Wholesale markets quarterly

Q1 2025

January - March

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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 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 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.

Contents

1 Executive Summary

This report presents trends in the wholesale electricity and gas markets over Quarter 1, January to March 2025. It focusses on wholesale energy prices and their drivers, including demand, generation, offers, contracts, market outlook and new entry and exit.

Results are based on AER analysis using data from the National Electricity Market (NEM), Australian Energy Market Operator (AEMO), Australian Securities Exchange (ASX), East Coast gas market, Gas Bulletin Board and Argus media.

1.1 Key insights

Energy market outcomes over summer were mixed, highlighting the complex relationship between weather conditions, shifting demand profiles and the diverse mix of generation types in the NEM.

Electricity prices were very low or negative during times of high intermittent renewable output, while high price periods emerged during times of unusually high demand or when operational issues reduced availability of lower-priced generation. Dispatchable generation (coal, gas, hydro and battery) continued to set prices at higher levels in times of tight supply-demand conditions. A record amount of new battery entered the market this quarter.

Gas prices also varied across regions, with lower than usual demand in Victoria supporting a $1-2 price difference between the DWGM and other domestic spot markets. Overall, prices across all domestic spot markets are sitting higher than a year ago for similar demand levels. Southern supply conditions have improved compared to the same time last year, with higher storage levels at Iona (Victoria's largest gas storage facility) and more stable production at Longford.

Electricity

- By region, compared with the previous quarter, prices were lower in the northern regions in Queensland and NSW due to a reduction in the number of high price events. Prices were higher in South Australia and Victoria, driven by seasonal increases in average quarterly demand. Tasmania's significant price increase was due to a reduction in lower-priced hydro offers.
- Similarly, compared with the previous year, prices were lower in the northern regions and higher in the southern regions. Lower prices in Queensland and NSW were largely due to lower demand and a reduction in the number of high price events. Higher prices in South Australia and Victoria were primarily driven by higher demand due to high temperatures.
- There were fewer high price events (11) this quarter than a year ago (26 events) and compared to the previous quarter (23 events, which included 2 FCAS events). High price events occurred in Queensland (3), NSW (4), Victoria (1) and South Australia (3). The reduction in high price events contributed to lower year on year average prices in NSW and Queensland.
- This quarter saw an increase in negative-priced 30-minute periods for the NEM compared with the same quarter last year, with significant increases in Queensland and

NSW. A new record of 699 negative prices was set for NSW in this quarter, driven by large-scale solar and wind setting the price more often.

- A new maximum daily electricity demand record was reached in Queensland on 22 January 2025, driven by hot weather with record maximum temperatures for much of the state.[1] There was also an observable dip in daily electricity demand leading up to Cyclone Alfred in Queensland (5 to 8 March 2025). Conversely, NSW, South Australia and Victoria recorded minimum daily demand records.
- The total volume of offers was higher compared with the previous year, with the largest increases recorded at either end of the price spectrum – in offers below $0 per MWh and above $5,000 per MWh. The volume of coal and hydro offers were lower overall. Offers below $70 per MWh decreased with black coal, brown coal, gas and hydro all reducing their offers. Solar and wind both increased the volume of their offers.
- Solar and wind set the price significantly more often in Queensland, NSW and South Australia. Hydro set the price less often in all regions except Tasmania.
- While the level of new entry was lower compared with the previous quarter (921 MW of generation, solar and battery) commencing this quarter, new entry of battery was the highest recorded to date (845 MW) and included 460 MW from the Eraring BESS in NSW.
- Base future prices for 2025 fell in Queensland, NSW and South Australia, indicating a general market expectation of decreasing spot market prices. Q1 2025 cap contract prices[2] declined in all regions (down between 94% in Victoria and 76% in South Australia during the quarter). This decrease reflects a relatively low number of 5-minute intervals priced above $300 per MWh across the NEM.

Gas

- Gas prices decreased from Q4 2024 in line with seasonal low demand over summer but were 14% higher than Q1 last year.
- While overall demand in Q1 was marginally higher compared to last year, Victoria recorded its lowest ever demand for Q1. This was partly due to decreased commercial and industrial gas consumption.
- The price differential between the Brisbane and Victorian downstream markets persisted, with Brisbane STTM averaging $1.45 per GJ higher than the Victorian DWGM prices across the quarter.
- Iona has been steadily refilling since mid-December 2024 and is on track to reach its capacity of 24.4 PJ by May 2025.
- Longford production exceeded levels from Q1 2024 and average daily production was also higher than Q1 last year.

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1 Bureau of Meteorology: Queensland in summer 2025 (accessed 15 April 2025).

2 The standard cap contract traded in the market is a “$300 cap”. This means the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh every time the spot price exceeds $300/MWh during the specified contract period (AEMC: Spot and contract markets).

- Northern flows have decreased from the all-time high recorded in Q4 2024, but remained elevated on average compared to levels seen in over the past 4 years in the January to March quarter.
- Trade volumes through short term bilateral contracts were lower compared to Q4 2024 and the same time last year. The average volume-weighted price for delivery over the remainder of 2025 is $13.70 per GJ, currently projected to peak in Q2 at $14.55 per GJ in the southern states - almost $2 per GJ higher than in Queensland.
- Combined shipments exported on the LNG spot market were down from the previous quarter but mostly in line with Q1 last year. During the quarter, disruptions linked to Ex-Cyclone Alfred led to some delays in LNG shipments.

2 Electricity

This section provides discussion of prices, demand, offers, generation, coal availability and interconnector flows.

Results are based on AER analysis using NEM data sourced from AEMO.

2.1 Electricity prices

Wholesale spot prices decreased in the northern states, but increased in the southern states

The NEM is a wholesale spot market where electricity is traded every 5 minutes.[3]

Compared to the previous quarter, prices fell in the northern regions and rose in the southern regions. Price falls in NSW (down 43%) and Queensland (down 31%) were primarily driven by a reduction in the number of high price events, while prices in South Australia (up 21%) and Victoria (up 25%) driven up by higher average demand and an increase in the number of high price events in Victoria. The significant price rise in Tasmania (up 49%) was driven by a reduction in the volume of low-priced hydro offers due to dry weather conditions.

Q1 2025 volume weighted average prices were lower than Q1 2024 prices in the northern states of Queensland and NSW but higher in the southern states of Victoria, South Australia and Tasmania (Figure 1):

- Queensland – $102 per MWh, down 26% from Q1 2024
- NSW – $97 per MWh, down 5% from Q1 2024
- Tasmania – $112 per MWh, up 64% from Q1 2024.
- South Australia – $98 per MWh, up 17% from Q1 2024
- Victoria – $72 per MWh, up 4% from Q1 2024

Price decreases in the northern states were driven by lower demand compared with the same quarter in the previous year and fewer high price events.

In Victoria and Tasmania, elevated prices throughout the day reduced the influence of fewer high price events. In South Australia and Victoria, price rises were largely driven by high demand caused by high temperatures. The significant price rise in Tasmania was due in part to hydro generators reducing their lower-priced offers in response to dry weather conditions.

The percentage of time that a region was price aligned with at least one other region was lower than a year ago, this was particularly evident for Victoria and South Australia. This suggests network limitations are contributing to price variances across the northern and southern regions in the NEM.

Wholesale electricity contracts that hedge the price of electricity in the future as opposed to the spot markets are not traded in the NEM and are discussed separately in Section 4.1.

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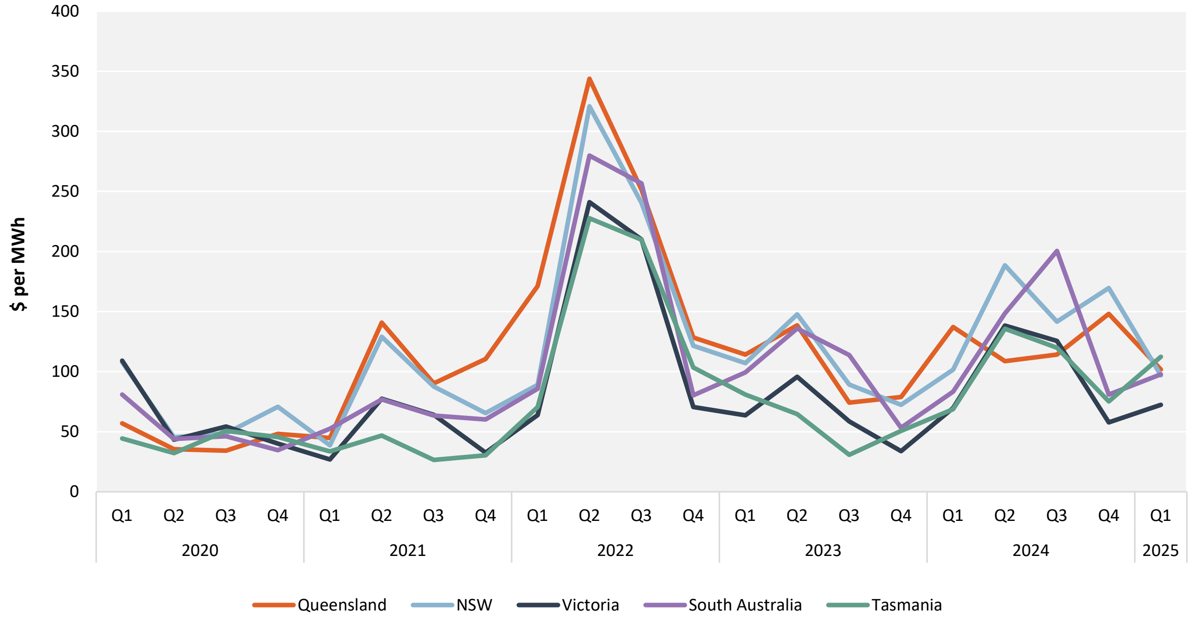
[3] The AER monitors volume weighted average prices, meaning prices are weighted against native demand in each region. AEMO generally uses time-weighted average prices in their publications.

Figure 1 Average quarterly prices in the NEM by region



Note: This chart illustrates volume weighted average quarterly prices, meaning prices are weighted against native demand in each region. Uses quarterly average native NEM demand. 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[4].

Source: AER analysis using NEM data.

