4 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.[216] Much of the chapter is focused on markets facilitated by the Australian Energy Market Operator (AEMO), but also includes information on bilateral commodity gas trades up to a year in duration.[217]

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 43% of Australia's total gas production.[218]

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 (Figure 4.1).

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.

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.

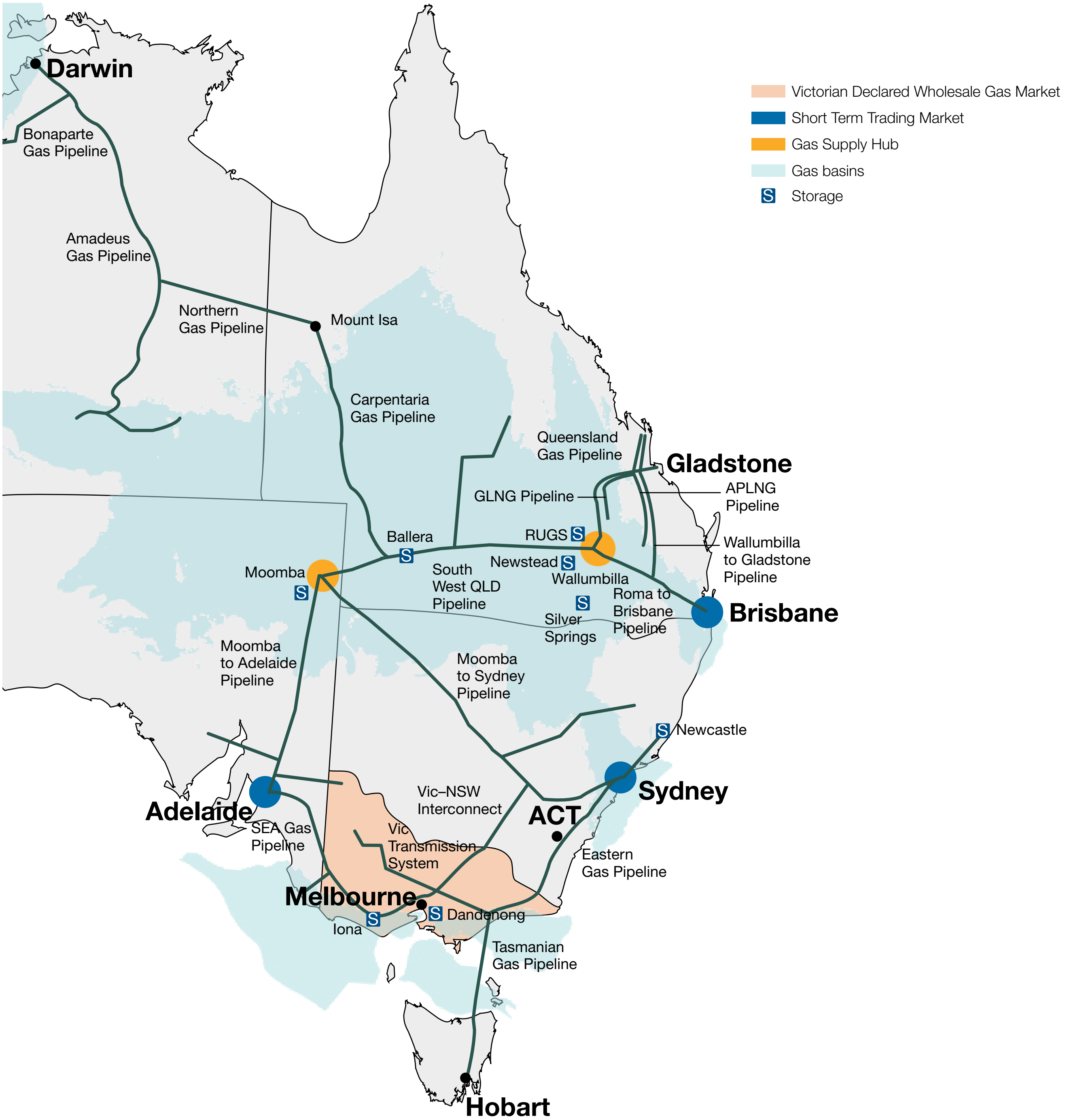
216 The Australian Energy Regulator (AER) has regulatory responsibilities in the eastern Australian gas market in Queensland, NSW, Victoria, South Australia, Tasmania and the ACT.

217 AEMO-facilitated markets includes 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.

218 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 production. Most of Australia's conventional gas resources are located off the north-west coast of Western Australia and at the end of 2023 they accounted for around 56% of total gas production.

Australian exports accounted for 20% of global exports in 2023, alongside Qatar (20%) and the United States (21%).[219] On the east coast, exports account for the majority of gas demand, significantly exceeding domestic consumption levels.[220]

Figure 4.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

219 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, March 2024, p. 71.

220 Compared with residential and commercial, industrial and gas generation demand, LNG demand accounted for around 70% of gas consumption on the east coast in 2023. AEMO, *2024 gas statement of opportunities*, March 2024, p. 12.

Box 4.1 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 AEMO-facilitated auctions for 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. In May 2024, new wholesale market monitoring powers were legislated to facilitate a review of gas contract markets. Additional reporting from 2025 will consider this new information alongside associated spot market impacts and implications on final costs faced by consumers.

The AER also has regulatory responsibilities for transmission and distribution pipelines (chapter 5) and retail markets (chapter 6).

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.

4.1 Gas market snapshot

Since the last *State of the energy market* report:

- Prices in facilitated gas markets stabilised from mid-2023, with milder winter conditions lowering demand and influencing a significant reduction from the unprecedented high prices of mid-2022 (section 4.3).
- In 2024, prices remained stable at around $9 to $13 per GJ until late May when a stretch of cold weather and constrained southern production put upwards pressure on market prices (section 4.3). Daily prices peaked at around $28 per GJ in June and influenced a period of high ancillary payments in Victoria in July (sections 4.3 and 4.5).
- Transportation capacity upgrades on the north–south pipeline corridor to increase the ability to flow more gas south were completed in May and June, delivering more supply from Queensland to southern markets (sections 4.6 and 4.8.3).
- Historically low demand was observed at the end of 2023 alongside lower levels of gas-powered generation (GPG). While lower GPG continued into the first quarter of 2024, the second quarter saw spikes in GPG output to offset low wind and solar generation. This demonstrates the interdependencies between electricity and gas markets in the National Electricity Market (NEM).
- Gas markets remains vulnerable to weather-driven peak demand days when existing supplies to southern states must be supplemented with drawdowns from storage. Southern gas storage inventory at Iona depleted rapidly over June and July 2024 before easing market conditions resulted in storage levels being replenished in August, averting the potential threat of a supply shortfall (section 4.5.4).
- Depleting offshore legacy gas fields in Victoria continue to limit southern production and increase supply shortfall risks, with reduced peak day capabilities declining further from the lower levels of 2023. Projected reductions in coming years are expected to drive a 58% decline in peak day production capacity from the Gippsland region by 2028, with one of Longford's 3 production trains scheduled for retirement after winter 2024 (section 4.5.3).

4.2 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 30% of gas is traded in these spot markets. All other gas trade is struck under confidential bilateral contracts separate to these markets.

4.2.1 Contract markets

The majority of gas in Australia is traded through bilateral contracts, which secure future supply and transportation capacity and limit participants' exposure to price fluctuations in downstream markets. Contract prices generally reflect expectations of future market conditions, but shorter-term transactions in 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.[221]

221 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 2017–2030 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, LNG spot transactions and bilateral short-term supply and swap transactions.

Long-term gas contracts historically locked in prices and other terms and conditions for several years. More recent analysis indicates the industry shifted towards shorter-term contracts (one to 2 years) with review provisions.[222] Although there has been a recent increase in the number of longer-term contracts executed at higher volumes, the overall volumes contracted for 2024 were lower than for 2023.[223]

4.2.2 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 if any arise.

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.

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 organise their gas trade across multiple 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. AEMO is also planning to introduce the Eastern Gas Pipeline and Iona underground storage trade points alongside swap products for the notional transfer of gas between different locations, which can be traded to achieve similar physical outcomes to trading currently existing spread products.[224]

222 ACCC, Gas inquiry 2017–2020, interim report, Australian Competition and Consumer Commission, July 2018, August 2018, pp. 24, 49.
223 ACCC, Gas inquiry 2017–2030, interim report, Australian Competition and Consumer Commission, December 2023, p. 34.
224 The introduction of the Eastern Gas Pipeline and Iona underground storage trade points on 11 July 2024 encountered technical issues. Changes are now expected to be incorporated into the Gas Supply Hub Exchange Agreement effective from 14 November 2024.

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.[225]

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 this 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. Since its inception, the auction has been widely used to move gas between the east coast gas markets. From late 2022, participation in the auction has increased significantly and set consecutive records for capacity won, with amounts procured more than double the highest levels observed across previous years (section 4.6.2).

4.2.3 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 as well as detailed reporting of spot LNG transactions
- short-term gas supply and swap transactions with a contract length up to a year
- 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 that expanded the scope of information reported with some participants required for the first time to report to the Gas Bulletin Board (section 4.11.1).

225 Most gas trading occurs ‘off-screen’ (not traded through the gas markets), but some of these trades are reported to the market operator and settled through the Gas Supply Hub trading platform.

4.3 Gas prices

Gas market prices are typically elevated during winter periods, when colder weather in southern markets increases demand for residential gas heating. This is particularly significant in the larger Victorian market, where daily demand can exceed 1 petajoule (PJ) on cold days. Gas prices can also increase during summer periods, influenced by higher demand for gas-powered generation in the electricity market, which coincides with warmer temperatures and increased demand for air conditioning.

Unlike previous years, winter 2023 temperatures were particularly mild. Prices did increase in the April to June quarter, but this was primarily driven by supply constraints during May rather than the typical price increases observed in June and July when demand is higher.[226] Over the winter months, there was generally lower demand for electricity generation and international prices were low. Alongside significant supply quantities coming south from Queensland, these factors, combined with the lower winter demand, contributed to putting downward pressure on gas market prices.

Prices across the downstream markets remained relatively stable at around $9 to $13 per GJ until late May 2024, when elevated market and gas generation demand occurred at the same time that planned maintenance work at Longford constrained southern supply. Similar factors in June, colder weather and a delayed ramp-up of production at Longford, drove an increased reliance on Iona's underground storage stocks.

4.3.1 Gas contract prices

Gas contracts can take many different forms, with variations in the time between traded and delivery dates, and the timespan in which the gas is delivered over. For example, gas can be contracted to be delivered in daily quantities for weeks or months at a time and can range from 1 to 10 years in length domestically. LNG export contracts are set over longer periods of around 20 years.[227]

Market participants are required to report their gas contract information to the ACCC. The ACCC then reports on these prices through its gas inquiry responsibilities. The inquiry's interim updates consider numerous factors influencing contract prices, including the impact of domestic market supply and market price trends, LNG export activity and links to international prices (section 4.3.4).

Domestic contract prices increased significantly during 2021 and 2022, influenced by international price volatility and global gas supply uncertainties. From mid-2023, domestic gas contract prices rose to be on par with international price levels but remained relatively stable as international prices gradually increased out to the end of the year.[228]

226 Constrained supply at Longford (Victoria's largest production source) due to an unplanned compressor outage and pipeline capacity constraints on the Moomba to Sydney Pipeline drove significant price increases in May 2023.

227 RBA, Understanding the East Coast Gas Market, March 2021, Reserve Bank of Australia.

228 While international price levels had decreased significantly from record highs in the years prior, they remained above the historical trend in mid-2023. International prices declined over 2024, returning to domestic price levels, with domestic prices briefly spiking above international levels in winter.

In 2024, international prices eased, returning to similar levels as domestic prices. However, local prices in winter increased temporarily above international price levels due to the numerous supply and demand factors present in the domestic market, particularly in the southern markets that experienced a prolonged stretch of cold weather.

Contract prices offered in the second half of 2023 for east coast supply across 2024, as observed by the ACCC, averaged $12.60 per GJ for producers and $17.30 per GJ for retailers, a decrease from levels observed in the preceding 6 months.[229] This was a significant decrease to the amount of offers exceeding $30 per GJ during the record high domestic prices over mid-2022.

Following announcements of potential government intervention to address the high prices, 2023 offer prices decreased markedly in late 2022. 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.[230] From 23 December 2022, the Competition and Consumer (Gas Market Emergency Price) Order 2022 (section 4.10.4) 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 under short-term gas supply agreements and traded on facilitated markets.[231] 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.

Over 2023, gradual decreases in contract prices have coincided with a period of more stable domestic price levels from mid-2023 as the east coast experienced a mild winter peak demand period.

Mandatory Gas Code of Conduct ($12 reasonable price provision)

Following the introduction of the Competition and Consumer (Gas Market Emergency Price) Order (section 4.10.4), the Australian Government implemented a Mandatory Gas Code of Conduct (the Code) to replace the order on its expiry in 2023. The Code came into effect from 11 July 2023 with a 2-month transitional period allowed to 11 September 2023, with the aim to ensure users' ability to contract for gas at reasonable prices and on reasonable terms.

The Code adopted a $12 per GJ reasonable price provision and provides an exemptions framework to incentivise short-term supply commitments and investment to meet ongoing domestic medium-term demand. It also includes transparency obligations on uncontracted gas production and expected domestic availability, as well as conduct provisions and process standards for commercial negotiations. The first mandated review of the Code is due 1 July 2025. After the Code was finalised, volumes of 1 year or less transactions for delivery in 2024 increased, most likely due to improved pricing certainty for buyers and sellers.

229 Prices agreed under contracts for 2024 supply were down 26% for producers and 10% for retailers compared with the preceding 6 months. ACCC, Gas inquiry 2017–2030, interim report, June 2024, Australian Competition and Consumer Commission, p. 5.

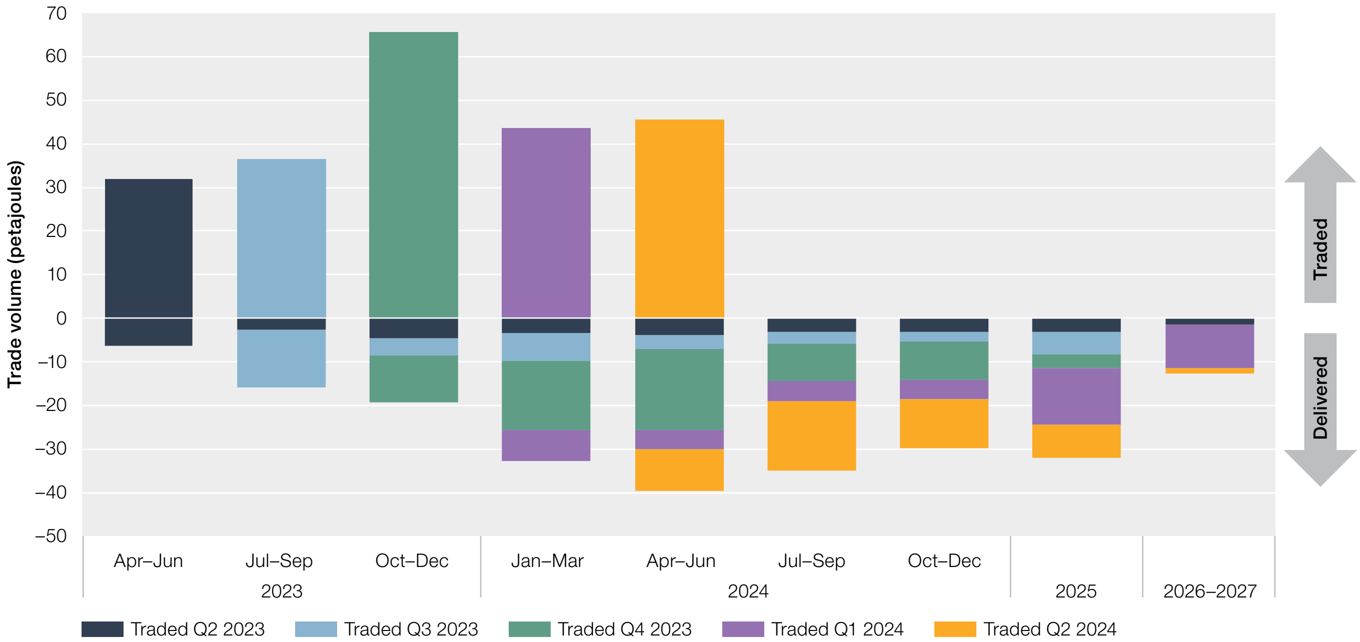
230 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 11.

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

4.3.2 Short-term transaction reporting

From 15 March 2023, information on east coast bilateral gas trades has been published on the Gas Bulletin Board that summarises the reporting of short-term transactions to AEMO as part of the new transparency measures.[232] The information reported covers bilateral trade between parties conducted outside of the AEMO-facilitated markets and includes transactions with a contract length of 12 months or less. Since the majority of gas trade up to 12 months in length is done bilaterally, this information materially improves the comprehensiveness of data available to the AER.[233] Figure 4.2 shows a breakdown by quarter of the traded transactions and the forward period of delivery since April 2023.

Figure 4.2 Traded versus delivered quantities



Note: Traded refers to the trade date of the short-term supply transaction, while delivered refers to the month the gas volume will be supplied. Where there is not enough trades or participants reporting in a period,the data is aggregated to a longer time frame.

Source: AER analysis of Gas Bulletin Board data.

The October to December quarter of 2023 marked a peak in short-term supply transactions reported, with 65.7 PJ traded – nearly 30 PJ more than the previous quarter. This surge appears driven by conditional producer exemptions being granted under the Gas Market Code and the resulting pricing certainty for sellers and buyers. There was a concentrated burst of activity taking place between November and December as participants finalised their contracting positions for 2024.[234] Of the total volume, 75% was contracted for 2024 delivery, with over half of these trades occurring within the $10 to $12 per GJ price range. Nearly two-thirds of trades priced above $12 per GJ were tied to the JKM futures index.[235]

For 2024 so far, approximately 90 PJ of short-term transactions have been reported. Almost one-third of these are for delivery between 2025 and 2027. Approximately half of the January to March 2024 trades were for deliveries in 2025 and 2026. April to June 2024 recorded a slight increase in trading volumes, reaching 45.7 PJ. Of this, 27.2 PJ (around 60%) was allocated for delivery across the last half of 2024 and around 20% over 2025 to 2027.

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

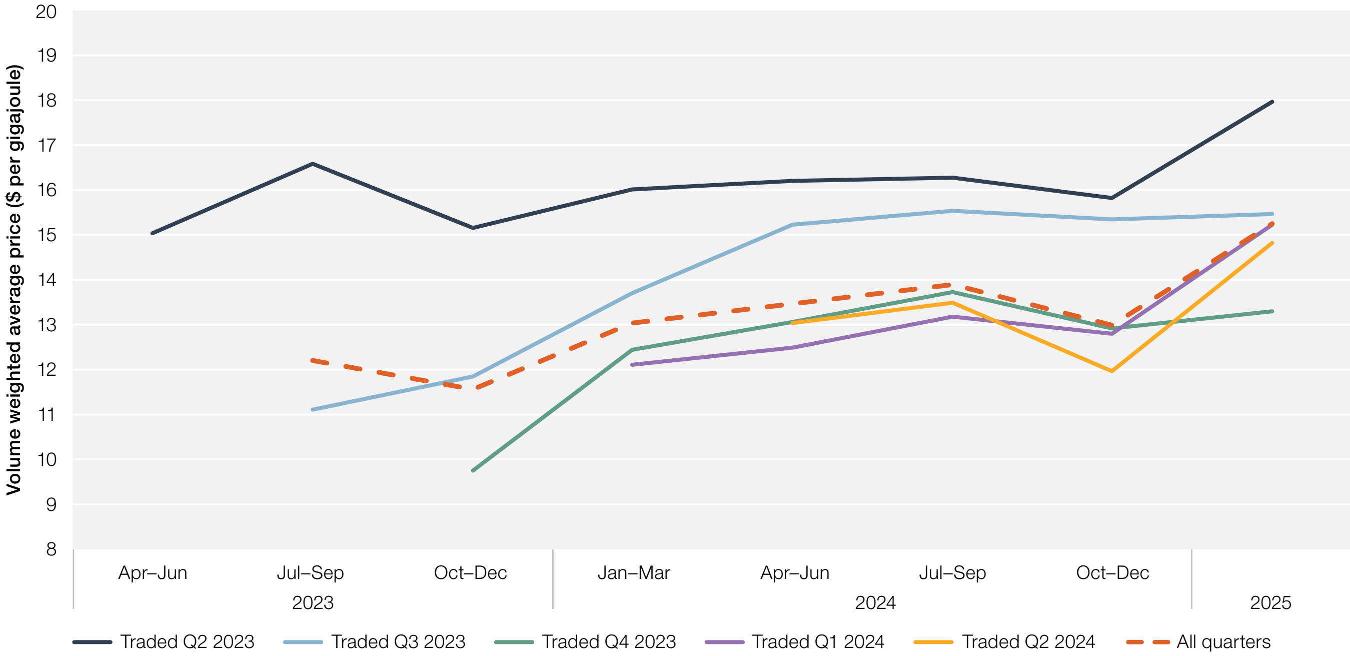
233 The AER published a special report in December 2023 providing analysis and insights into all short-term transactions reported up to 31 October 2023 to the Gas Bulletin Board. The report also includes feedback from industry stakeholders on the effectiveness of current reporting practices and recommendations to enhance this in future reporting. AER, Special report: Wholesale gas short term transactions reporting, Australian Energy Regulator, 6 December 2023.

234 ACCC, Conditional ministerial exemptions for gas suppliers, Australian Competition and Consumer Commission.

235 The Japan/Korea Marker (JKM) is the Northeast Asian spot price index for LNG delivered ex-ship to Japan and the Republic of Korea.

