used for the LNG netback price series, which is regularly published on the ACCC's website, and which is described in detail in the ACCC's Guide to the LNG netback price series.[55]

The domestic offers analysed in sections 2.3 and 2.4 are all for gas supply over the entire calendar year. Therefore, for the purpose of comparison for offers in a given year, 2021 as an example, we calculated an average 2021 LNG netback price that an LNG producer would need to receive to be indifferent between selling the gas to the domestic buyer over the entirety of 2021, and selling cargoes on the Asian LNG spot market in 2021.

For example, we calculated the average of LNG netback prices for 2021 that an LNG producer would have expected in July 2020 as follows:

- We obtained JKM futures prices for each month of 2021 that were quoted by ICE on each day during July 2020.
- We converted the monthly 2021 JKM futures prices into LNG netback prices at Wallumbilla by:
  - converting the prices from USD$/MMBtu into AUD$/GJ using contemporaneous exchange rates and a conversion factor between MMBtu and GJ
  - subtracting the short-run marginal costs of shipping, liquefaction[56] and transportation.[57]
- We averaged these monthly LNG netback prices to arrive at an average of LNG netback prices for 2021 expected on each day during July 2020.
- We then averaged these 2021 expectations for each day of July 2020 to arrive at an average of LNG netback prices for 2021 expected during the month of July 2020.

As has been noted before, our approach to calculating LNG netback prices does not involve deducting the capital costs of building the Queensland LNG export facilities. This is because these costs are sunk and do not influence the decisions of LNG producers, at the margin, to supply uncontracted gas to the domestic or export markets.

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54 For this, we have used JKM futures prices (source: ICE).

55 ACCC, Guide to the LNG netback price series, October 2018.

56 We estimated the incremental costs of liquefaction and fuel used in the operation of the LNG trains based on data obtained from LNG producers in Queensland.

57 We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from LNG producers.

Moreover, LNG spot prices are determined by short-run LNG market dynamics, such as LNG supply into spot markets, the level of competition, as well as demand and the ability for buyers to switch to alternative fuel sources (such as coal). These short-run dynamics are influenced by short-run supply, which in turn is determined by short-run incremental costs for the marginal supplier of LNG to spot markets (which are not influenced by the capital costs of building LNG export facilities).

There may be times, however, where LNG spot prices would be sufficiently high to allow LNG producers to recover apportioned capital costs (for their relevant LNG facility). There are also likely to be periods in which the opposite would be the case

C.3.2 Approach to comparing offers in the southern states

Due to the cost of transportation between the southern states and Queensland, there is a range of possible pricing outcomes in gas supply negotiations in the southern states, which would usually be expected to fall between:

- the buyer alternative (representing a ceiling in negotiations) – the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location
- the seller alternative (representing a floor in negotiations) – the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla.

Where a price actually achieved in a negotiation will fall within this range is likely to depend on a number of factors, including the location of the buyer, the expectations of the parties about supply and demand dynamics in the southern states, the relative bargaining strength of the parties and the non-price terms and conditions agreed by the parties.

The supply-demand outlook in the southern states is particularly important to the outcome. If there are limited supply options for gas users in the southern states, such as in the case of an expected gas supply shortfall, users that are unable to reach an agreement for gas supply with a southern supplier will need to transport gas from Queensland. In this scenario, gas suppliers in the southern states would be expected to offer a buyer alternative price in every region in the southern states.

Further, a southern supplier would be expected to seek a higher price the further away a gas user is from Queensland. Since gas users in Victoria are located further away from Queensland than users in NSW and South Australia, they will likely be offered higher prices than users in those other states, all other things equal. If, in a well-functioning market, a southern supplier were to make an offer above this, then regardless of the location of the buyer it would likely be more economic for the buyer to purchase gas from Queensland and transport it to its location. Therefore, the buyer's alternative price in Victoria is indicative of the maximum price that would be likely to prevail in a well-functioning market.

Conversely, if there were sufficient supply and diversity of suppliers in the southern states, this would be likely to alter the relative bargaining positions of gas suppliers and gas buyers. Gas buyers would be able to source gas from another supplier in the southern states rather than having to transport it from Queensland, and increased competition would be likely to lead suppliers to offer prices closer to the 'seller alternative' price. In this scenario, the prices offered by suppliers in the southern states would be lower the further away the source of supply is from Queensland.

To meaningfully analyse the level of prices offered in a particular location in the southern states using this bargaining framework, it is necessary to compare those prices to the buyer/seller alternative range in that specific location. In the analysis in chapter 2 and Appendix B we present a buyer and seller alternative for Victoria.

We note that the LNG netback price and buyer and seller alternative price do not account for other factors that may influence the prices offered to gas buyers, such as flexible non-price terms and conditions in GSAs, the contract length and, in the case of retailer offers, retailer costs and margins.

C.4 Reporting on GSA pricing and flexibility

The information in this section describes our approach to reporting on GSAs, as presented in section 2.4.1and should be read in conjunction with information above in section C.1

The following also applies to our analysis of GSAs:

- For the purpose of the analysis of producer prices, we have included GSAs executed at arm's length by producers with all counterparties. For the purpose of the analysis of retailer prices, we have only included GSAs between retailers with C&I users and gas-powered generators. Analysis may also include price amendments.
- We estimated prices payable using recent expectations of key variables, including, where relevant, the AUD/USD foreign exchange rate, inflation, Brent Crude oil and JKM.[58] To estimate the price payable in a given supply year, we have taken the simple average of expected prices in each supply month in that year.

We also report on the average load factor and take or pay multiplier in section 2.4.2. Both the load factor and the take-or-pay multiplier are measures of the level of flexibility allowed under the contract. Specifically:

- The load factor is calculated as the ratio of the annual aggregate of the maximum daily quantities allowed under the GSA and the annual contract quantity. The higher the load factor, the more gas a gas user can take on a given day above their average daily allowance.
- The take-or-pay multiplier is the percentage of the contracted gas that must be paid for by the buyer whether or not the buyer actually takes delivery of the gas. A GSA with a take-or-pay multiplier of 100% implies that the buyer has to pay for all of the gas it has contracted to take, irrespective of whether it uses the gas in the year. A GSA with a take or pay multiplier of 0% is considered an option contract as the buyer does not have any obligation to purchase gas under the contract.

[58] This differs to our approach to reporting on prices offered and bid, in which we estimate prices based on expectations in the month the offer or bid occurred.

