Gas markets in eastern Australia

This chapter covers upstream gas markets in eastern Australia, encompassing gas production, wholesale markets for gas and the transport of gas along transmission pipelines for export or domestic use.[1] Much of the chapter is focused on AEMO-facilitated markets, though for the first time includes information on bilateral commodity gas trades up to a year in duration.[2]

The main production basin in eastern Australia is the Surat–Bowen Basin in Queensland. There are smaller basins in South Australia, New South Wales (NSW), off coastal Victoria and in the Northern Territory. Combined, these basins account for around 37% of Australia's total gas production.[3]

The eastern gas market is interconnected by transmission pipelines, which source gas from these basins and deliver it to liquefied natural gas (LNG) facilities for export and to large industrial customers and major population centres for domestic use.

Due to the rapid expansion of the Australian LNG industry on both the east and west coasts, Australia has become one of the world's largest LNG exporters. Australian exports accounted for 21% of global exports in 2022, exceeding that of Qatar (20%) and the United States (19%).[4] On the east coast, exports account for the majority of gas demand, significantly exceeding domestic consumption levels.[5]

Since the launch of the LNG export industry in 2015, gas producers have had the choice to export or sell gas domestically. Consequently, prices in the domestic market are influenced by international gas prices.

1 The Australian Energy Regulator (AER) has regulatory responsibilities in the eastern Australian gas market in Queensland, NSW, Victoria, South Australia, Tasmania and the ACT.

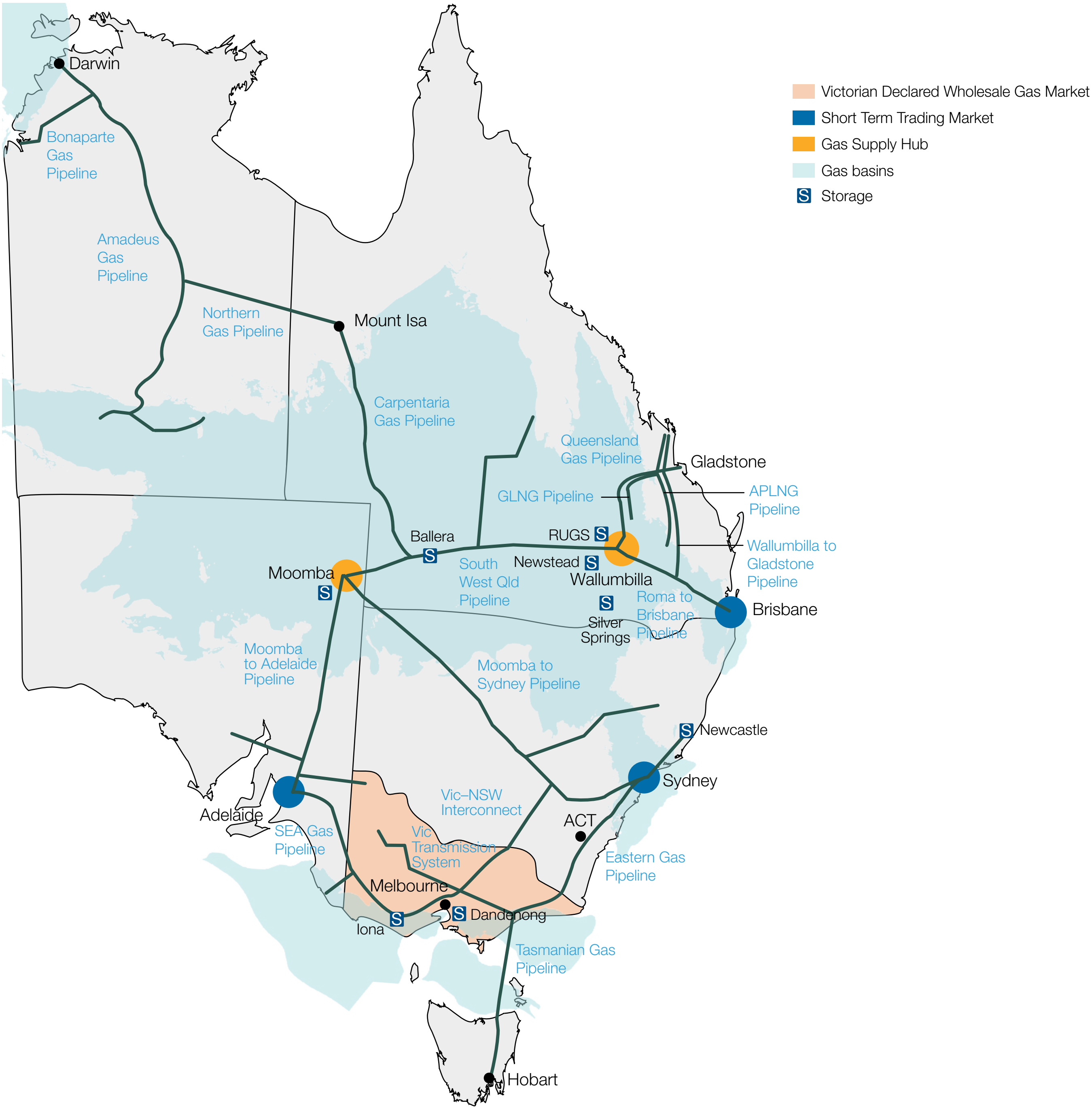
2 AEMO facilitated markets includes the Declared Wholesale Gas Market, the Short Term Trading Market hubs and the Gas Supply Hub. Bilateral commodity reporting under the Gas Rules commenced in 2023 adding to secondary bilateral transaction reporting since 2019.

3 71% of Australia's total gas reserves are conventional gas resources and 29% are unconventional (coal seam gas) resources. Surat–Bowen accounts for most of Australia's coal seam gas (CSG) production. Most of Australia's conventional gas resources are located off the north-west coast of Western Australia and at the end of 2020 they accounted for around 66% of total gas production.

4 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, June 2023, p. 70.

5 Compared with residential and commercial, industrial, and gas generation demand, LNG demand accounted for over 70% of gas consumption on the east coast in 2022.
AEMO, *2023 Gas Statement of Opportunities*, March 2023, gas annual consumption.

Figure 5.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board

Box 5.1 The AER's role in wholesale gas markets

The Australian Energy Regulator (AER) has regulatory responsibilities across the entire gas supply chain in eastern Australia. At the wholesale level, we monitor and report on spot gas markets in Sydney, Brisbane, Adelaide and Victoria; gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia); short-term secondary capacity markets for gas transportation; and activity on the Gas Bulletin Board, which is an open access information platform covering the eastern gas market.

We monitor the markets and bulletin board to ensure participants comply with the National Gas Law and National Gas Rules, and we take enforcement action when necessary. Our compliance and enforcement work aims to promote confidence in the gas market to encourage participation. We also monitor the markets for particular irregularities and wider inefficiencies. For example, our monitoring role at the Wallumbilla and Moomba hubs explicitly looks to detect price manipulation. We are also the compliance and enforcement body for a scheme to auction secondary capacity in transmission pipelines.

We publish various reports, including gas industry statistics and our Wholesale markets quarterly reports, which cover gas spot market activity, prices and liquidity. The quarterly reports also include analysis of eastern Australia's liquefied natural gas (LNG) export sector and its impact on the domestic market. From July 2023, the AER began reporting a wider set of information on the export, reserve, storage, and domestic sale and swaps of gas.

The AER also has regulatory responsibilities for transmission and distribution pipelines (chapter 6) and retail markets (chapter 7).

We continue to engage with the Energy Ministers' gas reform agenda and, when appropriate, we propose or participate in reforms to improve the market's operation. We also draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities.

Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory but plays no role in the territory's wholesale market. Facility operators in the Northern Territory must report gas flow activity to the Gas Bulletin Board. We have no regulatory function in Western Australia, where separate laws apply.

The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia and AEMO operates a spot gas market there.

5.1 Gas market snapshot

Since the last State of the energy market report:

- Prices in facilitated gas markets reached record high levels through the second half of 2022, peaking between $30 and $60 per GJ in August 2022 (section 5.3).
- So far in 2023, prices have moderated substantially and mostly remained at or below $12 per GJ through winter despite this being traditionally a time of high demand and high prices (section 5.3).
- These lower prices appear to have been a result of several favourable market dynamics, including mild weather conditions, reduced international price pressures, low demand and low gas-powered generation demand from the National Electricity Market (NEM) (section 5.3).
- Low prices have also contributed to and been supported by Iona storage remaining at record-high levels through winter, mitigating the risk of peak day gas shortfalls (section 5.5).
- Less positively, southern gas production continued to deplete reserves, increasing the risks of shortfalls. In particular, Longford peak day capabilities have declined from previous years due to legacy field depletion, which has led to a much stronger reliance on Queensland's northern supply sources flowing south to temperature-sensitive southern markets (section 5.5).
- Governments implemented significant market reforms and interventions to address market volatility and the risks of gas shortfalls (sections 5.10 and 5.11). Most notably, these included a $12 per GJ price cap on some gas trade, which has since been replaced with a mandatory gas code of conduct. This has been supported by 2 tranches of reliability measures.

5.2 Structure of the east coast gas market

The east coast gas market is made up of several separate underlying markets and supply hubs, as well as a supporting bulletin board. Around 10% to 20% of gas is traded in these spot markets. All other gas trade is struck under confidential bilateral contracts separate to these markets.

5.2.1 Contract markets

The majority of gas in Australia is traded through bilateral contracts. Contract prices reflect expectations of future market conditions, but the spot markets can reflect short-term shifts in market conditions due to factors such as gas supply and gas storage levels, the timing of LNG shipments and conditions in the electricity market. As a result, the price levels are not always aligned, but they often move in similar directions.

For many domestic users, contract prices are likely to be more indicative of the costs they face.

The 2 main levels of gas contracts (also known as gas supply agreements) are:

- offers by gas producers to very large customers, such as major energy retailers and gas-powered generators
- offers by retailers and aggregators that buy gas from producers and on sell it to commercial and industrial (C&I) customers.[6]

Long-term gas contracts traditionally locked in prices and other terms and conditions for several years. In recent years the industry has shifted towards shorter terms (1 to 2 years) for these contracts, with review provisions.[7]

5.2.2 Spot markets

Spot markets allow wholesale customers to trade gas without entering long-term contracts. Spot market trading can be a useful mechanism for participants to manage imbalances in their contract positions.

Several separate spot markets operate in eastern Australia – Victoria's Declared Wholesale Gas Market, the Short Term Trading Market, the Gas Supply Hub and a separate east coast wide market for transportation and compression services.

Victoria's Declared Wholesale Gas Market (DWGM)

Victoria's DWGM manages gas flows across the Victorian Transmission System. Participants submit daily bids ranging from $0 per gigajoule (GJ) (the floor price) to $800 per GJ (the price cap). Prices in the Victorian market cover gas as well as transmission pipeline delivery. AEMO selects the least cost bids needed to match demand to establish a clearing price.

AEMO operates the financial market and manages physical balancing, including by scheduling gas injections at above market price to alleviate short-term transmission constraints.

Short Term Trading Market (STTM)

The STTM is a short-term trading market for gas with hubs in Sydney, Brisbane and Adelaide that allows gas trading on a day-ahead basis. AEMO sets a clearing price at each hub based on scheduled withdrawals and offers by shippers to deliver gas, with a price floor of $0 per GJ and a cap of $400 per GJ. Pipeline operators schedule flows to supply the necessary quantities of gas to each hub.

AEMO operates a balancing service – called market operator services (MOS) – to meet any variations in gas deliveries or withdrawals from the schedule. These services are mainly paid for by the parties causing the imbalance.

6 Public information about contract prices was unclear. Much of the pricing was private and negotiated contract outcomes are often bespoke. There was also a disparity between the type of information available to large participants that are frequently active in the market and that available to smaller players. This imbalance favoured large incumbents in price negotiations. In response, in 2018 the ACCC began publishing gas price data as part of its 2017–2025 gas inquiry. Further reforms following the gas market transparency review require participants to report information to AEMO from 15 March 2023 for publication on the Bulletin Board, including reserves resources reporting, facility developments, and LNG and short-term transactions.

7 ACCC, Gas inquiry 2017–2020, interim report, Australian Competition and Consumer Commission, July 2018, August 2018, pp. 24, 49.

Gas Supply Hub (GSH)

Gas supply hubs at Wallumbilla in Queensland and Moomba in South Australia are a voluntary platform for gas trading. There are 5 standard product lengths that participants can use when trading at the gas supply hubs – balance of day, daily, day-ahead, weekly and monthly. Participants can trade gas up to a year in advance of physical supply.

Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia, making it a natural point of trade. A single trading location makes it easier for participants to trade across different pipelines, thus pooling potential buyers and sellers into a single market.

Like Wallumbilla, the Moomba hub is located at a major junction in the gas supply chain serving eastern Australia. Three critical pipelines – the South West Queensland, Moomba to Sydney and Moomba to Adelaide pipelines – connect to the hub. On 28 January 2021, trade points at Culcairn and Wilton were also introduced to facilitate trades at the Victorian and Sydney gas market locations, respectively.

A significant proportion of trade occurs 'off-screen', which allows participants to use brokers to match trades on their behalf or leverage their existing bilateral arrangements to facilitate spot trades.[8]

Day-ahead auction (transportation related services)

Gas produced in one region can help address a supply shortfall elsewhere, provided transmission pipeline capacity is available to transport the gas. However, several key pipelines experience contractual congestion, which arises when most or all of a pipeline's capacity is contracted, making the pipeline unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity. Reforms introduced in March 2019 enabled participants to access unutilised pipeline capacity across the east coast.

Unutilised (contracted but not nominated) pipeline transport and gas compression capacity for the next day is sold the day before through an auction. This auction has been widely used to move gas between the east coast gas markets since its inception. From late 2022, participation in the auction increased significantly and set consecutive records for capacity won, with amounts procured more than double the highest levels observed across previous years (section 5.6.2).

5.2.3 Gas Bulletin Board

The Gas Bulletin Board is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. It plays an important role in making the gas market more transparent, especially for smaller players that may not otherwise be able to access day-to-day information on demand and supply conditions. It supplies information such as:

- pipeline capabilities (maximum daily flow quantities, including bidirectional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities
- daily production capabilities and capacity outlooks for production facilities
- gas stored, gas storage capacity (maximum daily withdrawal and holding capacities) and actual injections/withdrawals
- gas field information – reserves and resources, movement, development status, commercial recovery, including information on the basis of estimate preparation, and prices underpinning reserve and resource estimates
- LNG export and import information – shipment dates and volumes
- short-term LNG export transactions and short-term gas sales agreements, 36-month outlooks for uncontracted primary firm capacity (compression, storage, production, and LNG import facilities) and short/medium-term outlooks for smaller users.

The bulletin board includes an interactive map showing gas plant capacity and production data, and gas pipeline capacity and flow at any point in a network.

Reforms were implemented in March 2023 to expand the scope of information reported (section 5.11.1).

8 While most gas trading occurs 'off-screen' (not traded through the gas markets), some of these trades are reported to the market operator and settled through the Gas Supply Hub trading platform.

5.3 Gas prices

Record high prices persisted for much of 2022, remaining at record levels throughout the final quarter despite dropping from the unprecedented levels observed over winter. The high prices were particularly evident in spot market prices and to a lesser extent in contract prices. Following the announcement of a $12 per GJ price cap on 9 December, prices reduced significantly even before the cap's introduction.

Export train outages from late December 2022 and late February 2023 saw additional supply availability in 2023. This led to supressed market prices at $12 per GJ or lower, with prices across the first half of the year generally below $15 per GJ most of the time. The exception was higher prices in May, as a result of planned and unplanned offshore maintenance outages at the Longford gas plant, which is the main southern supply source. Throughout the year, international prices have also continued to steadily decrease, putting downward pressure on local prices and increasing exporters' incentive to provide more gas to domestic users.

While the Longford extended outage from late April resulted in higher reliance on Iona's underground storage inventory, the reduced southern output also drove up demand to move gas south from Queensland supply sources. Most of this supply in March made its way down to the Sydney market. However, the amounts that flowed into Victoria were limited, partially influenced by planned compressor outages in the Victorian gas network. Further to this, planned maintenance on the Moomba to Sydney Pipeline constrained the level of gas that participants could obtain to flow south, which led to Sydney prices climbing as high as $30 per GJ briefly in late June when constrained supply capability was factored into the Short Term Trading Market's scheduling outcomes. Despite this, the level of gas being flowed south was higher than that for May in previous years.

Due to the combination of generally lower gas demand for electricity generation, milder winter temperatures driving lower winter demand, and low international prices alongside significant quantities of supply coming south, gas prices have been well below unprecedented levels observed last year.

5.3.1 Gas contract prices

The ACCC has access to gas contract information and reports on these prices through its gas inquiry.

Over previous years (2019 and 2020) domestic gas contract prices tended to track falling international prices, measured using LNG netback prices. However, prices offered for 2022 stabilised at the beginning of 2021.[9] Although prices increased over 2021 and 2022, domestic prices increased by less than international LNG prices, which were up by almost 230%. Since then, international LNG prices have markedly reduced back to mid-2021 levels and were on par with domestic gas market prices at the end of 2022–23. However, although international prices fell from record highs in 2022, they remain above long-term historical averages. This means that domestic offers linked to international gas prices exceeded historical east coast domestic gas market prices.[10]

Prices offered for east coast supply across 2023 increased sharply from March 2022, with the majority of offers exceeding $30 per GJ by August 2022.[11] Producer offers peaked in August, reaching over $70 per GJ. This reflected tight international market conditions. In comparison, retailer offers tracked below these levels at around $30 per GJ.[12] This was influenced by the high level of price volatility across mid-2022 and represented the highest price observation over the course of the inquiry, coinciding with a substantial increase in the price spread.[13]

In November 2022, 2023 offer prices decreased markedly. Producer offer prices fell to around $20 per GJ and short-term LNG netback prices also moderated from their peaks to just under $40 per GJ. Retail offers remained around $30 per GJ.[14] From 23 December, the Competition and Consumer (Gas Market Emergency Price) Order 2022 (section 5.10.8) came into effect for 12 months, with nearly all producer contracts from this period decreasing to $12 per GJ or less. Since the introduction of the price cap, the ACCC observed an increase in the volume of gas sold

9 LNG netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically.

10 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 38.

11 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, p. 13.

12 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 11.

13 Between March and August, producer offers averaged nearly $20 per GJ, ranging from $10.15 per GJ to $65.25 per GJ. This influenced retailer offers to C&I customers above $30 per GJ.
ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, p. 14.

14 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 11.

under short-term gas supply agreements and traded on facilitated markets.[15] However, there was also a reduction in 2022 offers for supply in 2024 compared with 2021 offers for 2023 supply. Prices quoted for supply in 2023–24 fell from around $65 per GJ before the price cap to around $19 per GJ in April 2023.

Impacts of the $12 per GJ price cap on market trade

Given the short-term trading window in downstream markets is exempt from the price cap (section 5.10.8), and the changing trend towards an increased level of shorter-term trading in the upstream Gas Supply Hub (section 5.7.2), trading in east coast gas markets has overwhelmingly been exempt from the $12 per GJ price cap imposed in late 2022. Gas has frequently been available in these markets at prices at or below the cap, but this appears to have been caused by favourable market dynamics more than the effect of the cap.

Prices in these markets have fluctuated above and below the price cap in line with market dynamics, with mild winter conditions putting downward pressure on prices over the typically high gas demand periods. This was evident in March and May when upstream and downstream market prices declined and increased respectively due to specific changes in the supply-demand balance. Over March, LNG exporter outages saw excess gas supply sold into these markets alongside prices predominantly settling below $10 per GJ (section 5.3.3). In May, southern production and pipeline transportation constraints put upwards pressure on prices, occurring alongside rising demand resulting from a particularly cold end to autumn (section 5.5.2).

With short-term trading activity deliberately excluded from the government-imposed price cap to preserve market pricing signals, it is difficult to determine the exact effect this has had on reducing gas prices over 2023. However, these market dynamics have shown a move towards shorter-term trading with limited longer-term contracted supply offers continuing into 2023. There appears to have been less long-term gas available for contracting for terms that would have been covered by the price cap. Similarly, the ACCC reported in June 2023 that long-term gas contracting has fallen significantly.[16]

As part of the energy price relief plan announced in December 2022, the Australian Government has implemented a Mandatory Gas Code of Conduct (section 5.10.8) on 11 July 2023, extending to gas supply from 2024.

5.3.2 Short-term transaction reporting

From 15 March, information on east coast bilateral gas trades has been published on the Gas Bulletin Board summarising the reporting of short-term transactions to AEMO as part of new transparency measures. The information reported covers trade directly between parties conducted outside of the AEMO-facilitated markets and includes transactions with a contract length of 12 months or less. This information materially improves the comprehensiveness of data available on gas trade up to a year in length, of which bilateral trade is the majority.

Of this newly reported trade, the volume weighted average price for gas delivered over April to June 2023 was $13.80 per GJ. Prices of individual trades for delivery over the July to September and October to December 2023 quarters varied between $13.10 per GJ and $15.20 per GJ (Table 5.1). This suggests price expectations over the remainder of 2023 were in line with the range of trades observed over the April to June quarter of 2023.

Looking forward at reported transactions into 2024 and as far out as 2027, prices have been reported closer to $18 per GJ, materially above current levels. This could suggest market expectations of enduring upward price pressures. However, it may also indicate that buyers have been willing to pay a premium to secure longer-term gas.

15 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, pp. 12, 54.

16 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 7.

Table 5.1 Forward pricing for short-term supply transactions

Period	Price (per GJ)	Range (per GJ)	Delivered quantity (PJ)
Q2 2023	$13.77	$11.49 – $16.12	10.7
Q3 2023	$14.73	$13.08 – $15.25	7.5
Q4 2023	$13.88	$13.23 – $14.24	9.6
2024	$17.47	$16.23 – $19.14	13.1
2025 to 2027	$17.70	$16.90 – $18.02	4.6

Note: The above prices and quantities are based on the actual delivered dates of the reported transactions and include all reported supply transactions and pricing structures. The volume weighted average price range is the minimum and maximum price accounting for all transactions on specific days of trade within that period. Forward trading prices are fixed, unlinked from any projection of a linked index price.

Source: AER analysis using Natural Gas Services Bulletin Board data.

