AUSTRALIAN COMPETITION & CONSUMER COMMISSION

Gas Inquiry 2017-2030

Interim update on east coast gas market

September 2025

Acknowledgment 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
Land of the Ngunnawal people
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Overview

The east coast gas market continues to adjust from the effects of volatility and regulatory change in 2022–23 and supplier responses. We have seen some improvement in investment activity, supply availability, pricing and conduct, but the underlying challenges persist.

This report provides an update to the short-term supply and demand outlook for each quarter of 2026, and prices, volumes and flexibility for 2026 and 2027 supply under recent long-term gas supply agreements.[1]

We also provide further observations about the impact of the Gas Market Code (Gas Code), the Commonwealth Heads of Agreement with LNG exporters (HoA) and the Australian Domestic Gas Security Mechanism (ADGSM), following our initial observations reported in June 2025 and review of additional information, documents and commentary obtained from producers.

This additional information confirms our preliminary observations that while the Gas Code, ADGSM and HoA may have resulted in some additional gas being offered or supplied into the domestic market, these instruments have not resulted in a material improvement in market outcomes to date. They may also be having some unintended incentive effects and causing some inefficiencies in gas supply negotiations.

The instruments were introduced or amended in periods of heightened concern about gas supply and prices. However, they have not addressed underlying constraints and so have had limited impact on the long-term outlook. While changes could be made to improve the operation of these instruments, it is important to recognise that there are limits to what they can achieve on their own if the underlying causes of inadequate supply and ineffective upstream competition are not addressed.

Our submission to the Gas Market Review outlines matters for governments to consider in pursuing reforms to promote longer term gas market efficiency and measures to ensure that the Code, ADGSM and HoA are fit for purpose in the interim.[2]

Gas policy reform

Natural gas will play a critical role in Australia's transition to lower emissions. As renewables are increasingly relied upon for electricity generation, gas will be required to support energy security, reliability and affordability, while remaining an important source of energy and feedstock for residential, commercial and industrial users.

However, as we have highlighted throughout the gas inquiry, there are longstanding concerns about the functioning of the east coast gas market. These include inefficiencies caused by the high degree of upstream concentration, continued projections of inadequate supply to meet demand from as early as 2028, and uncertainty about the sector's own transition path given varying gas policy objectives across governments and jurisdictions.

There are several reform workstreams currently under way aimed at addressing the problem of supply adequacy through the energy transition and accessibility of gas. These include:

- the Australian Government's review of the Code, ADGSM and HoA as part of its Gas Market Review, and

1 A new direction for the ACCC Gas Inquiry was made by the Treasurer on 29 August 2025.

2 ACCC, *Submission to the Commonwealth Gas Market Review*, August 2025.

- consideration by jurisdictions jointly of barriers to gas supply and a potential expansion of AEMO's powers to intervene in the gas market.

There is an opportunity now to take stock of the east coast gas market and consider more fundamentally the underlying drivers of its current challenges and how reforms could enable the market to support the economy efficiently through the transition. Throughout the gas inquiry, and in our submission to the Gas Market Review, we have provided information that can inform these policy considerations:

- In our June 2025 report, we set out preliminary observations on how the east coast market responded to the Code and recent changes to the ADGSM and HoA. We also examined more closely each of the LNG producers' domestic and export contracting positions.
- Our submission to the Gas Market Review outlines the underlying causes of problems in the east coast gas market and matters for governments to consider in pursuing reforms in the short and longer terms.
- In this report we provide further observations about the impact of the Code, HoA and ADGSM following our initial observations reported in June 2025 and review of additional information and documents obtained from producers.

Prices moderately improve and the supply-demand outlook eases for early 2026

Updated forecasts indicate an improved short-term supply and demand outlook for the first quarter of 2026, with expected supply surpluses between 2 PJ and 24 PJ depending on how much LNG producer uncontracted gas is supplied to the domestic market.

The improved outlook comes as the LNG producers have reported a reduction in contracted LNG exports. LNG producers are now forecast to have 22 PJ of uncontracted gas available to them in the first quarter of 2026. The ACCC will be monitoring whether and how this gas is offered to domestic buyers.

Despite this improvement, the supply-demand outlook remains tight in the southern states. In contrast with previous years, southern gas producers are not forecasting to produce surplus gas in first quarter of 2026. This may create some challenges for fully replenishing southern gas storage facilities, such as Iona, ahead of higher demand in the 2026 winter.

Contracting activity has been stronger so far in 2025, with an increase in the number of long-term gas supply agreements (GSAs) for supply in 2026 and 2027. Despite this growth, the total volume secured under these contracts remains below levels seen before 2022, and the majority of contracts have a supply period of exactly 1 year.

Long-term contracts with producers generally provided limited volume flexibility, with higher take-or-pay obligations and lower load factors. Retailer contracts included greater volume flexibility and other non-price terms. Most agreements over this period were fixed-price contracts, rather than commodity-linked.

Producer prices for 2026 supply eased in the first half of 2025, falling by an average of 2% to $13.12/GJ compared to the second half of 2024, while retailer prices averaged $14.33/GJ. In total, 18 PJ of gas was contracted for 2026 supply, and 21 PJ for 2027. The average price under producer contracts for 2027 supply was $13.93/GJ, while retailer contracts averaged $14.30/GJ.

Gas policy measures have not materially improved domestic market outcomes

The Australian Government is currently reviewing the Code, ADGSM and HoA as part of its Gas Market Review. This review provides a critical opportunity to consider how policy settings can best serve the interests of gas users, promote a well-functioning market and enable emissions reduction targets to be met efficiently and at least cost.

These instruments collectively seek to promote a well-functioning gas market, adequate and secure supply, downward pressure on prices and improved selling practices. However, the ACCC's gas inquiry has found that:

- East coast supply is unlikely to be enough to meet demand from 2028 despite there being sufficient reserves and resources for at least the next decade.
- Upstream markets are uncompetitive and remain dominated by the Queensland LNG producers and their associates, who influence over 90% of east coast reserves.
- With depleting fields in the Gippsland Basin, the southern market is projected to increase its reliance on gas transported from Queensland and potentially imported gas.
- The lack of effective upstream competition is contributing to the imbalance in bargaining power faced by gas buyers and their difficulties securing gas on acceptable terms.

In our June 2025 report, we set out preliminary observations on how the east coast market responded to the Code and recent changes to the ADGSM and HoA. These were informed by the information we routinely collect from producers as well as engagement with a range of gas buyers including retailers, C&I users and intermediaries.

We have examined the impact of the instruments in further detail, including by collecting information and internal documents from a range of small, medium and large producers (including LNG producers) in mid-2025 using our compulsory information gathering powers.

The Gas Code and HoA have not materially influenced supply and prices, while ADGSM changes may have increased shortfall risks

The additional information obtained from producers has corroborated our preliminary observations on the effects of the Code, ADGSM and HoA on supply, investment, contract supply periods, prices, non-price terms and selling practices.

To date, the Code's exemptions framework has led to some additional supply, but this supply collectively represents a relatively small proportion of annual domestic demand and so has not materially influenced domestic prices. The information we collected from producers confirms our preliminary view that conduct provisions have not led to material improvements in bargaining power and may be affecting the efficiency of negotiations.

The move to quarterly ADGSM assessments has provided for greater flexibility to deal with any shortfalls that may emerge through the year. Increased transparency also appears to have positively influenced some LNG producers' behaviour in terms of taking steps to avoid quarterly shortfalls. However, the 2023 reforms to the ADGSM appear to have reduced LNG producers' incentives to make a net contribution to the domestic market and to produce uncontracted gas. These changed incentives appear to have had the unintended consequence of exacerbating the risk of domestic supply shortfall.

Since the 2022 HoA was entered, we have found that the LNG producers have complied with their commitments to offer uncontracted gas to the domestic market before exporting. However, the volumes of gas being offered and supplied by the exporters to the domestic market has declined over time, while LNG export volumes have increased.

The reduction in domestic supply of LNG producers' uncontracted gas may have occurred in response to the 2023 ADGSM changes, which, as noted above, have reduced the exporters' incentives to supply the domestic market. The additional information we obtained from the exporters indicates that the relatively low take-up of uncontracted gas is a function of both the HoA price commitment (that domestic buyers pay no more than international customers) and the fact that LNG netback prices have materially exceeded domestic prices for much of the last 3 years.

1. East coast supply-demand outlook for quarter 1 2026

Key points

- The east coast outlook for quarter 1 2026 has improved since our June 2025 report. The latest forecasts indicate a supply surplus of between 2 PJ and 24 PJ, depending on how much LNG producers' uncontracted gas is supplied to the domestic market.
- The southern states are expected to have sufficient supply to meet demand in quarter 1 2026. However, in contrast with previous years, the southern gas producers are not forecasting to produce surplus gas in this quarter.
- Queensland LNG producers are anticipated to hold most of the surplus gas available to the east coast gas market in quarter 1 2026.
- Sufficiency of supply remains a concern for winter 2026. Surplus southern gas supply has historically supported storage refills ahead of higher-demand winter quarters. The tight supply demand outlook in quarter 4 2025 and quarter 1 2026 could make replenishing key storage facilities challenging.

1.1. Introduction

This chapter provides the supply and demand outlook for the east coast gas market in quarter 1 2026 (January, February and March).[3] This information may be relevant and used to inform decisions by the Minister for Resources under the Australian Domestic Gas Security Mechanism (ADGSM). The chapter also includes updated supply and demand outlooks for the remaining quarters of 2026.

The forecasts in this chapter are based on gas production and contracted demand provided by gas producers as of 1 July 2025, and the Australian Energy Market Operator (AEMO) forecasts of domestic demand.[4,5]

The ACCC's June 2025 report, which was based on information from producers as at 13 January 2025, reported risks of a gas shortfall in each quarter of 2026 if LNG producers exported all their uncontracted gas.[6] The June report further noted the difficulty this could pose for refilling gas storage facilities, which traditionally has occurred in quarters 1 and 4 of each year to help meet higher demand for gas in the southern states during winter.[7]

The most recent information indicates an improvement in the outlook for quarters 1 and 4 in 2026, but continuing risks of supply shortfalls in quarters 2 and 3 if LNG producers export all

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3 This outlook projection is an update to the forecasts contained in our June 2025 report (see ACCC, *Gas Inquiry 2017–2030 Interim Report*, June 2025.

4 Our approach to calculating the market outlook is consistent with previous interim reports. The supply-demand outlook is based on total forecast supply of gas on the east coast, including net withdrawals from storage, and total forecast demand, including domestic demand and the quantities of gas required by the Queensland LNG producers to meet their long-term LNG SPA commitments and LNG spot sales.

5 AEMO, *Gas Statement of Opportunities*, March 2025, pp 22–46.

6 ACCC, *Gas Inquiry 2017–2030 Interim Report*, June 2025, p 16.

7 ACCC, *Gas Inquiry 2017–2030 Interim Report*, June 2025, p 18.

their uncontracted gas. The improvement in quarters 1 and 4 is primarily due to forecast reductions in contracted LNG exports.

Despite the improvement, the supply-demand outlook for quarter 1 remains tight. LNG producers are anticipated to hold most of the surplus gas available to the east coast gas market in quarter 1 2026.

We are concerned that there has been a further deterioration in projected supply in the southern states. The southern states are now projected to have no surplus gas during the quarter, which means that there will be no additional gas available to be directed into southern storage facilities ahead of winter, as has occurred historically.

The remainder of this chapter outlines the 2026 supply and demand outlook in more detail, including the important role of storage facilities, risks to the supply and demand outlook, and the role of the LNG producers.

1.2. Forecast supply sufficient to meet demand on the east coast in Q1 2026

The east coast gas market is projected to have a supply surplus of between 2 PJ and 24 PJ in quarter 1 2026, depending on how much LNG producer uncontracted gas is supplied to the domestic market (Chart 1.2). LNG producers project that they will have 22 PJ of uncontracted gas available during the first quarter of 2026, which comprises most of the surplus gas potentially available to the east coast.

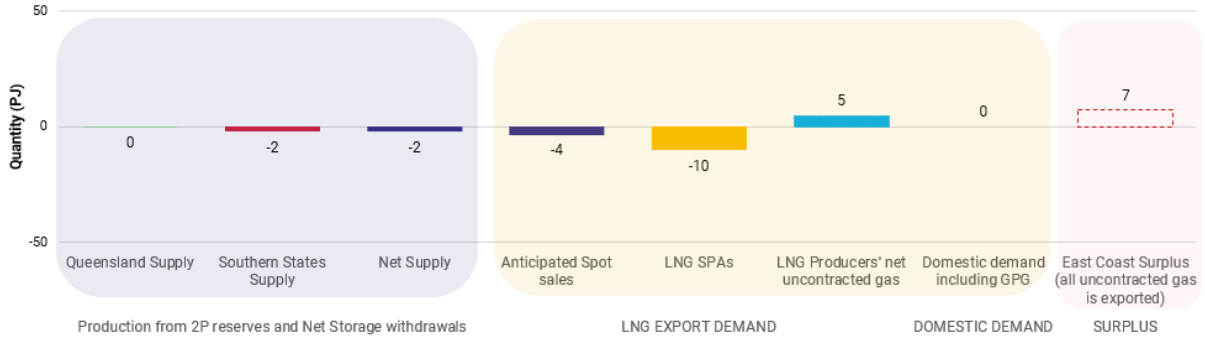
In comparison to projections published in June 2025,[8] the outlook has improved overall by 7 PJ (Chart 1.1). This is primarily due to a reduction in LNG export demand, offset by a small decrease in forecast supply in the southern states.

The projected decrease in demand is attributable to decreases in contracted export volumes (-10 PJ) and anticipated spot sales by the LNG producers (-4 PJ). As we have observed in recent inquiry reports, LNG export cargoes under Sales and Purchase Agreements (SPA) are often adjusted to meet seasonal gas demands of buyers.[9] In this instance, the reported decrease in export cargoes in quarter 1 2026 may need to be made up in future quarters or future years (see section 1.4 for more detailed discussion on LNG producers' change in outlook).

8 ACCC, *Gas Inquiry 2017–2030 Interim Report*, June 2024, p 22.

9 ACCC, *Gas Inquiry 2017–2030 Interim Report*, June 2025, p 70.

Chart 1.1: Reasons for change in quarter 1 2026 east coast supply-demand outlook



Source: ACCC analysis of data obtained from gas producers in January 2025 and July 2025 and of the domestic demand forecast (Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), March 2025.

Note: Totals may not sum due to rounding.

Despite the improvement in the market outlook for quarter 1 2026, the east coast continues to be in a finely balanced state. The outcome for the quarter will depend on actual volumes of gas produced, domestic demand and actual export volumes under SPAs and additional sales.

