Wholesale markets quarterly

Q2 2024

April - June

July 2024

AUSTRALIAN ENERGY REGULATOR

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Our wholesale market reporting

The AER's wholesale markets quarterly report analyses trends in the electricity and gas wholesale markets, focusing on the most recent quarter, and alerts participants and stakeholders to issues of concern. The quarterly reports include discussion of prices, demand, generation, contracts, market outlook and new entry and exit.

A comprehensive dataset for each quarter is available on our website, including additional charts not featured in this concise report.

Additional related regular reporting from the AER covers:

- Details of significant high price events when the electricity spot market 30-minute price exceeds $5,000 per MWh and whenever consecutive 30-minute prices exceed $5,000 per MW in Frequency Control Ancillary Service markets.
- The annual State of the energy market report which presents an accessible, consolidated picture of the energy market.
- The biennial Wholesale electricity market performance report which provides longer term and more technical analysis of the performance of markets.

These scheduled reports will be supplemented by detailed special reporting on topics of interest and impact.

Q2 2024

Wholesale markets at a glance

Electricity spot prices increased in all regions except Queensland, with VWA prices ranging between $109 per MWh in Queensland to $189 per MWh in NSW.

Electricity prices increased due to a combination of higher demand, network and generator outages, and lower wind and solar output increasing the share of electricity generated by higher-priced gas and hydro.

Gas markets remain vulnerable to price shocks and supply shortfalls over winter, despite record gas supply flowing south from Queensland.

Lower than expected **gas** supply from Longford over the quarter drove an increased reliance on Iona storage, which ended June at 14.8 PJ at similar low levels to those observed in 2021 and 2022.

In NSW, network and generator outages combined with rebidding drove high price events from 2 to 8 May and led to the price safety net being triggered.

Domestic **gas** prices increased to $13.76 over the quarter, influenced by cold weather driving up demand in southern states, and lower gas production from Longford, Victoria.

Base futures prices were up in all regions, indicating an expectation of higher spot **electricity** prices going forward.

A low level of new generation entered the market compared to previous quarters, with a build-up of new generation now expected in the second half of 2024 and Q1 2025.

Low Iona storage prompted AEMO to issue a risk or threat to system security notice, likely to be in place until end September.

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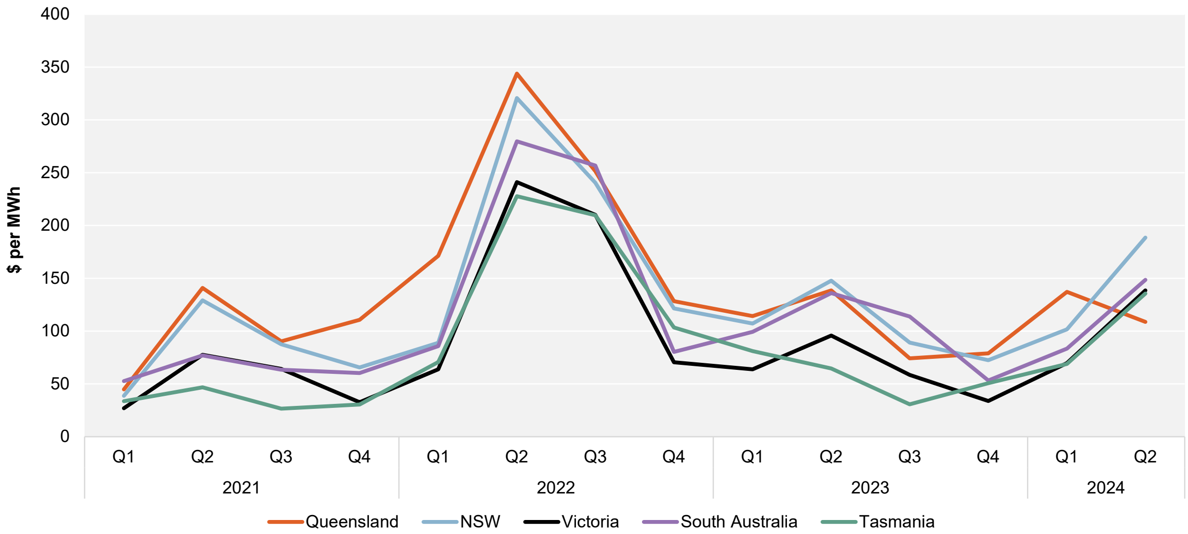
1 Prices increased for all regions except Queensland

Different factors impacted price across regions

In Q2 2024, volume weighted average NEM prices ranged from $109 per MWh in Queensland to $189 per MWh in NSW. Compared with Q1 2024, Queensland's price fell $29 per MWh (21%) while all other regions recorded significant increases – NSW $87 per MWh (up 86%), Victoria $69 per MWh (up 99%), South Australia $65 per MWh (up 78%) and Tasmania $67 per MWh (up 97%).

A year-on-year comparison reflects the same trend. Prices for all regions increased with the exception of Queensland, where volume weighted average price decreased by $30 per MWh (down 22%). Across other regions, NSW's price increased by $41 per MWh (up 28%), driven by generator and network outages combined with rebidding from some market participants; Victoria experienced cold weather[1] that increased demand and coincided with lower wind and solar generation, leading to the increase of $96 per MWh (up 45%). South Australia had a $13 per MWh increase (9%). Price increased in Tasmania by $71 per MWh (110%), mainly driven by hydro offering at higher prices, likely due to lower storage levels at major dams caused by the lower than average rainfall in the region[2]. The price increase brought prices up to similar levels as neighbouring Victoria.

Figure 1 Average quarterly prices in the NEM



Note: This chart illustrates volume weighted average quarterly prices, meaning prices are weighted against native demand in each region. The AER defines native demand as that which is met by local scheduled, semi-scheduled and non-scheduled generation. It does not include demand met by rooftop solar PV systems.
Source: AER analysis using NEM data.

[1] Bureau of Meteorology (BOM), Victoria in autumn 2024, 2 June 2024.

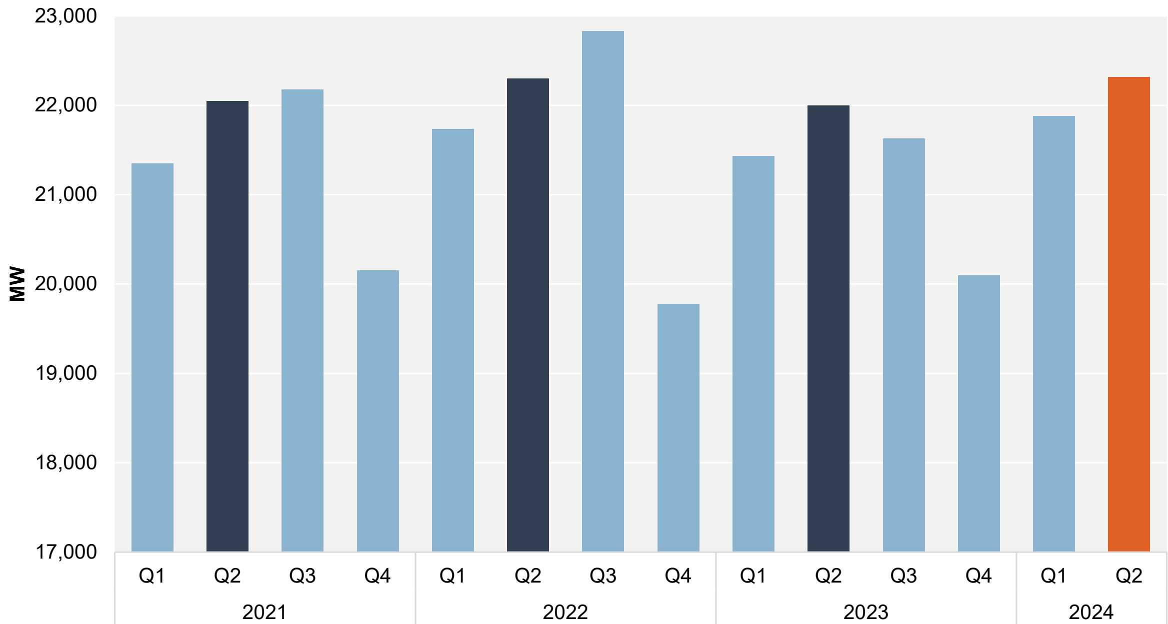
[2] Bureau of Meteorology (BOM), Drought Statement, 4 July 2024.