As well as offering insights into forward trade, the trades reported so far since these reporting requirements commenced on 15 March 2023 suggest:[17]

- Most upstream trade takes place bilaterally – outside of the AEMO facilitated markets. Participants reported to the Bulletin Board supply transactions totalling 47 petajoules (PJ) compared with only 12.4 PJ traded through the Gas Supply Hub.[18]
- Producers (56%) and GPG gentailers (40%) sold the highest volumes of gas through reported bilateral trade.[19]
- Participants make extensive use of swaps, which they are also required to report. Almost 26 PJ of swap transactions have been reported to the Bulletin Board so far.[20]
- Most swap transactions are location swaps within Queensland as well as between Queensland and Victoria, where the majority of east coast gas production is concentrated.[21] In May, when Longford experienced production constraints coupled with constraints on the Moomba to Sydney Pipeline and higher demand, swap transactions were observed between Wallumbilla and delivery locations in the southern states that facilitated moving gas from north to south.

5.3.3 Spot market prices

Since notably reducing from volatile 2022 levels in mid-December, prices have largely stayed subdued over 2023 but remain above historical price levels (Figure 5.2). The decrease in wholesale market prices followed the Australian Government's announcement of a $12 per GJ cap on forward trades (section 5.10.8).

17 This comparison is based on all trades between 15 March 2023 and 30 June 2023 reported as short-term transactions to the Bulletin Board or traded through the Gas Supply Hub.

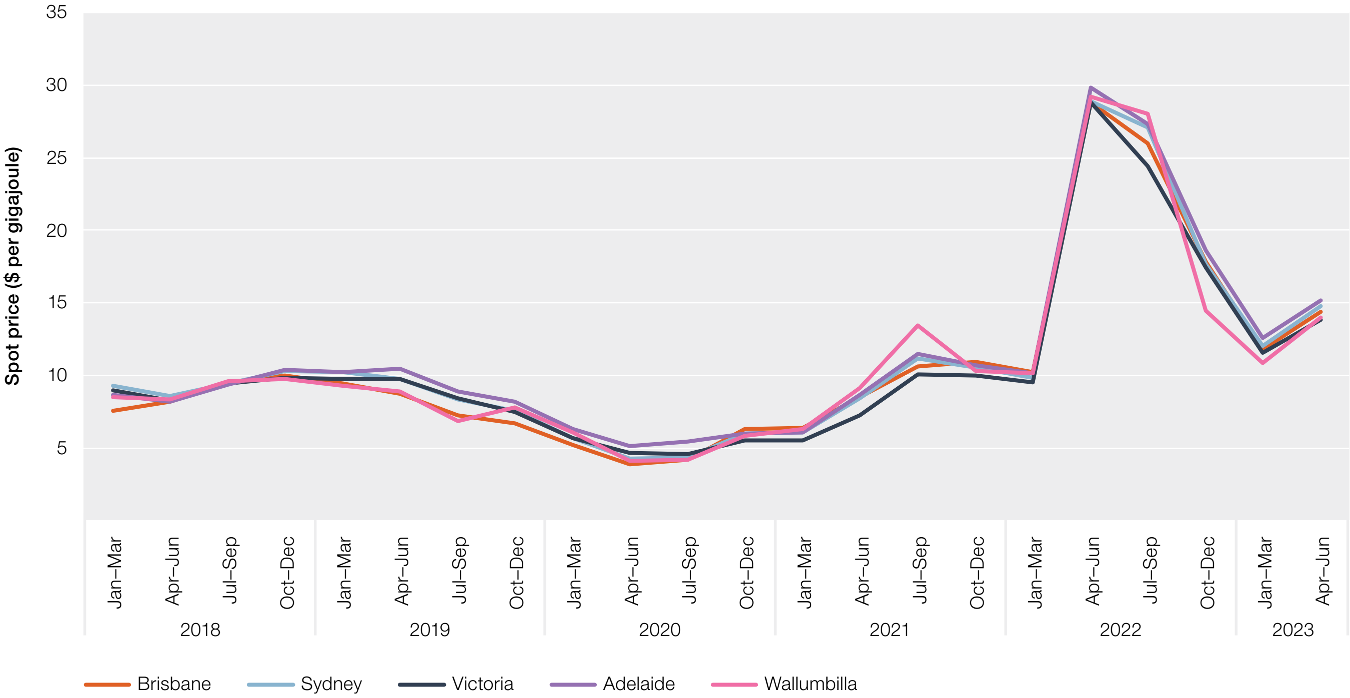
18 30.4 PJ of the 47 PJ reported in 2023 is for delivery in 2023.

19 Gas Powered Generation (GPG) gentailer refers to gas retailers that have gas-fired electricity generation assets. In this category, Energy Australia, Origin and Shell sold the most by volume and reflected almost 80% of gentailer sales; the other participants the AER classified as gentailers are Alinta, AGL, CleanCo, Engie and Hydro Tasmania.

20 When reporting short-term transactions to the Bulletin Board, sellers are required to identify if it is a supply transaction, location swap, time swap or swap of both time and location. Both parties to a swap transaction are required to report the transaction with the associated location and price information attached to the swap transaction.

21 The most popular swap locations in Queensland are the Wallumbilla high pressure trading point and the Roma to Brisbane in pipe trading point, while in Victoria most location swaps are at Longford. In New South Wales most of the location swaps are to Wilton, a delivery point into the Sydney STTM.

Figure 5.2 Eastern Australia gas market prices



Note: The Wallumbilla price is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the average daily weighted imbalance price.

Source: AER analysis of Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market data.

Gas prices settled following unprecedented volatility in 2022

Prices across the gas markets reduced into August, averaging $17 per GJ for the month and diverging from high international prices, which continued to increase. Contributing factors included reduced demand for gas generation and gas heating as the weather warmed, with depleted southern storage levels at Iona starting to be refilled.

The fall in prices also coincided with the Victorian market coming out of an administered price cap state, incentivising participants to offer additional capacity to the market above their own portfolio requirements as tight supply and demand conditions eased. While prices rebounded over the following month and remained at record high levels for the end of the year, there was a significant decrease in market volatility, with lower NEM demand lessening the strong link between gas and electricity prices observed over mid-2022.

During the lower demand period in December, prices also decreased sharply from 9 December following the government's announcement of a $12 per GJ gas contract price cap for 2023. Prices then rebounded gradually over January, settling around $12 to $14 per GJ in the following months.[22]

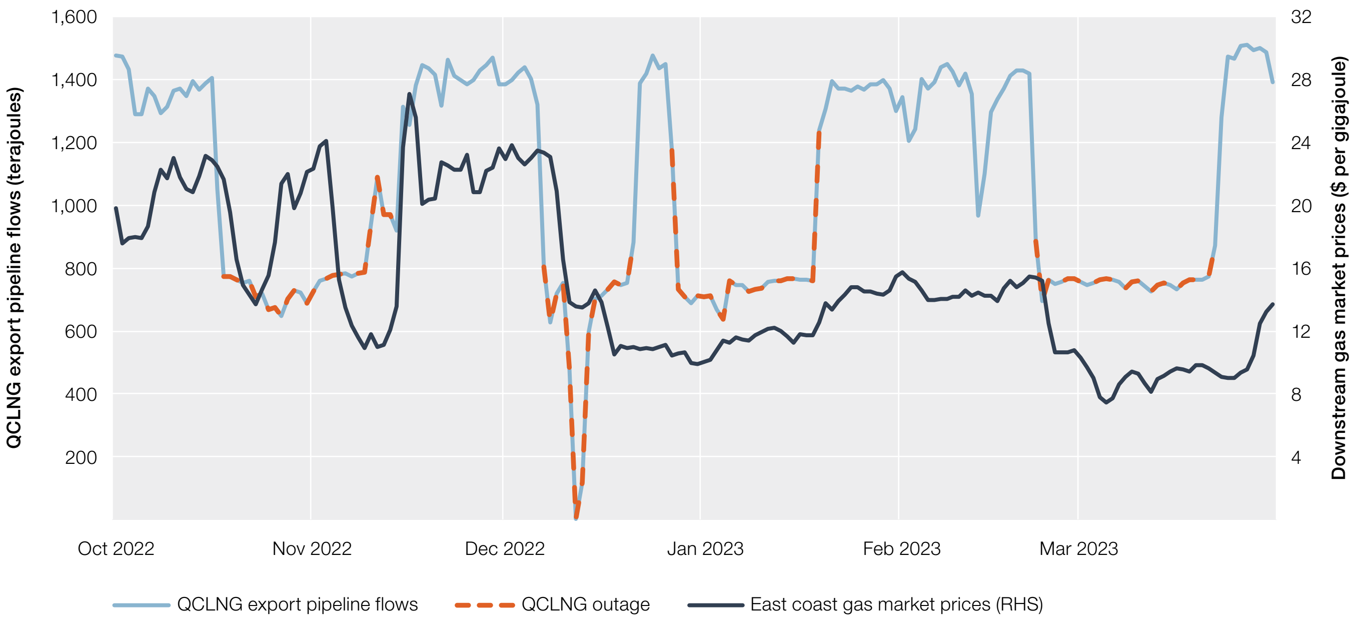
Gas prices in 2023

In the January to March quarter of 2023, gas spot market prices declined amidst substantial short-term trade. Lower market demand and additional gas availability during export train outages reduced pressure on gas prices, with low prices in March driving the quarterly average east coast market prices below $12 per GJ. A planned QCLNG export train maintenance outage from late February was extended out to 22 March, increasing the window of additional cheaper gas availability that helped to suppress prices across the east coast markets (Figure 5.3). This contributed to prices averaging under $10 per GJ across March, dropping as low as $7 per GJ in Brisbane and Victorian markets.[23]

22 The exceptions to this were average east coast gas market prices rising to $18.81 per GJ in May 2023 and low prices in March 2023 (Figure 5.4).

23 Relatively low gas generation levels in the National Electricity Market (NEM) also contributed to lower demand levels in and upstream of the gas markets (Figure 5.9), while steadily declining international gas prices also eased the upwards pressure on local prices that was evident in mid-2022 (Figure 5.6).

Figure 5.3 QCLNG maintenance outages and average east coast gas market prices



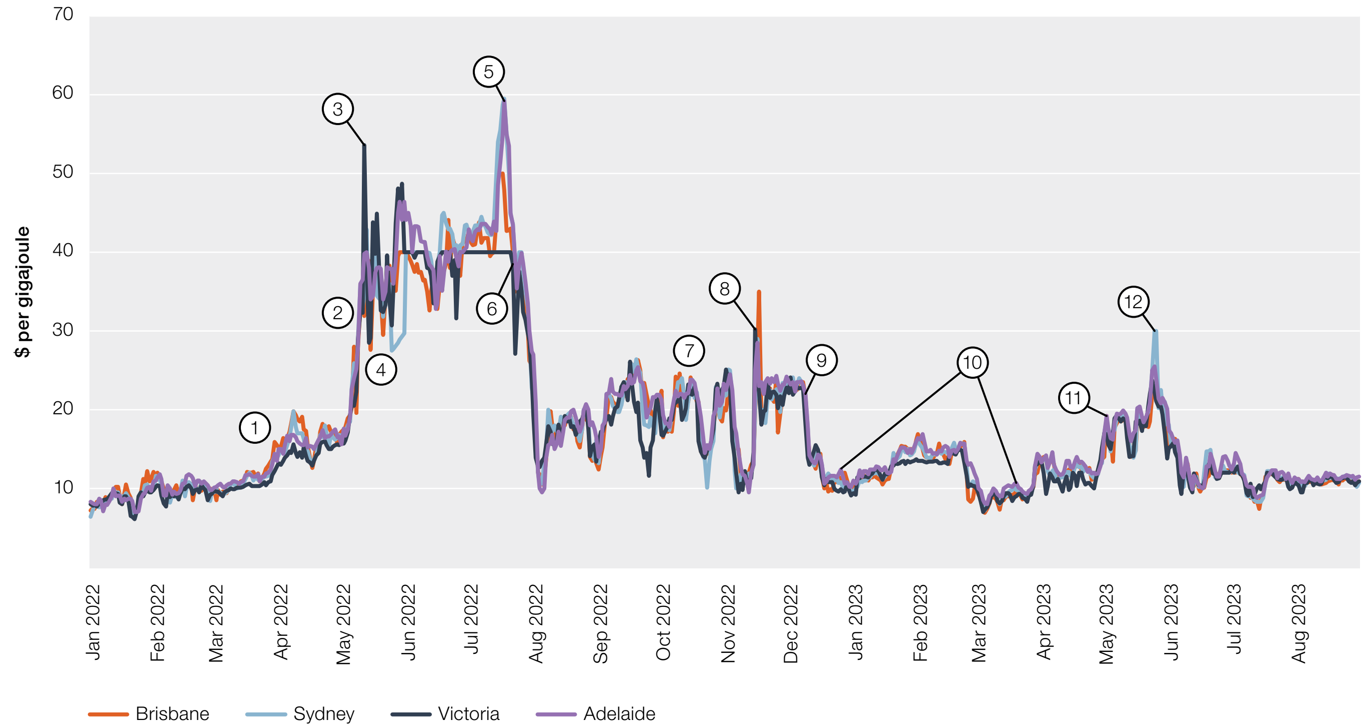
Source: AER analysis using Gas Bulletin Board and market price data (STTM and DWGM)

In the April to June quarter of 2023, average spot prices increased to roughly $14.50 per GJ. This was largely driven by higher prices in May, when prices in southern markets increased above $19 per GJ. The price increases for that month were driven by constraints on Victoria's Longford production facility, which provides most of the state's gas supply. While gas flows south from Queensland were high over the period, planned pipeline maintenance restricted more supply coming from the north that could have put downward pressure on the elevated prices. As a result, participants in the south were more reliant on Iona's underground storage during periods of higher demand. However, unlike in previous years, when substantial run-down on storage inventories reduced storage to critically low levels mid-winter, participants this year topped up storage levels to near full capacity heading into winter.[24] Prices decreased in subsequent months, averaging below peak levels observed over winter 2022 and 2021.

Figure 5.4 sets out an annotated timeline of key pricing events in 2022 and 2023 to date.

24 Refer to the AER Wholesale market quarterly report for Q2 2023 for a more detailed description of the interacting factors contributing to higher gas prices in May.

Figure 5.4 Daily gas spot prices



Note:

1. From late March 2022: Gas prices become increasingly volatile, with drivers of higher prices including a combination of cold weather, low wind levels, coal generation outages and elevated gas-powered generation, with some gas contracts reset at higher prices into the new quarter.
2. From early May 2022: Gas flowing north in contrast to gas flowing south in May 2021, coupled with increased gas demand for electricity generation (14 PJ in May compared with 10 PJ in April on mainland) influenced by baseload outages, with very high NEM prices.
3. 12 May 2022: Victoria, consecutive demand forecast increases and reduced $15 to $30 per GJ supply, with 211 TJ of controllable withdrawals further driving up demand (record price).
4. From late May 2022: Administered prices in Brisbane, Sydney and Victoria contribute to unprecedented gas market price volatility.
5. 15 and 18 July 2022: Record market price in Brisbane ($50.11 per GJ on 15 July), Adelaide ($59.23 per GJ on 18 July) and near-record in Sydney ($59.49 per GJ on 18 July).
6. From late July 2022: Victorian daily prices reduce below the $40 per GJ Administered Price Cap, with the cumulative 7-day price falling below the threshold and triggering the removal of the cap from 1 August.
7. Mid-September to mid-November 2022: Post-winter prices stabilise around $20 to $25 per GJ but remain historically high, with periodic dips below $20 per GJ driven by milder temperatures lowering southern market demand.
8. 15 to 18 November 2022: Record seasonal prices. Prices exceed record levels prior to May 2022 in the STTMs ($28.50 per GJ in Adelaide and $28.99 per GJ in Sydney on 16 November, $35 per GJ in Brisbane on 17 November), also high in Victoria ($30.25 per GJ on 15 November). Significant price variations triggered by ex-ante price decreases in Sydney (17 November) and Brisbane (18 November).
9. 9 December 2022: Government announces $12 per GJ gas contract price cap.
10. 27 December to 19 January and 22 February to 8 March: QCLNG planned maintenance outages influencing additional production capacity becoming available to downstream market participants.
11. May 2023: Cold weather and constrained supply from Longford influencing higher prices in Victoria, which flowed through to other markets.
12. 24 to 26 May 2023: Limits on Moomba to Sydney Pipeline flows impact the Sydney market, resulting in constraint pricing and high ex-ante prices.

Source: AER; AEMO (raw data).

5.3.4 2022 local prices and international price trends

Annual domestic prices increased over 2022, rising by 133% from the previous year. Price increases occurred alongside soaring international prices, but they were primarily driven by several overlapping local factors outlined below.

2022 average prices were driven up by particularly high prices that commenced from April and persisted throughout the winter months. Continued price volatility remained in the latter part of the year, albeit at much lower levels than the unprecedented increases in May, June and July.

Unprecedented price volatility from May to August 2022

Following a noticeable increase from late March, when prices are usually subdued before winter, spot market prices from May 2022 reached record highs. This reflected a series of overlapping factors, including:

- high international gas prices and changes to global supply and demand conditions, strengthening the incentive for producers to export LNG rather than supply into the domestic market
- significant demand from gas-powered generators due to other supply-side constraints in the NEM (section 5.4.1)
- demand pressures arising from residential heating demand in southern states following a particularly cold start to winter.

These factors led to events that increased participant uncertainty during a time of very tight supply-demand conditions, including:

- the suspension of a market participant resulting in administered pricing mechanisms being applied in short-term trading markets alongside the Retailer of Last Resort (RoLR) mechanism being triggered[25]
- high cumulative prices in Victoria accruing due to sustained high market prices, which triggered administered pricing due to the Administered Price Cap (APC) being exceeded
- distorted price signals resulting in participants reducing their offers to the market to retain gas supply quantities in their portfolios
- AEMO invoking the first ever activation of the Gas Supply Guarantee (GSG) mechanism to ensure the availability of gas supply to gas-fired electricity generators (section 5.10.2) – this encouraged increased flows south from Queensland to meet upstream and downstream demand requirements in southern regions
- high gas generation requirements on numerous days coinciding with high downstream gas market demand, putting further pressure on gas market supply and driving high prices in the electricity market
- the run-down of Iona underground storage levels in Victoria to near critical low levels by mid-winter,[26] which then led to multiple notifications about threats to system security in Victoria from 11 July, culminating in the notification of potential shortfalls across the whole south-eastern region from 19 July until the end of September
- low Iona storage levels also led to:
  - the re-activation of the GSG out to the end of September following an industry conference
  - the direction to market participants to cease sourcing gas supply from the Victorian market for electricity generation to balance volatile supply and demand requirements.

Linkages between domestic and international prices

The growth in Queensland's LNG exports from late 2020, combined with other factors including state-based moratoriums on gas development and a tightened supply-demand balance, has placed increasing pressure on east coast domestic markets.

Over 2021, a severe northern hemisphere winter combined with shipping constraints drove up Asian prices early in the year. Later in the year, competition between Asian, European and South American buyers combined with higher demand from replenishment of European storage levels. This led to higher prices in late 2021 over the northern hemisphere winter. In early 2022, the Russian[27] invasion of Ukraine put upwards pressure on global oil and gas prices. Bans on Russian oil drove countries to diversify their supply and to decrease dependence on Russia for both oil and gas, sending ripple effects across global supply chains.

In 2022 further pressure from gas-powered generation heading into the higher demand winter period contributed to driving gas market prices up to unprecedented levels. This coincided with a particularly cold start to winter, which drove higher east coast demand. This in turn led to domestic prices converging with surging international prices in mid-2022 (Figure 5.5). The curtailment of Russian gas supply to Europe drove up international LNG demand from alternative supply sources. While Russian gas supply to Europe was maintained and underground storage levels increased, netback prices briefly reduced below $30 per GJ in mid-2022, resulting in international prices briefly

25 The Retailer of Last Resort (RoLR) scheme is a mechanism used to transfer retail customers to other entities in the event of a retailer failure, to ensure those customers continue to receive electricity and gas.

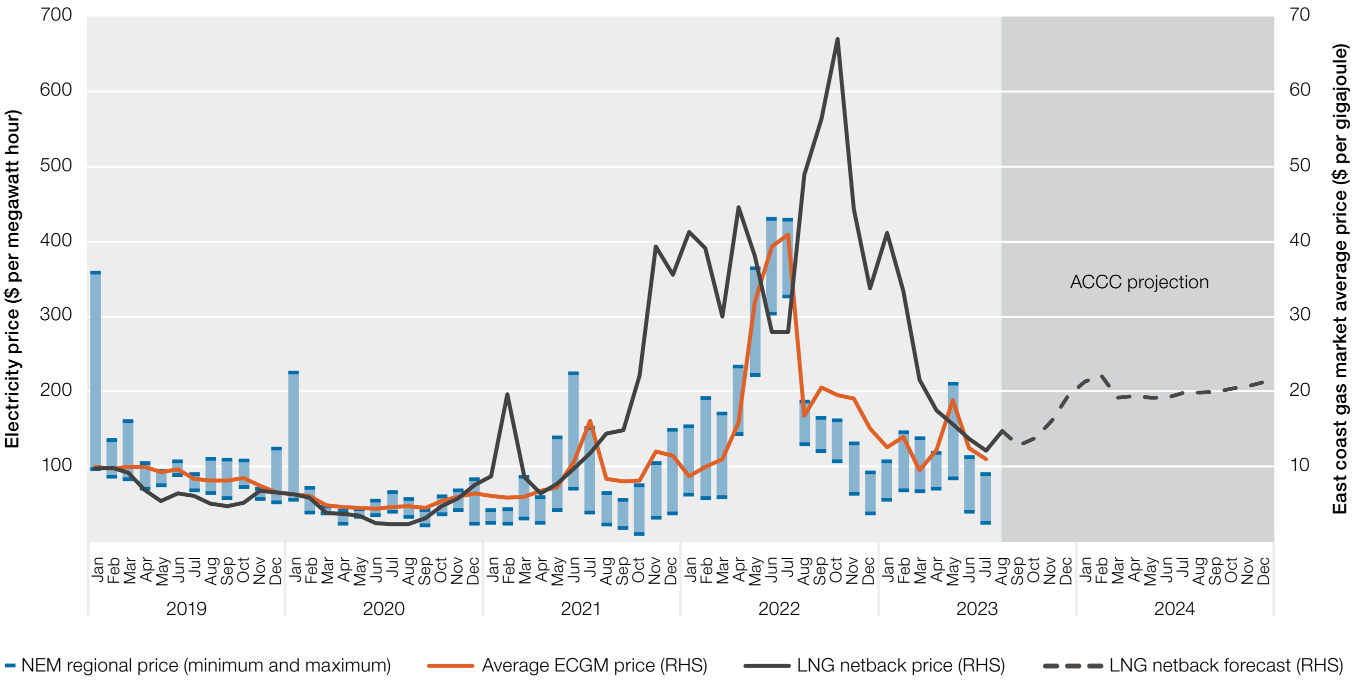
26 Optimum storage levels at Iona must remain above 6 PJ to sustain the required pressure levels in the tank for the facility to ensure adequate supply requirements can be met.