In conditions of tight supply, the outlook for the east coast market is heavily influenced by each of the LNG producer's decisions on export cargo volumes and the amount of gas therefore made available to, or bought from, the domestic market either by domestic sales agreements or via the Heads of Agreement.[10]

1.2.1. Insufficient east coast supply forecast for quarters 2 and 3 in 2026

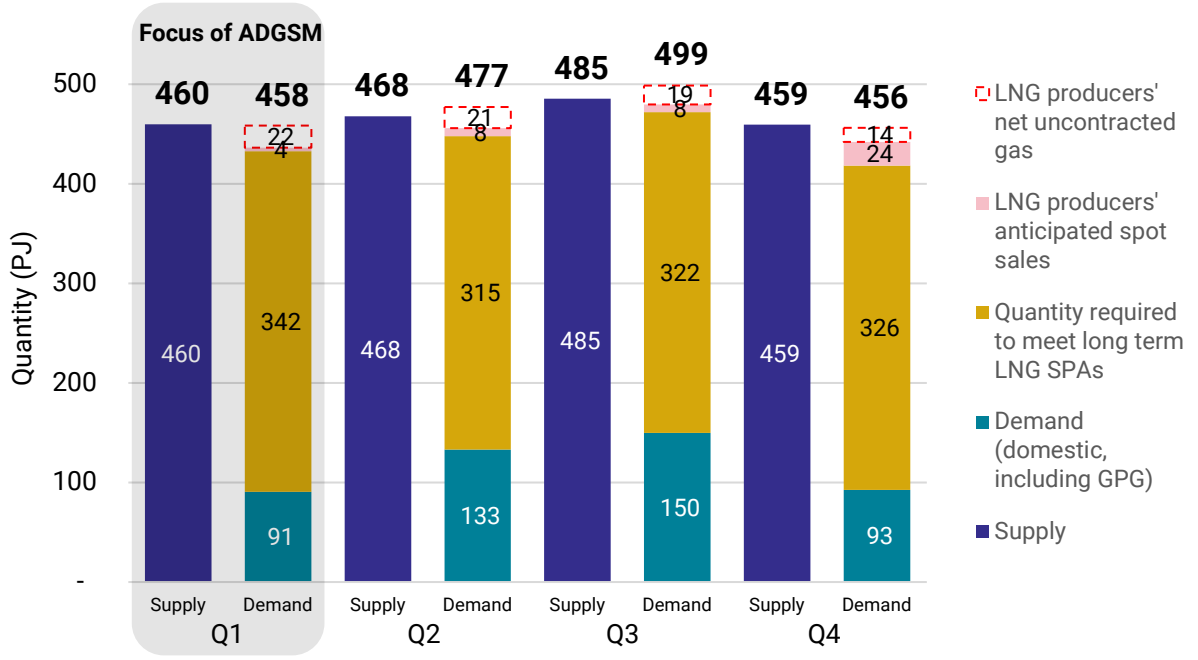
Updated information for the remainder of 2026 indicates that both quarters 2 and 3 continue to be at risk of a supply shortfall if LNG producers export all their uncontracted gas. However, the quarter 4 outlook has slightly improved from a potential shortfall to a projected surplus (Chart 1.2).[11]

The change in supply-demand outlook for 2026 is mostly due to lower LNG exports under SPAs and reduced anticipated spot sales. Given forecasts of domestic annual demand remain unchanged, the downward change in export volumes is largely offset by increases in forecast net uncontracted gas available to the LNG producers. Forecast gas production has also increased in later quarters of 2026, leading to an improved market outlook for quarter 4.

[10] For more information on the outcomes of the Heads of Agreement, please see Chapter 3.

[11] ACCC, *Gas Inquiry 2017–2030 Interim Report*, June 2025, p 16.

Chart 1.2: Quarterly supply-demand balance for the east coast in 2026 (PJ)



Source: ACCC analysis of data obtained from gas producers in July 2025 and of the domestic demand forecast (Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), March 2025.

Note: Totals may not sum due to rounding. The quantity required to meet long-term LNG SPAs includes feed gas requirements (such as fuel) required to produce LNG. LNG producers' uncontracted gas has been zeroed out when negative as this gas must be acquired from the domestic market, either as additional gas production, purchases or a reduction in exports which would have a net 0 impact on the forecast.

13. Queensland gas needed as buffer against supply-demand shocks

Queensland production is the key contributor to any overall east coast surplus in quarter 1 2026. The market may need to rely on LNG producers' uncontracted volumes to meet domestic demand, including for facilitating storage injections and to cover potential supply or demand shocks.

Queensland is projected to have a 1 PJ surplus if LNG producers export all their uncontracted gas, or a surplus of 24 PJ if LNG producers only export their anticipated spot sales (Chart 1.3).[12] This represents a 9 PJ improvement to the Queensland outlook.[13]

In contrast, southern states are projected to have a balanced supply-demand outlook in quarter 1 2026 (Chart 1.3). Since our June 2025 forecast,[14] the southern gas producers have reduced their expected production by 3 PJ.

This outlook does not include gas that may be directed into southern storage facilities. Historically, excess gas produced in southern states is directed into storage after meeting residential and industrial demand and gas for electricity generation (discussed in the next

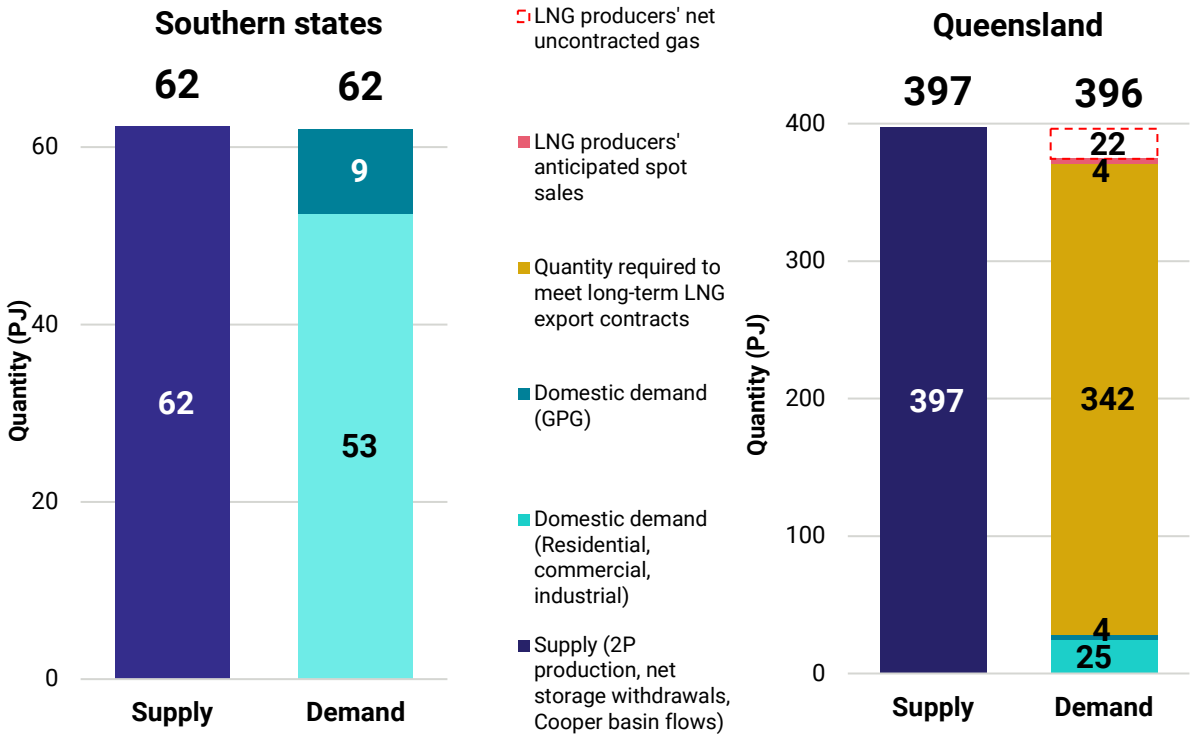
12 Due to rounding, the sum of regional surplus (Chart 1.3) does not match the overall total surplus (Chart 1.2) for Q1 2026.

13 ACCC, *Gas Inquiry 2017–2030 Interim report*, June 2025, p 18.

14 ACCC, *Gas Inquiry 2017–2030 Interim report*, June 2025, p 18.

section). Given the balanced outlook in southern states, it may be difficult to meet demand and fill storage facilities without additional production or relying on gas from Queensland.

Chart 1.3: Regional supply-demand outlooks for quarter 1 2026 (PJ)



Source: ACCC analysis of data obtained from gas producers in July 2025 and of the domestic demand forecast (Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), March 2025.

Note: Totals may not sum due to rounding. The quantity required to meet long-term LNG SPAs includes feed gas requirements (such as fuel) required to produce LNG. LNG producers' uncontracted gas has been zeroed out when negative as this gas must be acquired from the domestic market, either as additional gas production, purchases or a reduction in exports which would have a net 0 impact on the forecast.

1.3.1. Tight southern supply balance poses challenges to Iona storage injections

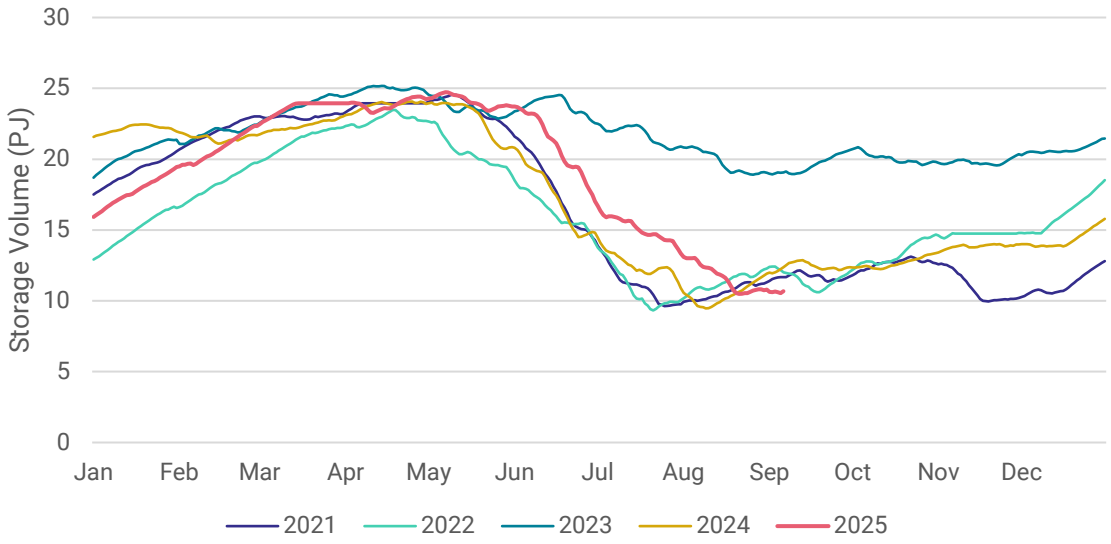
Southern states typically rely on gas storage and Queensland piped gas over the winter months in Australia. The forecast southern shortfalls predicted in 2026 highlight the need for adequate southern state storage and pipeline capacity to act as a buffer if there is no surplus gas available.

Gas stored at Iona plays a pivotal role in meeting southern state demand spikes. In 2025, 13 PJ of gas was withdrawn between June and August 2025 to meet demand (Chart 1.4), even though storage drawdowns started later than in previous years.

Recent experience suggests that Iona will require up to 15 PJ to be injected by May 2026 to fill required storage levels (Chart 1.4). Since 2021, quarter 1 has accounted for 70% of net injections into Iona, with up to 9 PJ injected.[15] With storage levels at a low level following high demand in winter 2025, large gas injections in quarter 1 2026 will be needed.

[15] AEMO, *Actual flow and Storage (all data)*, Gas Bulletin Board, as at 17 August 2025.

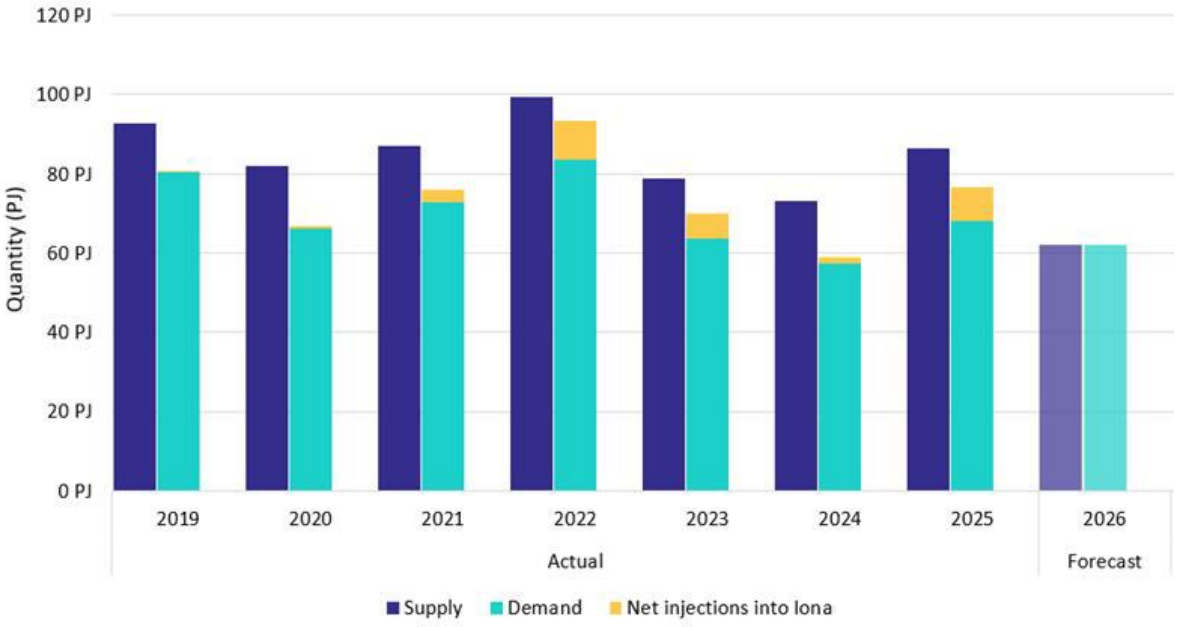
Chart 1.4: Year-on-year Iona underground storage levels (2021–2025)



Source: AEMO, Gas Bulletin Board Gas flows and capacity outlooks as of 6 September 2025.

Iona storage injections are typically sourced from surplus southern gas production, with any excess gas piped north to support Queensland's domestic demand. If projected tight supply and demand conditions are realised in quarter 1 2026 there will be limited surplus gas available from southern production to fill storage (Chart 1.5). As noted, there is projected to be up to 22 PJ of uncontracted gas held by the Queensland LNG producers.