There were 11 high price events in Q1 2025 (down from 26 in Q1 2024 and 23 events in the previous quarter), where the 30-minute prices exceeded $5,000 per MWh – 3 were recorded in Queensland, 4 in NSW, 3 in South Australia and 1 in Victoria. These high price events were largely driven by high demand, following higher than usual average maximum and minimum temperatures across most of the NEM. During the high-price periods, network outages prevented some low-priced offers making it to market. Similar to the previous quarter, most outages were in southern NSW and were planned. The AER will publish a high price report in May 2025 containing detailed analysis of the January to March high price periods.

While the number of high price events has reduced year on year, the number of 30-minute negative prices has increased. In Q1 2025, the NEM recorded 3,598 negative price 30-minute periods, 834 more compared with the same period last year (Figure 2). Consistent with the previous quarter, South Australia and Victoria had the largest number of negative price intervals (1,305 and 1,031 respectively), driven by higher rooftop solar output, increased wind generation and, to a lesser extent, increased grid-scale solar. In Victoria the impact of negative prices on average quarterly prices outweighed the impact of high price events.

By region, high-price periods drove up the average quarterly price by:

- $16 per MWh in South Australia (up from $14 per MWh in Q1 2024)

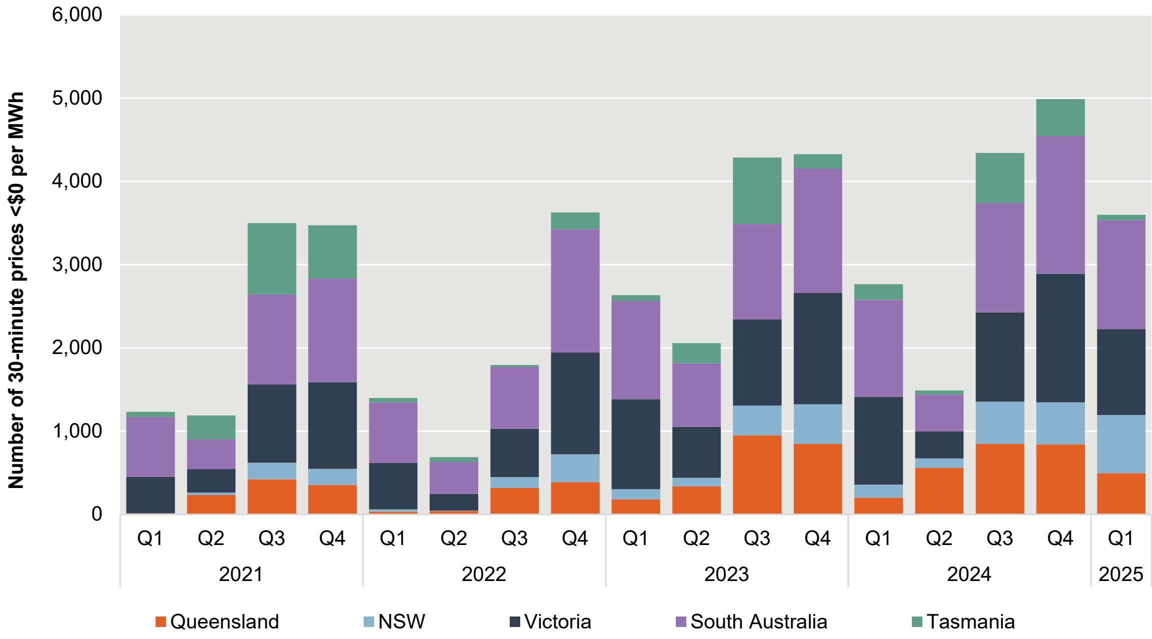
[4] For definitions of demand terms used by AEMO in its reporting, see *Demand terms in the EMMS data model*, June 2024.

- $14 per MWh in Queensland (down from $30 per MWh in Q1 2024)
- $8 per MWh in NSW (down from $14 per MWh in Q1 2024)
- $3 per MWh in Victoria (down from $23 per MWh in Q1 2024).

By region, negative prices reduced the quarterly volume-weighted average price by:

- $8 per MWh in South Australia (up from $7 per MWh in Q1 2024)
- $6 per MWh in Victoria (down from $9 per MWh in Q1 2024)
- $4 per MWh in Queensland (up from $0 per MWh in Q1 2024)
- $2 per MWh in NSW (up from $1 per MWh in Q1 2024).

Figure 2 Count of 30-minute negative prices per quarter



Note: This chart illustrates the number of 30-minute prices under $0 for each quarter.

Source: AER analysis using NEM data.

2.2 Electricity demand

All-time maximum and Q1 minimum demand records were set this quarter

Across the NEM, average demand[5] Q1 2025 was similar to the same period in 2024, with a very small 0.2% year on year increase (Figure 3). Demand continued to increase in the evening peak and overnight, but was lower during solar hours due to higher rooftop solar output reducing demand from the grid.

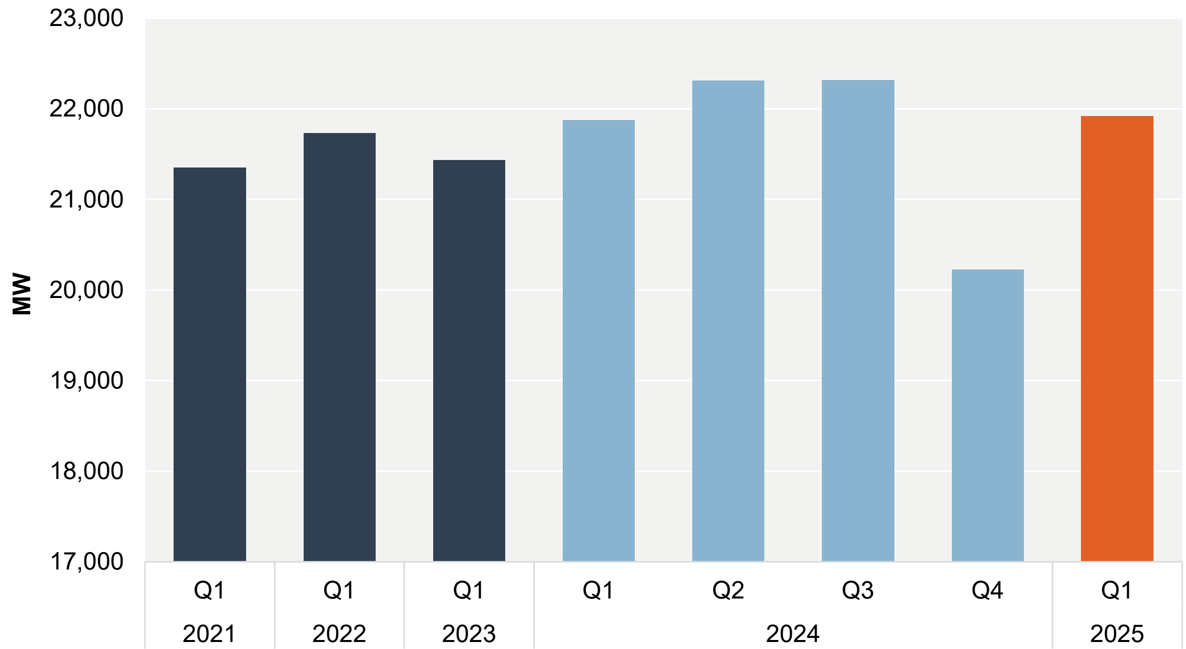
Overall, increases in South Australia (+6%) and Victoria (+5%) were largely offset by decreases in Tasmania (-6%), Queensland (-2%) and NSW (-1%). In South Australia and

[5] The AER defines native demand as the sum of initial supply and total intermittent generation in a region. This figure presents outcomes in NEM time (Australian Eastern Standard Time).

Victoria, high demand was driven by a series of hot days with both high maximum and high minimum temperatures. Maximum daily demand in South Australia approached its all-time record set in Q1 2011 (3,397 MW) on some days this quarter, despite an overall downward trend in demand due to increased uptake of rooftop solar in recent years.

On 16 February 2025 both NSW and South Australia recorded minimum Q1 demand records, at 3,620 MW and -13 MW respectively. Victoria also hit minimum Q1 demand record at 1,598 MW on 1 January 2025. In Queensland, an all-time maximum demand record of 11,258 MW was set on 22 January, partly due to warm and humid evening conditions, surpassing the previous record (notably reached on the same day in 2024) by 203 MW.

Figure 3 Quarterly average NEM demand

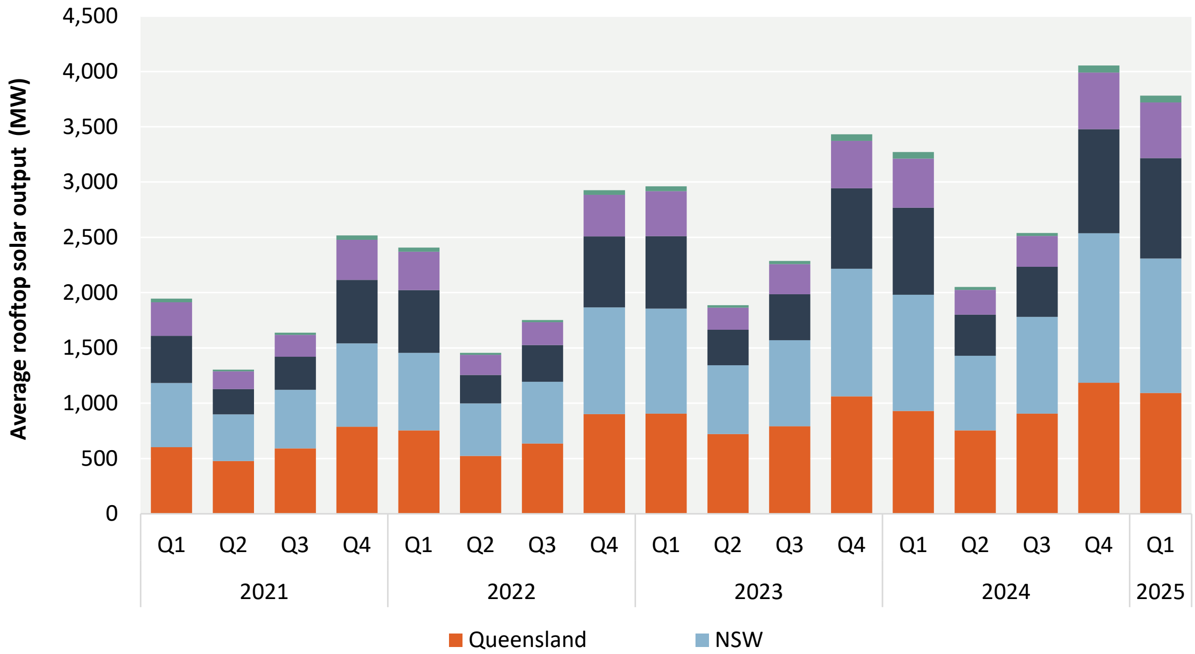


Note: The AER defines native demand as that which is met by all local scheduled, semi-scheduled and non-scheduled generation, plus interconnector imports. It does not include demand met by rooftop solar systems.