27 Russia is one of the biggest global producers of both oil and gas commodities.

dipping below domestic price levels. However, subsequent Russian supply threats resulting in pipeline flow reductions, and an explosion at Freeport LNG that took a significant amount of US LNG off the market, drove prices back up in August.

In 2023, international gas fuel supply risk reduced as storage inventories grew, particularly in Europe. This resulted in international prices continuing to decline, falling to levels observed one year prior. While international prices converged with domestic gas market prices, they remain above historical averages. This means that domestic offers linked to international gas prices exceeded the prices historically seen in the east coast domestic gas market.

Figure 5.5 Comparison of east coast gas market, NEM and LNG netback prices

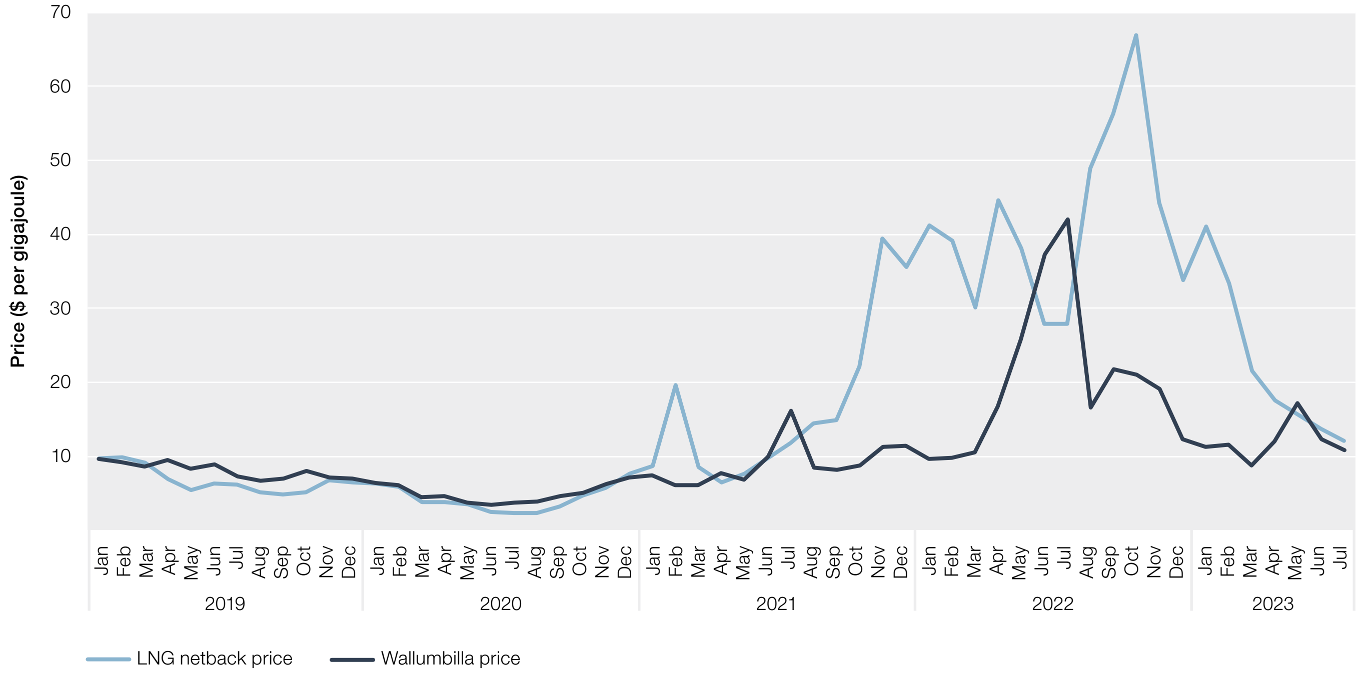


Note: ECGM is east coast gas market. NEM is National Electricity Market. The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers. LNG netback forecast 28 July 2023.

Source: AER analysis of NEM, Short Term Trading Market, Victorian Declared Wholesale Gas Market and ACCC LNG netback price data.

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the northern hemisphere winter. Policy measures that influence gas use and broader economic factors can also be strong drivers of changes internationally.

Figure 5.6 LNG netback and Wallumbilla prices



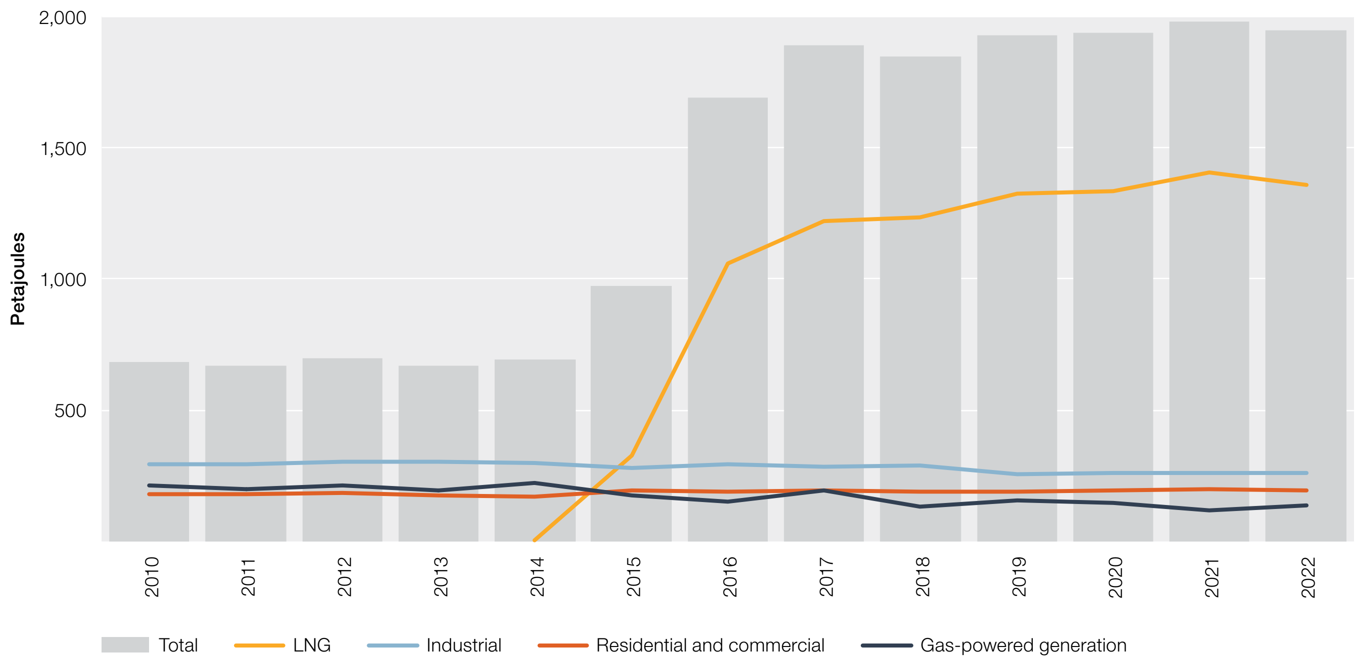
Note: The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers.

Source: AER analysis of Gas Supply Hub data; ACCC (LNG netback prices).

5.4 Gas demand in eastern Australia

Around 70% of domestic gas production in eastern gas markets (excluding the Northern Territory) is exported and the balance is sold into the domestic market (Figure 5.7).

Figure 5.7 Eastern Australian gas demand



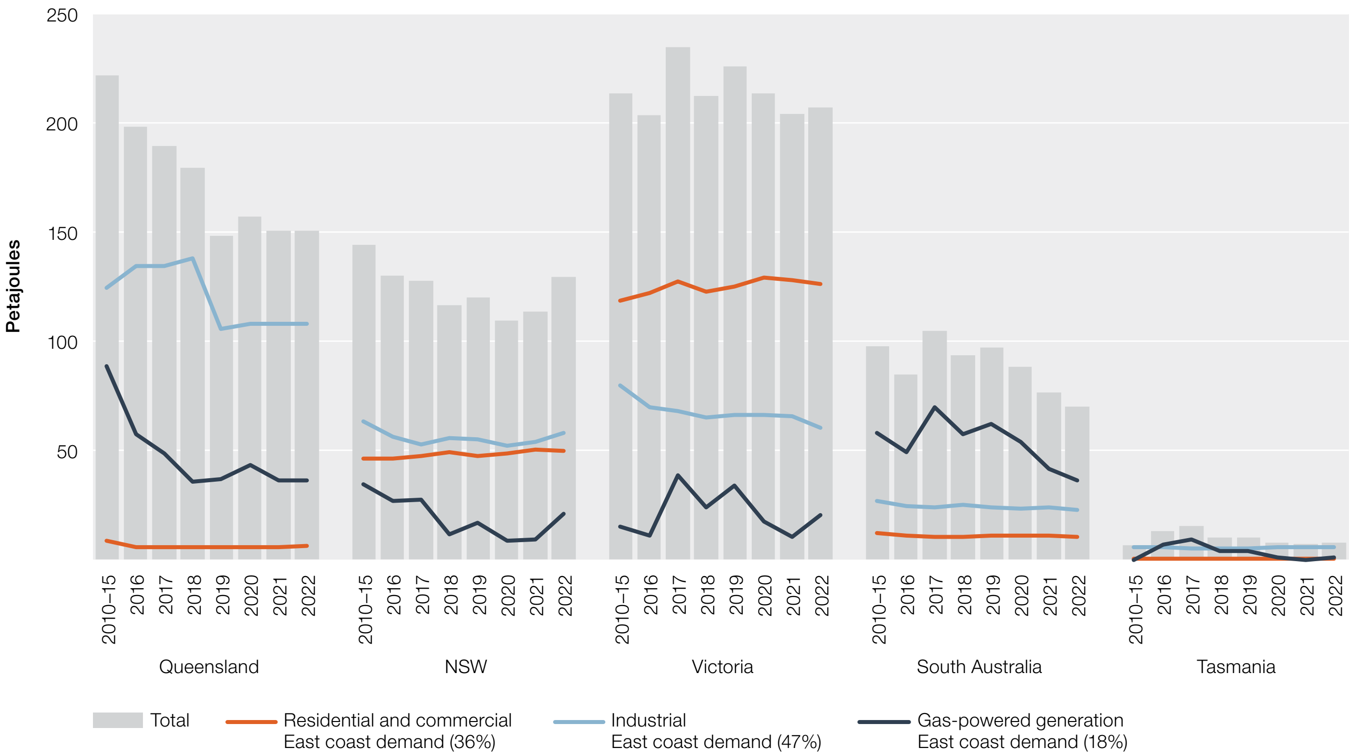
Source: AEMO, *2023 Gas Statement of Opportunities*, March 2023.

5.4.1 Domestic demand

Domestic customers in eastern Australia used around 590 PJ of gas in 2022 (Figure 5.8). These customers included industrial businesses, electricity generators, commercial businesses and households.

Industrial customers consumed 44% of gas sold to the domestic market. Gas is used as an input to manufacture pulp and paper, metals, chemicals, stone, clay, glass and processed foods. Gas is also a major feedstock in ammonia production for fertilisers and explosives.

Figure 5.8 Eastern Australian gas demand by state



Note: Data for 2010–15 is average annual consumption over that period.
Source: AEMO, *2023 Gas Statement of Opportunities*, March 2023.

Residential and commercial customers accounted for 33% of domestic gas demand, but this share varies from state to state. For example, in Victoria more than 60% of gas is consumed by small residential and commercial customers, who use gas mostly for heating and cooking. In Queensland, where much fewer households are connected to a gas network, the share of gas consumed by residential and commercial customers falls to 4%.

The electricity sector is another major source of gas demand, accounting for 23% of domestic gas use in 2022, down from 29% in 2017. South Australia and Queensland used the most gas-powered generation (GPG) in 2022 (each on par using 31% of GPG in the NEM). The rapid responsiveness of gas-powered generators makes them suitable for meeting peak electricity demand and managing variable wind and solar generation. Consequently, the volume of gas used for electricity generation fluctuates with electricity market conditions. Long-term forecasting of expected usage for GPG in the NEM is difficult due to the unpredictability of factors, including unforeseen events.[28]

Domestic gas use in 2022 and 2023

In 2022, GPG gas usage was 20.7 PJ – almost double that of 2021 (10.5 PJ). This was driven by higher gas generation demand from late May, influenced by multiple coinciding factors. An early winter cold snap occurred, combined with low solar and wind generation levels, driving up domestic gas consumption and gas generation requirements.[29]

28 Multiple events, including baseload generation retirement, coal shortages during hot weather, bushfires and flooding, transmission outages, and prolonged coal generation maintenance outages and plant failures, have affected the NEM in recent years.

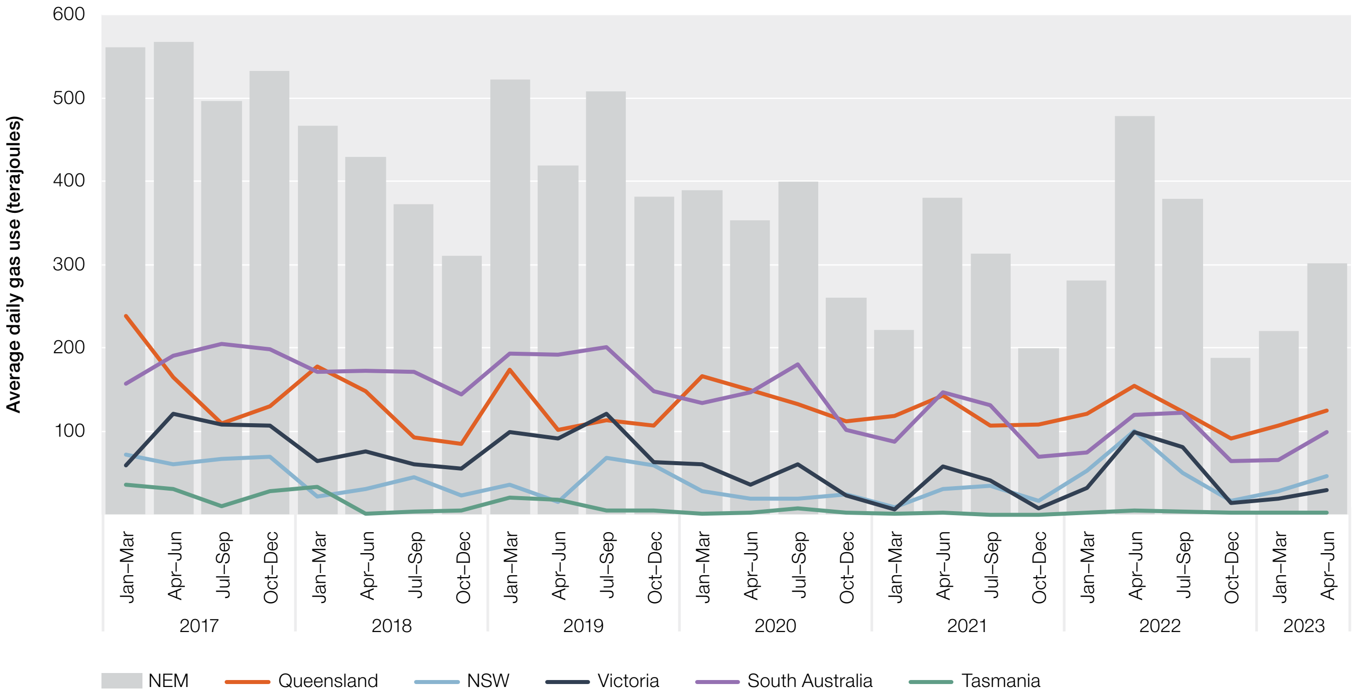
29 While large commercial and industrial demand was the lowest since market start (65 PJ) due to the closure of the Mobil refinery and mothballing of a Qenos plant in Altona, and Saputo Dairy Australia winding down its Maffra facility, small commercial and residential demand (128 PJ) was at its third highest level since market start (after 2020 and 2017).

This was further impacted by continued high demand resulting from reduced coal generation in Victoria and NSW, with some facilities impacted by flooding that also put limits on hydroelectric generation output. Further to this, planned and unplanned electricity network outages limited access to cheaper generation in the Queensland and South Australian regions of the NEM, all occurring at a time of high electricity demand. To get around limitations on gas supply, some generators switched to running their gas generation assets on liquid fuels.

The combination of very high fuel prices, fuel constraints and fuel rationing led to unprecedented NEM prices and AEMO suspending the electricity market. High gas prices and the suspension of a gas market participant also resulted in successive administered price periods coming into place across multiple downstream gas markets.

Over 2023 to date, GPG has been down from levels observed in previous years.

Figure 5.9 Quarterly gas demand for gas-powered generation



Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

5.4.2 Liquefied natural gas exports

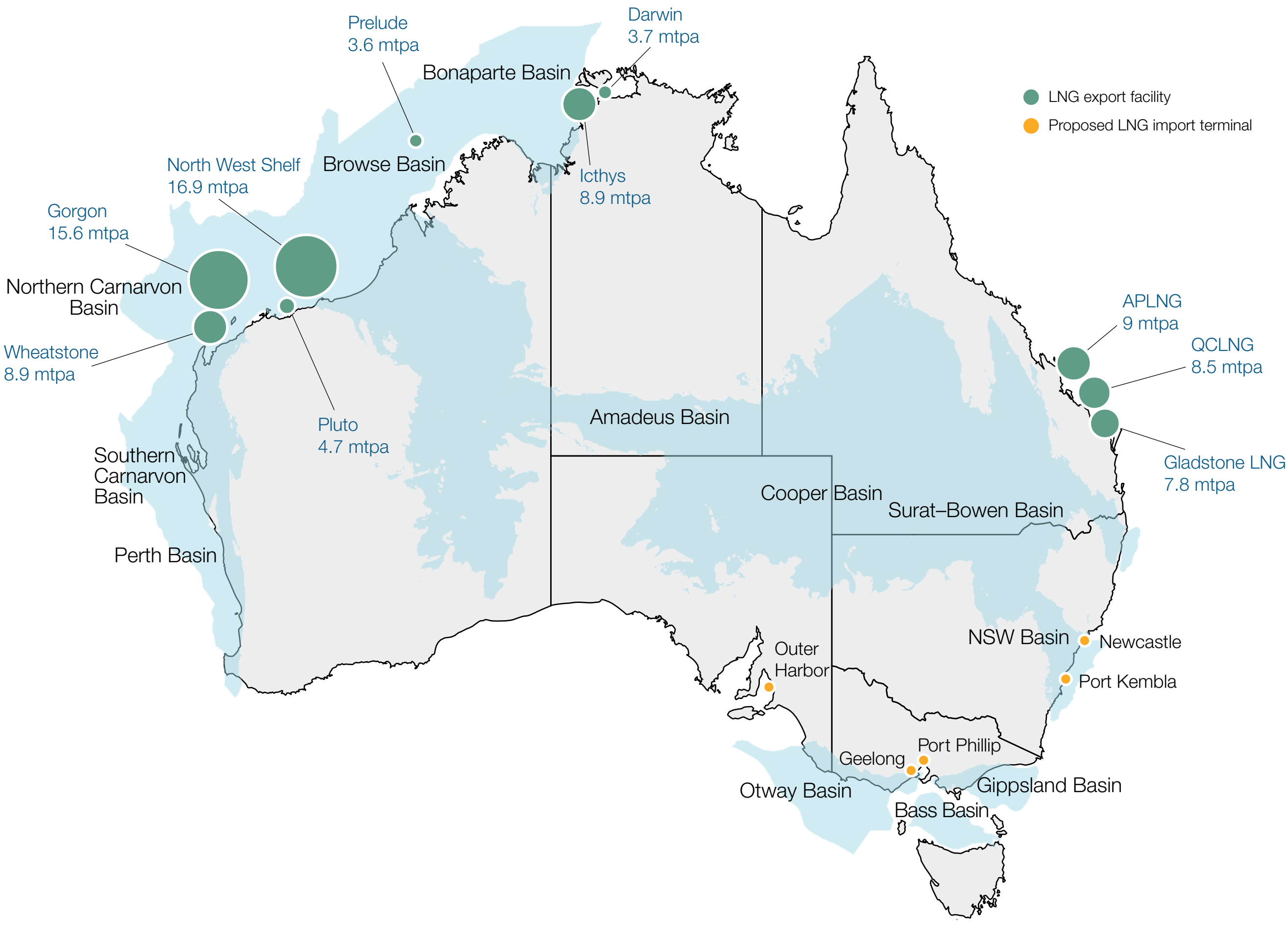
Most of the gas produced in eastern Australia is exported as liquefied natural gas (LNG).

In eastern Australia, export gas is liquefied in processing facilities in Queensland to make it economic to store and ship in large quantities (Table 5.2). Australia also operates 5 LNG projects in Western Australia and 2 in the Northern Territory (Figure 5.10).

In 2022 LNG exports totalled $91 billion, up from $49.8 billion in 2021, making gas Australia's second largest resource and energy export behind iron ore and putting Australia on par with Qatar as the world's largest LNG exporter in 2022.[30] These export levels are expected to be overtaken by Qatar and the United States due to significant growth in coming years.

30 EnergyQuest, *EnergyQuarterly*, March 2023; Department of Industry, Science, Energy and Resources, Resources and energy quarterly, December 2022.

Figure 5.10 Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa). EPIK ceased development of a Newcastle import terminal due to the project being economically unfeasible.

Source: AER; DISER, Resources and energy quarterly, June 2023.

