Wholesale markets quarterly

Q4 2024

October - December

January 2025

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 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 4, October to December 2024. It provides discussion of prices, demand, generation, offers, contracts, market outlook and new entry and exit.

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

1.1 Key insights

The influence of both seasonal factors and supply conditions were evident across the wholesale gas and electricity markets in the October to December 2024 quarter. Significant coal outages and higher-priced offers, combined with interconnector limitations and more variable demand profiles, drove price outcomes and resulted in notable differences between the northern and southern regions.

Average prices for both gas and electricity were higher in Q4 2024 compared with the same period in 2023. This contributed to annual average prices for the 2024 calendar year also being higher than the previous year, though lower than those recorded in 2022. Compared to the previous quarter, electricity prices rose in the northern regions but fell in the southern regions.

Electricity prices were more volatile across the day, as more expensive fuel types were needed outside hours of high solar generation output (both grid-scale and rooftop solar generation sources).

New records were set in Q4 2024 in relation to rooftop solar output, the highest number of negative-priced 30-minute periods, minimum daily electricity demand and entry of new registered generation capacity

NEM conditions put upward pressure on downstream gas market prices during November and December due to increased gas-powered generation demand, most notably in Queensland. Other domestic gas demand remained muted this quarter, with downstream gas demand reaching record low levels similar to Q4 2023, while export demand increased to record levels. This contributed to record levels of gas flowing north for this time of year, and a price differential emerging between the Brisbane and Victorian downstream markets.

Electricity

- By region, compared with the previous quarter, prices were higher in NSW and Queensland. Conversely, prices were lower in South Australia, Victoria and Tasmania, largely due to typical changes in seasonal demand.
- While changes in overall demand in Q4 were relatively consistent with previous years and reflected seasonal differences across the regions, several factors contributed to both annual and Q4 2024 prices being higher than recorded in 2023. This included a decrease in low-priced offers and increases in coal outages, higher demand at peak times and

high-price events. Black coal, gas and hydro generators all set higher prices than the previous year. Interconnector limitations also constrained import of cheaper capacity from the southern states to the northern states, contributing to the higher prices observed in NSW and Queensland.

- There were more high price events this quarter than a year ago (23 events, including 2 FCAS events), and these contributed to higher average prices in NSW and Queensland.
- Q4 2024 also saw a record number of negative-priced 30-minute periods in the NEM, including a record number in both South Australia and Victoria. Negative price intervals were more frequent compared with Q4 2023 due to an increase in low-priced offers by renewable generators at times combined with higher rooftop solar output.
- Minimum daily electricity demand records were reached in South Australia and NSW, as rooftop solar output reached record levels, peaking at 14,980 MW at 12 pm on 16 December 2024.
- Total volume of offers increased slightly compared with the previous years. However, there was a decrease in offers in lower price bands. On average 1,508 MW less black and brown coal was offered below $70 per MWh, with some of this due to a higher outage rate (on average, an additional 634 MW was offline due to outages compared to a year ago).
- There was significant new entry in terms of registered capacity, 1,354 MW of wind capacity entered (maximum of 105 MW has been dispatched so far), 1,055 MW of solar (137 MW dispatched) and 191 MW of batteries (111 MW dispatched). While this new capacity is not fully operational, it is the highest level of quarterly new entry recorded of the transition to date.
- Commissioning of the Hunter Power Station (gas) in NSW (formerly known as Kurri Kurri) has been further delayed.
- Base futures prices for 2025 rose during the quarter for Queensland, NSW and (to a lesser extent) Victoria. High spot-price events appeared to only have an immediate impact on the current quarter’s base futures prices. However, as average spot prices remained higher over Q4, forward prices for Q1 2025 (and to a lesser extent Q4 2025) began to rise too.

Gas

- Average gas prices were 8% higher than the previous quarter and 25% higher compared with the same period in 2023. Price increases were more evident in the northern markets, with Brisbane daily prices peaking at $21 per GJ on 16 December.
- A price differential between the Brisbane and Victorian downstream markets emerged this quarter, where the Brisbane STTM averaged $1.93 per GJ higher than Victorian DWGM prices throughout the quarter, rising to $3.50 per GJ between 18 November and 20 December. This was primarily driven by a period of higher gas generation demand in Queensland driving up prices in Brisbane.
- Gas-powered generation (GPG) demand was elevated compared to the same time in 2023, most notably in Queensland, while overall demand fell in line with the typical

seasonal decrease. GPG gentailers adjusted their offer profiles across their portfolios, purchasing at higher prices within the downstream markets. Record-high export demand out of Queensland also put pressure on prices.

- Average Longford production was higher than Q4 2023, despite shutting down a processing plant earlier this year. A fall in production from 17 December to mostly sit below 500 TJ for the rest of the year coincided with falling downstream prices towards the end of December as GPG demand reduced in Queensland.
- Iona storage levels also began refilling at a faster rate from 20 December after remaining flat in November, though were still below levels seen at the end of 2022 and 2023. Storage reached 15.8 PJ at the end of 2024.
- Gas flows north were significantly higher than previous years, with corresponding increases in volumes for north-flowing spare capacity being won on the Day Ahead Auction. Near-record flows north occurred through the QSN link at Moomba (almost 370 TJ per day), supported by record flows through the VNI in Victoria (more than 100 TJ per day).
- There were also three high Market Operator Services (MOS) payment events on 28 November, 14 December and 20 December, all occurring within the Sydney STTM. The initial event was triggered by a loss of pressure in the distribution system. MOS payments were more than $250 000 on each of the three days, triggering AER’s reporting requirement.
- Volume weighted average (VWA) prices for bilateral gas transactions up to one year in length for delivery in 2025 were $13.56 per GJ with record trade volumes reported for Q4 of 94 PJ. The VWA price for short term transactions of one year in length for delivery in 2026 was $14.17 per GJ.

2 Electricity

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

Results are based on AER analysis using National Electricity Market (NEM) data sourced from AEMO.

2.1 Electricity prices

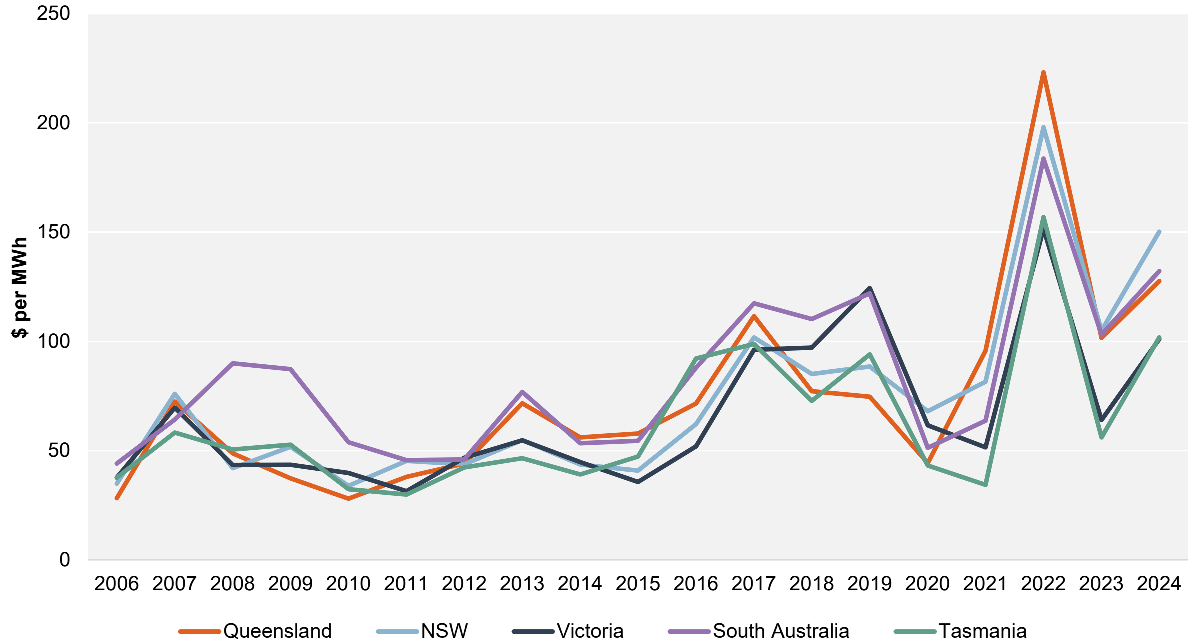
Wholesale spot prices were higher than a year ago in all regions

The NEM is a wholesale spot market where electricity is traded every 5 minutes. Across 2024, annual average volume weighted NEM prices were higher than the previous year across all regions, though remained more moderate than the record levels of 2022.In each region:

- NSW – $150 per MWh, up 43% from 2023
- Queensland – $128 per MWh, up 26% from 2023
- South Australia – $132 per MWh, up 28% from 2023
- Tasmania – $102 per MWh, up 82% from 2023
- Victoria – $101 per MWh, up 58% from 2023.

Wholesale electricity contracts, that hedge the price of electricity in the future as opposed to real time, are not traded in the NEM and are discussed separately in section 4.1.

Figure 1 Average annual prices in the NEM by region



Note: This chart illustrates volume weighted average annual (calendar year) 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.

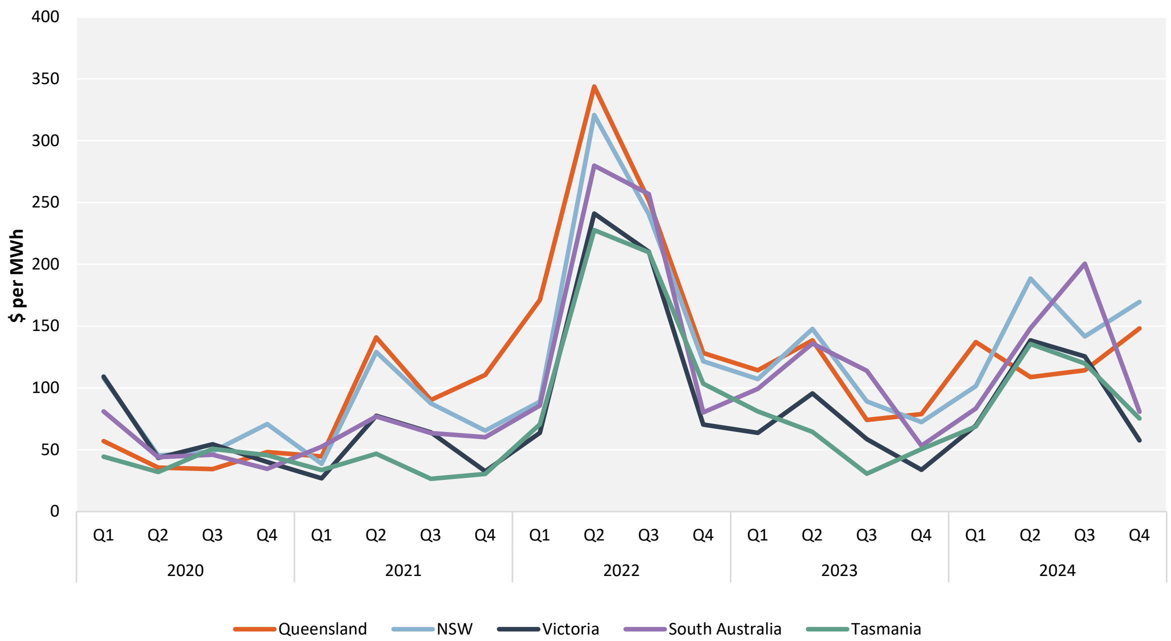
Source: AER analysis using NEM data.