In 2023, the volume weighted average forward price curve for supply transactions declined quarter on quarter. April to June 2024 was the first quarter that average prices increased since reporting commenced (Figure 4.3).

Figure 4.3 Volume weighted average forward price curve based on the traded quarter



Note: The volume weighted average prices are based on the supply dates of the reported transactions in the quarter the transactions occurred. These prices exclude pricing structures linked to the STTM or DWGM. Where there is not enough trades or participants reporting in a period, the data has been aggregated.

Source: AER analysis of Gas Bulletin Board data.

Quarterly volume weighted prices were $12.21 per GJ for gas delivery over July to September 2023 and $11.57 per GJ for delivery over October to December 2023.[236] For gas deliveries in 2024, the volume weighted average prices ranged between $13 and $14 per GJ.

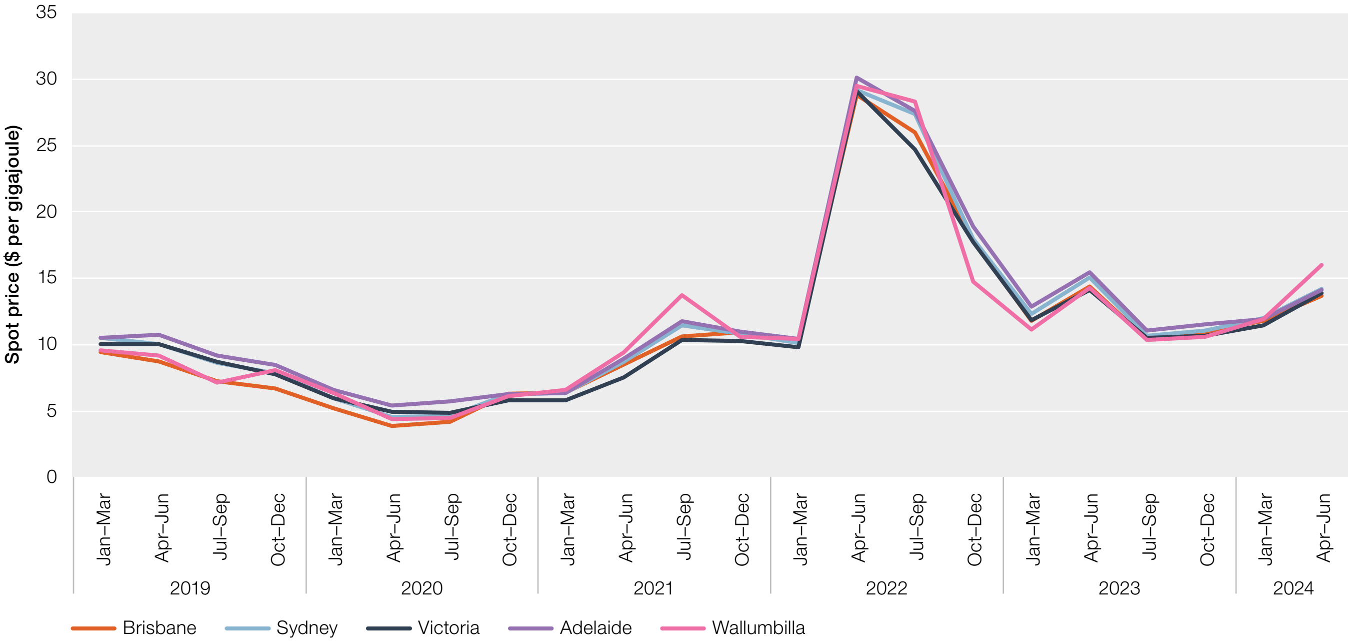
Looking ahead to 2025, forward prices are projected to average $15.26 per GJ based on observed trades to date. This increase is largely driven by the significant volume of contracts secured over the January to March quarter of 2024 at similar price levels. As the year progresses, particularly in the last quarter of 2024, we expect trading volumes for 2025 and beyond to increase as market participants finalise their contracts for the upcoming year. This ongoing activity indicates a market that continues to adjust and evolve in response to changing conditions and expectations.

236 The volume weighted average prices are based on the supply dates of the reported transactions and excludes pricing structures linked to the STTM or DWGM.

Spot market prices

Gas spot market prices over 2023 initially sat above historical price levels but stabilised from mid-2023 onwards. A temporary upturn in prices in the April to June quarter of 2024 primarily resulted from tight supply-demand conditions in Victoria over winter. However, quarterly prices in downstream markets remained below levels over the same period in 2023, despite much colder conditions in comparison to the mild 2023 winter (Figure 4.4).[237]

Figure 4.4 Eastern Australian 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 (WAL product location). 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 spot market prices stabilised from mid-2023

Lower prices from mid-2023 were influenced by an unusually warm winter driving lower gas market demand. In the July to September quarter of 2023, lower gas-powered generation and market demand saw prices reduce slightly below quarterly levels observed in 2021 ahead of the record highs in 2022. During the third quarter of 2023, higher renewable energy output and reduced electricity prices saw gas generation record its lowest July to September quarterly output since 2004.[238] Grid-scale variable renewable energy output reached an all-time quarterly high in the October to December quarter of 2023, with gas-powered generation falling slightly again.[239] Decreasing international export prices from late 2023 also put downward pressure on domestic gas prices heading into 2024.

In 2024, historically low gas market demand put further downward pressure on prices despite the return of higher volumes of exports from late 2023.[240] Short periods of suppressed gas prices also resulted in retailers offloading contracted supply into the downstream markets at the end of September. Additional export supply entered downstream markets in late-November due to an export carrier becoming stranded at the Curtis Island LNG facility (Figure 4.5).

237 Cold weather and constraints limiting production and transportation capacity drove up prices just before winter 2023, resulting in higher prices over the April to June quarter.

238 Black coal generation also fell to its lowest July to September quarterly average since the start of the NEM. AEMO, Quarterly Energy Dynamics Q3 2023, Australian Energy Market Operator, October 2023, p. 25.

239 AEMO, Quarterly Energy Dynamics Q4 2023, Australian Energy Market Operator, January 2024, p. 4.

240 This was despite a month of reduced supply capacity at Longford, Victoria's largest production facility, with participants utilising the high levels of storage at Iona to supply the market.

Gas spot market prices in 2024

From June 2023 to the end of April 2024, monthly average prices in downstream markets ranged from $8.82 per GJ in Victoria to $12.95 per GJ in Adelaide. Following the period of stable prices from mid-2023, prices increased above $13 per GJ from 20 May. This was driven by a combination of higher demand and constrained supply, which prevented Victoria's underground storage facility at Iona fully restocking ahead of winter. The price impacts of these events flowed through to other downstream markets in Sydney and Adelaide, and to a lesser extent in Brisbane.

Compared with the week before, Victorian demand increased by around 100–150 TJ per day from 21 May due to cold weather driving up residential heating demand. At the same time, gas-powered generation (GPG) demand increased across mainland regions in response to higher electricity demand. Increases in southern demand coincided with Victoria's largest supply source at Longford operating at reduced capacity during a period of offshore maintenance.[241] To meet the increased demand, participants drew down on Iona storage at an average of just over 300 TJ per day. Although gas flows south from Queensland had increased from the start of May, with further increases of around 100 TJ per day or more from late May, this did not correspond to additional interstate supply making its way into Victoria over the period of elevated prices that continued over the following week.

Following the period of relatively flat levels of downstream market trade over 2023, net trade volumes started to rise in May 2024 and reached over 6.5 PJ across June, returning to more typical trends that would be observed over the winter period. Day Ahead Auction activity was also high from June, with transportation capacity levels won by participants exceeding previous records for June and July.[242]

From June 2024 pipeline capacity expansions on the transmission corridor between Queensland and south-east Australian demand centres were completed, allowing for more gas supply to flow to southern markets (section 4.8.3). Despite this, similar price increases occurred on 4–5 June and 2 July, driven by the same factors that occurred in May, with further increases in demand levels driven by colder weather.[243] However, the most significant daily price increases occurred over 13 June to 24 June, with prices in downstream markets reaching a peak of $28 per GJ on 20 June (Figure 4.5). Tight supply and demand conditions in southern markets and elevated gas-powered generation requirements across mainland regions contributed to the price increases, with lower than expected supply from Longford in Victoria driving a greater reliance on Iona storage supply.[244] This led to the rapid depletion of Iona's underground gas storage levels despite significant gas flows south from Queensland. AEMO identified this as a potential threat to system security (section 4.5, Box 4.2).[245]

Figure 4.5 sets out an annotated timeline of key pricing events in 2023 and 2024 to date.

241 Capacity at the Longford production facility was capped at a bit below 550 TJ per day over May, around half the facility's nameplate capacity rating.

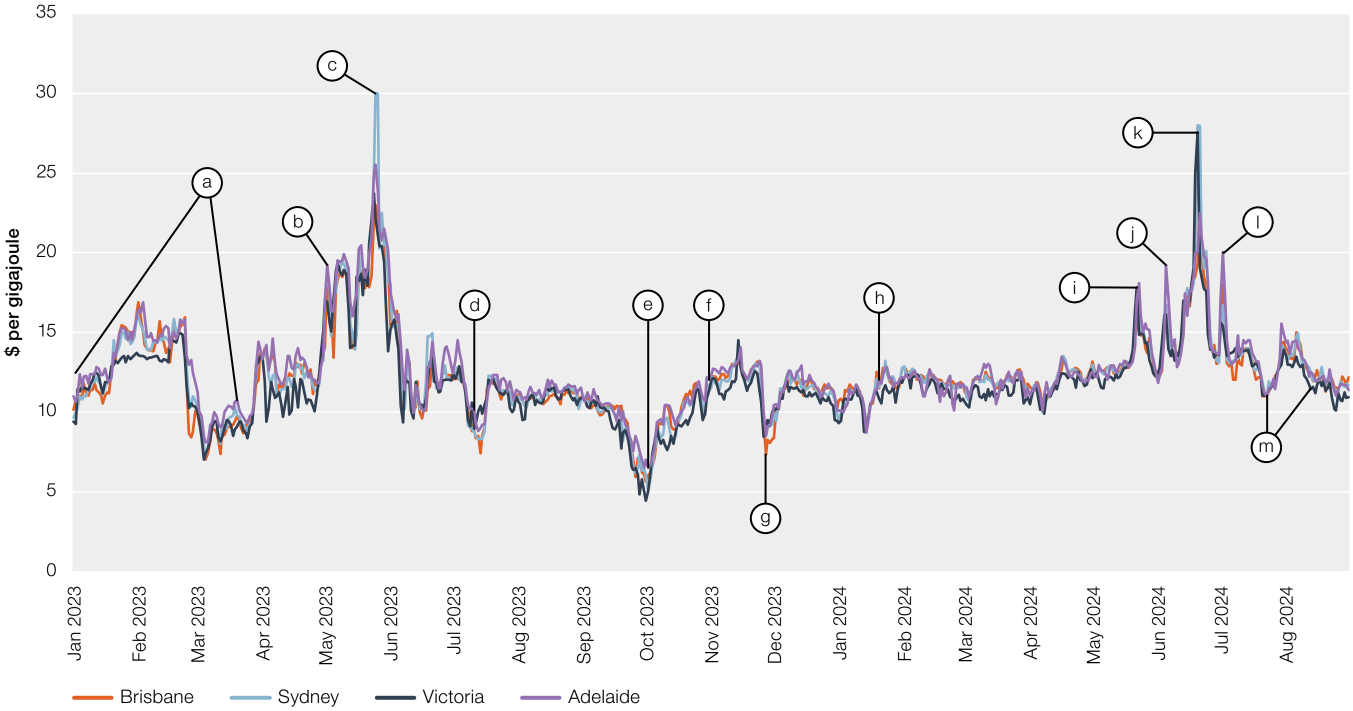
242 Auction capacity won in June totalled 13.9 PJ (close to 4.6 PJ higher than the record set the previous year), with capacity in July totalling 12.1 PJ (2.7 PJ higher than July 2023).

243 Maximum temperatures in Melbourne averaged just over 14 degrees over that period, with minimum temperatures averaging below 9 degrees. On 19 June, the temperature in Melbourne dropped to 1.4 degrees, contributing to prices spiking in downstream markets.

244 Longford provides most of Victoria's gas supply, with Iona the second largest supply source in the region.

245 AER, Wholesale markets quarterly – Q2 2024, Australian Energy Regulator, July 2024.

Figure 4.5 Daily gas spot prices



Note:
- a 27 December 2022 to 19 January 2023 and 22 February to 8 March: QCLNG planned maintenance outages influencing additional production capacity becoming available to downstream market participants.
- b May 2023: Cold weather and constrained supply from Longford influencing higher prices in Victoria, which flowed through to other markets.
- c 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.
- d 8 to 16 July 2023: Warmer weather driving a decrease in downstream market demand. An unseasonably warm winter resulted in the lowest observed July to September quarterly demand over the past decade.
- e Late September 2023: Lower than expected gas demand led to retailers offloading contracted (take-or-pay) supply at low prices at the end of the quarter.
- f Mid-October into November 2023: Higher export volumes put upwards pressure on domestic prices.
- g Late November 2023: A boost in domestic sales from export supply due to an LNG export carrier becoming stranded at the Curtis Island export facility. The docked vessel became stranded on 22 November and prevented the refill of 3 LNG tankers before its departure on 1 December.
- h From mid-January 2024: Increased price stability in downstream markets, with historically low market demand offsetting elevated LNG export flows.
- i 21 to 23 May 2024: Cold weather driving increased heating demand, offshore maintenance constraining Longford supply and elevated mainland GPG demand.
- j 4 to 6 June 2024: Cold weather demand and elevated GPG and delayed Longford ramp-up following maintenance.
- k 18 to 22 June 2024: Continuing constrained output from Longford with high demand and high GPG, continued reliance on Iona storage supply and elevated Tasmanian GPG demand due to drought conditions reducing hydro-electric generation. A pipeline constraint in Victoria also resulted in significant ancillary payments to compensate for the scheduling of higher priced gas.
- l 1 to 2 July 2024: High market demand and elevated GPG.
- m 21 to 26 July and 11 August 2024 onwards: Reduced market demand and GPG eases price pressures, with an unseasonably warm end to winter in August.

Source: AER; AEMO (raw data).

Significant price variations in June 2024

During the period of elevated prices in June, an issue with a new pipeline segment in Victoria restricted the supply capability of facilities located in the west of the state.[246] This resulted in the requirement to source higher-priced supply from other supply points in the Victorian market, resulting in ancillary payments to recover increased supply costs. From 18 to 21 June, daily ancillary payments levels above $89,000 breached the AER's significant price variation reporting threshold of $250,000 on 2 occasions.[247] These events were investigated and summarised in a significant price variation report published on the AER website.

4.3.3 2023 local prices and international price trends

Annual domestic prices decreased over 2023 following unprecedented price increases in 2022. While prices reduced by 43% compared with 2022 levels, they still remained elevated – sitting around 34% higher than average downstream market prices in 2021.

Factors contributing to prices decreasing from 2022 levels included low market demand and gas generation levels across the year.

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. In previous years (2021 and 2022), domestic contract prices increased yet remained well below increases in international price levels, which were up almost 230%.[248]

From late 2021 during the Northern Hemisphere winter, competition between Asian, European and South American buyers combined with higher demand to replenish European storage levels, driving up prices in Asia. By mid-2022, domestic prices converged with surging international prices as unprecedented local price increases[249] coincided with a brief dip in international price levels (Figure 4.6).[250] After peaking in late 2022, international price levels reduced significantly into 2023 but remained elevated compared with historical levels.[251]

From mid-2023, domestic prices were on par with international price levels and remained relatively stable as international prices gradually increased out to the end of the year.[252] At the end of 2023, European storage inventories entered the October to December quarter at a record high of 97% full alongside record floating storage supply.[253] High storage over the quarter and a mild Northern Hemisphere winter suppressed demand,[254] reducing pressure on international prices into 2024 alongside increases in other sources of LNG supply.[255]

246 High vibration levels during low flow conditions at the Wollert compressor's Pressure Reduction Station on the eastern end of the Western Outer Ring Main (WORM) – see section 4.8.3 – necessitated the requirement for capacity reductions to test and locate the source of the problem.

247 On 19 and 21 June 2024, ancillary payments accrued to $354,957.62 and $341,944.79, respectively, across the gas days.

248 In prior years (2019 and 2020), domestic gas contract prices tended to track falling international prices, measured using LNG netback prices. LNG netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting gas rather than selling it domestically.

249 Local price increases drove multiple markets into administered price states, resulting from numerous overlapping factors. Higher international prices strengthening export incentives, NEM constraints impelling significant gas generation requirements, and high residential heating demand during a particularly cold winter, contributed to a very tight supply and demand balance across the east coast.

250 The Russian invasion of Ukraine in early 2022 drove other countries to diversify supplies in oil and gas, impacting global supply chains. Despite the curtailment of Russian gas supply to Europe, increases in underground storage levels saw international prices briefly dip below $30 per GJ in mid-2022. However, this was followed by subsequent Russian supply threats and pipeline flow reductions, and an explosion at Freeport LNG, which removed a significant amount of US LNG supply from the market.

251 Rising storage inventories, particularly in Europe, influenced the decline in international prices. However, domestic prices linked to international gas prices exceeded historical levels as domestic and international prices converged again in mid-2023.

252 While international price levels had decreased significantly from record highs in the years prior, they remained above the historical trend in mid-2023.

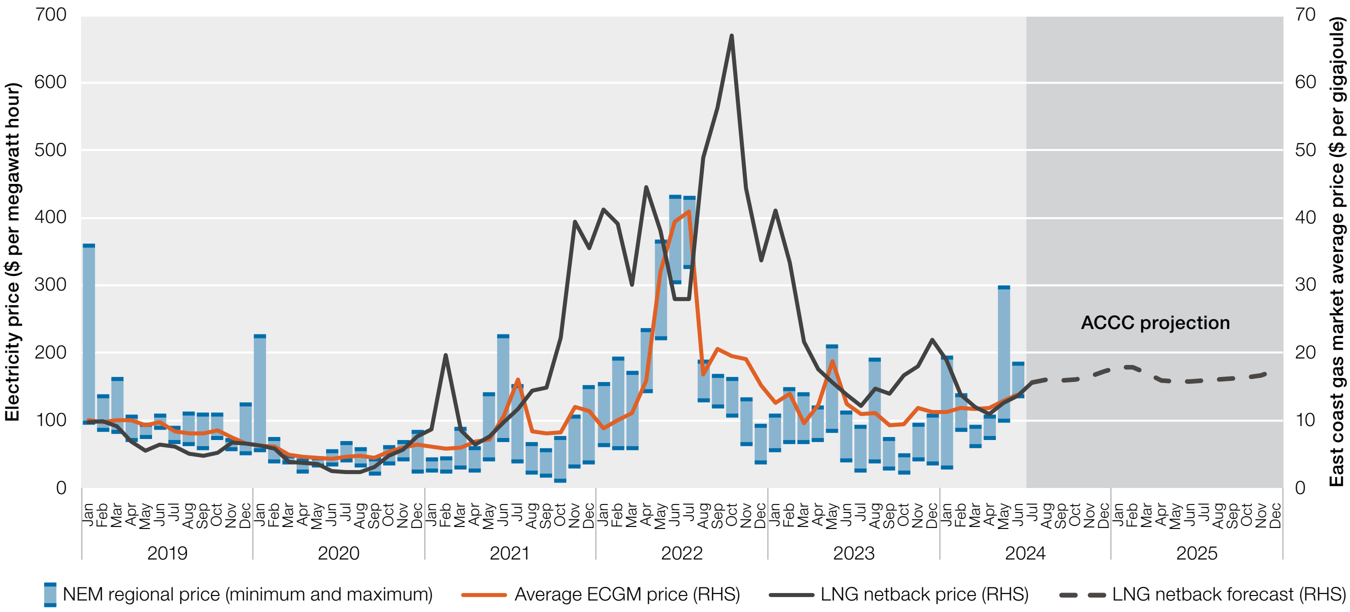
253 AER, Wholesale markets quarterly – Q4 2023, Australian Energy Regulator, January 2024.

254 Storage levels rounded out the quarter at 87% of capacity. Argus direct, *Europe LNG: Des prices tick down*, 29 December 2023.

255 LNG availability from the United States increased by 6% and Norway's availability was also up 1.5% following the resolution of unplanned outages from 2022.

In 2024, international LNG spot prices gradually decreased across January and February before starting to rebound slightly from March, with prices in February reaching some of the lowest levels observed over the past 2 years. By winter, local prices had risen above international price levels due to numerous supply and demand factors, particularly in the southern markets that experienced a prolonged stretch of cold weather (Figure 4.7).