Chart 1.5: Quarter 1 southern supply-demand balance and Iona injections (2019–2026)



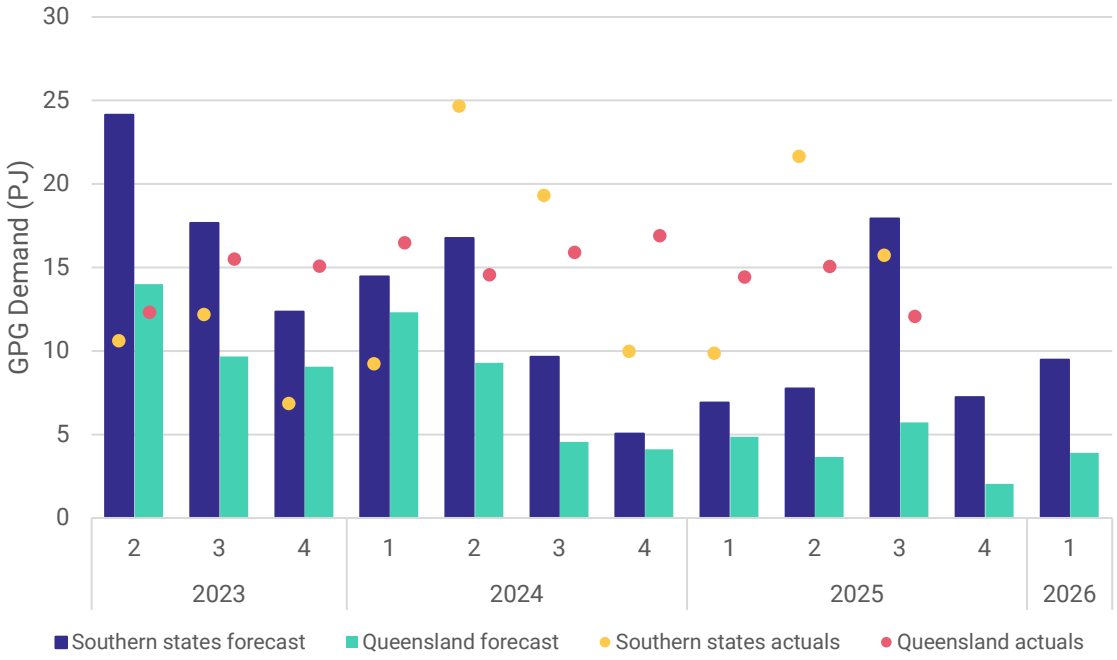
Source: AEMO, Gas flows and capacity outlooks, Gas Bulletin Board, as at 29 August 2025.
Note: Iona injection is not included in the demand forecast for 2026.

Historic Southern State production values have not taken out Cooper production contracted in Queensland. This is typically between 9.5 PJ and 9.7 PJ for 2023 – 2025. This information is not available for years prior to 2023.

1.3.2. High variability of gas demand for power generation

Past patterns suggest a risk of higher than forecast GPG demand (Chart 1.6). GPG demand is sensitive to several factors, including weather events, unplanned coal plant maintenance, outages in the NEM, and the progress of renewable generation and battery integration in the electricity network.[16] As existing coal plants age and continue to have their operating lifetimes extended, the rate of unplanned outages is increasing, adding uncertainty to gas demand forecasts for electricity generation.[17] While GPG demand can be difficult to forecast, there is relative stability in residential, commercial and industrial demand projections.[18]

Chart 1.6: Gas powered generation forecast v actual consumption (2023–2025)



Source: ACCC analysis of data obtained from the domestic demand forecast (Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), March 2022 – March 2025. and AEMO's Gas Bulletin Board Gas flows and capacity outlooks as at 7 September 2025.

1.3.3. Northern Territory supply

There is no gas flow expected from the Northern Territory to Queensland during 2026. The Northern Territory gas market continues to face supply problems, as the output from the ENI's Blacktip gas fields fall short of demand following well intervention works.[19]

The Northen Gas Pipeline has been upgraded to allow for bi-directional flows, allowing for gas to flow from Queensland to the Northern Territory in situations where there is unmet local gas demand. The Northen Gas Pipeline resumed operation from April 2025, however, there has been no northward flow of gas from Queensland to date.[20]

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16 AEMO, *Electricity Statement of Opportunities*, August 2024, p 46.

17 Institute for Energy Economics and Financial Analysis, *Delaying coal power exits: A risk we can't afford*, article, accessed 18 August 2025.

18 ACCC, *Gas Inquiry 2017–2030 Interim Report*, March 2025, pp 6–8.

19 AEMO, *Gas Statement of Opportunities*, March 2025, p 79.

20 AEMO, *Medium Term Capacity Outlook (Future)*, Gas Bulletin Board, accessed 30 August 2025.

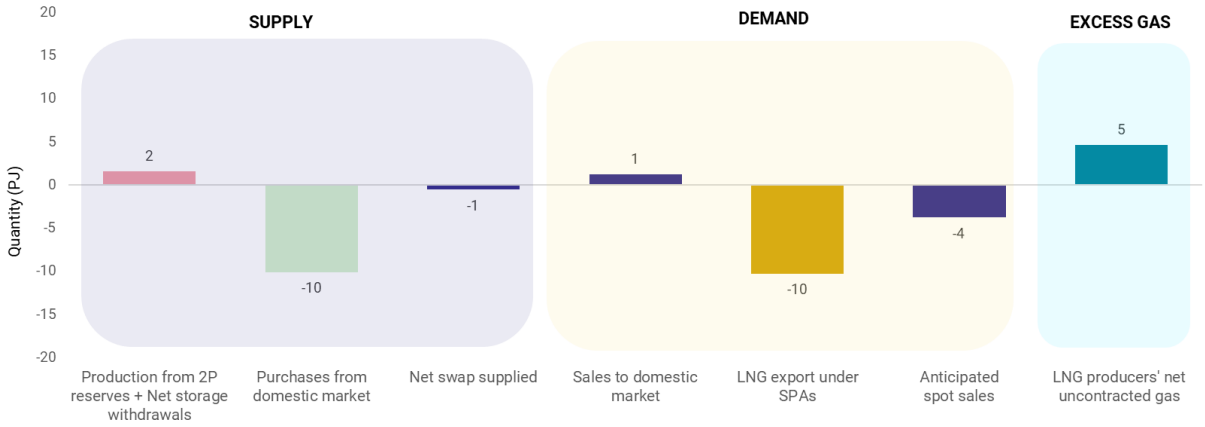
The Northern Territory has sufficient committed and anticipated supply to meet local demand through to 2041, however their supply sources are required to be developed from 2028.[21] The Northern Territory government has also secured gas supply agreements with both Central Petroleum and Beetaloo Energy (formerly Empire Energy) for the domestic market, commencing in 2025. These agreements are expected to provide a combined volume of gas up to 54 TJ/day over the long-term, with Beetaloo Energy's agreement lasting 10 years and Central Petroleum's agreement until the end of 2030, which will likely be sufficient to meet the local demand.[22, 23, 24]

As such, Northern Territory gas demand is not a present risk to the east coast gas supply outlook in 2026.

14. LNG producers' outlook

The updated information suggests LNG producers have reduced their forecast export volumes by a total of 14 PJ, with a 10 PJ decrease in contracted exports and a 4 PJ reduction in anticipated spot sales (Table 1.1 and Chart 1.7).

Chart 1.7: Change in LNG producer's outlook in quarter 1 2026



Source: ACCC analysis of data obtained from gas producers in January 2025 and July 2025.
Note: Totals may not sum due to rounding.

LNG producers also reported forecast production increases of 2 PJ, and net uncontracted gas increases of 5 PJ. However, this increase in net uncontracted gas has been partially offset by a 10 PJ reduction in purchases from the domestic market (Table 1.1 and Chart 1.7).

[21] AEMO, *Gas Statement of Opportunities*, March 2025, p 81.

[22] Central Petroleum, *Central Petroleum Analysis*, Report, 26 March 2025, accessed 25 July 2025.

[23] Chief Minister of Northern Territory, *NT Gov gas supply deal with Mereenie*, [media release], Northern Territory Government, 29 July 2024, accessed 30 August 2024.

[24] Empire Energy Group, *Empire Energy signs a 10-year deal with NT gov*, ASX release, Empire Energy, 25 July 2024, accessed 30 August 2024.

Table 1.1: LNG producers' forecast supply and contracted sales in quarter 1 2026 (PJ)

LNG forecast	Q1 2026	Change in forecast for Q1 2026
Supply		
Production from 2P reserves + net storage withdrawals	343	2
3rd party purchases from suppliers other than LNG projects	47	-10
LNG producers' gas swap received	18	-1
Total supply available to LNG producers	407	-9
Demand		
Contracted east coast market demand	32	1
Quantity required to meet LNG SPAs	342	-10
LNG producers' gas swap supplied	15	-1
Total gas demand for LNG producers	388	-14
LNG producers' anticipated LNG spot and additional sales (out of their uncontracted gas)	4	-4
LNG producers' net uncontracted gas	**22**	**5**

Source: ACCC analysis of data obtained from LNG producers in July 2025.

Note: 3rd party purchases can include purchases with associates that are not majority owned by the LNG producer. Totals may not add up due to rounding.

It is increasingly important that LNG producers meet their long-term contracted export volumes through their own reserves, reducing their purchases from domestic gas markets for export. Current forecasts suggest some LNG producers have insufficient supply from their production to meet their contracted export demand. The LNG producer/s may need to purchase additional gas volumes, from other LNG producers or domestic gas producers, that could otherwise be directed to the domestic market.

2. Long-term GSA price outlook

Key points

- The number of long-term producer and retailer contracts (contracts for supply of 12 months or longer) increased from 7 to 16 in the first half of 2025 compared to the first half of 2024.
- Volumes agreed under long-term contracts continue to track notably below levels agreed prior to the volatile market conditions in 2022.
- Producers continued to execute contracts with little volume flexibility, with higher take-or-pay and lower load factor terms for 2027 supply compared to 2026 supply. Retailers agreed to greater levels of volume flexibility than producers.

2026 supply

- Average producer prices under long-term contracts in the first half of 2025 decreased by 2% to $13.12/GJ compared to the second half of 2024.
- Average retailer prices in the first half of 2025 increased to $14.33/GJ, compared to calendar year 2024.
- Suppliers agreed to supply 18 PJ under long term contracts in the first half of 2025. Of this volume, producers contributed 46% and retailers contributed 54%.

2027 supply

- Average producer prices were $13.93/GJ, and retailer prices were $14.30/GJ in the first half of 2025.
- The total volume contracted for 2027 supply in the first half of 2025 was 21 PJ, with producers contributing 71% and retailers accounting for 29%.

2.1. Introduction

This chapter provides an update on:

- contracting activity in 2025 for supply in 2026 and 2027
- prices expected to be paid under long-term Gas Supply Agreements (GSA) for supply in 2026 and 2027
- the pricing mechanisms specified in these GSAs
- volume-flexibility terms (take-or-pay and load factors).

Our analysis includes GSAs that contain clear indications of price, quantity and supply start and end dates. GSAs included in this analysis were:

- entered into by producers and by retailers, except sales by retailers to other retailers, between 1 January 2024 and 30 June 2025 for 2026 supply and between 1 January 2025 and 30 June 2025 for 2027 supply
- based on annual contract quantities of at least 0.5 PJ and term lengths of at least 12 months.

We estimate the prices expected to be paid under GSAs using assumptions relating to several variables, including market expectations of the AUD/USD exchange rate, the consumer price index, and the price of oil and LNG for the relevant supply year. Appendix B sets out the approach to reporting on prices agreed to under long-term GSAs.

2.2. Contracting activity increased in the first half of 2025

There was an increase in the number of contracts in the first half of 2025 compared to the first half of 2024, with 2026 volumes rising to 18 PJ (table 2.1). However, the number of contracts was lower than in the second half of 2024. We have combined producer and retailer data in this table for confidentiality reasons.

Table 2.1: Count of long-term gas supply contracts for supply in 2026 and 2027

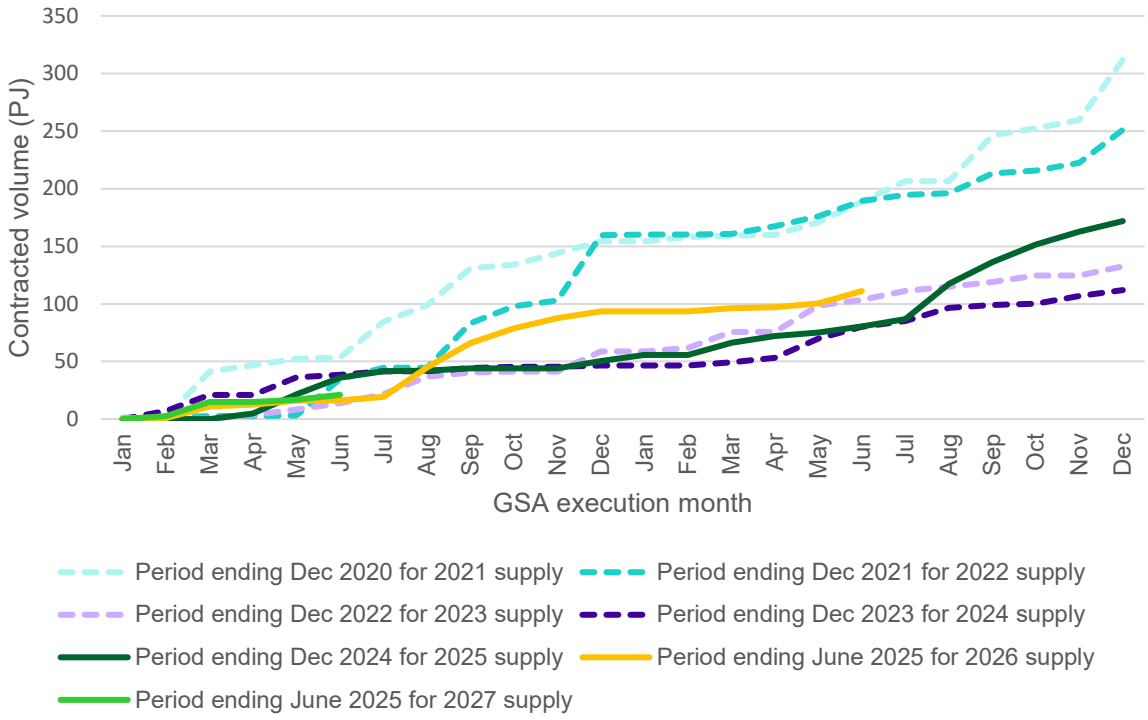
	2026 supply		
	Jan – June 2024	**July – Dec 2024**	**Jan – June 2025**
Number of contracts	7	23	16
Volumes (PJ)	16	77	18
	2027 supply		
	Jan – June 2025		
Number of contracts	13		
Volumes (PJ)	21		

Source: ACCC analysis of GSA information provided by suppliers.

Note: All GSAs are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months as well as other inclusion criteria as listed in Appendix B.1. Table 2.1 includes GSAs executed between 1 January 2024 and 30 June 2025 for supply in 2026 and between 1 January 2025 and 30 June 2025 for supply in 2027.

The total volumes contracted for 2026 and 2027 supply remain below levels for 2021 and 2022 supply (chart 2.1).

Chart 2.1: Cumulative volumes contracted under long-term GSAs for supply years 2021–2027



Source: ACCC analysis of information provided by suppliers.

Notes: This chart shows the volumes of gas contracted by producers and retailers for supply for a given year in the 2 calendar years preceding that supply year (for example, the volumes contracted in 2024 and 2025 for supply in 2026). All GSAs are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months as well as other inclusion criteria as listed in Appendix B.1.