In Q4 2024, quarterly volume weighted average prices were also up year on year across all regions:

- NSW – $170 per MWh, up 134% from Q4 2023
- Queensland – $148 per MWh, up 88% from Q4 2023
- Victoria – $58 per MWh, up 71% from Q4 2023
- South Australia – $81 per MWh, up 52% from Q4 2023
- Tasmania – $75 per MWh, up 49% from Q4 2023.

Price increases from Q4 2023 were driven by a number of factors, including a decrease in low-priced offers and increases in coal generator outages, demand at peak times and high-price events.

Figure 2 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.

Source: AER analysis using NEM data.

Compared to the previous quarter, prices rose in the northern regions but fell in the southern regions. The variance between north and south this quarter reflects regional differences in seasonal demand patterns, with Queensland recording an increase in average demand while other regions experienced decreased demand. It also reflects that interconnector limitations constrained the ability of the northern regions to import cheaper capacity from their southern neighbours.

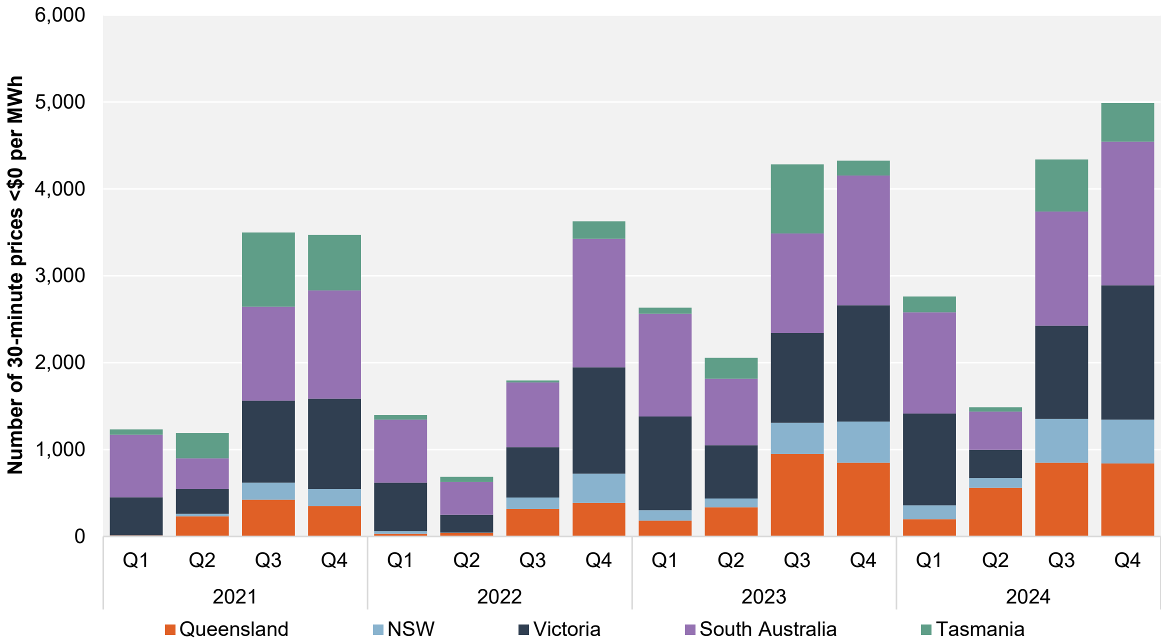
Prices in Queensland and NSW were heavily affected by a high number of price periods where the 30-minute prices exceeded $5,000 per MWh. 23 of these periods occurred in Q4 – 13 in NSW, 7 in Queensland and 3 in South Australia. By region, these periods drove up the average quarterly price by:

- $46 per MWh in NSW
- $26 per MWh in Queensland
- $5 per MWh in South Australia.

Low wind conditions and planned network outages[1] were frequently factors in the high price events during the quarter. The AER will publish a high price report in February 2025 containing detailed analysis of the October to December high price periods.

Despite the high average prices this quarter, there were a record number of negative price 30-minute periods in the NEM. Victoria and South Australia had the largest number of negative price intervals, with both regions setting records, due to the combination of seasonal mild weather conditions (especially in October), high rooftop solar output and the continued increase in generation from renewable generators. Negative prices led to the quarterly volume-weighted average price being $11 per MWh lower in Victoria and $9 per MWh lower in South Australia.

Figure 3 Count of 30-minute negative prices per quarter



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

[1] Planned outages are used by networks to carry out essential maintenance work on the grid. The dates of these outages are communicated to AEMO in advance and published in the Network Outage Schedule (NOS) which is accessible within the MMS database.

Source: AER analysis using NEM data.

2.2 Electricity demand

All-time minimum and Q4 maximum demand records were set this quarter

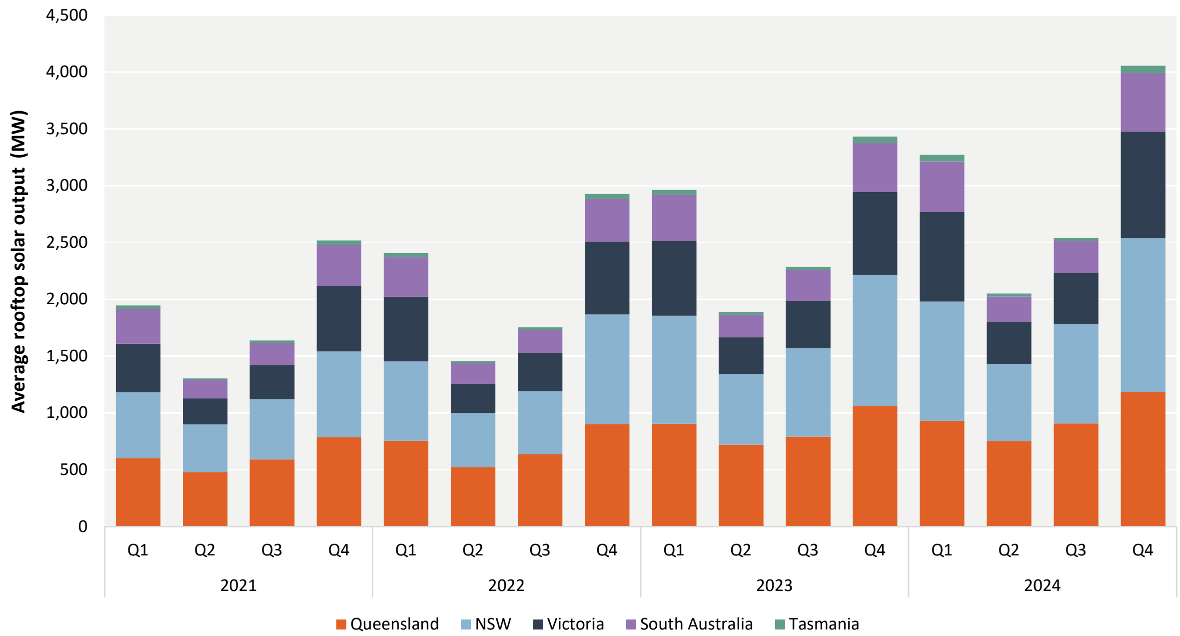
Average demand in Q4 2024 increased compared to the same period in 2023 in both Queensland (by 2%) and NSW (by 1%), though was slightly lower in Tasmania (by 2%). Higher Queensland demand coincided with the region experiencing its warmest spring on record.[2]

Overall demand in Victoria and South Australia was relatively consistent with the same quarter in the previous year. However, demand in these regions was higher in the evening peak and overnight, but lower during the day due to higher rooftop solar output (which reduces the need for electricity to be supplied from the grid). Aggregate NEM demand at peak times was slightly higher than in Q4 2023.

NSW and South Australia set all-time records for minimum daily demand (3,509 MW and -206 MW respectively) during daytime periods of mild weather conditions and periods of high rooftop solar output. A new NEM-wide minimum daily demand record of 11,209 MW was also set on 26 October 2024. The previous record had stood since 26 December 1998.

Average quarterly NEM rooftop solar output reached its highest ever level this quarter (Figure 4). In addition, at 12 pm on 12 December rooftop solar output reached an all-time high of 14,980 MW. Prior to this quarter, record maximum rooftop solar output was 13,311 MW, set on 2 February 2024.

Figure 4 Quarterly average rooftop solar output



2 BOM, Australia in spring 2024, 1 December 2024 (accessed 22 January 2025).

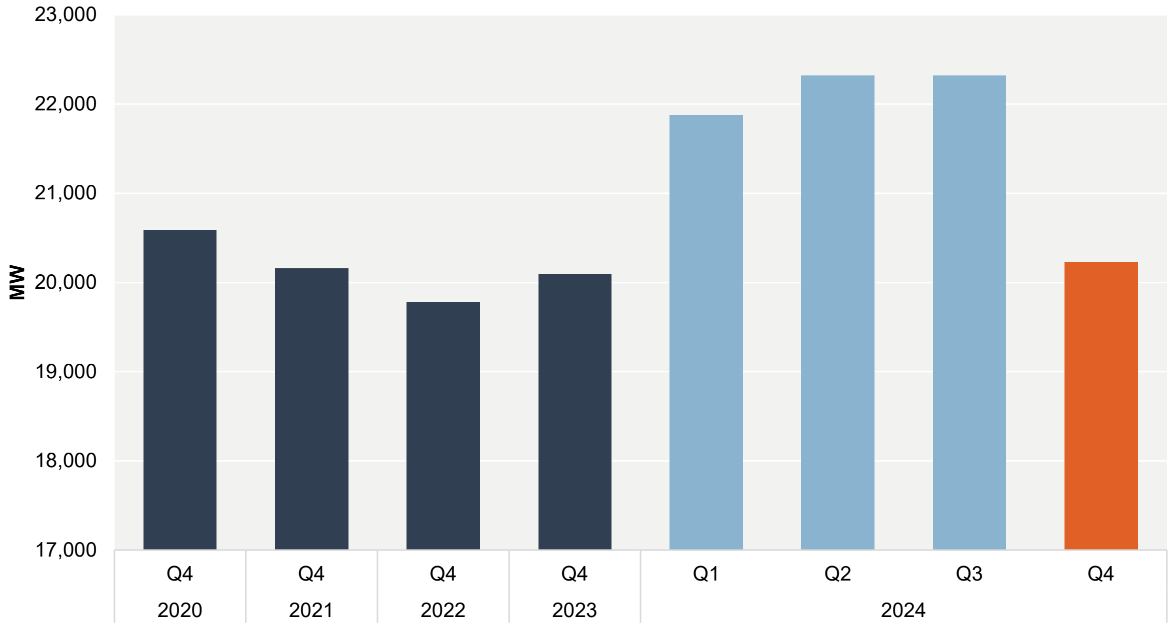
Note: Shows average rooftop solar output by region and quarter. Due to the time-of-day pattern of solar output, maximum output can be several times higher than average output.

Source: AER analysis using AEMO rooftop PV data.

Queensland, Victoria and the NEM set records for their highest Q4 maximum daily demand. These occurred on very hot days and reflected an increased use of air conditioners. In Victoria, this was the highest demand level in the past 10 years.