The AER is required to investigate and report on instances where the *30-minute price* for a given region exceeds $5,000 per MWh. In Q2 2024, the threshold was breached 19 times. Almost all of these occurred in NSW within 7 days. Generator and network outages created the opportunity for some market participants to profit maximise. Participants were able to shift energy offers to higher price bands, reducing low-priced capacity further. The run of very high prices from 2 May to 8 May caused the cumulative price (7-day rolling sum) to exceed the Cumulative Price Threshold (CPT)[3]. The breach of the CPT triggered a period of administered pricing cap (APC)[4] to protect consumers from extended high prices. The administered price period lasted from 8 May to 15 May. These events contributed around $55 per MWh to NSW's quarterly average price increase from the last quarter. The last time AEMO declared administrative pricing was in winter 2022[5]. Further details of this price event can be found in our recent report [6].

Demand increased in all regions except for Queensland

Average NEM demand in Q2 2024 was 22,315 MW, up 2% from the previous quarter (Figure 2). Demand increased in all regions except for Queensland, due to cooler weather.

Figure 2 Quarterly average NEM demand



Note: Uses quarterly average native NEM demand. The AER defines native demand which is met by local scheduled, semi-scheduled and non-scheduled generation. It does not include demand met by rooftop solar PV systems.
Source: AER analysis using NEM data.

[3] Cumulative Price Threshold (CPT) from AEMC.
[4] Australian Electricity Market Operator (AEMO), Administered price cap activated in NSW, May 9, 2024.
[5] Australian Electricity Market Operator (AEMO), AEMO Announcement, June 13, 2022.
[6] Australian Energy Regulator (AER), Q2 2024 High Electricity Price Events, July 17, 2024

Queensland demand fell 11% to 6,268 MW after very high Q1 demand of 7,052 MW (which was the highest since Q1 2017 and included record maximum daily demand). The rest of the regions had an increase in demand ranging from 241 MW (up 3%) in NSW to 729 MW (up 16%) in Victoria.

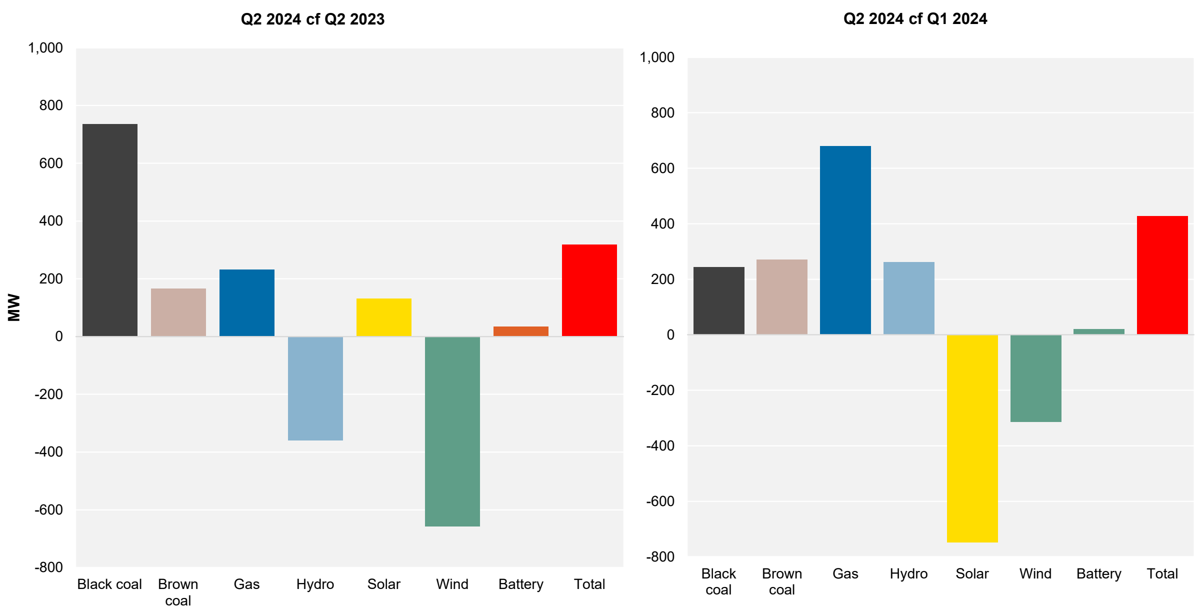
Compared to Q2 2023, average quarterly demand increased by 320 MW (up 1%). Regional average demand comparison shows a slight increase for Queensland and Victoria (up 3%), while the rest of the regions had a similar level of average quarterly demand.

Gas-powered generation increased to meet higher demand

Average quarterly generation increased from last quarter and was higher than Q2 2023 (Figure 3). This quarter's wind generation share was the lowest since Q2 2021. Black coal generation had the biggest year on year increase of 736 MW from 10,613 MW last year (up 7%), due in part to the decrease of baseload outages.

Summer months have higher solar generation, which decreases through the middle of the year. Less solar, combined with less wind, drove the Gas-Powered Generation (GPG) share increase from 973 MW to 1,653 MW, a 70% increase (680 MW) from the previous quarter, and a 16% increase (233 MW) from the same time last year.

Figure 3 Changes in NEM generation, by fuel type



Note: Change in average quarterly metered NEM generation by fuel type, this quarter's data compared with the same period last year, Q2 2023, (left) and compared with the previous quarter, Q1 2024 (right). Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.
Source: AER analysis using AEMO data.

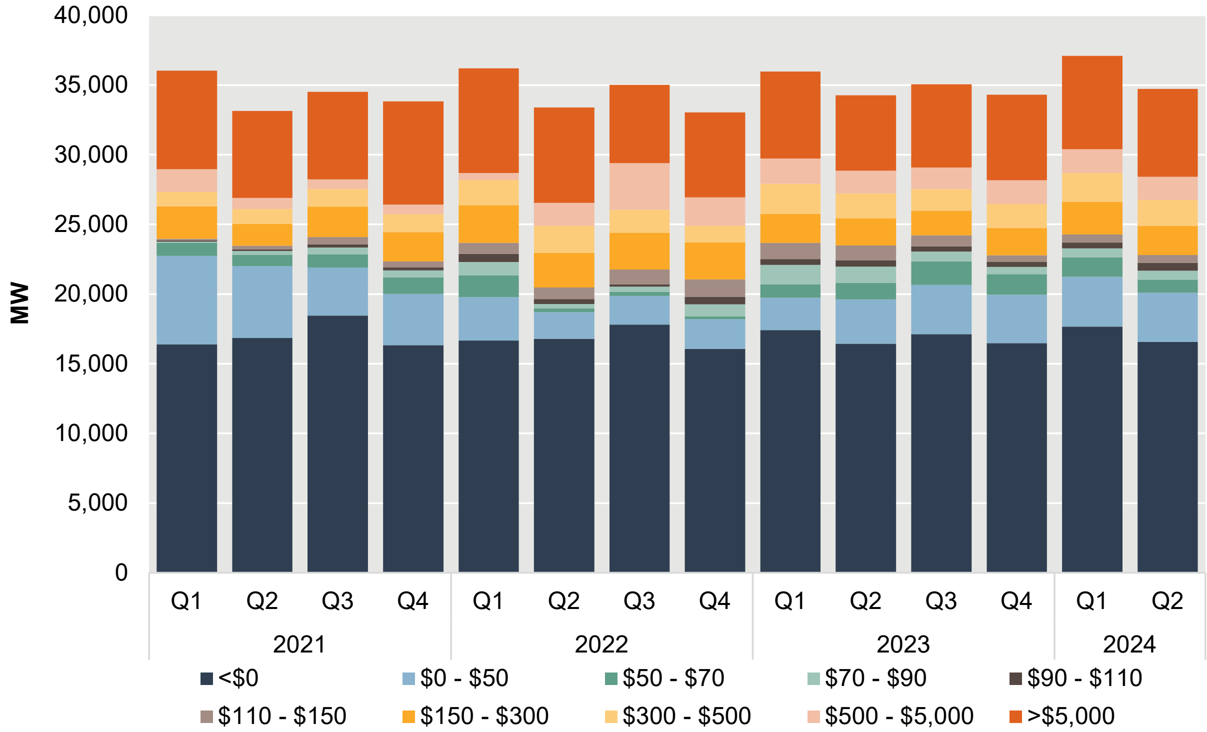
More high-priced capacity was offered this quarter with less wind and solar

With reduced low-priced generation available, negative prices fell, while high-priced fast generators like gas and hydro increased their offer share.