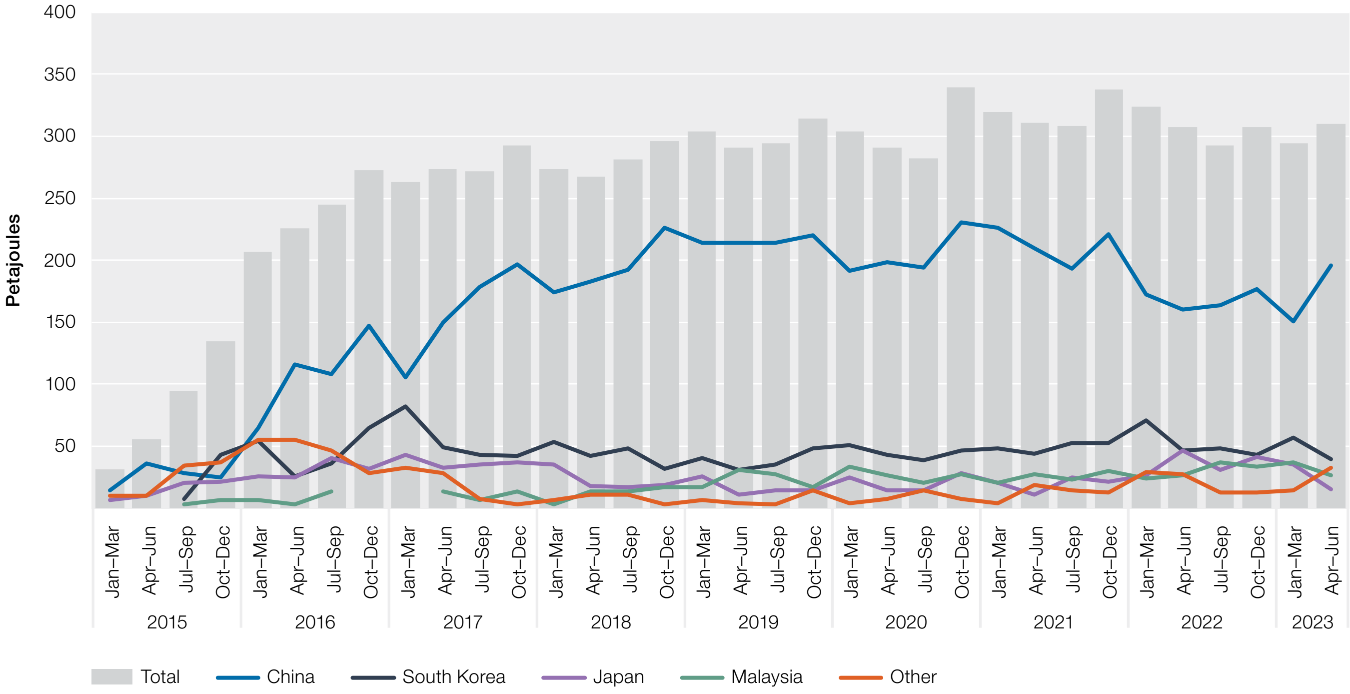
Queensland's LNG industry comprises 3 major projects, which source gas mainly from the Surat–Bowen Basin:

- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). Shell (73.75%), CNOOC (50% equity in Train 1) and Tokyo Gas (2.5% equity in Train 2) own the project.
- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. Santos (30%), Petronas and Total (27.5% each) and Kogas (15%) own the project.
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa. Origin Energy and ConocoPhillips (37.5% each) and Sinopec (25%) own the project.

These LNG projects control close to 90% of 2P reserves in eastern Australia.[31] They also source gas from other producers through long-term contracts and spot markets. East coast gas exports are typically lower mid-year, when domestic demand increases in winter, and higher over summer as northern winter conditions drive up international demand.

31 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, January 2023, p. 7. 2P reserves represent proven and probable reserves (probable reserves are deemed 50% likely to be commercially recoverable).

Figure 5.11 Eastern Australian gas exports



Source: AER analysis using Gladstone Port Corporation data.

East coast LNG exports in 2022 reduced by around 45 PJ compared with last year's record level. APLNG operated above capacity across most of 2022, contributing to near record eastern Australian production levels (Figure 5.11 and Figure 5.13).

China is the primary market for eastern Australian LNG, accounting for 55% of exports in 2022 (674 PJ). These exports decreased significantly from the previous year's 851 PJ volume (67%), falling to their lowest level since 2017. While China's LNG demand is expected to continue to grow, supported by expanded industrial and residential gas use, high prices and lockdowns over 2022 influenced reduced imports alongside higher pipeline supply and domestic production. China has offset reduced Australian supply by sourcing additional imports from Russia, which increased by 77% in the 3 months following the invasion of Ukraine.[32]

Conversely, while Chinese imports declined over 2022, Korean and Japanese east coast imports increased to their second highest level since 2017. The Republic of Korea, the other main source of east coast LNG demand, increased their imports by over 10 PJ from last year to 208.7 PJ.[33] This followed the easing of restrictions aimed at reducing coal generation from April 2022, with the South Korean government subsequently extending its tariff exemption on LNG imports until the end of March 2023.[34] Japanese imports also rose to 144.9 PJ, just less than the 148.6 PJ record set in 2017, with Australian exports offsetting reduced imports from the United States and Qatar.[35]

Northern Territory and Western Australia exports

The Northern Territory's LNG projects are Darwin LNG (3.7 mtpa capacity) and Ichthys LNG (8.9 mtpa capacity). Both projects connect to the territory's domestic gas market as emergency supply sources but otherwise produce gas for export.

Western Australia has 5 LNG projects with a combined capacity of around 50 mtpa – including the North West Shelf, which is Australia's largest LNG project by capacity (16.9 mtpa). The other projects are Gorgon (15.6 mtpa), Wheatstone (8.9 mtpa), Pluto (4.7 mtpa) and Prelude (3.6 mtpa).

32 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, June 2022, p. 77; Department of Industry, Science, Energy and Resources, Resources and energy quarterly, December 2022, p. 73.

33 Compared to 216.1 PJ record demand set over 2017.

34 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, December 2022, p. 74.

35 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, December 2022, p. 74.

5.5 Gas supply in eastern Australia

Gas supply to the northern gas market is largely supplied from Queensland's Surat–Bowen Basin. But gas is also sourced from the Cooper Basin in South Australia and from the Northern Territory. At times, southern gas is also transported north to meet LNG export demand. Gas from the northern fields is also required to supplement Victorian gas production to meet domestic gas demand in southern Australia over winter.

After consecutive yearly increases, exports drove a ramp up in production from Queensland's Roma gas fields, peaking in 2021.[36] While exports remained high in 2022, Roma production decreased to 4,034 terajoules (TJ) per day as LNG projects eased export levels slightly from the previous year (Figure 5.11 and Figure 5.13). The 129 TJ per day decrease was largely offset by a 115 TJ per day increase in southern production, which supplied an additional 10 PJ into Queensland over 2022 compared with 2021 (Figure 5.19).

Background

From 2021, to avoid export controls, Queensland's LNG producers entered into a series of Heads of Agreement with the Australian Government, committing to offer uncontracted gas to domestic buyers on competitive terms before offering it for export.[37] On 29 September 2022 a new Heads of Agreement was signed with exporters, which resulted in the government's decision not to trigger the operation of the Australian Domestic Gas Security Mechanism (ADGSM) for 2023 (section 5.10.1).

In 2023, east coast gas users have become more reliant on northern production because of the continuing decline in Victoria's Gippsland Basin output due to the depletion of legacy fields supplying the Longford gas plant.[38] While annual southern production forecasts have decreased, the short-term maximum daily forecast in 2023 increased from previous AEMO gas statement of opportunities (GSOO) reports. However, annual production from southern fields is expected to reduce from 392 PJ in 2023 to 255 PJ in 2027.[39]

Current conditions

Over winter 2023, peak day output from Longford was forecast at 915 TJ per day in the 2023 GSOO, but this reduced to 860 TJ per day coming into the winter months. Actual peak day production reached 793 TJ in winter 2023, well below the facility's maximum production level of 1,046 TJ in winter 2022.[40] This resulted in Victoria relying more on gas flows south from Queensland from May 2023. These higher southern flows were assisted by the completion of upgrade works on the South West Queensland and Moomba to Sydney pipelines in June (section 5.8.3).[41]

Gas supply from Iona was also better managed this winter, with the storage facility in an improved position to mitigate potential shortfalls compared with periods of rapid draw-down to very low levels mid-winter in 2021 and 2022. Upgrades to the facility had also increased storage capacity before winter, with works to add additional pipeline compression and additional capacity via the western outer ring main (WORM) project expected to be commissioned from late September to early October. This allows for additional gas flows across the Victorian transmission system and enables Iona to supply and refill from the Victorian market at higher rates (section 5.8.3).

These brownfield solutions have assisted in ensuring southern gas demand is met, but risks of peak day shortfalls remain. Low levels of gas-fired generation requirements in the electricity market have assisted in not putting upward pressure on gas prices this winter.

Upcoming greenfield plans, such as the Senex Atlas, Cooper Otway and Santos Narrabri projects, are important in meeting demand but will not become available in the short term and will be insufficient to fill the longer-term supply gap.[42] AEMO's 2021 outlook had improved from previous years due to planning progress for AIE's Port Kembla LNG import terminal. However, despite pipeline expansions taking place to facilitate the delivery of this gas to east coast markets, AIE was unable to secure sufficient interest in contracting supply to justify the relocation of a floating storage and regassification unit (FSRU) to receive and supply the gas in coming years.

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36 Queensland gas production reached consecutive record levels from 2013 to 2021.

37 The LNG projects use various methods to sell more gas domestically, including selling short-term gas on the Wallumbilla Gas Supply Hub, launching expression of interest (EOI) processes for customers for long-term gas contracts, and entering bilateral arrangements for short-term and long-term gas contracts.

38 Longford is the largest and most flexible source of southern gas supply.

39 AEMO, 2023 gas statement of opportunities, Australian Energy Market Operator, March 2023, p. 48.

40 Actual maximum winter production output from Gippsland production facilities in 2022 was 1,126 TJ; AEMO, 2023 gas statement of opportunities, Australian Energy Market Operator, March 2023, p. 6.

41 APA, east coast grid expansion project.

42 EnergyQuest, *EnergyQuarterly*, June 2023, pp. 31–32.

Outlook

Despite improved short run supply forecasts, the longer-term outlook remains uncertain. Supply outlooks across 2024 to 2026 are forecast to be improved, yet production over this period is expected to become increasingly reliant on uncertain and undeveloped sources of supply. Potential supply shortfalls have been forecast to occur in southern states from 2023 and across the east coast from 2027. While more supply and associated infrastructure is clearly needed, most of the proposed projects to facilitate additional production have been delayed, with supply not expected to commence until 2025 or 2026. The speculative nature of unsanctioned new domestic supply sources, with a range of barriers including significant investment in infrastructure to bring gas to market, have led to producers finding it increasingly difficult to obtain finance to invest in fossil fuel projects.[43]

Further factors also contribute to uncertainty surrounding long-term supply conditions, including underperformance of developed resources and the potential for southern production to decline faster than expected. Forecasts also make assumptions about undeveloped resources – uncertain reserves, which are increasingly unreliable, depend on more speculative sources of supply. While some development proposals in eastern Australia have shown promising signs, others face significant regulatory hurdles linked to environmental concerns.

In response to this ongoing supply uncertainty, the Australian Government and some state governments launched initiatives to encourage new projects to supply the domestic market (section 5.10).

5.5.1 Gas reserves and production

Eastern Australia had 37,101 PJ of 'proven and probable' (2P) gas reserves in March 2023, having produced almost 2,000 PJ of gas in 2022 (Table 5.2).

Ownership is highly concentrated in some gas basins, but more diverse across the east coast (Figure 5.1). APLNG owns the majority of reserves in eastern Australia through an incorporated joint venture with Origin Energy, ConocoPhillips and Sinopec.

Table 5.2 Gas basins serving eastern Australia

	Gas production – 12 months to December 2022			2P gas reserves (March 2023)	
Gas basin	Petajoules	Share of eastern Australian supply	Change from previous year	Petajoules	Share of eastern Australian reserves
Surat–Bowen (Qld)	1,477	75.3%	-3%	29,252	79%
Cooper (SA–Qld)	80	4.1%	-13%	1,024	3%
Gippsland (Vic)	310	15.8%	7%	1,687	5%
Otway (Vic)	48	2.5%	37%	600	2%
Bass (Vic)	5	0.2%	-34%	24	0.1%
Sydney, Narrabri, Gunnedah (NSW)	3	0.1%	-16%	7	0.02%
Amadeus (NT)	15	0.8%	-2%	220	1%
Bonaparte (NT)	24	1.2%	-45%	4,287	12%
Eastern Australia total	1,962	–	-3%	37,101	–
Domestic gas sales	572	–	-2%	–	–
LNG exports	1,390	–	-3%	–	–

Note: 2P: proven plus probable reserves estimated to be at least 50% sure of successful commercial recovery.

Totals may not add to 100% due to rounding. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and reserves in other basins are mainly conventional gas.

Source: EnergyQuest, *EnergyQuarterly*, March 2023.

Queensland's Surat–Bowen Basin holds 79% of gas reserves in eastern Australia and supplied 75% of gas produced in 2022. Queensland's 3 LNG projects produced close to 95% of the basin's output in 2022.

43 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, January 2023, p. 125.

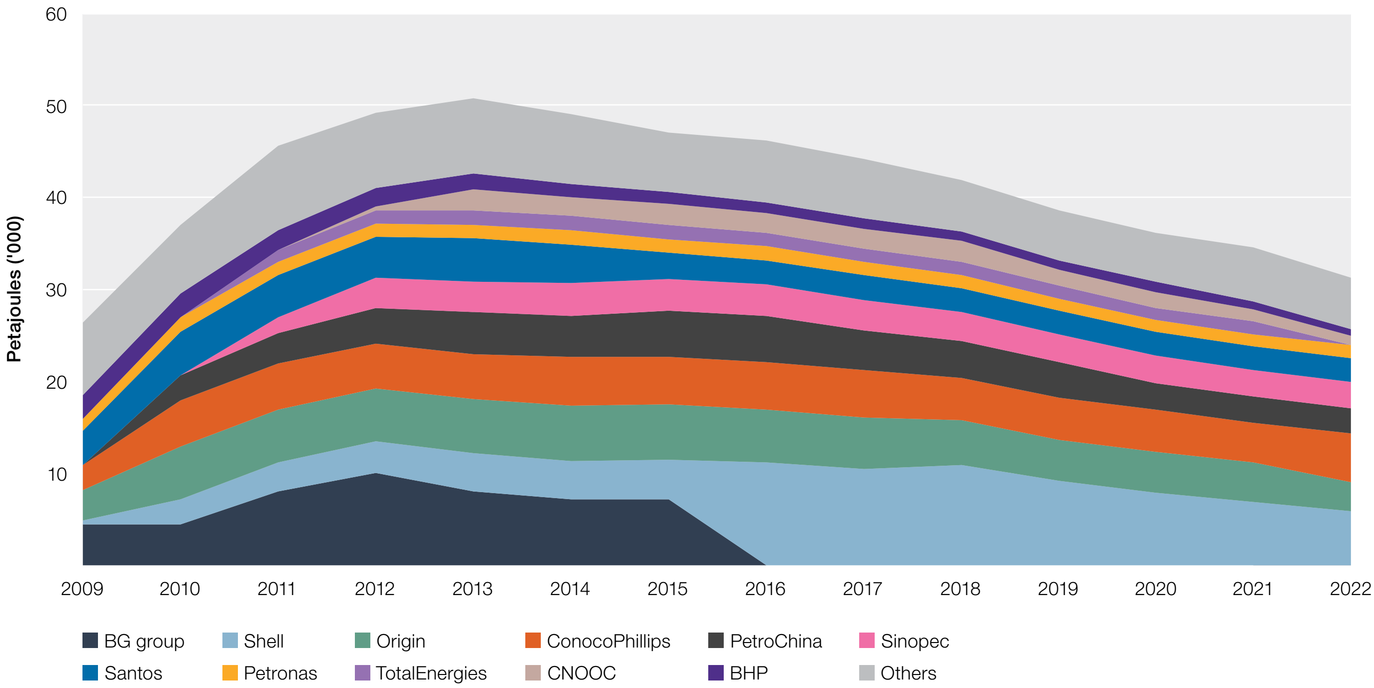
Victorian basins account for 7% of eastern Australian reserves but these reserves are declining, largely due to anticipated decreases from Gippsland legacy fields. This is important because Victoria is the highest domestic consumer of gas. AEMO forecasts a steep decline in southern field production in the coming years. The Gippsland Basin is the largest Victorian basin, while the Bass and Otway basins are smaller.

The Cooper Basin in central Australia has over 1,000 PJ of eastern Australia's 2P reserves and accounted for 4% of gas production in 2022. Reserves in the basin have declined over the past decade. The Cooper Basin plays an important role as a 'swing' producer in managing seasonal and short-term supply imbalances in the domestic gas market.

NSW has significant contingent resources[44] (around 2,264 PJ) but only 6 PJ of 2P reserves and negligible current production. Santos received approval to develop reserves near Narrabri in the Gunnedah Basin; however, appeals against the approval have delayed the project. The final investment decision depends on project approvals being cleared (section 5.8.1).

The Northern Territory has the Bonaparte Basin and the smaller Amadeus Basin. The basins are estimated to have over 4,500 PJ of 2P reserves. Most gas produced is converted to LNG for export.

Figure 5.12 Market shares in 2P gas reserves in eastern Australia

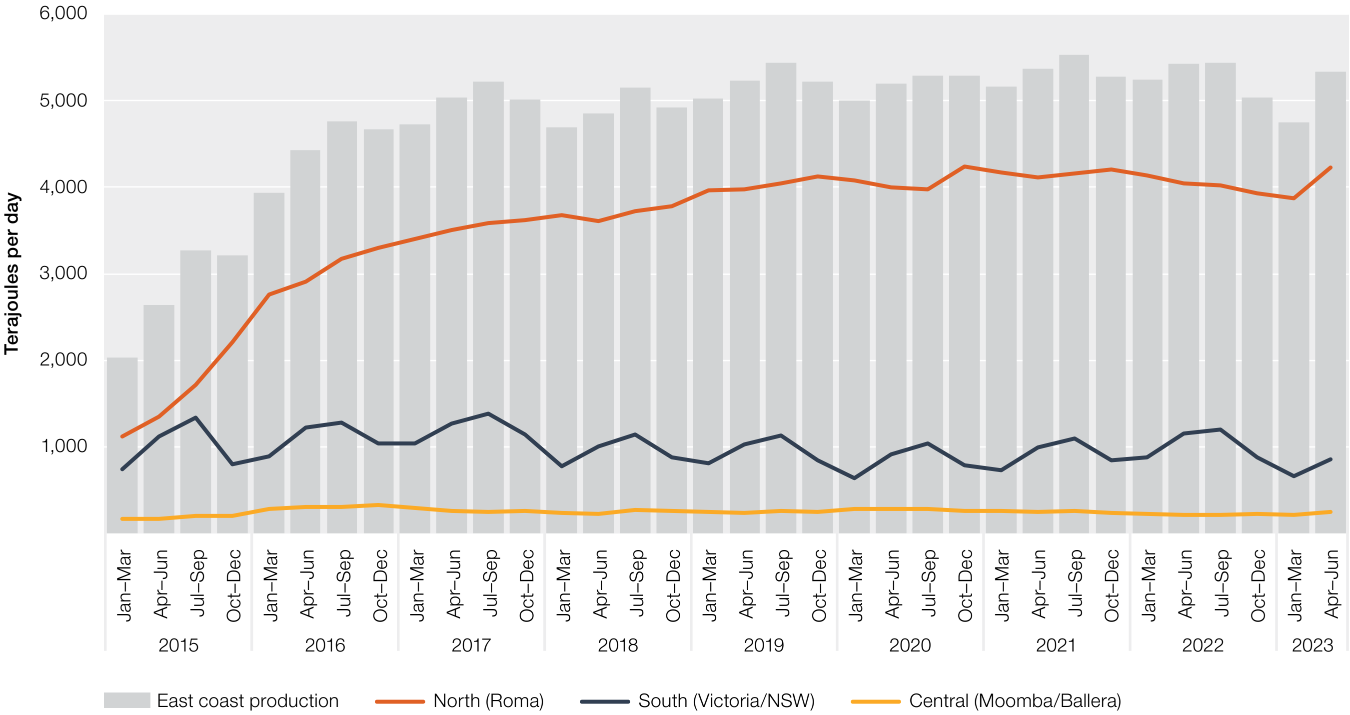


Note: Aggregated market shares in 2P (proven and probable) gas reserves in the Surat–Bowen, Gippsland, Cooper, Otway, Bass and NSW basins. 2P reserves are those for which geological and engineering analysis suggests at least a 50% probability of commercial recovery.

Source: EnergyQuest, *EnergyQuarterly* (various years).

44 2C contingent resources are reserves estimated to be potentially recoverable from known deposits, but which are not currently considered to be commercially recoverable.

Figure 5.13 Eastern Australia gas production



Source: AER analysis of Gas Bulletin Board data.

Record quarterly production levels occurred over the first 2 quarters of 2022 before declining in the October to December quarter to their lowest level since 2018, then continuing to decline in the January to March quarter of 2023 to their lowest level since 2017. Over the April to June quarter of 2023, production levels finished the financial year below 2021 and 2022 levels.

Southern production has been particularly low over 2023, with Longford running down its supply from the depleting legacy fields in the Gippsland Basin. Gas production in Queensland again rose to near record levels in the April to June quarter of 2023 (Figure 5.13), with elevated LNG export levels despite declining international prices (Figure 5.5).[45] This was also accompanied by strong demand from participants to bring significant quantities of gas south to offset lower southern production levels (Figure 5.19).

Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce. Production from the Longford plant has been falling and the plant is becoming less reliable, with plant constraints and maintenance outages increasingly disrupting production. Although AEMO's 2023 production forecasts have improved from 2022, actual production output at the facility is significantly down from the previous year.[46]

Changing basin profiles

Activity in all gas basins across eastern Australia has evolved to meet the needs of the LNG industry. Production from the Surat–Bowen Basin is mainly earmarked for export. But supply from other eastern Australian basins rose between 2015 and 2017 to help LNG projects meet their export contracts. This shift accelerated a depletion of gas reserves in southern basins. AEMO and the ACCC have identified the ongoing depletion of southern gas fields as a significant risk to supply in the coming years.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market. Over 2019 and 2020, Surat–Bowen Basin production increased (9%), largely matching LNG export growth (10%), while production from southern basins decreased by a similar proportion (10%). Over 2021, strong southern supply and gas flows north to support high exports coincided with export levels growing more than Queensland production increases.
The drawdown of southern supply has led to a projected 44 PJ shortfall in the south for 2024 alongside a 71–135 PJ surplus in the north. Projected domestic supply from LNG exporters is expected to range between 27 PJ and 90 PJ.[47]

45 LNG exports in the April to June quarter increased following lower levels of gas exports across the past financial year.

46 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2023, p. 5.

47 ACCC, Gas inquiry 2017–2025, interim report, June 2023, Australian Competition and Consumer Commission, June 2023, p. 10.