Appendix D: Transportation and Storage

D.1 Introduction

This appendix provides additional analysis of:

- contracted pipeline capacity from April 2023 to October 2025, and physical flows on key pipelines between March 2022 and March 2023, and
- contracted capacity for use of the Dandenong LNG and Iona underground storage facilities from April 2023 to March 2026, and actual gas held in these storage facilities between January 2019 and March 2023.

D.2 Background

The east coast gas market transmission pipelines transport gas from production fields in the Northern Territory, Queensland, South Australia and Victoria to major demand centres in cities and regional areas in the east coast. While the cost of transporting gas on a single pipeline is relatively small when compared to gas commodity prices, gas is generally not transported on a single pipeline. Rather, it can involve the transportation of gas across an interconnected set of pipelines in the east coast, the cost of which can quickly add up.

Generally, gas pipelines exhibit natural monopoly characteristics. These characteristics mean that paying for access to an existing pipeline is often more economically efficient than constructing a new pipeline. They can also accord the service provider with substantial market power. The exercise of market power can have a detrimental effect on economic efficiency, the costs of which are ultimately borne by consumers.

Market participants contract a diverse range of gas storage services to help meet seasonal peak demand in southern states, lower overall supply costs (by taking advantage of variable seasonal commodity pricing) and manage market risks. These services are provided by different storage facilities including large longer-term storage facilities located close to gas fields, small seasonal or peaking storage facilities located close to demand centres, and short-term peaking storage services on gas pipelines.

The Dandenong LNG and Iona underground storage facilities are the only facilities that provide storage services to third parties in the east coast gas market. The Dandenong LNG storage facility plays an important role in meeting intraday peak periods for retailers and other major users, as well as system security more generally.

D.3 Pipeline capacity on key pipelines remains limited

Declining gas production in the southern states has placed increasing importance on transmission pipelines to transport additional gas south from Queensland to meet demand. The charts below provide an outlook of the uncontacted capacity for key southern haul pipelines, including the South West Queensland Pipeline (SWQP), Moomba to Adelaide Pipeline System (MAPS) and Moomba to Sydney (MSP).

Pipelines that do not have sufficient uncontracted capacity available, may prevent some shippers from being able to access firm transport capacity. These shippers may need to rely instead on less certain services, such as available/interruptible services and the Day Ahead Auction, to transport gas to southern states, especially during peak periods in winter months.

The outlooks for major transmission pipeline contracted capacities for the period from April 2023 to October 2025 are provided in charts D.3.1 and D.3.2.[59]

Chart D.3.1 indicates that some of the southern haul pipelines have limited uncontracted capacity available over the period to October 2025. This is in contrast to the other key east coast pipelines and compression facilities that still have significant uncontracted capacity available over the outlook period.

The uncontracted capacity on key southern haul pipelines including the SWQP, MSP and MAPS and compression services remains limited. While there is likely to be sufficient pipeline capacity to meet gas demand in the southern states, the lack of uncontracted capacity may affect the ability of some shippers to transport additional gas from the north.

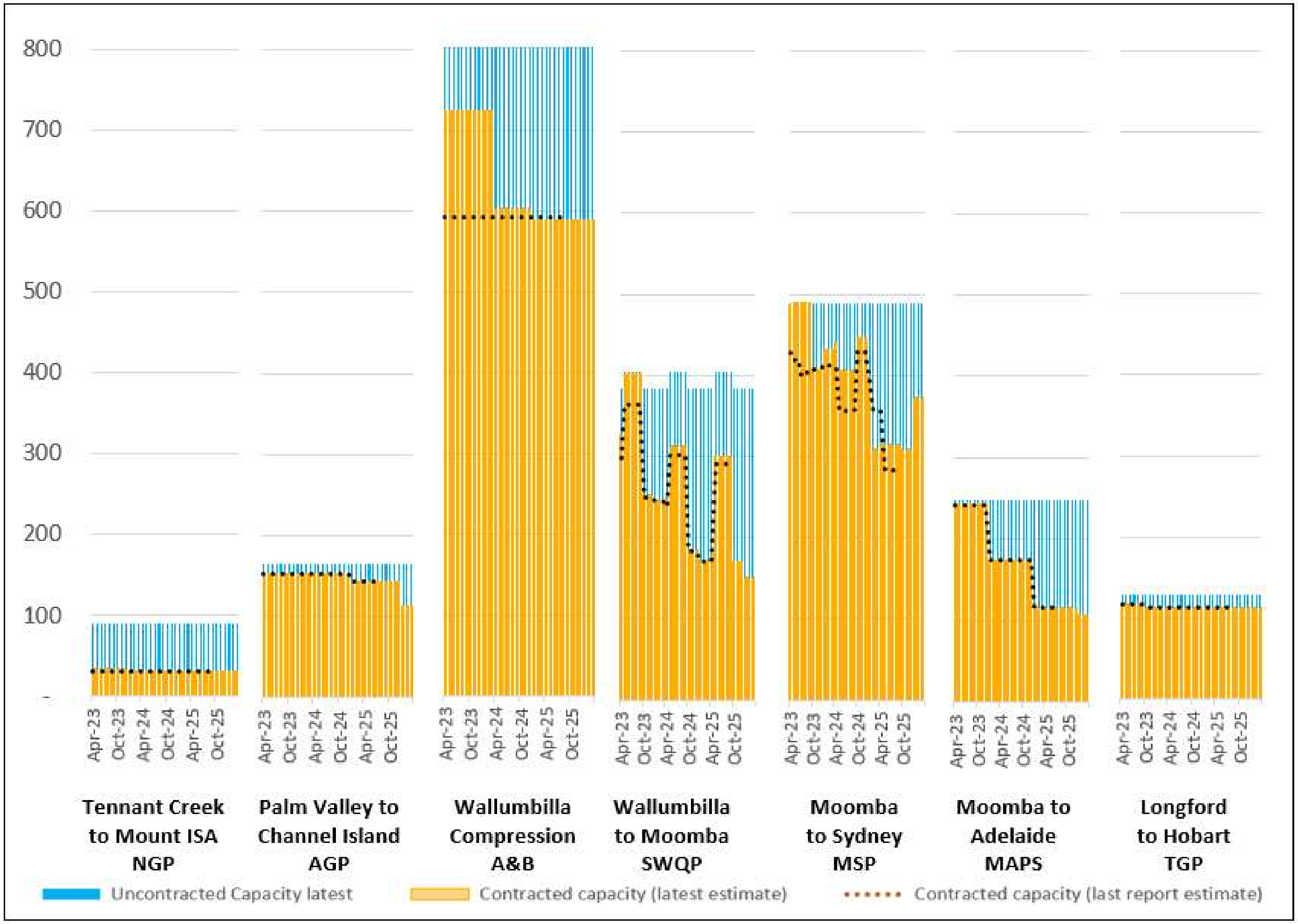
The uncontracted capacity on the southern haul SWQP and MSP pipelines are very limited until the end of 2023, while the MAPS does not have significant uncontracted capacity until 2024. The Tasmanian Gas Pipeline (TGP) from Longford to Hobart and the Amadeus Gas Pipeline (AGP) from Palm Valley to Channel Island LP pipeline are nearly fully contracted over the entire outlook period, consistent with our previous reports.