The majority of contracts agreed by producers and retailers in the first half of 2025 for both 2026 and 2027 supply have a term length of exactly one year. This continues the trend of shorter-term contracting, which the ACCC has noted in previous reports.[25]

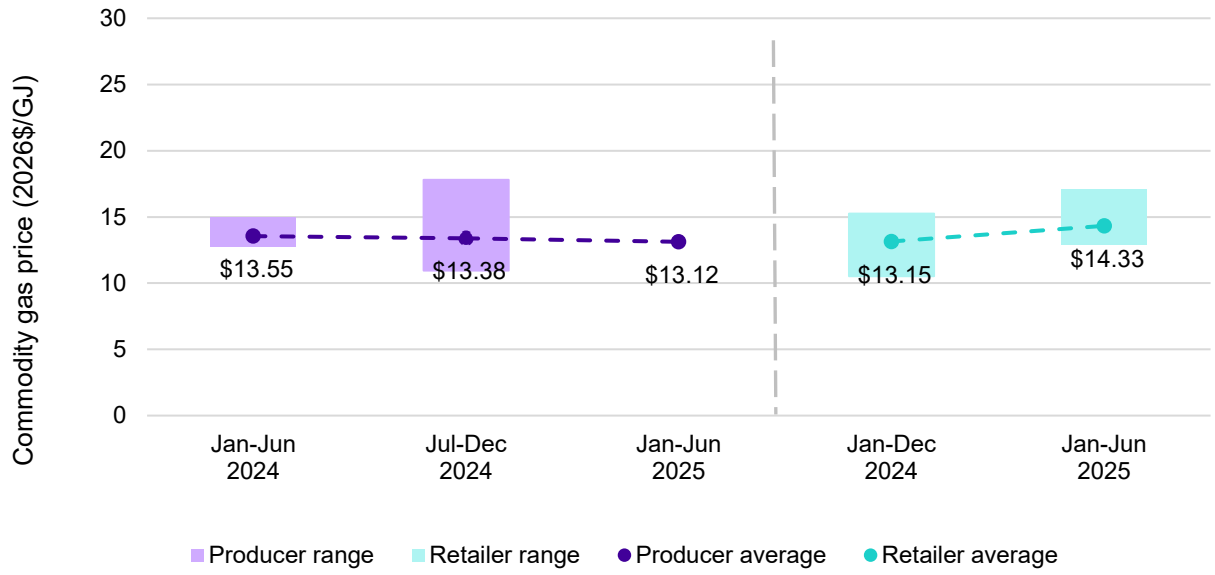
2.3. Long-term contract prices in the east coast gas market

2.3.1. Producer prices have eased for 2026 supply

Volume-weighted average producer prices agreed in the first half of 2025 for 2026 supply decreased by 2% to $13.12/GJ from the second half of 2024. Notably, the range of agreed producer prices has more than halved. This reflects a lower number of different producers actively contracting long-term volumes in the east coast gas market in the first half of 2025. Retailer prices increased by 9% to $14.33/GJ in the first half of 2025 compared to calendar year 2024 (chart 2.2). This increase was largely influenced by a single high-volume, higher-priced contract, and may not reflect broader market trends. We have not presented the range for producer prices in the Jan-Jun 2025 period in this chart for confidentiality reasons.

[25] ACCC, *Gas Inquiry 2017-2030 Interim report*, December 2024, p 40; ACCC, *Gas Inquiry 2017–2030 Interim report*, June 2025, p 34

Chart 2.2: Gas commodity prices in the east coast gas market for 2026 supply



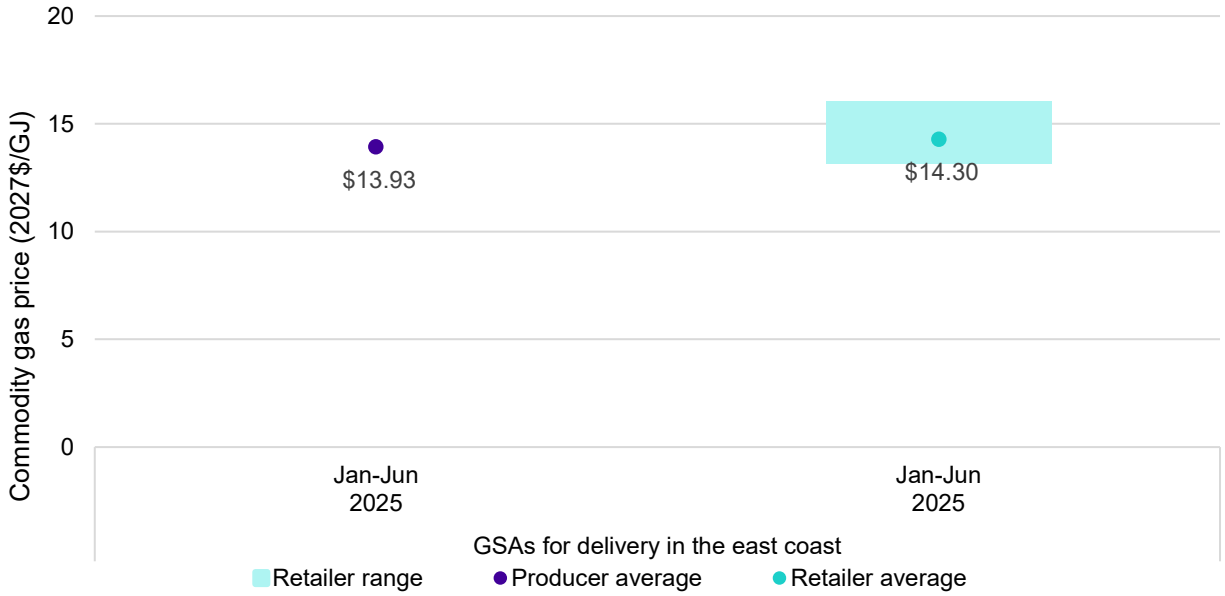
Source: ACCC analysis of GSA information provided by suppliers.

Notes: Volume-weighted average prices are displayed next to the point. All GSAs are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months as well as other inclusion criteria as listed in Appendix B.1. Prices are based on assumptions as of 30 June 2025.

2.3.2. Producer prices for 2027 supply slightly higher than for 2026

The volume-weighted average producer price agreed in the first half of 2025 for supply in 2027 was $13.93/GJ, slightly higher than for 2026 supply. The equivalent average retailer price was $14.30/GJ, broadly similar compared with 2026 supply (chart 2.3). We have not presented the range for producer prices in this chart for confidentiality reasons.

Chart 2.3: Gas commodity prices in the east coast gas market for 2027 supply



Source: ACCC analysis of GSA information provided by suppliers.

Notes: Volume-weighted average prices are displayed next to the point. All GSAs are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months as well as other inclusion criteria as listed in Appendix B.1. Prices are based on assumptions as of 30 June 2025.

2.3.3. The majority of contracts were fixed-price rather than commodity-linked contracts

As noted in recent Gas Inquiry reports, there has been a shift away from commodity-linked GSAs towards fixed-price contracts in recent years.[26] The GSAs agreed in the first half of 2025 for 2026 and 2027 supply years continued to be dominated by fixed-price contracts in terms of both numbers of contracts and the volumes of gas contracted (table 2.2).

For 2026 supply, no commodity-linked contracts were signed in the first half of 2025, compared to 14% by number and 27% by volume executed in the second half of 2024. Fo 2027 supply, commodity-linked contracts accounted for 19% by number and 37% by volume in the first half of 2025. On average, GSAs with commodity-linked prices had relatively larger volumes.

The recent low number of commodity-linked contracts may be linked to the volatility in commodity prices due to uncertainty in global conditions in the second quarter of 2025.

[26] ACCC, *Gas Inquiry 2017-2030 Interim reports*, December 2024, p 27, June 2025, p 31.

Table 2.2: GSAs by pricing mechanism, agreed between January and June 2025

Year/Variable	Fixed Price	Commodity linked	Combined
2026 VWA price	$13.75	NA	$13.75
2026 % Count	100%	0%	
2026 % Quantity	100%	0%	
2027 VWA price	$14.19	$13.76	$14.03
2027 % Count	81%	19%	
2027 % Quantity	63%	37%	

Source: ACCC analysis of information provided by suppliers.

Notes: Table 2.2 includes GSAs executed between 1 January 2025 and 30 June 2025 for supply in 2026 and 2027. Analysis includes GSAs which have an annual contract quantity of at least 0.5 PJ and a contract length of 12 months or more as well as other inclusion criteria as listed in Appendix B.1. Commodity-linked contracts include contracts linked to Brent, Japan Crude Cocktail and Japan Korea Marker price indices. Prices are based on assumptions as of 30 June 2025.

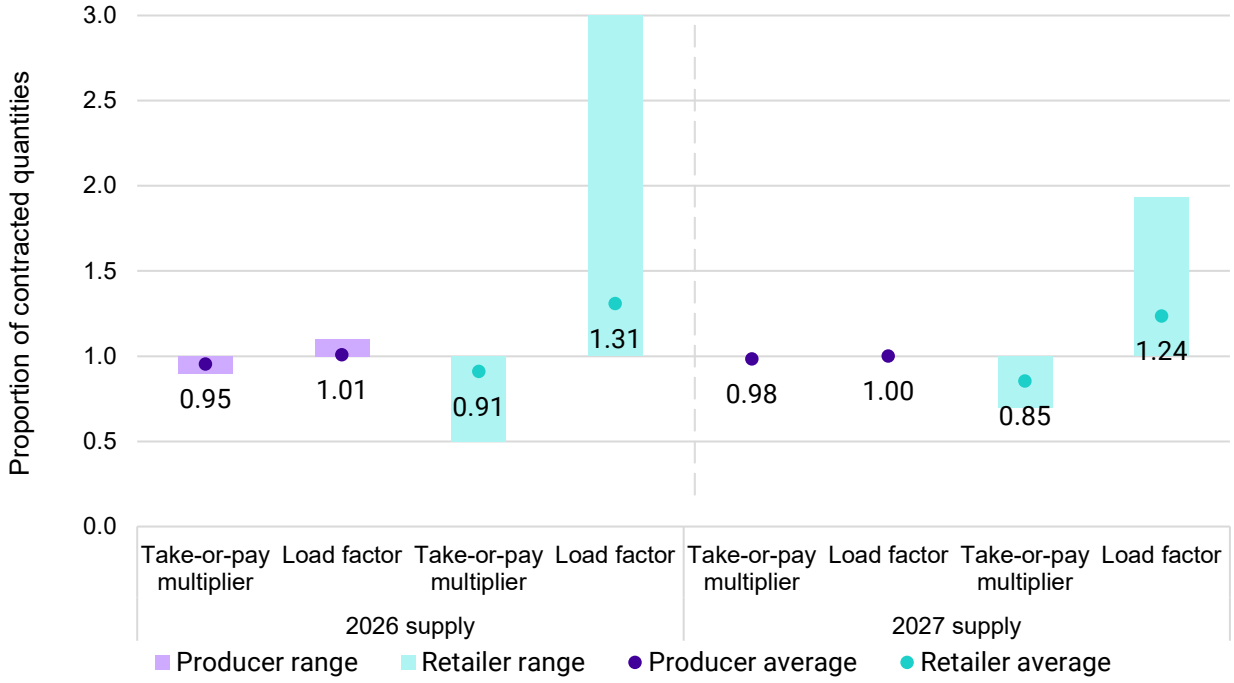
2.4. Retailers continued to execute more flexible terms than producers

Take-or-pay multipliers and load factors are key non-price terms in GSAs that provide buyers with flexibility in how they manage their gas usage.[27] Producers agreed to a lower level of volume flexibility for supply in 2027 compared to 2026 (chart 2.4). We have not presented the range for 2027 supply take-or-pay multiplier or load factor in chart 2.4 for confidentiality reasons. Retailers agreed to more flexible terms for take or pay but provided lower load factor flexibility for supply in 2027 compared to 2026. The range of both take-or-pay and load-factor terms for both retailers and producers has narrowed for 2027 supply compared to 2026.

Retailers continued to provide a greater level of flexibility than producers. This likely reflects their ability to manage changes in demand for gas on a portfolio basis.

[27] Take-or-pay multipliers specify the minimum proportion of annual contract quantities (ACQ) a buyer must pay for in each year, regardless of whether they take the gas or not. A 0% multiplier implies the buyer only pays for what it takes, while a 100% multiplier implies the buyer has to pay for all the gas it has contracted, irrespective of whether they take all that gas. Load factors measure 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 ACQ. A load factor of 1 implies the buyer has no flexibility to take more on a gas day than the average daily contract quantity, while a load factor greater than 1 implies that the buyer can take more on a gas day than the average daily contract quantity. The load factor may be constant through the year or may vary.

Chart 2.4: GSA take-or-pay multipliers and load factors for supply in 2026 and 2027



Source: ACCC analysis of information provided by suppliers.

Notes: Take-or-pay as a proportion of ACQ (Annual Contract Quantity) and Load factor as a proportion of ADQ (Average Daily Quantity). GSAs for 2026 supply were executed between 1 January 2024 and 30 June 2025, while GSAs for 2027 supply were executed between 1 January 2025 and 30 June 2025. Analysis includes GSAs which have an Annual Contract Quantity of at least 0.5 PJ and a contract length of 12 months or more as well as other inclusion criteria as listed in Appendix B.1.

3. Impact of 2022–2023 regulatory changes

Key points

- This chapter provides further observations on the impact of the Gas Code, HoA and ADGSM following our initial observations reported in June 2025 and review of additional information and documents obtained from producers in mid-2025.
- This additional information confirms our preliminary view that while these measures may have resulted in some additional gas being offered or supplied into the domestic market, they have not led to a material improvement in market outcomes. They may also be having some unintended incentive effects and causing inefficiencies in gas supply negotiations.
- The instruments were introduced or amended in periods of heightened concern about gas supply and prices. However, the instruments have not addressed underlying constraints and so have had limited impact on the long-term outlook.

Producer investment and domestic supply

- Producers confirmed that the announcement of the Emergency Price Order and Gas Code affected their decisions about longer term gas supply and, for some, contributed to decisions to pause investment.
- Finalisation of the Gas Code and the granting of exemptions enabled investment to resume, according to producers. Small supplier exemptions, together with commitments in conditional Ministerial exemptions, appear to have led some producers to decide to not supply gas to LNG exporters. However, some stated that the threat of future regulatory changes is affecting their investment decisions.
- The 2023 amendments to the ADGSM appear to have reduced LNG producers' incentives to produce uncontracted gas and to make a net contribution to the domestic market. They may also have contributed to LNG producers' decisions to sell more gas to the domestic market on a shorter-term intra-year basis and to not commit to supplying gas in a period where there is a perceived risk of ADGSM being triggered.
- The 2022 changes to the HoA appear to have had minimal impact on LNG producers' production or domestic supply strategies.