Source: AER analysis using NEM data.

Average rooftop solar output was lower this quarter than the previous, which is typical due to seasonal changes in solar patterns. However, year on year solar output continued to rise, up 16% (Figure 4), and underpinned by new installation throughout the year.

Figure 2 Quarterly average rooftop solar output



Note: Shows average rooftop solar output by region and quarter. Due to the time-of-day pattern of solar output, maximum output can be several times higher than average output.

Source: AER analysis using AEMO rooftop PV data.

2.3 Offers

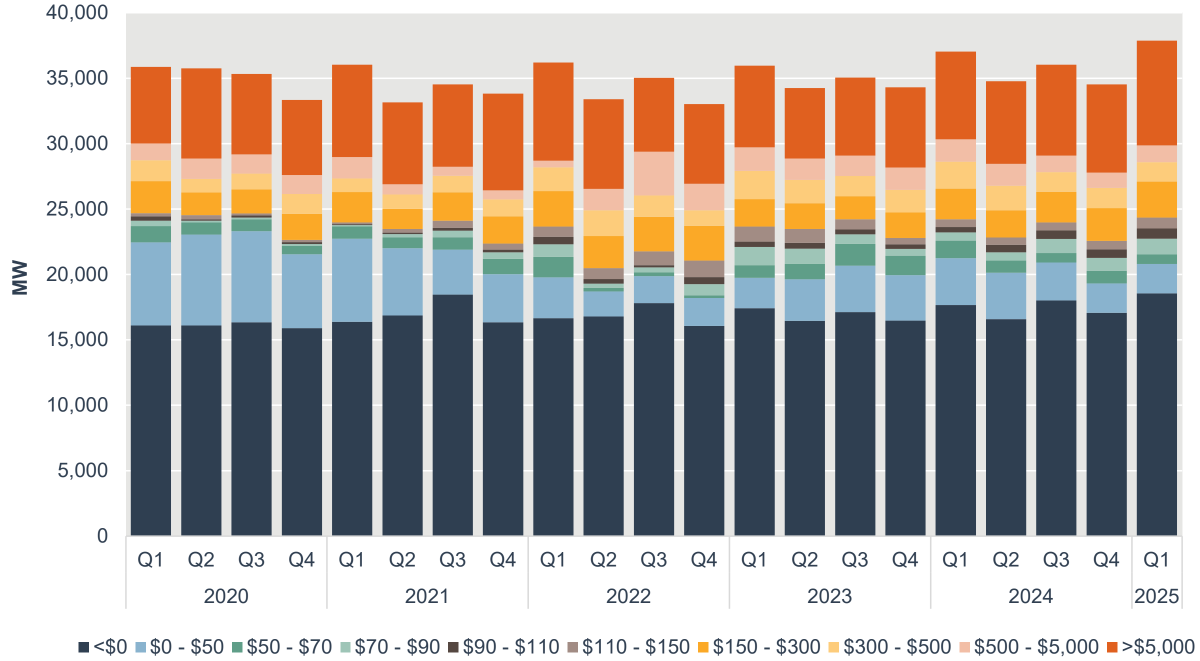
Offers shifted towards both ends of the price band range

The volume of total offers increased by 778 MW compared with the first quarter of 2024. Black coal (341 MW), hydro (256 MW) and brown coal (205 MW) all reduced their total offers, while volumes of offers from all other fuel types were higher.

Offers below $70 per MWh decreased by 1,108 MW, despite an increase of 895 MW in offers below $0 per MWh. Dispatchable generation (excluding batteries) all reduced their offers (black coal 951 MW, hydro 543 MW, brown coal 399 MW and gas 136 MW). Wind (606 MW) and solar (322 MW) increased their offers in these price bands.

Offers between $70/MWh and $300/MWh increased by 1,593 MW, mainly due to an increase in offers from black coal (679 MW) and hydro (515 MW). Offers above $5,000 per MWh increased by 1,308 MW, driven by hydro (488 MW) and black coal (453 MW).

Figure 5 NEM offers by price band



Note: Average quarterly offered capacity by price bands.

Source: AER analysis using NEM data.

Hydro generators moved offers to higher-priced bands in response to dry weather and low dam levels. The shift in black coal offers to higher prices may be driven in part by higher fuel costs, as international coal prices remain above the market intervention price (which was in effect in Q1 2024). The shift towards higher priced offers by gas-powered generators may reflect higher input costs compared with a year ago (Section 3.1).

Figure 6 NEM offers in Q1 2025 compared to Q1 2024

Note: Change in NEM average quarterly offered capacity by price bands from Q1 2024 to Q1 2025.

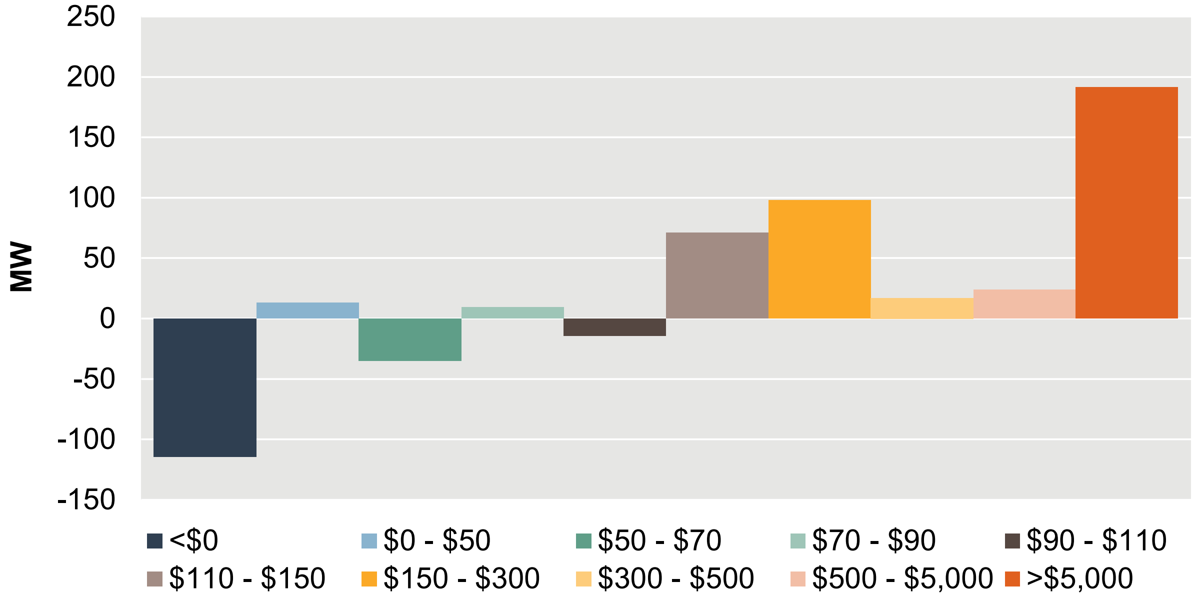
Source: AER analysis using NEM data.

Figure 7 NEM black coal offers in Q1 2025 compared to Q1 2024

Note: Change in NEM black coal average quarterly offered capacity by price bands from Q1 2024 to Q1 2025.

Source: AER analysis using NEM data.

Figure 8 NEM gas-powered generation offers in Q1 2025 compared to Q1 2024



Note: Change in NEM gas average quarterly offered capacity by price bands from Q1 2024 to Q1 2025.

Source: AER analysis using NEM data.

2.4 Price setter

Large-scale solar and wind generation set the price higher and more often

Compared with Q1 2024, large-scale solar and wind generation set the price more often and at higher prices across all NEM regions, with significant increases in South Australia (21% to 27%), Queensland (7% to 17%) and NSW (6% to 14%). Higher amounts of wind in Victoria and South Australia also reduced the number of times dispatchable generators set the price outside of solar hours compared with the same time in the previous year.

Coal set the price less often but at higher levels in all regions, with significant reductions in frequency in Victoria and South Australia. In Victoria, coal was replaced by other dispatchable generation, while in South Australia it was primarily replaced by increased wind and solar generation.

Batteries set the price more often across all regions, which reflects a significant increase in battery generation compared with a year ago (Section 2.5).[6]

Hydro set the price less often than a year ago in all regions except for Tasmania. Hydro set the price at lower levels in the northern regions, but at much higher levels in the southern regions.

2.5 Generation by fuel source

Intermittent renewables generation increased significantly

Year on year, total NEM generation increased slightly. Intermittent renewable generation (large-scale solar and wind generation) increased significantly with wind up 545 MW and solar up 221 MW. Battery discharge volumes continued to grow and were up 85.5% compared with Q1 2024. Generation by all other fuel types declined.