5.5.2 Gas storage

Storage facilities can store surplus gas produced in summer for use during higher demand winter periods, providing supply flexibility and quick delivery capability to meet peak demand requirements. Refill and drawdown rates for these facilities can be impacted by connected pipeline capacity and low storage levels, limiting the amount of gas in storage that can be replenished or delivered. Eastern Australia's gas storage capacity includes:

- large facilities using depleted gas fields in Queensland, Victoria and South Australia:
  - Iona underground storage (Victoria) has a nameplate storage capacity of 24.4 PJ, with a delivery capability of 570 TJ per day[48] – this is the second largest supply source in the south and can deplete and refill at a much higher rate than other east coast storage facilities. The facility typically refills with large quantities of gas, which are drawn down over the higher demand winter period
  - Moomba Lower Daralingie Beds (LDB) storage (South Australia) has a nameplate storage capacity of 70 PJ, with a delivery capability of under 5 TJ per day[49]
  - Silver Springs storage (Queensland) has a nameplate storage capacity of 45 PJ, with a delivery capability of 8 TJ per day[50]
  - Roma Underground Gas Storage (RUGS, Queensland) has a nameplate storage capacity of 54 PJ, with a delivery capability of up to 50 TJ per day[51]
- LNG storage in smaller seasonal or peaking facilities located near demand centres – for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria[52] – these facilities have relatively high supply rates, but depletion cannot be sustained for many days due to slow refill rates. The primary use for the Dandenong LNG facility is to store small volumes of gas to be injected quickly into the Victorian Transmission System (VTS) to cater for short-term peak requirements and manage threats to system security
- short-term peak storage services on gas pipelines, which are mostly contracted by energy retailers – for example, the Tasmanian Gas Pipeline stores gas that can be sold into the Victorian market at times of peak demand.

The Dandenong LNG and Iona underground storage facilities are the only ones that currently provide storage services to third parties in the east coast gas market.[53] The importance of storage in managing supply and demand has risen since the LNG industry began operating, with some storage facilities drawn down to meet LNG export demand and replenished when prices were low. Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks and seasonal demand. Average storage levels have decreased since 2021 and in the July to September quarter of 2022 reached their lowest levels since reporting began. This brought average storage levels down to a third of capacity (Figure 5.14).[54] Iona replenished significantly at the end of 2022, reaching its highest end of year storage level since reporting commenced. However, draw down of supply from the other large facilities has continued, with declining pressure in the storage wells adding to constraints on supply capability.[55] In June 2022, Newcastle gas storage reduced all the inventory in their LNG storage tank for the first time since the facility started operating. The facility did not commence refilling significant quantities until December.

48 The maximum supply rate achieved in 2021 with a nameplate capacity of 530 TJ per day was 455 TJ.

49 Progressive depletion of storage levels has reduced delivery capacity to 10 TJ per day from late 2021, with current delivery capabilities now sitting around 5 TJ per day since April 2022.

50 Silver Springs delivery outlooks reduced to around 10 TJ per day from mid-October 2021 and have been sitting around 8 TJ per day or lower since 2022.

51 Following the continuing depletion of storage levels, short-term outlooks progressively reduced delivery capacity to 50 TJ per day as storage declined to 30 PJ (from 16 March), then 40 TJ per day as storage dropped to 27.6 PJ (from 27 May). Supply capability has since increased to 50 TJ per day.

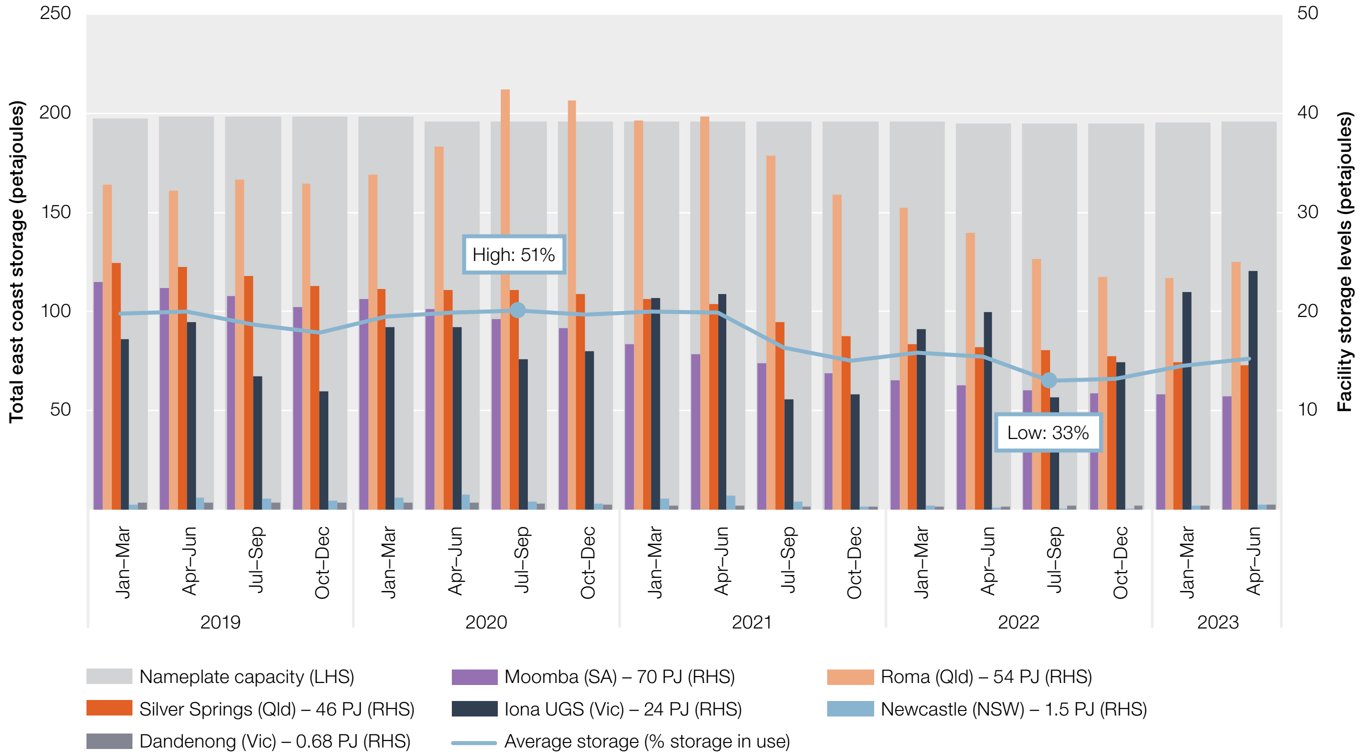
52 The Dandenong LNG storage facility reached record low levels in 2021 (since the commencement of the Declared Wholesale Gas Market in 1999), driven by a reduction in contracted capacity for winter. Following a rule change by the AEMC, AEMO has now contracted gas storage supply at the facility and acts as a buyer and supplier of last resort to mitigate potential supply shortfalls, with the facility close to full capacity at the beginning of winter 2023.

53 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, February 2023, pp. 86–87.

54 Storage levels fell to record lows across all east coast facilities in 2022, with this trend continuing at most facilities in 2023.

55 For example, Moomba has reduced its nameplate supply capability from 100 TJ per day when it commenced reporting in late 2016, with current storage levels below 12 PJ limiting its physical injection capacity as low as 3 TJ per day since June 2022.

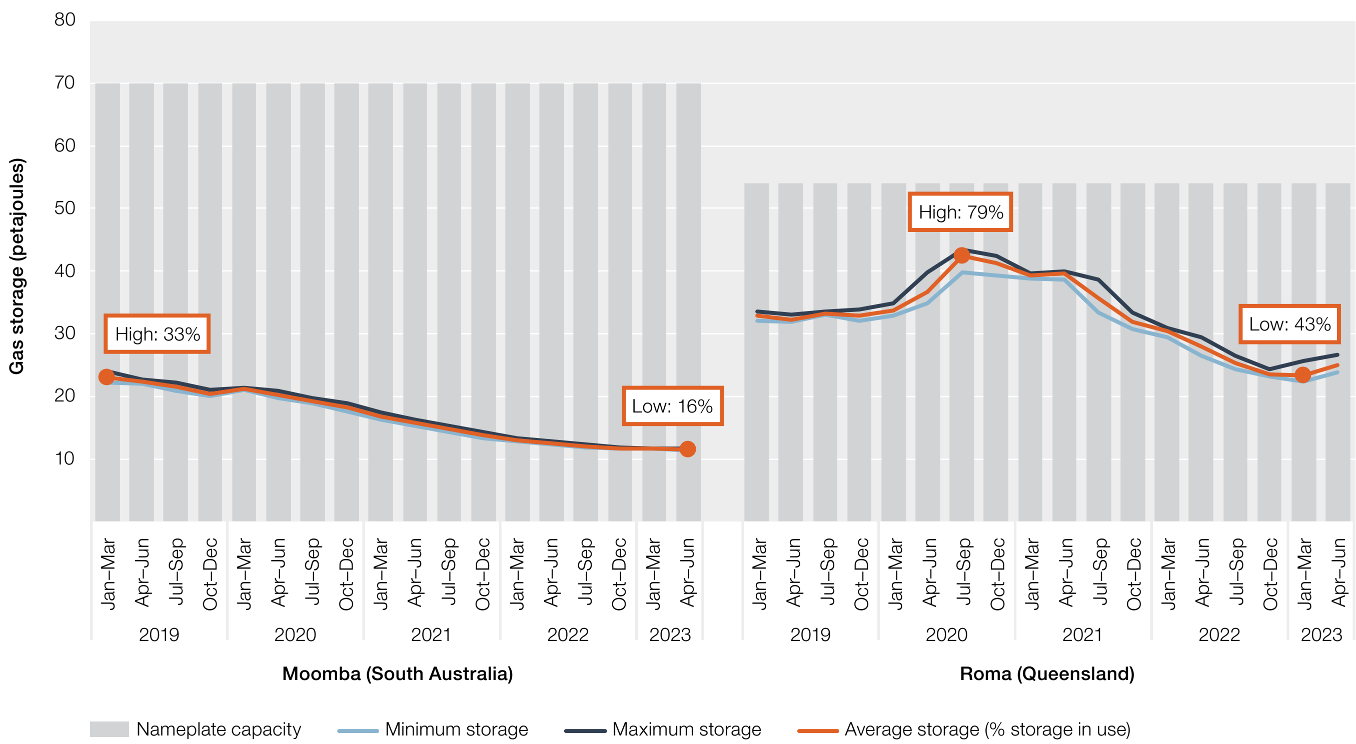
Figure 5.14 Gas storage in eastern Australia



Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.

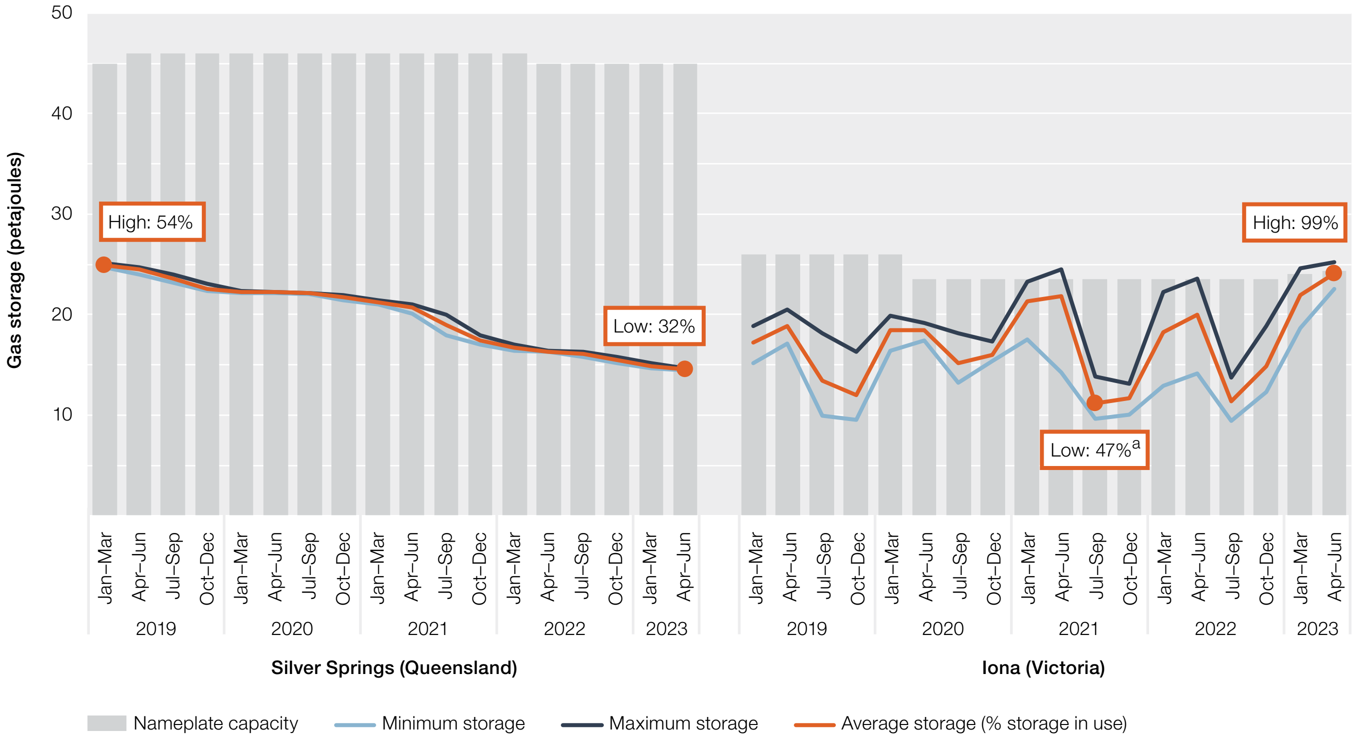
Source: AER analysis of Gas Bulletin Board data.

Figure 5.15 Large gas storage facilities – Moomba (South Australia) and Roma (Queensland)



Source: AER analysis of Gas Bulletin Board data.

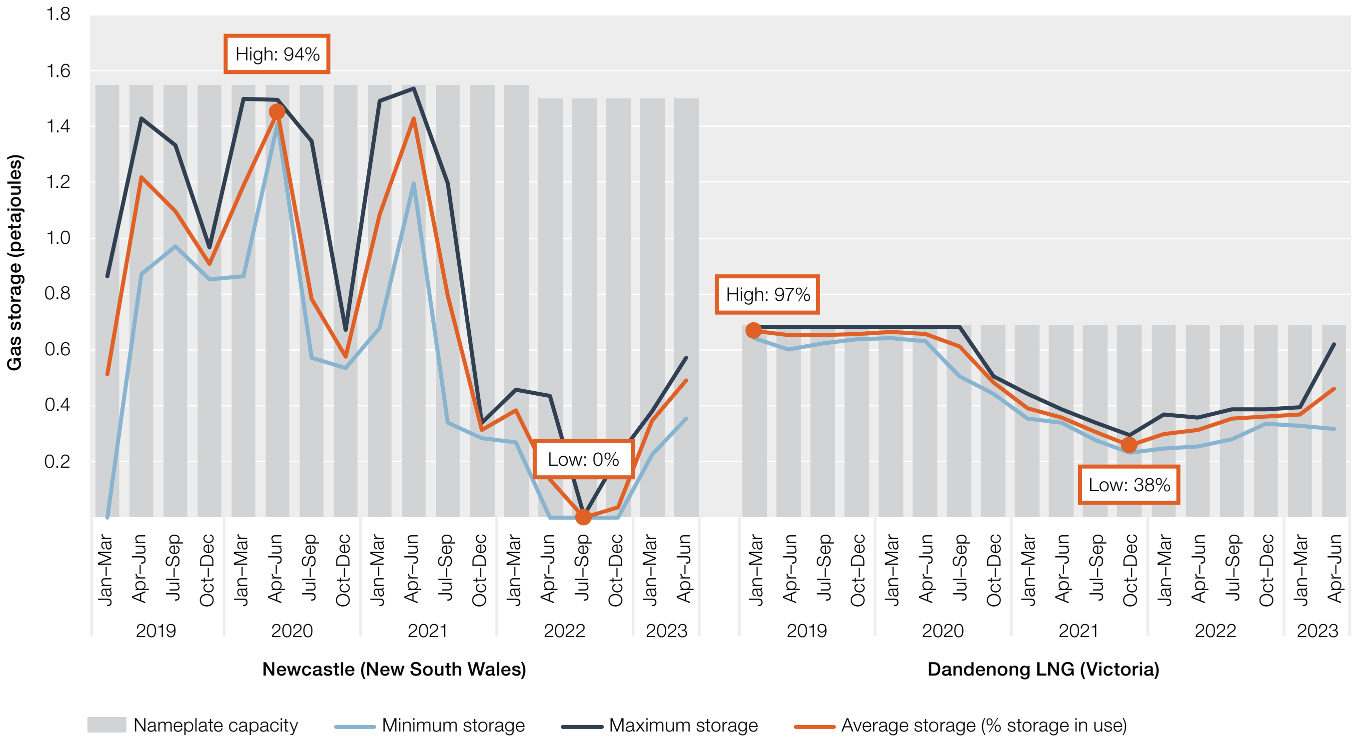
Figure 5.16 Large gas storage facilities – Silver Springs (Queensland) and Iona (Victoria)



Note: a Lower storage inventory, lower proportionally for October to December 2018.

Source: AER analysis of Gas Bulletin Board data.

Figure 5.17 Small LNG gas storage facilities – Newcastle (NSW) and Dandenong (Victoria)

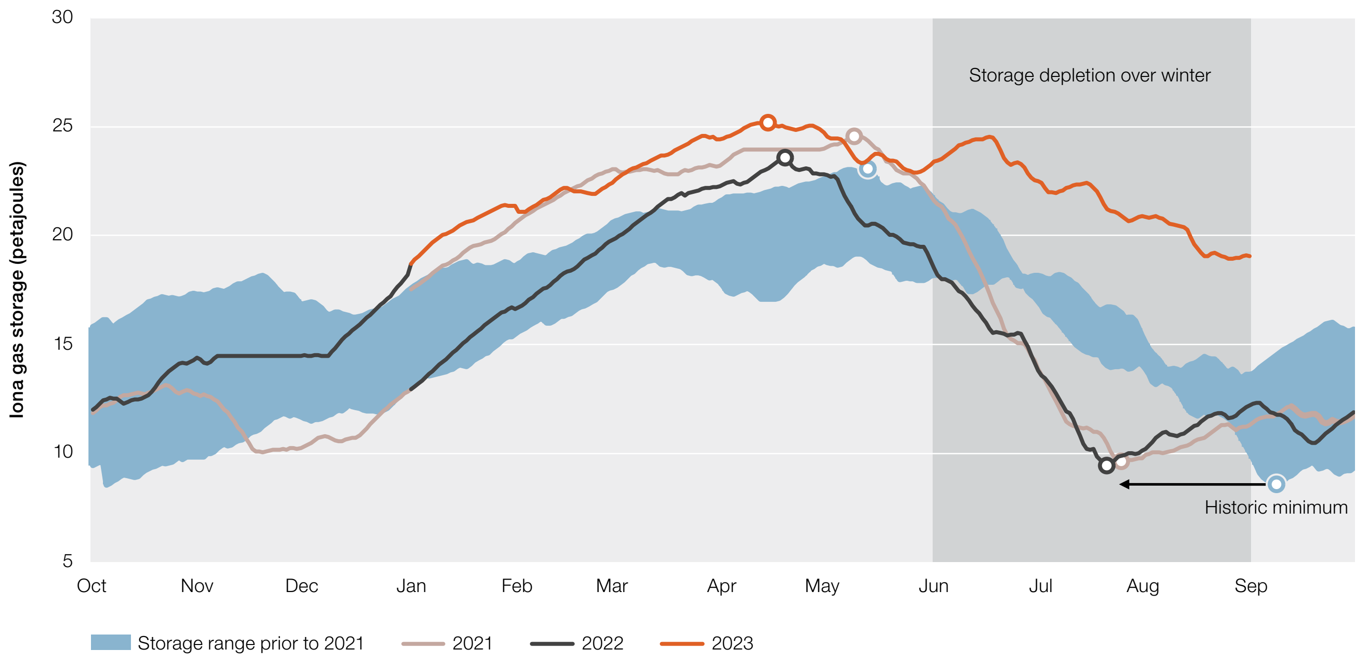


Source: AER analysis of Gas Bulletin Board data.

Investments to develop or expand storage capacity are under way.[56] Lochard Energy expanded Victoria's Iona facility in 2018 and made further improvements to the gas processing facility that progressively became operational from 2021.[57] This operates more dynamically than other storage facilities, with a larger capacity to inject and withdraw gas on any given day. Further expansion of storage capacity is currently taking place and supply capacity is expected to increase from 558 TJ per day to 570 TJ per day by early 2024. However, this capability is currently limited by existing pipeline capacity.[58] Storage capacity at the facility could also potentially increase by 3.3 PJ by 2026.[59] An expansion through their Heytesbury (HUGS) development is currently in the planning phase.[60]

In recent years, Victoria has become increasingly reliant on gas storage inventory from Iona. In 2021 and 2022, storage levels fell to their lowest point since reporting commenced. The significant draw down on gas inventories reduced available supply capacity to very low levels by mid-winter in both years. The fast depletion in 2022 led AEMO to issue a notice of a threat to system security.[61] Recent upgrades have improved supply rates; however, this has also led to storage inventory being drawn down quicker than could have previously been achieved. Supply trends in 2021 and 2022 reducing to these low levels earlier into winter (minimum levels have historically been observed from the end of winter) demonstrate an increasing risk of supply being insufficient to meet demand on peak days. In 2023, upgrades to increase storage capacity at the facility and provide additional supply capacity, combined with pipeline upgrade works to increase supply and refill capacity at the facility, have improved Iona's ability to hold more gas and replenish its gas inventories. Despite a particularly cold end to autumn leading to Iona being relied on over May, the facility headed into winter in a good position and storage was topped up into June as gas flows south from Queensland increased following upgrades to the main pipeline routes in Queensland and NSW.[62] Winter 2023 storage levels were maintained at their highest level since reporting commenced.

Figure 5.18 Iona underground storage, low storage levels in winter 2021 and 2022



Source: AER analysis of Gas Bulletin Board data.

Further to this, the much smaller Dandenong LNG storage facility fell to particularly low levels in June 2022 following a reduction in participants contracting the emergency supply. While much smaller than Iona, the facility plays an important role in mitigating curtailment during potential supply shortfalls, providing critical system security to avoid pressure drops at the Dandenong city gate. Due to the high potential for the facility to be needed over winter 2023 as

56 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, February 2023, p. 142.

57 Following Lochard's takeover from EnergyAustralia in 2015, the storage facility's capacity has expanded significantly from a 390 TJ per day supply capacity to 530 TJ per day (17 March 2021), 545 TJ per day (28 January 2022) and 558 TJ per day (1 January 2023).

58 The South West Pipeline (SWP) is currently undergoing upgrades to increase pipeline capacity that will support higher injection rates from the Iona storage facility. Further expansion of the storage facility could raise supply capacity to 600–700 TJ per day.

59 Lochard Energy, Heytesbury Underground Gas Storage (HUGS) Project, fact sheet.

60 The Heytesbury Underground Gas Storage (HUGS) Project to expand storage capacity proposes to develop existing depleted reservoirs and supply gas through the construction of a new underground gas pipeline.

61 The AEMO notice highlighted the possibility of reduced injection capability due to low pressure, increasing the risk of curtailment on peak demand days.