Producer prices, non-price terms and supply periods

- Most producers stated that they consider a range of cost- and market-based factors when determining prices. While producers complied with price provisions in the various instruments, they had little influence on price levels. Some producers reported that they were also incorporating regulatory risk into their price assessments when making investment decisions.
- While the HoA does not prevent gas being offered at lower prices, most of the uncontracted gas offered by LNG producers over the last 3 years has been around the LNG netback price, which has exceeded domestic prices for much of this period. This may help explain the relatively low take up of uncontracted gas by domestic buyers.
- Most producers observed that supply periods have shortened since 2022, citing factors such as regulatory uncertainty, barriers to supply, and elements of the Gas Code and ADGSM that reduced incentives to enter into longer term agreements.
- Most producers told us that the regulatory measures had no impact on the non-price terms and conditions that they offer gas buyers.

Producer selling practices

- Producers share gas buyers' concerns about the rigidity of the Gas Code's EOI obligations, which they report are leading to protracted negotiations. Producers noted that the obligations impeded their ability to engage flexibly and have led some to contract for shorter durations or to consider offering gas in ways that would not trigger a formal EOI process.
- Producers also highlighted the impacts of the Gas Code's offer and negotiation obligations on their ability to conduct timely and effective negotiations with gas buyers. Several producers noted that their ability to explore commercial solutions to meet the needs of buyers has been restricted as a result.

3.1. Introduction

In 2022–23, the Australian Government sought to counter the impacts of gas market volatility and projected supply shortfalls by introducing the Gas Code and amending the ADGSM and HoA (figure 3.1). The Government stated that that these measures were intended to "improve energy security, reliability and affordability"[28] and enable domestic users to access "adequate supply at reasonable prices and on reasonable terms".[29] AEMO's powers were also extended around this time to enable it to monitor, communicate and respond to reliability and supply adequacy threats the market was unable to address.

In our June 2025 report, we set out our preliminary observations on how the east coast gas market had responded to these regulatory instruments. These observations were informed by the information we routinely collect from producers using our compulsory information gathering powers and engagement with a range of gas buyers (retailers, C&I users and intermediaries) and a small number of producers.

At the time, we noted our intention to further examine the impact of the regulatory instruments, including by collecting information, documents and commentary from producers. We collected this additional information from a mix of small, medium and large producers, including the three LNG producers, in mid-2025.

This additional information has corroborated our preliminary observations and provided some additional insights into the effect that each of the regulatory instruments have had, individually and collectively, on producers' incentives and activities in the domestic market.

Taken together with the observations set out in our June 2025 report, we have found that while the Gas Code, ADGSM and HoA may have resulted in some additional gas being offered or supplied into the domestic market, they have not resulted in a material improvement in long-term energy security, reliability, or affordability to date.

Further, elements of the instruments appear to be giving rise to some inefficiencies and having a range of unintended impacts on:

- LNG producers' incentives to supply the domestic market and produce uncontracted gas
- the supply periods that producers are prepared to offer
- the timeliness and effectiveness of negotiations between producers and gas buyers.

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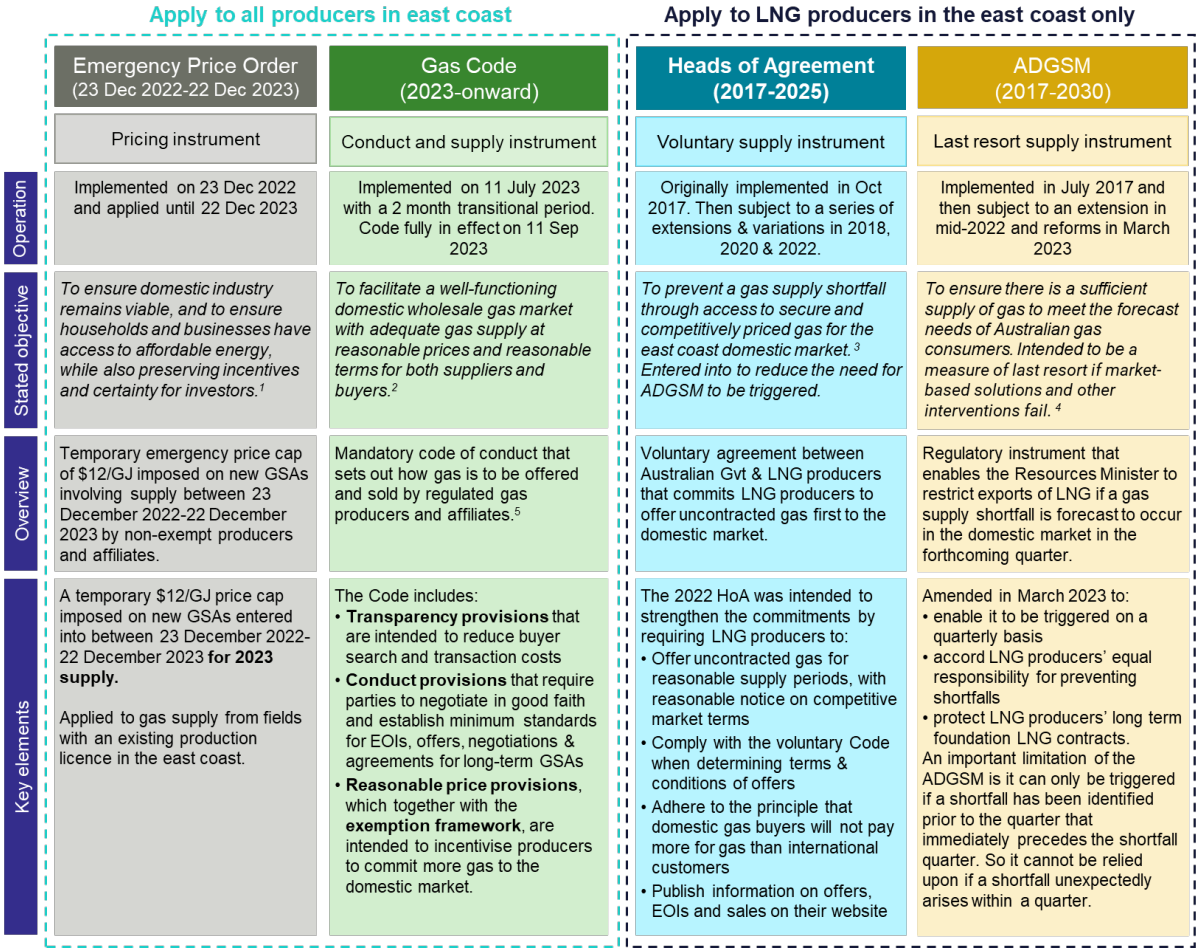
[28] Hon. M King MP, *Reforms ensure domestic gas supply, protect long-term contracts*, [media release], DISR, 30 March 2023, accessed 29 August 2025.

[29] Australian Government, *Options to ensure the domestic wholesale gas market delivers for Australians – Consultation Paper*, December 2022, p 4, accessed 29 August 2025.

Table 3.1 provides an overview of our findings on the impacts of the instruments that are currently in place.

Figure 3.1: Regulatory instruments implemented or amended in 2022-23



Notes: 1. Australian Government, Options to ensure the domestic wholesale gas market delivers for Australians, December 2022. 2. *Explanatory Statement Competition and Consumer (Gas Market Code) Regulations 2023. 3. 2022 Heads of Agreement*. 4. *Customs (Prohibited Exports) Operation of the Australian Domestic Gas Security Mechanism) Guidelines 2023*. 5. The HoA also states Individual prices for gas and related services offered to domestic customers will have regard to the producer's cost of production and supply and factors relevant to user's individual circumstances.

As we noted in our submission to the Gas Market Review, while changes could be made to improve the operation of these instruments, it is important to recognise that there are limits to what the instruments can achieve if the underlying causes of inadequate supply and ineffective upstream competition are not addressed.[30]

The instruments were introduced or amended in periods of heightened concern about gas supply and prices. However, they have not addressed underlying constraints and have therefore had limited impacts overall. Our submission outlines matters for governments to consider in pursuing reforms to promote longer term gas market efficiency and measures to ensure that the Gas Code, ADGSM and HoA are fit for purpose in the interim.

Addressing the underlying constraints on supply and competition will take time, but doing so should reduce the need for these types of regulatory instruments over the medium to longer term. That is, by supporting the development of a more efficient domestic gas market that is

30 ACCC, *Submission to the Commonwealth Gas Market Review*, August 2025.

adequately and reliably supplied and enables gas buyers to procure gas on competitive terms through the energy transition.

The remainder of this chapter provides further detail on what producers told us about the impact that the regulatory instruments have had on their:

- investment and domestic supply activities (section 3.2)
- contract supply periods (section 3.3)
- prices and non-price terms (section 3.4)
- selling practices (section 3.5).

This chapter should be read in conjunction with chapter 5 of our June 2025 interim report.

Table 3.1: Overview of Code, HoA and ADGSM impacts based on June and September 2025 report findings

Observations		Gas Code	HoA	ADGSM
Summary		The Gas Code does not appear to have materially improved domestic market outcomes: – While the reasonable price-exemption framework has had some success in incentivising producers to commit to supplying the domestic market, the additional volumes have been too small to date to materially affect prices. – The conduct provisions also appear to be unintentionally impeding timely and effective negotiations and discouraging some producers from entering longer term GSAs.	The 2022 changes to the HoA may have led to some improvements in how LNG producers offer gas domestically. However, there are some inherent limitations in the HoA's design: – It is a voluntary instrument and LNG producers have only committed to 'offer' (not supply) gas to the domestic market. – The price commitment means that additional gas is unlikely to be supplied into the domestic market unless domestic and LNG netback prices are aligned and at levels that domestic buyers can accept.	The 2023 changes to the ADGSM had a mix of negative and positive impacts: – Allocating LNG producers equal responsibility for shortfalls appears to have unintentionally increased the risk of domestic shortfalls by reducing their incentives to produce uncontracted gas, make a net contribution to the domestic market and enter into longer term GSAs. – Quarterly assessments have provided greater flexibility to deal with shortfalls, although there are still temporal limits to when this tool can be used (i.e. shortfalls must be identified with 6 months' notice). It can also be difficult to forecast and address shortfalls in a 6-month window.
Investment and supply	**Changes:**	Most producers decided to pause domestic contracting in response to the Emergency Price Order and Gas Code development, with some also pausing investment. While contracting and investment has resumed, gas supplied by producers into the domestic market fell by around 100 PJ between 2022 and 2024. Uncontracted gas offered and supplied by LNG producers to the domestic market also fell, while exports increased.		
	Impact of instruments:	The finalisation of the Gas Code and exemption process enabled 'paused' contracting and investments to resume. Most producers are exempt from the reasonable price provisions, covering almost all the expected medium term domestic supply. Committed supply represents a small proportion of annual domestic demand. The small domestic supplier exemption does, however, appear to be discouraging these producers from supplying LNG projects. There is overlap between LNG producers' commitments under the Gas Code and ADGSM and there was some overlap with the Queensland Australian Market Supply Condition in 2024-25.	Since the 2022 HoA was entered into, the take up of uncontracted gas by the domestic market has averaged around 30% of volumes offered. This likely reflects the impact of the HoA price commitment (see price row below).	The reduction in uncontracted gas being produced and offered to the domestic market may be an unintended effect of the changes to the ADGSM. These changes resulted in LNG producers being accorded equal responsibility for shortfalls, rather than accounting for net contributions to the domestic market.
Contract periods	**Changes:**	Supply periods have shortened, and an increasing volume of gas has been sold on a short-term intra-year basis (particularly by LNG producers).		
	Impact of instruments:	The focus of the conduct provisions on GSAs with a term of 12 months or more may have unintentionally affected the willingness of producers to enter longer term GSAs.	The shorter-term focus of the HoA may affect the willingness of LNG producers to enter into longer-term GSAs.	ADGSM design changes may have unintentionally reduced LNG producers' willingness to enter longer term GSAs, particularly during periods where there is a risk that ADGSM may be triggered.

Observations		Gas Code	HoA	ADGSM
Prices	**Changes:**	Prices have eased but remain higher than pre-2022 levels and continue to be shaped by international and domestic supply-demand dynamics.		
	Impact of instruments:	The reasonable price provisions have had little influence on prices to date. This is because most producers have an exemption from these provisions and the supply that has been committed (including the volumes committed at around $12/GJ) has represented a relatively small proportion of domestic demand. For the very limited number of producers that have not obtained an exemption, the reasonable price provisions may be affecting their incentives to offer flexibility and enter into longer term contracts.	The relatively low take-up of LNG producers' uncontracted gas that has been offered to the domestic market appears to be a function of both: – the HoA price commitment (that domestic buyers pay no more than international customers), and – the fact that LNG netback prices have materially exceeded domestic prices for much of the last 3 years. For example, over the last 12 months LNG producers' offers have been around $1-$6/GJ higher than domestic prices.	No identified impact.
Selling practices	**Changes:**	Buyer bargaining power does not appear to have improved and negotiations under the Gas Code are more protracted and less effective.		
	Impact of instruments:	The Gas Code's conduct provisions, together with the penalty provisions, appear to be unintentionally impeding timely and effective EOI processes and negotiations between gas buyers and producers, with both parties noting that the current provisions are too prescriptive and rigid. The conduct and reporting provisions have also resulted in higher compliance and administrative costs for producers.	The 2022 changes to the HoA may have led to some improvements in the way LNG producers offer uncontracted gas, but buyers continue to report challenges procuring this gas.	No identified impact.
Competition	**Changes:**	The upstream market remains highly concentrated and dominated by the LNG producers, who together with their associates have influence over more than 90% of reserves in the east coast. Competition between producers remains ineffective. While the instruments were not intended to directly address upstream competition, they may have inadvertently contributed to the reduction in competition to supply gas under long-term GSAs, particularly in Queensland where more gas is being sold on a short-term basis (see supply period row).		

Source: ACCC, Gas Inquiry 2017-2030 Interim report, June 2025; ACCC analysis of information provided by suppliers.