Chart D.3.2 indicates that the Moomba Compression facility and the QGP to Gladstone pipeline have limited uncontracted capacity over the outlook period. While the PCA, RBP, EGP, CGP and the northern haul SWQP, MSP and MAPS pipelines, have significant uncontracted capacity for most of the outlook period.

Figure D.3.1 below shows the amount of firm capacity contracted for the 12 months from April 2023 to March 2024.

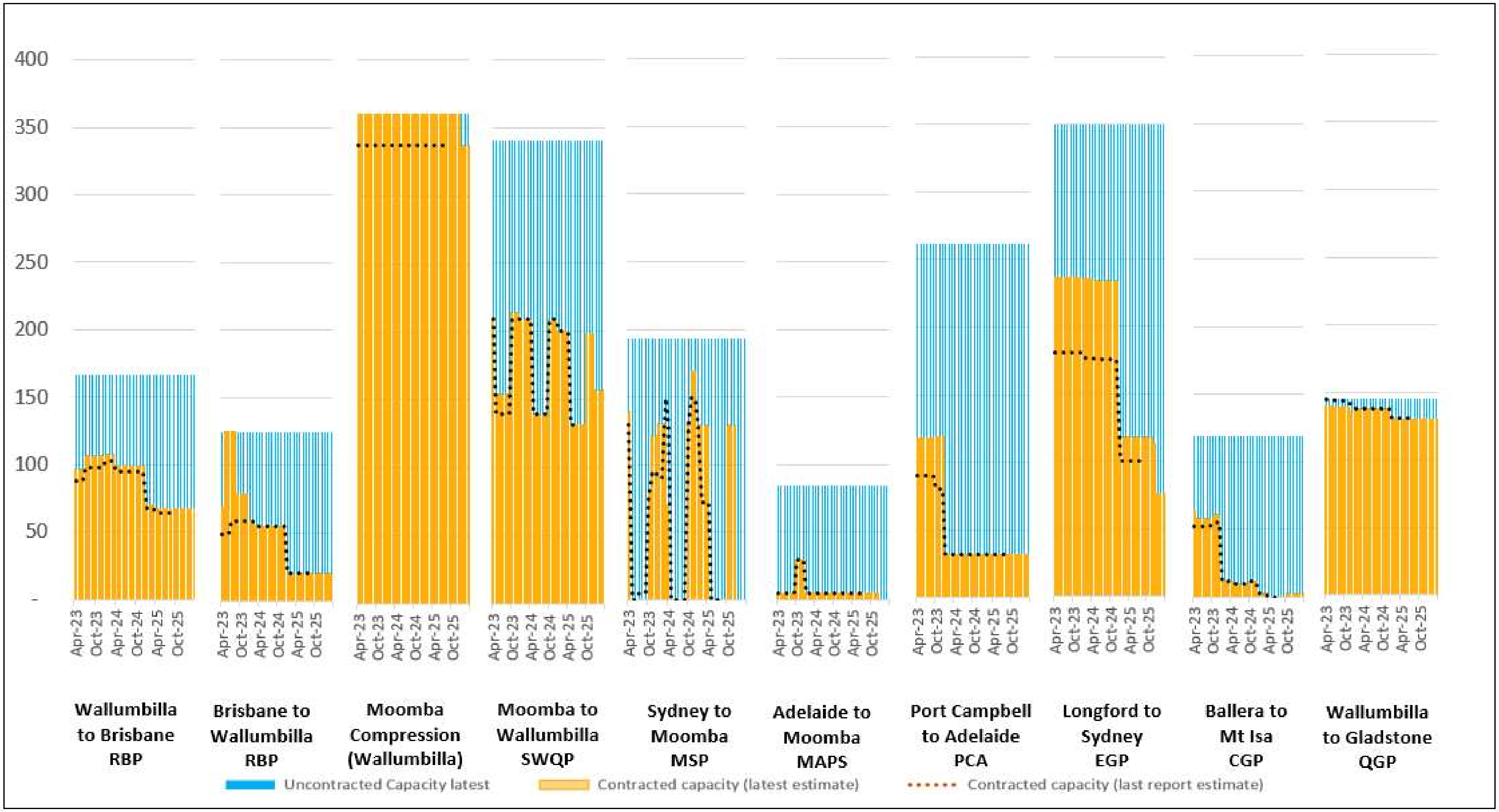
[59] These charts include the outlook from our January interim report to provide an indication of the change in contracted capacity.

Chart D.3.1: Facilities that can transport gas to southern states contracted capacity (TJ/day, 2022 and 2023 outlook)