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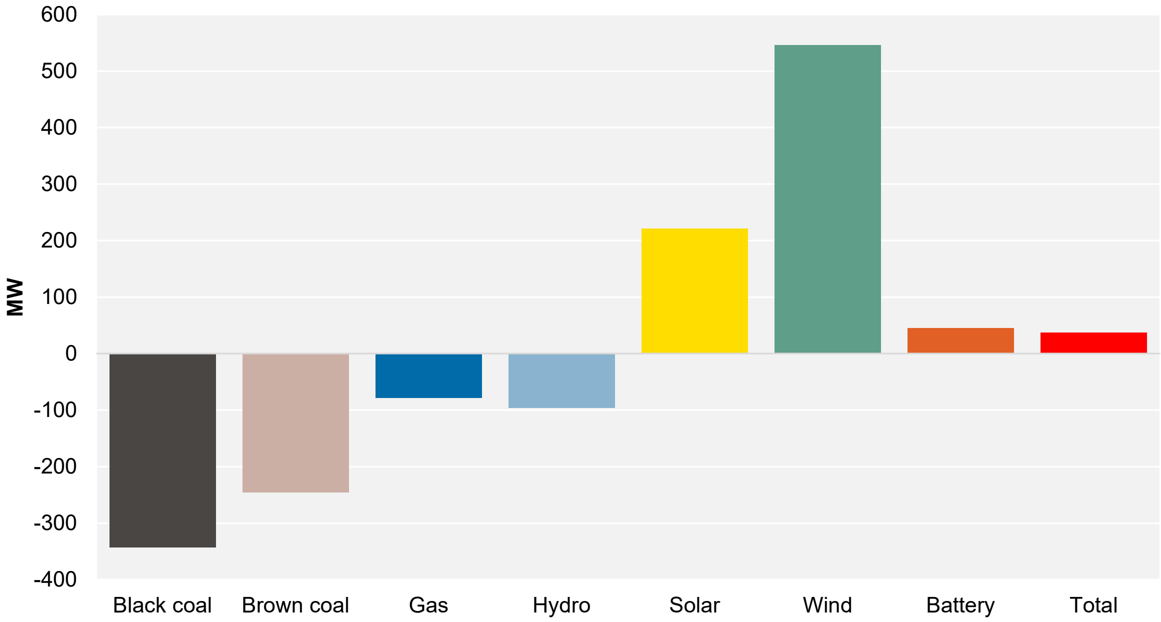
6 Loads, including charging batteries, can set price in the NEM. For example, loads can set price when it is more cost effective to reduce load consumption by 1 MW than to increase generation by a MW. Reducing load consumption can lead to reduced generation requirements, which can mean that more expensive generation is not required to meet demand.

Figure 9 Change in NEM generation output by fuel source, Q1 2025 vs Q1 2024



Notes: This chart illustrates the change in average quarterly metered NEM generation by fuel type, Q1 2025 compared with Q1 2024. 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 NEM data

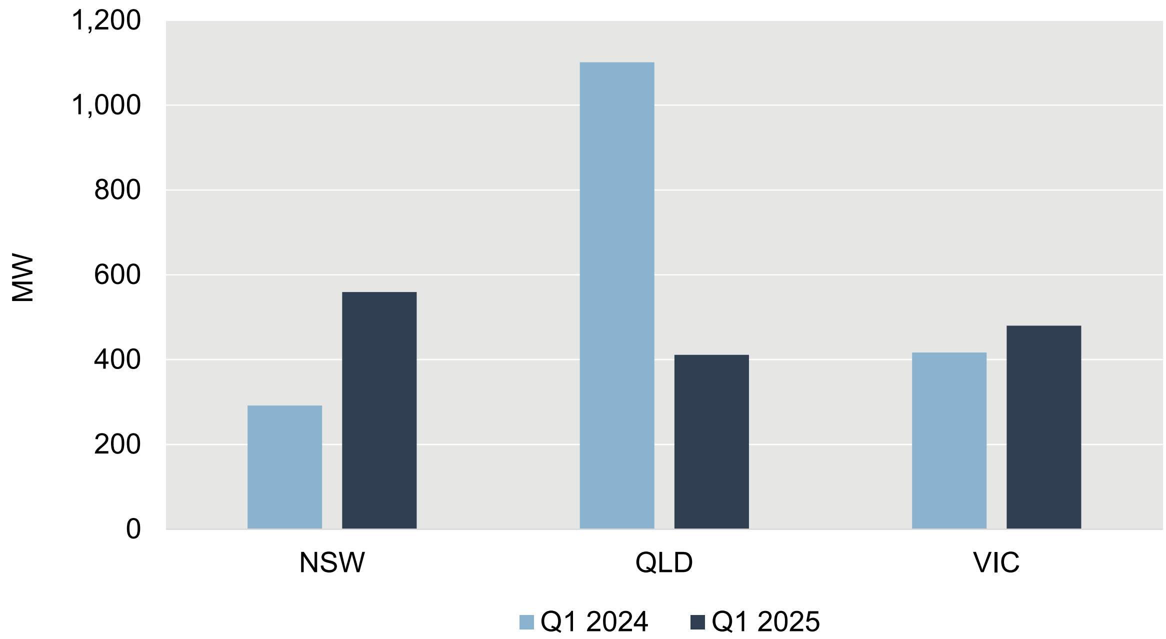
2.6 Coal outages

Offline coal capacity decreased both quarterly and annually

Overall, the average level of coal capacity unavailable due to outages was lower by 359 MW (20% reduction) compared with Q1 2024. This improvement was predominantly due to units from the Callide C power station coming back online in Queensland during Q2 and Q3 2024.[7] The coal capacity offline due to outages in Queensland decreased by 59% compared with the same time in 2024. However, this was partially offset by increases in offline capacity in NSW (108%) and Victoria (45%).

[7] Callide C3 went offline in October 2022 and returned to service in April 2024. Callide C4 went offline in May 2021 and returned to service in August 2024.

Figure 10 Average capacity unavailable due to coal outages, Q1 2024 and Q1 2025



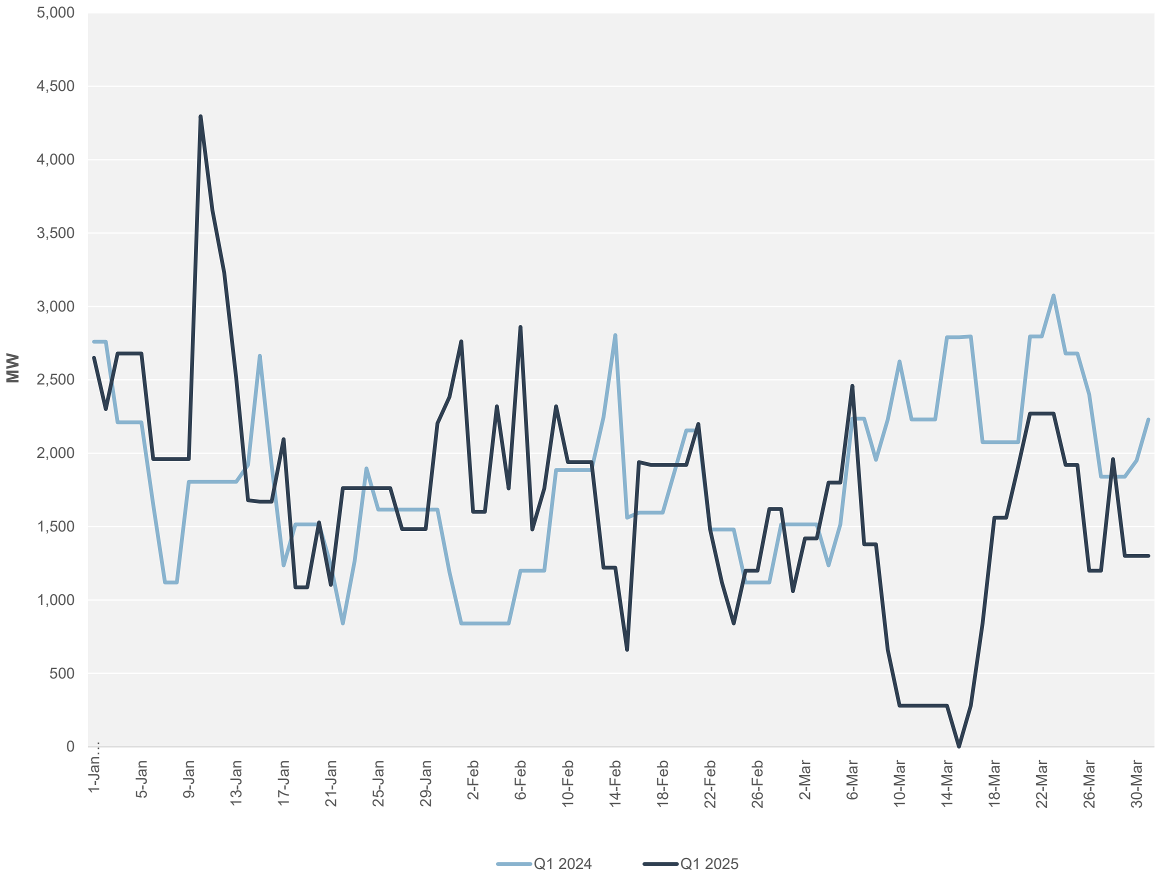
Note: This chart illustrates the average registered capacity unavailable due to coal outages. The AER counts units as unavailable only if the unit is completely offline for the whole day (This differs from AEMO's method to calculate its outage data and this can lead to differences between AEMO and AER's reported outage data).

Source: AER analysis using NEM data.

Outages usually peak in spring and autumn seasons and remain relatively low in Q1 when demand is high. Outages in March 2025 were significantly lower compared with March last year, which is notable given outages usually start to increase leading into autumn. This reflected an overall improvement in baseload capacity after the Callide C power station returned to service during 2024.

However, there was an unusual spike in January this year due to a number of unplanned outages on 10 January 2025 in NSW, Queensland and Victoria.

Figure 11 Daily NEM coal capacity offline



Note: Daily registered capacity unavailable due to coal outages. The AER counts units as unavailable only if the unit is completely offline for the whole day (This differs from AEMO's method to calculate its outage data and this can lead to differences between AEMO and AER's reported outage data).

Source: AER analysis using NEM data.