Total offers averaged 34,768 MW this quarter, a 7% decrease (2,321 MW) from last quarter (Figure 4). Offers in the below $0 per MWh price band decreased by 1,081 MW (down 6%), composed mainly of solar and wind generation.

Compared to Q2 2023, total offers increased slightly (up 2%), with the largest increase in offers in the >$5,000 per MWh price band (923 MW). The increase in offers in the high-priced band were mainly in Queensland, NSW and Victoria. On the high price days in May, some NSW participants rebid offers from low to high prices which led to the breach of the CPT and administered pricing period from 8 to 15 May.[7]

Figure 4 NEM offers by price bands



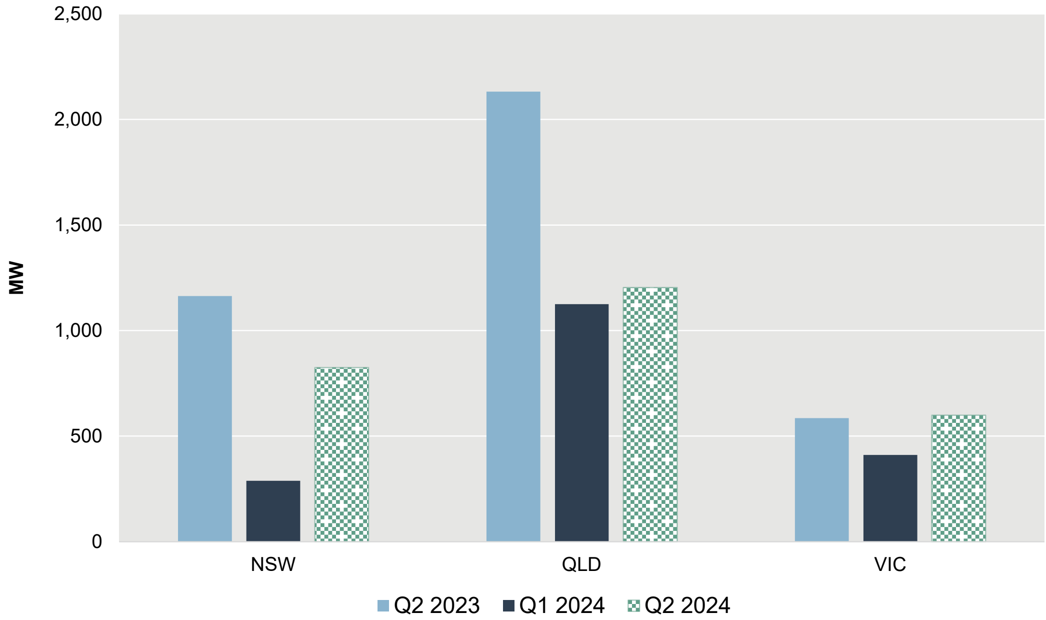
Note: Average quarterly offered capacity by price bands.
Source: AER analysis using NEM data.

[7] Australian Energy Regulator (AER), Q2 2024 High Electricity Price Events, July 17, 2024

Baseload outages increased from last quarter, decreased from last year

The average baseload capacity unavailable due to outage increased from last quarter by 79 MW (up 7%) in Queensland, 189 MW (up 46%) in Victoria and 536 MW in NSW (up 186%). Compared to last year, Queensland (down 44%) and NSW (down 29%) had much lower levels of baseload outages with Victoria largely unchanged (2% increase).

Figure 5 Baseload outages

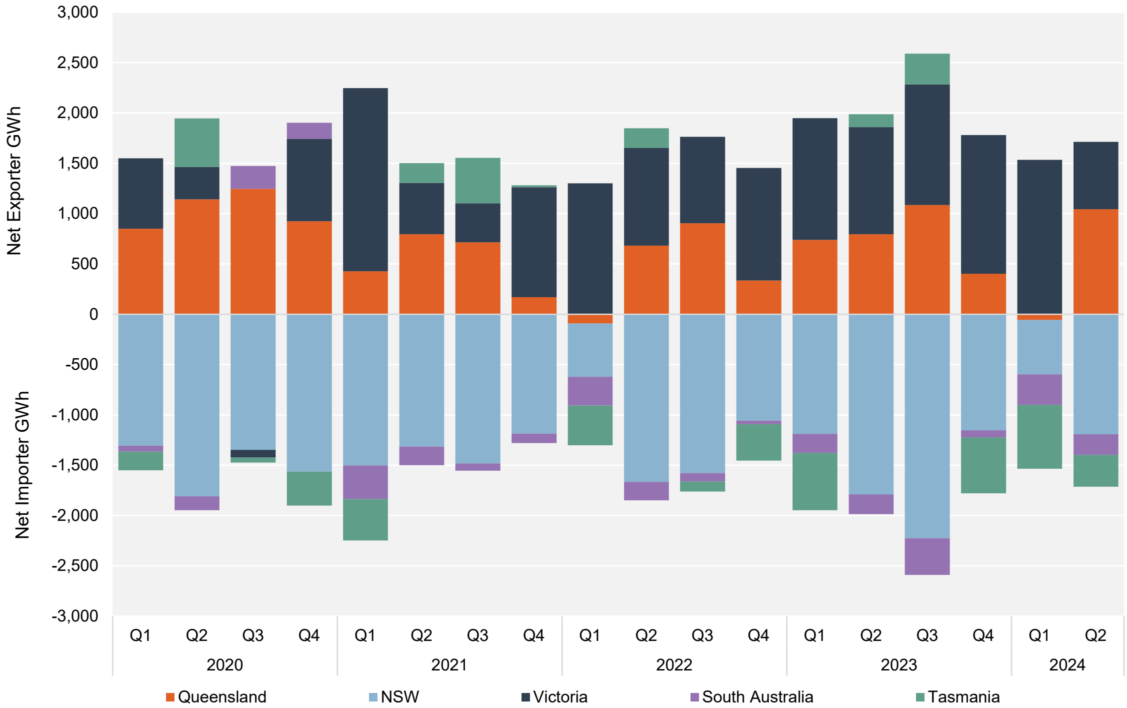


Note: Average capacity unavailable due to baseload outages. Black and brown coal units are generally expected to operate 24x7.
Source: AER analysis using NEM data.

Queensland and Victoria were net exporters

Interconnectors allow regions to import cheaper generation from neighbouring regions. Historically, Victoria and Queensland tend to be net exporters, providing surplus energy to NSW and South Australia. This quarter Victoria's net exports were 668 GWh, around 56% lower than last quarter (Figure 6). The decrease can be attributed to less wind and solar generation combined with the 16% increase in demand in the region due to the colder weather. Queensland's 11% decrease in demand enabled the region to export energy.

Figure 6 Interconnectors



Notes: Net amount of energy either imported or exported each quarter by region.
Source: AER analysis using NEM data.

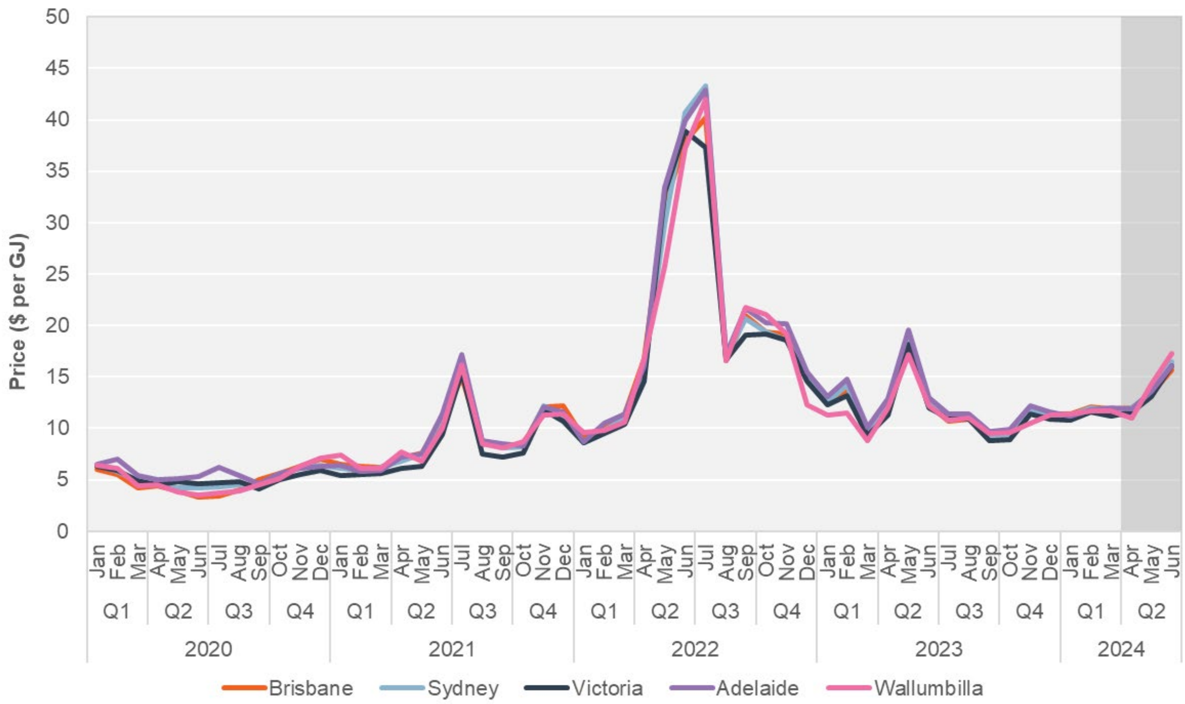
2 East Coast Gas market spot prices increased in Q2 2024