Figure 4.6 Comparison of east coast gas market, NEM and LNG netback prices

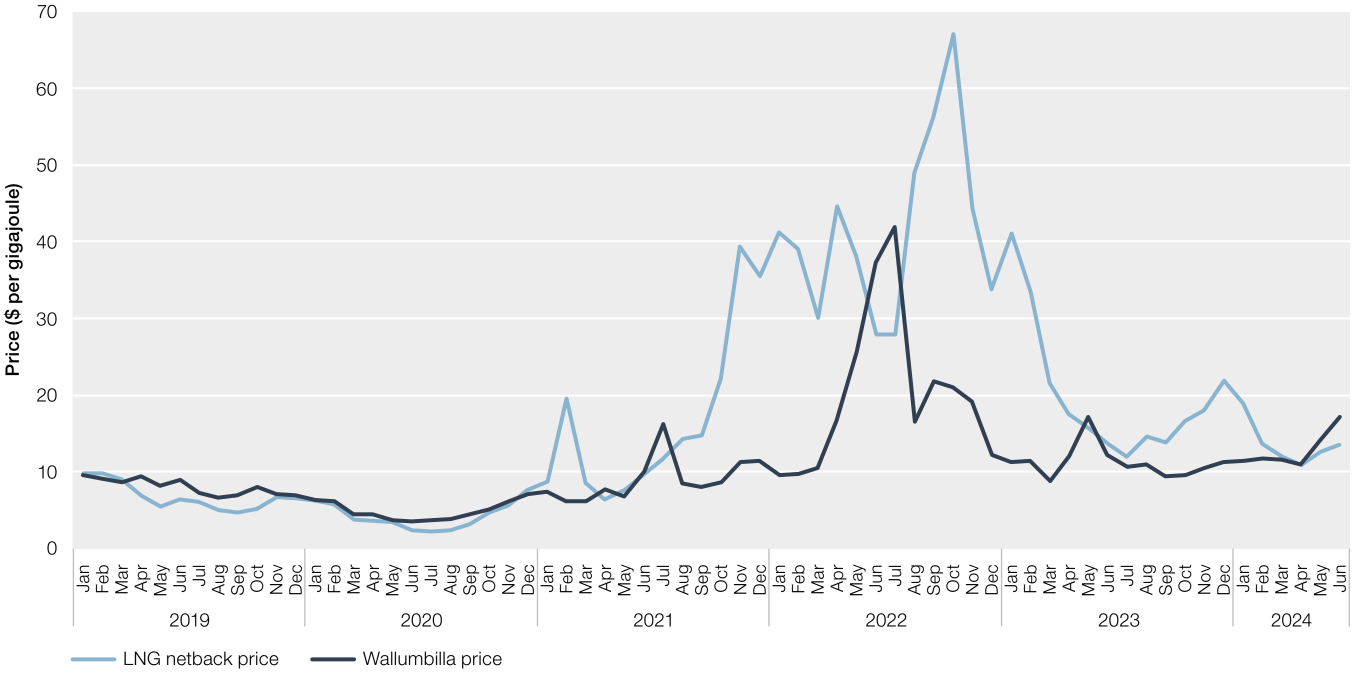


Note: ECGM is east coast gas market. NEM is National Electricity Market. The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers. LNG netback forecast 28 June 2024.

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 4.7 LNG netback and Wallumbilla prices

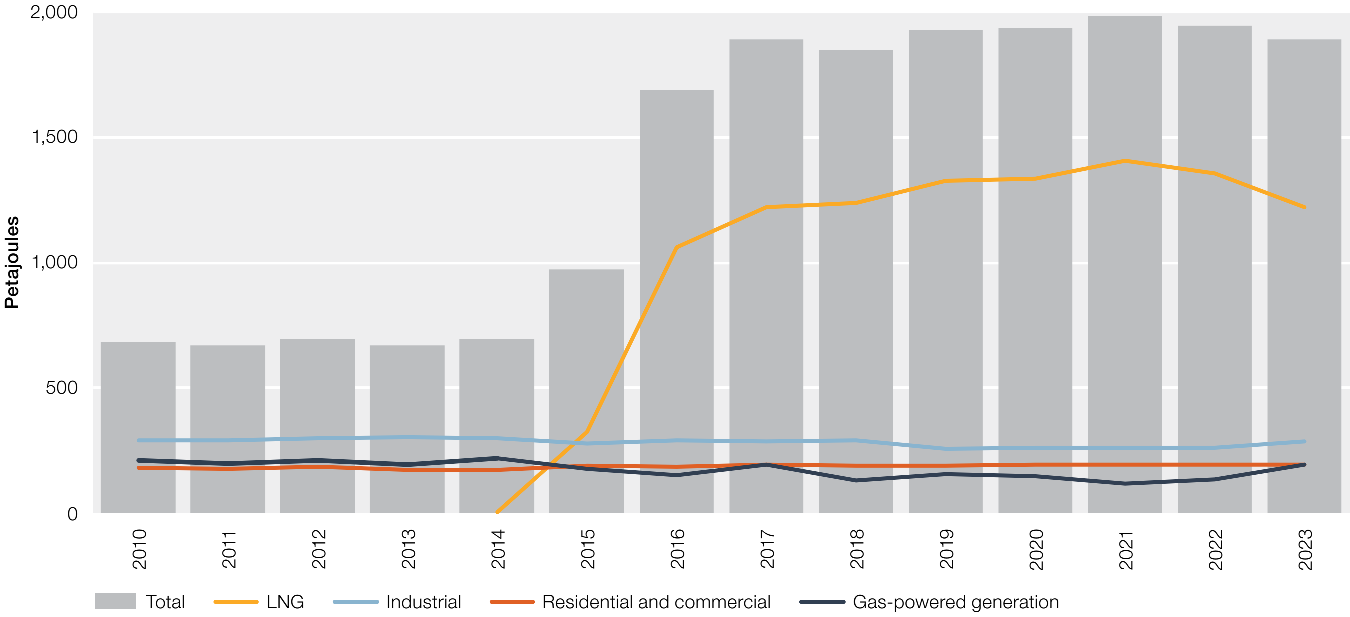


Note: The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers.
Source: AER analysis of gas supply hub data; ACCC (LNG netback prices).

4.4 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 4.8).

Figure 4.8 Eastern Australian gas demand



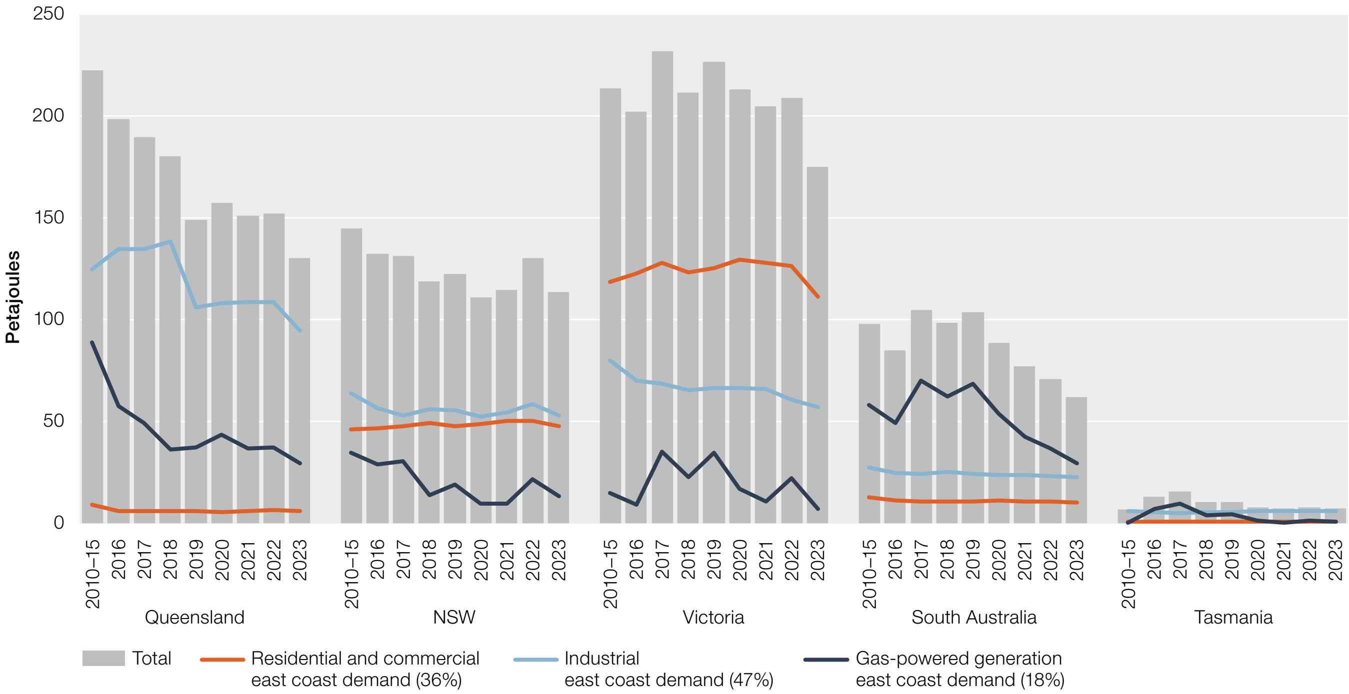
Source: AEMO, *2024 Gas Statement of Opportunities*, March 2024.

4.4.1 Domestic demand

Domestic customers in eastern Australia used around 490 PJ of gas in 2023 (Figure 4.9). These customers included industrial businesses, electricity generators, commercial businesses and households.

Industrial customers consumed 48% 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 4.9 Eastern Australian gas demand, by state



Note: Data for 2010–15 is average annual consumption over that period.
Source: AEMO, *2024 Gas Statement of Opportunities*, March 2024.

Residential and commercial customers accounted for 36% of domestic gas demand, but this share varied 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 5%.

The electricity sector is another major source of gas demand, accounting for 21% of domestic gas use in 2023, down from 29% in 2017. South Australia and Queensland used the most gas-powered generation (GPG) in 2023 (each using 37% 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 relevant drivers such as weather, availability of other fuel types and unforeseen events.[256]

256 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.

Gas-powered generation use in 2023 and 2024

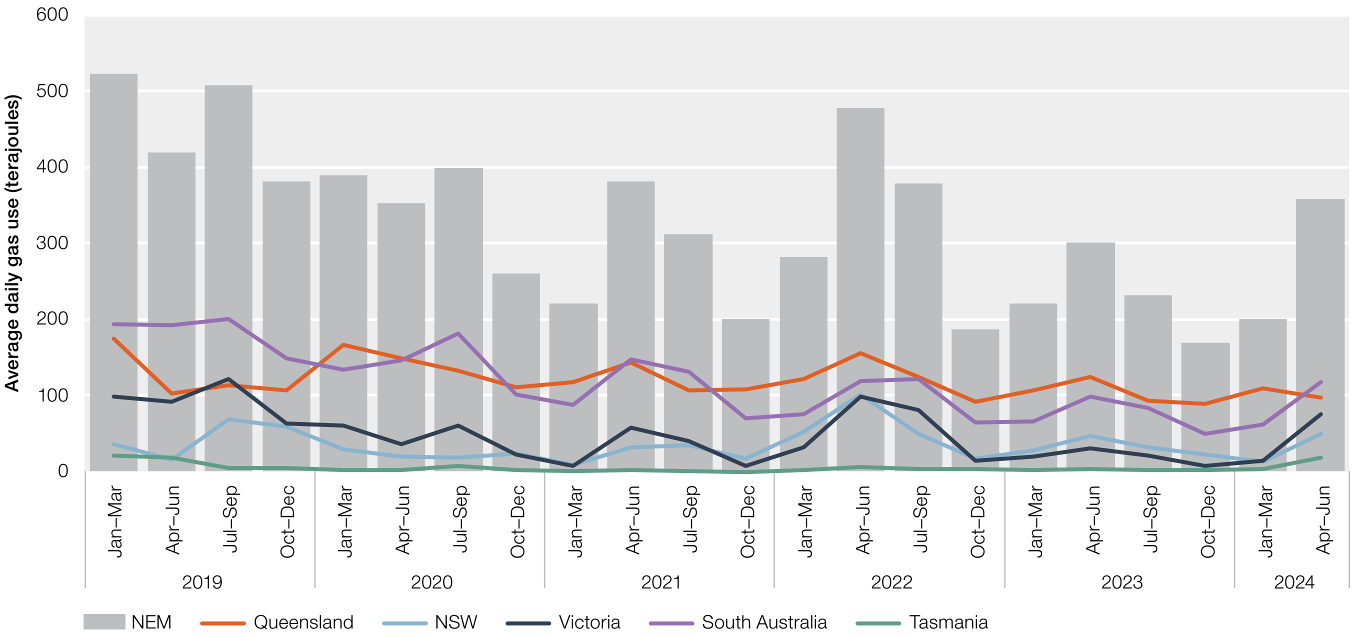
In 2023, gas-powered generation (GPG) gas usage was lower across mainland regions (Figure 4.10). New South Wales GPG gas usage reduced to almost half of 2022 GPG levels at 11.6 PJ, and the other states recorded their lowest yearly levels of GPG gas usage over the past decade, ranging from 7 PJ in Victoria to 37.6 PJ in Queensland.

GPG gas usage increased in the January to March quarter of 2024, but GPG demand was also at its lowest Q1 demand level observed over the past decade. In the April to June quarter, low wind and shorter days reduced wind and solar generation. This resulted in increased generation from higher priced gas and hydro generators, driving higher electricity prices in the southern regions.[257]

This illustrates the ongoing complexity of gas generation acting as a firming capacity in the NEM. Demand for GPG to fill in for low renewable generation output levels can be unpredictable at times and may coincide with elevated gas demand due to colder weather and electricity system constraints, potentially leading to gas shortfalls. Despite generally declining demand for gas across the east coast, GPG demand is projected to increase in the coming years unless new renewable sources of firming capacity can be found to replace it. AEMO's Integrated System Plan (ISP) forecasts flexible gas capacity of 8.8 GW will be needed by 2030–31, climbing to 15.4 GW by 2051–52.

Projections indicate 7.8 GW of the existing GPG fleet will still be in service by 2030. A total of 750 MW of committed generation, and 200 MW of anticipated GPG will be needed to avoid generation shortfalls between now and 2030. New generation capacity of 12.8 GW is needed by 2051–52.[258] At the same time, governments are taking actions to reduce consumption of natural gas in order to meet net zero commitments. These include electrification where possible and investments into alternative fuels where electrification is not suitable, such as industrial processes involving high temperatures or where methane is a feedstock rather than a source of energy. This poses challenges to the market in identifying least cost options for avoiding shortfalls while also minimising the creation of redundant investment. The various actions being taken to stabilise supply-demand balances are discussed further in section 4.10.

Figure 4.10 Quarterly gas demand for gas-powered generation



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

257 AER, Wholesale markets quarterly – Q1 2024, Australian Energy Regulator, April 2024.
258 AEMO, 2024 Integrated System Plan (ISP), Australian Energy Market Operator, June 2024.

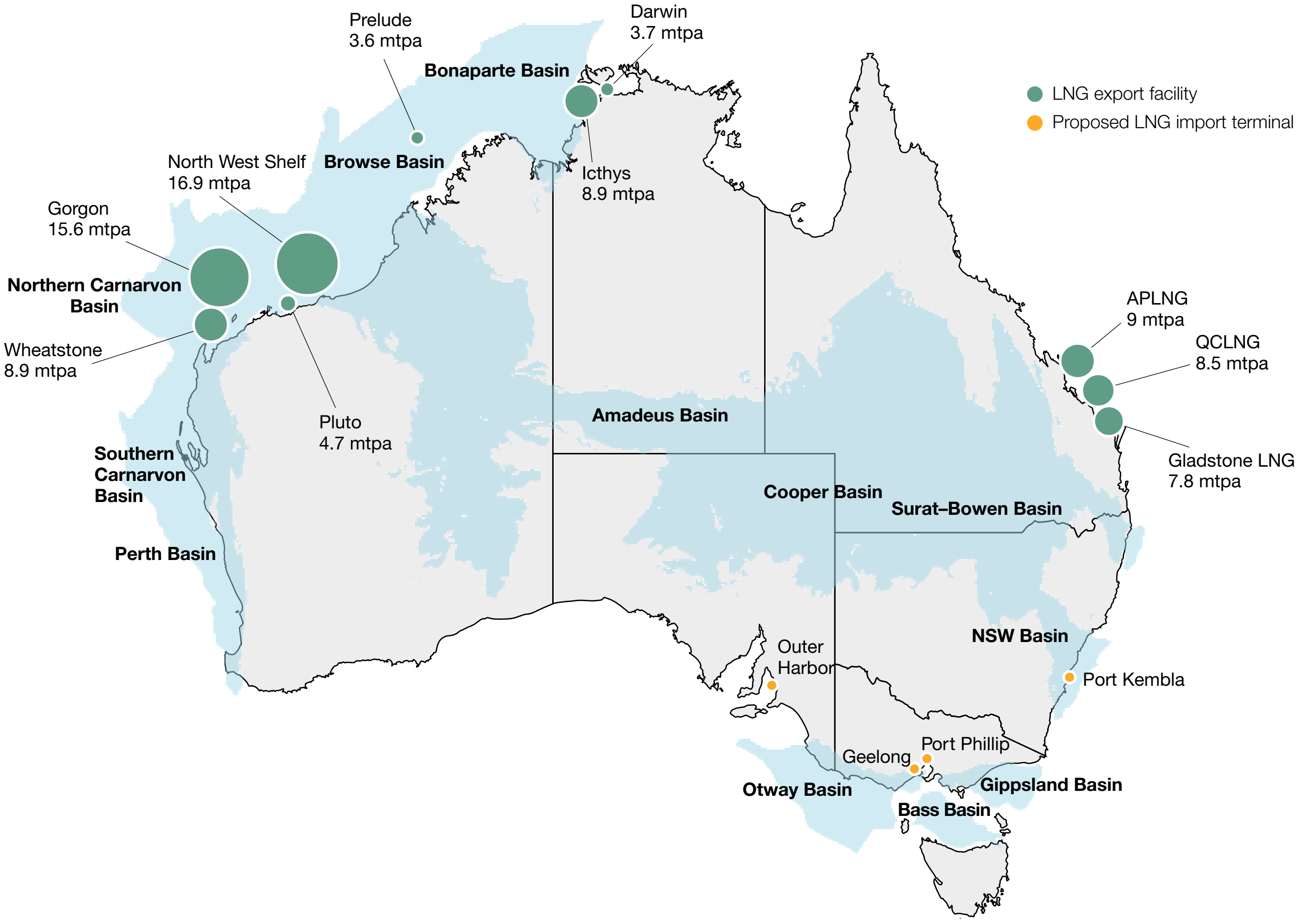
4.4.2 Liquefied natural gas exports

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 4.1). Australia also operates 5 LNG projects in Western Australia and 2 in the Northern Territory (Figure 4.11).

In 2023 LNG exports totalled $74.7 billion, a historically high level but down from the 2022 total of $91 billion. Gas remains one of Australia's largest resource and energy exports behind coal and iron ore. Australia was the second highest exporter of gas in 2023 behind the United States, following the restart of Freeport LNG in Texas.[259]

Figure 4.11 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 2024.

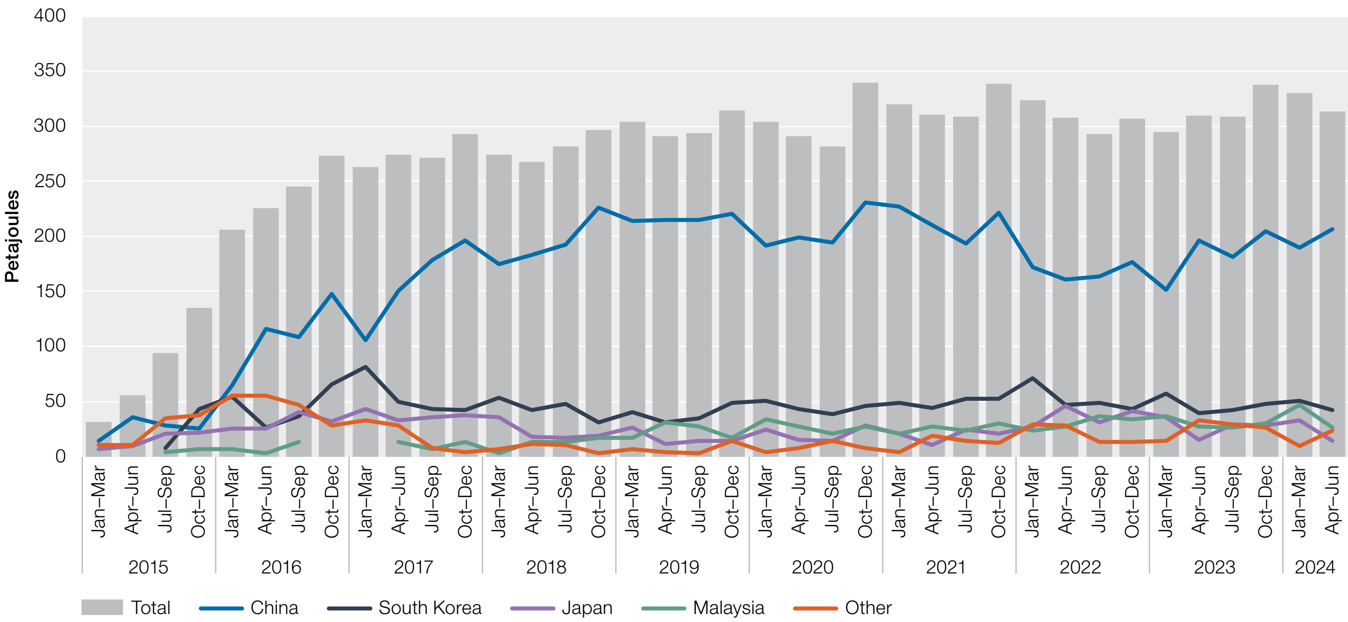
259 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, March 2024.

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

- 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) collectively own the project.
- Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. Santos (30%), Petronas (27.5%), Total (27.5%) and Kogas (15%) collectively own the project.
- Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa. Origin Energy and ConocoPhillips (37.5% each) and Sinopec (25%) collectively own the project.

These LNG projects control close to 90% of 'proven and probable' (2P) reserves in eastern Australia.[260] They also source gas from other producers through long-term production contracts and spot markets to manage volatility and ensure they can meet their long-term exports supply obligations. East coast gas exports are typically lower mid-year, when the gas produced supplements increased domestic demand over winter, and higher over the rest of the year as Northern Hemisphere winter conditions drive up international demand.

Figure 4.12 Eastern Australian gas exports



Source: AER analysis using Gladstone Port Corporation data.