In most regions and NEM-wide, average demand this quarter was much lower than Q1 to Q3 2024 (Figure 5), reflecting seasonal mild weather conditions for most of the quarter and consequently reduced electricity demand for heating and cooling. Queensland is typically the exception to this, as its warmer climate means that demand is typically higher in Q4 than Q3. Average demand this quarter was slightly higher compared with previous October to December periods in 2022 and 2023.

Figure 5 Quarterly average NEM demand



Note: 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.

Source: AER analysis using NEM data.

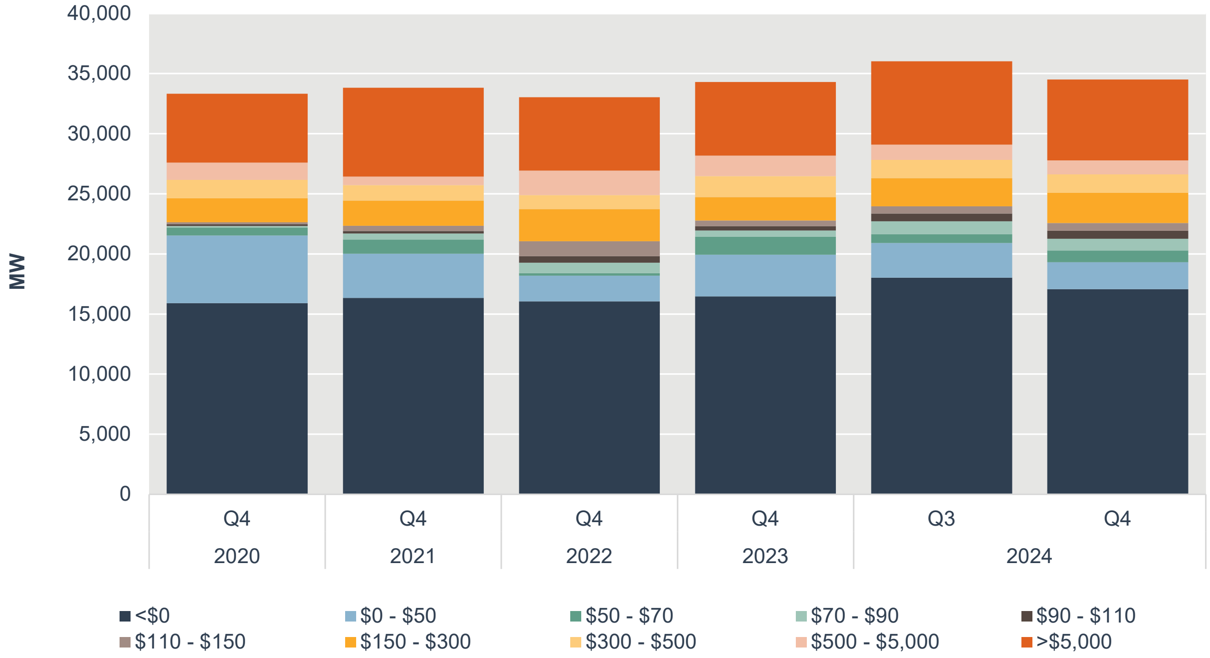
2.3 Offers

Offers below $70 per MWh fell

Compared to Q4 2023, offers below $70 per MWh fell by 1,141 MW (Figure 7). This was due to a large reduction in offers priced between $0 and $70 per MWh, partly offset by an extra 598 MW offered below $0 per MWh. There was also an increase in higher priced offers, resulting in total offers increasing slightly.

If there is less low to mid-priced capacity, prices will spike more often due to changing supply and demand. Low-to-mid priced offers partly recovered in 2023 after being squeezed in 2022 (Figure 6). However, in Q3 and Q4 2024 low-to-mid priced offers reduced compared to 2023.

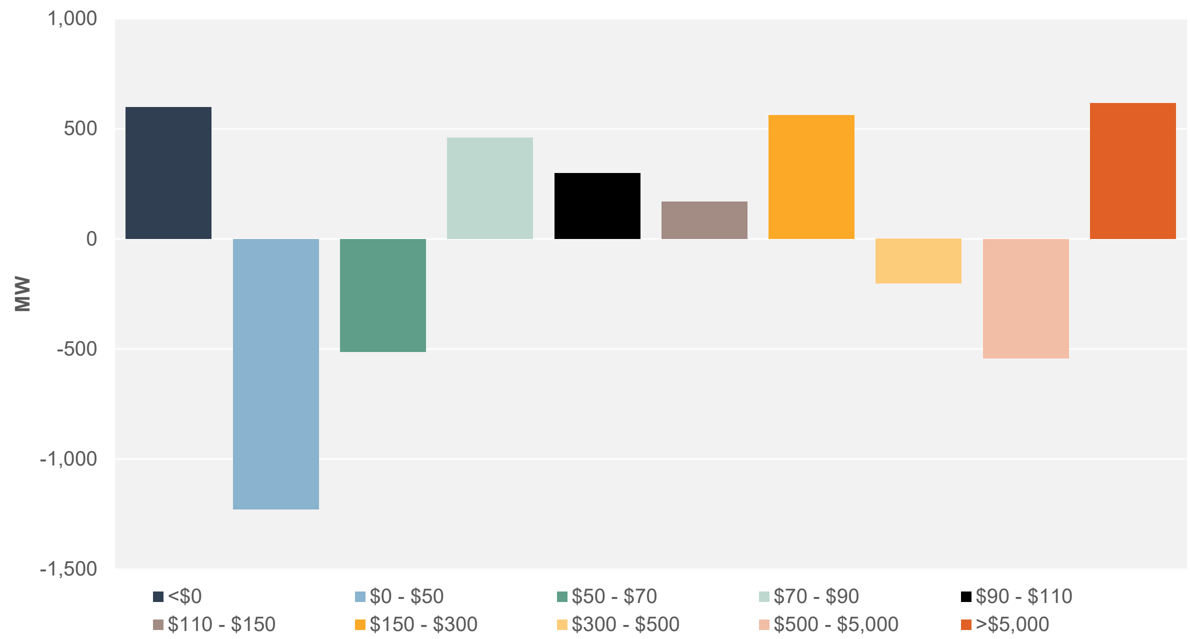
Figure 6 NEM offers by price band



Note: Average quarterly offered capacity by price bands.

Source: AER analysis using NEM data.

Figure 7 NEM Offers in Q4 2024 compared to Q4 2023



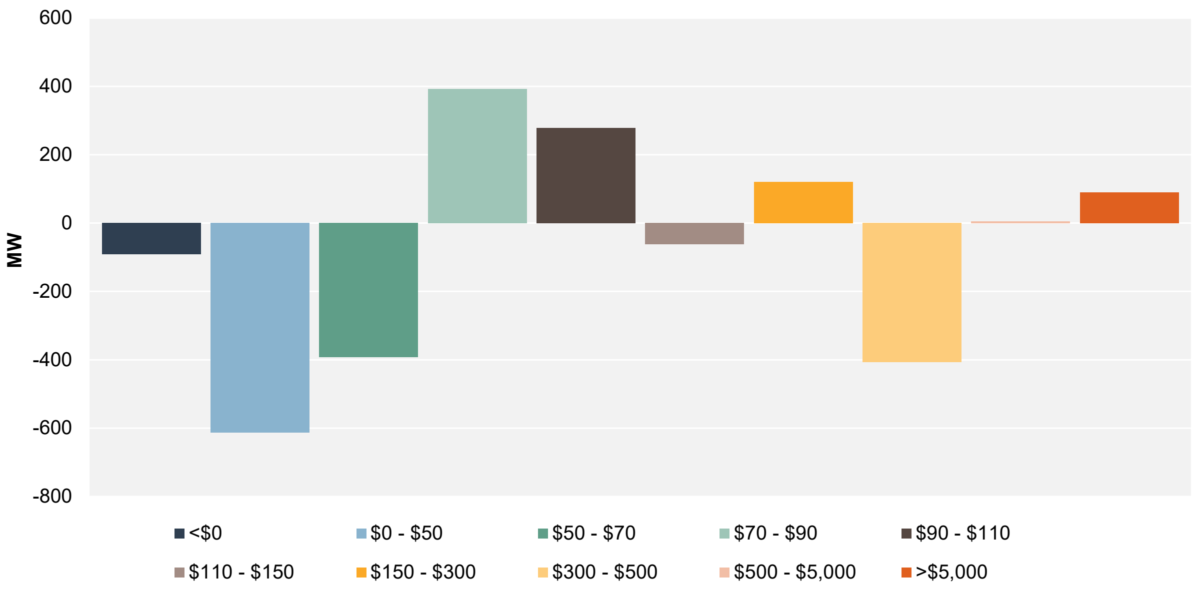
Note: Change in NEM average quarterly offered capacity by price bands from Q4 2023 to Q4 2024.

Source: AER analysis using NEM data.

Coal was a key driver of changes in offers this quarter. 1,096 MW less black coal and 412 MW less brown coal was offered below $70 per MWh compared to Q4 2023. This was partly due to an increase in outages this quarter which drove a reduction in the total black coal capacity offered. But there was also a significant shift in offers from lower to higher prices. Offers above $70 per MWh increased by 418 MW for black coal and 187 MW for brown coal compared with Q4 2023. Average prices set by black coal increased from under $70 per MWh in all regions a year ago to above $100 per MWh in all regions this quarter (average prices set by brown coal remained low).

The shift in black coal offers to higher may be driven in part by higher fuel costs. Market interventions to cap the price of coal paid by power stations to coal suppliers ended on 30 June 2024. With international coal prices currently higher than the market intervention price cap, many power stations are now exposed to higher fuel prices. Brown coal is low quality and not suitable for export, so not exposed to international prices.

Figure 8 NEM Black coal offers in Q4 2024 compared to Q4 2023



Note: Change in NEM black coal average quarterly offered capacity by price bands from Q4 2023 to Q4 2024.

Source: AER analysis using NEM data.

Hydro generators also contributed to the reduction in offers below $70 per MWh. Gas offered a net increase in capacity below $70 per MWh, as well as increasing offers in higher price bands.

Solar, along with wind, offered an extra 380 MW on average into the market than last Q4, reflecting new entry into the market over 2024. Offers below $0 per MWh increased by 416 MW, as in addition to new entry, some existing solar capacity was shifted to lower prices. Battery storage units also offered more total capacity, again reflecting new entry, but much of this was high-priced.

2.4 Price setter

Dispatchable generators are setting the price higher

In all NEM regions, black coal, gas and hydro generation set prices higher on average than in Q4 2023.

- Black coal set the price less often, but at much higher prices in all regions than a year ago. For example, in NSW it set price at $120 per MWh on average, up from $60 per MWh in Q4 2023. This reflects the change in coal offers described in section 2.3.
- Gas also set higher prices, particularly in Queensland ($203 per MWh on average, up from $121 per MWh), NSW ($245 per MWh on average, up from $105 per MWh) and Victoria ($143 per MWh on average, up from $107 per MWh).
- Hydro also set higher prices than a year ago in all regions. However, in mainland regions, where hydro typically sets prices higher than black coal, the price gap between black coal and hydro has narrowed.
- Batteries set prices more often in Q4 2024 than a year ago in all regions. When discharging, batteries generally set the highest prices of all fuel types. However, batteries set relatively lower prices when charging.[3]

2.5 Generation by fuel source

Gas, hydro and solar generation offset lower coal output

Slightly more generation overall was required this quarter compared with Q4 2023 due to slightly higher NEM demand. However, with increased coal outages generation by other fuel types increased.