2.7 Interregional trade of electricity

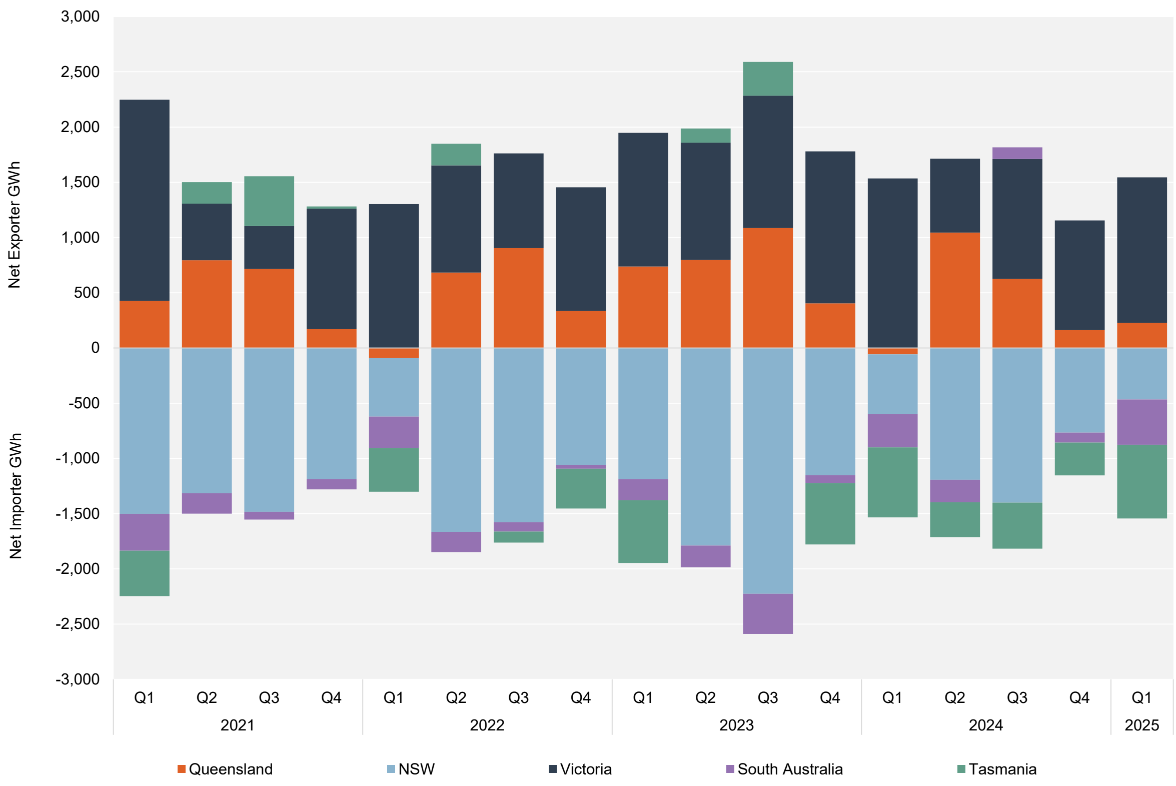
NSW's net import dropped significantly, while Tasmania's levels continued to grow

Interconnectors allow regions to import cheaper generation from neighbouring regions. Queensland and Victoria tend to be net exporters, providing surplus capacity to NSW and South Australia.

Queensland's interregional trade often follows a seasonal pattern, exporting more during winter and less during summer when it experiences higher demand. In Q1 2025, Queensland's net exports remained at typical low levels, despite a slight increase from the previous quarter, and a more significant increase compared with the previous year when it was a net importer due to unusually high demand.

NSW's net imports this quarter were the lowest in the last decade, partly driven by low demand. Net imports in South Australia and Tasmania increased year on year. Hot weather conditions in South Australia drove demand significantly higher, while local generation remained steady. In Tasmania, continued dry weather and higher-priced offers from hydro generation increased the demand for imported electricity.

Figure 12 Net interconnector flows by regions



Note: Net amount of energy either imported or exported each quarter by region.

Source: AER analysis using NEM data.

3 Gas

This section provides a discussion of domestic prices, demand, storage and transportation, and international prices and demand.

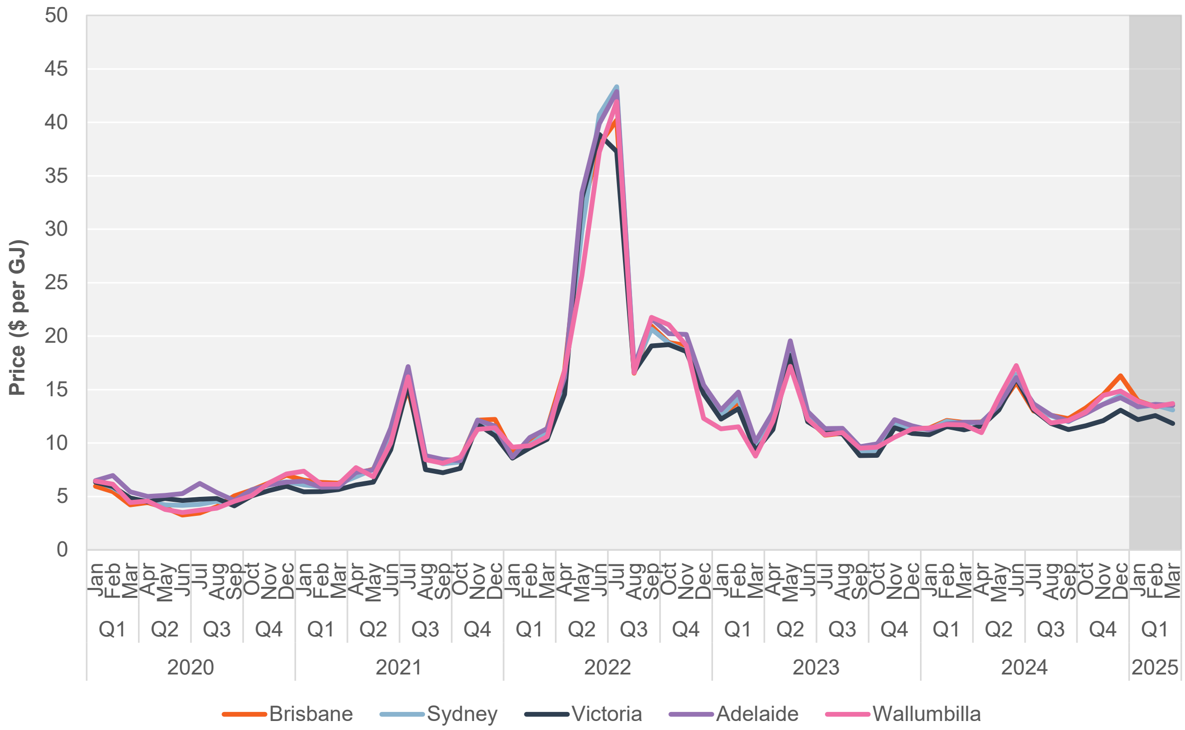
Results are based on AER analysis using data from the East Coast gas market, Gas Bulletin Board and Argus media.

3.1 East Coast gas market spot prices

Gas prices decreased over Q1, averaging $13.17 per GJ

East Coast downstream gas market spot prices decreased by 2.8% from the previous quarter to $13.17 per GJ, but were 13.7% higher than the same period last year despite marginally lower demand levels (Figure 13). Average quarterly prices ranged from $12.19 per GJ in Victoria to $13.64 per GJ in Brisbane.

Figure 13 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).

Downstream market prices remained relatively stable below $15 per GJ across the quarter. Prices in Victoria remained around $1-2 per GJ lower than prices in the STTM regions (Adelaide, Brisbane and Sydney).

Victorian prices experienced short-term declines, dropping to levels close to $10 per GJ in late February and late March.[8]

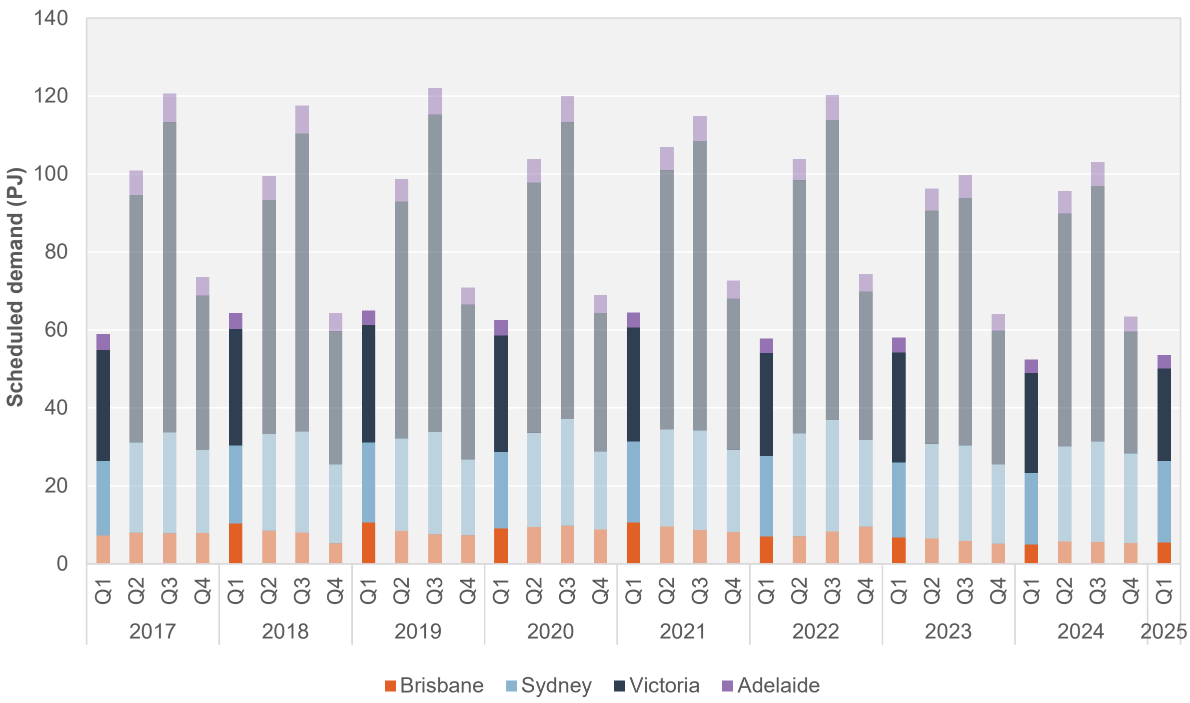
Overall, net trade increased compared with Q1 levels in 2024 but did not maintain the large increases that occurred in December 2024.

3.2 Scheduled demand for gas

Demand decreased in Q1, though was marginally higher compared to the same time last year

Downstream demand levels remained low, decreasing from the previous quarter to levels slightly above the record low Q1 levels observed in 2024 (Figure 14).

Figure 14 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 and Sydney demand each include one gas-powered generator (GPG) (Swanbank E and Colongra), 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).