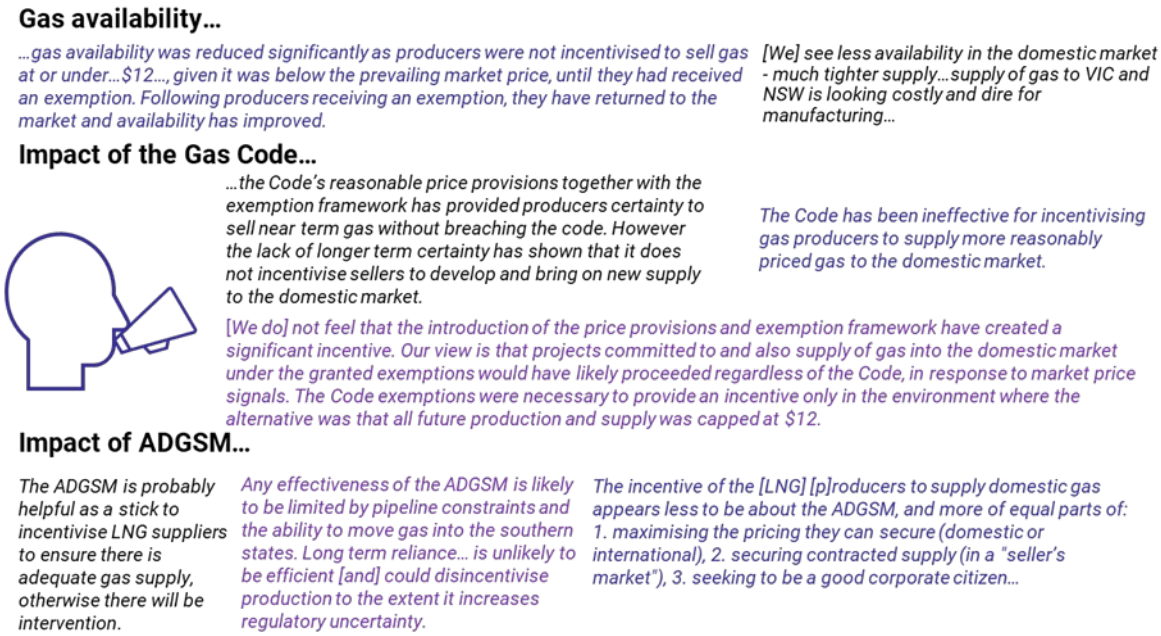
3.2. Investment and domestic supply

One of the objectives in implementing the regulatory instruments was to ensure sufficient supply is made available to the domestic market. In our June 2025 interim report, we observed that:[31]

- total gas supplied by producers into the domestic market has fallen by around 100 PJ since 2022, while LNG exports are around 80 PJ higher
- producers decided to pause contracting and investment in gas production due to what they considered increased regulatory uncertainty over the period 2022–2023
- exemptions from the Gas Code's reasonable price provisions were intended to incentivise producers to supply the domestic market. Most producers are exempt from these provisions, covering almost all expected medium term domestic supply. Noting this, we observed that:
  - material increases in this supply is not expected until 2026, and collectively the committed supply represents a small portion of annual domestic demand
  - there is some overlap between the LNG producers' commitments under the Gas Code and ADGSM and there was some overlap with the Queensland Australian Market Supply Condition in 2024–25, which raised the question of the 'additionality' of some of the committed supply.

Gas buyers made similar observations in our June 2025 report (see figure 3.2), with some noting that gas availability may have improved following the implementation of the Gas Code alongside other instruments, but remains tight, particularly in the southern states.

Figure 3.2: Gas buyer observations on availability of gas and the influence of the Gas Code and ADGSM on supply



Source: ACCC, Gas inquiry Interim Report 2017-2025, June 2025, pp 89, 95, 99.

[31] ACCC, *Gas inquiry Interim Report 2017-2025*, June 2025, pp 86–100.

Overall, we have found that while the Gas Code, ADGSM and HoA may have resulted in some additional gas being offered or supplied into the domestic market, they have not resulted in a material improvement in east coast gas supply.

This section outlines producers' views on the impacts of each the instruments on their investment and domestic supply activities.

3.2.1. Producers decided to pause investment in response to the Emergency Price Order & development of the Gas Code

Some producers noted that increased uncertainty following the announcement of the Emergency Price Order in December 2022 and the implementation of the Gas Code affected decisions about longer term supply and contributed to the decision by some producers to pause investment. One producer said:

> "The announcement of the Emergency Price Order (EPO) and the Consultation of the Gas Mandatory Code (the Code) created significant regulatory uncertainty causing the Supplier Group to pause its planned expansion and frustrated the associated EOI process that was in progress… resulted in the majority of the Domestic Buyers who were continuing to participate in the 2022 EOI either withdrawing from the process or requesting new offers…"

Several producers also pointed to projects and investment being delayed while the Gas Code was being developed and implemented. One producer, for example, noted that the introduction of the Gas Code resulted in "…other parties considering investment opportunities in [the producer's] assets being disinterested…". Another commented that "[investments] in new capacity or wells was frozen until there was certainty around if these could be sold at an economic price or not."

These observations are consistent with what we reported in our June 2025 report, with producers such as Senex, Esso and Woodside not recommencing investment until they received a conditional Ministerial exemption.[32] Producers also pointed to some indirect impacts on investment, such as the impact of regulatory interventions on their return on investment calculations, difficulties in capital raising and debt funding, impacts on shareholder sentiment and a negative impact on exploration.

3.2.2. While investment has resumed, the perceived risk of further intervention may be affecting investment decisions

Some producers noted that the finalisation of the Gas Code allowed investment to recommence and provided some comfort for future investment decisions. However, others noted that the threat of future regulatory changes continues to make long-term investment decisions difficult.

One producer, for instance, noted that the general regulatory uncertainty and suddenness of the Emergency Price Order and Gas Code introduction continues to affect future investment decisions. Elaborating on this further, the producer noted that the:

> "… impact is further exacerbated by the interventionist nature of many of the new regulations that were introduced in rapid succession and with very limited industry consultation or regulatory impact assessments, including the introduction of gas

[32] ACCC, *Gas inquiry Interim Report 2017-2025*, June 2025, p 90.

> price controls for the first time in the east coast gas market which has created a particularly damaging barrier towards the future attractiveness of Australia as a jurisdiction to invest in. This gives rise to material ongoing concerns about potential future interventions by the Commonwealth Government in the east coast gas market, including through its recently announced wholesale review of the Australian gas market, which may result in new forms of intervention that have an alternative and potentially worse impact on [the producer's] future business. This regulatory uncertainty will continue to have a destabilising effect on [the producer] and the east coast gas market…"

Other producers also noted that they had started to incorporate the risk of regulatory intervention into their price assessments when making investment decisions. One producer, for instance, noted that before the Gas Code was implemented, it undertook investment activities based on their view of future gas market dynamics, including price, but following implementation of the Gas Code, they have not invested unless underwritten by a customer GSA.

We note Woodside Energy's recent announcement that it intends to take over operatorship of the Gippsland Basin Joint Venture from Esso. Woodside noted that it had identified potential sources of additional gas, from within existing contingent resources, that could be supplied into the domestic market. We note that development of this gas is still subject to final investment decision.

3.2.3. The Gas Code's exemption framework has had some success in incentivising domestic supply, but there is doubt about the additionality of some of the gas

As we noted in our June 2025 interim report, the reasonable price provisions in the Gas Code were not intended to impose a cap on prices in the way that the Emergency Price Order did. Rather, these provisions were intended to incentivise producers to commit to supply gas into the domestic market in exchange for obtaining an exemption.

Consistent with that intention, most producers supplying gas into the domestic market now have an exemption from the reasonable price provisions, either because they:

- have obtained a conditional Ministerial exemption, or
- satisfy the criteria for a deemed small domestic supplier exemption.

Some suppliers mentioned that indirect benefits of receiving an exemption include potentially reduced risk of regulatory intervention, and the confidence to invest in projects that were otherwise considered too risky to proceed (i.e. because there was no ability to charge prices above the $12/GJ reasonable price).

One producer, for example, noted that, despite their conditional Ministerial exemption not being linked to investment, if the exemption had not been secured their production plans may have required flexibility (of capital and operating expenses) to deliver more or less volume as required.

Producers also observed the following about the likelihood of the supply and investment-related commitments set out in their conditional Ministerial exemptions going ahead without the Gas Code:

- Senex, which committed to supply at least half of its gas domestically, maintains that it would still have had a strong domestic focus, but the Gas Code caused disruption by pausing their expansion plans.
- Another producer that had an investment-related conditional Ministerial exemption stated that their development would have likely gone ahead without the Gas Code.
- LNG producers who committed to supply gas stated that the gas would still have been offered domestically, but in accordance with the terms of the HoA. As discussed in section 3.4.1 below, over the last 3 years, most of the uncontracted gas offered by LNG producers under the HoA has been priced close to the LNG netback price, which has exceeded domestic prices for most of this period.

These observations are broadly consistent with those reported in our June 2025 interim report and raise questions as to the 'additionality' of some of the gas supplied under the conditional Ministerial exemptions.[33]

In the case of small domestic supplier exemptions, a small number of producers with this type of exemption stated that they are continuing to supply LNG projects under contracts that were entered into prior to the Gas Code coming into effect. Others told us they have decided not to supply LNG producers so that they could retain this exemption. Some producers with conditional Ministerial exemptions also noted that as a condition of their exemption, they are not supplying gas to LNG producers.

This element of the exemption framework therefore appears to be working as intended.

3.2.4. LNG producers had mixed views on the effect the 2023 ADGSM changes had on their incentives to supply the domestic market

One of the major changes to the ADGSM in 2023 was to remove any reference to each LNG producer's net contribution to the domestic market. Where previously LNG producers that had made a net contribution to the domestic market would not be allocated any share of a market shortfall to address, the changes to the ADGSM in 2023 resulted in responsibility for any shortfall being shared equally among the three LNG producers.

LNG producers expressed mixed views about the impact of this change. One LNG producer, for instance, stated that the change had negatively impacted its incentives to produce uncontracted gas and supply the domestic market in quarters at risk of the ADGSM being triggered:

> "The heightened exposure to export restrictions… because of the 2023 amendments… represents a material risk factor that is explicitly taken into consideration by the… board of directors when they make annual decisions as to how much uncontracted Gas the Supplier Group should plan to develop and produce…"
>
> "The LNG project receives no credit… for proactively contracting sales of Gas to Domestic Buyers for a quarter prior to the Minister providing notice of a potential domestic shortfall..."

[33] ACCC, *Gas inquiry Interim Report 2017-2025*, June 2025, pp 94–96.

> “[the producer’s] investors currently do not see the attraction of investing in further uncontracted gas because of the structure of the ADGSM. The current construct benefits net takers from the domestic market. The more [the producer] contributes to the domestic market, the less AV export permits it is allocated in case of a shortfall.”
>
> “New regulatory instruments HOA, Gas market Code, ADGSM and other measures have not increased net supplies from Queensland. ADGSM disincentives net contribution. … Gas market intervention has shaken the confidence of investors and buyers.”

This LNG producer noted that, due to a range of factors, volumes of gas supplied domestically are expected to fall. Another LNG producer noted that the 2023 changes had increased the risk that supply under its long-term SPAs would be affected because in its view the protection offered to long-term SPAs are “of little meaningful benefit given the stringent criteria to be satisfied.” This LNG producer noted that this increased risk has incentivised it to “play its part in ensuring that a domestic market shortfall does not arise by continuing to offer gas to Domestic Buyers” to “avoid activation of ADGSM”.

A third LNG producer did not refer to any specific impacts of this change to the ADGSM, but did note that it has sought to reduce its reliance on the domestic market for gas:

> **“**As [the LNG producer’s] third party gas supplies have started to reduce, [the LNG producer] has increased investment in its equity fields to improve production. [The LNG producer] spends around $1 billion per annum on operating, maintaining and developing its equity fields”. “[The LNG producer] formed a “New Acreage” Subcommittee and has been looking at now potentially investing in new tenements.”

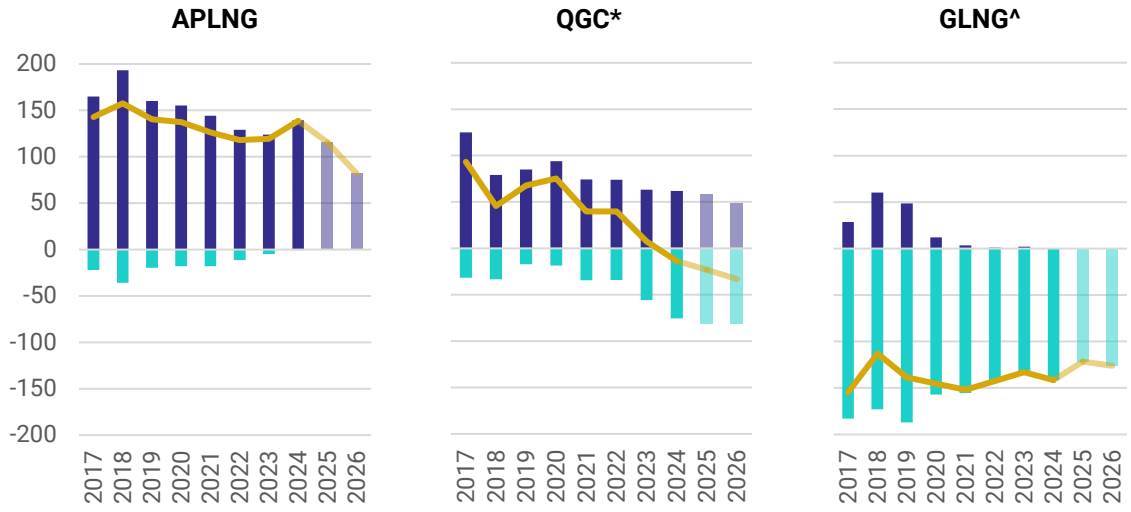
This LNG producer also noted that the move to quarterly assessments has provided the government more flexibility to deal with threats that emerge.

While LNG producers had mixed views on the impact of the 2023 changes to the ADGSM, it would appear from our review of LNG producer responses and documents that the threat of ADGSM being triggered is still perceived as a material risk. Mitigating the risk of export controls, for example, featured prominently in LNG producer documents:

> “Identified potential threats to [the producer], including 1. Activation of Export Controls….”
>
> “Priorities: 3. Protect LNG export contracts and portfolio value through structural solutions to mitigate ADGSM shortfall risk….”

Despite this risk, domestic supply by the LNG producers has fallen in recent years. Figure 3.3 shows LNG producers’ domestic sales and third-party purchases over time. The 2023 changes to the ADGSM may have removed the incentive to mitigate the risk of the export controls by making a net contribution.

Figure 3.3: LNG producers' domestic sales and third-party purchases (PJ)



Source: ACCC, Gas Inquiry 2017-2030 Interim Report, June 2025, pp 67–69.

Note: 2017–2024 is based on actuals data provided to the ACCC while 2025 and 2026 are based on the latest forecasts available for those years. Positive values are domestic sales; negative values are domestic purchases.
* Domestic purchases refer to gas purchased under the Strategic Gas Sales Agreement with Arrow Energy.
^ Gas purchased from the domestic market and other long-term purchase arrangements with third parties.

3.2.5. The 2022 changes to the HoA reportedly had little impact on LNG producers' supply strategies

As part of our questions to LNG producers, we asked whether the changes made to the HoA in 2022 had any effect on their production, investment and/or supply strategies.

One LNG producer noted the changes had minimal impact because the general obligations remained consistent between the 2020 and 2022 HoAs.

3.3. Contract supply periods

Historically, most of the gas in the east coast has been sold by producers to domestic buyers under long-term GSAs (i.e. with a term of 12 months or more). However, since the regulatory instruments were implemented in 2022–23, increasing volumes of gas have been sold by producers on a short-term basis. This is particularly the case in Queensland, where LNG producers are increasingly selling gas under short-term intra year GSAs and swaps.[34]

In our June 2025 interim report, we noted that the increased prevalence of shorter-term contracting was posing challenges for gas buyers and investment and could be:

- occurring in response to the uncertainty facing the market, and/or
- an unintended consequence of the focus of the Gas Code's conduct provisions on supply periods of 12 months or more and/or the change to the design of the ADGSM.