Compared with the same period last year, solar generation increased by 191 MW, gas by 170 MW and hydro by 140 MW on average. Batteries discharged an additional 43 MW on average which, though a small change in absolute terms, represented a 91% increase in battery discharge volumes. These changes met the increased demand and decreased generation by brown coal (down 304 MW) and black coal (down 95 MW). Wind generators provided a similar level of output compared to Q4 2023.

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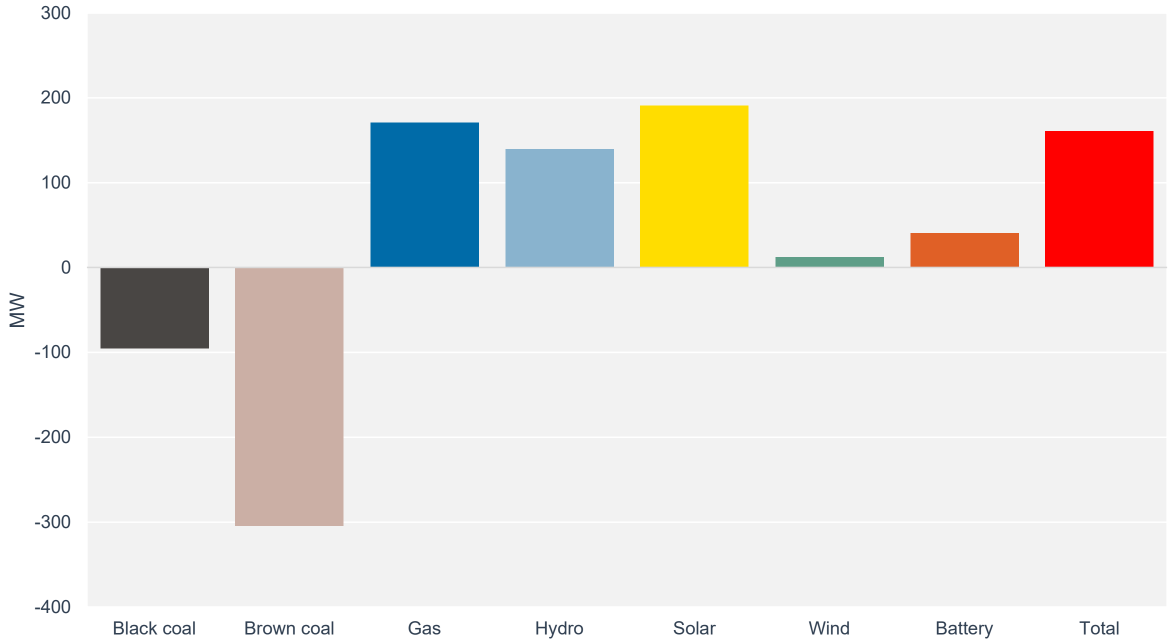
[3] Loads, including charging batteries, can set price in the NEM. For example, loads can set price when it is more cost effective to reduce load consumption by 1 MW than to increase generation by a MW. Reducing load consumption can lead to reduced generation requirements, which can mean that more expensive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

Figure 9 Change in NEM generation output by fuel source, Q4 2024 vs Q4 2023



Notes: This chart illustrates the change in average quarterly metered NEM generation by fuel type, Q4 2024 compared with Q4 2023. Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.

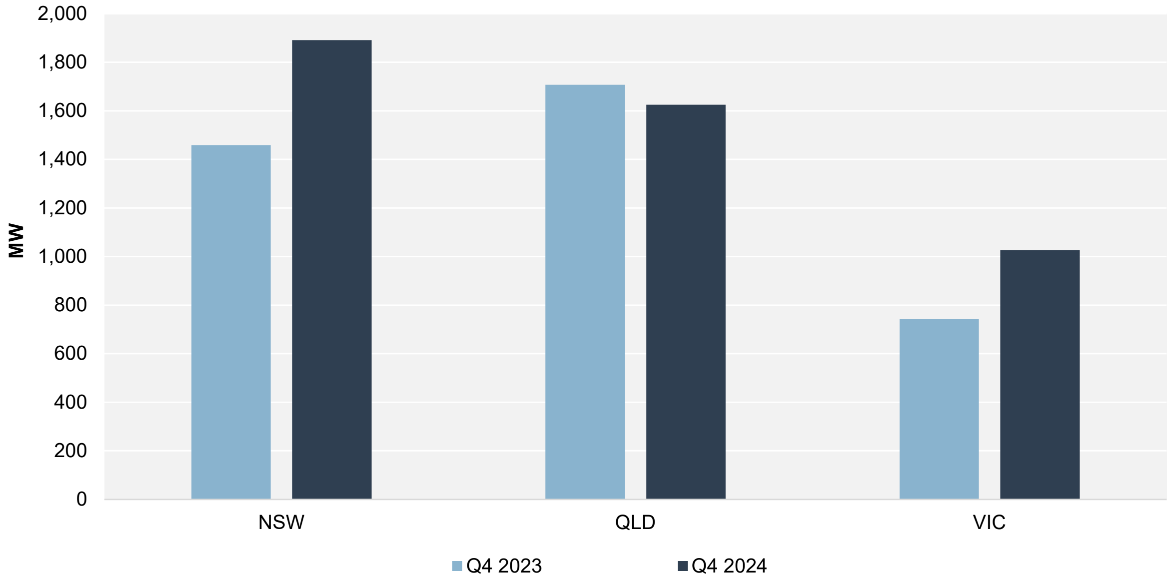
Source: AER analysis using NEM data

2.6 Coal outages

Coal capacity offline increased compared to Q4 2023

The decrease in coal output was partly due to an increase in generator outages. The average level of coal capacity unavailable due to outages was 16% (634 MW) higher than in Q4 2023. In Queensland, where Callide C power station has now returned to service following long outages,[4] the outage rate was 5% lower than a year ago. But in NSW the outage rate was 30% higher and in Victoria it was 38% higher.

Figure 10 Average capacity unavailable due to coal outages, Q4 2023 and Q4 2024



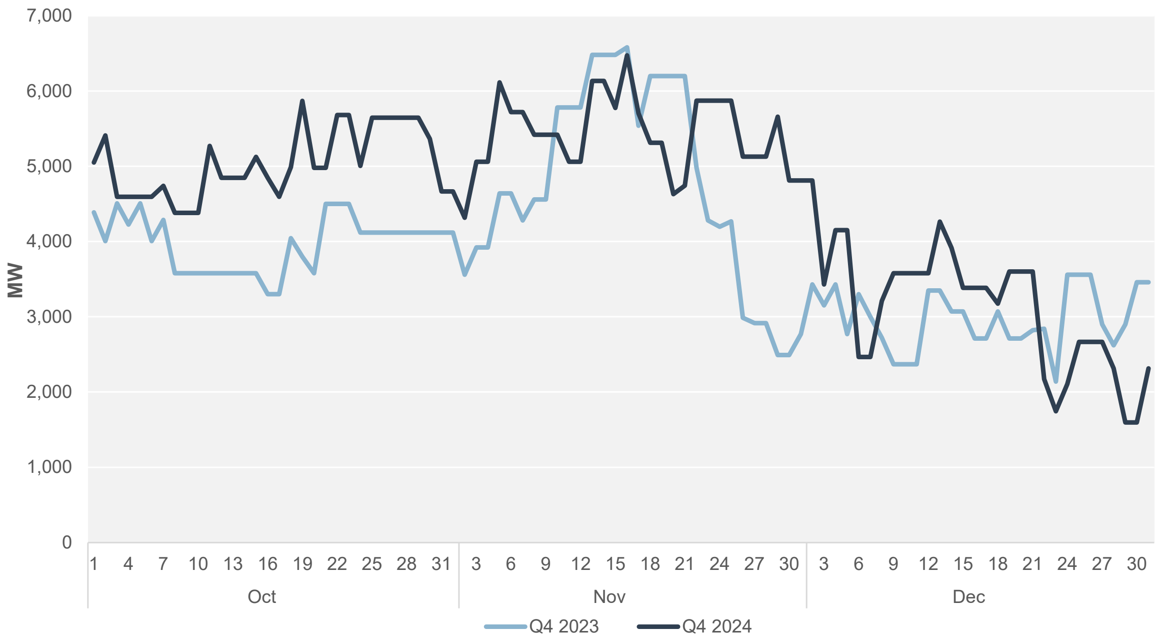
Note: This chart illustrates the average registered capacity unavailable due to coal outages. Unavailability is only counted if the unit is completely offline for the whole day (AEMO uses a different method in its reporting of outage data).

Source: AER analysis using NEM data.

4 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.

Outages were highest in October and November, reflecting that generators usually schedule more outages during the spring "shoulder" period to ensure generators are available in time for summer.

Figure 11 Daily NEM coal capacity offline



Note: Daily registered capacity unavailable due to coal outages. Unavailability is only counted if the unit is completely offline for the whole day.

Source: AER analysis using NEM data.

2.7 Interregional trade of electricity

Queensland exports were lower this quarter

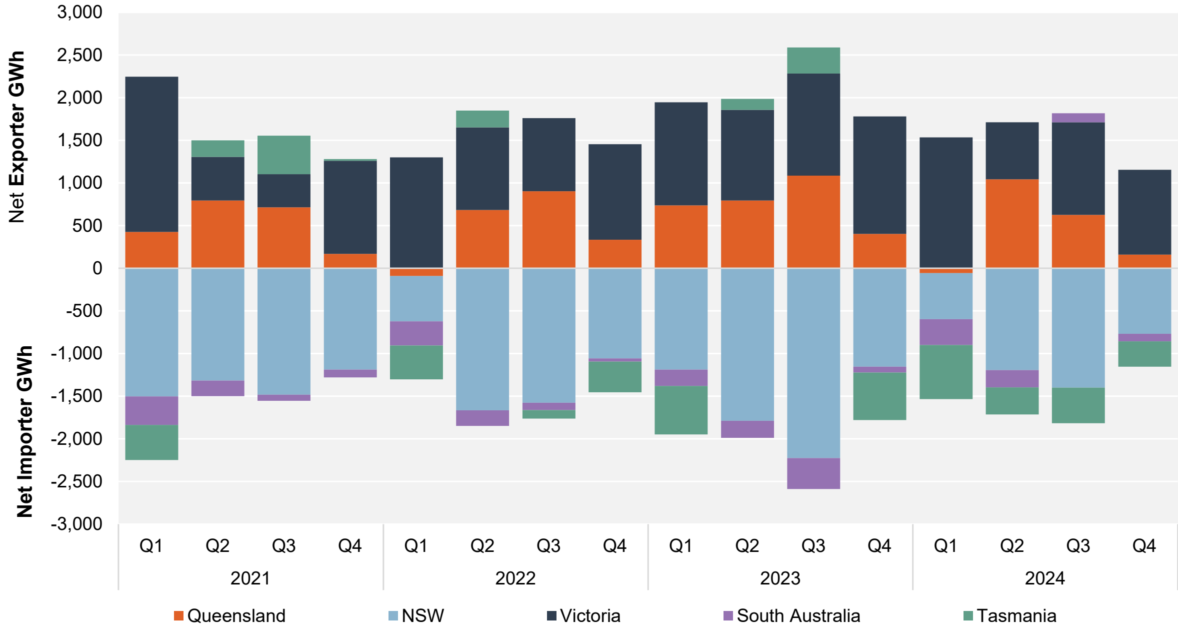
Interconnectors allow regions to import cheaper generation from neighbouring regions. Queensland and Victoria tend to be net exporters, providing surplus capacity to NSW and South Australia. Q4 2024 was consistent with this general pattern.