East coast LNG exports have risen consistently since they began in 2015, until 2022 when they reduced. They remained at relatively lower levels across 2023 compared with the record high volumes exported in late 2020 and 2021, but began to climb again from late 2023. Exports across the first half of 2024 rose to quarterly record levels of up to 330 PJ (Figure 4.12). In December 2023, total export pipeline deliveries to Curtis Island reached their highest daily flow rates above 4,300 TJ per day on 2 occasions.[261]

In 2023, China was the primary market for eastern Australian LNG, accounting for 59% of exports (733 PJ). This was a significant increase from the previous year's 674 PJ.[262] China's combined gas and LNG imports from Australia and other countries remained strong in 2024, increasing to a record level for July assisted by a scheduled rise in gas flows from Russia.

260 ACCC, Gas inquiry 2017–2030, interim report, December 2023, Australian Competition and Consumer Commission, December 2023, p. 27. 2P reserves represent proven and probable reserves (probable reserves are deemed 50% likely to be commercially recoverable).

261 On 22 December (4,338 TJ) and 31 December (4,341 TJ).

262 In 2022, high prices and lockdowns in China alongside higher pipeline supply from domestic production influenced reduced imports from Australia, with the country also sourcing additional imports from Russia.

International gas markets have been relatively stable over the past year, with no significant disruptions this year so far. While exports were at record levels for the April to June quarter, export demand declined in winter and the ramp-up in export flows did not impact the high level of domestic gas flows transported south from Queensland (Figure 4.22).

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).

4.5 Gas supply in eastern Australia

Gas supply to the northern gas market is largely supplied from Queensland's Surat–Bowen Basin. Gas is also sourced from the Cooper Basin in South Australia and was supplemented by supply from the Northern Territory from 2019 to 2024. Gas from the northern fields is required to supplement Victorian gas production to meet domestic gas demand in southern Australia over winter. At other times of the year, southern gas is also transported north to meet LNG export demand. Ensuring sufficient gas remains in Australia to service the domestic market is a key priority for governments. Both AEMO and the ACCC regularly assess and publish analysis of the future supply conditions and the likelihood of future shortfalls so that these can be addressed ahead of time.

4.5.1 Background

Southern states rely on local gas production to supply the majority of their demand levels. However, as production in southern states has slowed, gas has also been sourced from Queensland.

Victoria's Gippsland Basin output has been falling due to the depletion of legacy fields supplying the Longford gas plant.[263] From 2023, east coast gas users have become more reliant on northern production. While Gippsland's 2024 production forecasts were higher than the previous year's estimate, Gippsland's projected peak day production has been falling since 2022 and dropped to 767 TJ in mid-2024, representing a significant decrease compared with actual peak production levels prior to 2023.[264]

4.5.2 Current conditions

Despite historically low average gas demand levels in recent quarters, colder weather from late May 2024 drove up southern demand compared to winter 2023 when weather conditions were milder. Due to the significant changes in demand driven by cold weather, southern gas markets are persistently vulnerable to cold weather events. This year, tight supply and demand conditions have arisen with reduced production capability at Longford, Victoria's largest source of supply. This has increased participants' reliance on obtaining gas from southern storage and Queensland gas fields to meet demand in southern markets. Other events in the Northern Territory and Tasmania have also put upward pressure on the tight supply-demand conditions in southern markets.

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

264 Reduced production forecasts from 877 TJ per day until mid-2024 coincide with the retirement of Longford's Gas Plant 1, with the expected retirement of Gas Plant 3 later this decade set to leave only a single plant in operation. This will lead to a significant reduction in output from the facility's legacy fields. AEMO, 2024 Gas Statement of Opportunities, Australian Energy Market Operator, March 2024, p. 5.

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.[265] AEMO's 2021 outlook had improved from previous years due to planning progress for Australian Industrial Energy's (AIE) 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 regasification unit to receive and supply the gas in coming years.

Longford production decline and increased reliance on Iona underground storage

Low production output from Longford beginning in early 2024 led to participants utilising Iona storage supply much earlier in the year than in 2023. Iona was at record high levels for the beginning of the year and replenished supplies from mid-February to a peak of 24 PJ in mid-April ahead of winter. The early onset of cold weather drove a rapid drawdown in storage levels from late May. This was exacerbated by prolonged supply capacity restrictions at Longford following planned maintenance that took longer than expected, and the facility was only able to gradually ramp up production capacity over June (section 4.5.3, Figure 4.16).

As a result, the heavy reliance on Iona storage supply caused a rapid drawdown on Iona's storage inventory, similar to the record rates of depletion observed in 2021 and 2022, despite record gas flows bringing gas south from Queensland (Figure 4.22).[266] On 19 June, AEMO highlighted the potential for upcoming supply issues in a system-wide notice to market participants. In early August, Iona's storage fell below 10 PJ (Figure 4.21) but began to recover over the rest of the month as winter weather conditions eased.

Due to the significant changes in demand driven by cold weather, southern gas markets are persistently vulnerable to cold weather events.

Box 4.2 AEMO East Coast Gas System Risk or Threat Notice[267]

On 19 June AEMO issued a system risk or threat notice, identifying the supply of gas in all or part of the east coast gas system may be inadequate to meet demand. The notice was implemented to remain in place until 30 September 2024, with AEMO outlining an expectation of an industry response to mitigate the system threat and prevent the requirement for market intervention.[268]

AEMO highlighted that reduced storage delivery capacity resulting from low inventory levels heightens the risk to winter supply adequacy on peak demand days.[269]

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

266 Gas flows south this winter were well in excess of levels over 2021 and 2022. Higher flow rates on the north–south pipeline corridor were facilitated by the commissioning of the second stage of delivery capacity expansions in June, adding further compression capability on the South West Queensland Pipeline and Moomba to Sydney Pipeline (section 4.8.3).

267 AEMO, East Coast Gas System Risk or Threat Notice, Australian Energy Market Operator, June 2019.

268 AEMO expectations included:
- participants taking reasonable measures to maximise production and supply from Queensland for delivery to southern jurisdiction end users, to reduce the rate of storage depletion
- consideration of specific gas demand requirements (including GPG) and the supply sources required to meet that demand.

269 Other potential risks outlined by AEMO identified and included:
- gas supply and demand trends in southern jurisdictions and the impact of storage inventory depletion, particularly at Iona
- the combination of lower than forecast Longford production and high seasonal demand and GPG, which has already significantly impacted Iona's storage levels
- constrained Longford production and the expected impact on continued high withdrawals from southern storage
- expected storage depletion resulting from unplanned events impacting demand or supply
- the southern supply capacity impacts due to low or depleted storage inventory.

Iona plays a crucial role in supporting elevated demand through winter. Upgrades to the Iona storage facility in June 2023 have increased storage capacity to a nameplate rating of 24.4 PJ, with works to add another 3.3 PJ of storage capacity by 2026 (section 4.5.4). Additional compression and pipeline capacity expansions were also commissioned before winter, enabling higher gas flows from western Victoria to meet demand in the Victorian transmission system. This allows Iona to supply and refill from the Victorian market faster, but also increases participants' ability to draw down storage to critically low levels before the end of the peak winter demand period (section 4.8.3).[270]

Northern Gas Pipeline gas shortfall

As southern demand for gas from northern regions increases, supply previously provided to the east coast from the Northern Territory from 2019 has ceased. Production issues at the Blacktip offshore gas fields has led to the pipeline connection between Queensland and the Northern Territory being restricted. Demand on the Carpentaria Pipeline is now reliant on gas supplies from south-east Queensland to fuel industrial demand in the north-west of the state. Work is currently underway to convert the Northern Gas Pipeline to flow gas bidirectionally, allowing east coast supply to be delivered to the Northern Territory to fuel local gas generation, where supply shortfalls triggered a power outage in early February (section 4.8.5).

Tamar Valley power station returned to service in response to Tasmanian drought

Tasmanian gas demand also saw an upturn in late June, with continuing drought conditions impacting hydro-electric generation output. From 6 June, pre-emptive measures were put in place to maintain water storage levels in the state, resulting in the return to service of a gas generation unit at Tamar Valley to fill the gap in local electricity generation requirements.[271] This is the first time in 5 years the state's largest gas-fired generator has produced power, with gas requirements increasing gas flows on the Tasmanian Gas Pipeline by around 35 TJ per day.

Loss of containment event on the Queensland Gas Pipeline

On Tuesday 5 March a loss of containment on the Queensland Gas Pipeline (QGP) resulted in a large fire south-west of Rockhampton (Figure 4.13). AEMO directed Westside to divert gas supply from their Meridian gas production facility, the only main production source downstream of the fire, and issued curtailment directions to downstream consumers. A backflow process was also initiated on the adjacent GLNG export pipeline to support Meridian supply, with APLNG, GLNG, Meridian and Jemena coordinating the response to increase gas supply.

The large industrial users impacted by the incident were taken offline or run at minimum standby load for safety reasons, with some smaller regional towns also affected downstream of the QGP's Wide Bay offtake.

AEMO held a follow-up conference with industry stakeholders on 8 March to provide updates on expected repair timeframes. Subsequently, AEMO advised that welding repairs were completed on 12 March, which preceded further inspections, pipeline coating and backfilling of gas, and additional works on pressure protection systems.

From 17 March, the QGP was recommissioned at a reduced operating pressure, with Meridian supply directions being revoked as gas flows resumed on the affected pipeline segment.[272]

From Monday 18 March, pipeline flow and customer offtakes began ramping up from the 85 TJ per day limit via the Meridian Gas Plant, increasing to the expected maximum flow rate at reduced operating pressure of around 105 TJ.

The facility was ramped up to 118 TJ per day from mid-May. End users remain on restricted rates until a higher operating pressure can increase the maximum capacity to its usual limit of 145 TJ per day.[273]

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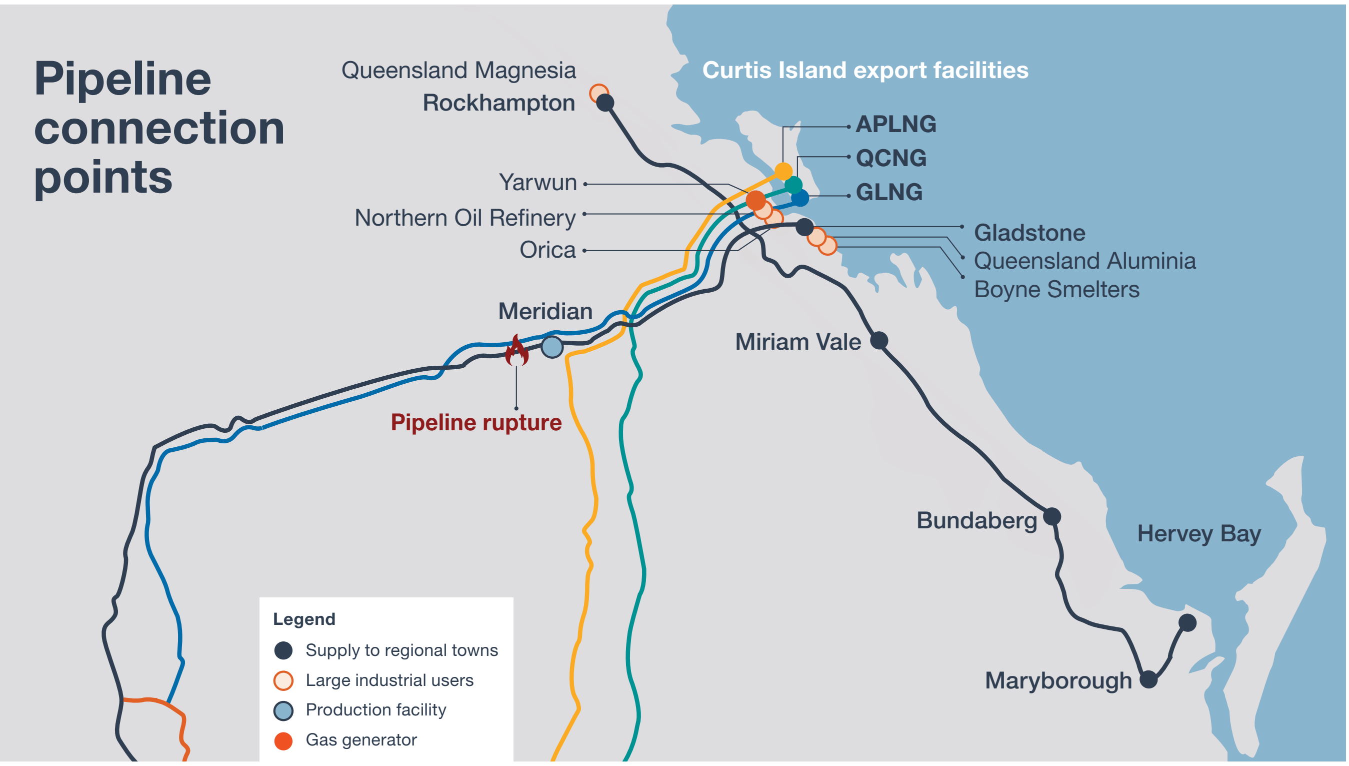
270 Low pressure levels significantly reduce withdrawal capacity when storage inventories fall below 6 PJ.

271 Renew Economy, Drought forces Tasmania to fire up its biggest gas plant for first time in five years, 8 August 2024.

272 Large industrial customer curtailments remained in place, but most large users had transitioned to contractual pro-rata allocations agreed with Jemena, the pipeline operator.

273 Information is current as at 22 August 2024.

Figure 4.13 Queensland Gas Pipeline and surrounding downstream infrastructure



Source: AER analysis using Gas Bulletin Board facility information and AEMO's detailed gas pipeline map.

4.5.3 Gas reserves and production

Eastern Australia had 36,493 PJ of 'proven and probable' (2P) gas reserves in June 2024, having produced almost 1,900 PJ of gas in 2023 (Table 4.1).

Ownership is highly concentrated in some gas basins, but more diverse across the east coast (Figure 4.1, Figure 4.14). APLNG owns the majority of reserves in eastern Australia through an incorporated joint venture with Origin Energy, ConocoPhillips and Sinopec.

Table 4.1 Gas basins serving eastern Australia

Gas basin	Gas production – 12 months to December 2023 Petajoules	Share of eastern Australian supply	Change from previous year	2P gas reserves (June 2024) Petajoules	Share of eastern Australian reserves
Surat–Bowen (Qld)	1,516	80.5%	3%	29,206	80%
Cooper (SA–Qld)	78	4.1%	-3%	987	3%
Gippsland (Vic)	215	11.4%	–31%	1,434	4%
Otway (Vic)	38	2%	–21%	530	1%
Bass (Vic)	4	0.2%	–10%	20	0.1%
Sydney, Narrabri, Gunnedah (NSW)	0.3	0.02%	–88%	6	0.02%
Amadeus (NT)	15	0.8%	2%	210	1%
Bonaparte (NT)	17	0.9%	–33%	4,100	11%
Eastern Australian total	**1,883**	**–**	**–4%**	**36,493**	**–**
Domestic gas sales	457	–	–20%	–	–
LNG exports	1,426	–	3%	–	–

Note: 2P: proven and 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 2024 and June 2024.

Queensland's Surat–Bowen Basin holds 80% of gas reserves in eastern Australia and supplied 81% of gas produced in 2023. Queensland's 3 LNG projects produced 95% of the basin's output in 2023.

Victorian basins, which account for 5% of eastern Australian reserves, have continued to decline 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.

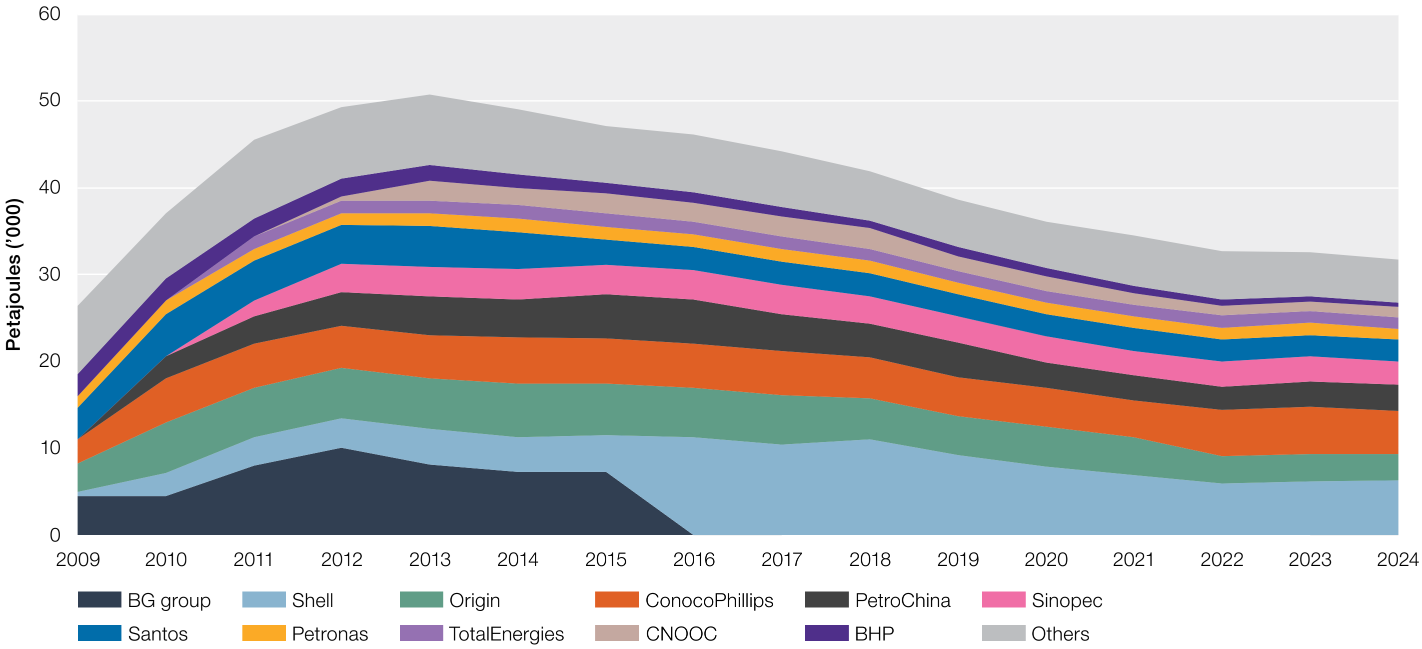
The Cooper Basin in central Australia has close to 1,000 PJ of eastern Australia's 2P reserves and accounted for 4% of gas production in 2023. Reserves in the basin have declined over the past decade. The Cooper Basin plays an important role as a 'swing' producer in managing seasonal and short-term supply imbalances in the domestic gas market.

NSW has significant contingent resources[274] (around 1,500 PJ) but only 6 PJ of 2P reserves and no current production since AGL's Camden facility ceased production in late August 2023. Santos received approval to develop reserves near Narrabri in the Gunnedah Basin but appeals against the approval have delayed the project. The final investment decision depends on project approvals being cleared (section 4.8.1).

The Northern Territory has the Bonaparte Basin and the smaller Amadeus Basin. These basins are estimated to have over 4,300 PJ of 2P reserves. Most gas produced is converted to LNG for export.

274 2C contingent resources are reserves that are estimated to be potentially recoverable from known deposits, but are not currently considered to be commercially recoverable.

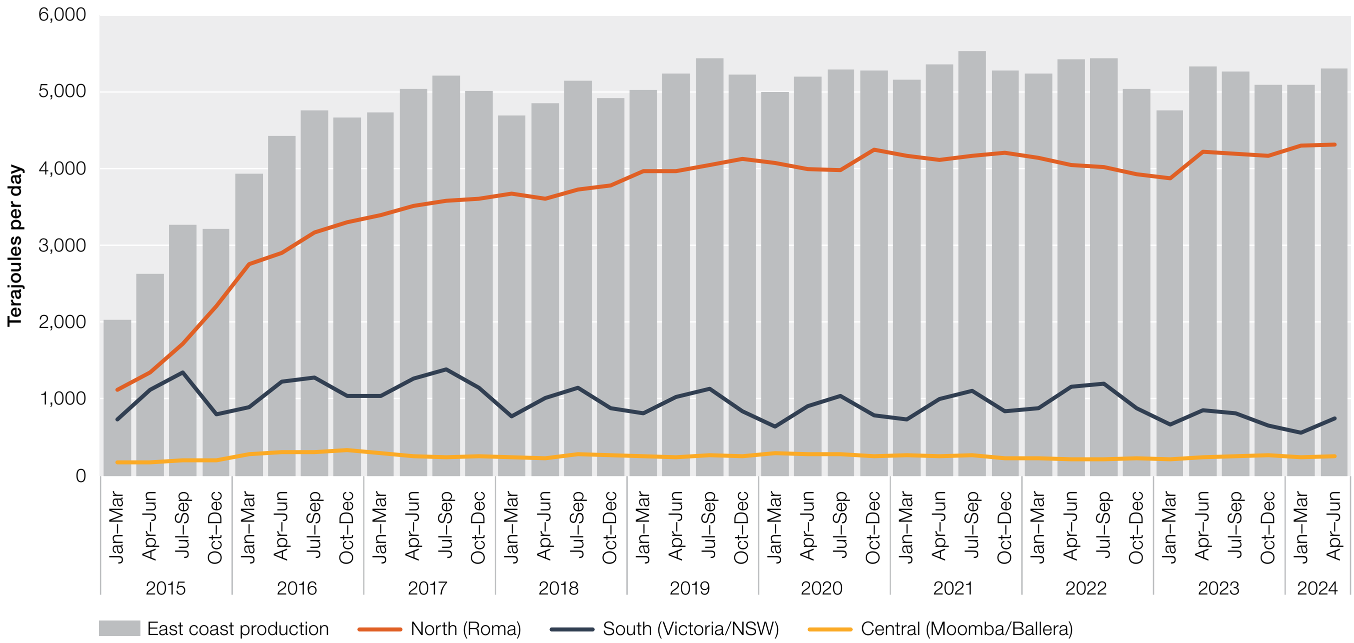
Figure 4.14 Market shares in 2P gas reserves in eastern Australia



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).