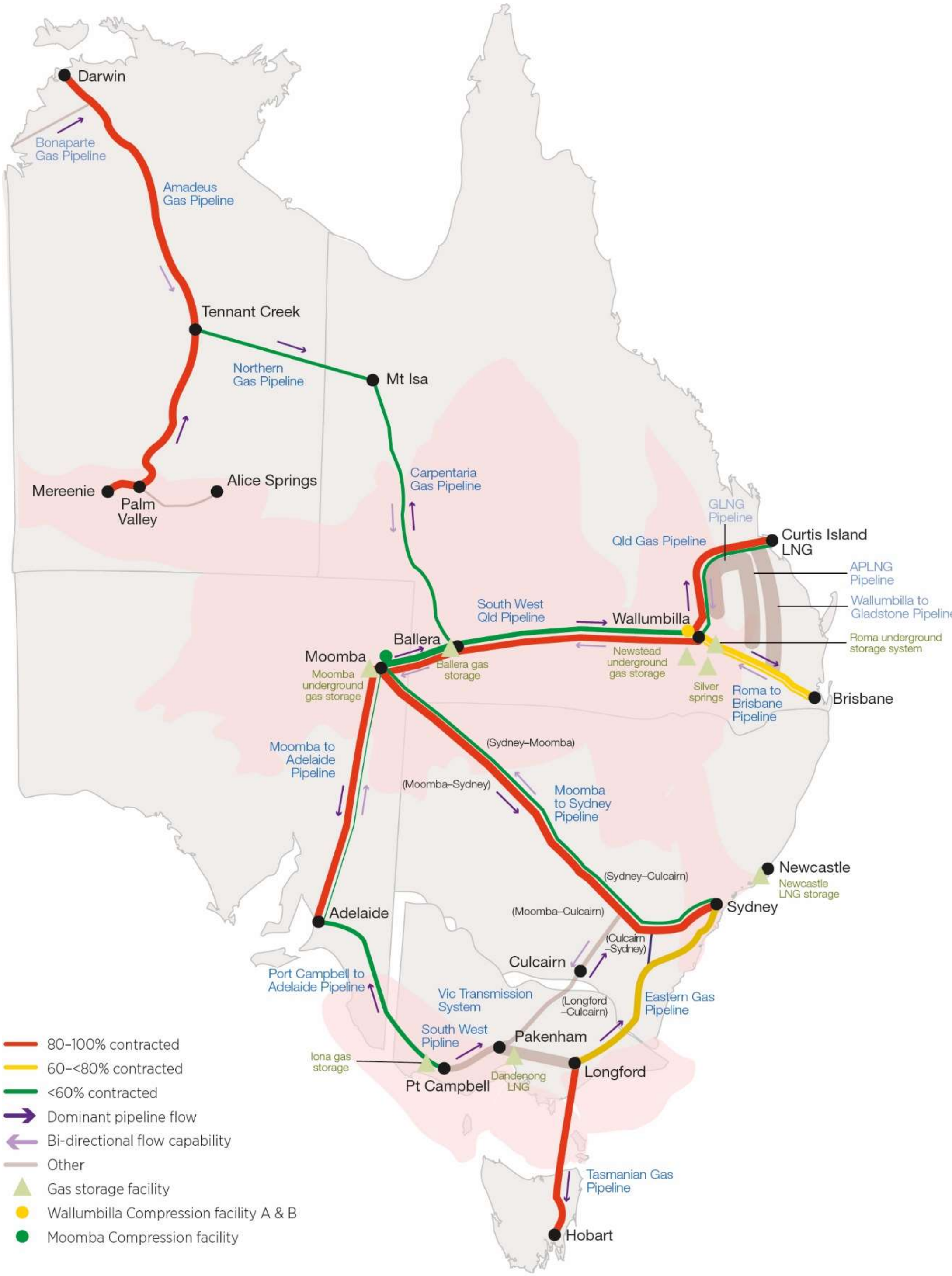
Sources: Contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (March 2023).

Chart D.3.2: Other facilities contracted capacity (TJ/day, 2022 and 2023 outlook)



Sources: Contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (March 2023).

Figure D.3.1: Pipeline contracted capacity between April 2023 and March 2024



Sources: Contracted capacity has been calculated using the uncontracted capacity outlook and the nameplate rating information reported on the Natural Gas Services Bulletin Board (March 2023).

Notes: Percentage of contracted pipeline capacity indicated by red, yellow and green lines. It reflects the average contracted capacity of the pipeline over the twelve months between May 2023 and April 2024. Pipeline nameplate capacity is indicated by the width of the pipeline, with the widest representing the greatest nameplate capacity.

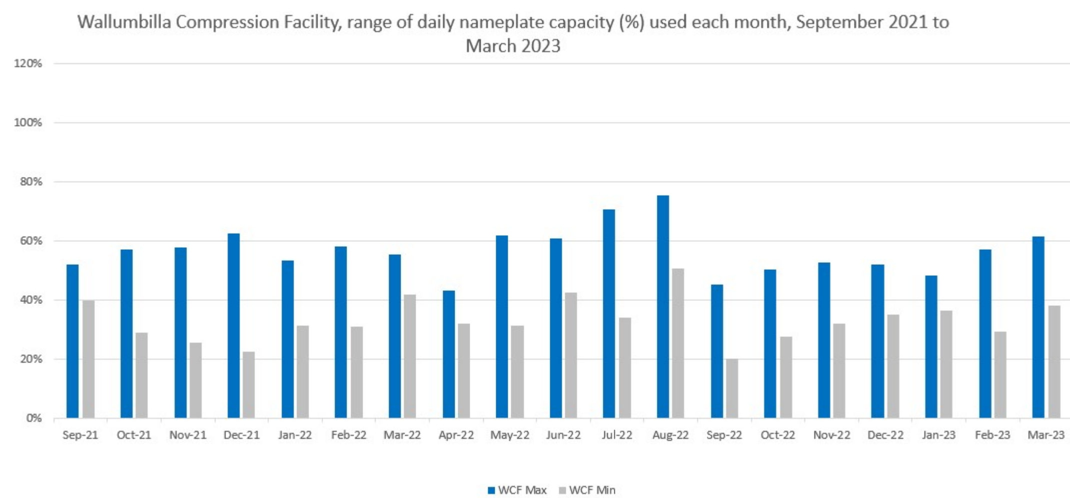
D.4 Physical flows on key southern pipelines

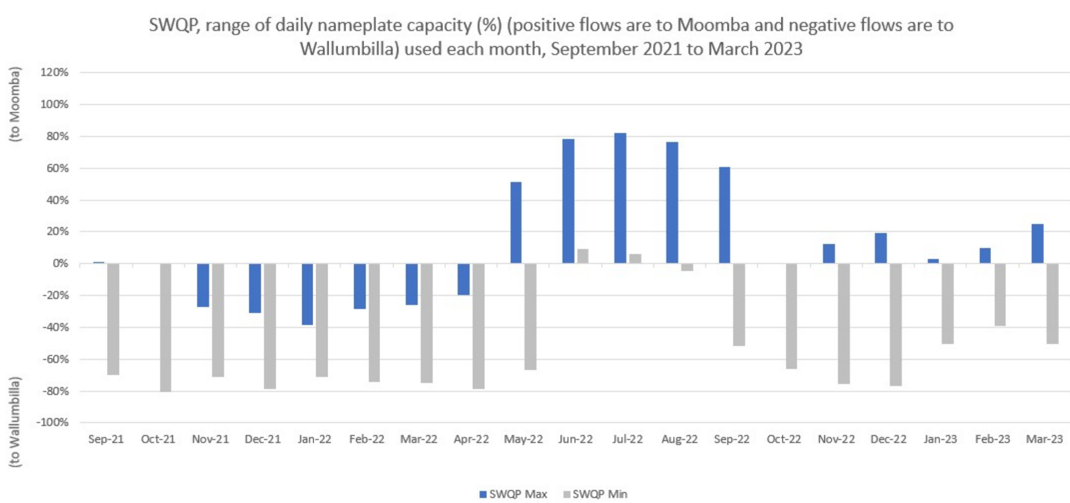
The maximum daily percentage of pipeline nameplate capacity used each month, on the SWQP, MSP and MAPS bi-directional pipelines and the Wallumbilla compression facility, are depicted in chart 3 for the period from September 2021 to March 2023.