Queensland's interregional trade often follows a seasonal pattern, exporting more during winter and less during summer when it experiences higher demand. Consistent with this, its net exports were lower than in Q2 and Q3.

Tasmania was a net importer for the 5th consecutive quarter, reflecting a period of drier weather and higher-priced offers from the region's hydro generation fleet.

Overall, there was less difference than usual between net importer and exporter regions this quarter. The net exporters (Victoria and Queensland) provided only a net 1,154 GWh to the net importers (NSW, South Australia and Tasmania). This was the smallest quarterly difference between exporters and importers in 6 years, despite total trade between regions being fairly typical. This suggests that on average each region varied more between being an exporter and an importer this quarter.

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.

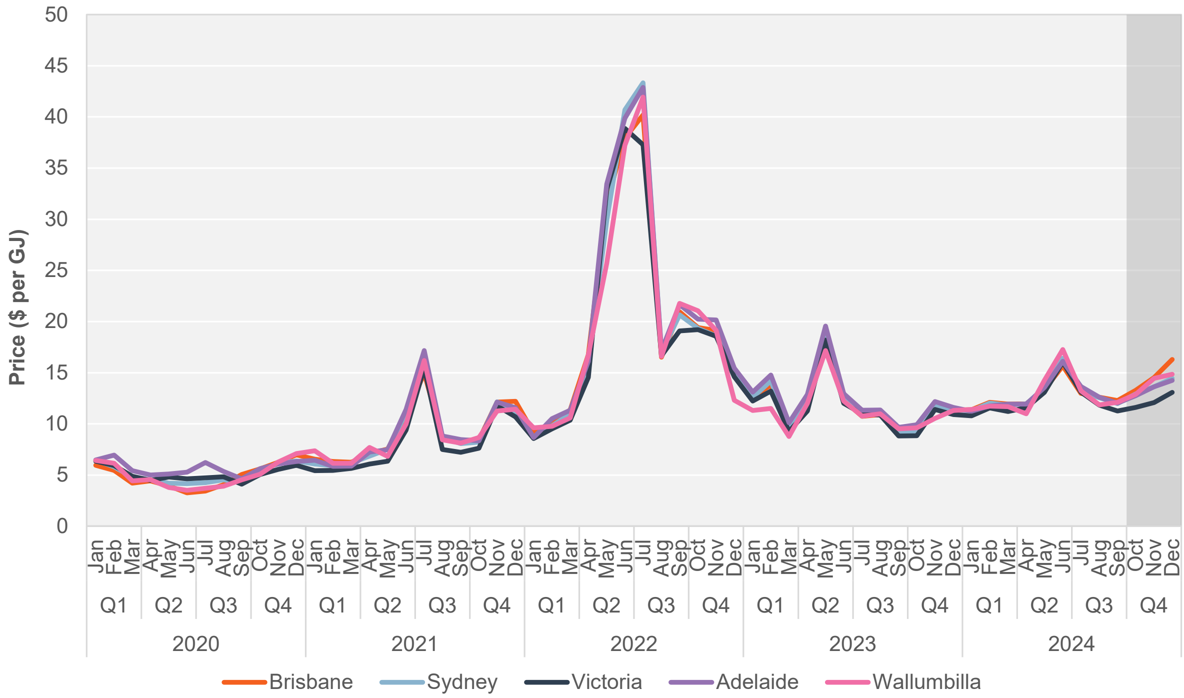
Results are based on AER analysis using data from the East Coast gas market, Gas Bulletin Board and Argus media.

3.1 East Coast gas market spot prices

Gas prices increased over Q4 averaging $13.54 per GJ

East Coast downstream gas market spot prices increased by 8.2% from the previous quarter to $13.54 per GJ and exceeding Q4 2023 prices by 25% (Figure 13). Average quarterly prices ranged from $12.26 per GJ in Victoria to $14.71 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 over the first half of Q4 ranged between $10.95 to $14 per GJ until around mid-November, and increased until mid-December when prices eased. The higher prices primarily impacted the Brisbane market, coinciding with elevated gas-powered generation (GPG) demand in Queensland and GPG gentailers adjusted their offer profiles across the STTMs and purchased at higher prices.

The impact on Victorian market prices was less evident, and a larger average price gap emerged between the Brisbane and Victorian markets of $3.50 per GJ from 18 November and 20 December when Brisbane spot prices reached their highest levels. Daily prices in

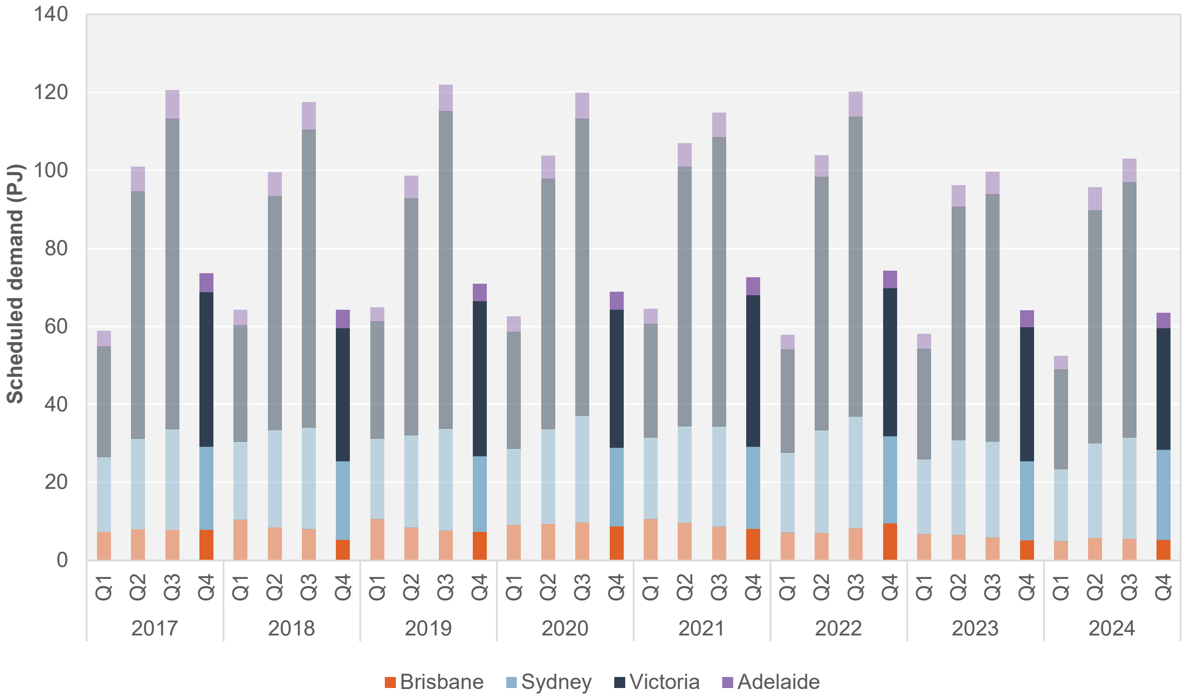
Victoria did not exceed $14.80 per GJ in the quarter, whereas daily prices in Brisbane remained above that level and peaked at just over $21 per GJ on 16 December.[5] Price spikes occurred on a number of occasions and tended to coincide with spikes in Queensland's GPG output and Queensland's NEM spot prices, with Queensland NEM spot prices exceeding $300 per MWh on more than 50 occasions during the elevated price period in the Brisbane gas market.

3.2 Scheduled demand for gas

Demand increased in Q3, though was lower than previous years

The typical demand decrease following winter was evident in the downstream markets, with demand falling to levels similar to the previous year, which were a record 10-year low (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 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 downstream market demand was low, elevated GPG output in Queensland and record high export demand put upwards pressure on prices. GPG demand levels in the other

5 Prices in Brisbane exceeded $15 per GJ on 35 occasions. Adelaide also recorded 12 days above that level, and Sydney recorded 9 instances.

regions decreased from the previous quarter, particularly in South Australia and Victoria.[6] Notably, GPG demand levels in Queensland, South Australia and Victoria were above last year's Q4 output.

3.3 Gas production and storage

Southern production higher despite reduced processing facilities

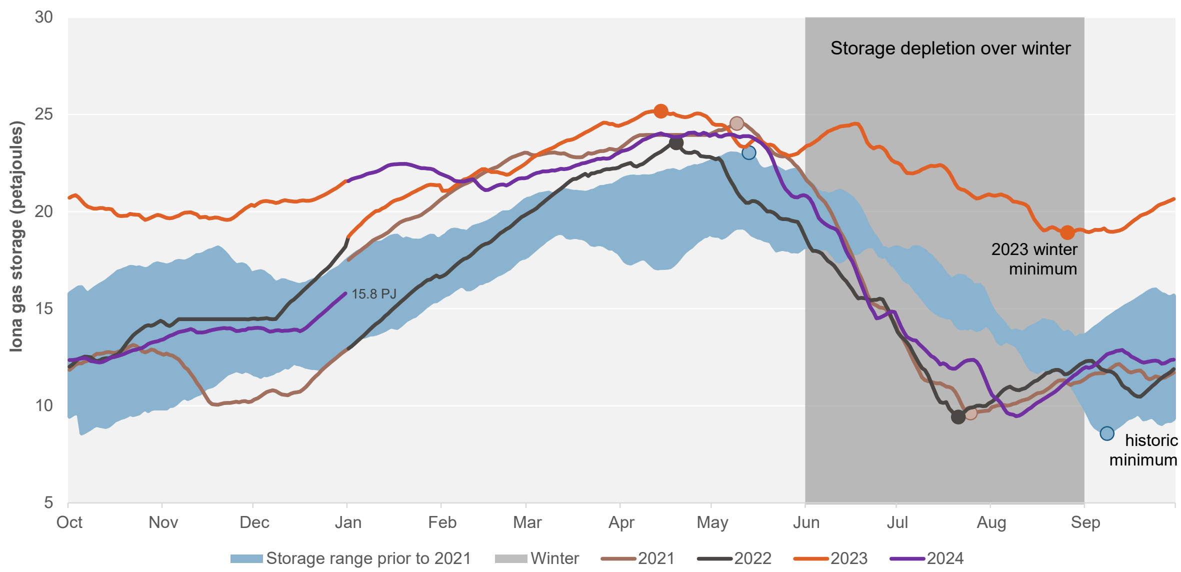
Quarterly production levels at Victoria's primary supply source at Longford were above those observed across Q4 2023, despite one of the 3 processing plants being taken offline from 15 September. The facility produced 3.7 PJ more than in Q4 the previous year, remaining at reasonably consistent output levels across the quarter.

Quarterly production also increased at Ruby Jo in Queensland, with the region's 2nd largest production source increasing its output by over 2 PJ compared with Q3 in line with strong export flows.

Iona Storage replenished from late December

Following the depletion of Iona's storage levels over winter, gradual refilling occurred heading into the beginning of Q4 before refilling paused from 10 November and recommenced from 18 December at a higher-than-average rate. Iona's storage reached 15.8 PJ by the end of the quarter. The increased refilling also coincided with reduced daily downstream market prices as demand to transport gas north through the VNI fell alongside lower GPG demand in Queensland.

Figure 15 Iona underground gas storage levels



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

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6 Decreased GPG demand in Tasmania followed increased hydro generation output from the end of last quarter, which removed the region's reliance on back-up generation from the reinstated Tamar Valley gas-powered generator.