Gas prices increased over Q2 averaging $13.76 per GJ

East Coast downstream gas market spot prices increased across Q2 2024, averaging $13.76 over the quarter and representing an increase of 18.8% on Q1 2024 prices. Average price increases were driven by a combination of high residential and GPG demand days in May and June coinciding with low Longford production.

Price increases between Q1 and Q2 are consistent with winter price spikes observed since 2021, when East Coast gas demand in the southern states is highest.

Figure 7 East coast gas market average monthly prices



Note: The Wallumbilla price is the day-ahead exchange traded price.
Source: AER analysis using east coast gas market (ECGM) data (includes: Victoria, Adelaide, Brisbane and Sydney gas markets and Wallumbilla gas supply hub data).

Gas markets remain vulnerable to price shocks, despite record gas flows south from Queensland. Prolonged lower production from Longford leading to depletion of Iona stored gas raises the possibility of supply shortfalls. Severe cold weather combined with unexpected events affecting supply or demand increase the potential for AEMO to intervene in the market or curtail users to manage system security risks.

On 19 June, AEMO issued a system risk or threat notice, indicating that the supply of gas in all or part of the east coast may be inadequate to meet demand (Box 1). Q2 daily spot market prices peaked on June 20 and 21, with downstream markets reaching $27.55 per GJ in

Victoria and $28 per GJ in Sydney on 20 June. By 30 June, spot prices had fallen significantly to an average of $13.34 per GJ across downstream spot markets as market conditions softened. Box 2 sets out a timeline of the daily domestic spot market prices and their drivers including demand, GPG and supply.

Box 1: AEMO East Coast Gas System Risk or Threat Notice[8]

On 19 June AEMO issued a system risk or threat notice, identifying that the supply of gas in all or part of the east coast gas system may be inadequate to meet demand. The notice is likely to remain in place until 30 September, with AEMO outlining an expectation of an industry response to mitigate the system threat and prevent the requirement for market intervention.[9]

AEMO highlighted that reduced storage delivery capacity resulting from low inventory levels heightens the risk to winter supply adequacy on peak demand days.[10]

Scheduled demand increased in Q2 but remains lower than previous years

Downstream gas demand increased in Q2 compared to Q1, largely driven by increased residential and GPG demand during winter. However, Q2 demand remained low on average, being the lowest Q2 demand since 2016. This reduction in demand likely offset the supply conditions leading to higher prices over the quarter.

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8 AEMO, East Coast Gas System Risk or Threat Notice, June 2019, East Coast Gas System Risk or Threat Notice.

9 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.

10 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.

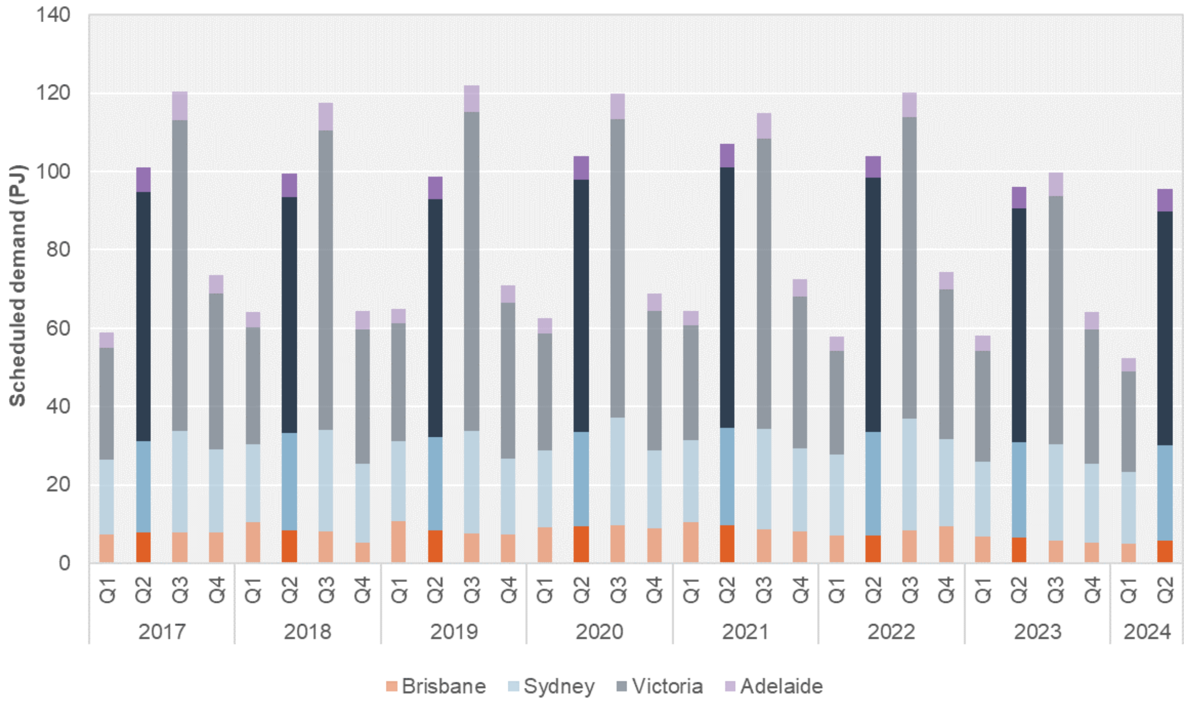
• The combination of lower than forecast Longford production and high seasonal demand and GPG, which has already significantly impacted Iona's storage levels.

• 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.

Figure 8 Scheduled demand in east coast gas markets



Note: Scheduled demand based on beginning-of-day forecast demand data (6 am Victorian DWGM schedule and ex-ante STTM schedules for Brisbane, Sydney and Adelaide). Brisbane demand includes one gas powered generator (GPG) and Victoria demand includes Jeeralang, Laverton, Loy Yang B, Newport, Somerton and Valley Power GPG.
Source: AER analysis using east coast gas market (ECGM) data (includes: Victoria, Adelaide, Brisbane and Sydney gas markets).

While average quarterly demand was lower than in Q2 last year, high demand days put pressure on gas reserves and resulted in increased prices. Q2 daily demand peaked on 20 and 21 June, surpassing 1.5 PJ per day, with Sydney demand hitting record volumes at 422 TJ on June 20. The high demand days were driven by cold weather in the southern states increasing residential demand, and increased GPG usage to compensate for low wind generation output (section 1).

Production at Longford has been constrained or below capacity

Production at Longford, Victoria's largest production facility, increased in Q2 2024 from Q1, however, this also represented its lowest Q2 output on record.[11]

In April, Longford operated slightly below its capacity, with production averaging 450 TJ a day. In May, Longford production increased and operated at capacity, which was mostly constrained to 525 TJ a day for planned maintenance.