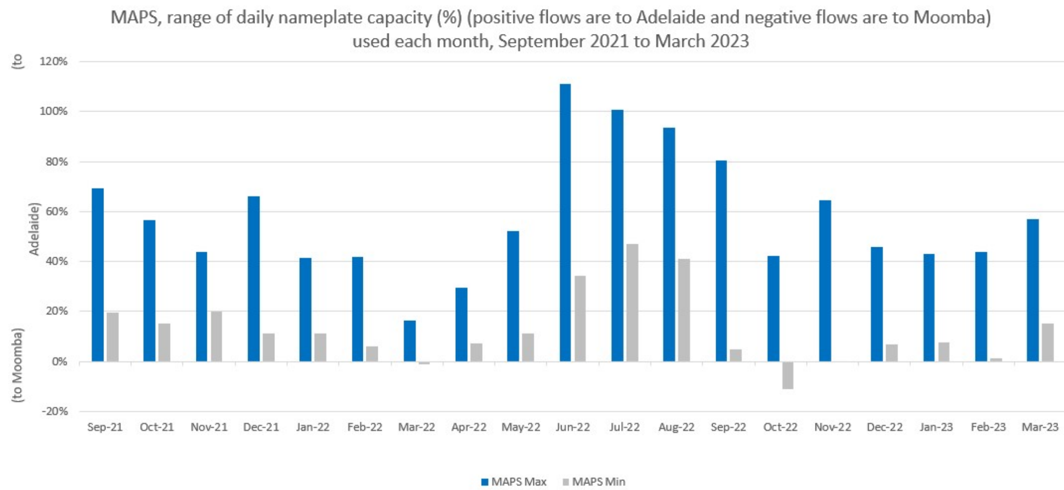
This chart demonstrates how pipelines, such as MAPS, are able to increase physical capacity, above nameplate capacity, in the short term to meet peak demand.

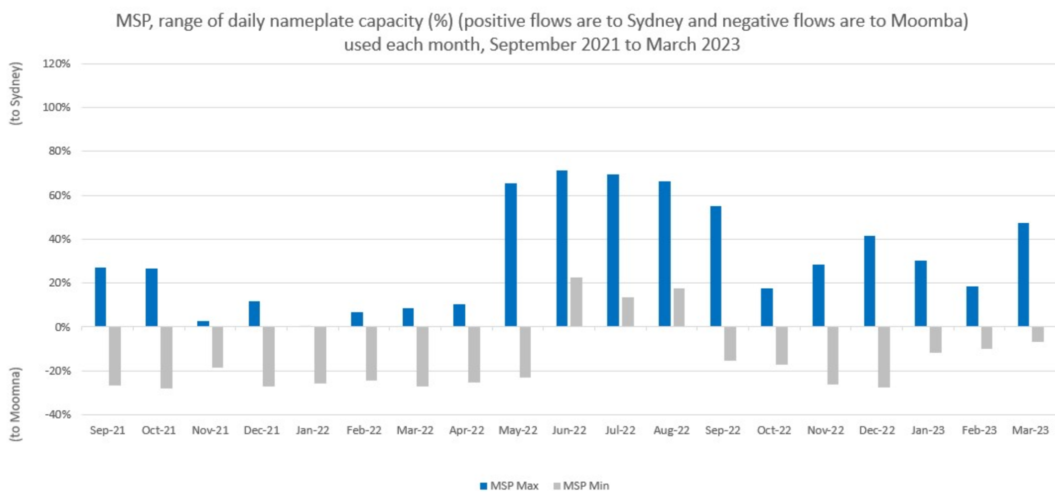
Chart D.4.1 also indicates that the SWQP, MSP and Wallumbilla compression facilities were near capacity on certain winter days, indicating that it would not have been possible for significant additional gas volumes to flow south.

Chart D.4.1: Range of daily nameplate capacity (%) used each month, September 2021 to March 2023









Source: Pipeline connection flow and nameplate rating information reported to the Natural Gas Services Bulletin Board. The monthly utilisation measure represents the daily minimum and maximum physical gas flows in each month for the period 1 September 2021 to 31 March 2023, expressed as a percentage of the facility's nameplate capacity.

D.5 Storage remains important in the southern states

The Dandenong LNG (owned by APA) and Iona underground storage (owned by Lochard Energy) are the only facilities that currently provide storage services to third parties in the east coast gas market.

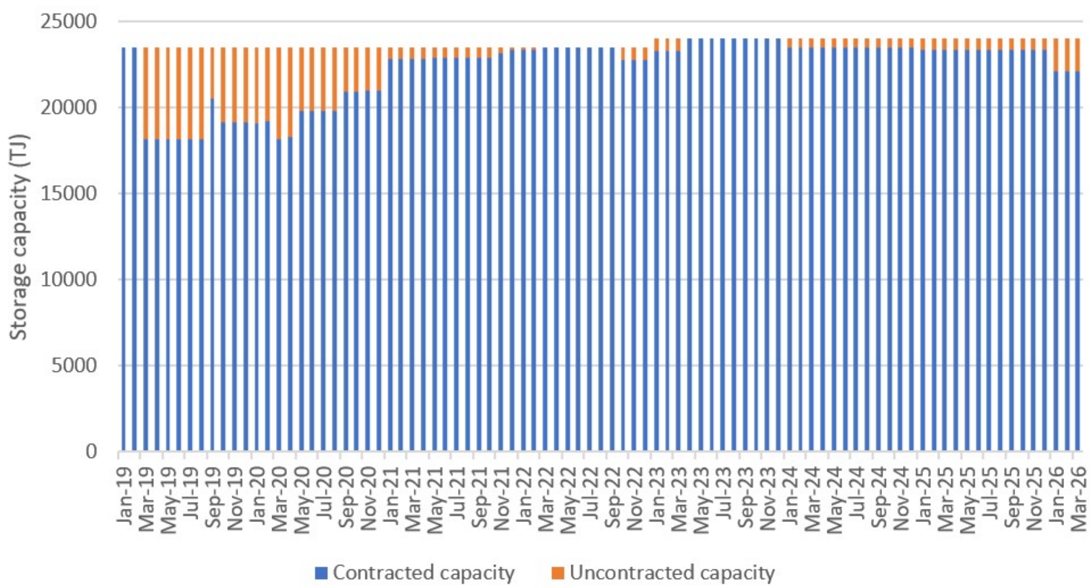
The Dandenong LNG storage facility is used to store small volumes of gas to be injected quickly into the Victorian Transmission System (VTS). This gas is usually used to address short-term peaks and system security issues in Victoria. A large part of the cost of storing gas at Dandenong LNG is the liquefaction cost to turn the gas into LNG. In contrast, the Iona underground storage facility is a now-depleted conventional gas field that has been adapted to allow gas to be pumped back down into the reservoir and stored. The Iona facility is ordinarily used to store large volumes of gas during summer months, which is withdrawn in winter to meet seasonal demand for gas.