Source: AER analysis using Gas Bulletin Board data.

3.4 Gas pipeline flows

High gas flows north as exports reach a record high

Daily flows north over the QSN link at Moomba reached similar levels to the record highs observed at the beginning and end of 2016, which was soon after LNG exports first commenced. Flows were also sitting well above Q4 levels recorded in previous years. Daily flows through the QSN reached highs of almost 370 TJ per day, supported by record flows north from Victoria through the VNI, which exceeded 100 TJ per day over most of the quarter.[7]

This led to quantities of gas flowing north reaching their fourth highest level since the beginning of 2017, with close to 21.4 PJ of gas and nearing record levels for the QSN.[8] The high northerly flows on QSN were supported by high levels of gas flowing north across the VNI.[9] Daily flows above 100 TJ per day across 60 days saw 11.2 PJ of gas transported north from Victoria, which is a record for the quarter.[10]

The price differential between Brisbane and Victoria had some influence on the higher quantity of withdrawal bids scheduled at Culcairn, with VNI flows reducing in late December alongside reduced GPG demand in Queensland and an easing of price levels, particularly in southern markets.

Market participants made use of 35.3 PJ of pipeline capacity won through the Day Ahead Auction (DAA) in Q4 2024, slightly higher than the previous year’s record for the quarter and 4.4 PJ higher than the prior record set in Q4 2022. The increase in gas won on northern routes that began towards the end of the previous quarter on the MSP and SWQP continued in line with high northerly gas flows. On the MSP, 67% of capacity won during the quarter was obtained on northern routes compared to 36% last year, while on the SWQP 82% of capacity was won on routes north compared to 43% last year.

7 Over the quarter, daily flows north via the QSN link at Moomba reached the highest levels observed since the years following LNG exports coming online. Daily flows north on the QSN exceeded 200 TJ per day over 61 days throughout the quarter, reaching over 300 TJ per day on 14 occasions with a high of 366.8 TJ on 29 December.

LNG exports from Curtis Island in Gladstone commenced in 2015, with a ramp up in export volumes in 2016 and 2017 resulting in significant quantities of gas flowing north. Summer periods at the beginning and end of 2016 reached levels in excess of 300 TJ per day, reaching a high of over 370 TJ in late 2016.

8 QSN: Queensland / South Australia / New South Wales.

9 VNI: Victoria / New South Wales Interconnect.

10 The amount of gas shipped north on the VNI was 1.2 PJ higher than the previous record set over Q2 2022.

Figure 16 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.

3.5 International LNG prices

Winter in the northern hemisphere support LNG prices in Asia

In Q4, the daily ANEA price increased from AUD$18.06 per GJ on 1 October to AUD$22.40 per GJ by 31 December, with the start of the winter season in Asia and associated increased heating demand putting upwards pressure on LNG prices.

The average ANEA price across Q4 2024 was AUD$20.04 per GJ, below the AUD$21.34 per GJ average set over Q4 2023. Daily prices were less volatile than the same period in 2023 when prices ranged between AUD$16.24 and AUD$25.25 per GJ.

Lower prices from the start of Q2 2024 to the end of 2024 are understood to be predominantly driven by increased global gas availability. Q4 saw a premium in northeast Asia deliveries over European deliveries, as Europe's demand for gas weakened due to their high storage levels.[11] Prices for both regions increased over the quarter but remain below levels a year ago.

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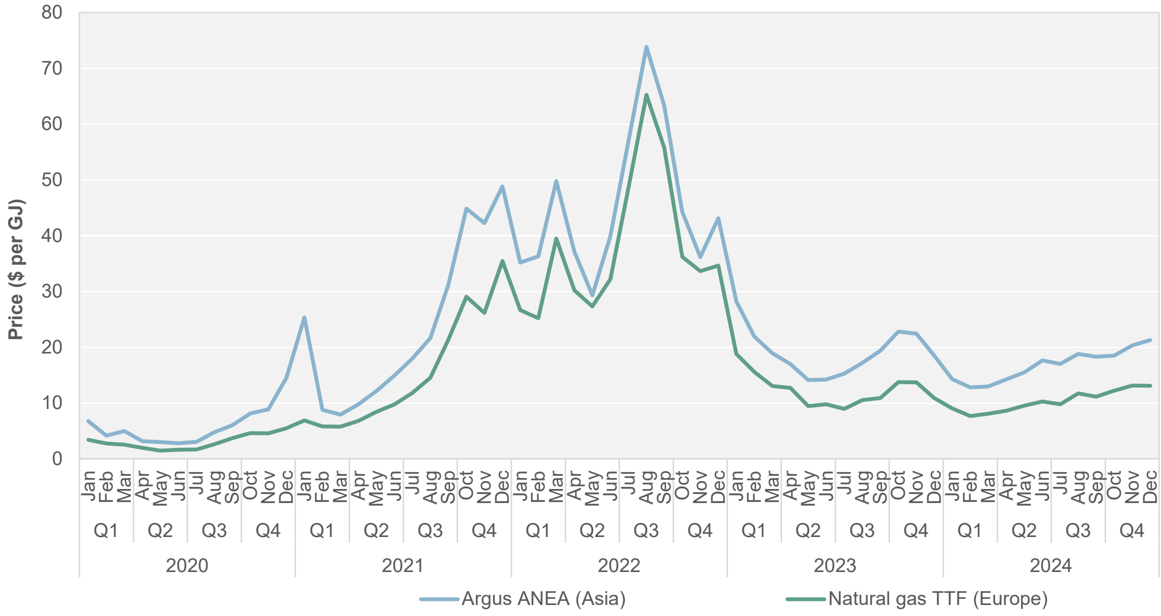
[11] Storage levels in 2024 tracked at a 5-year high but an earlier start to winter in Europe has lowered storage levels to the 5-year average. (Swiss Federal Office of Energy SFOE, Energy Dashboard Switzerland (accessed 13 January 2025)

Figure 17 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 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.

3.6 Other gas events

Significant price variations in the Sydney hub

In November and December, a significant price variation (SPV) reporting threshold of $250,000 for the provision of MOS (balancing gas) services[12] in the Sydney STTM was breached on 3 occasions.[13] The primary driver of the high service costs was attributable to

12 MOS (Market Operator Service) is a mechanism used to balance differences between the forecast supply requirement and the actual supply outcomes. The mechanism has a commodity and service component, where providers of MOS services that can park or loan gas get paid as bid for the amount of the service required on a given day.

13 In accordance with the National Gas Rules (the Rules), the AER is required to publish a report whenever there is a significant price variation (SPV) in the Victorian Declared Wholesale Gas Market (DWGM) or Short Term Trading Markets (STTM). The AER has published guidelines setting out what constitutes a SPV event.

MOS decrease services (to park gas on the pipeline) allocated on the EGP, with counteracting MOS requirements also contributing to higher cost on 2 of these occasions.[14]

Table 1 illustrates the distribution of costs allocated for MOS services on these days. These events will be investigated in a significant price variation report to be published on the AER website during Q1 2025.

Table 1 Significant price variations in the Sydney STTM[15]

Date	MSP MOS cost	EGP MOS cost	Total service cost
28 November	$180,785.42	$848,982.44	$1,029,767.86
14 December	$43,435.90	$262,246.81	$305,682.71
20 December	$1,120.34	$321,878.07	$322,998.41

Source: AER analysis using east coast gas market data for the Sydney short term trading market (STTM).

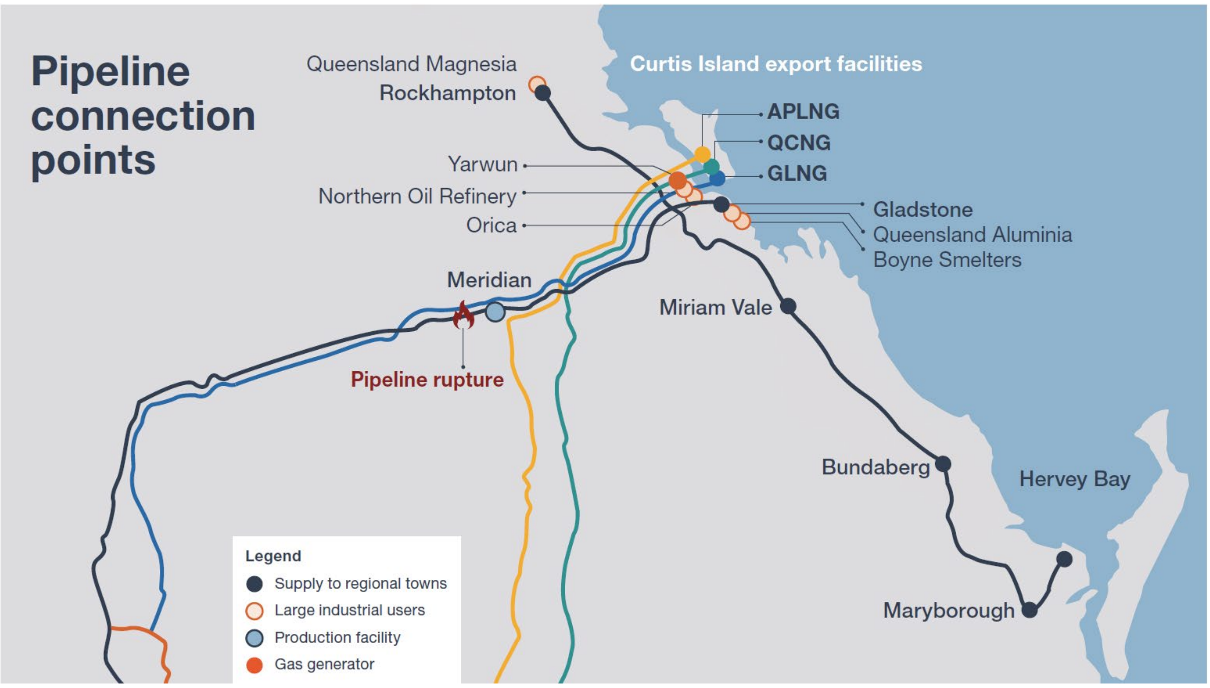
Queensland Gas Pipeline returns to normal operation

On 10 December Jemena returned the Queensland Gas Pipeline to normal operating pressure levels following a pipeline rupture that occurred on 5 March 2024. The initial event, which resulted in the curtailment of numerous downstream users, required a segment of the pipeline to be closed for repair. This was followed by gradual ramping up of delivery capabilities using deliveries from sources around Meridian, downstream of the event. The pipeline ramped up to just over 130 TJ in early September and has now returned to its nameplate delivery capability of 145 TJ per day. More details about this event are covered in section 4.5.2 of the 2024 State of the energy market report.

14 Counteracting MOS can occur due to physical differences in pressure, where one pipeline provides more gas than is scheduled (resulting in an increase MOS allocation to deliver additional gas supply from the pipeline), offsetting another pipeline which provides less gas than scheduled (resulting in a decrease MOS allocation to park gas upstream of the market).

15 EGP = Eastern Gas Pipeline, MSP = Moomba to Sydney Pipeline.

Figure 18 Queensland Gas Pipeline and surrounding downstream infrastructure



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

4 Electricity and gas markets forward outlook

This section provides discussion of electricity futures prices, electricity generation entry/exit and bilateral gas contracts.