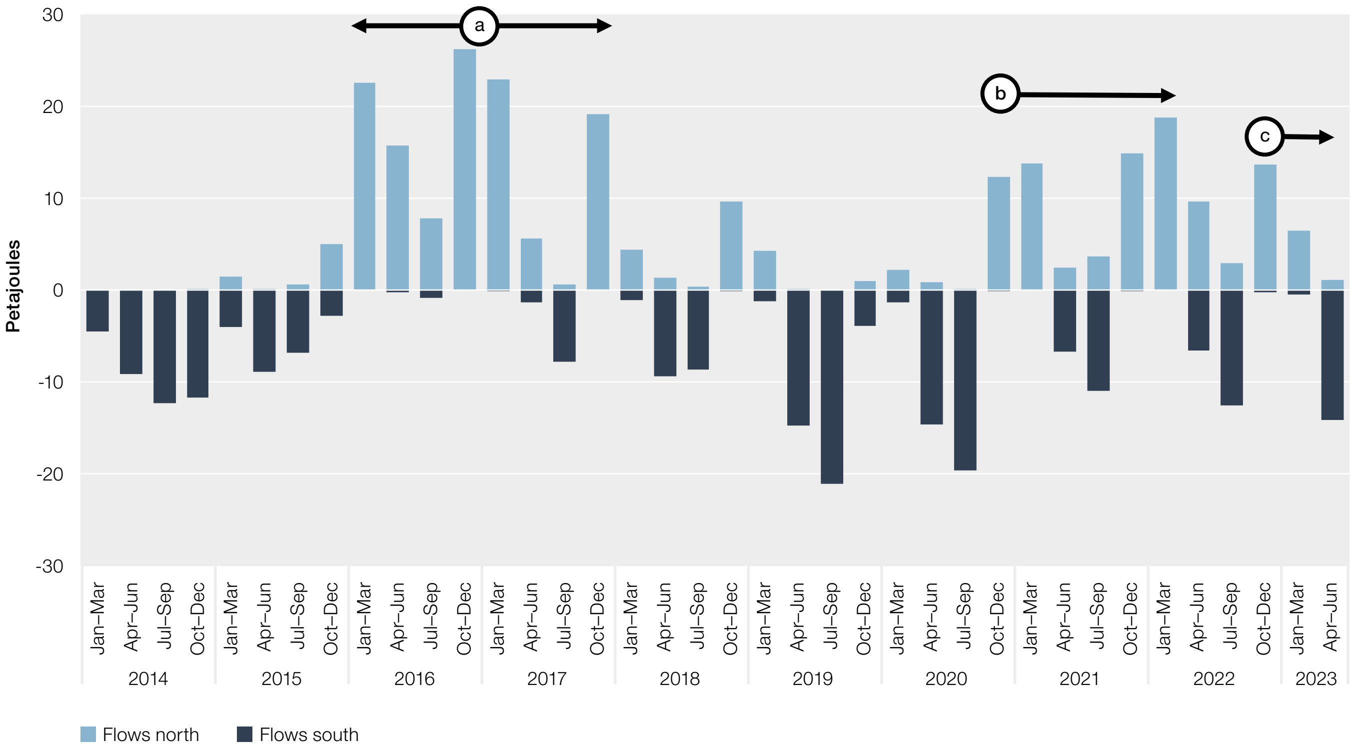
62 The cold temperatures in May coincided with constraints limiting gas flows south from Queensland and an outage at the Longford production facility.

supply at Longford drops off, Energy Ministers submitted an urgent rule change in August 2022 to give the AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023.[63] Subsequent refilling saw the storage facility close to full capacity by mid-June.

5.6 Inter-regional gas trade

Domestic gas typically flows south in the Australian winter (to meet heating demand) and north in the Australian summer (the northern hemisphere winter) when Asia's LNG demand peaks (Figure 5.19).

Figure 5.19 North–south gas flows in eastern Australia



Note: Flows on the QSN (Queensland / South Australia / New South Wales) Link segment of the South West Queensland Pipeline (flowing through the Moomba location).

a 2016 to 2017: Increased southern production to meet LNG demand.

b Late 2020 onwards: record LNG exports continue to rise.

c Late 2022 onwards: LNG exports reduce closer to 2019 levels.

Source: AER analysis of Gas Bulletin Board data.

Northerly gas flows increased from late 2020 in line with record export pipeline flows (Figure 5.11) and reduced flows south over winter periods (Figure 5.19, note b). However, from May 2023 southerly flows increased significantly, exceeding levels observed over the past decade. While flows south over May were higher than May's monthly flows in previous years, demand to bring additional gas south was higher than capacity to do so.[64]

Due to recent upgrades on the South West Queensland and Moomba to Sydney pipelines, there is now additional capacity to bring more Queensland gas supply south to offset reduced southern production levels (section 5.8.3).[65] Observed gas flows south have remained strong into winter, despite exports increasing back to near record levels from the April to June quarter this year.

Following the increase in Moomba to Sydney Pipeline capacity from June, day-ahead auction activity increased, with most capacity won bringing gas south from Moomba – 1.9 PJ in June and 2.16 PJ in July – accounting for over 85% of capacity won. The Moomba to Adelaide Pipeline also climbed to the highest levels observed at the facility from May

63 Energy Ministers Meeting, Communique, 12 August 2022.

64 This was due to planned maintenance constraints on the Moomba to Sydney Pipeline (MSP), leading to little or no unutilised transportation capacity being available through the day-ahead auction. Surplus demand for southward delivery capacity on the MSP was 1.5 PJ, significantly outweighing capacity ultimately won on the route (0.7 PJ).

65 Pipeline upgrades increased SWQP and MSP capacity from June 2023.

with over 1.1 PJ won to bring gas south over May out to the end of July. However, in contrast to this, while most capacity won on the South West Queensland Pipeline was on routes to bring gas south at the start of 2023, this trend reversed from May with only minimal activity on southern delivery routes.

Data on trade flows may understate the extent of north–south gas trading. Some gas producers enter swap agreements to deliver gas to southern gas customers without physically shipping it along pipelines. An example is an agreement between Shell and Santos to swap at least 18 PJ of gas.[66] Under the agreement, Shell draws on its CSG reserves to meet part of Santos's LNG supply obligations in Queensland, while Santos diverts gas from the Cooper Basin to meet demand in southern Australia.[67] The swap allows the producers to increase supply to the domestic market, while enabling Shell to avoid transporting gas on the South West Queensland Pipeline, which is contracted to near full capacity. To improve transparency, from 2023 participants' reporting requirements were expanded to encompass a range of bilateral arrangements, including physical swaps (section 5.11.1).

5.6.1 Gas transmission pipelines

Supply conditions depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, pipeline operators are considering a range of upgrades to extend or expand existing infrastructure. For example, in 2021 APA announced the first stage of an expansion of the South West Queensland Pipeline and Moomba to Sydney Pipeline to increase delivery capacity from northern fields to southern markets (section 5.8.3).

Wholesale customers buy capacity on transmission pipelines to transport their gas purchases to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (key pipeline routes are shown in Figure 5.1). Dozens of smaller pipelines fill out the transmission grid.

The eastern gas market's transmission system has evolved from a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre, into an integrated network. Many gas pipelines became bidirectional and gas increasingly flows across multiple pipelines to reach its destination. Additionally, the Northern Gas Pipeline provides eastern Australia's pipeline interconnection with the Northern Territory (section 5.8.5). Access to capacity on key pipelines is important because it provides participants with more options to purchase and move gas between different regions. This ability to move gas gives participants a wider range of options in managing their portfolios across different regions, making it easier to arbitrage the purchase and sale of gas supply without the need to negotiate swap agreements.

Gas production and transmission pipelines assets are owned by separate companies. A gas customer must negotiate with a gas producer to buy gas and separately contract with one or more pipeline businesses to get the gas delivered. This separation adds a layer of complexity to sourcing gas, especially for smaller customers (section 5.6.2).

The range of services provided by transmission pipelines is expanding to meet the needs of industry as the market evolves. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements such as bidirectional and backhaul shipping, and park and loan services.[68]

Investments to develop or expand transmission capacity are underway (section 5.8.3).

Pipeline ownership

Australia's gas transmission sector is privately owned (chapter 6). The publicly listed APA Group is the largest owner of pipeline assets, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Another major pipeline owner with equity in numerous pipelines is Jemena. The pipelines fall under different regulatory arrangements, now classified as either scheme or non-scheme pipelines under recent pipeline reforms (section 5.11.2 and Table 6.1).[69]

66 Santos, 'Santos facilitates delivery of gas into southern domestic market' [media release], August 2017.

67 EnergyQuest, *EnergyQuarterly*, March 2020.

68 Pipelines with bidirectional flows can ship gas in both directions. Backhaul shipping is the 'virtual transport' of gas in a direction opposite to the main flow of gas. Parking gas is a way of temporarily storing gas in the pipeline by injecting more than is to be withdrawn. Loaning gas allows users to inject less gas into the pipeline than is to be withdrawn.

69 Full regulation pipelines have their prices assessed by the AER. Light regulation pipelines do not have their prices assessed by the AER, but parties can seek arbitration to address a dispute. Part 23 pipelines are subject to information disclosure and arbitration provisions. Exempt pipelines are subject to no economic regulation. Chapter 6 outlines the various tiers of regulation.

5.6.2 Pipeline access

Wholesale gas customers buy capacity on transmission pipelines to transport their gas purchases from gas basins. Gas production companies and gas pipelines are separately owned, so a gas customer must negotiate separately with producers to buy gas and with pipeline businesses to have the gas delivered. To reach its destination, gas may even need to flow across multiple pipelines with different owners.

Access to transmission pipelines on key north–south transport routes is critical for gas customers. But many critical pipelines have little or no spare, uncontracted capacity, making it difficult to negotiate access. In addition, many pipelines face little competition and charge monopolistic prices.

Capacity on some pipelines is fully contracted to gas shippers, who do not fully use it. Reforms introduced in March 2019 made it easier to access this capacity, giving other parties an opportunity to procure capacity through trading platforms or win auctioned quantities – see section Pipeline capacity trading (day-ahead auction).

Capacity can be acquired in 2 ways. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold in this way must be offered at a mandatory day-ahead auction. Any shipper can bid at the auction, which is finalised shortly after the nomination cut-off time a day in advance of the relevant gas day.

Auction revenues go to the pipeline, or facility operator, rather than the shippers that own the capacity rights. The auctions have a reserve price of zero and most settlements have occurred at no cost.[70]

Pipeline capacity trading (day-ahead auction)

In 2023 the AER reported on the continued increase in the popularity of the day-ahead auction.[71] Since the commencement of the auction in March 2019, over 250 PJ of contracted but unnominated pipeline capacity has been won across 14 of the 22 auction facilities.[72]

Around 80% of all capacity procured was won at the reserve price of zero dollars and almost two-thirds of this capacity has been won on 4 key pipelines: the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP), which facilitate gas flows south and north between spot markets; the Eastern Gas Pipeline (EGP) and the Roma Brisbane Pipeline (RBP), which facilitate flows to gas-powered generators.

Over the January to March quarter 2023, auction quantities exceeded the previous record quarterly trade level by 24%, reaching 38.5 PJ (almost 3 to 4 times more than Q1 levels over previous years). Of this capacity, 12.9 PJ was traded on gas routes that transport gas between northern and southern markets (SWQP/MSP), with record levels won on both pipelines. There were also record levels of trade on the EGP (4.8 PJ), Berwyndale to Wallumbilla Pipeline (2.8 PJ) and the Wallumbilla Compression Facilities (9.2 PJ).

While decreasing markedly from the first quarter's record levels, quantities won across the April to June quarter continued to exceed previous record levels for Q2.

The day-ahead auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low-priced northern gas into southern spot markets, easing price pressure in those markets.[73]

The AER's *Pipeline capacity trading – two-year review* found day-ahead auction capacity increased liquidity in both upstream and downstream markets. It also reported on how the auction can indirectly ease supply costs for some gas-powered generators in the NEM.

However, auction activity on some pipelines remains low. In particular, the AER reported on the limited trade on the Moomba to Adelaide Pipeline and SEA Gas Pipeline System supplying the Adelaide market, although participation is increasing.[74] Under-utilisation of these pipelines may result from higher fees and lower activity levels in Adelaide compared with other markets. Auction fees can discourage smaller players, in particular. While most capacity is won

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70 While participants can win capacity for $0 per GJ, additional charges and registration fees make the real cost slightly higher.

71 AER, Wholesale markets quarterly – Q4 2022, Australian Energy Regulator, February 2022; AER, Wholesale markets quarterly – Q1 2023, Australian Energy Regulator, April 2023.

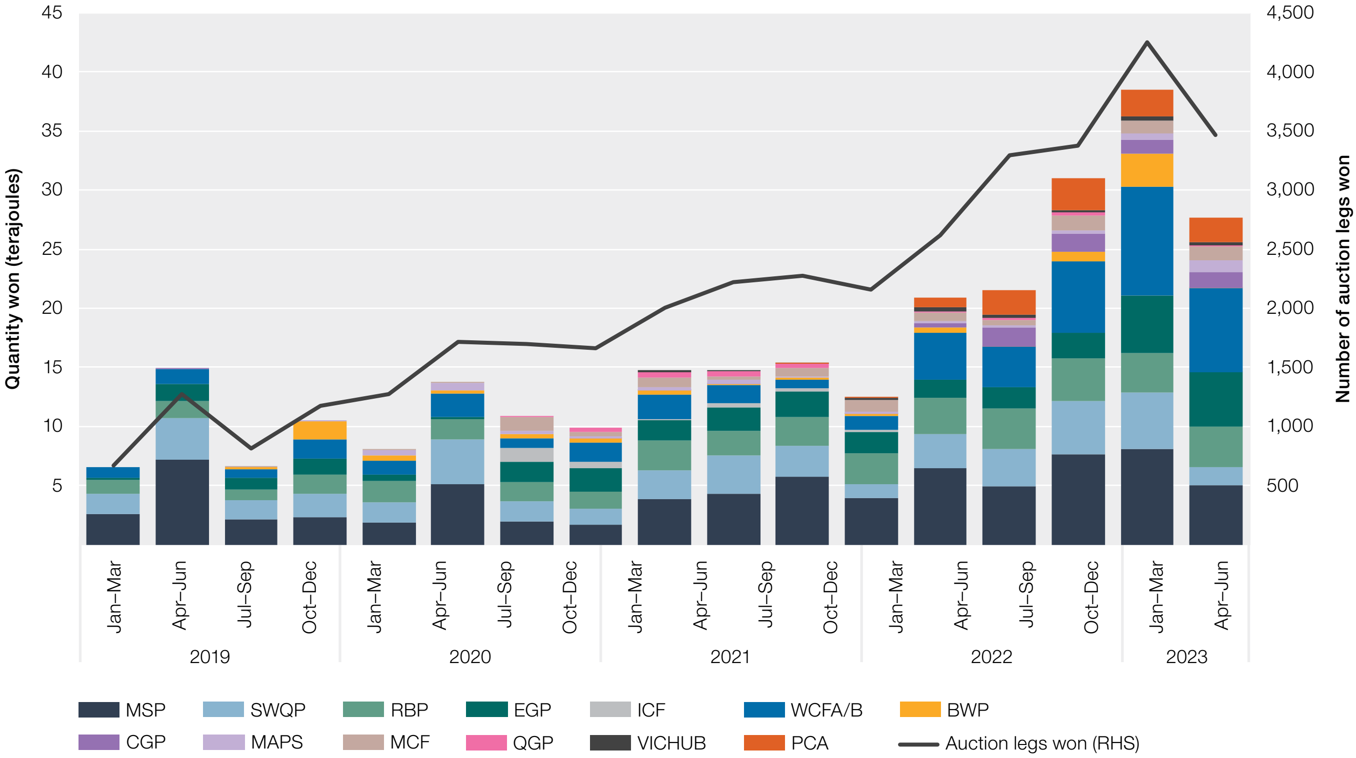
72 There has been no significant activity on the voluntary capacity trading platform since its introduction.

73 AER, Pipeline capacity trading – two-year review, March 2021, Australian Energy Regulator, p. 23.

74 The Port Campbell to Adelaide pipeline (SEA Gas) had over 2 PJ of capacity traded each quarter since mid-2022; however, trade levels on the Moomba to Adelaide Pipeline remain low, rarely exceeding 0.5 PJ over a quarter.

at the reserve price of $0 per GJ, the total cost is higher, because participants need to pay pipeline and storage operators for facility use (which can include both fixed and variable fees). Smaller participants also may be required to provide credit support or collateral to use auction services – in some cases these costs can be significant.

Figure 5.20 Day-ahead auction quantities won, by facility



Note: BWP: Berwyndale to Wallumbilla Pipeline; CGP: Carpentaria Gas Pipeline; EGP: Eastern Gas Pipeline; ICF: Iona Compression Facility; MAPS: Moomba to Adelaide Pipeline; MCF: Moomba Compression Facility; MSP: Moomba to Sydney Pipeline; PCA: Port Campbell to Adelaide Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; VicHub (eastern Victoria); WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of day-ahead auction data.

5.7 Trade in east coast gas markets

Gas markets were more liquid in 2022 than in previous years, with trade levels in the Gas Supply Hub increasing significantly and trading activity on the day-ahead auction continuing to set consecutive quarterly records from April 2022 into 2023.

The continued drawdown of southern production reserves has left those states more reliant on Queensland gas supplies going forward, with physical gas flows south in May up significantly from previous years. With some long export train maintenance outages across the first quarter of 2023, market participants appeared to capitalise on the availability of the extra gas available to domestic customers.[75] This included:

- exporters and producers offered record volumes of gas into the Gas Supply Hub and supplied record Q1 volumes in downstream markets
- traders bought record volumes (2.6 PJ) of gas through the Gas Supply Hub
- traders also sold record volumes of gas into downstream markets (2.64 PJ) at higher prices than the hub purchases, suggesting the gas was being on-sold from the hub to metropolitan markets.

Trade in gas commodity and transportation markets set records in the January to March quarter, with forward trade increasing later in the quarter. There were record deliveries at Wallumbilla and an increase in forward trading at the end of March, with volumes traded concentrated around deliveries over winter months (Figure 5.21). Record transportation capacity was acquired through the day-ahead auction – more than 3 times the volume of trade

75 AER, Wholesale markets quarterly – Q1 2023, Australian Energy Regulator, April 2023.

compared with any previous first quarter and above levels won over any previous quarter (Figure 5.20). While quantities of transportation capacity won at auction reduced in the April to June quarter, they remained higher than Q2 levels in previous years.

Domestic gas prices had increased significantly in April 2022 ahead of the increased southern demand for gas heating over winter, with unprecedented price increases occurring over the following months.[76] This led to multiple markets being placed in administered states and resulted in distorted pricing signals across the east coast as participants held on to their contracted supply. It also compelled contingency market outcomes to mitigate risks of short-term supply shortfalls from late May. Prices remained above historical levels and did not ease significantly until mid-December 2022, with prices heading into 2023 settling at roughly $10 to $15 per gigajoule.

Uncertainty around the availability of sufficient supply levels beyond 2022 has also coincided with delays in bringing new supply sources online.

5.7.1 Victoria's Declared Wholesale Gas Market (DWGM)

Around 40 participants traded in the Victorian market in 2022. The market's participants include energy retailers, power generators and other large gas users, and traders.

Volumes traded in the Victorian market rose by 7% in 2022. Since mid-2019, quarterly flows of gas into Victoria through the Culcairn injection point have increased consistently, particularly across the winter months. The majority of this is by operators of gas-powered generation, but other participants have been increasing their deliveries recently, facilitated by the day-ahead auction. In 2023, quarterly spot trade picked up in Q1, rising from a low of 12.5% of demand in the fourth quarter of 2022 to almost 19% over January to March 2023.

The volume of trade in the Victorian gas futures market decreased by 21% in 2022 from 2021 after increasing by 17% from 2020. This was the lowest level of futures trading observed since 2018. Ultimately, this quantity still accounts for only a small proportion (less than 5%) of the total volume traded in the market.

5.7.2 Gas Supply Hub (GSH)

In 2022, 21 participants traded at the gas supply hubs, 20 of which were active, with numerous off-market trades facilitated by a broker participant.[77] LNG export businesses and gas producers were among the most active participants in 2022, closely followed by gentailers.[78]

LNG producers are large suppliers of gas into the hubs, although operational issues can limit their participation. In addition, the physical interconnection of LNG facilities allows them to trade easily among themselves. Some market participants have suggested the scale of the LNG producers' operations may involve greater volumes than the hubs can currently absorb. Other participants include large industrial users and traders.

In 2022, 20 participants traded on-screen, with 15 actively trading. Similarly, 21 participants traded off-screen, with 20 of them active. On average, participants executed around 322 trades per month in 2022 – an increase of 69% from 2021.

In the first half of 2023 approaching winter, there was very little forward trade through the Gas Supply Hub. This was markedly different to the trade activity observed over the same periods in 2021 and 2022, during which trade at Wallumbilla materially exceeded gas delivered at the hub. This indicated a substantial volume of forward trade. This trend in previous years suggests participants sought to lock in gas supply approaching winter, whereas trading activity in 2023 shows a trend towards more shorter-term trading for delivery closer to the date of trade. The lower volumes of forward trade suggest a greater reliance on spot market trade to meet participants' demand levels over winter (Figure 5.21).

Wallumbilla hub activity

Users of the Wallumbilla hub include the LNG projects, gas-powered generators and, more recently, trader participants taking advantage of the day-ahead auction to arbitrage prices between Wallumbilla and the downstream markets.

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76 Potential upcoming shortfalls in southern gas supply, due to depleted legacy gas reserves in the Gippsland Basin, may be driving suppliers to set higher prices to limit further run-down of existing supply before a possible significant southern supply shortfall over winter 2023. Considering underlying contract positions reviewed in previous ACCC gas inquiry reports, local contract links to international oil and gas prices would potentially be impacted by international price increases following Russia's invasion of Ukraine.

77 We consider a participant 'active' if it makes at least 12 trades in a year. The broker is not included as an active trader.

78 Gentailers are participants that own electricity generation assets and retail market portfolios.

Following a rebound in trade over 2021 driven by an increase in off-screen activity, further growth occurred across 2022, particularly during the period of volatile pricing that took place mid-year over Q2 and Q3 (Figure 5.21). Notably, off-screen products tend to involve larger volumes of gas than on-screen alternatives do. In 2022 off-screen trade levels hit a record high, with close to 32 PJ traded. This was driven by higher volumes being traded for longer-term deliveries, including monthly product and strip trades of daily products.[79] From mid-2022, delivered quantities have exceeded previous quarterly records across consecutive quarters.[80]

However, ultimately, gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral, off-market arrangements. In 2022 gas traded through the Wallumbilla hub accounted for 15.9% of total gas flows through pipelines in the Wallumbilla bulletin board zone, almost double that of the previous year. In total, 36.6 PJ of gas was traded over 2022 and 16.9 PJ was traded across the first half of 2023.