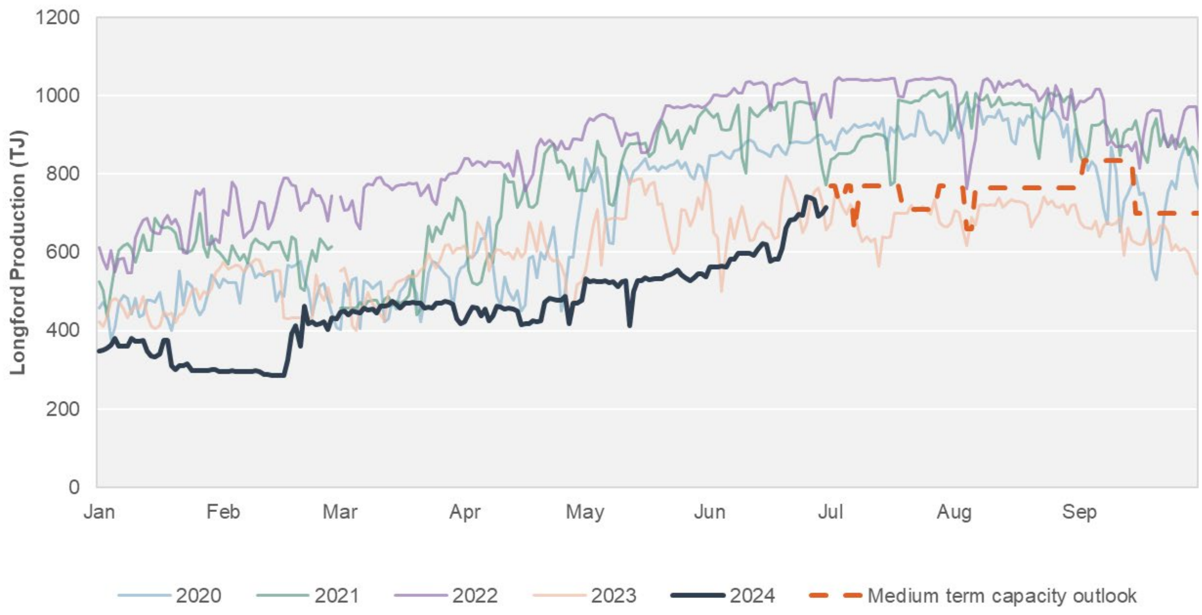
Capacity was forecast to increase to above 750 TJ at the end of May, however, delays in returning production to capacity forecasts following unplanned maintenance meant that production slowly increased across June. This meant Longford production was unavailable to

[11] Since data commenced on the Gas Bulletin Board in 2009.

meet increased demand in southern regions, which relied heavily on the Iona storage facility and gas flowing south from Queensland.

Longford production increased from 18 June to 22 June by around 100 TJ, with production surpassing 700 TJ a day on 24 June. This increased Longford production, alongside reduced GPG demand, put downward pressure on prices.

Figure 9 Longford production and medium-term capacity outlook



Source: AER analysis using Gas Bulletin Board data.

At the beginning of July, the medium-term capacity outlook forecast for production at Longford indicated an expected production range between 695 TJ and 775 TJ a day over the remainder of winter. In periods of high demand, southern markets will continue to rely on gas from the Iona storage facility, and gas flowing south from Queensland.

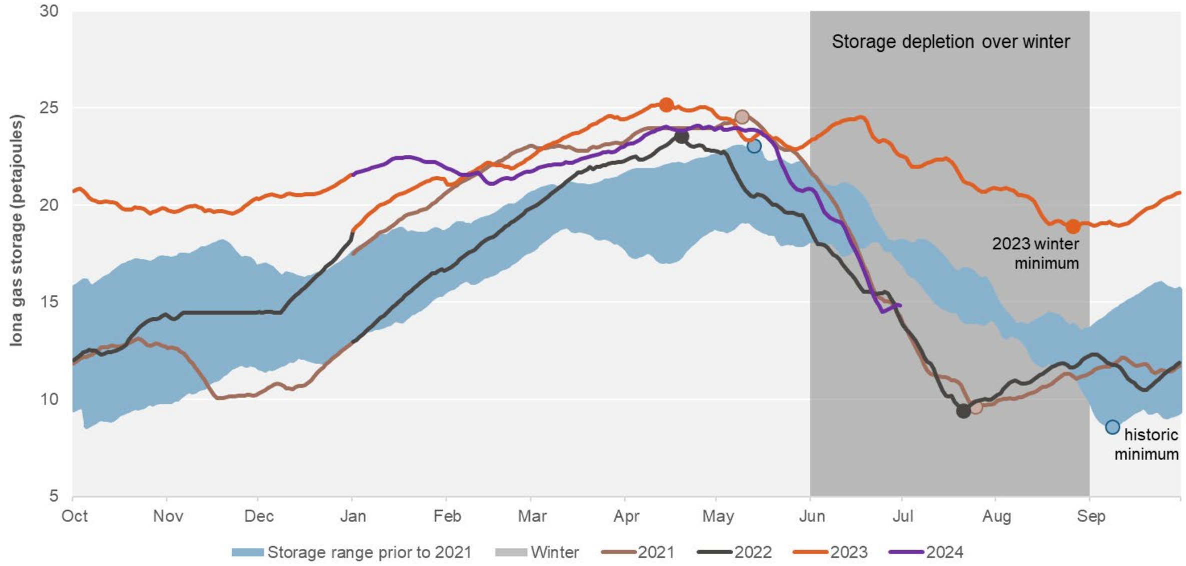
Iona Storage was drawn down heavily

The Iona storage facility saw a large volume of gas withdrawn across the quarter to meet increased demand. Iona began Q2 at lower levels than 2023, at 23.1 PJ. Storage levels increased over the month and peaked at the end of April at 24.1 PJ.

From mid-May storage levels were drawn down aggressively to support high-demand days across May and June. Withdrawal rates between 12 June and 24 June were particularly strong, averaging just under 350 TJ a day. This period coincided with high downstream demand and low Longford production.

Storage levels began to increase on 24 June, when Longford's production reached 700TJ a day, increasing 323 TJ to 30 June. Storage level ended the month at 14.8 PJ, much lower than 2023 levels, and similar to the low levels seen in 2021 and 2022.

Figure 10 Iona underground gas storage levels



Source: AER analysis using Gas Bulletin Board data.

Record daily gas flows south

In winter months southern markets depend on gas flowing south from Queensland production sources to meet the increased demand. In Q2 2024, more gas flowed south along the South West Queensland Pipeline (SWQP) than any previous Q2 since 2020. Gas began flowing south earlier than in previous years, beginning in the last week of March. Gas flow south increased in volume in April and across the quarter. Daily flows reached its highest recorded level on 12 June, with 428 TJ flowing south into Moomba.

Market participants also made use of over 30 PJ of pipeline capacity won through the Day Ahead Auction (DAA) in Q2 2024, with June recording the 4th highest monthly volumes on record. The DAA was used to send gas south, particularly in June, with volumes won south on the Moomba to Sydney Pipeline the highest on record at 3.1 PJ.

Figure 11 North-South gas flows

Note: North-South flows depict net physical flows on the SWQP around Moomba – north or south calculated as a weekly average.
Source: AER analysis using Gas Bulletin Board data.

Flows along the SWQP around Wallumbilla surpassed 500TJ a day in June, following APA's stage 2 expansion to the pipeline which increased pipeline capacity to 512 TJ per day, for gas flowing south. The stage 2 expansion facilitates additional gas flowing south during winter months.

However, ongoing production issues in the Northern Territory have meant that gas that would normally flow south along the Northern Gas Pipeline into Queensland from the Northern Territory was unavailable. This has resulted in more gas from the SWQP being diverted at Ballera to flow north on the Carpentaria Gas Pipeline towards Mt Isa to meet industrial demand.