As the Iona and Dandenong storage facilities are used by customers for different purposes, they do not compete directly with each other and do not face competition from other operators for similar services. This lack of competition affords each storage facility considerable market power when setting prices for their services and are reflected in each facility's price structure. This market power issue was raised in our July 2022 report. The ACCC recommends that governments consider the implementation of a third party access regime for storage facilities.

D.5.1 Iona storage capacity continues to be fully contracted

Contracted capacity at the Iona facility has been close to or at 100% since the beginning of 2021, and Iona is forecast to be contracted at near capacity (around 24 PJ) in the forward period until March 2026 (chart D.5.1).

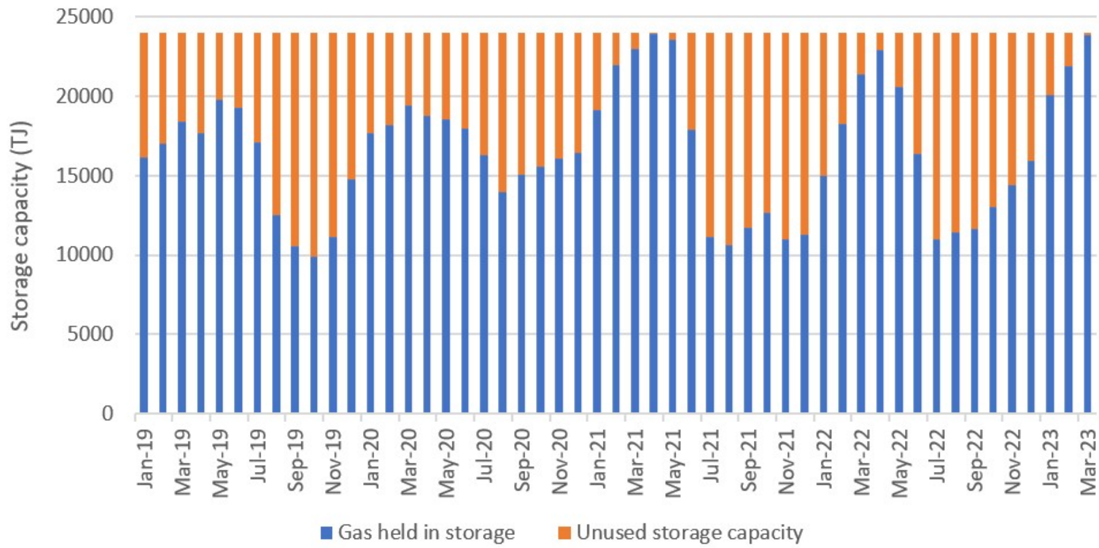
Chart D.5.1A: Iona underground storage contracted capacity (TJ), 2019 to 2026



Source: Publicly available data from AEMO’s Gas Bulletin Board, March 2023.

Chart D.5.1B shows the actual gas held in the Iona storage facility, with large amounts of gas stored during summer months being drawn down during winter to meet seasonal demand. Iona’s current storage use is typical for the facility.

Chart D.5.1B: Iona underground storage actual gas held in storage (TJ), 2019 to 2023



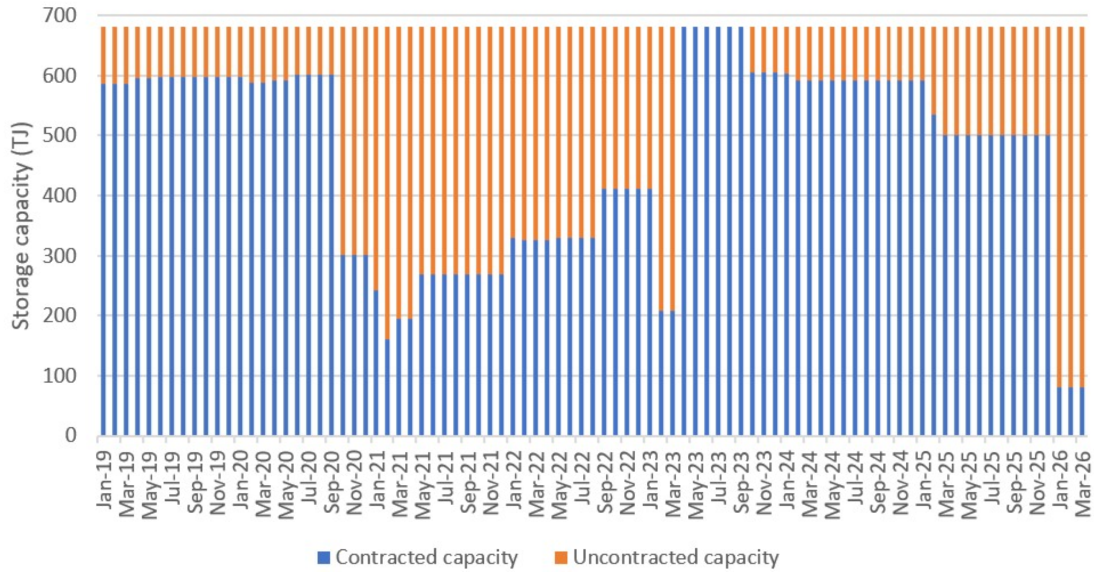
Source: Publicly available data from AEMO's Gas Bulletin Board, March 2023.

The contracting of Iona at near capacity, and consistent usage pattern by users, indicate the importance of storage generally and the greater level of price stability of the facility. This is in comparison to the Dandenong LNG storage facility which is discussed in the next section.

D.5.2 Dandenong LNG intervention to address system security risks

Charts D.5.2A and D.5.2B show the levels of contracted and uncontracted capacity at the Dandenong LNG facility from January 2019 to March 2026 and actual gas held in storage from January 2019 to March 2023.