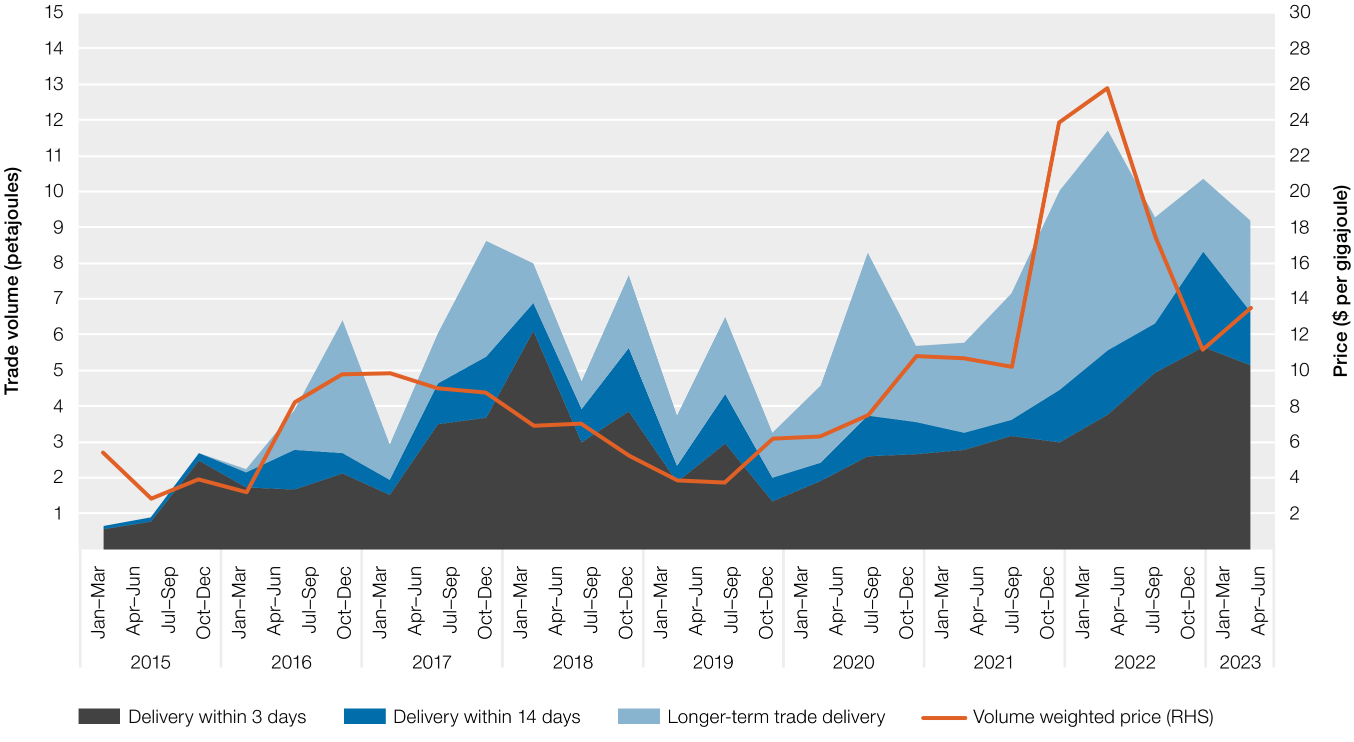
Moomba hub activity

Trade at Moomba has been slow to develop. The first trade was executed in September 2017, with 141 trades executed in 2019. Like Wallumbilla, trades at the Moomba location decreased significantly in 2020, declining further in 2021 before a very slight upturn in 2022. However, in 2023 an upturn in trade has seen quantities traded over the first half of the year exceeding previous yearly trade levels, reaching 1.75 PJ. This was partially driven by an upturn in trade levels on the Moomba to Sydney Pipeline.

Victoria and Sydney activity

Trade levels at the Culcairn (Victoria) and Wilton (Sydney) trading locations have occurred in small volumes, reaching a total of 264 TJ and 1,699 TJ, respectively, to date.[81]

Figure 5.21 Gas Supply Hub – increase in shorter-term trade



Note: Volume weighted average price includes all GSH products (excluding capacity trading platform) at all locations, excluding brokered sales.
Source: AER analysis of Gas Supply Hub data.

79 Strip trades, introduced in late 2020, allow participants more flexibility, providing the ability to bundle a string of daily products together over a selection of days, which can be traded further out (for delivery periods similar to monthly products).

80 Delivered quantities: July–September 2022 (13.6 PJ), October–December 2022 (10.5 PJ), January–March 2023 (10.1 PJ) and April–June 2023 (7.2 PJ).

81 Quantities traded from 2021 up to 30 June 2023.

5.7.3 Short Term Trading Market (STTM)

In 2022, 39 participants traded in the Sydney STTM and the Adelaide and Brisbane markets had 26 and 22 participants, respectively. The participants included energy retailers, power generators, large industrial gas users, gas producers and exporters, and traders. The markets are particularly useful for gas-powered generators because they can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

Shippers deliver gas for sale into the market and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users but in effect trade only their net positions – that is, the difference between their scheduled gas deliveries into and out of the market. In the fourth quarter of 2022, gas traded through the STTM met around 20% of demand in Sydney, 18% in Adelaide and around 10% in Brisbane. These levels increased close to twofold in Adelaide and Brisbane in 2023, reaching around 32% and 19% respectively over the January to March quarter.

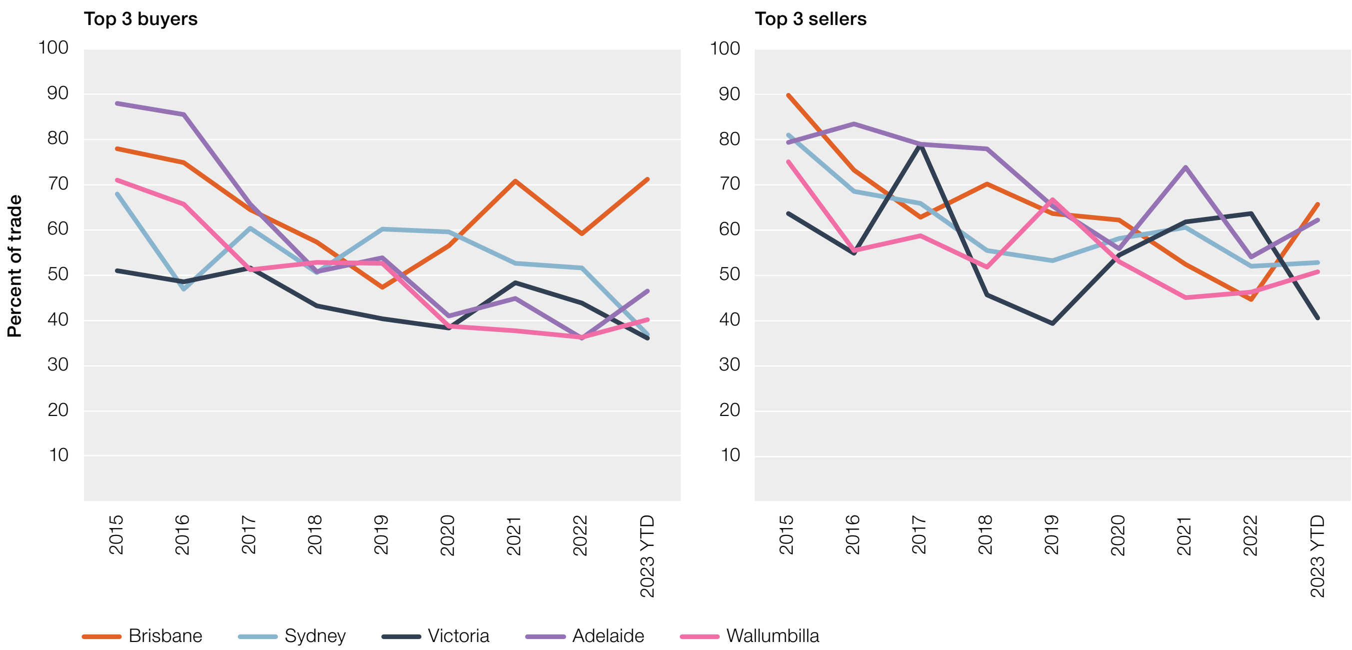
Traded volumes at the Sydney market were down slightly from record levels observed in 2021 – 97.7 PJ of net trade in 2022 was 6% lower than the previous year. Spot trade in the Adelaide and Brisbane markets for 2022 also fell by 18.5% (20 PJ) and 13.8% (32 PJ), respectively.

Trading profiles varied across the markets. Concentration across the top 3 sellers fell in Adelaide, Sydney and Brisbane from 2021 to 2022 and rose slightly in Victoria and Wallumbilla (Figure 5.22). Among the top 3 buyers, market concentration decreased over 2022, particularly in Brisbane. Importantly, the diversity of large suppliers participating in the spot markets is increasing. Similarly, in 2022 trader participants' share of gas scheduled into the STTM remained high despite reducing from record levels over 2021. This continued into 2023 with record quarterly sales by traders in the downstream markets over January to March (over 2.6 PJ). These participants took advantage of cheap capacity won on the day-ahead auction to arbitrage prices between markets.

In 2022 participants used the DWGM more heavily, with retailers and industrial participants being prominent gas purchasers and trade primarily dominated by those with gas generation assets. The latter group of participants accounted for around 68% of trade in the DWGM in 2022, compared with around 57% in 2021.

Despite traditionally benefiting from lower spot prices, high spot market exposure can be highly risky for spot market participants. In 2022, while spot prices early in the year were as low as $6.10 per gigajoule (GJ), volatile pricing over winter saw pricing between mid-May and late July largely in the vicinity of $27.12 to $59.49 per GJ. This resulted in 2023 contract offers increasing significantly compared with the prices offered in 2021, which ranged between $6.79 and $16.33 per GJ. Over 2022, contract offers for gas delivery in 2023 were between $8.61 and $71.54 per GJ.

Figure 5.22 Top 3 buyers and sellers in eastern Australian gas markets



Note: Year-to-date (YTD) to 30 June 2023.

Source: AER analysis of data from the Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market.

5.8 Market responses to supply risk

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response. AEMO's *2023 gas statement of opportunities* continues to highlight the risk of both short-term and long-term shortfalls in the east coast gas markets, particularly due to the depletion of legacy gas fields in Victoria's offshore Gippsland Basin. However, several projects that could help fill the supply gap have either stalled, been postponed or abandoned.

5.8.1 Gas field development

Numerous projects have been progressing to bring additional supply to the domestic market:

- In Queensland, Senex agreed to supply 10% of the reserves of its Atlas expansion project (up to 42 PJ) in the Surat Basin to AGL and 14 PJ of gas to Orora's glassmaking plant over 10 years starting 2025. Senex also agreed to supply BlueScope's Port Kembla plant with 20 PJ of gas from 2026 following a similar contingent arrangement with Visy, contributing to a total of 130 PJ in deals from 2025. The expansion plans to increase annual production by 60 PJ by the end of 2025. An earlier expansion of the facility commissioned in the July to September quarter of 2022 saw production increased from 12 PJ to 18 PJ over the January to March quarter of 2023.
- Gas production from the Meridian joint venture increased to 3.1 PJ in the January to March quarter of 2023 (34 TJ per day) following the drilling of one development well. The WestSide/Mitsui partnership plans to drill 350 wells in the Bowen Basin to supply GLNG.[82]
- In Victoria, Cooper Energy announced plans to expand its Otway gas hub. After commencing production at the Athena gas plant (formerly Minerva) from mid-December 2021, the Otway Phase-3 Development (OP3D) project is targeted to bring additional gas to the market before winter 2025.[83] Cooper entered into a long-term gas sales agreement (GSA) with AGL to supply up to 10 PJ per year for up to 6 years.[84]
- Exxon Mobil announced funding of the Kipper Compression Project in the January to March quarter 2022, committing supply from 2024 and additional investment to develop and produce gas from the Kipper and Turrum fields over the following 5 years.[85] While additional gas is expected to be processed at Longford from 2026, supply is not expected to increase winter capacity to levels provided by their depleting legacy field production.[86]
- Beach Energy committed to the development of Geographe, and Thylacine North and West fields to increase Port Campbell supply, including the drilling of 6 new production wells commencing in February 2021. From mid-May 2023, Otway's actual daily production output increased above 170 TJ (producing over 10 PJ across Q2 2023). Beach has also prioritised the ongoing development of its Yolla West field and deferred FID for Trefoil, which is now considered as potential supply.[87]
- In NSW, Santos proposed to develop 850 wells across its 95,000-hectare Narrabri gas project with the potential to supply up to 200 TJ per day. The staged development was expected to provide up to 55 PJ per year in 2026, all of which is voluntarily committed to the domestic market. However, appeals against the project's approval have delayed any final investment decision, which now depends on project approvals being cleared.[88]

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82 The partners began supplying GLNG in 2015 under a 20-year deal linked to oil prices. EnergyQuest, *EnergyQuarterly*, June 2023, p. 122.

83 Athena sources gas from the Otway Basin's Casino, Henry and Netherby fields, some of which was formerly processed at Iona (Casino).

84 Gas Sales Agreement with AGL for the next phase of Otway Basin development and exploration.

85 ExxonMobil, Opportunities for the Gippsland Basin and Australia's energy transition, 22 March 2022.

86 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2023, p. 63.

87 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2023, p. 63.

88 The Australian Government approved the project in November 2020, with the conditions of approval consistent with those set by the NSW Independent Planning Commission.

Regulatory barriers to gas development

In some states and territories, community concerns about environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development.[89] Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- The Victorian Government banned onshore hydraulic fracturing and exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[90] In March 2021 the government committed the ban on fracking and CSG exploration to the Victorian Constitution.[91] Onshore conventional gas exploration recommenced from July 2021.
- In 2018 South Australia introduced a 10-year moratorium on fracking in the state's south-east. It introduced the moratorium by direction and announced its intention to legislate it. However, unconventional gas extraction is allowed in the Cooper and Eromanga basins. South Australia has no restrictions on onshore conventional gas.
- The Tasmanian Government banned fracking for the purpose of extracting hydrocarbon resources (including shale gas and petroleum) until March 2020. This has since been extended to 2025.[92]
- The Northern Territory has made 51% of the territory eligible for hydraulic fracturing. The decision covers much of the Beetaloo Basin, which holds most of the territory's shale gas resources.
- NSW has no outright ban on onshore exploration, but significant regulatory hurdles have stalled development proposals. Regulatory restrictions include exclusion zones, a gateway process to protect 'biophysical strategic agricultural land', an extensive aquifer interference policy, and a ban on certain chemicals and evaporation ponds.[93] The state's regulations also require community consultation on environmental impact statements and a detailed review process for major projects, as highlighted by the protracted process for Santos' Narrabri gas project.[94] Under an agreement reached in early 2020, the NSW and Australian governments set a target of increasing supply to the NSW market by 70 PJ per year.[95]

5.8.2 Liquefied natural gas import terminals

To address future supply concerns, market participants have proposed numerous gas projects to develop LNG import facilities on the east coast. Each project would involve importing LNG through floating storage and regasification units (FSRU). While development of import terminals have been delayed over the past year, proponents of these projects remain committed to their continuing development.[96]

- Australian Industrial Energy's (AIE) terminal at Port Kembla (NSW) is no longer classified by AEMO as an anticipated project due to uncertainty around the contracting of gas supply. In 2021 AIE and Jemena signed a project development agreement to connect to the Eastern Gas Pipeline, with modifications set to allow bidirectional flows to deliver gas to Sydney and Victoria (Section 5.8.3). These infrastructure modifications are on track to be completed by December 2024 but the import facility is not expected to be operational before 2026.
- Venice Energy's proposed terminal at Port Adelaide (South Australia) is projected to potentially supply gas by 2026.[97] However, gas deliveries to Victoria are currently constrained due to the SEAGas Pipeline, currently only able to flow gas out of Victoria, and the limited available capacity on the South West Pipeline.
- Viva Energy's Geelong (Victoria) Gas Terminal project was projected to deliver gas as early as 2024. The project would require the duplication of the South West Pipeline. Viva was expected to make a final investment decision on the project by the end of 2022; however, the Victorian Minister for Planning requested supplementary information to their Environmental Effects Statement in March 2023.

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89 Hydraulic fracturing, also known as fracking, is a process that involves injecting a mixture of water, sand and chemicals at high pressure into underground rocks to release trapped pockets of oil or gas. A well is drilled to the depth of the gas or oil bearing formation, then horizontally through the rock. The fracturing fluid is then injected into the well at extremely high pressure, forcing open existing cracks in the rocks, causing them to fracture and breaking open small pockets that contain oil or gas. The sand carried by the fluid keeps the fractures open once the fluid is depressurised, allowing oil or gas to seep out.

90 Department of Economic Development, Jobs, Transport and Resources (Victoria), Onshore gas community information, August 2017.

91 Victorian Government, Enshrining Victoria's ban on fracking forever [media release], March 2021.

92 Department of State Growth (Tas), Tasmanian Government policy on hydraulic fracturing (fracking) 2018, DSG website, accessed 28 May 2021.

93 Department of Planning and Environment (NSW), Initiatives overview, July 2018.

94 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed' [media release], 7 June 2017.

95 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions' [media release], January 2020.

96 Energy Quest, *EnergyQuarterly*, June 2023, p. 23.

97 AEMO, 2023 Gas Statement of Opportunities, Australian Energy Market Operator, March 2023, p. 65.

- Vopak's import terminal in Port Phillip Bay (Victoria) is expected to be completed in 2026. An environmental plan was submitted to the Victorian Government in December 2022.[98]
- EPIK ceased development of a Newcastle import terminal due to the project being economically unfeasible.[99]

5.8.3 Transportation capacity expansion

To assist with reducing existing gas supply transportation constraints, pipeline expansions have been progressing to bring more gas south from Queensland, bring more gas from western Victoria into Melbourne, and provide upcoming import supply with the ability to provide gas to NSW and Victoria.

South West Queensland and Moomba to Sydney pipelines project

APA has been expanding the pipeline corridor through Queensland into NSW by adding additional compression on the South West Queensland Pipeline (SWQP)[100] and the Moomba to Sydney Pipeline (MSP).[101] The expansion enables more gas flow on pipelines where capacity is fully or close to fully contracted.[102] Stage 1 of the expansion was completed by June 2023, increasing transportation capacity by 49 TJ on the SWQP (to 453 TJ per day) and by 30 TJ on the MSP (to 475 TJ per day).[103] This was the first of 3 stages of a 25% increase in transportation capacity.[104]
The additional proposed expansion stages include:

- Stage 2 – a 59 TJ per day increase to the nominal capacity from Queensland to the southern markets, with an additional compressor station constructed on both the SWQP and MSP. This will bring the 453 TJ per day increase from stage 1 up to 512 TJ per day on the SWQP, with the 475 TJ per day capacity on the MSP to increase by 90 TJ to 565 TJ per day. Subject to foundation contracts, this stage is expected to be commissioned in the January to March quarter 2024.
- Stage 3 – a further 92 TJ per day expansion with increases to capacity on both pipelines is currently in initial design phases and is subject to customer demand and project approval.[105]

South West Pipeline, Western Outer Ring Main (WORM) project

APA is also upgrading the Victorian Transmission System (VTS), building a 51 km high pressure transmission pipeline to address a key capacity constraint currently limiting the connection of existing gas supply from the west of the state to demand in the north and east. The transportation of gas will also be assisted by the upgrade of the existing compressor station at Wollert. The project is expected to be completed from late September to early October 2023.

The South West Pipeline (SWP) is a bidirectional facility that primarily transports gas from Port Campbell supply (gas from the Otway Basin and Iona underground storage) into Melbourne. The pipeline also supports refilling the Iona reservoir and transports gas west, fuelling the Mortlake power station and South Australia (through the SEAGas pipeline) during periods of lower demand. Limited capacity on the SWP restricts supply being provided from Port Campbell in the state's west. Following the completion of the WORM, the maximum daily capacity will increase from 447 TJ to 476 TJ on peak demand days.[106]

AEMO forecasts show the SWP constraining flows towards Melbourne during peak demand periods, when the full capacity of the Iona underground gas storage (UGS) facility is most needed. Further expansions of the SWP are proposed, to bring its capacity in line with the capacity of Iona UGS (section 5.8.4), following completion of the WORM.

98 Oil & Gas Journal, Vopak submits Victorian LNG import terminal environmental plan, 23 December 2022.

99 AEMO, 2023 Gas Statement of Opportunities, Australian Energy Market Operator, March 2023, p. 65; Mandurah Mail, Gas market volatility kills off $590m gas terminal, 3 February 2023.

100 The SWQP connects to the Northern Territory through Carpentaria Gas Pipeline and is a gateway between large northern gas fields in Queensland (including the 3 Gladstone LNG projects), and southern regions with highly seasonal demand. AEMO, *2022 Gas Statement of Opportunities*, Australian Energy Market Operator, March 2022, p. 51.

101 The MSP connects the Moomba hub in South Australia to southern markets in Sydney/ACT and Victoria (through Young and the Victoria/New South Wales Interconnector). Seasonal (non-peak) capacity on the MSP can be limited by up to 50% due to annual maintenance, while southern haul capacity on the VNI lateral can be limited by dynamic interactions between Young, Sydney and GPG requirements at Uranquinty.

102 ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 15.

103 Stage 1 of the expansion includes an additional compressor on the SWQP and an additional compressor between Moomba and Young on the MSP.

104 AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022. pp. 76–77.

105 This potential expansion is expected to add a further 25% to the Stage 1 (12%) and Stage 2 (13%) increases. ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 67.

106 Based on AEMO modelling of a 1-in-20 (5% probability of exceedance) peak system demand day. AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022. P. 9.

The WORM was one of 4 priority projects implemented to address shortfalls highlighted in the 2021 Victorian gas planning report.