Figure 4.15 Eastern Australian gas production



Source: AER analysis of Gas Bulletin Board data.

Production output for the January to March quarter of 2023 was the lowest level recorded since 2018 (Figure 4.15). In 2024, lower production levels from Longford were partially offset by increased output from Queensland's Roma gas fields.[275] Roma production over the January to March and April to June quarters in 2024 reached record levels of 390 PJ and 392.4 PJ, respectively, similar to production output levels when exports were at a record high in late 2020.[276]

New gas supply from the Otway Gas Plant in Victoria increased from mid-June to over 150 TJ per day on average, reaching daily output levels close to 200 TJ.[277] Moomba production also continued to increase over late 2023, with average daily output close to 250 TJ across 2023 and 2024 to date.[278]

Longford production decline

Southern production has been particularly low in recent years, with Victoria's largest supply source at Longford running down reserves from its depleting legacy fields in the Gippsland Basin. Since 2023, supply levels from Longford have declined markedly compared with previous years (Figure 4.16). Projected 2024 availability for Longford published in March 2024 was comparable to actual production output over 2023. However, actual output in 2023 was influenced by low gas consumption and increased winter supply from Queensland last year, rather than reflecting available production capacity at that time.[279]

In 2024, continued production declines saw Longford's 35 PJ of supply over the January to March quarter drop to the lowest level recorded since the commencement of Bulletin Board reporting in mid-2008.[280] Production over the quarter was well below available capacity, even with planned maintenance from late January to mid-February reducing capacity levels lower than previously observed.[281] The following quarter also saw output fall to a record low for the period, due to a delayed ramp-up following planned maintenance scheduled to conclude in late May preventing supply levels reaching expected higher rates until late June.

275 Longford's production has been overtaken by QCLNG's Woleebee Creek facility in Queensland, which is now the largest production facility on the east coast. AEMO, Quarterly Energy Dynamics Q4 2023, Australian Energy Market Operator, January 2024, p. 4.

276 Queensland production exceeded 390 PJ when export demand reached a record 339.8 PJ in the last quarter of 2020. While exports levels were lower over the first half of 2024, they were record high levels for the January to March and April to June periods.

277 Production from Port Campbell (including the Otway and Athena gas plants) is forecast to increase from the 38 PJ produced in 2023 to 55 PJ in 2024, with the connection of new gas supply to the Otway Gas Plant including the Enterprise field in mid-2024 and the Thylacine West wells later in 2024. AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 9.

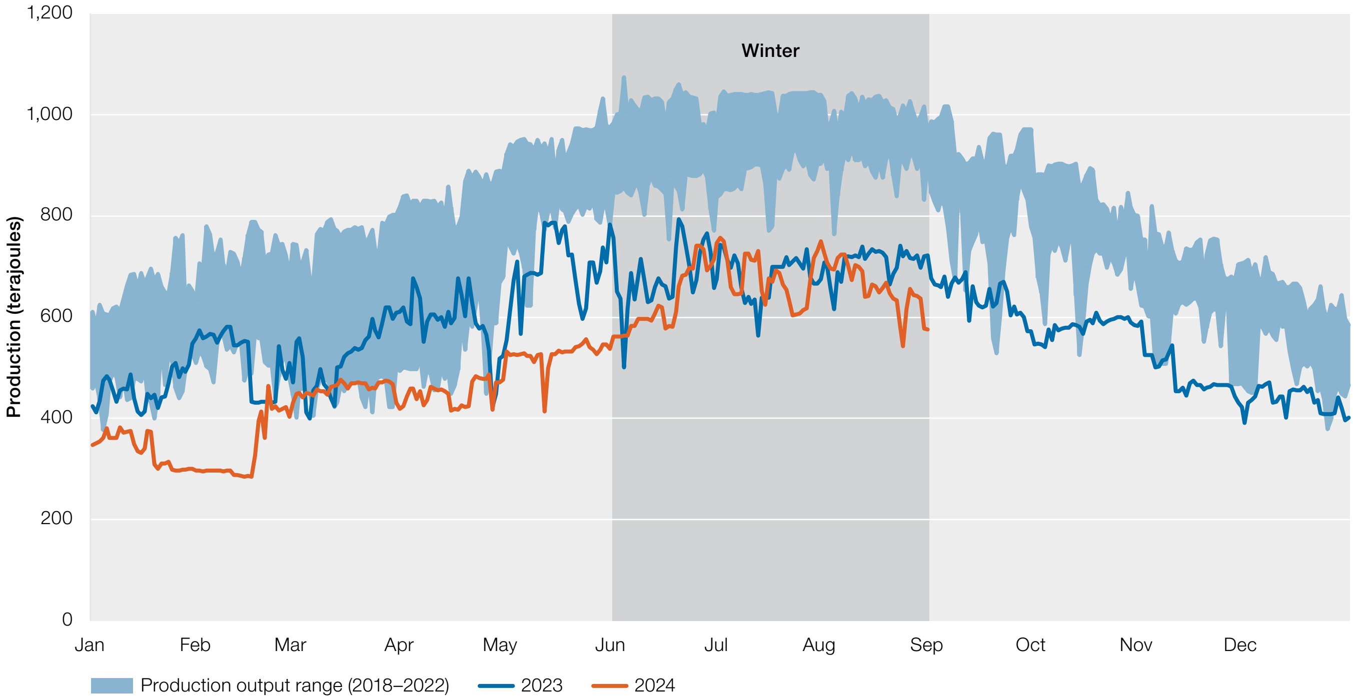
278 Average production in 2022 was just over 220 TJ per day. Increased production coincides with an increase in the number of wells drilled in the Cooper Basin throughout 2023. AEMO, Quarterly Energy Dynamics Q4 2023, Australian Energy Market Operator, January 2024, p. 57.

279 AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 9.

280 Available production capacity of 45 PJ was also at the lowest level recorded. AEMO, Quarterly Energy Dynamics Q1 2024, Australian Energy Market Operator, April 2024, p. 56.

281 Offshore maintenance at Longford from mid-January to mid-February saw participants draw down on Iona's underground storage inventories, which were at record high levels heading into 2024 following a mild 2023 winter.

Figure 4.16 Longford production levels since 2018



Source: AER analysis of Gas Bulletin Board data.

Gippsland region producers have advised that maximum peak day production capacity will reduce by 58% over the next 4 years, from 767 TJ per day in 2024 to 325 TJ per day in 2028.[282] Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce.[283] Production from the Longford plant has been falling and the plant is becoming less reliable, with plant constraints and maintenance outages increasingly disrupting production. Large reductions in Gippsland production reported in the 2023 Victorian gas planning report are still expected to occur in 2024 and 2027, with an additional reduction in 2028.[284]

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. Gas shortfalls are expected to emerge from 2027 unless new sources of supply are made available.[285] Potential gas supply has

282 AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, pp. 9, 49.

283 Projected production levels have included the committed Kipper compression project since the 2022 VGPR Update, which is expected to provide additional supply from October 2024.

284 Capacity is forecast to decrease to 700 TJ per day following the retirement of Gas Plant 1 scheduled from mid-September. This makes production capability reliant on the remaining 2 production trains, elevating the likelihood of production capacity halving in the event of an issue with either of the remaining plants.

285 This reflects lower forecast supply due to delays in anticipated regulatory approvals for new projects and problems with legacy gas fields. ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 7.

been identified by producers to reduce the risk of near-term shortfalls, but this is mostly conditional on the ability to obtain regulatory approvals and making final investment decisions (section 4.5.5). Import terminals may also help address supply gaps, but their viability is subject to international price movements and the ability to secure foundation customers to contract gas supplies.[286]

4.5.4 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 are 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[287] – 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 (Figure 4.19).
  - 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 (Figure 4.18).[288]
  - Silver Springs storage (Queensland) has a nameplate storage capacity of 45 PJ, with a delivery capability of 8 TJ per day (Figure 4.19).[289]
  - Roma Underground Gas Storage (RUGS, Queensland) has a nameplate storage capacity of 54 PJ, with a delivery capability of up to 60 TJ per day (Figure 4.18).[290]
- LNG storage is 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 (Figure 4.20)[291] – 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 to cater for short-term peak requirements and manage threats to system security.
- There are 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.

286 Import terminals will not replace the requirement to develop more domestic supply sources.

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

288 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.

289 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.

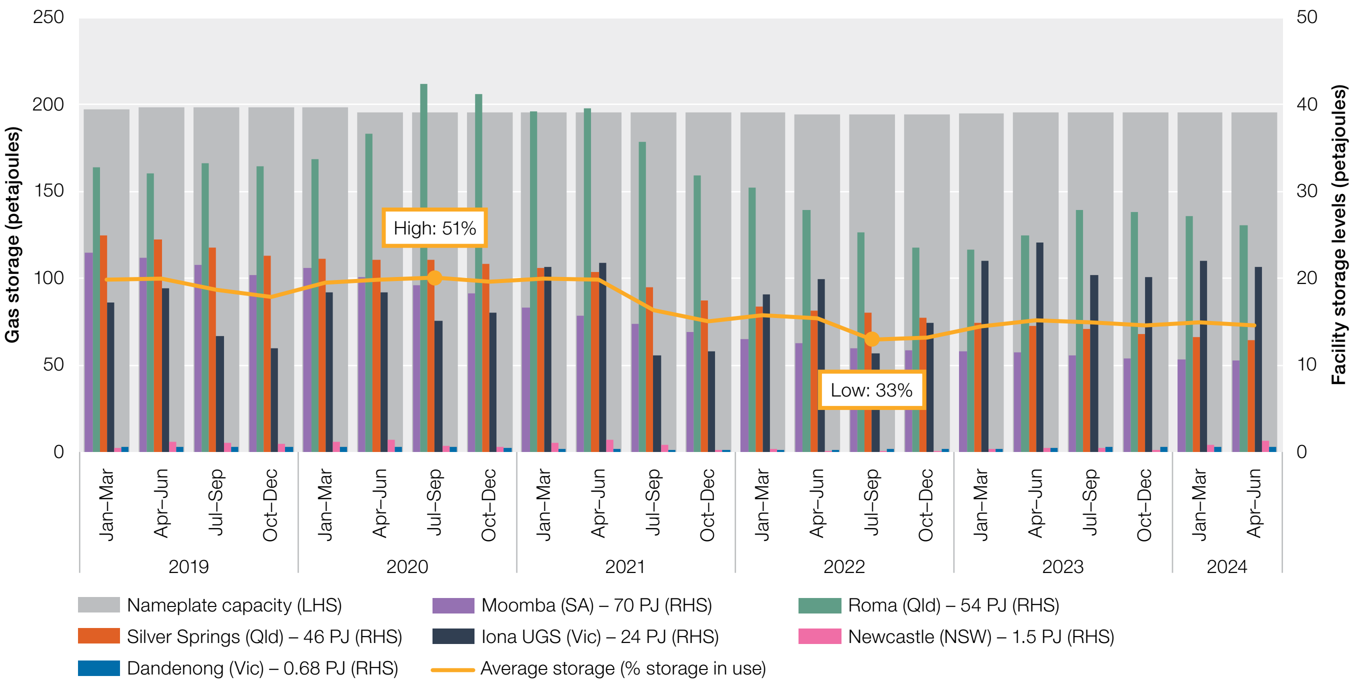
290 Short-term capacity outlooks for the Roma Underground Gas Storage facility can range from 25 TJ per day up to 60 TJ per day.

291 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 now acquires uncontracted gas storage supply at the facility and acts as a buyer and supplier of last resort to mitigate potential supply shortfalls, ensuring the facility is at or near full capacity heading into winter.

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.[292] 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 commenced in late 2016. This brought average storage levels down to one-third of capacity (Figure 4.17).[293] Iona entered 2024 above the record high storage level reached the previous year. However, high utilisation this winter has resulted in rapid depletion of inventories despite high levels of gas flowing south from Queensland. The drawdown of supply from other large facilities has also continued, with declining pressure in the storage wells constraining supply capability.[294] This demonstrates the dominant impact of weather-driven demand levels on supply adequacy for the southern states.

In contrast, some refilling at the Roma facility in Queensland over 2023 saw supply rates[295] return to higher levels, while refilling of the smaller Newcastle gas storage facility commenced in December 2022 and storage levels were at close to full capacity by late April 2024.[296] After 2024 winter utilisation, Newcastle storage levels had decreased to around one-third of full capacity by late August. Low daily supply capabilities at the Moomba and Silver Springs storage facilities mean they do not make a significant contribution to gas supply.

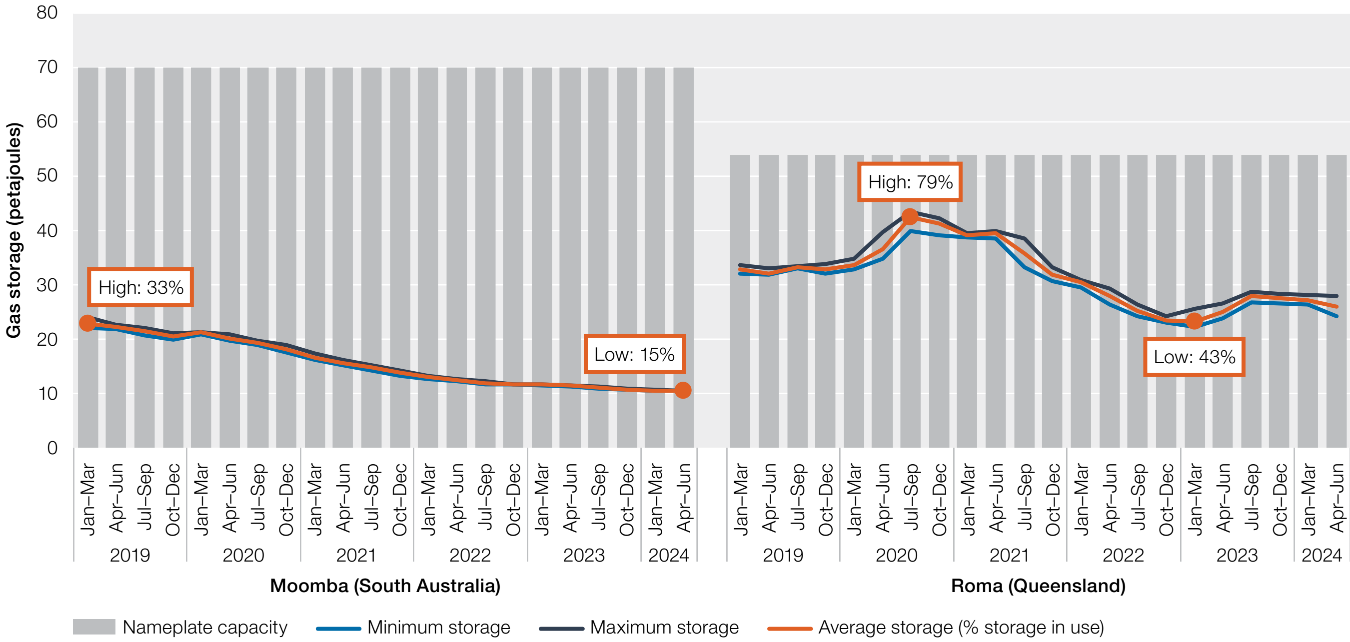
Figure 4.17 Gas storage in eastern Australia



Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.
Source: AER analysis of Gas Bulletin Board data.

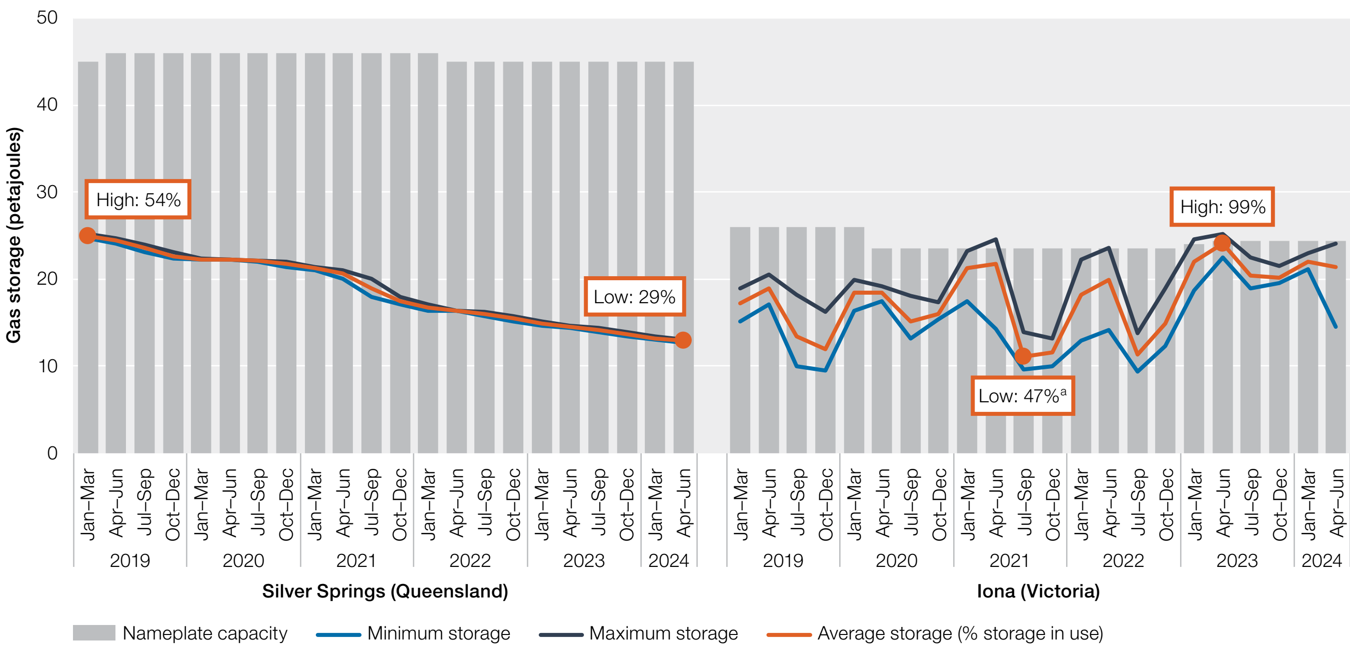
292 ACCC, Gas inquiry 2017–2030, interim report, December 2023, Australian Competition and Consumer Commission, December 2023, p. 127.
293 Storage levels fell to record lows across all east coast facilities in 2022, with this trend continuing at most facilities in 2023.
294 For example, Moomba has reduced its nameplate supply capability from 100 TJ per day when it commenced reporting in late 2016, with current storage levels below 11 PJ limiting its physical injection capacity as low as 3 TJ per day since June 2022.
295 Different levels of storage can impact the daily supply capability of storage facilities.
296 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 filled to around one-third of capacity over winter 2023, with lower utilisation during a period of lower than usual demand.

Figure 4.18 Large gas storage facilities – Moomba (South Australia) and Roma (Queensland)



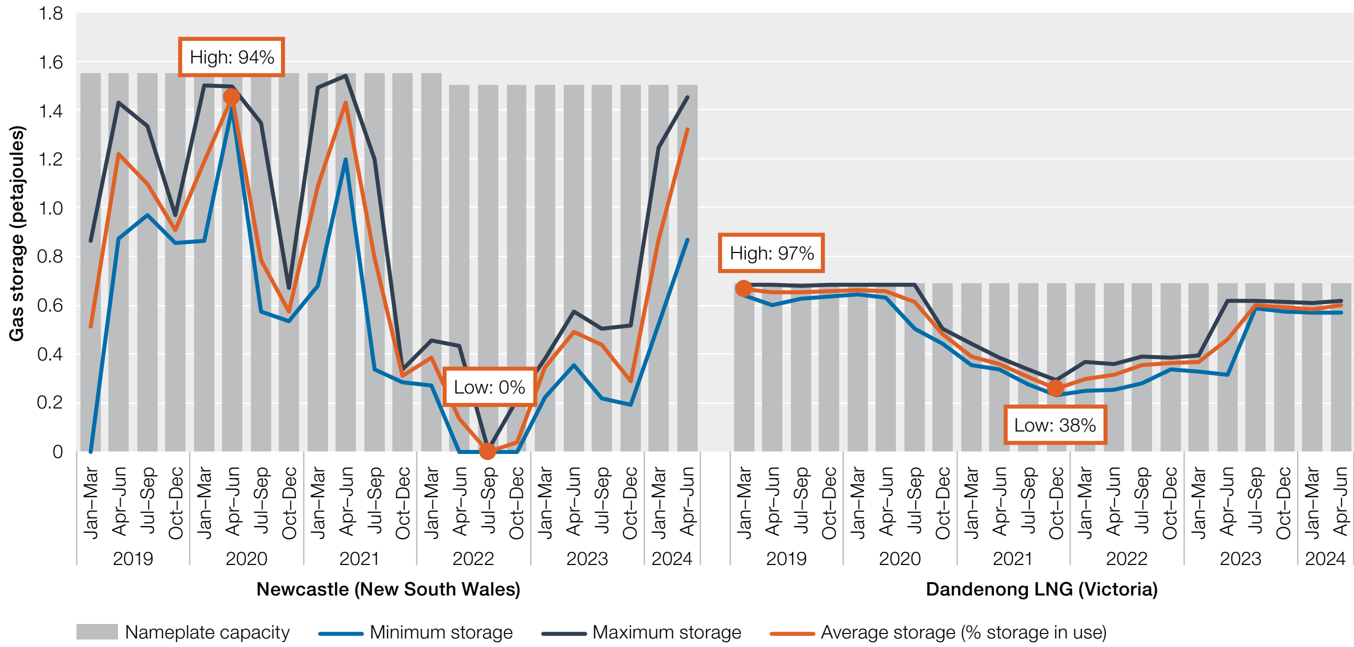
Source: AER analysis of Gas Bulletin Board data.

Figure 4.19 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 4.20 Small LNG gas storage facilities – Newcastle (NSW) and Dandenong (Victoria)



Source: AER analysis of Gas Bulletin Board data.