Chart D.5.2A: Dandenong LNG storage contracted capacity and gas held in storage (TJ), 2019 to 2026



Source: Publicly available data from AEMO's Gas Bulletin Board, March 2023.

Chart D.5.2A shows that the Dandenong LNG facility was contracted at near capacity until around late 2020, when contracted capacity declined steadily until March 2023 following APA's adoption of its new contracting model.[60] The recent low levels of storage at the Dandenong LNG facility magnified the risks to system security in Victoria's Declared Transmission System.

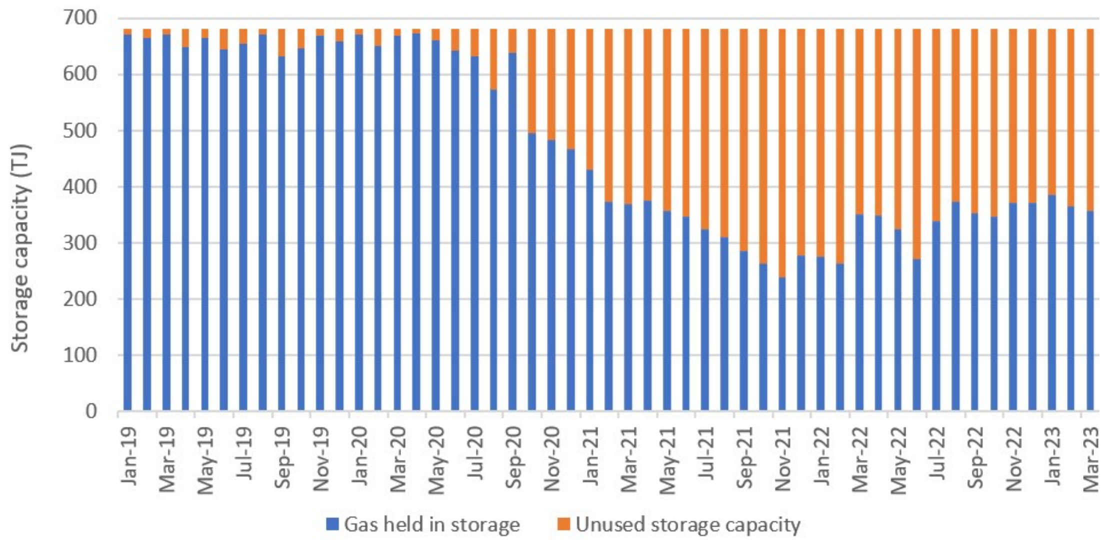
After March 2023 the facility is almost nearly fully contracted until 2026. This increase in contracted capacity coincides with the interim rule change to require AEMO to act as a buyer and supplier of last resort with respect to the Dandenong LNG facility from 2023 to 2025.

The intervention represents an interim measure to address the impacts to system security arising from underutilisation of the facility. However, it does not address the underlying issue of APA's market power at Dandenong LNG and additionally exposes AEMO to this market power. This issue was raised in our previous reports. The ACCC again recommends that governments consider the implementation of a third-party access regime for storage facilities.

Chart D.5.2B, which shows the actual gas held in storage, further illustrates the effect the change in the contracting model has had on the facility. The Dandenong LNG facility was historically filled near capacity, with gas being withdrawn periodically to address short-term demand peaks and system security issues.

60 As described in our January 2023 Interim report, under the previous model, users contracted storage capacity rights which would in turn be used to determine (on a pro rata basis) access to vaporisation services (the service required to withdraw gas from storage). Under the new model, users contract a required amount of firm vaporisation directly, and are provided with a multiple of this amount as an associated storage capacity right. The new model caused effective storage prices at the facility to increase significantly.

Chart D.5.2B: Dandenong LNG storage actual gas held in storage (TJ), 2019 to 2023



Source: Publicly available data from AEMO's Gas Bulletin Board, March 2023.

From 2021 onward, the volume of gas held in storage at the Dandenong LNG facility was equivalent to about half of the facility's capacity, with changes in capacity since then likely reflecting LNG storage being drawn down and refilled periodically.

Glossary

ACCC's 2015 inquiry: The ACCC's inquiry into the east coast Gas Market in 2015, as reported in April 2016.

Annual contract quantity: The quantity of gas specified in the transportation contract between the buyer and the seller, based on the buyer's maximum historical 12-month usage.

Buyer alternative: the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location. It represents a price ceiling in negotiations.

Capacity trading platform: An online platform that shippers can use to trade secondary capacity ahead of the nomination cut-off time. It provides for exchange-based trading of commonly traded products and a listing service for more-bespoke products. The capacity trading platform forms part of the Gas Supply Hub exchange.

Congestion: A pipeline is congested when there is insufficient spare capacity to transport the volume of gas to fulfil demand. Physical congestion refers to where demand for actual deliveries exceeds the technical capacity of the pipeline at some point in time, whereas a pipeline is contractually congested when the demand for firm capacity exceeds the technical capacity of the pipeline.

Contracted but un-nominated capacity: A quantity of contracted pipeline capacity that is not nominated to be used by a shipper on a gas day.

Conventional/unconventional gas: Conventional gas is contained in sedimentary rocks such as sandstone and limestone (referred to as reservoir rock). The gas is trapped by an impermeable cap rock and may be associated with liquid hydrocarbons. The reservoir rock has a relatively high porosity (percentage of space between rock grains) and permeability (the rock's pores are well connected and the gas may be able to flow to the gas well without additional interventions). Gas is extracted by drilling a well through the cap rock allowing gas to flow to the surface. Depending on the structure of the rock containing the gas (amount of faulting or compartmentalisation), only a few wells may be required to produce gas over the life of the gas field.

Unconventional gas is a broad term that covers gas found in a range of sedimentary rocks which typically have low permeability and porosity. The International Energy Agency categorises the 3 major types of unconventional gas as:

- shale gas: natural gas contained within shale rock
- coal seam gas (CSG): natural gas contained in coalbeds
- tight gas: natural gas found in low permeability rock formations.

A range of techniques may be required to promote gas flow including pumping water from the rock to reduce pressure holding the gas in place (in the case of CSG) or hydraulic fracture stimulation (fracking) to open pathways for the gas to enter the well (in the case of shale gas, tight gas and some CSG). An unconventional gas field may require a large number of wells to be drilled (in the thousands for the large CSG liquefied natural gas (LNG) projects in Queensland) over its life to ensure consistent production.