In contrast to Victoria where monthly demand dropped to record low levels over Q1, demand in Sydney was at a record high for January at 7.2 PJ compared to 6.5 PJ this time last year.[9]

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8 Victorian price decreases in late February coincided with reduced demand for gas flowing north across the VNI into New South Wales. Over 100 TJ of daily demand to refill Iona's storage inventory also reduced from mid-March, putting downward pressure on prices. Withdrawals refilling Iona ceased as the facility reached 24.1 PJ nearing its nameplate capacity (24.4 PJ).

9 Demand of 7.2 PJ was slightly above Sydney's previous high of just under 7.1 PJ in January 2019.

However, overall lower demand over the quarter and relatively low GPG demand compared to Q4 2024 put downward pressure on prices. Total GPG demand reduced from last quarter to levels below Q1 2024, with Queensland's GPG demand significantly lower than the previous quarter and Q1 2024.[10]

3.3 Gas production and storage

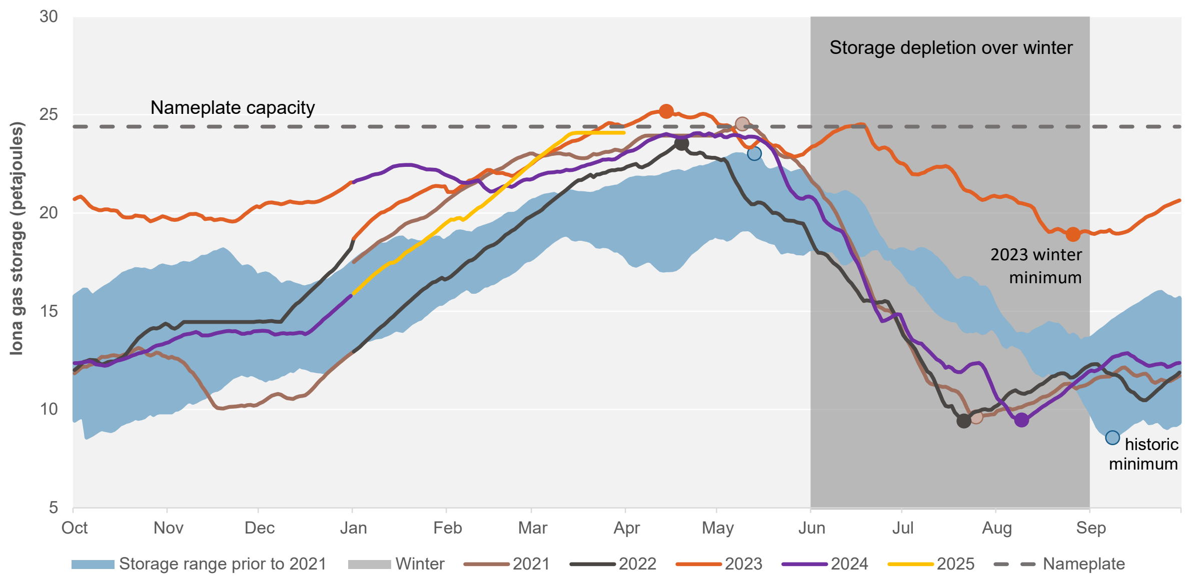
Southern production was higher despite reduced processing facilities

Quarterly production levels at Victoria's primary supply source at Longford were stable across the quarter and exceeded last year's Q1 output levels. Production levels of 43.4 PJ were well above the 34.6 TJ produced in Q1 2024, with lower-than-expected output last year driven by offshore maintenance. Longford's medium term capacity outlook also increased to 700 TJ per day from May 2025 until the end of winter.

Iona Storage levels increased to be close to full capacity

Iona continued refilling at a higher-than-average rate from late Q4 2024, supported by continued low demand and stable Longford production (Figure 15). The facility ceased refilling from mid-March as it neared full capacity, and 2 weeks of planned maintenance between 17 March and 2 April prevented injections and withdrawals during this time.

Figure 15 Iona underground gas storage levels



Note: Dots represent minimum and maximum storage levels for each period.

Source: AER analysis using Gas Bulletin Board data.

10 Queensland's GPG demand of 7.9 PJ was more that 2 PJ lower than Q1 last year (9.9 PJ) and Q4 2024 (10.3 PJ), with higher demand last quarter from November coinciding with high NEM prices in the region.

3.4 Gas pipeline flows

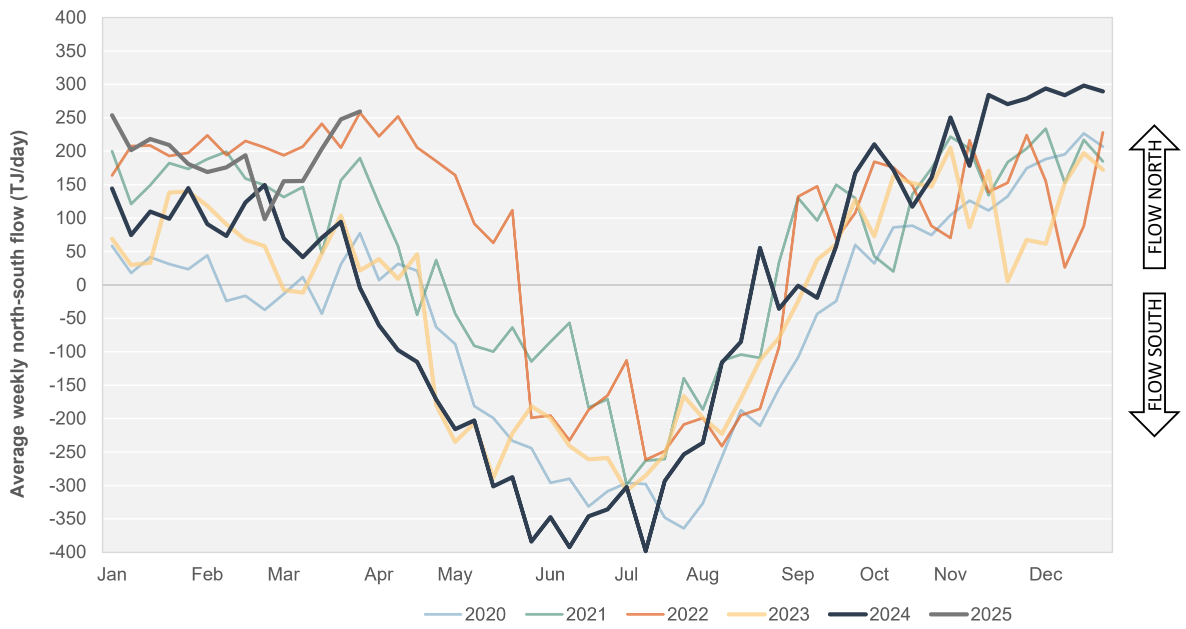
Gas flows north remained high despite reducing from last quarter

Northern flows reduced from last quarter's record highs, which reached close to 9 PJ over the month of December. Northern flows declined across January to late March before rebounding at the end of March. Northern flows remained at levels above those observed over the January to March period in the past 4 years, with Queensland importing 50% more gas than in Q1 2024. Higher flows were supported by more gas flowing north from Victoria, which exported 25% more than in Q1 2024, with continued lower downstream Victorian gas market prices encouraging participants to source southern gas supply.

Flows north were supported by activity on the Day Ahead Auction (DAA), with 82% of capacity won on the Moomba to Sydney Pipeline (MSP) procured on northward routes.[11] While quantities won on the DAA were higher than the previous quarter, they were lower than levels observed in Q1 2024. The maximum clearing price this quarter was $1.90 per GJ, above Q1 2024 ($1.45 per GJ).[12]

Trade volumes on the gas supply hub (GSH) were higher this quarter, with the 13.1 PJ traded across January to March 2025, up from Q4 2024 levels (10 PJ) and Q1 2024 (11 PJ). While the volume weighted price of gas sales was lower than the previous quarter, it was up 17% compared to Q1 2024, consistent with price observations of the downstream gas spot markets. Exporter/producers increased their purchases of gas on the GSH, offsetting a reduction in purchases by GPG gentailers compared with the previous quarter.

Figure 16 North-South gas flows



[11] On the South West Queensland Pipeline (SWQP), only 42% of capacity was won on routes sending gas towards Wallumbilla, down from 82% across the previous quarter when exports were higher.

[12] Over the first half of the quarter, the Carpentaria Pipeline (CGP) and Eastern Gas Pipeline (EGP) were the main facilities setting the maximum clearing prices on day ahead auction facilities, with EGP accounting for the majority of higher clearing prices over the 2nd half of the quarter.

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.

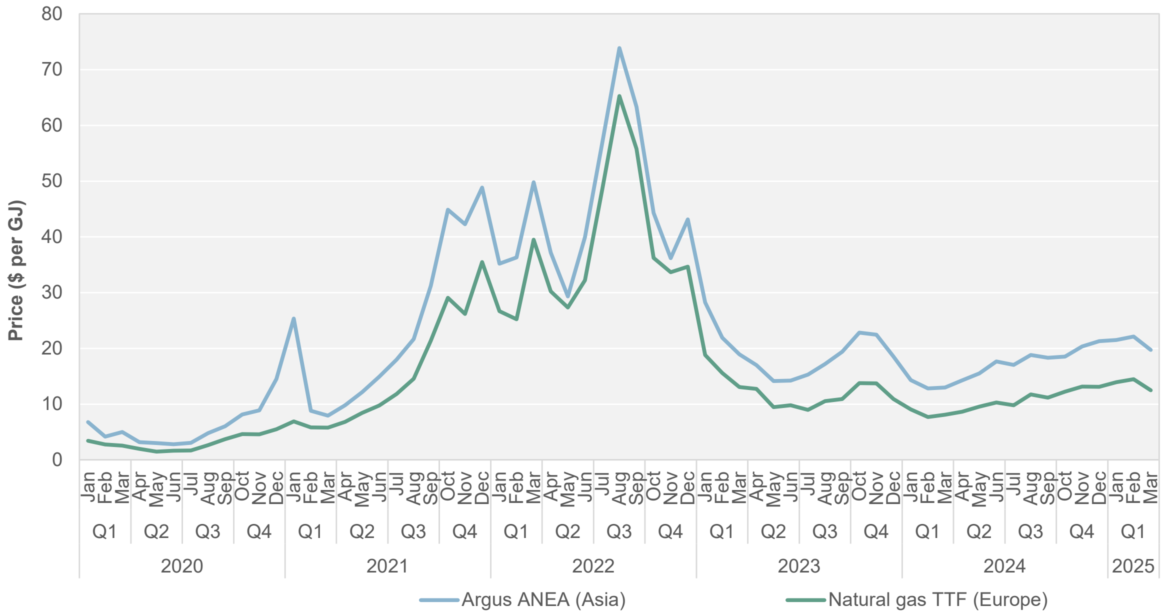
3.5 International LNG prices

Winter in the northern hemisphere supported LNG prices in Asia

The Argus LNG Northeast Asia des (ANEA) price continued to rise in line with elevated northern hemisphere winter demand, peaking at $25.66 per GJ in mid-February before starting to ease below $20 per GJ by the end of March.[13] Increased demand for gas in Europe put upward pressure on Asian prices despite a relatively mild Asian winter, alongside ongoing geopolitical uncertainties.