Unlike other storage facilities, Lochard Energy's Iona underground gas storage facility (Iona) operates more dynamically with higher supply and refill rates and is an integral southern supply source during winter. Since 2018, upgrades to Iona have expanded storage capacity and supply capability in the Victorian gas market.[297]

Supply into the Victorian market is still limited by available pipeline capacity in the transmission system, but recent upgrades have effectively increased peak day supply capability to 530 TJ per day (section 4.8.3).[298] Both the facility and transmission system upgrades have resulted in the facility being better able to respond to daily supply requirements. However, much faster depletion of storage levels in recent years has demonstrated an increased risk of reducing storage inventories to critically low levels prior to the end of the peak winter demand period. To mitigate some of this risk, preparatory works have commenced on the Heytesbury Underground Gas Storage (HUGS) Project to expand storage capacity through the development of existing depleted gas fields.[299] This could potentially increase Iona's storage capacity by 3.3 PJ by 2026.

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 (Figure 4.21). The significant drawdown 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, which remained in place until 30 September.[300] Similar circumstances occurred in 2024 but the notice was revoked on 23 August due to the later improvement in gas supply and demand trends (section 4.5.2).[301] In contrast to the mild winter conditions that resulted in record high winter storage levels in 2023, similar storage drawdown in 2024 mirrored the high rates recorded over the preceding 2 years. This was the result of cold weather conditions from mid-May, which coincided with production issues at Longford.

297 Following Lochard's takeover from EnergyAustralia in 2015, the storage facility's supply capacity has expanded significantly from 390 TJ per day to 530 TJ per day (17 March 2021), 545 TJ per day (28 January 2022) and 558 TJ per day (1 January 2023). The most recent upgrade increased the facility's supply capability to 570 TJ per day in early 2024.

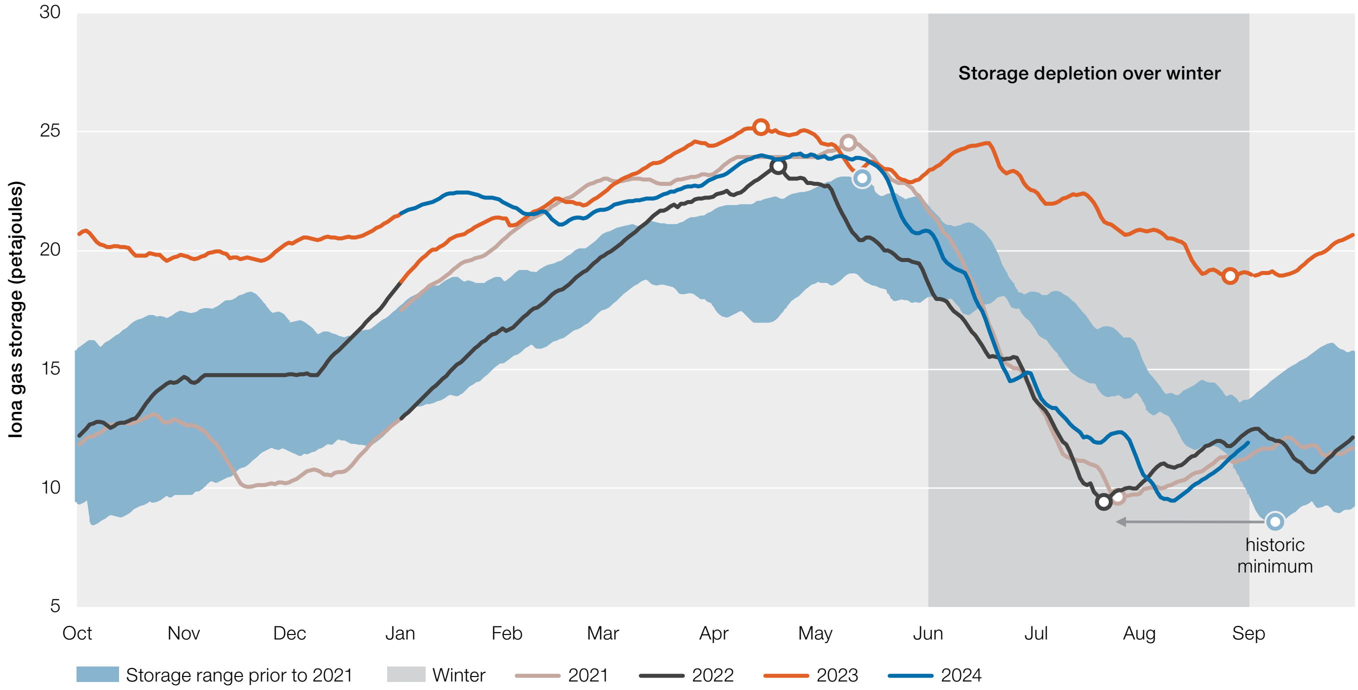
298 A new pipeline segment added to Victoria's transmission system's Western Outer Ring Main (WORM) and a second compressor at Winchelsea have been commissioned and are now operational. These upgrades have increased peak supply capacity to Melbourne by 83 TJ per day. AEMO, *2024 gas statement of opportunities*, March 2024, pp. 44, 55.

299 Lochard Energy, Heytesbury Underground Gas Storage (HUGS) Project.

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

301 AEMO, Revocation of East Coast Gas System Risk or Threat Notice, Australian Energy Market Operator, 23 August 2024.

Figure 4.21 Iona underground storage, rapid winter depletion rates since 2021



Source: AER analysis of Gas Bulletin Board data.

In 2022, the much smaller Dandenong LNG storage facility fell to particularly low levels in June following a reduction in participants contracting supply. While much smaller than Iona, the facility plays an important role in mitigating curtailment during potential supply shortfalls, as well as providing critical system security to avoid pressure drops at the Dandenong city gate. Due to the high potential for the facility to be needed from winter 2023 as supply at Longford drops off, Energy Ministers submitted an urgent rule change giving AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023. The facility entered winter 2024 at close to full capacity. The facility ended winter with 11.9 PJ (49% of nameplate capacity) after refilling from 10 August.[302]

4.5.5 Outlook

Despite improved short-run supply forecasts, the longer-term outlook remains uncertain. Decreases in projected demand for gas generation, residential and commercial demand, and industrial gas usage have improved recent forecast shortfalls, but a projected 28 PJ shortfall is still expected in southern states in 2025.[303] Production is expected to become increasingly reliant on uncertain and undeveloped sources of supply, with Victoria's primary supply source having already declined due to legacy gas fields in the Gippsland Basin coming to the end of their productive lives. Potential supply shortfalls have been forecast to occur in southern states in the coming years and across the east coast from 2027.[304] High levels of demand over the peak winter period in 2024 have already displayed an increased risk of peak day shortfalls, with heavy reliance on Iona gas storage inventories despite significantly higher volumes of gas flowing south.[305]

302 An unseasonably warm end to winter put downwards pressure on market demand, which eased prices.

303 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 25.

304 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 33.

305 Storage depletion in 2024 mirrored the rapid rates of drawdown that occurred in 2021 and 2022, yet higher supply output from Longford in previous years reduced the requirement for gas to flow south from Queensland.

More supply and associated infrastructure is clearly needed, but projects proposed to increase production between 2026 and 2029 have been delayed, reportedly due to long regulatory approval processes and planned maintenance.[306] 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.[307]

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.

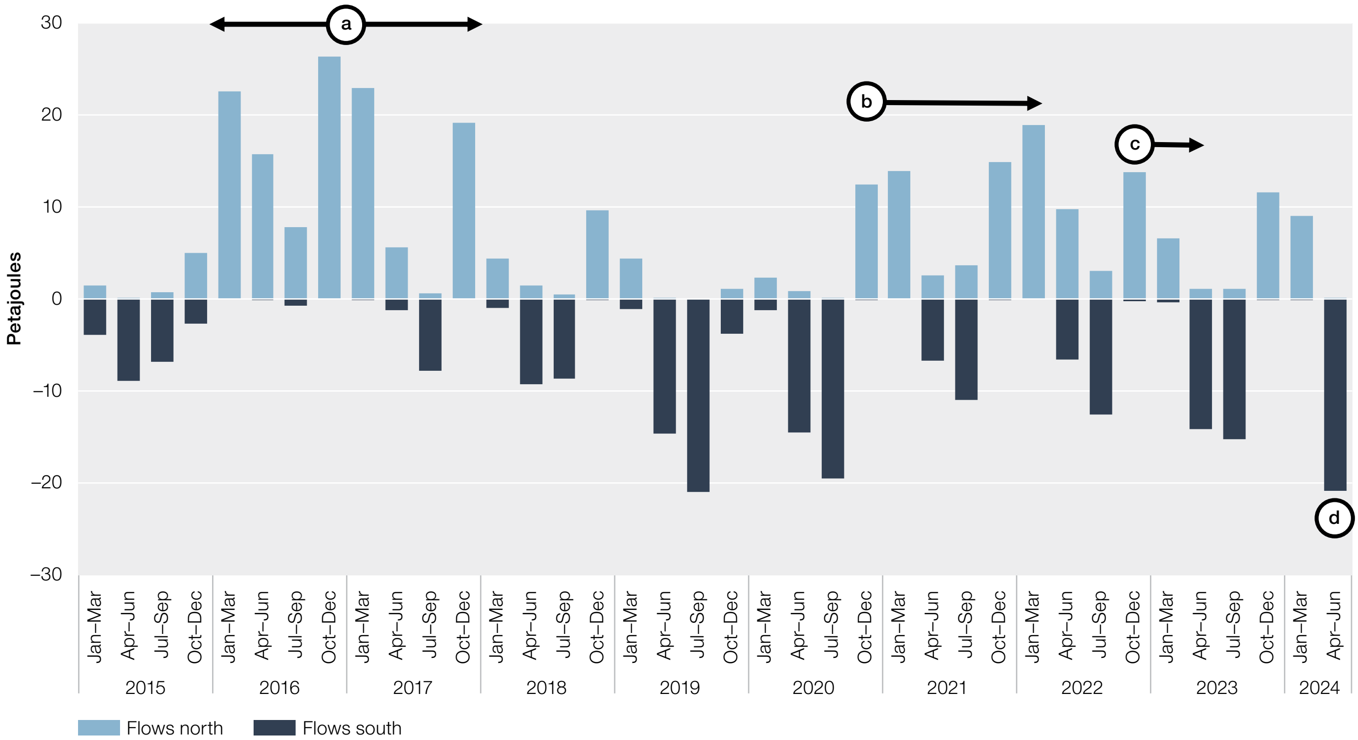
In response to ongoing supply uncertainty, the Australian and state governments have launched initiatives to encourage new projects to supply the domestic market (section 4.10).

306 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 36.
307 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, January 2023, p. 125.

4.6 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 4.22).

Figure 4.22 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.

d Winter 2024: additional compressors commissioned on the Moomba to Sydney Pipeline and South West Queensland Pipeline in May and June. Expanded capacity facilitates record monthly gas flows south in June (close to 11 PJ).

Source: AER analysis of Gas Bulletin Board data.

Northerly gas flows increased from late 2020 in line with record export pipeline flows (Figure 4.12) and reduced flows south over winter periods (Figure 4.22, note b). Over the January to March quarter of 2024, flows remained predominantly north despite reduced production from Longford, with exports for the quarter at the highest level observed for the start of the year. While export flows for the April to June quarter continued at high levels, southerly flows increased significantly from May 2024, with demand to bring gas south exceeding capacity to do so.[308]

From June 2024, stage 2 capacity expansions increased the ability to bring more gas south on the South West Queensland Pipeline and Moomba to Sydney Pipelines (section 4.8.3). As a result of this and elevated southern market demand over winter, record gas flows south from Queensland were recorded for June 2024. Southerly flows reached close to 11 PJ and increased the quarterly quantity shipped south to a level equal to the record reached in 2019 (Figure 4.22, note d).

Activity on the Day Ahead Auction once again increased on the Moomba to Sydney Pipeline following the stage 2 expansion. This occurred primarily on routes bringing gas south from Moomba, which accounted for 98% of the record 3.5 PJ of capacity won in June. The South West Queensland Pipeline also experienced an increase in capacity won on routes to bring gas south, with more than 1.3 PJ accounting for over 90% of the quantity won in June.

308 Significant auction capacity was won on auction routes south on the MSP reaching almost 2.5 PJ for May 2024.

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.[309] Under the agreement, Shell draws on its coal seam gas 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.[310] 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 4.11.1).

4.6.1 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 an expansion of the South West Queensland Pipeline and Moomba to Sydney Pipeline to increase delivery capacity from northern fields to southern markets. Two stages of this expansion have taken place, with each adding additional compression on both pipelines in mid-2023 and mid-2024 (section 4.8.3). An additional stage has been planned to be completed in two parts but the final investment decision has been delayed to at least the first half of 2025, with a further stage also in consideration.

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 4.1). 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. While the Northern Territory was connected to the east coast transmission pipelines in 2019, steadily declining output from the offshore Blacktip gas field led to the interim closure of the Northern Gas Pipeline (section 4.8.5). 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 4.6.2).

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.[311]

Pipeline ownership

Australia's gas transmission sector is privately owned (chapter 5). 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 4.11.2 and Table 5.1).[312]

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

310 EnergyQuest, *EnergyQuarterly*, March 2020.

311 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.

312 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 5 outlines the various tiers of regulation.

4.6.2 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 need to flow across multiple pipelines with different owners and use compression to facilitate the movement of gas.

Capacity on some pipelines is fully contracted to gas shippers, who do not fully use it. Access to transmission pipelines on key north–south transport routes is critical for gas customers. But if many critical pipelines have little or no spare, uncontracted capacity, it makes it difficult to negotiate access. In addition, many pipelines face little competition and may charge monopolistic prices.

Reforms introduced in March 2019 made it easier to access this capacity to pipelines and compression facilities, 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 through AEMO-facilitated markets. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold 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.[313]

Pipeline capacity trading (Day Ahead Auction)

Since the commencement of the auction in March 2019, over 330 PJ of contracted but unnominated pipeline capacity has been won across 16 of the 22 auction facilities (Figure 4.23).[314]

Around 80% of all capacity procured through the Day Ahead Auction has been 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 several gas-powered generators. Around 20% of the remaining zero-dollar capacity has been won on the Wallumbilla B compressor (WCFB).[315]

Trading activity on the auction has continued to grow over 2023 and the first half of 2024, with trade over the January to March quarter 2024 (39.4 PJ) exceeding the record set over the same period in 2023.[316] Of this capacity, around one third or 13.4 PJ was traded on gas routes that transport gas between northern and southern markets (SWQP/MSP). The quantity won for the period on the SWQP set a record at close to 5.5 PJ and the WCFB also set a record of 10.8 PJ.

Despite decreasing markedly from the first quarter's record levels, quantities won across the April to June quarter 2024 continued to exceed previous record levels for the April to June quarter.

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.[317]

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.

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

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

315 The Wallumbilla B facility can compress gas to a restricted specification, rather that the Australian Standard gas specification of the Wallumbilla A facility, allowing participants with the ability to provide gas at the restricted specification the opportunity to win capacity on the auction.

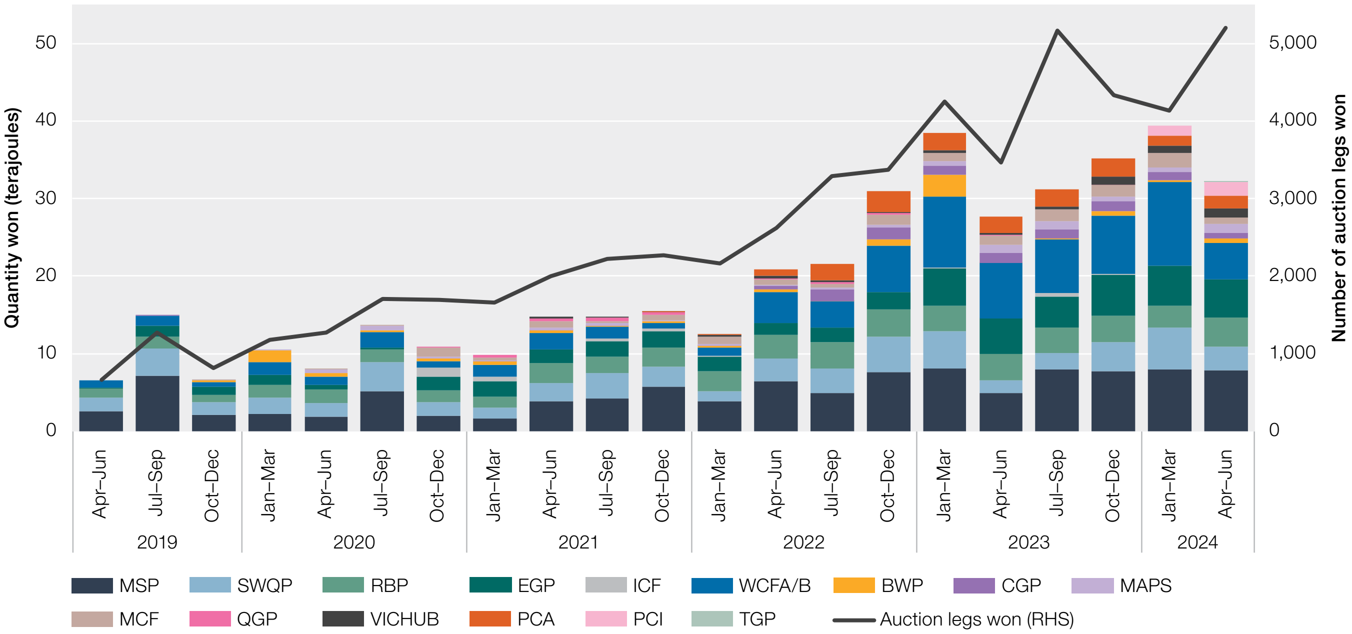
316 The January to March quarter record set in 2023 was 24% higher than all prior quarters since the auction commenced, and around 3 to 4 times higher than previous January to March quarters.

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

However, auction activity on some pipelines remains relatively low. Under-utilisation may result from higher auction fees, which can discourage smaller players in particular. While most capacity is won 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.

The AER recently released a focus report on the Day Ahead Auction, assessing the extent it has supported efficiency and competition in the east coast gas wholesale market.[318]

Figure 4.23 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; PCI: Port Campbell to Iona Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; TGP: Tasmania Gas Pipeline; VicHub (eastern Victoria); WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of Day Ahead Auction data.

318 AER, Wholesale gas market focus report: Day Ahead Auction, Australian Energy Regulator, October 2024.

4.7 Trade in east coast gas markets

In 2023, upstream commodity trade remained strong in the Gas Supply Hub, supported by continued high trade levels for transportation capacity won through the Day Ahead Auction.

The continued decline of southern production reserves has left southern states more reliant on Queensland gas supplies going forward, with physical gas flows south in May, June and July this year, up significantly from previous years. This coincided with a rise in Day Ahead Auction capacity won on the Moomba to Sydney Pipeline to bring gas south, with capacity upgrades commissioned from May allowing for increased flows.

In downstream markets, the high levels of net trade observed over the middle of 2021 and 2022 diminished in 2023, with unseasonably warmer weather over winter driving lower domestic demand across the east coast. However, there were some periods of higher proportions of market trade coming from gas purchased through the markets in the January to March quarter of 2023 and again in late September and late November 2023, which put downward pressure on market prices (Figure 4.5).

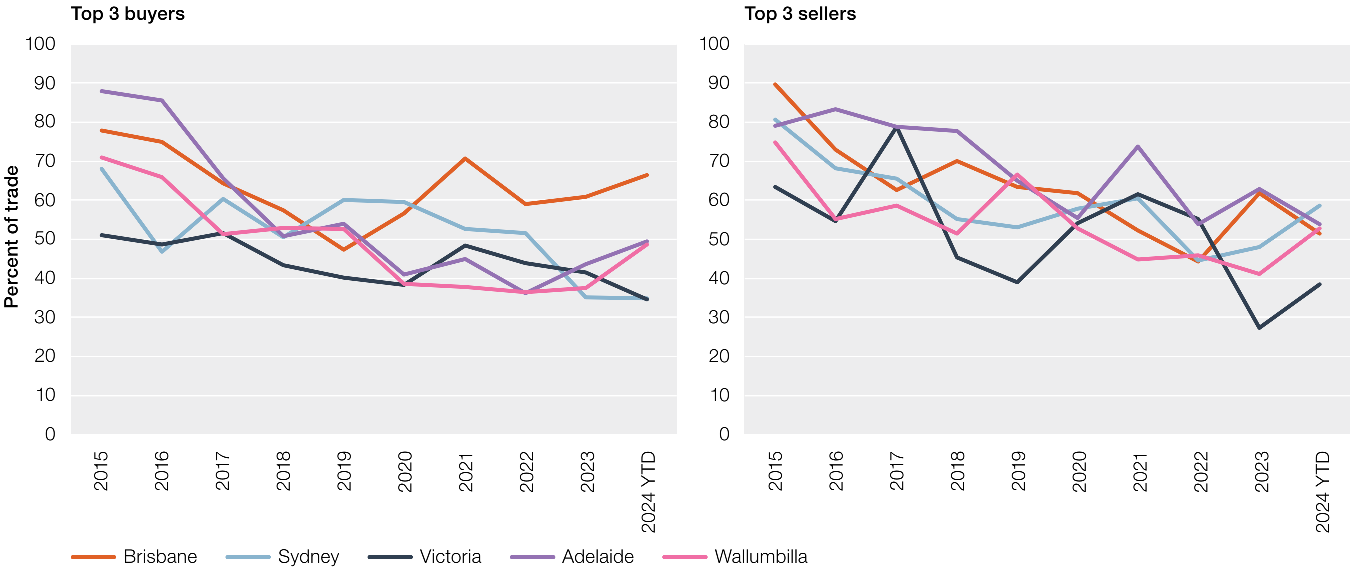
Net trade was generally flat into 2024 as prices remained stable, with lower domestic demand offsetting higher export levels until mid-May when colder weather drove increased demand and price levels. This influenced an increase in net trade quantities over the April to June quarter this year, particularly in Victoria where demand is higher, but not to the very high levels of 2021 and 2022.