Box 2: Q2 2024 Domestic spot market price drivers during high price periods between 1 May and 30 June 2024

Figure 12 Downstream gas spot market prices

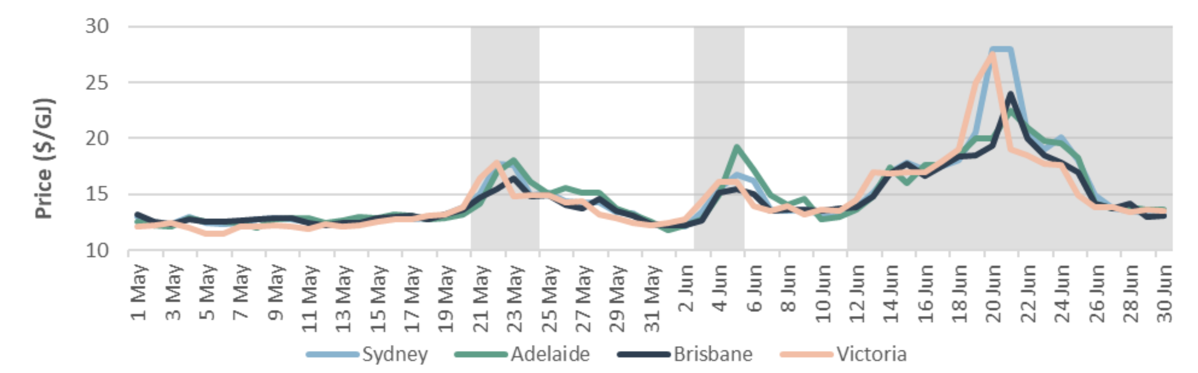


Figure 13 Scheduled demand in east coast gas markets

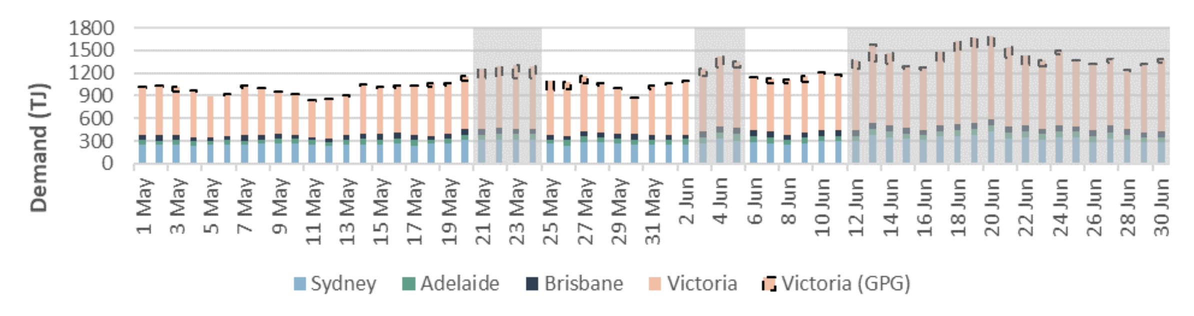


Figure 14 Gas-powered generation demand

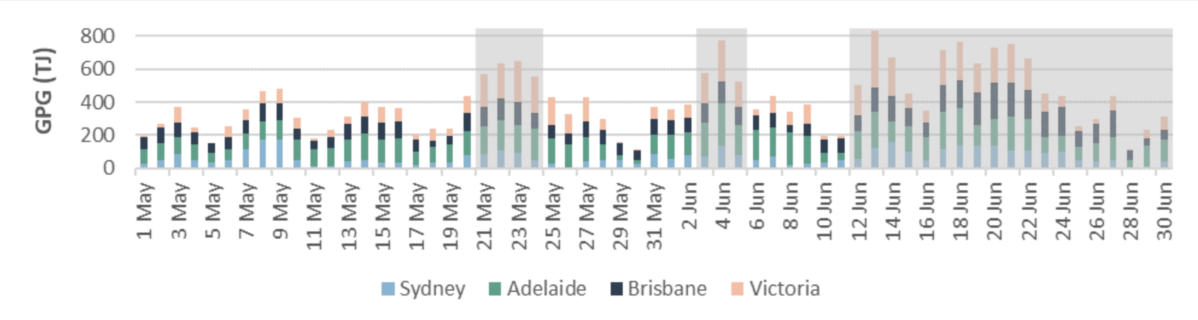
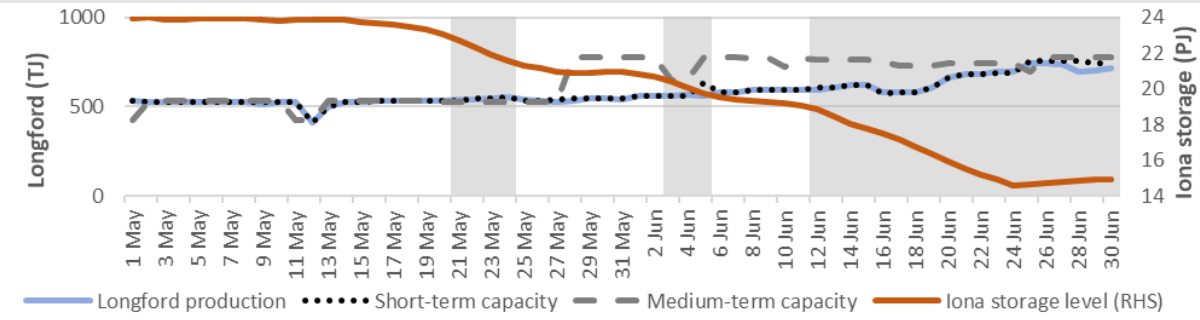


Figure 15 Longford production and Iona underground gas storage



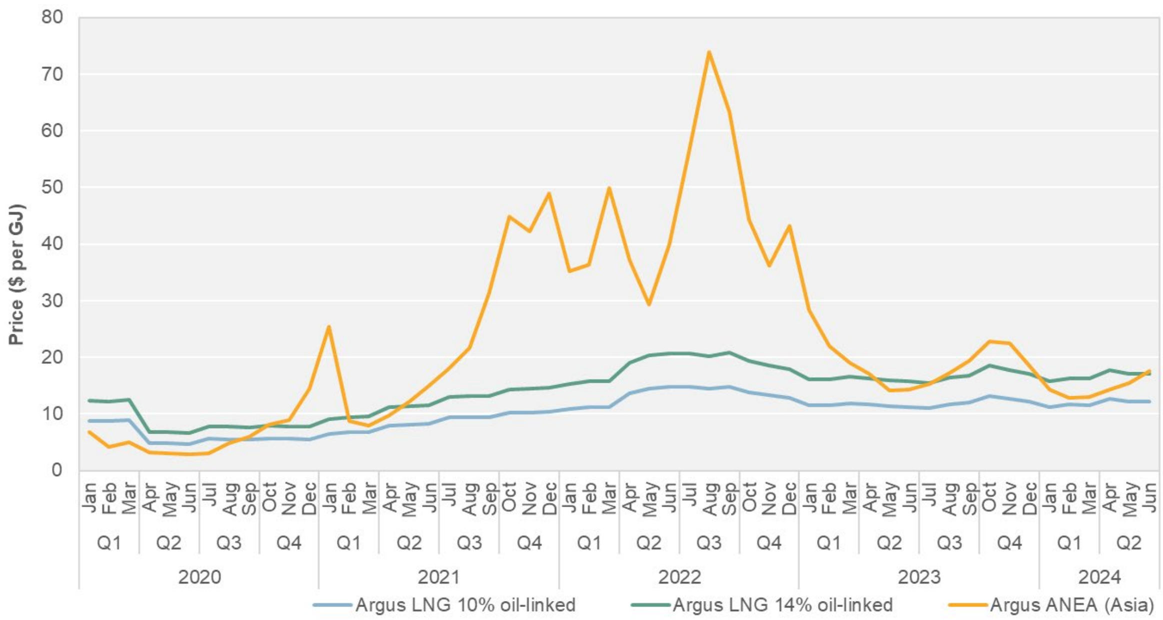
Source: AER analysis using DWGM, STTM, NEM and Gas Bulletin Board data.

Note: Gas powered generation (GPG) within the Victorian market is highlighted with a black dotted border. The only two gas-powered generators outside the Victorian market are Mortlake and Bairnsdale. Elevated east coast market demand above 1200 TJ per day is highlighted with darker shading.

Asian LNG prices increased across the quarter

International LNG spot prices increased from Q1 2024, but remain well below record levels observed in late 2021 and 2022. Asian LNG prices (measured by Argus LNG Northeast Asia price) increased 18% across the quarter compared to Q1 finishing the quarter averaging $17.64 per GJ in June. The LNG oil-linked 10% and 14% price increased in Q2 by 7% compared to Q1. The international price remains sensitive to supply constraints, however, high European storage levels should limit price pressure.

Figure 16 International LNG spot prices



Note: The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4–12 weeks before the date of delivery.
The Argus LNG 14% and 10% oil linked contract prices are indicative of a 14% and 10% 3-month average Ice Brent crude futures slope.
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Source: AER analysis using Argus Media data.

Gas market transparency measures, which commenced in March 2023, require East Coast LNG exporters to report sales of spot LNG cargoes to AEMO's Gas Bulletin Board. This is our first time reporting this information. Since March 2023, LNG exporters have reported 30 LNG spot cargo sales totalling 95 PJ of gas for delivery between October 2023 and June 2024 and 15 PJ for delivery in July to September 2024. The volume of spot cargo sales made up approximately 9.7% of total LNG exports leaving Gladstone between October 2023 and June 2024.