Day-ahead auction: An auction of contracted but un-nominated capacity. It is conducted after nomination cut-off and is subject to a reserve price of zero. Compressor fuel is provided in-kind by shippers.

Domestic demand: The quantity of gas demanded by users located in Australia.

Downward quantity tolerance: The amount a buyer may fall short of its full Annual Contract Quantity in a Take or Pay gas sales contract without incurring penalties.

East coast gas market: The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Export demand: The quantity of Australian gas demanded by overseas buyers.

Gas storage service: A service that allows users to store gas in a facility (either underground depleted gas fields or domestic LNG storage).

Gas supply agreement: A contract between the buyer and seller for the supply of gas

Gas transportation agreement: A contract between the shipper and the pipeline operator for the transport of gas on that pipeline

Heads of Agreement: In the context of this report, this refers to an agreement between LNG producers and the Australian Government to offer uncontracted gas first to the domestic market on ‘competitive market terms’ before it is offered to the international market.

Henry Hub: Is the major gas hub for spot and futures trading in the United States and acts as the notional point of delivery for gas futures contracts. Henry Hub is based on the physical interconnection of 9 interstate and 4 intrastate pipelines in Louisiana.

Japan Korea Marker: Is an international benchmark price for LNG spot cargos. It reflects the spot market value of cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan.

Japan Customs Cleared: Represents the average price of crude oil imported to Japan and reported by the Japanese Custom. It is commonly used as an index by LNG traders.

Liquefaction: The process of liquefying natural gas.

Liquefied natural gas (LNG): Natural gas that has been converted to liquid form for ease of storage or transport.

LNG producer: LNG producers process and prepare natural gas, using liquefaction, into LNG for transmission and sale to overseas markets. In this report, the term is usually used in reference to one or more of the 3 LNG producers in Queensland, being Australia Pacific LNG (APLNG), QGC, and Gladstone LNG (GLNG). There are also LNG producers in the Northern Territory and in Western Australia.

LNG netback price: 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 liquefied natural gas plant’s liquefaction and purification facility.

Load factor: measures the extent to which a buyer can take more than the average daily contract quantity throughout the year, subject to the cap imposed by the annual contract quantity.

Looping: Increasing the capacity of a pipeline system, by adding parallel piping along parts or the whole of the route. This does not include adding compression facilities.

Pipeline transportation services

As available transportation service: A service that allows the transportation of gas on an 'as available' basis, subject to the availability of capacity. This service has a lower priority than a firm transportation service.

Compression service: A service that increases the pressure of gas to improve the efficiency of transportation. Compression services are provided by compression service facilities.

Firm transportation service: A service that allows the transportation of gas on a 'firm' basis up to a maximum daily quantity and maximum hourly quantity. It has the highest priority of any transportation service.

Interruptible transportation service: A service that allows the transportation of gas on an 'interruptible' basis. The pipeline operator does not have an obligation to guarantee capacity and has the right to curtail the service if the pipeline becomes capacity constrained or higher priority services are required. This service has a lower priority than firm and as available transportation services.

Loan service: A service that allows users to "borrow" gas from a pipeline, which in practice involves withdrawing more gas from a pipeline than what is injected on a particular day.

Park service: A service that allows users to store gas in a pipeline, which in practice involves injecting more gas into a pipeline than what is taken out on a particular day.

Producer: Gas producers extract gas and process it for transmission and sale.

Reserves and resources

Reserves: Quantities of gas expected to be commercially recoverable from a given date under defined conditions.

Developed reserves: Gas expected to be recovered from existing wells and facilities

Undeveloped reserves: Gas that requires further investments to bring online.

1P (proved) reserves: Commercially recoverable reserves with at least a 90% probability that the quantities recovered will equal or exceed the estimated quantity.

2P (proved and probable) reserves: Commercially recoverable reserves with at least a 50% probability that the quantities recovered will equal or exceed the estimated quantity.

3P (proved and probable and possible) reserves: Commercially recoverable reserves with at least a 10% probability that the quantities recovered will equal or exceed the estimated quantity.

Contingent resources: quantities of gas estimated to be potentially recoverable from known accumulations but are not yet considered able to be developed commercially due to one or more contingencies. Contingent resources may include gas accumulations for which there are currently no viable markets, where commercial recovery is dependent on technology under development or where the evaluation of the accumulation is insufficient to assess if it can be produced commercially. 2C resources are classified as a best estimate of the resource (1C is the low estimate and 3C is the high estimate).

Prospective resources: Estimated quantities associated with undiscovered gas. These represent quantities of gas which are estimated, as of a given date, to be potentially recoverable from gas deposits identified on the basis of indirect evidence but which have not yet been drilled. Prospective resources represent a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the gas accumulation must be further evaluated and an estimate made of quantities that would be recoverable under appropriate development projects.

Retailer: For the purpose of this report, this term captures both entities that purchase natural gas in wholesale markets to sell to retail customers and entities that purchase natural gas in wholesale markets to resell to other buyers in those markets. This includes AGL, Alinta Energy, EnergyAustralia, Macquarie Bank, Power and Water Corporation, Origin Energy and Shell Energy Australia.

Sale and purchase agreement: An agreement between the buyer and seller for LNG. In this report

Secondary capacity: Capacity that is on-sold by primary capacity holders on a pipeline.

Seller alternative: the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla. It represents a price floor in negotiations

Shipper: A user or prospective user of pipeline services.

Southern states: South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Spot market transaction: The sale or purchase of gas using a spot market. In Australia's facilitated markets, these are typically for delivery on a single gas day shortly after the transaction has been finalised. Australia's Gas Supply Hub allows for the trade of gas over longer time frames (i.e. more than one day). Spot market transactions are distinct from transactions under gas supply contracts.

Standing prices: prices or reference tariffs that pipelines subject to Part 10 of the National Gas Rules, light regulation or full regulation are required to publish.

Swap arrangement: An arrangement between 2 or more gas market participants to swap rights or obligations. For example, 2 gas producers in different locations may swap gas delivery obligations to minimise transportation.

Take or pay: A contract term specifying the minimum proportion of ACQ the buyer must pay for in each year. Take-or-pay multipliers are expressed as a percentage in GSAs, and provide users with flexibility in how they manage their gas usage.

Tenement: A claim, lease or licence for the purpose of prospecting or mining gas.

Units of Energy

Joule: a unit of energy in the International System of Units

Gigajoule (GJ): a billion joules

Terajoule (TJ): a trillion joules

Petajoule (PJ): a quadrillion joules

Million British Thermal Units (MMBtu): a unit of heat; 1 MMBtu = approximately 1.055 GJ.