This is in stark contrast to the same period last year when European inventory hit record highs in December and a milder European winter supressed prices. The average midpoint ANEA price for Q1 2024 was $13.40 per GJ and $21.12 per GJ in Q1 2025, which represents a 57.5% increase over the same period.

Figure 3 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 Natural gas TTF price is a month ahead delivered spot price calculated at the Title Transfer Facility (TTF) in the Netherlands.
The AER obtains confidential proprietary data from Argus Media under license, from which data the AER conducts and publishes its own calculations and forms its own opinions. Argus Media does not make or give any warranty, express or implied, as to the accuracy, currency, adequacy, or completeness of its data and it shall not

13 The 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.

be liable for any loss or damage arising from any party's reliance on, or use of, the data provided or the AER's calculations.

Source: AER analysis using Argus Media data.

4 Electricity and gas markets forward outlook

This section provides discussion of electricity futures prices, electricity generation entry/exit and bilateral gas contracts with deliveries in the future and ASX gas futures prices.

Results are based on AER analysis of ASX, AEMO and Gas Bulletin Board data.

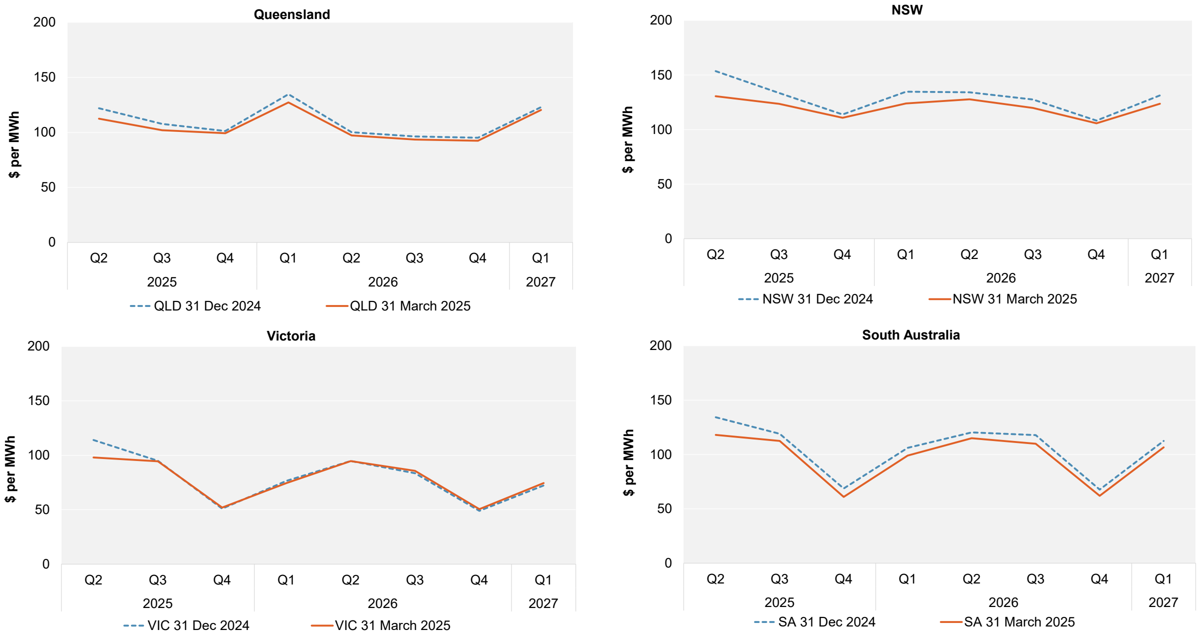
4.1 Forward electricity prices lower

Generators and retailers enter derivative contracts to fix the price of electricity in the future. This function is integral to protecting both parties against price fluctuations in the spot markets, and results in the physical electricity market and financial contracts markets being inextricably connected. The prices of forward base futures can illustrate price expectations for electricity spot prices in future periods.

During the first quarter of 2025 base futures prices fell between 42% (Queensland) and 25% (Victoria). This fall was driven by market expectations of high summer prices (sparked by very warm November 2024 conditions) not materialising. Queensland's Q1 2025 base futures price decrease was proportionally the largest for Q1 in 12 years, while NSW recorded the second largest fall at 38%. Large decreases in base futures prices for Q1 2025 however, did not flow through to future quarters which remain elevated.

At the end of March 2025, Queensland, NSW and South Australian base futures prices for all forward quarters were lower than their levels at the end of Q4 2024, indicating a general market expectation of decreasing wholesale spot prices. While in Victoria the Q2 2025 base futures price decreased over the course of Q1 2025, prices for the other forward quarters were very similar to what they were at the end of Q4 2024 (Figure 18).

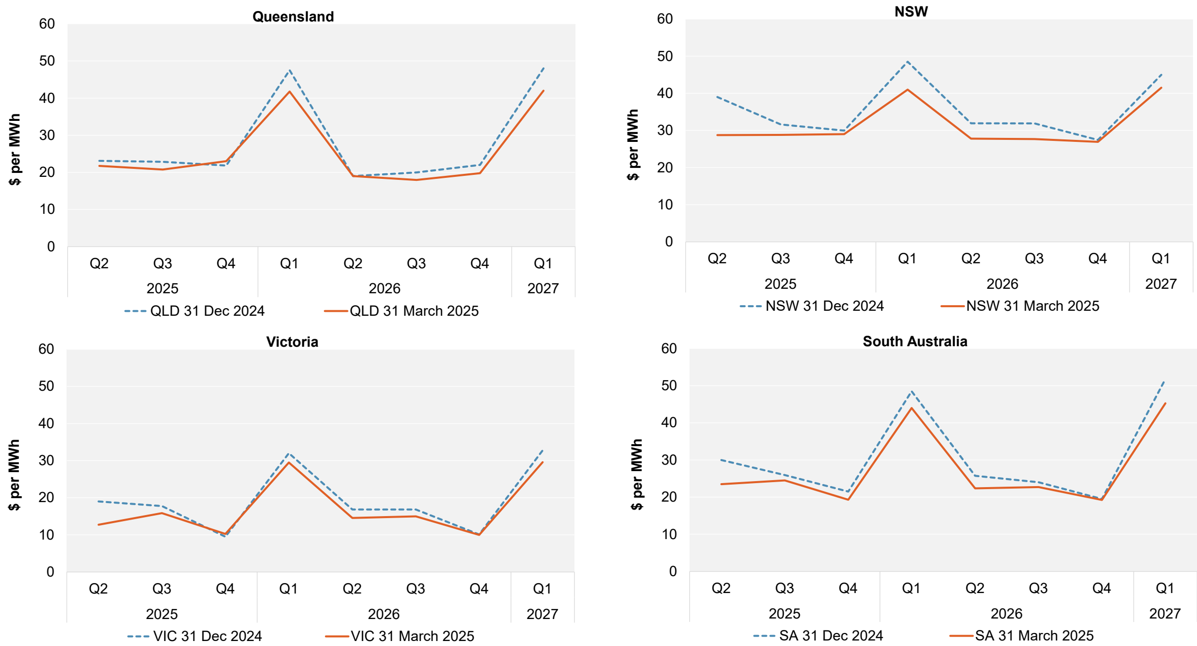
Figure 18 Base quarterly electricity futures prices



Note: Base future prices for each quarter as of 31 December 2024 (end Q4) and 31 March 2025 (end Q1).
Source: AER analysis using ASX data.

Final Q1 2025 cap prices ranged from $1.95 per MWh in Victoria to $12.95 per MWh in Queensland, having declined in all regions over the course of Q1 2025 (down between 94% in Victoria and 76% in South Australia). While not unusual from a historical perspective, these price decreases reflect a low number of spot market 5-minute intervals priced above $300 per MWh (721 out of this period's 25,920 intervals across the NEM).

Figure 19 Quarterly electricity cap prices



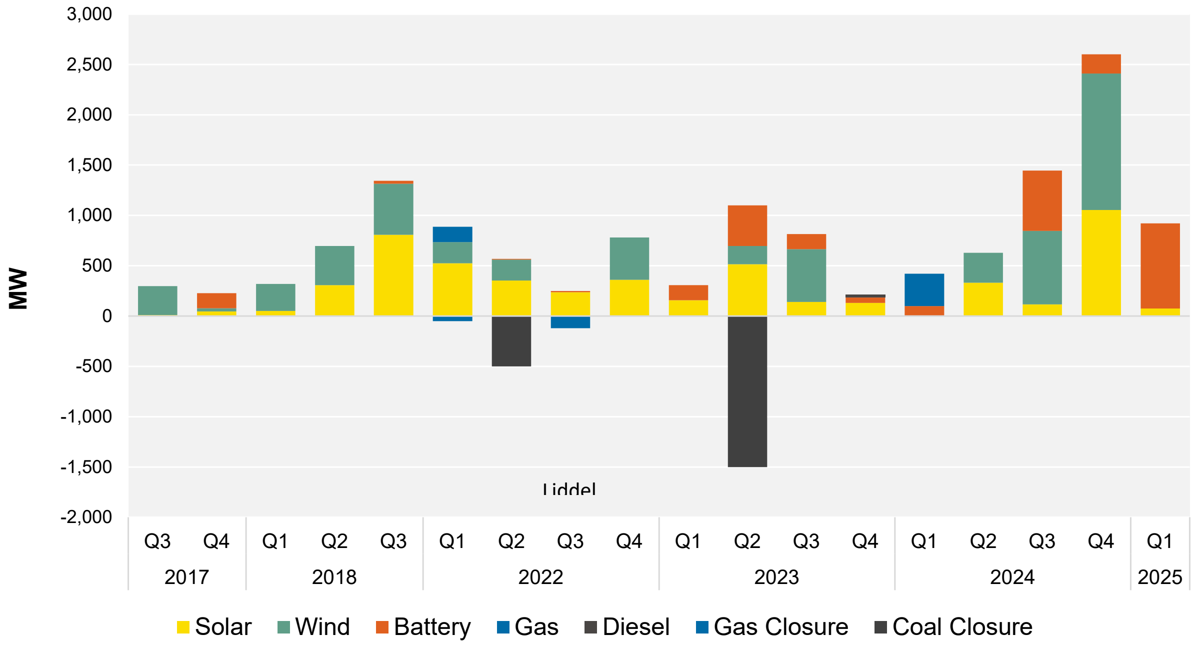
Note: Cap prices for each quarter as of 31 December 2024 (end Q4) and 31 March 2025 (end Q1).
Source: AER analysis using ASX data.