The volume weighted average FOB[12] price for all reported LNG spot cargo transactions was $16.35 per GJ with prices broadly in line with the Argus LNG FOB midpoint price[13]. 43 PJ of gas was traded in Q4 2023, with 36.5 PJ delivered in the same quarter, when international demand is typically at its highest and the ANEA prices averaged $21.62 per GJ. A significant portion of the transactions reported had prices linked to the JKM futures index.[14]

12 The FOB (Free on Board) price is the price for LNG at the point the LNG is loaded on the ship at the export terminal. It excludes shipping costs.

13 Argus LNG FOB midpoint price is an average price of LNG sold from Australia calculated by using delivered price of LNG to Asia-Pacific markets less the freight cost.

14 JKM (Japan Korea Marker) is the Northeast Asian spot price index for LNG delivered ex-ship to Japan, South Korea, China and Taiwan, assessed by S&P Global Platts.

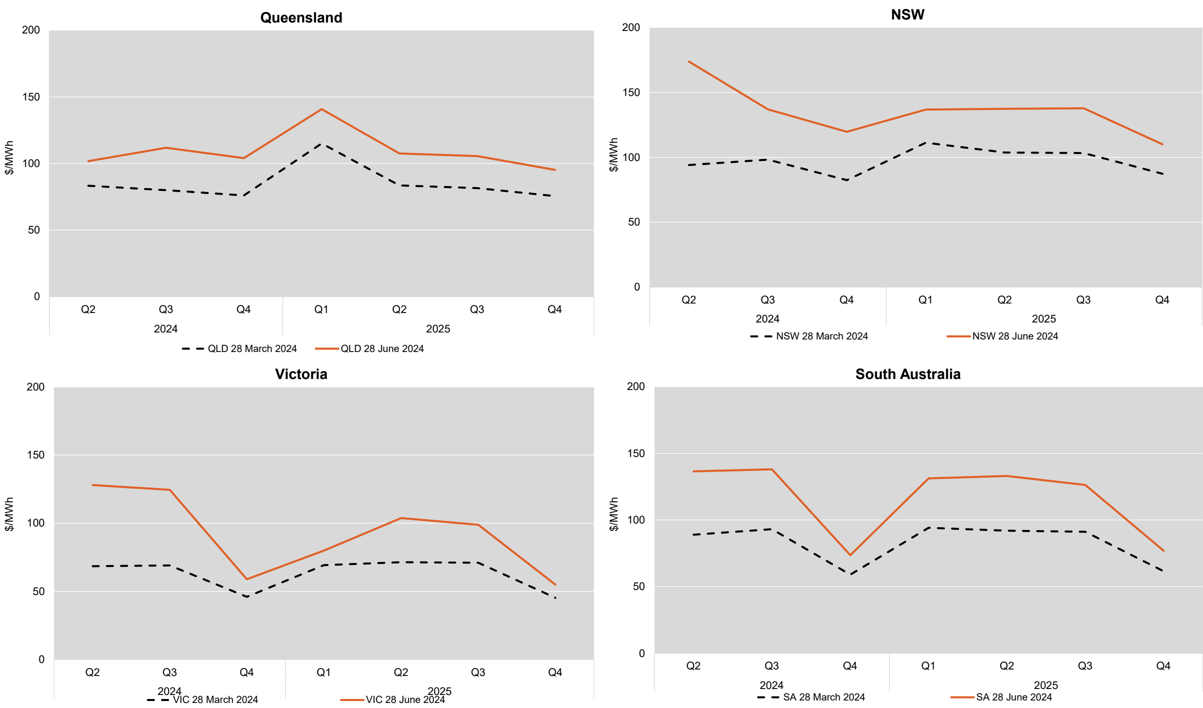
3 Electricity and gas market outlooks over winter

Forward prices of electricity increased

Generators and retailers enter derivative contracts to limit the price volatility they are exposed to when purchasing from a wholesale spot market. This function is integral to protecting both parties against price fluctuations in the spot markets resulting in the physical market and contracts markets being inextricably connected. Forward base future prices illustrate price expectations for electricity spot prices in future periods.

Base futures prices increased in Q2, reflecting higher prices in the spot market and coinciding with slowing new entry. Average forward prices for the 2025 calendar year traded in Q2 2024 increased in all regions (17), ranging from an increase of $23 per MWh in Queensland to an increase of $32 per MWh in South Australia.

Figure 17 Base quarterly electricity futures prices

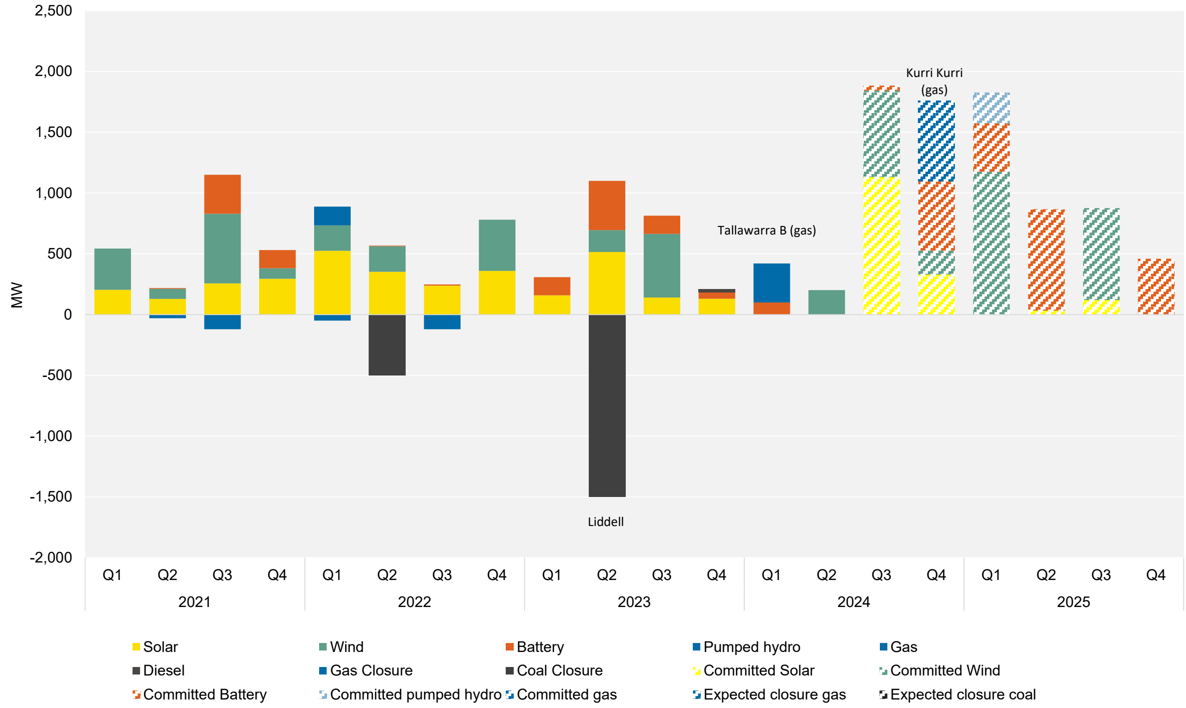


Note: Base futures prices for each quarter as of 28 March 2024 (last trading day in Q1) and 28 June 2024 (last trading day in Q2)
Source: AER analysis using NEM data.

Minimal new entry into the market

Across the NEM there was only one new generator entry in Q2. Goyder South Wind Farm 1A in South Australia was in service from April 2024. This wind farm has a registered capacity of 201 MW, but is not yet generating at full capacity. New entry is expected to increase across the rest of 2024 (18), with some of this capacity originally scheduled to come online in 2023.

Figure 18 New entry and exit



Note: Uses registered capacity, except for solar and batteries where we use maximum capacity. The new entry date is taken as the first day the station receives a dispatch target. Solar reflects large-scale solar and does not include rooftop solar PV systems. Committed projects include some projects that are listed as anticipated in AEMO's Generator Information.
Source: AER analysis using AEMO Generator Information.

Gas markets are vulnerable to shocks for the remainder of winter

AEMO's system threat or shock notice identified the likely duration of the risk to gas supply will continue until 30 September 2024. Southern markets remain susceptible to demand and supply shocks, including persistently high residential and GPG demand, further unplanned outages at Longford and any further constraints on pipelines bringing gas south.