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

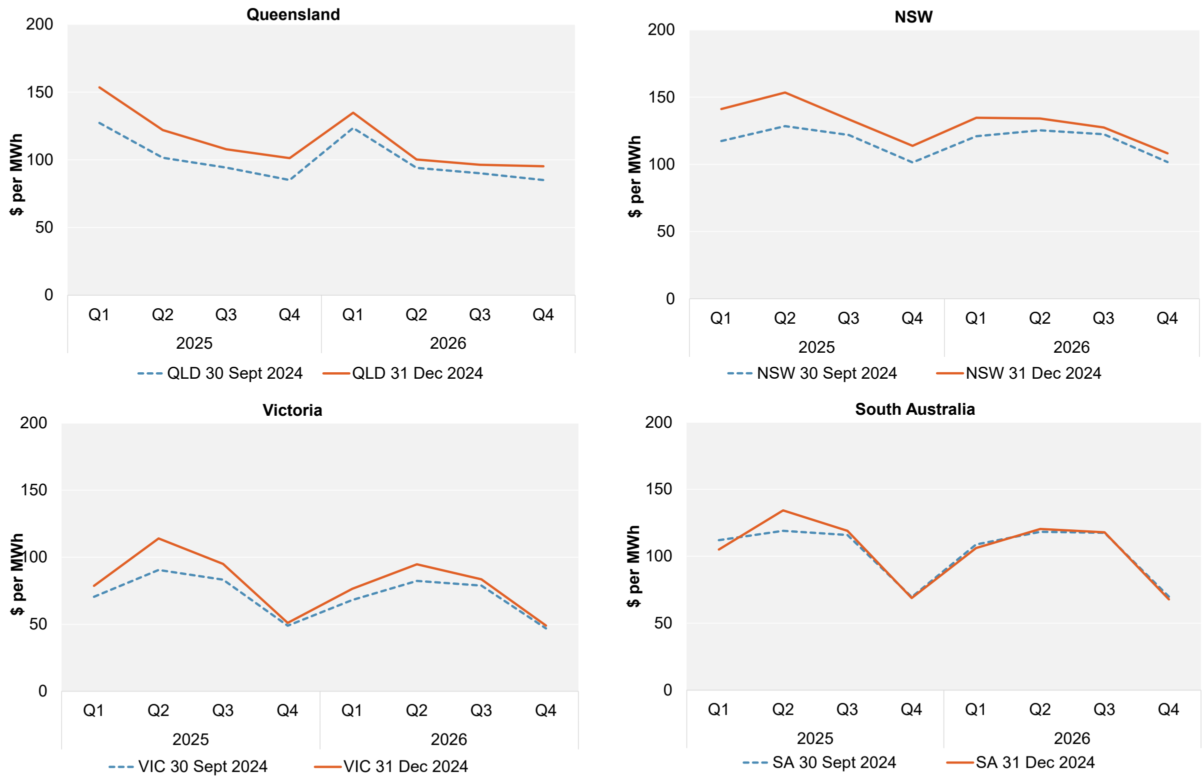
4.1 Forward prices

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, resulting 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.

At the end of Q4, base futures prices for 2025 dates were generally higher compared with the end of Q3 2024 (Figure 19). This was most notable in Queensland and NSW. Victorian base futures prices rose slightly for most forward quarters, but remained steady for Q4 2025. South Australian base futures prices rose for some forward quarters but fell for others. Liquidity in South Australian contract markets is very low, which can distort the movements in contract prices.

2026 base future price movements in each region were similar to, but smaller than, 2025 price movements.

Figure 19 Base quarterly electricity futures prices

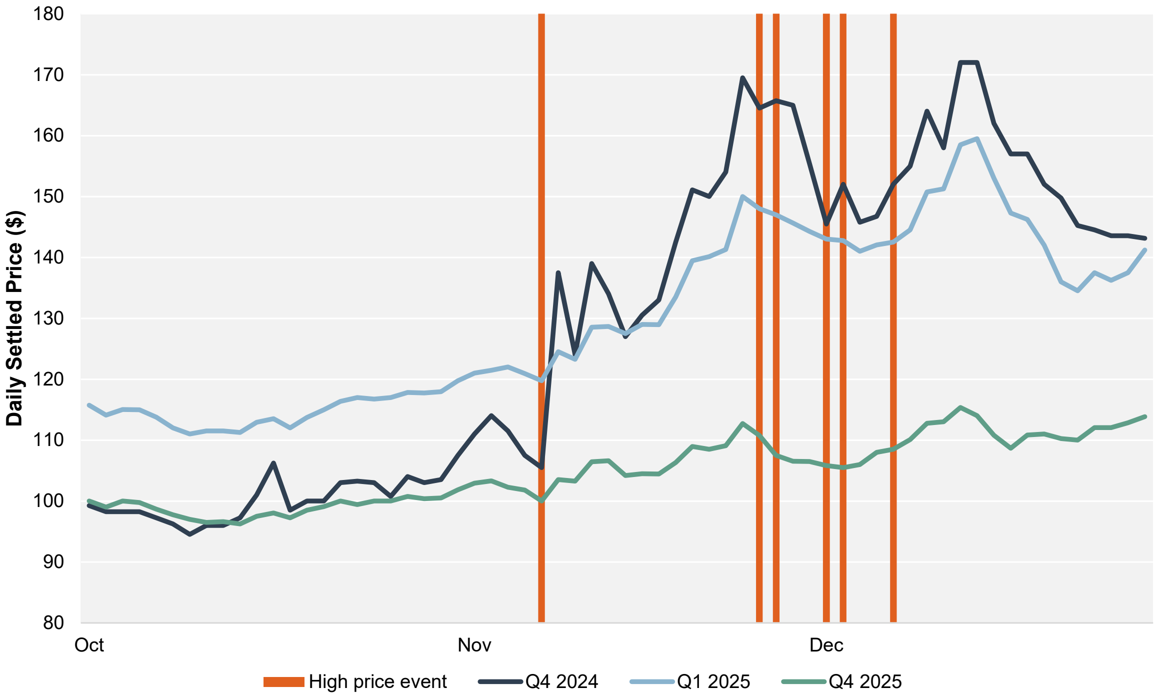


Note: Base future prices for each quarter as of 30 September 2024 (end Q3) and 30 December 2024 (end Q4).

Source: AER analysis using ASX data.

The increase in base futures prices during the quarter, for 2025 quarters as well as Q4 2024, appeared to reflect higher-than-expected spot prices. The 7 November high price event in Queensland and NSW had an immediate impact on the current quarter's futures price. This suggests either that traders had not anticipated the price event, or that they anticipated high price events would continue to occur across the quarter. The event also preceded a rise in futures prices for Q1 and Q4 2025, but to a lesser extent (especially for Q4). Further increases in futures prices for these 3 quarters coincided with high underlying average spot prices throughout the remainder of November. However, subsequent high price events did not appear to further impact future prices.

Figure 20 NSW daily settled base futures prices traded in Q4 2024 mapped against days when high price events occurred



Note: Average daily settled price for Q4 2024, Q1 2025 and Q4 2025 NSW quarterly base futures contracts, mapped against days when there were 30-minute prices above $5,000 per MWh in the region. The contracts are settled at the end of the quarter, so the Q4 2024 product reached its final price (equal to the quarterly average spot price) at the end of the time series (31 December 2024).

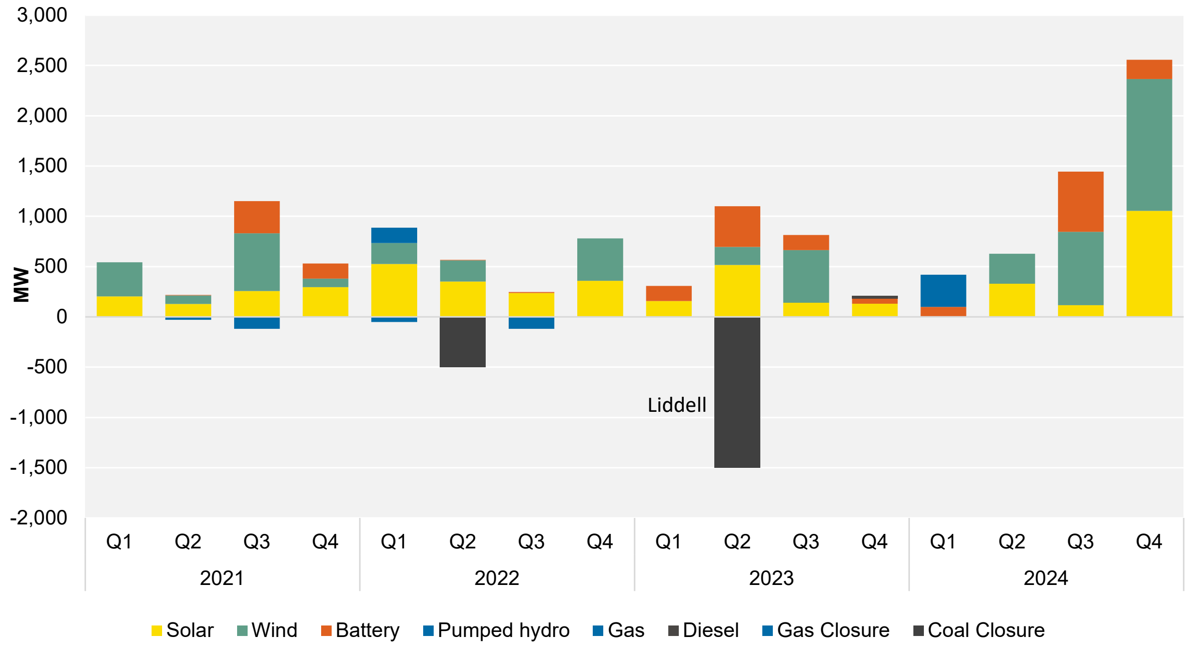
Source: AER analysis using NEM data and ASX data.

4.2 Entry and exit of capacity

Major projects commenced commissioning in Q4

There was significant new entry in Q4 2024, with several large projects commencing generation. In total, these projects constitute over 2,500 MW in registered capacity, which is the highest quarterly new entry of renewable generation to date. However, many of these projects are yet to achieve full output – for example, Acciona Energy's Macintyre Wind Farm has a registered capacity of 923 MW but only 27 of the planned 162 turbines have been connected to the grid so far.[16] Output from these partially connected generators will increase over time as they progress toward full commissioning. A comparison of registered capacity and output to date is below in Table 2.

Figure 21 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 AEMO Generator Information.

Another large project to commence generation this quarter is the Waratah Super Battery. The battery project has been developed as a System Integrity Protection Scheme (SIPS), designed to provide protection against sudden power surges.[17] The SIPS is also designed to provide a virtual transmission solution that improves the performance of the transmission network. The battery can discharge at a rate of 850 MW, but 700 MW of continuous active power capacity is guaranteed under the SIPS. As such, we have allocated 150 MW to be considered available new entry into the NEM.

Entry of Snowy Hydro's 750 MW[18] Hunter Power Station in NSW (formerly known as Kurri Kurri) had been expected this quarter but was delayed to Q2 2025.

Overall, AEMO's Generation information workbook lists 3,201 MW of committed projects[19] that are expected to come online before next summer, 2,206 MW of which will be

16 Acciona Energy, First power from Macintyre wind farm exported, 3 October 2024 (accessed 9 January 2025).

17 NSW Government, Waratah Super Battery, accessed 9 January 2024.

18 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).