4.2 Entry and exit of capacity

Largest new entry of batteries

There was a total of 921 MW of new entry this quarter, with batteries accounting for 845 MW. This was a new record for battery entry (previously 600 MW in Q3 2024). Solar was the only other fuel type to enter, with 2 plants totalling 76 MW. While the solar plants reached full capacity during the quarter, the 3 batteries were not dispatched at their full capacity (Table 1).

Figure 20 Quarterly entry and exit



Note: This chart illustrates market entry and exit. 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.

Source: AER analysis using NEM data.

Overall, AEMO's Generation information workbook lists 2,780 MW of committed projects[14] that are not active and are expected to come online before the end of 2025, 2,219 MW of which will be dispatchable generation. Entry of Snowy Hydro's 750 MW[15] Hunter Power Station in NSW (formerly known as Kurri Kurri) is expected to occur in Q2 2025. In addition to this, 966 MW of battery capacity is expected before December 2025, with 155 MW in Queensland, 700 MW in Victoria and 111 MW in South Australia.

14 Projects that will proceed, with known timing, satisfying all five of AEMO's commitment criteria. The generation information workbook (accessed 2 April 2025) was last updated January 2025. We have removed projects that have commenced dispatching generation.

15 Snowy Hydro notes that while the power station will have a capacity of 750 MW, 660 MW will be supplied to the grid initially. See Hunter power project (accessed 15 January 2025).

Table 1 New projects that commenced generation during the quarter

Region	Fuel type	Station	Capacity (MW)	Highest dispatched volume (MW)
Queensland	Battery	Greenbank Battery	200	122
NSW	Battery	Eraring Battery Energy Storage System	460	9
Victoria	Solar	Kerang Solar Plant	30	30
Victoria	Battery	Koorangie Energy Storage system	185	67
Victoria	Solar	Mokoan Solar Farm	46	46

Note: This table lists market new entry for this quarter. It 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.

Source: AER analysis using AEMO Generator Information.

4.3 Bilateral gas transactions

A significant proportion of gas trade is negotiated directly between participants outside of the AEMO-facilitated markets. Since March 2023, as part of the Gas Market Transparency reforms, participants have been required to report details of these bilateral transactions up to a year in duration to the Gas Bulletin Board.

Quarterly trade volumes subdued after record trade volumes in Q4 2024

In Q1 2025, there were 38 PJ of gas sales reported, a significant reduction compared to the record high 101 PJ traded last quarter when contracts were being secured before the end of the year (Figure 21).[16] The traded volume in Q1 2025 was also 20% lower compared to Q1 last year when we observed more longer-term contracts still being entered into for 2024.

However, gas deliveries in Q1 2025 exceeded volumes reported last quarter and the same time last year. Around 49 PJ of gas was delivered throughout Q1 2025, with an increase in Queensland gas deliveries aligning with relatively strong northern flows for the period. Based on gas trades up to the end of the quarter, around 112 PJ has been traded so far for delivery over the remaining 2025 quarters and 42 PJ is marked for delivery in 2026. Delivery volumes for oncoming quarters currently range between 36 and 39 PJ per quarter and is likely to exceed 2024 volumes, which averaged 43 TJ delivered over the same period.

[16] The trade volume for Q4 2024 was reported as 94 PJ in our previous quarterly. The increase in volume reflects a feature of the reporting framework where contracts can be amended / volumes updated before delivery but is also reflective of late or inaccurate reporting which the AER monitors.

Figure 21 Traded and delivered quantities and VWA price forward curve

Note: Traded volume refers to the trade date of the short-term supply transaction, while delivered volume refers to the quarter the gas volume will be supplied.
The VWA forward price curve is based on the supply dates of the reported transactions. These prices exclude pricing structures linked to the STTM or DWGM or where the transaction was between related parties. Where there is not enough trades or participants reporting in a period the data has been aggregated or not included in the reporting.
Source: AER analysis using Natural Gas Services Bulletin Board data.

Short term contract prices for 2025 continue to average below $14 per GJ

The volume weighted average (VWA) price for delivery in Q1 2025 was $13.29 per GJ, which is $0.10 per GJ higher than the same period last year, but slightly lower compared to the previous quarter. The VWA price for gas to be delivered over the remaining quarters of 2025 is $13.70 per GJ while for deliveries in 2026, the VWA price is $14.29 per GJ. This is only slightly higher compared to the VWA price for 2025 reported at the end of Q4 2024 ($13.56 per GJ) and similar to the price reported for 2026 ($14.25 per GJ).[17]

Based on trades until the end of the quarter, prices for deliveries over the coming winter are lower compared to deliveries during last winter. The VWA prices for southern states in Q2 and Q3 2025 are currently projected to be around $14.55 per GJ, compared to $15.41 per GJ for the same quarters last year.[18] Forward pricing expectations are also higher in the southern states compared to Queensland. For 2025, the VWA price for gas deliveries to

17 AER, Wholesale markets quarterly – Q4 2024, Australian Energy Regulator, accessed 10 April 2025.

18 While forward prices for Q2-Q3 2025 are currently lower than the VWA prices for the same quarters last year, it is important to note that the forward prices are based only on trades up to March 31, 2025. In contrast, the VWA price for Q2-Q3 2024 includes all trades up to and including those respective quarters.

southern states are around $14.34 per GJ compared to $12.98 per GJ for deliveries to Queensland. The average price differential between Queensland and the southern states for 2025 is $1.36 per GJ peaking at $1.67 per GJ in Q2 2025. This price differential reflects tighter supply in the southern states over winter and the cost of transporting gas from the north to the south.

Higher forward prices for southern states align with findings from the ACCC Gas Inquiry Interim report released in March 2025, where prices in producer gas supply agreements were higher in southern states than in Queensland.[19] The AER's recent Wholesale gas reserve price assumptions report published in April 2025 also highlighted that field owners with reserves in southern gas basins reported higher uncontracted reserve price assumptions compared to those with reserves in northern basins.[20] A price differential of $1 per GJ was reported for 2025 between uncontracted reserves in southern and northern basins.

4.4 ASX Gas Futures

Limited trade in the ASX Wallumbilla Natural Gas Futures Product

The ASX Wallumbilla Natural Gas Futures product is a monthly product which can be traded up to 3 years in the future with each futures contract of gas representing a delivery obligation of 100 GJ/day of the calendar month being traded. Five (5) business days before the beginning of the month traded, any open interest positions are converted to physical obligations on the GSH in a Monthly Netted Product deliverable at the Wallumbilla High Pressure Trade Point, referred to as Delivery Exchange for Physical (Delivery EFP).

Over Q1 2025, trade on the ASX Wallumbilla Natural Gas Futures product remained limited.[21] Throughout the quarter, 26 futures were traded, equating to 78 TJ when delivered. Delivery Exchange for Physical (EFP) prices ranged from $14.15 per GJ to $14.50 per GJ in Q1 2025. This is more expensive than the previous quarter, where the maximum EFP price was $13.50 per GJ. Delivery EFP prices were also higher compared to the VWA price for monthly products traded on the Gas Supply Hub during Q1 2025 ($14.02 per GJ).

Looking ahead to futures with settlement dates in the rest of 2025, there are 41 futures traded (124 TJ, noting not all interest may remain open for physical delivery) with prices in the range of $12-$15 per GJ. For deliveries in 2026-2027, bid prices sit in the $11-$15 per GJ range while asking prices fall within a $13-$17 per GJ range.

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19 ACCC, Gas inquiry March 2025 interim report: Gas supply agreements, Australian Competition Consumer Commission, accessed 8 April 2025.

20 AER, Wholesale gas reserves price assumption report, Australian Energy Regulator, accessed 15 April 2025.

Northern basins include the Bowen, Surat, Eromanga/Cooper and Amadeus basins. Southern basins include the Bass, Otway, Gippsland and Gunnedah basins.

21 The new ASX Wallumbilla Natural Gas Futures product commenced trading on 19 August 2024 for first delivery in October 2024.

Forward prices reduce for Winter 2025 on the ASX Victorian Gas Futures Product

Forward prices on the ASX Victorian gas futures product have eased since June 2024, most notably for the Winter quarters of 2025 (Figure 22). In previous quarters, forward prices for Victorian gas delivery in Q2 to Q3 of 2025 were in the range of $15 to $16 per GJ. In Q1 2025, the forward prices dropped to a range of $14.65 to $15.20 per GJ. The decrease aligns with pricing expectations observed through short term bilateral trades for gas deliveries in southern states. It could also reflect adequate supply expectations, with seasonal supply gaps only expected to emerge in the south from 2028 in the latest Gas Statement of Opportunities.[22]

Figure 22 ASX Victorian gas futures pricing by date

Note: Victorian gas futures on the ASX are thinly traded and there is usually a large difference between bids and offers for these products on the exchange. Settlement prices for ASX gas futures usually reflect the lower part of this range but actual market expectations may be somewhat higher.

Source: AER analysis using ASX data.

22 AEMO, 2025 Gas Statement of Opportunities, Australian Energy Market Operator, accessed 20 March 2025.