In the Gas Supply Hub, strong trade from the October to November quarter of 2023 saw traded commodities exceed the previous record set in the July to September quarter of 2022, exceeding 13.2 PJ.[319] The Day Ahead Auction also set a record at 39.4 PJ of capacity won at auction, close to 1 PJ higher than the record set in the January to March quarter of 2023.

Trading profiles varied across the markets. The concentration of trades amongst the top 3 sellers increased in the Adelaide, Brisbane and Sydney STTM hubs over 2023, with decreases recorded in the other regions (Figure 4.24). In Victoria, the drop in the level of trade attributed to the top 3 sellers over 2023 was more pronounced, falling to 28% compared with 56% in 2022. Among the top 3 buyers, the proportion of gas purchased in 2023 was relatively similar to the previous year in the Wallumbilla Gas Supply Hub, Brisbane and Victoria. In Sydney, the proportion dropped from 52% in 2022 to 35% in 2023. Conversely, the top 3 buyers in Adelaide increased their share of net trades from 36% in 2022 to 44% in 2023.

319 High trade in mid-2022 coincided with high demand and unprecedented price volatility across the east coast, with gas traded through the Gas Supply Hub reaching 11.69 PJ over the July to September quarter.

Figure 4.24 Top 3 buyers and sellers in eastern Australian gas markets



Note: YTD: Year-to-date to 30 June 2024.
Source: AER analysis of data from the Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market.

4.7.1 Victoria's Declared Wholesale Gas Market (DWGM)

In 2023, 38 participants traded in the Victorian market. The market's participants include energy retailers, power generators and other large gas users, and traders. Volumes traded were down from 2021 and 2022, dropping 17% from the previous year with flatter levels of mid-year trade. However, despite this decrease the total of 27.4 PJ of gas traded exceeded levels set in the preceding years.

Production output from Victoria's main supply source at Longford has declined, leading to participants increasingly supplying the market with additional gas quantities via the Victorian Northern Interconnect through Culcairn. Despite the high levels of gas flowing to southern markets this winter through expanded capacity on the SWQP and MSP, the depletion of Iona's underground storage reserves in 2024 mirrored similarly high rates of storage inventory drawdown observed in 2021 and 2022, when southerly flows were lower.

The volume of trade in the Victorian gas futures market in 2023 was down 46% on the previous year. Ultimately, this quantity still accounts for only a small proportion (less than 5%) of the total volume traded in the spot market.

4.7.2 Gas Supply Hub (GSH)

In 2023, 24 participants traded at the gas supply hubs, 22 of which were active in trading both on-screen and off-screen products, with numerous off-market trades facilitated by a broker participant.[320] On average, participants executed around 420 trades per month in 2023 – an increase of 35% from 2022. LNG export businesses and gas producers were among the most active participants in 2023, accounting for 42% of transactions. Gentailers (28%) and traders (24%) had similar transaction numbers.[321]

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 trading were large industrial users.

320 We consider a participant 'active' if it makes at least 12 trades in a year. The broker is not included as an active trader.
321 Gentailers are participants that own electricity generation assets and retail market portfolios.

In the first half of 2024, approaching winter, there was very little forward trade through the Gas Supply Hub, continuing the same trend observed the previous year. This was markedly different to the same periods in 2021 and 2022, where Gas Supply Hub trade 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 and 2024 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. Trade volumes over the first half of 2024 were up 14% in comparison to the previous year, but most deliveries occurred closer to the date of trade, particularly for gas traded within 3 days of the delivery date (Figure 4.25).

Wallumbilla hub activity

Wallumbilla is the larger of the 2 primary hubs that make up the Gas Supply Hub. Users of the Wallumbilla hub include the LNG projects, gas-powered generators and trader participants taking advantage of the Day Ahead Auction to arbitrage prices between Wallumbilla and the downstream markets. Trade at the Wallumbilla hub represents the bulk of gas traded through the Gas Supply Hub.

In 2021, off-screen trade began to increase, with further growth in off-screen trades in 2022. While this trend continued in 2023 and the first half of 2024, the January to March quarter of 2024 saw an uptick in on-screen trading transacted on the trading platform, which accounted for 43% of quantities traded over the quarter. Over 2023, delivered quantities were on par with the record levels recorded the previous year above 35 PJ.

However, 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 2023 gas traded through the Wallumbilla hub accounted for 15% of total gas flows through pipelines in the Wallumbilla bulletin board zone, roughly the same proportion as the previous year. In total, close to 38 PJ of gas was traded in 2023 and 19.5 PJ was traded across the first half of 2024.

Moomba hub activity

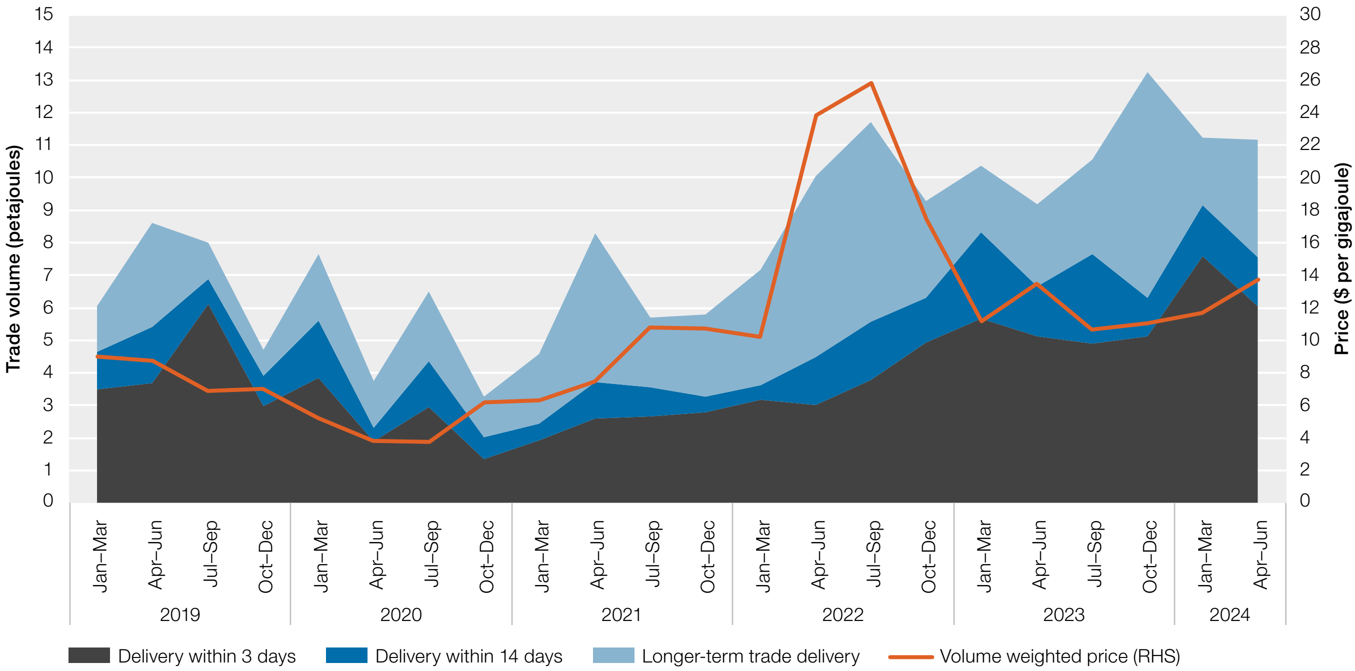
Trade at Moomba has been slow to develop. The first trade was executed in September 2017 and 141 trades were executed in 2019. Like Wallumbilla, trades at the Moomba location decreased significantly in 2020, declining further in 2021 before a very slight upturn in 2022. However, an upturn in 2023 saw traded quantities reach 1.75 PJ over the first half of 2023 and over 2 PJ was traded across the last half of the year. This was partially driven by an upturn in trade levels on the Moomba to Sydney Pipeline. In 2024, 2.6 PJ of gas was traded at Moomba, with increased trades delivered at points on the Moomba to Adelaide Pipeline, which accounted for around half of the trade across the first half of the year. While still significantly lower than trade levels at Wallumbilla, this represented around 11% to 12% of the total volume of gas traded through the Gas Supply Hub during those periods.

Victoria and Sydney activity

Trade levels at the Culcairn (Victoria) and Wilton (Sydney) trading locations have occurred in small volumes, reaching a total of 293 TJ and 3,279 TJ, respectively, to date.[322]

322 Quantities traded from 2021 up to 30 June 2024.

Figure 4.25 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.

4.7.3 Short Term Trading Market (STTM)

In 2023, 38 participants traded in the Sydney STTM, 27 participants traded in the Adelaide market and 22 in the Brisbane market. 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. From the start of 2023 to mid-2024, quarterly trade levels accounted for 15.9% to 24.4% of the total quantities scheduled in the Sydney market and 15.1% to 17.8% in Brisbane. Brisbane has historically traded below 10% of market demand prior to 2023. In Adelaide, the proportion of trade reached record high levels above 30% in the January to March quarters of 2023 and 2024. In Sydney, which has the highest volume of traded quantities across the STTM hubs, trade levels across 2023 were down 24% from the previous year (16.2 PJ), with scheduled demand 9% lower (88.5 PJ).

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.

4.8 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 *Gas Statement of Opportunities* reports have repeatedly highlighted 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.

4.8.1 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 Atlas 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 increase 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.[323]
- 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.[324] 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.[325]
- 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.[326] While additional gas is expected to be processed at Longford from 2026, supply is not expected to increase winter capacity to levels previously supplied by their depleting legacy field production.[327] In addition to the Turrum phase 3 project, the Gippsland Basin Joint Venture is considering the Longford Late Life Optimisation project to maximise production from depleting reserves later in the decade.[328]
- 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 in the April to June quarter of 2023). From mid-June 2024, daily production output reached close to 200 TJ (producing 11.9 PJ across the April to June quarter of 2024). Beach has also prioritised the ongoing development of its Yolla West field and deferred FID for Trefoil, which is now considered as potential supply.[329]
- 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.[330]

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

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

325 Cooper Energy, Gas Sales Agreement with AGL for the next phase of Otway Basin development and exploration, media release, 10 November 2022.

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

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

328 The project depends on the progression of the Turrum phase 3 project.
AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 63.

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

330 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.[331] 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 coal seam gas or any onshore petroleum until 30 June 2020.[332] In March 2021 the government committed the ban on fracking and coal seam gas exploration to the Victorian Constitution.[333] 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.[334]
- 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.[335] 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's Narrabri gas project.[336] 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.[337]

331 Hydraulic fracturing, also known as fracking, 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.

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

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

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

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

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

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

4.8.2 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. Although development of import terminals has been delayed over the past year, proponents of these projects remain committed to their continuing development.[338]

- Due to uncertainty around the contracting of gas supply, AIE's terminal at Port Kembla (NSW) was reclassified by AEMO and removed from the list of anticipated projects feeding into forecast supply outlooks. In 2021 AIE and Jemena signed a project development agreement to connect to the Eastern Gas Pipeline (EGP), with modifications set to allow bidirectional flows to deliver gas to Sydney and Victoria (section 4.8.3). Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023, while physical construction at the LNG Terminal continues.[339]
- Venice Energy's Outer Harbour LNG project at Port Adelaide (South Australia) is projected to potentially supply gas by 2026.[340] However, gas deliveries to Victoria are currently constrained due to the SEAGas Pipeline, which is currently only able to flow gas out of Victoria, and the limited available capacity on the South West Pipeline.

  The first stage of enabling works for site preparation have been completed, with a new commercial agreement to guarantee the receipt of a floating storage regasification unit. Venice entered negotiations with Origin for exclusive use of the import terminal for 10 years, for an expected supply capacity of up to 446 TJ per day or 110 PJ per year.
- Viva Energy's Geelong (Victoria) Gas Terminal project is continuing to progress with a supplementary data request for the Environment Effects Statement required by the Victorian Minister for Planning. The terminal is forecast to supply up to 140 PJ per year, have a capacity of 620 TJ per day, and potentially be operational and available to the market as early as 2027.
- Vopak's import terminal in Port Phillip Bay (Victoria) is planned to have a supply capacity of up to 778 TJ per day, supply around 270 PJ per year and be operational in 2028.
- EPIK ceased development of a Newcastle import terminal in early 2023 due to the project being economically unfeasible.[341]

4.8.3 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)[342] and the Moomba to Sydney Pipeline (MSP).[343] The expansion enables more gas flow on pipelines where capacity has been fully or close to fully contracted.[344]

338 Energy Quest, *EnergyQuarterly*, June 2023, p. 23.
339 The forecast supply capacity of 500 TJ per day is projected to be available from 2026 following physical mechanical completion. AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 64.
340 AEMO, Gas Statement of Opportunities, Australian Energy Market Operator, March 2023, p. 65.
341 AEMO, 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.
342 The SWQP connects to the Northern Territory through the 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.
343 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.
344 ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 15.

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).[345] Further stage 2 expansions on the pipelines added 2 more additional compressors, with commissioning completed by June 2024, increasing transportation capacity by 59 TJ on the SWQP (to 512 TJ per day) and by 90 TJ on the MSP (to 565 TJ per day). These were the first 2 of 4 stages, providing a 25% increase in transportation capacity.[346]

The additional proposed third stage includes a further expansion with increases to capacity on both pipelines. APA has deferred a final investment decision on stage 3, with an expected 6-to-12-month delay pushing a decision into the first half of 2025.[347] Stage 3 has been split into two parts: stage 3a and stage 3b:[348]

- Stage 3a consists of an additional compressor on the MSP between Moomba and Young and will increase the nominal capacity of the MSP by 34 TJ per day to 599 TJ per day.
- Stage 3b consists of an additional compressor between Young and Culcairn to provide a capacity increase of 41 TJ per day to Culcairn and further 5 TJ per day for the mainline MSP. Both stage 3a and stage 3b are currently in design phases.

APA is considering an additional stage, which would increase the MSP capacity to 657 TJ per day.

Despite the high levels of gas flowing to southern markets this winter through expanded capacity on the SWQP and MSP, the depletion of Iona's underground storage reserves in 2024 mirrored similarly high rates of storage inventory drawdown observed in 2021 and 2022.

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

APA has also upgraded the Victorian Transmission System by building a 51 km high pressure transmission pipeline to address a key capacity constraint previously limiting the connection of existing gas supply from the west of the state to demand in the north and east. The WORM pipeline was commissioned in February 2024, increasing capacity on the South West Pipeline from 447 TJ per day to 530 TJ per day, facilitated by the addition of a second compressor station at Winchelsea. The transportation of gas is also assisted by the upgrade of the existing compressor station at Wollert.

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.

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 4.8.4), following completion of the WORM.[349]

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

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

347 Argus media, Australian pipeline operator APA has deferred a final investment decision (FID) for stage 3 of its planned east coast grid expansion, given potential rule changes for the South West Queensland pipeline (SWQP), 13 May 2024.

348 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 64.

349 The Western Outer Ring Main (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.[350]

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 4.8.4) at Kembla Grange. If the project is developed, 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.[351]

4.8.4 Storage expansion

Iona underground gas storage (UGS)

Lochard Energy upgraded their underground storage facility to increase supply capabilities to 570 TJ per day, with a recently commissioned South West Pipeline (SWP) expansion – the WORM pipeline upgrade – increasing transportation capacity into Melbourne to 530 TJ per day (section 4.8.3).

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.[352] The project would increase Iona's capacity following the development of existing depleted reservoirs to provide additional storage space, with daily supply capacity increasing to 620 TJ.[353]

An increasing reliance on Iona following recent capacity expansions has enabled a more rapid drawdown rate of storage inventory levels. Due to low pressure levels, when Iona's storage inventory falls below 6 PJ withdrawal capability also decreases, potentially reducing to half of the facility's usual supply capacity. The Iona gas storage facility will continue to play a critical role in meeting southern gas demand requirements in winter due to declining output from Longford's legacy gas fields diminishing the supply capabilities at Victoria's largest supply source.

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 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.[354] 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.[355] In May 2023, the Minister for Energy and Resources accepted Golden Beach Energy's environment plan to drill the Golden Beach-2 appraisal well.[356] This was completed on 17 July 2023 with the post-drilling evaluation program also complete, including the drafting of the future development plan.

The facility is forecast to supply up to 35 PJ over 2 years from mid-2026 (delayed from 2025), with an initial delivery capacity of up to 125 TJ per day for winter 2026.[357]

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

351 Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023. The EGP could also be upgraded to flow 325 TJ per day to Victoria.
AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 64.

352 Lochard Energy, Our HUGS Project, April 2022.

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

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

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

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

357 AEMO, 2022 Gas Statement of Opportunities, Australian Energy Market Operator, March 2024, p. 63.

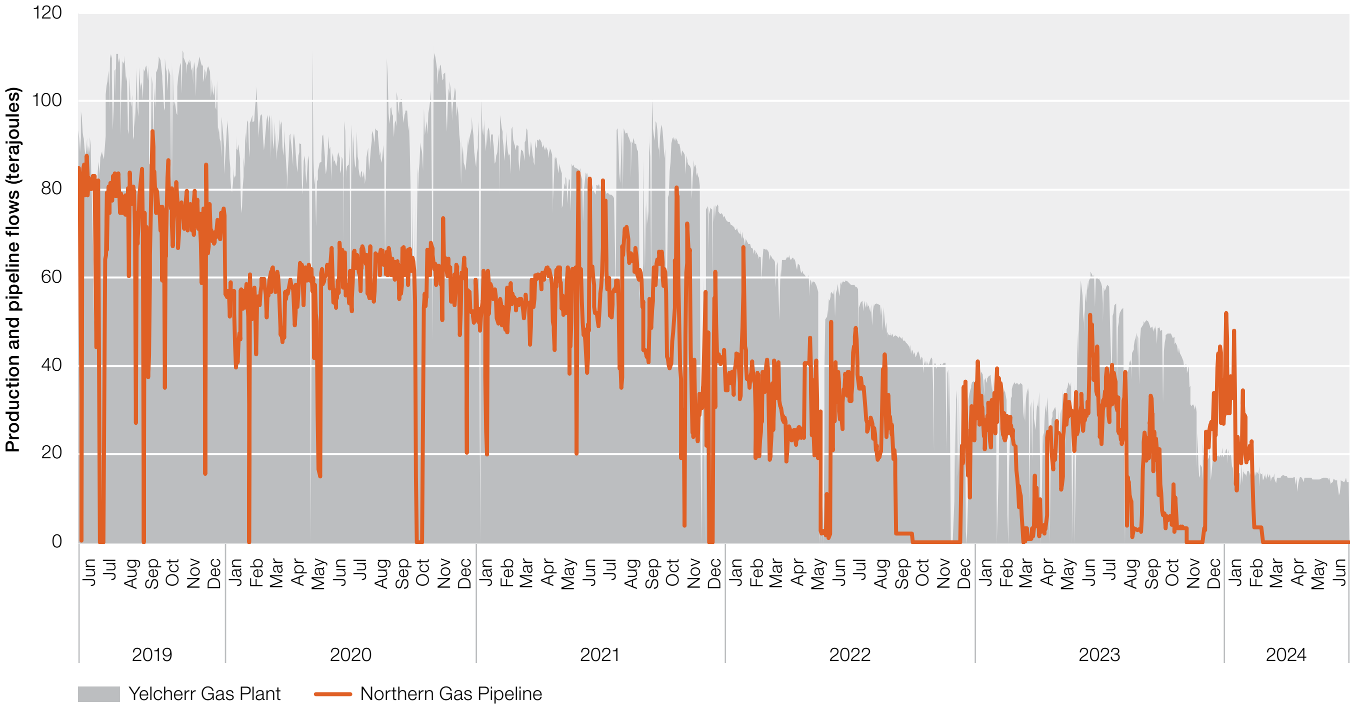
4.8.5 Northern Territory gas

From 2019, Jemena's Northern Gas Pipeline connected the east coast gas pipeline transmission system to supply in the Northern Territory. However, production issues at the offshore Blacktip gas field have led to the closure of the Northern Gas Pipeline.

Since the pipeline commenced operation, it has delivered more than 80 PJ of gas to the east coast. Initial supply across 2020 and 2021 saw pipeline deliveries average around 55 TJ per day before a decline from 2022. With the prospect of other potential gas sources being brought online in the Northern Territory, Jemena had planned to connect Beetaloo Basin supply to the Queensland's Wallumbilla gas supply hub and increase capacity on the pipeline from its nameplate 90 TJ per day up to 200 TJ per day by 2025.

Reduced flows on the pipeline from 2022 have mirrored production declines at the Yelcherr gas plant, the largest supply source in the Northern Territory sourcing gas from the offshore Blacktip gas field (Figure 4.26). Reduced supply from Blacktip led to average flows decreasing to just over 30 TJ per day over the first half of 2022 before production issues resulted in flows ceasing from October to mid-December 2022.[358] Subsequent flows averaged below 20 TJ per day, fluctuating up to a high of just over 50 TJ before the pipeline's closure from late February 2024. As a result, this has contributed to reduced supply and increased demand in the east coast markets, with supply on the Carpentaria Pipeline now requiring gas to be sourced from east coast production sources.

Figure 4.26 Northern Gas Pipeline flows and Yelcherr production decline



Source: AER analysis of Gas Bulletin Board data.

358 The low pressure in the pipeline forced Jemena to temporarily shut down the pipeline due to safety concerns, requiring Mount Isa to be supplied from east coast production sources.