At the beginning of July, the medium-term capacity outlook forecast for production at Longford indicated an expected production range between 695 TJ and 775 TJ a day over the remainder of winter. Southern markets will need to rely on continued gas flows south from Queensland and gas from the Iona storage facility to supplement gas sourced from Longford.

At the end of June, the Iona storage facility was at 14.8 PJ. If levels fall to around 6 PJ, pressure constraints will limit the rate at which gas can be withdrawn, putting further pressure on supply and downstream prices, particularly on peak demand days.

AEMO has not been required to intervene in the market, however it outlined the industry response, if any, it considered necessary to mitigate the system threat:

- Market participants delivering gas to end users in southern jurisdictions, to take reasonable measures to maximise production and supply from Queensland to reduce the rate of storage depletion.
- Relevant entities to consider their gas demand requirements (including GPG) and the source of supply to meet that demand.

If the risk to reliability or supply adequacy worsens, AEMO may be required to intervene. In accordance with the NGL and NGR, AEMO has the power to give a written direction to relevant entities to maintain and improve the reliability or adequacy of the supply of natural gas within the east coast gas system.

AEMO utilised these powers in 2022, requesting market participants not to withdraw gas from the DWGM unless they were supplying sufficient gas to meet the demand. Following this request, AEMO directed the curtailment of gas withdrawals for two gas-powered generators.[15]

Short term contract prices for 2025 averaging around $15 per GJ

A significant proportion of gas trade is negotiated directly between participants outside of the AEMO-facilitated markets. Since March 2023, participants have been required to report details of these bilateral transactions up to a year in duration to the AER.[16]

In Q2 2024, participants traded 45.7 PJ of gas under short-term bilateral contracts, around 2 PJ more than traded in Q1 2024. 27.2 PJ of gas was sold for delivery in Q3 and Q4 2024, with around 7.5 PJ for delivery in 2025 and 1.3 PJ for delivery as far out as 2026-2027. Most gas traded in Q2 2024 was priced between $12 and $16 per GJ (58%), with 32% of gas priced below $12 per GJ, and the remainder priced between $16 and $20 per GJ.

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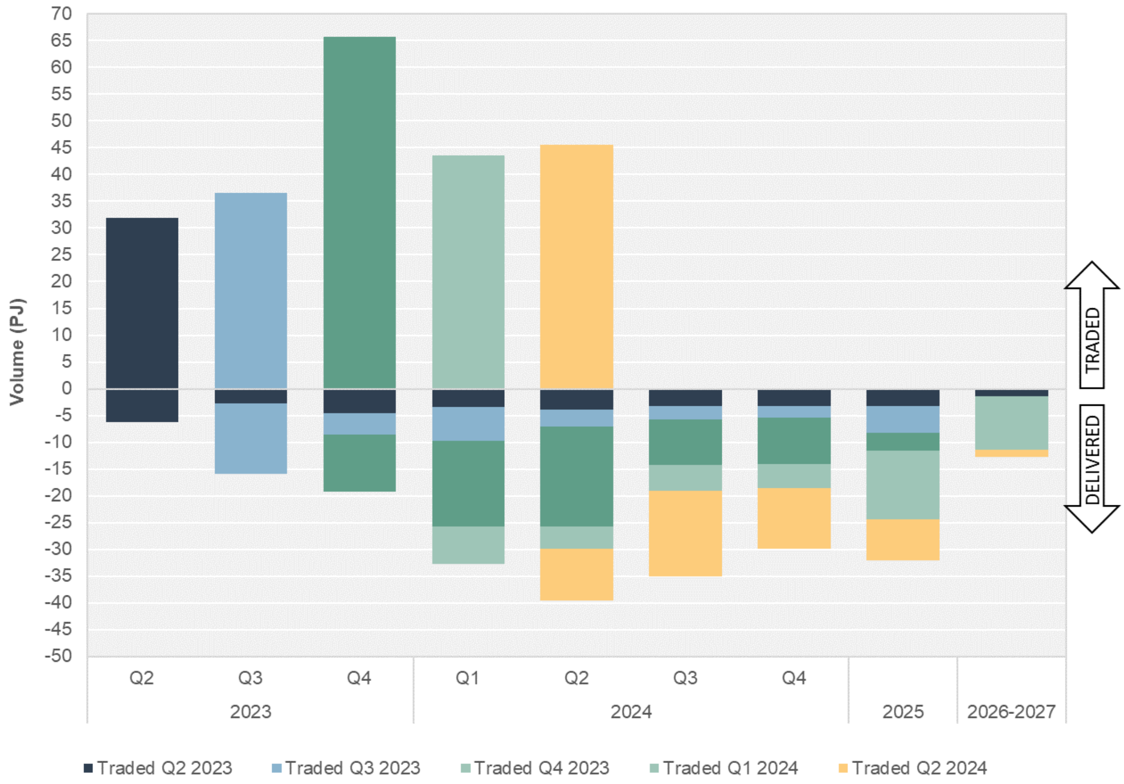
15 AEMO, Declared Wholesale Gas Market – Intervention Report, October 2022, Declared Wholesale Gas Market – Intervention Report

16 From 15 March 2023, as part of the Gas Market Transparency reforms, short term transactions with a contract length of 12 months and less are required to be reported to the Bulletin Board.

Figure 19 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 using Natural Gas Services Bulletin Board data.

The volume weighted average (VWA) price for gas delivered in Q2 was $13.48 per GJ with forward prices for the remainder of 2024 remaining relatively stable, averaging $13.9 per GJ in Q3 and $12.99 per GJ in Q4 (Figure 20).[17]

When comparing the VWA forward prices for each quarter, prices for delivery in 2024 decreased quarter on quarter with Q2 2024 the first quarter where average prices increased.

Forward prices for delivery in 2025 are higher than 2024 prices, averaging $15.26 per GJ. The 2025 VWA price is still heavily influenced by a large volume of contracts traded in Q1 2024, with an average price of $15.23 per GJ. We anticipate increased volumes of gas being traded for 2025 and beyond over the remainder of this year, particularly in Q4 when market participants generally finalise their contracted positions for the year ahead.

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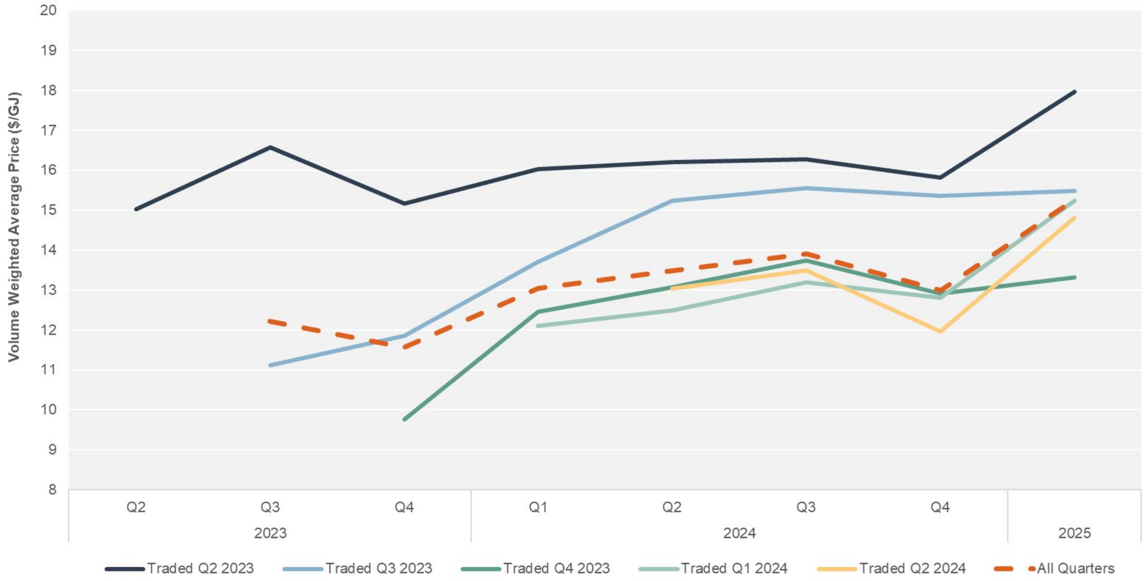
[17] The volume weighted average prices are based on the supply dates of the reported transactions and excludes pricing structures linked to the STTM or DWGM.

Figure 20 VWA forward price curve based on the traded quarter



Note: The above 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 using Natural Gas Services Bulletin Board data.