Further expansions are not yet committed because they are subject to approval under APA's Access Arrangement. However, they have been proposed to increase supply capacity from Port Campbell to between 528 TJ and 570 TJ per day through pipeline augmentation (compression or looping) and up to 670 TJ per day with additional looping and/or compression.[107]

Eastern Gas Pipeline expansion project

The Eastern Gas Pipeline (EGP) is a unidirectional pipeline that transports gas from the Gippsland Basin (Victoria) into Sydney. In 2021 Jemena and AIE signed a project development agreement to connect the PKET import terminal (section 5.8.2) at Kembla Grange at a capacity of 522 TJ per day. Jemena plans to modify the pipeline to allow for bidirectional flows, with an initial ability to supply 200 TJ into Victoria and up to 440 TJ towards Sydney per day.[108]

The earliest practical completion of the EGP expansion project in 2024 aligns with the planned completion of the delayed Port Kembla project. Potential future expansion, including the installation of a compressor at Kembla Grange, will increase daily capacity to supply as much as 323 TJ into Victoria and 550 TJ towards Sydney. Onshore infrastructure remains on track for completion in December 2024.[109]

5.8.4 Storage expansion

Iona underground gas storage (UGS)

Lochard Energy upgraded their underground storage facility to increase supply capabilities to 570 TJ per day,[110] with 1 PJ of additional storage capacity following the drilling of a new storage well. Well pad construction of the Seamer 2 well in a field adjacent to Iona's existing field was completed in November 2021 before ministerial approval of the operational plan on 28 January 2022.[111] However, daily supply capacity into Melbourne via the South West Pipeline will be constrained to 476 TJ when the WORM project is completed – expected in late 2023 (section 5.8.3).

Further upgrades after the development of the Heytesbury Underground Gas Storage (HUGS) project have been proposed to add additional pipeline assets and approximately 3 PJ of additional storage capacity through construction of a new wellsite at Mylor, Fenton Creek and Tregony (MFCT) gas fields.[112] The project would increase capacity following the development of existing depleted reservoirs, with daily supply capacity increasing to 620 TJ.[113] Proposed construction would commence in October 2023 for completion by 2024, but is subject to regulatory approvals and market requirements that could delay the commencement of the project to October 2024.

Golden Beach project

A proposed plant to process gas from the Golden Beach field in the Gippsland Basin could provide additional supply to assist with peak day demand in Victoria in 2024 and 2025, before operating as an underground storage facility. Golden Beach Energy received $32 million from the Australian Government in 2022 to accelerate development of the project.[114] The facility was projected to have a storage capacity of 12.5 PJ but would require 43 PJ of production to be procured over a 2-year period before being used as a storage facility.[115] In May 2023, the Minister for Energy and Resources accepted Golden Beach Energy's environment plan to drill the Golden Beach-2 appraisal well.[116]

107 AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022, p. 14.

108 AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022, pp. 75–76.

109 AEMO, 2023 Gas Statement of Opportunities, Australian Energy Market Operator, March 2023, p. 65.

110 Nameplate supply capacity increased from 530 TJ per day to 545 TJ per day on 28 January 2022. Storage capacity will increase from 23.5 PJ to 24.5 PJ.

111 Lochard Energy, Seamer 2 Project – Community Update, January 2022.

112 Lochard Energy, Our HUGS Project, April 2022.

113 AEMO, 2022 Gas Statement of Opportunities, Australian Energy Market Operator, March 2022, p. 55.

114 The Hon Angus Taylor MP, Unlocking critical local gas production and storage, 21 March 2022.

115 ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 68.

116 Earth Resources, Golden Beach Gas Project, 20 June 2023.

5.8.5 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in January 2019. Current nameplate capacity of the pipeline is 90 TJ per day, but Jemena plans to increase this to 200 TJ per day by 2025.[117] This plan would also extend the pipeline to connect the Beetaloo Basin directly to the Gas Supply Hub.

2021 east coast supply from the Northern Territory averaged around 55 TJ per day until October, before declining in 2022. Supply over the first half of 2022 was down to an average of just over 30 TJ per day to the end of August, before Blacktip production issues led to Mt Isa deliveries reducing to essentially 0 TJ per day from early September and into December. Since then, average supply from the Northern Territory has averaged just under 23 TJ per day up to mid-2023. The low pressure in the pipeline forced Jemena to temporarily shut down the pipeline due to safety concerns, requiring Mt Isa to be supplied from east coast production sources. This contributed to reduced supply and increased demand in east coast markets over late 2022.

5.8.6 Demand response

Volatile markets and the expiry of legacy gas supply agreements are prompting commercial and industrial (C&I) customers to take a more active role in gas procurement. Some customers have become direct market participants by engaging in collective bargaining agreements.

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, using brokers to secure supply agreements, participating in gas markets and investing in new LNG import facilities.[118] Some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments.

In addition, some C&I users are considering alternatives to gas, such as renewable energy.[119]

Government initiatives can also play a role in reducing gas demand. The ACT initially removed mandatory gas connection requirements for new homes, before legislating a stop to new gas connections from 2023.
Other initiatives, such as the Victorian Gas Substitution Roadmap and Energy Upgrades program, have identified electrification as the best solution to achieve a short-term reduction to gas consumption levels.[120]

5.9 Compliance and enforcement activities

The AER's compliance and enforcement work ensures that important protections are delivered and rights are respected. It gives consumers and energy market participants confidence that the energy markets are working effectively and in their long-term interests, so they can participate in market opportunities as fully as possible and are protected when they cannot do so.

Compliance work helps to proactively encourage market participants to meet their responsibilities and enforcement action is an important tool when breaches occur.

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in east coast gas markets.

Over 2022–23, 2 of the AER's compliance and enforcement priorities related to gas markets:

- ensuring service providers meet information disclosure obligations and other Part 23 National Gas Rules obligations
- ensuring timely and accurate gas auction reporting by registered participants.

High-quality market information is vital to improve transparency among participants and promote competition.

The AER undertook a range of compliance and enforcement activities in support of these priorities, including:

- following an industry-wide review of service provider compliance against Part 23 reporting requirements, we issued a compliance bulletin in September 2022 outlining expectations of non-scheme pipeline service providers' compliance with numerous information disclosure obligations

117 Jemena, 'Jemena partners with shale gas experts to develop Beetaloo' [media release], November 2020.

118 ACCC, Gas inquiry 2017–2025, interim report, January 2021, Australian Competition and Consumer Commission, February 2021, pp. 73–74.

119 ACCC, Gas inquiry 2017–2025, interim report, January 2020, Australian Competition and Consumer Commission, February 2020, p. 74.

120 AEMO, 2022 Gas Statement of Opportunities, Australian Energy Market Operator, March 2022, p. 23.

- continued targeted reviews of recovered capital values reported by specific pipeline operators
- issued $630,000 of infringement notices for alleged breaches of record-keeping and report requirements under the National Gas Rules relating to the day-ahead auction
- developed guidelines for Part 10 and Part 18A obligations following the revocation of Part 23 in March 2023, covering publication requirements for non-scheme pipelines and standalone compression and storage facility service providers
- published a compliance bulletin on new obligations under the gas pipeline reforms in June 2023.[121]

More detail on the AER's compliance and enforcement work is outlined in the annual compliance and enforcement report 2022–23.[122] More information on AER observations of short-term transactions under the new Gas Market Transparency measures is available in the Wholesale markets quarterly report.[123]

5.10 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand, the Australian Government and some state and territory governments have intervened in the market.

5.10.1 Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism (ADGSM) empowers the Australian Government Minister for Resources to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[124] The Minister may determine in the preceding September whether a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

To avoid export controls, Queensland's LNG producers entered agreements with the government committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls.[125] They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.[126] Following a review by the Australian Government Department of Industry, Science, Energy and Resources, the scheme was extended until 2030.[127]

On 29 September 2022 the Australian Government announced it had signed a new Heads of Agreement (HoA) with LNG exporters, indicating that they would offer an estimated additional 157 PJ of gas to domestic customers in 2023 through a combination of supplying uncontracted gas and utilising existing and improved gas marketing methods. This resulted in the Australian Government's decision not to trigger the operation of the ADGSM for 2023.[128]

5.10.2 Gas Supply Guarantee

Facility and pipeline operators developed the Gas Supply Guarantee (GSG) as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM.[129] The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023.[130]

AEMO triggered the GSG for the first time on 1 June 2022.[131] Following activation of the mechanism, gas producers in Queensland diverted gas into the domestic market and AEMO subsequently deactivated the mechanism the next day. AEMO reactivated the mechanism from 19 July following the notification of a threat to system security (TTSS) in Victoria due to insufficient storage, after directing 2 generators to cease taking gas from the Victorian market until 30 September 2022 (with the GSG and TTSS to remain in effect until sufficient supply is available).[132]

121 AER, Compliance bulletin – new obligations on gas pipeline, compression and storage service providers, Australian Energy Regulator, 7 June 2023.

122 AER, Compliance and enforcement report 2022–23.

123 AER, Wholesale markets quarterly report, Q2 2023, Australian Energy Regulator, July 2023, p. 22.

124 Department of Industry, Science Energy and Resources, *Australian Domestic Gas Security Mechanism*, July 2018.

125 Department of Industry, Science, Energy and Resources, *Securing Australian domestic gas supply*, DISER website, accessed 28 May 2021.

126 The agreement specifically notes that LNG netback prices, as referenced by the ACCC, play a role in influencing domestic gas prices.

127 Department of Industry, Science, Energy and Resources, *Australian Domestic Gas Security Mechanism review*, January 2020.

128 Johnson Winter Slattery, *Commonwealth enters new Heads of Agreement to safeguard Australia's east coast domestic gas market*, October 2022.

129 AEMO, *Gas supply guarantee*, Australian Energy Market Operator website, accessed 28 May 2021.

130 AEMO, *Gas supply guarantee guidelines consultation final determination*, Australian Energy Market Operator, March 2020.

131 AEMO, *Gas supply guarantee*, Australian Energy Market Operator, accessed 28 May 2021.

132 AEMO, AEMO takes further steps to manage tight gas supplies, Australian Energy Market Operator, 19 July 2022.

5.10.3 Additional powers for AEMO

On 12 August 2023 Energy Ministers agreed to take a range of actions to support a more secure, resilient and flexible east coast gas market. These actions sought to address winter 2023 east coast gas supply adequacy concerns that were raised in ACCC and AEMO reporting.

The actions include regulatory amendments providing additional powers to the Australian Energy Market Operator (AEMO) to manage gas supply adequacy and reliability risks ahead of winter 2023 (tranche 1) and longer-term solutions to manage threats to the east coast gas market (tranche 2).[133] The tranche 1 initiatives provide the regulatory framework covering:

- data transparency to assess supply-demand trends and determine the likelihood of a threat to reliability or adequacy of gas supply
- identification, communication and publication of information about actual or potential threats to signal an east coast gas system response
- powers to issue directions to gas industry participants to resolve potential or actual threats to system security (including a compensation framework)
- the ability for AEMO to trade in natural gas to maintain or improve reliability or adequacy of gas supply.

A Bill giving effect to these changes commenced on 27 April 2023, alongside supporting regulations. The corresponding Rule amendments came into effect on 4 May 2023.[134]

5.10.4 State government schemes

To encourage gas exploration, the Queensland Government grants exploration authorities for 'domestic only' exploration tenements.

As part of this grants program, it released almost 70,000 km^2 of land for exploration between 2015 and 2019, of which around 25% was reserved for domestic supply. The Queensland Government released a further 3,000 km^2 of land in September 2020, with over 15% tagged for domestic supply.[135] In 2021, the Queensland Government announced it would make 14,100 km^2 available for oil and gas exploration.[136] In June and July 2022, the Queensland Exploration Program released prospect tenders for petroleum and gas exploration (8 areas, 14,420 km^2) and greenhouse gas storage (14,500 km^2).[137]

In January 2020, through a memorandum of understanding with the Australian Government, the NSW Government committed to bringing new gas supplies to the domestic market. It set a target of injecting an additional 70 PJ of gas per year into the NSW market.[138]

In April 2021 the Australian and South Australian governments announced an agreement to invest in energy infrastructure and reduce emissions in South Australia. As part of this, the state set a target of an unlocking an additional 50 PJ per year by 2023.[139]

In April 2022 the Australian and Northern Territory governments signed an energy and emissions reduction agreement to deliver affordable and reliable power and unlock gas supplies to help prevent shortfalls in the market.

5.10.5 ACCC gas inquiry

The Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. The inquiry was initially tasked to run until 30 April 2020, with successive governments extending the inquiry to 2025 (in July 2019) and then out to 2030 (in October 2022).[140]

133 AEMO, East Coast Gas Reforms, Australian Energy Market Operator.

134 National Gas (South Australia) (East Coast Gas System) Amendment Act 2023; National Gas (South Australia) (East Coast Gas System) Amendment Regulations 2023; National Gas Amendment (East Coast Gas System) Rule 2023.

135 Queensland Government, 'Queensland gas exploration ramping up' [media release], September 2020.

136 Queensland Government, 2021 Queensland Exploration program, November 2021, accessed 28 June 2022.

137 Queensland Government, *Queensland Exploration Program*, Business Queensland website, accessed 25 May 2023.

138 NSW Government, *Memorandum of understanding – NSW energy package*, 31 January 2020.

139 Australian Government, 'Energy and emissions reduction agreement with South Australia' [media release], April 2021.

140 ACCC, *Gas inquiry 2017–2030*, Australian Competition and Consumer Commission, accessed 24 May 2023.

5.10.6 Electrification of liquefied natural gas production

On 8 February 2020 the Australian Government announced it would allocate up to $1.5 million to work with the Queensland Government and industry on electrifying the Curtis Island LNG facilities. The production facilities currently use their own gas as a power source in production. Partly electrifying these processes would make available up to 12 PJ of gas for delivery to the domestic market.

The first project will be a 100 MW Pleasant Hills Solar Project in Queensland developed by TotalEnergies and Gentari Renewables. The solar farm will supply renewable energy to the Roma field's gas production and processing facilities, which feed into the Gladstone LNG export project.

5.10.7 National hydrogen strategy

The Australian Government identified hydrogen as a potential fuel to facilitate cuts to emissions across energy and industrial sectors. As part of this strategy, the government is looking at introducing hydrogen to the gas distribution network as part of the mix with natural gas. Currently, hydrogen can be added to gas pipelines at concentrations of up to 10% to supplement gas supplies and a number of trials are being explored.

In July 2020 the Australian Renewable Energy Agency (ARENA) shortlisted 7 projects to be considered as part of its $70 million fund to develop large-scale electrolysers, 3 of which are based in eastern Australia.[141] In April 2023 ARENA launched a $25 million funding round to support research and development of large-scale renewable hydrogen.

In February 2023 Australian Government Ministers agreed to lead jurisdictions in a review of the National Hydrogen Strategy.[142]

5.10.8 Competition and Consumer (Gas Market Emergency Price) Order

On 23 December, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months.[143]

The Order introduced a price cap on gas of $12 per GJ (and does not apply in Western Australia) during the price cap period set as 12 months, effectively 2023 gas supply. Generally, the price cap applies to gas producers and affiliates of gas producers (regulated producers).

There are several exceptions, including gas to be exported as LNG, retailers that meet certain criteria, trades on the Short Term Trading Market (STTM) or Declared Wholesale Gas Market (DWGM), near term (next 3 day) trades and offers on the Gas Supply Hub (GSH) Exchange.

Separate to the exceptions, the Order also allows the Minister to grant exemptions. The Minister has delegated the power to grant a gas price cap exemption to the ACCC.[144] The delegation commenced on 23 December 2022.

Further information on the price cap, the process of applying for an exemption (including information requirements) and the ACCC's process after receiving an exemption application can be found on the ACCC's website.[145]

From 11 July 2023, as part of the Energy Price Relief Plan announced in December 2022, the Australian Government implemented a Mandatory Gas Code of Conduct.[146] The Code aims to ensure that east coast gas users can contract for gas at reasonable prices and on reasonable terms. It also includes a 2-month transitional period to allow companies to adapt to the conduct provisions, record keeping and process standards for commercial negotiations. The key elements of this code include:

- the price cap, initially set at $12 per GJ, with the first mandated review of the Code by 1 July 2025
- an exemptions framework to incentivise short-term supply commitments and incentivise investment to meet ongoing medium-term demand

141 ARENA, *Seven shortlisted for $70 million hydrogen funding round*, Australian Renewable Energy Agency, accessed 28 May 2021.

142 DCCEEW, *National Hydrogen Strategy review*, Department of Climate Change, Energy, the Environment and Water, accessed 25 May 2023.

143 Australian Government, Competition and Consumer (Gas Market Emergency Price) Order 2022, December 2022.

144 A list of exempted entities is available on the ACCC's website (Gas price exemptions register).

145 ACCC, Gas cap price exemption, Australian Competition and Consumer Commission, December 2022.

146 DCCEEW, Mandatory Gas Code of Conduct, Department of Climate Change, Energy, the Environment and Water, 11 July 2023.

- transparency obligations to increase visibility of uncontracted gas production and its expected availability to the domestic market
- conduct provisions aimed at reducing bargaining power imbalances between producers and gas buyers and establishing minimum conduct and process standards for commercial negotiations.

5.11 Gas market reform

On 30 September 2022, National Cabinet agreed to establish the Energy and Climate Change Ministerial Council (ECMC) within the streamlined model of Australia's federal relations architecture, replacing the Energy National Cabinet Reform Committee (formerly the COAG Energy Council). Energy Ministers, along with the ECMC, direct gas market reforms, which regulatory and market bodies implement.[147] A key focus of reform is to address information gaps and asymmetries in the market.

In its inaugural meeting on 24 February 2023, the ECMC agreed to 5 strategic priorities, which will be reviewed annually alongside the terms of reference.[148] The ECMC also agreed to expedite a package of carefully designed measures expanding the Australian Energy Regulator's (AER) gas and electricity market monitoring powers.[149] This follows the introduction of new laws providing the AER with greater powers to monitor wholesale gas and electricity markets, which was passed into legislation on 23 June 2022.[150]

Reform stems from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group. The reforms aim to increase transparency in the gas market, improve the Gas Bulletin Board and improve the availability of information on market liquidity, prices and gas reserves.

5.11.1 Gas Bulletin Board reforms

The Gas Bulletin Board aims to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia.

Market participants can access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations and capacity outlooks. This adds transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must submit daily disaggregated receipt and delivery point data. The data includes information on flows at key supply and demand locations along pipelines.

The AER assesses the quality and accuracy of the data submitted by market participants against an 'information standard' to ensure the information presented on the bulletin board has integrity.

In June 2022 states adopted the National Gas Amendment (Market Transparency) Rule 2022, which extended reporting to large gas users and LNG processing facilities. These laws give the AER new powers to monitor information related to price and volume in the shorter-term gas market, including how gas is exported overseas and how it is traded here in Australia. In particular, the AER now monitors the export, reserve, storage and domestic sale and swaps of gas to report more comprehensively on competition.

Price and reserves transparency

With gas markets shifting towards shorter-term contracts, and suppliers using EOI processes, the transparency of price and other market information is critical. The ACCC publishes data on LNG netback prices to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts.[151]

Reporting of new information commenced on 15 March 2023, requiring participants to provide information to AEMO through the Gas Bulletin Board. New information published on the Bulletin Board includes Reserves Resources Reporting and Facility Developments and LNG and Short Term Transactions. [152]

147 The Energy Advisory Panel includes the AER, the AEMC, AEMO and the ACCC. On 19 May 2023, state and federal energy ministers voted unanimously to disband the Energy Security Board, replacing it with a new specialist advisory panel to fast-track new connections of renewable energy sources to the east coast grid.

148 Energy and Climate Change Ministerial Council.

149 Department of Climate Change, Energy, the Environment and Water, gas and electricity market monitoring powers.

150 AER, AER welcomes new powers to keep watch on wholesale gas markets, news release.

151 ACCC, Gas inquiry 2017–2030 – LNG netback price series, Australian Competition and Consumer Commission.

152 AEMO, Reserves Resources Reporting and Facility Developments and LNG and Short Term Transactions.

These reforms were designed to enhance transparency in the eastern and northern Australian gas markets, to address information gaps and asymmetries relating to:

- gas and infrastructure prices
- supply and availability of gas
- gas demand
- infrastructure used to supply gas to end-markets.

More information on the introduction of regulatory amendments can be found on the energy.gov.au website.[153]

5.11.2 Pipeline reforms

Recent reforms to the National Gas Law (NGL) and National Gas Rules (NGR) have significantly changed the way gas pipelines are regulated. In March 2022, Energy Ministers agreed to a package of gas pipeline regulatory amendments to deliver a simpler regulatory framework. The reforms aim to limit the exercise of market power, facilitate better access to pipeline capacity and provide greater support for commercial negotiations between shippers and service providers through increased transparency of information and improvements to the negotiation framework and dispute resolution mechanisms.

Key changes have been made to the following elements:

- the greenfields incentive regime[154]
- regulatory powers to determine the form of regulation to which a pipeline should be subject
- service provider information disclosure requirements[155]
- numerous other clarifications and refinements.

Under the new regime, all transmission and distribution pipeline service providers will be required to provide third party access where it is sought, subject to available exemptions.[156]

The new reforms have abolished the concept of 'light regulation', subjecting all pipelines to a range of uniform access, transparency and ring-fencing requirements. All pipelines are now classified as either scheme or non-scheme pipelines, with scheme pipelines subject to a stronger form of regulation based on the 'full regulation' regime.[157] Non-scheme pipelines are subject to a lighter commercially oriented form of regulation and dispute resolution mechanism.

There are also requirements on standalone compression and storage facility service providers to publish standing terms of services offered and information on individual prices paid by shippers. Pipelines are now required to publish actual prices payable instead of weighted average prices that they previously reported.

The reforms also require the AER to regularly and systematically monitor service providers' behaviour and report on this to the Ministerial Council on Energy every 2 years. The information that the AER must monitor and report on includes the actual prices charged, non-price terms and conditions for pipeline services, financial information reported by service providers, outcomes of access negotiations, service providers compliance with ring fencing requirements, dealings with associates and their compliance with other requirements of the NGL and NGR. An aggregated version of the MCE report will also be published by the AER on its website as soon as practicable.[158]

More information on the new regulatory framework is available in chapter 6.

153 Department of Industry, Science, Energy and Resources, Regulatory amendments to increase transparency in the gas market, 19 November 2020.

154 Greenfields (new) pipeline projects are eligible for a greenfields incentive determination (which protects the pipeline from becoming a scheme pipeline for up to 15 years from commissioning) and a greenfields price protection determination (which specifies prices for pipeline services that are binding on an arbitrator in the event of an access dispute).

155 For pipeline service providers – Part 10 of the NGR and for standalone compression and storage facilities – Part 18A of the NGR.

156 Exemptions to reporting obligations are available to facilities with no third-party users, where facilities would be exempt from all reporting obligations. Single user pipelines, or those with a capacity of less than 10 TJ per day are able to seek an exemption from the obligation to publish historical and service usage information.

157 Previous concepts of 'full regulation', 'light regulation' and 'Part 23 regulation' are described in previous State of the energy market reports. Full regulation involved negotiation and arbitration with reference tariffs approved by the regulator and contained a regulatory-oriented dispute resolution mechanism.

158 Pursuant to section 63B(4) of the NGL.