Further to this, current supply conditions in the Northern Territory have been impacted by the Blacktip decline, with blackouts experienced across the region.[359] With gas generation being the primary source of electricity in the region, the government-owned Power and Water Corporation has sought to obtain gas supply from other sources to continue providing power, including offtake agreements with the Northern Territory LNG producers. Jemena also commenced works to make the Northern Gas Pipeline bidirectional to allow supply to be sourced from Queensland, which is expected to be completed by the end of 2024.[360] New reporting connection points were registered on the Gas Bulletin Board from 17 August 2024 in line with the scheduled commissioning of pipeline upgrades.[361]

These factors contribute to a heightened risk of supply shortfalls in the event of production outages and high gas-powered generation requirements, particularly if they coincide with peak winter demand in the southern markets that are increasingly reliant on Queensland gas supply.

4.8.6 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.[362] 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, as longer-term options.[363] The suitability of options such as electrification or switching to green hydrogen, biomethane or other biofuels is set out in more detail in the *Future of Gas Strategy Analytical Report*.[364]

In the more immediate term, demand response has a key role in managing peak day shortfalls. Although a formal demand response mechanism is not yet in place in wholesale gas markets, the Energy and Climate Change Ministerial Council has requested the Australian Energy Market Commission (AEMC) introduce an administered demand response mechanism as part of a broader supplier of last resort mechanism (section 4.10.3). A study by ACIL Allen of suitability of C&I users to supply demand response indicates that up to 22 TJ per day could potentially be used to absorb shortfalls with 6 hours or less notice.[365]

Governments have also started enacting policy to reduce residential gas demand. The ACT initially removed mandatory gas connection requirements for new homes, before legislating a stop to new gas connections from 2023.[366]

Victoria's Gas Substitution Roadmap and Energy Upgrades program identified electrification as the best solution to achieve a short-term reduction to gas consumption levels for residential consumers.[367] The roadmap offers options and support for Victorian residential and small commercial consumers who are interested in switching from gas to solar or electricity.

Since 1 January 2024, all new homes in Victoria requiring a planning permit are required to be all-electric, with new homes and residential subdivisions no longer able to connect to the gas network.

359 ABC news, Gas supply interruption triggers widespread power outage from Darwin to Katherine, 6 February 2024.
360 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 24.
361 The commissioning and testing phase is expected to be completed at the end of October 2024.
362 ACCC, Gas inquiry 2017–2025, interim report, January 2021, Australian Competition and Consumer Commission, February 2021, pp. 73–74.
363 ACCC, Gas inquiry 2017–2025, interim report, January 2020, Australian Competition and Consumer Commission, February 2020, p. 74.
364 DISR, Future Gas Strategy Analytical Report, Department of Industry, Science and Resources, 9 May 2024, accessed 19 August 2024.
365 AEMC, ECGS Supplier of Last Resort Mechanism, Australian Energy Market Commission, July 2024, p. 82. 22 TJ per day is calculated as 28% of 82 TJ per day, based on data obtained as part of the demand response study summarised in Appendix D.
366 ACT Government, ACT reaches milestone preventing new fossil fuel gas connections, media release, 8 June 2023.
367 AEMO, Gas Statement of Opportunities, Australian Energy Market Operator, March 2022, p. 23.

4.9 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 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.

For 2023–24, the AER's compliance and enforcement priority related to gas markets was to clarify obligations and monitor compliance with reporting requirements under the new Gas Market Transparency Measures.

4.9.1 Compliance with Gas Market Transparency Measures

New gas market transparency reforms were legislated in late 2022, following the passage into law of the National Gas Amendment (Market Transparency) Rule 2022. These reforms promote transparency in east coast gas markets through enhanced and expanded reporting of traded gas volumes and prices and the provision of information on overall gas supply adequacy to the Gas Bulletin Board and to AEMO's Gas Statement of Opportunities.

New participant reporting to the Gas Bulletin Board commenced on 15 March 2023. The AER has focused on the following activities:

- worked with AEMO and participants to clarify how short-term gas transactions should be reported, with guidance provided in AEMO's Gas Transparency Measures FAQ fact sheet,[368] and captured feedback from participants in our *Special report: Wholesale gas short term transactions reporting*, published on 6 December 2023[369]
- worked with field owners and AEMO to clarify how reserves and resource data should be reported to meet AER's compliance expectations, and updated our *Guidance Note: Reserves and Resources Reporting by Gas Field Owners* in August 2023[370]
- in April 2024, we published our analysis of the contracted and uncontracted reserve price assumptions submitted by gas field owners to the AER in our first *Wholesale gas reserves price assumption report*[371]
- started monitoring new obligations for participants to report under Part 27 and Part 18 of the Gas Rules, extending demand forecast reporting to retailers and large users. The reporting requirements came into effect ahead of winter 2023 and the AER has been monitoring compliance with registration and reporting obligations since that time.[372]

368 AEMO, Bulletin Board FAQs, Australian Energy Market Operator, accessed 8 September 2024.

369 AER, Wholesale gas short term transactions reporting, Australian Energy Regulator, 6 December 2023.

370 AER, Guidance Note – Reserves and Resources Reporting by Gas Field Owners, Australian Energy Regulator, 29 June 2023.

371 AER, Wholesale gas reserves price assumption report, Australian Energy Regulator, 15 April 2024.

372 *National Gas (South Australia) (East Coast Gas System) Amendment Act 2023* enhanced AEMO's ability to manage system supply adequacy, providing it with added functions and powers to monitor and manage any threat of east coast gas markets supply shortfalls.

4.9.2 Other compliance and enforcement activities

The AER also carried out the following activities, some of which relate to the AER's 2022–23 Compliance & Enforcement Priority 5 – Ensure timely and accurate gas auction reporting and demand forecasting in downstream wholesale gas markets by registered participants:

- issued a waiver to Evoenergy to continue to own and operate 2 natural gas distribution pipelines in NSW and the ACT[373]
- instituted proceedings against Santos for alleged breaches of important record keeping obligations in the National Gas Rules relating to the Day Ahead Auction for gas pipeline capacity, and secured Federal Court ordered penalties totalling $2.75 million[374]
- instituted proceedings against 4 Jemena subsidiaries for alleged large-scale failures to submit accurate auction quantity limits to AEMO for 4 pipelines and failure to ensure auction services were correctly scheduled for 3 pipelines[375]
- received payment from Jemena Northern Gas Pipelines totalling $135,600 for 2 infringement notices and accepted a court enforceable undertaking for alleged breaches related to Gas Bulletin Board accepted a court enforceable undertaking from Evoenergy to address concerns that Evoenergy breached its ring-fencing obligations[376]
- consulted on and published a new Annual Compliance Order, which came into effect on 1 July 2024 for the 2024–25 financial year – this order monitors the behaviour of gas pipeline service providers and supports the AER's monitoring obligations under s63A of the National Gas Law. To cover the intervening period, the AER issued an interim information request for the 2022–23 financial year and plans to issue a second interim information request in September 2024[377]
- began consultation on the AER Compliance Procedures and Guidelines (Gas) for gas pipeline service providers to assist market participants to better understand their compliance obligations, and our approach to new audit powers under the new framework.[378]

More detail on the AER's compliance and enforcement work is outlined in the Annual compliance and enforcement report 2023–24.

4.10 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand and prolonged price volatility seen in 2022, the Australian Government and some state and territory governments have intervened in the market. This has included measures to Increase supply stability, reduce demand and limit price volatility, and provide additional monitoring powers to market bodies.

In 2017, 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).[379]

373 AER, Evoenergy ring-fencing waiver November 2023, Australian Energy Regulator, accessed 8 September 2024.
374 AER, Santos Direct: breaches of the National Gas Rules, Australian Energy Regulator, accessed 8 September 2024.
375 AER, Jemena: alleged breaches of the National Gas Rules, Australian Energy Regulator, accessed 8 September 2024.
376 AER, AER accepts court enforceable undertaking from Evoenergy for ring-fencing breaches, Australian Energy Regulator, accessed 8 September 2024.
377 AER, Annual Compliance Order for gas pipeline service providers 2024, Australian Energy Regulator, 7 June 2024.
378 AER, AER begins consultation on the AER Compliance Procedures and Guidelines for gas pipeline service providers August 2024, accessed 8 September 2024.
379 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, accessed 24 May 2023.

Enhanced wholesale market monitoring

The National Energy Laws Amendment (Wholesale Market Monitoring) Bill 2023 (Amendment Bill) was proclaimed on 8 May 2024, enhancing the AER's wholesale market monitoring and reporting functions to include wholesale gas markets and electricity and gas contract markets. Access to contracts and related information will provide the AER with visibility of the underlying drivers influencing participant behaviour in gas and electricity markets, allowing for the examination of effective competition and whether wholesale markets are operating efficiently. Improved understanding and insights will allow for the enhancement of our existing suite of reports to provide timely and transparent information to relevant stakeholders throughout the energy transition.

The Amendment Bill requires the AER to develop a guideline outlining the scope of our wholesale market monitoring functions and related information collection and reporting activities. We remain committed to undertaking meaningful stakeholder engagement to develop a guideline that maximises the benefit of our reporting functions while minimising increased burden on participants reporting information to the AER. Following the publication of an Issues Paper on 21 March 2024,[380] a Draft Guideline was published for consultation on 2 July 2024.[381]

4.10.1 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.[382] Since 2017, the Minister has been able to determine if a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

Following the introduction of this mechanism, Queensland's LNG producers entered agreements with the government, committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls.[383] They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.[384] In 2023, following a review by the Australian Government Department of Industry, Science, Energy and Resources, the scheme was extended until 2030. The changes made to the ADGSM introduced more flexibility to activate the mechanism to secure domestic supply on a quarterly basis, rather than the yearly timeframe in the previous regulations.[385]

The new reforms came into place on 30 March 2023 with a newly negotiated Heads of Agreement with East Coast LNG Exporters in place until 1 January 2026. To prevent a gas supply shortfall, an additional 157 petajoules of gas was committed to the east coast market in 2023. The Australian Government decided not to activate the Australian Domestic Gas Security Mechanism (ADGSM) for the October to December 2024 quarter.

380 An issues paper was released for consultation through to 30 April 2024.

381 AER, Enhanced wholesale market monitoring guideline (2024), 2 July 2024, Australian Energy Regulator, accessed 12 September 2024.

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

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

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

385 The Hon Madeline King MP, Reforms ensure domestic gas supply, protect long-term contracts, Minister for Resources and Minister for Northern Australia, media release, 30 March 2023.

4.10.2 Gas Supply Guarantee

The gas industry 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. The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023, with a review recommending a further extension to March 2026.[386] The Gas Supply Guarantee has since been replaced by AEMO's new reliability and supply adequacy functions and powers under the National Gas Law and National Gas Rules, which came into effect in May 2023.[387]

AEMO triggered the GSG for the first time on 1 June 2022.[388] 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 2022 following 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 (the GSG and TTSS remained in effect until sufficient supply was available).[389]

In June 2024, AEMO issued a threat to system notice (section 4.5) but as at 1 September 2024 has not yet needed to intervene in the downstream markets.

4.10.3 Additional powers for AEMO to support reliability and supply adequacy

On 12 August 2022 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 build on actions taken ahead of winter 2023 to address east coast gas supply adequacy concerns that were raised in ACCC and AEMO reporting.

The actions included regulatory amendments providing additional powers to AEMO to manage gas supply adequacy and reliability risks to the east coast gas market:[390]

- 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.[391]

In June 2024, the AEMC published the 'Better integrating gas into the ISP (gas)' rule change proposal. Alongside other proposals to enhance the ISP through improved consideration of demand-side factors and better integration of community sentiment, this rule change would require AEMO to publish gas market projections and undertake an expanded consideration of gas generation, supply and infrastructure, including costs, when preparing the ISP. It also requests changes to the NGR to ensure AEMO has the power to access, use and disclose information gathered for NGR purposes to support the gas analysis in the ISP.[392]

386 AEMO, Gas supply guarantee guidelines consultation final determination, Australian Energy Market Operator. AEMC, Review of the Gas Supply Guarantee, Australian Energy Market Commission, 4 November 2021.
387 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2023, p. 105.
388 AEMO, Gas supply guarantee, Australian Energy Market Operator, accessed 28 May 2021.
389 AEMO, AEMO takes further steps to manage tight gas supplies, Australian Energy Market Operator, 19 July 2022.
390 AEMO, East Coast Gas Reforms, Australian Energy Market Operator.
391 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.
392 AEMC, Better integrating gas into the ISP (Gas), Australian Energy Market Commission, accessed 18 September 2024.

In July 2024, a further set of rule change proposals were provided to the AEMC (from DCCEEW) outlining longer-term solutions to manage threats to the east coast gas market:

- The 'ECGS Reliability standard and associated settings' rule change request proposes the introduction of a reliability standard for gas markets. This standard would be used to assess the sufficiency of the supply of covered gas and the capacity of relevant infrastructure. The level of the standard would reflect the value gas customers place on reliability (gas VCR) and would inform:
  - reliability settings such as price caps and floors in the facilitated markets
  - forecasts of any reliability shortfalls or credible risks to system resilience, as well as the communication of and actions to take for any risks or threats to reliability or adequacy of supply in the east coast gas system.

The VGCR would be set by the AER, similar to the AER's role in setting the VCR for electricity.[393]

- The 'ECGS Supplier of last resort mechanism' rule change request would give AEMO power to establish a storage reserve and/or reserve of any other gas service such as demand response or gas supply, and to use that reserve in the absence of a response from market participants, as a last resort. This mechanism would need to meet certain pre-conditions before being triggered. It would also require AEMO to maintain separate financial accounts for the mechanism and publish biannual reports on its Supplier of Last Resort activities. Consistent with the current rules, AEMO would also be required to publish post intervention reports and report to Energy Ministers on its east coast functions.[394]
- The 'Notice of closure for gas infrastructure' rule change request would extend the medium-term capacity reporting requirements in Part 18 of the NGR to require the reporting of planned closure of supply and delivery infrastructure at least 36 months before closure. It would apply to operators of production, pipeline, compression and storage facility infrastructure that meet the Bulletin Board reporting threshold.[395]

4.10.4 Competition and Consumer (Gas Market Emergency Price) Order

On 23 December 2022, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months.[396]

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

Several exemptions to the cap included LNG exports, downstream market trade in the Short Term Trading Market (STTM) and Declared Wholesale Gas Market (DWGM), and retailers that met certain criteria. The cap also exempted near-term trades on the upstream Gas Supply Hub (GSH) exchange that occurred within a 3-day window of the delivery date, and provided the Minister powers to grant additional exemptions outside of the standard exceptions that were delegated to the ACCC.[397]

393 AEMC, ECGS Reliability standard and associated settings, Australian Energy Market Commission, 8 July 2024, accessed 8 September 2024.
394 AEMC, ECGS Supplier of last resort mechanism, Australian Energy Market Commission, 8 July 2024, accessed 8 September 2024.
395 AEMC, Notice of closure for gas infrastructure, Australian Energy Market Commission, 29 April 2024, accessed 8 September 2024.
396 Australian Government, Competition and Consumer (Gas Market Emergency Price) Order 2022, December 2022.
397 A list of exempted entities is available on the ACCC's website (Gas price exemptions register). The delegation commenced on 23 December 2022.

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.[398] 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
- 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.

4.10.5 National hydrogen strategy

The Australian Government identified hydrogen as a potential alternative fuel to natural gas to facilitate emission reductions across energy and industrial sectors. This strategy has several elements:

- The government is looking at introducing hydrogen to the gas distribution network as part of the mix with natural gas, as well as other uses for hydrogen to replace natural gas when used as feedstock or in high-heat production processes such as smelting. Currently, hydrogen can be added to some existing gas pipelines at concentrations of up to 10% to supplement gas supplies and several trials are exploring the feasibility of this. Legislative changes have also been made to recognise the presence of hydrogen and other biofuels within the existing regulatory framework.[399]
- 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.[400] In April 2023 ARENA launched a $25 million funding round to support research and development of large-scale renewable hydrogen.
- In December 2023 the Australian Government announced 6 shortlisted applicants for its Hydrogen Headstart Program, operated by ARENA. The program will provide up to $2 billion in revenue support for large-scale renewable hydrogen projects through production credits. The credit is intended to cover the current commercial gap between the cost of producing renewable hydrogen and its market price, enabling producers to offer hydrogen to users at a price that will encourage its use.
- In February 2024 the Australian Government announced the fifth location for regional hydrogen hubs in the Pilbara in Western Australia. Hydrogen hubs are locations where producers, users and exporters of hydrogen can work side by side to share infrastructure and expertise. Hydrogen hubs have been announced for the following sites:
  - the Pilbara and Kwinana in Western Australia
  - the Hunter in NSW
  - Bell Bay in Tasmania
  - Gladstone and Townsville in Queensland
  - Port Bonython in South Australia.

AEMO's ISP models a green energy export scenario to examine potential requirements of expanding the existing transmission system and present different options to replace retiring coal-fired generation assets.

Most recently, the Future of Gas Strategy has noted low-emission gases – such as biomethane, hydrogen, ammonia and e-methane – have the potential to substantially decarbonise gas supply chains.

398 DCCEEW, Mandatory Gas Code of Conduct, Department of Climate Change, Energy, the Environment and Water, 11 July 2023.
399 Energy and Climate Change Ministerial Council, Extending the national gas regulatory framework to hydrogen and renewable gases, 14 July 2023.
400 ARENA, *Seven shortlisted for $70 million hydrogen funding round*, Australian Renewable Energy Agency, accessed 28 May 2021.

4.10.6 State-government schemes

State governments are responsible for different elements of gas infrastructure and exploration in Australia – for example, approving new gas exploration licences in their respective jurisdictions.

To encourage stability in the domestic supply of gas, 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.[401] In 2021, the Queensland Government announced it would make 14,100 km^2 available for oil and gas exploration.[402] 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).[403]

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.[404]

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.[405]

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.

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

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

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

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

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

4.11 Gas market monitoring reforms

The Energy and Climate Change Ministerial Council (ECMC), established in late 2022 to direct gas market reform for implementation by market bodies, agreed to an expedited package of carefully designed measures expanding the Australian Energy Regulator's (AER) gas and electricity market monitoring powers.[406] 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.[407]

The reforms stem from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group on shortcomings in the current regulatory framework. 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.

4.11.1 Gas Bulletin Board reforms

The Gas Bulletin Board is a publicly accessible source of information. It began publishing data on 1 July 2008 and 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 bilateral gas contract market, including how gas is exported overseas and how it is traded in Australia. In particular, the AER now monitors subsets of information on the export, reserve, storage and domestic sale and swaps of gas to report more comprehensively on competition.

Price and reserves transparency

Transparency of price and other market information is critical for effective market functioning. 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.[408]

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, LNG Transactions and Short Term Transactions.[409]

406 Department of Climate Change, Energy, the Environment and Water, Gas and electricity market monitoring powers, accessed 18 September 2024.
407 AER, AER welcomes new powers to keep watch on wholesale gas markets, news release, Australian Energy Regulator, 1 July 2022.
408 ACCC, Gas inquiry 2017–2030 – LNG netback price series, Australian Competition and Consumer Commission.
409 AEMO, Reserves Resources Reporting and Facility Developments and LNG and Short Term Transactions, Australian Energy Market Operator.

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.[410]

4.11.2 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[411]
- regulatory powers to determine the form of regulation to which a pipeline should be subject
- service provider information disclosure requirements[412]
- numerous other clarifications and refinements.

Under the new regime, all transmission and distribution pipeline service providers are required to provide third party access where it is sought, subject to available exemptions.[413]

Pipelines (unless they hold a Category 1 exemption) are now required to publish actual prices payable instead of weighted average prices that they previously reported. 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.

The reforms also require the AER to regularly and systematically monitor service providers' behaviour and report on this to the Energy and Climate Change Ministerial Council (ECMC) 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 ECMC report will also be published by the AER on its website as soon as practicable.[414]

More information on the new pipeline regulatory framework is available in chapter 5.

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

411 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).

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

413 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, can seek an exemption from the obligation to publish historical and service usage information.

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

4.11.3 Future of gas strategy and transition to net zero.

With Australia's commitment to net zero by 2050, governments have been consulting on how to shift from natural gas to renewable energy sources throughout the economy. The Australian Government released its Future Gas Strategy in May 2024, which explains the principles the Australian Government will use to guide policymaking about gas to support the transition to net zero. The guiding principles note the importance of gas remaining affordable for Australian users throughout the transition to net zero, and that gas and electricity markets must adapt to remain fit for purpose throughout the energy transformation. The strategy reiterates Australia's commitment to supporting global emissions reductions to reduce the impacts of climate change and reaching net zero emissions by 2050.[415]

In recognition of the uncertainty surrounding demand for gas, including gas-powered generation between now and 2050, governments have taken actions to better integrate gas assumptions into the Integrated System Plan. The AEMC released its consultation paper *Better integrating gas into the ISP (gas)*[416] on 20 June 2024, with an expected completion date of 19 December 2024.

The rule change proposal sets out several areas of specific gas analysis that are significantly influential over the development of the electricity system, including costs associated with gas infrastructure investments and the likelihood or commercial feasibility of GPG in the ISP, and availability of gas to service GPG in the quantity or price anticipated.

It would also require AEMO to develop projections about the future utilisation of gas infrastructure and collated pipeline closures or conversion dates. The intention is that the additional analysis will:

- allow AEMO to better consider whether alternatives to gas investments (such as storage) might be more economically beneficial for improving the optimal development path identified in the ISP
- provide more visibility to stakeholders about these options and their electricity sector alternatives, which may underpin more efficient market conduct
- better facilitate the transition to net zero in the electricity sector and better inform stakeholders on the future state of gas infrastructure throughout the transition.

415 DISR, Future Gas Strategy, May 2024 Australian Government Department of Industry, Science and Resources.
416 AEMC, Better integrating gas into the ISP (Gas), Australian Energy Market Commission, accessed 18 September 2024.