Similar observations were made by a number of the gas buyers we spoke to in the first half of 2025 (see figure 3.4) and producers, as the responses outlined below reveal.

[34] ACCC, *Gas Inquiry 2017–2030 Interim report*, June 2025, pp 88–89 and Appendices B and D.

Figure 3.4: Gas buyer observations on producer supply periods

Gas is available but there is limited options short term. Longer term offers are either not available at all or price prohibitive.

The availability of long term supply offers have disappeared due to the uncertainty regarding future changes to the code. This has forced industrial customers into short term arrangements only.

…we have had good engagement from Southern producers, they are happy to provide indicative pricing for 2026 and 2027…If you contrast this with Queensland producers, none of them want to talk about 2026 and 2027, they have been running EOI's for quarterly half year periods

It is challenging to negotiate tenures beyond two years. Prior to the announcement of the Gas Code, it was possible to negotiate gas supply agreements over an extended period (e.g. up to five-years periods). Since that time general uncertainty around the availability and price of supply over the medium to longer term may be impacting a willingness to supply for longer periods. The time-limited nature of conditional exemptions and uncertainty around the outcomes of the 2025 Code Review could also be a contributing factor in this respect.

Source: ACCC, Gas Inquiry 2017-2030 Interim report, June 2025, Box 5.1.

3.3.1. The supply periods offered by some producers have shortened in response to the Gas Code and ADGSM

Most producers observed that supply periods have shortened since 2022. Some of the factors that they stated had contributed to this shift to shorter term contracting include:

- market and regulatory uncertainty
- gas production and reserve constraints
- a perception that buyers may be holding out for further regulatory interventions.

A number of producers also noted that elements of the Gas Code and ADGSM had contributed to the shift to shorter term contracting. Several producers, for example, noted the focus of the Gas Code's conduct provisions on GSAs with a term of one year or more had incentivised them to sell gas on a shorter-term basis:

> "The cumbersome EOI process discourages gas offerings of one year or more, as the severe consequences of procedural non-compliance and the ambiguous nature of the good faith obligation create significant risks for wholesale producers. This disincentivises producers from proactively offering gas to the domestic market where no obligation exists. Furthermore, the 2023 changes to the ADGSM, including the shift to quarterly assessments and the disincentive to sell gas before a shortfall is declared, have further exacerbated the reduction in medium to long-term domestic contracting. This has placed commercial and industrial (C&I) users, who rely on stable and predictable 'flat strips' of supply to support their operations, at a competitive disadvantage."

> "Prior to the [Gas Code] we preferred to lock in longer term GSAs, following the code we have signed shorter agreements particularly ones that are less than 1 year as these are less restricted by the [Gas Code]."

Another noted that while this was not a major consideration for it, “the increased compliance risk and cumbersome processes associated with supply periods over 12 months decreases the attractiveness of marketing volumes for longer supply terms.”

An LNG producer also noted that the Gas Code has increased their perceived compliance risk, leading to a conservative approach in comparison to the period before the Gas Code. Additionally, this LNG producer mentioned that the Gas Code “has introduced limitations for supply under multi-year agreements”.

For the small number of producers that do not have an exemption, the Gas Code’s reasonable price ($12/GJ) provisions may also encourage shorter term contracting. One producer, for example, noted that because the reasonable price is a fixed price, it prevents non-exempt producers from using standard methods to manage inflation and other cost and market related risks (e.g. through CPI, change of law, cost pass through and price review mechanisms). These producers may therefore be incentivised to try and manage the risks by contracting on a shorter-term basis, or selling gas in the STTM, DWGM and/or GSH (for trades less than 3 days) because the reasonable price provisions don’t apply to these trades.

Separately, but relatedly, two producers noted that the term of their conditional Ministerial exemption was an important factor in what supply terms to offer, because they had no certainty about whether they would be exempt from the reasonable price provisions beyond this point. One of these producers highlighted that contracting beyond the term of their conditional Ministerial exemption introduced significant risk, as there was no guarantee the producer would continue to be exempt from the reasonable price provisions under the Gas Code. The producer also noted the potential risk that the reasonable price provisions could be reviewed and the uncertainty this created about the price at which the producer could offer and receive for supply in future periods. A recent variation to extend the term of a conditional Ministerial exemption may have been at least partially intended to reduce this risk and allow longer term contracting.

Similarly, another producer has introduced a provision in its GSAs that provides for supply after the expiration of its current conditional Ministerial exemption to be conditional on it obtaining an extension to that exemption (see also section 3.4.2).

In the case of the ADGSM, one LNG producer noted that the 2023 changes had affected its willingness to supply gas during periods where there is a risk the ADGSM will be triggered. This is because selling gas prior to a shortfall being called does not count towards the LNG producer’s shortfall contribution. This element of the ADGSM, together with the movement to quarterly assessments, may therefore have contributed to the decision by some LNG producers to sell more of their gas on a shorter-term intra-year basis and not to commit to supplying gas in a period where there is a perceived risk of ADGSM being triggered.

The combined effect of these provisions appears to be motivating some producers to contract gas for shorter contract terms across a range of timescales.

3.4. Prices and non-price terms

One of the objectives in implementing the regulatory measures outlined in section 3.1 was to enable domestic buyers access to gas at reasonable prices and on reasonable terms.

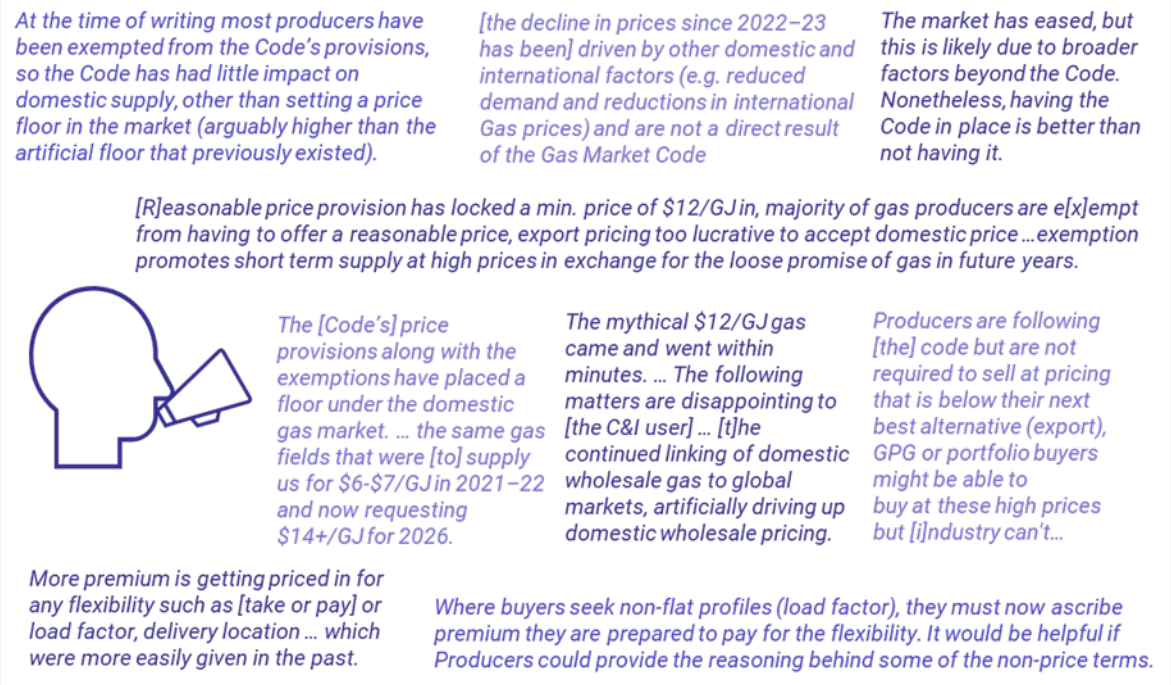
As we observed in our June 2025 interim report, while conditions have eased since 2022: [35]

- producer prices remain above their pre-2022 levels and continue to be shaped by international and domestic supply demand dynamics, with the Gas Code's reasonable price provisions having little influence on prices to date
- producers are increasingly offering limited or no volume flexibility in their GSAs and are seeking higher premiums for any volume flexibility that is provided.[36]

These observations are broadly consistent with what gas buyers have observed (see figure 3.5) and would appear to suggest that, with the exception of the Emergency Price Order, the regulatory measures have had little, if any, effect on producer prices or non-price terms to date. As we noted in the June 2025 interim report, this may be because:

- most producers are exempt from the Gas Code's reasonable price provisions and the additional gas supplied into the domestic market as a result of commitments made under both the Gas Code and HoA has been relatively small over the last 2–3 years
- there has been no improvement in competition between producers to supply the domestic market, with the upstream market remaining highly concentrated and dominated by the LNG producers.

Figure 3.5: Gas buyer observations on producer prices and non-price terms



Source: ACCC, Gas Inquiry 2017-2030 Interim report, June 2025, Boxes 5.6 and 5.7.

In the case of the Emergency Price Order, the $12/GJ emergency price cap did pose more of a constraint on the price that producers could sell gas for under new GSAs entered in between 23 December 2022 and 22 December 2023 for supply in 2023. It also had a range of other adverse effects, including limiting gas buyers' access to gas and increasing the costs and risks gas buyers faced when procuring gas.

35 ACCC, *Gas Inquiry 2017-2030 Interim report*, June 2025, pp 100–107.

36 ACCC, *Gas Inquiry 2017-2030 Interim report*, June 2025, p 106.

Our observations on the impact that the regulatory measures have had on producers' prices and non-price terms are broadly consistent with what we have heard from producers, as discussed in further detail below.

3.4.1. Prices continue to be driven by market conditions, rather than the regulatory instruments

We sought information from producers on the factors they considered when determining the prices to offer the domestic market over the last 3 years and what effect, if any, the regulatory instruments had on their prices. Most producers responded by stating that they had regard to a range of cost- and market-based factors when determining prices and that while they complied with the price provisions in the various regulatory instruments, they had little influence on their prices:

> "The key consideration in all pricing decisions was prevailing market conditions. [We] always [attempt] to price our contracts at or near market expectations for the given period and product offered."

> "With domestic and international prices well above [the cost of production] throughout the Relevant Period, this cost of production was considered but was determined to be less relevant in determining prices."

The key exception to this was the Emergency Price Order, which a large number of producers noted affected their pricing in 2023. A small number of producers also commented on the impact that the Gas Code's reasonable price provisions could have on non-exempt producers and the HoA price commitment.

The price cap in the Emergency Price Order had a range of distortionary effects on the market

The Emergency Price Order provided for prices under new GSAs entered into between 23 December 2022 and 22 December 2023 for supply in 2023 to be capped at $12/GJ.

According to producers, the $12/GJ price cap temporarily distorted market signals and had a range of other adverse effects on negotiations and competition between producers and other suppliers in the market that were not subject to the price cap (e.g. retailers, aggregators and traders). One producer, for example, observed that:

> "The implementation of the Emergency Price Order made it very difficult to agree on prices because it distorted market signals by setting a price below where market equilibrium was around the time of its introduction."

Another noted that:

> "[We] had to reject some customers who wanted to pay more than the price cap for our gas… created an environment that favours the aggregators and allows them to clip the ticket and make gas more expensive for customers."

Some producers also pointed to the impact that the Emergency Price Order had on buyers:

> "Buyers withdrew price bids due to the uncertainty of government interventions."

> "…the Supplier Group believes the pricing provisions [in the Price Order] may have influenced pricing expectations during that period."

The reasonable price provisions in the Gas Code have had little, if any, effect on most producers' pricing decisions

A key element of the Gas Code's design is the reasonable price provision, which applies to non-exempt producers, and is currently set at $12/GJ. Together with the exemption framework, the reasonable price provision is intended to incentivise producers to commit to supplying the domestic market.

As expected, most producers now have an exemption from the reasonable price provision, which may help to explain why very few referred to this provision having any impact on their prices. One producer did, however, observe that the fixed price nature of the reasonable price provision could affect the willingness and/or ability of the limited number of non-exempt producers to offer flexibility and to enter into longer-term contracts:

> "If the supplier does not have an exemption, such an approach discourages suppliers from offering any kind of related service as part of a gas supply offer (such as a flexibility service via MDQ or seasonal variation in supply). This is because the consequences of noncompliance for such service charges being considered by the ACCC as part of the gas price could exceed the value of a deal. This is detrimental to a market where demand is both highly seasonal and increasingly weather dependent (GPG as firming for renewables) … A similar issue arises regarding the potential to escalate the reasonable price with CPI."
>
> Further… the reasonable price provisions of the Gas Market Code are unsuitable for long term contracts because these contracts inherently demand a different risk profile for gas pricing (e.g. requiring allowance for CPI changes and change of law risks)."

One producer also questioned the value of some of the conditional Ministerial exemptions:

> "Conditional Exemptions granted to [some LNG producers] in return for selling a small proportion of their Uncontracted Gas into the market, allowed them to offer their remaining "Uncontracted Gas" to the domestic market via EOIs at Spot LNG (JKM) Netback pricing. Based on [our] understanding of the Gas Inquiry reports, it appears that very little of this remaining Uncontracted Gas has been sold into the domestic market."

The HoA price commitment has a number of inherent limitations

The HoA includes a voluntary commitment by the LNG producers to not offer uncontracted gas internationally unless an equivalent volume is first offered to the domestic market on "competitive market terms".[37] The HoA also includes a principle that "domestic gas customers will not pay more for the LNG Exporters' gas than international customers".

While the HoA does not prevent gas being offered at lower prices, most of the uncontracted gas offered by LNG producers over the last 3 years has been around the LNG netback price, which has exceeded domestic prices for much of this period.[38] As we have previously observed, this price differential may help to explain the relatively low take up of uncontracted gas by the domestic market over the last 3 years. The price benchmarks used by some LNG producers may also be affecting take up. A producer stated that it had offered 26 PJ of uncontracted gas to the domestic market during H1 CY25 at a price of 85.2% JKM

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37 Department of Industry, Science and Resources, *Heads of Agreement*, DISR website, n.d., accessed 29 August 2025, p 1.

38 ACCC, *Gas Inquiry 2017-2030 Interim report*, June 2025, Chart 5.5.

(equivalent to $16.27/GJ at that time). The producer noted that the lack of uptake may have been due to limited interest in JKM-linked pricing under the specific market conditions prevailing at the time. This observation was limited to those conditions and market dynamics and customer preferences can change.

The relatively low take up of uncontracted gas that has occurred over the last 3 years highlights one of the more fundamental limitations with the HoA, which is that it is only a commitment to offer gas and not to supply gas. Another inherent limitation with the HoA is that the price commitment may only result in additional gas being supplied into the domestic market if domestic and LNG netback prices are broadly aligned and at levels that can be accepted by domestic buyers. This is because if:

- LNG netback prices exceed domestic prices, then domestic buyers are unlikely to take the gas up
- domestic prices exceed LNG netback prices, LNG producers may consider they cannot offer gas at domestic price level because the commitment not to charge domestic users more than international customers poses a cap on what they can charge.