19 Projects that will proceed, with known timing, satisfying all five of AEMO's commitment criteria. The generation information workbook (accessed 15 January 2025) was last updated 8 November 2024. We have removed projects that have commenced dispatching generation.

dispatchable generation. In addition to the Hunter Power Station (gas), 1,206 MW of battery storage units and 250 MW of pumped hydro are expected before December 2025.

Table 2 New projects that commenced generation during the quarter

Region	Fuel type	Station	Capacity	Highest dispatched volume
Queensland	Wind	Clark Creek wind farm stage 1	171 MW	5 MW
Queensland	Wind	Macintyre Wind Farm	923 MW	39 MW
NSW	Wind	Crookwell 3 Wind Farm	57 MW	55 MW
NSW	Solar	Walla Walla Solar Farm	300 MW	100 MW
NSW	Solar	Stubbo Solar Farm	400 MW	6 MW
NSW	Solar	Wollar Solar Farm	280 MW	5 MW
NSW	Battery	Waratah Super Battery (NSW Gov)	150 MW	70 MW
Victoria	Solar	Wunghnu Solar Farm	75 MW	26 MW
South Australia	Battery	Tailem Bend Battery Project	41 MW	41 MW
South Australia	Wind	Goyder South Wind Farm 1B	203 MW	6 MW

Note: This table lists market entry for the 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

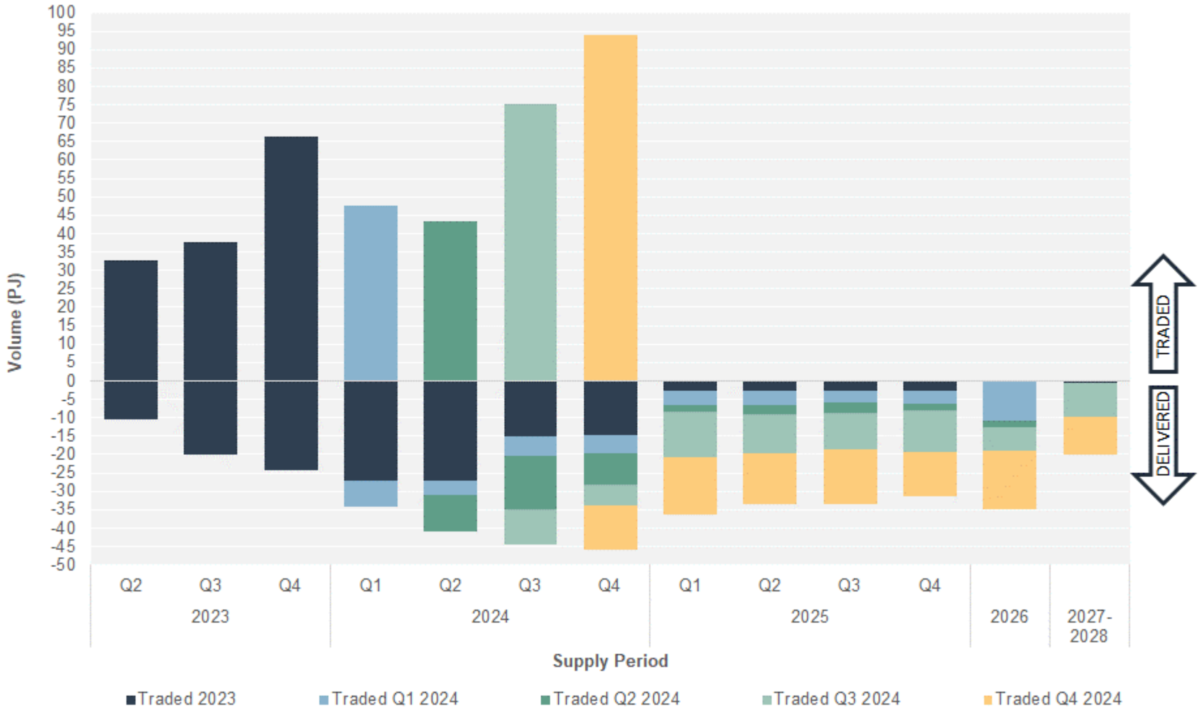
A significant proportion of gas trade is negotiated directly between participants outside of the AEMO-facilitated markets. Since March 2023, participants have been required to report details of these bilateral transactions up to a year in duration to the Gas Bulletin Board.

Short term contract prices for 2025 averaging below $14 per GJ

There was 94 PJ of gas sales reported in Q4, this is 25% higher than the Q3 2024 volume of 75.3 PJ and 42% higher than the Q4 2023 volume of 66.4 PJ (Figure 22). The combined Q3 and Q4 2024 total gas sales reported was 169 PJ, representing an increase of 63% compared to the same period in 2023. Most of the gas traded in Q4 was for delivery over 2025 and 2026, with 56.1 PJ of these sales for delivery in 2025, 15.7 PJ for delivery in 2026 and 10.2 PJ for delivery over 2027-2028. With two years' worth of short-term bilateral transactions now reported, it is evident that trade significantly increases in the last quarter of the year as participants are securing and finalising supply for the following year and beyond.

Overall, the volumes of trade reported in the last two quarters of 2024 were the highest volumes of trade reported since reporting commenced in March 2023, which potentially indicates a shift to shorter term contracting (up to a year in length) and away from transactions longer in length (greater than a year), which are not currently reported to the Gas Bulletin Board.[20]

Figure 22 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. The trade in previous quarters before Q4 2024 has changed slightly from what was reported in our previous quarterly - this 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.
Source: AER analysis using Natural Gas Services Bulletin Board data.

Over 2024 the forward volume-weighted average (VWA) price has continued to trend lower every quarter with the VWA price for gas traded in Q4 2024 for delivery over 2025 at $12.72 per GJ, the lowest compared to all previous quarters (Figure 23). As a result of the lower contracting prices and larger traded quantity in Q4, the 2025 VWA price has reduced to $13.56 per GJ compared to $14.09 per GJ reported at the end of Q3 2024. The VWA price of transactions reported in Q4 for delivery in 2026 was $13.75 per GJ, which is also lower when compared to the VWA price for all deliveries in 2026 of $14.25 per GJ.

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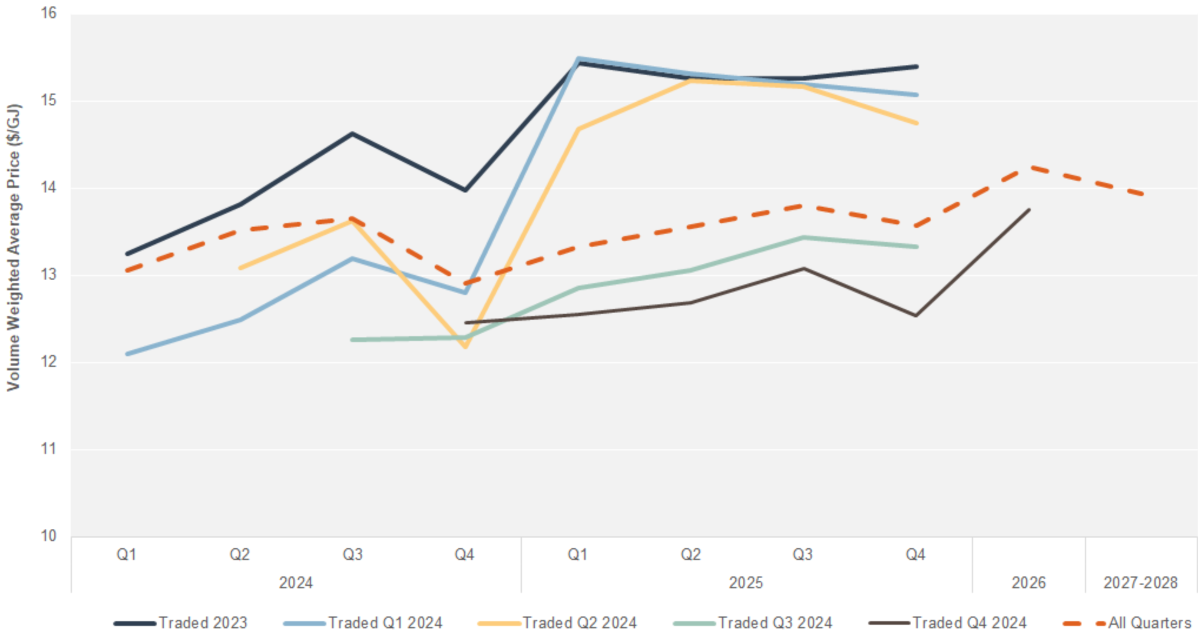
20 The ACCC in its December 2024 interim report also noted that gas is increasingly being sold by producers under shorter-term Gas Supply Agreements, with most new agreements having a term of less than 2 years.

Figure 23 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 for 2024, while all transactions for 2023 was grouped together. 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.

Prices of contracts with 1-year length deliveries are averaging just above $14 per GJ for 2025 and 2026

The VWA price for contracts with a one-year long delivery length in 2025 was $14.15 per GJ, which is marginally higher than the VWA price for all contracts reported with a delivery in 2025 of $13.56 per GJ.[21]

This difference reflects that some one-year contracts for 2025 delivery were struck over 2023 and early 2024, with participants paying higher prices of between $15-$18 per GJ. This price also reflects an aspect of the reporting framework where some of the short term transactions that are linked to a futures index are reported using the reference price and exchange rate at the trade date, which may differ from the actual price that will be paid at delivery date. For 2025 delivery dates, around 20% of reported one-year transactions were linked to a JKM futures index or the Brent oil price, with the remaining 80% of one-year transactions reported as fixed-price contracts.[22] The VWA price for one-year long delivery length contracts reported

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21 For 2025 delivery dates, one-year contracts were made up of 16 unique sellers and 41 unique buyers, and for delivery in 2026 it was between 10 unique sellers and 18 unique buyers.

22 JKM 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. When reporting short term transactions linked to the JKM futures index or Brent oil participants are required to report the reference price as reported on the Intercontinental Exchange on the trade date and report in Australian Dollar based on the exchange rate published by the Reserve Bank at 4 pm.

to date for delivery in 2026 is $14.17 per GJ, with prices reported in a wide price band between $10 per GJ and $17 per GJ, with a median price of around $13.80 per GJ.

Limited trade to date in the new ASX Wallumbilla Natural Gas Futures product

The new ASX Wallumbilla Natural Gas Futures product commenced trading on 19 August 2024 for first delivery in October 2024.[23] This 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. 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). This product aims to provide a transparent forward price curve out to 3 years, improve liquidity at the GSH and provide an additional hedging tool for participants to manage their risk.

Over Q4 2024 the number of futures traded each month increased, although volumes remained low with 26 futures traded for the quarter, equating to 80 TJ when delivered. Prices for these products also increased over the quarter in line with movements observed in other domestic gas markets, with Delivery EFP prices ranging from $13.00 per GJ to $13.50 per GJ compared to the GSH-traded VWA price for equivalent 2024 monthly products of $12.26 per GJ.

Looking ahead to futures with settlement dates in 2025, there are 50 futures traded (151 TJ, noting not all interest may remain open for physical delivery) covering each month of 2025 at prices in the range of $12-$16 per GJ compared to a VWA price for monthly GSH products of $13.26 per GJ. For deliveries in 2026-2027, bid prices for the ASX futures product sit in the $11-$14 per GJ range while asking prices fall within a $13-$17 per GJ band.

23 For more information see: https://www.asx.com.au/markets/trade-our-derivatives-market/overview/energy-derivatives/gas