The latter of these points was made by one of the LNG producers:

> "…the HOA provisions on pricing have constrained [us] from participating in the short-term markets when domestic prices spike above LNG netback. The 2022 Heads of Agreement assumes that LNG Netback will always exceed domestic prices. Hence in situations when LNG [netback] is lower, it means that [we] potentially cannot offer at domestic prices because it would breach [our] commitments under the 2022 Heads of Agreement. This is especially problematic in the Day to Day + 4 markets."

3.4.2. There has been little impact on non-price terms, but some producers are now factoring regulatory risk into contracts

Most producers told us that the regulatory instruments had no impact on the non-price terms and conditions that they offer gas buyers (see box 3.1). One producer did, however, observe that the Emergency Price Order increased the compliance risk associated with more complex structured transactions, particularly those with flexibility and/or transport.

The same producer noted that until they obtained a conditional Ministerial exemption under the Gas Code, they were unwilling to offer flexibility on their non-price terms and conditions as it had been unclear as to whether they could charge more for that flexibility.

> "It was not clear during [the period from the introduction of the Gas Market Code to the granting of the Producer's Conditional Ministerial Exemption] whether [the producer] could charge for services, and therefore [the producer] generally did not offer flexible Non-Price Terms on gas sales."

It would appear that some producers have sought to include additional terms (e.g. change of law and termination provisions) into their GSAs to help manage their risks in the event of specific further regulatory changes.

Box 3.1: Producer observations on non-price terms

Most producers told us that they have a standard set of non-price terms that they offer gas buyers but are willing to negotiate more bespoke arrangements on a case-by-case basis. They did, however, note that this usually came at a premium, because it can cost more to provide the flexibility sought by gas buyers.

Some also noted that legal, commercial, geological, engineering and other risk factors may limit the extent to which non-price terms and conditions may be varied. For example, one producer noted that:

> "When determining Non-Price Terms and Conditions during the Relevant Period, [the producer] took into account a variety of legal, commercial and engineering considerations, with the primary goal of minimising exposed risk to [the producer], while being flexible where possible to the terms requested by counterparties".

3.5. Selling practices

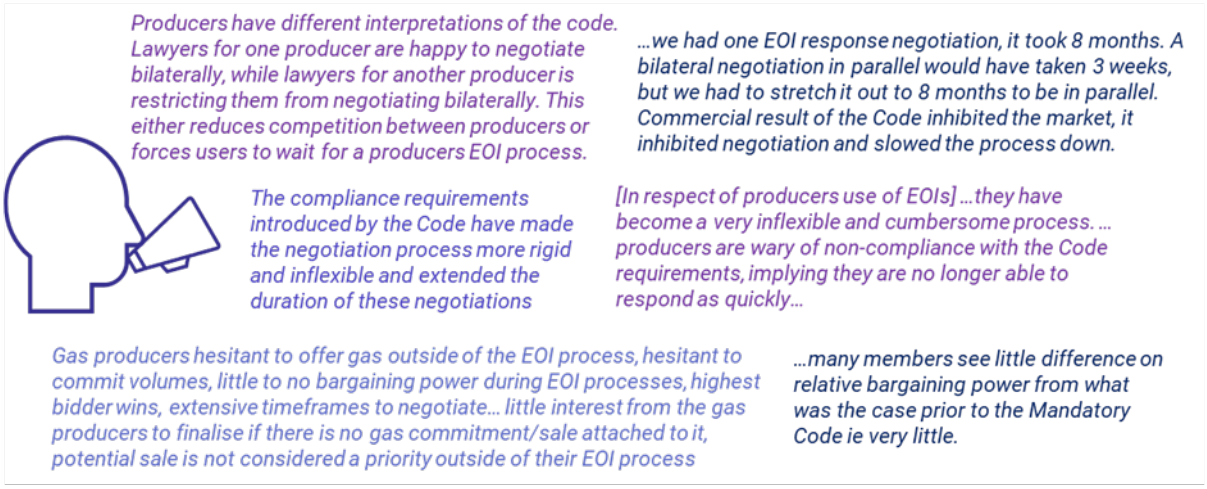
The Gas Code includes a number of conduct related provisions that are intended to try and improve producer selling practices and reduce the imbalance in bargaining power faced by gas buyers. That is, by:

- imposing an obligation on producers and gas buyers to negotiate in good faith for agreements of any supply term
- requiring producers to comply with minimum standards for EOIs, offers, negotiations and agreements with a supply term of 12 months or more.

As we observed in our June 2025 interim report, these provisions do not appear to have resulted in a material improvement in buyer bargaining power. Nor do they appear to be supporting timely and effective negotiations between gas buyers and producers, with significant concerns being raised by gas buyers about the rigidity and protracted nature of the EOI and offer processes (see figure 3.6).[39]

[39] ACCC, *Gas Inquiry 2017-2030 Interim report*, June 2025, pp 107–110.

Figure 3.6: Gas buyer observations on producer selling practices



Source: ACCC, Gas Inquiry 2017-2030 Interim report, June 2025, section 5.6.

As discussed further below, similar concerns were raised by producers, who noted that the prescriptive nature of the EOI and offer provisions in the Gas Code, together with the penalties for non-compliance, are impeding timely and effective negotiations.

3.5.1. Producers share buyers' concerns about the impact of the Gas Code's EOI provisions

The Gas Code sets out minimum standards for both EOIs and bilateral offer processes.[40] The EOI provisions were included in the Gas Code to address some of the more fundamental concerns that had been raised about producer EOI processes prior to its introduction. That is, that not all buyers in the market were aware when EOIs were being conducted and that minimum standards were not being met.

Producers share gas buyers' concerns about the rigid nature of the obligations set out in the Gas Code, which they claim are leading to protracted EOI processes.[41] Producers reported that the inflexibility of the EOI processes has impeded their ability to engage flexibly with gas buyers. Several producers, for example, noted that the 'prescriptive' nature of the EOI processes has resulted in more rigid and protracted negotiations with gas buyers:

> "The implementation of the Code created an excessively complicated EOI process which appear to have no benefit to sellers or buyers and constrains market activity. …. [We] would not be able to conduct more than one EOI a year due to the long period it takes to run a Code compliant EOI process."
>
> "… we have also been forced to run an onerous and time consuming EOI process ..."

These obligations appear to have led some producers to consider offering gas in ways that would not trigger a formal EOI process. For example, one producer's internal compliance training documents indicates that staff were encouraged to not offer gas to more than 2 buyers and to offer supply periods of less than 12 months.

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[40] Importantly, the Gas Code does not mandate the use of EOIs by producers nor does it prohibit bilateral negotiations between producers and buyers. Rather, the EOI provisions in the Gas Code only apply where a producer is offering to supply gas for 12 months or more and the producer issues an expression of interest to more than 2 people. They may also apply where a producer has committed to conduct EOIs as part of a conditional Ministerial exemption.

[41] ACCC, *Gas Inquiry 2017-2030 Interim report*, June 2025, p 108.

Another producer also observed:

> "The prescribed process for issuing an EOI and negotiating a longer-term gas supply agreement under the Gas Code is more formal, and less flexible, than market practice. The prescriptive nature of the Gas Code, and the fact that it includes civil penalty provisions has required suppliers to engage more formally than was the case prior to the Gas Code. This may be a factor that has led some suppliers and buyers to favour short term deals, as the Gas Code provides for greater flexibility with negotiations for short term gas transactions."

3.5.2. Producers also reported the Gas Code has affected their ability to conduct timely and effective negotiations

As we observed in our June 2025 interim report, gas buyers appeared to have had a range of experiences since the Gas Code conduct provisions were implemented, with some having a more positive experience while others stated that there has been 'limited' or 'little' negotiation with producers.

Producers have further stated that the conduct provisions, particularly the offer and negotiation obligations, have affected their ability to effectively negotiate with gas buyers. Some producers attributed their 'unwillingness' or difficulties negotiating with gas buyers to their obligations under the Gas Code:

> "The way [negotiation is undertaken] is restricted by the [Gas Code] not what suits both parties - customers are increasingly frustrated by this. None of this is driven by our willingness to negotiate which remains unchanged."

> "Now the risk of inadvertently entering a "negotiation", by those interactions being treated as an "offer" … mean it is preferable to not engage in this manner, and to simply respond to fully fledged bids via email as the aspects of the bid that can be negotiated can be clearly set and responded to."

> "Iterative discussions with buyers on key terms can lead to extended negotiation periods, noting each may constitute a new Gas Initial Offer or Gas Final Offer which is subject to minimum timeframes as stipulated by the Gas Market Code."

A number of producers also noted that their ability to explore commercial solutions to meet the needs of buyers has been restricted as a result. One producer, for example, noted that EOIs under the Gas Code has "[limited] creativity and... the natural process of negotiation is somewhat constrained…[and] general concept exploration ... with counterparties [has] been disincentivised", due to the risk of commencing a negotiation subject to the provisions of the Gas Code. Another producer observed:

> "…from a seller's perspective the Gas Market Code has changed an organic deal process that evolves based on a buyer and seller finding mutual deal space, to become a more formulaic and procedural process. The seller is required to be very prescriptive up front around all the terms it can adjust and vary offers under, making it appear quite restrictive to customers that are not yet used to this new way of working…. Prior to the Gas Market Code, this might have meant that individual traders could have explored a range of ideas including those that were yet to have obtained internal business support or mandate. Given that all negotiations must be in good faith, there is a reluctance to simply explore ideas that might not be capable of evolving into any kind of offer."

Several producers stated that the way in which they offer gas to the domestic market has also changed as a result of the inflexibility of the Gas Code's conduct provisions, with some noting it has led to a preference to selling gas on a shorter-term basis (see section 3.3).

> "[The producer] has been unable to participate in customer RFPs or bids due to the fact it could lead to a binding GSA … This has made marketing gas so challenging that it has resulted in us selling less gas, delays to selling gas and for it being done for shorter durations i.e. < year."

> "The Code is adversely impacting on gas offering and contracting practices within the market… as the severe consequences of procedural non-compliance and the ambiguous nature of the good faith obligation create significant risks for wholesale producers. This disincentivises producers from proactively offering gas to the domestic market where no obligation exists, particularly when assessed in parallel with the 2023 changes to the ADGSM, including the shift to quarterly assessments and the disincentive to sell gas before a shortfall is declared, and therefore adversely impacting incentives for medium to long-term domestic contracting."

> "Customers have expressed great frustration at our reduced ability to sell them gas due to the [Gas Code]."

> "Restrictions reduced our ability to freely offer gas to customers given the formal bid process imposed on suppliers which reduced / delayed the volumes we could made available."

3.5.3. Producers pointed to the increased administrative burden associated with the conduct & reporting provisions

Producers, particularly smaller producers, expressed concerns that the Gas Code's conduct and reporting provisions have increased their administrative burden. One producer, for example, noted that:

> "[we are] very unlikely to ever offer Gas under an EOI due to the administrative burden placed on the Supplier Group under the Gas Market Code, and the risk of non-compliance for a small company… [we would] only ever participate in bilateral Offers, or respond to Domestic Buyer bids or tender processes"

Another producer noted:

> "…the prescriptive nature of record keeping and frequent reporting and significant penalties for non-compliance has seen more staff allocated to/spending time on compliance to mitigate that risk for the Company."

Appendix A

Table compares the supply demand outlook for quarter 1 2025, as published in the September 2024 interim report,[42] with actuals over the same period, obtained from AEMO's Gas Bulletin Board (GBB).[43]

Table 1.2: Comparison of forecast vs actuals for Quarter 1 2025

	Quarter 1 2025 forecast	Quarter 1 2025 actuals	Quarter 1 2025 difference (*actual - forecast*)	Quarter 1 2026 forecast
Supply				
Supply total	*488*	*463*	*-25*	*460*
Demand				
Quantity to meet LNG SPAs	*359*	*344*	*-15*	342
LNG producers' net uncontracted gas	*15*	*NA*	*NA*	22
LNG producers' spot sales	*8*	*22*	*14*	4
Net storage injections	*Included in supply total above*	*Included in supply total above*	*NA*	*Included in supply total above*
Queensland demand ex LNG	*31*	*30*	*-1*	29
Southern states	*64*	*70*	*6*	62
Demand total	*477*	*466*	*-11*	*458*
Outlook				
Surplus/shortfall	*12*	*-3**	*-14*	2

Source: ACCC analysis of data obtained from producers in July 2024 and AEMO Gas Bulletin Board Actual flow and Storage (all data) as at 23 July 2025.

Notes: Totals may not sum due to rounding.
*Actual supply and demand not balancing can be attributed to pipeline linepack, where gas compression can result in injected gas being greater than withdrawn gas.

Actual supply and demand were both lower than expected, resulting in a closer supply-demand balance. Quarter 1 generally exhibits lower domestic gas demand, as noted in 2025, due to seasonal variation in gas required for power generation over the east coast.

[42] ACCC, *Gas Inquiry 2017–2030 Interim Report*, March 2023, p 10.

[43] AEMO, Gas Bulletin Board, *Actual flow and Storage (all data)* as at 17 July 2024.

The closer than expected supply-demand balance was driven by:

- decreased gas production in Queensland
- downward revision of export volumes required to meet SPAs
- higher volumes of uncontracted gas exported as spot cargoes
- higher than expected domestic demand in southern states.

Declining and inconsistent production from legacy fields, delays to production from 2P undeveloped resources, planned and unplanned maintenance and business rationalisation decisions are the most likely contributing factors to the observed differences between actual and forecast supply.

Appendix B

This Appendix sets out the ACCC's approach to reporting on prices agreed under GSAs in the report. The following apply to our analysis of prices reported in chapter 2:

- 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.
- Only transactions with a term of at least one year and an annual contract quantity of at least 0.5 PJ are reported.
- 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.
- The 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', where the section 95ZK and 53ZT data is used: Origin Energy, AGL, EnergyAustralia, Engie, Alinta Energy, Shell, Energy Australia, Macquarie Bank and PetroChina.
- Prices reported do not include contracts for delivery into the Northern Territory.
- We only report on GSAs with clear indications of price. We do not report on GSAs that are either spot-linked or directly linked to realised supplier costs.

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 and has separately reported on GSA flexibility in section 2.4.

Glossary

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 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 three 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 many 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.

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

Downward quantity tolerance: The amount a buyer may fall short of their 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: The major gas hub for spot and futures trading in the United States. This hub acts as the notional point of delivery for gas futures contracts. Henry Hub is based on the physical interconnection of nine interstate and four intrastate pipelines in Louisiana.

Japan Korea Marker: 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.

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 based on 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 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, Energy Australia, Macquarie Bank, Power and Water Corporation, Origin Energy, PetroChina and Shell Energy Australia.

Sale and purchase agreement (SPA): An agreement between the buyer and seller of LNG.

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 periods (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 two or more gas market participants to swap rights or obligations. For example, two 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 license 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 = approx. 1.055 GJ.