Quarterly Energy Dynamics Q1 2024

April 2024

Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q1 2024 (1 January to 31 March 2024). This quarterly report compares results for the quarter against other recent quarters, focusing on Q4 2023 and Q1 2023. Geographically, the report covers:

- The National Electricity Market (Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania).
- The Wholesale Electricity Market and domestic gas supply arrangements operating in Western Australia.
- The gas markets operating in Queensland, New South Wales, Victoria and South Australia.

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Version control

Version	Release date	Changes
1	23/04/2024	First release
2	24/04/2024	Corrections to Section 1.2.2 (Basslink flow on 13 February) and Section 1.3.1(Figure 40)

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Executive summary

East coast electricity and gas highlights

Increasing National Electricity Market (NEM) demand and wholesale price volatility

- High temperatures in the summer months drove NEM operational demand to an average of 21,552 megawatts (MW) in Q1 2024, the highest Q1 average since 2020 and a 1.7% increase from Q1 2023. This increase was most evident in the northern regions with Queensland experiencing a record maximum operational demand of 11,005 MW on 22 January 2024.
- Despite high price volatility driven by increasing demands and weather events, NEM wholesale spot prices averaged $76 per megawatt hour (MWh) over Q1 2024, an 8% decrease from Q1 2023. Overall price volatility (spot prices above $300/MWh) contributed $17/MWh, or 23%, to the quarterly average, partially offsetting a reduction in energy prices driven by increasing renewable output and increased black coal capacity offered to the market at prices under $100/MWh.
- Queensland was the only NEM region where wholesale spot prices increased on Q1 2023, recording the highest regional quarterly average of $118/MWh, followed by New South Wales at $87/MWh. The divide between northern and southern regions continued with Tasmanian wholesale spot prices averaging $67/MWh, and South Australia $55/MWh. Victoria recorded the lowest quarterly average price of $52/MWh despite a severe storm event on 13 February 2024 causing the loss of transmission lines, generation outages and price volatility which contributed nearly $15/MWh to that quarterly average.

Renewables continued to increase NEM market share

- Output from all generation sources other than gas-fired and hydro stations increased to meet the growth in underlying NEM demand. Renewables led the increase in output, lifting their overall share of total NEM supply to 39.0% over Q1 2024, up from 37.4% over the previous Q1.
- Grid-scale solar generation had the greatest increase in output, with an 18% lift in quarterly average output from the previous Q1 to a new record of 2,164 MW this quarter. This increase continued to be driven by new and recently commissioned capacity in New South Wales and Queensland.
- Distributed photovoltaics (PV) output hit record highs in South Australia, Victoria and Tasmania, and reached its highest level for any Q1 in Queensland and New South Wales, leading to an overall increase in quarterly output of 10% compared to Q1 2023. Wind generation had the next largest increase, up 5% year-on-year to an average output of 2,971 MW this quarter.
- Increases in black coal-fired quarterly average generation (up 1.1% to 10,613 MW) and brown coal-fired generation (up 0.6% to 3,675 MW) partially offset the decreases in hydro (down 10% to 1,344 MW) and gas-fired generation (down 8% to 1,026 MW).
- Output from grid-scale batteries continued to grow, reaching a quarterly average of 53 MW this quarter (up 134% year-on-year), and lifted batteries' frequency control ancillary services (FCAS) market share to a combined 57% across the NEM's 10 FCAS markets.

East coast and international gas prices continued to trend lower, Queensland liquefied natural gas (LNG) demand increased

- East coast gas prices have fallen slightly from Q1 2023, averaging $11.60 per gigajoule (GJ) for the quarter, although they were higher than Q4 2023 which averaged $10.83/GJ.
- Gas demand increased by 10% compared to Q1 2023, solely driven by higher demand for Queensland LNG exports (+44 petajoules (PJ)). AEMO markets demand decreased (-4 PJ) and there was slightly lower usage for gas-fired generation (-1 PJ).
- Domestic gas supply shifts that have been observed since Q2 2023 continued, with declining production from gas fields connected to the Longford Gas Plant in Victoria the main contributor. Production at Longford fell by 10 PJ compared to Q1 2023, with available capacity at Longford dropping below 300 terajoules per day (TJ/day) for part of the quarter, the lowest planned capacity in decades.
- A pipeline rupture on the Queensland Gas Pipeline (QGP) on 5 March resulted in a threat to the adequacy of supply to the Gladstone region in Queensland, with remaining supply inadequate to meet demand. As a result, AEMO exercised its east coast gas system function, for the first time, and issued directions to mitigate the risk. Gas flows on the QGP have not yet returned to regular levels.

Western Australia electricity and gas highlights

Heatwave conditions drove record Wholesale Electricity Market (WEM) demand

- Multiple heatwave events over the quarter resulted in multiple operational demand records being set. Record maximum operational demand of 4,233 MW was observed on 18 February 2024, an increase from the previous record of 4,040 MW from Q4 2023.
- Average operational demand for the quarter was 2,735 MW in Q1 2024, an increase of 223 MW from Q1 2023. The increase in demand was met primarily by gas (+88 MW), distributed PV (+76 MW), and wind (+29 MW). The latter was partially driven by the installation of the Flat Rocks Wind Farm.
- Even with additional generation from other sources to meet demand, renewables accounted for an increased share of generation, up 0.5 pp from Q1 2023 to 39.1% of the overall generation mix in Q1 2024.
- Procured demand reduction, including from Supplementary Reserve Capacity providers, was used on 14 occasions and was a critical capability to maintain power system security and reliability during periods of high demand.

Prices are stabilising in the WEM's new Real Time Market

- Prices and costs per MWh decreased compared to the previous quarter, with the Final Reference Trading Price decreasing by 6% to $78.49/MWh. Total Real Time Market costs as price per MWh normalised by total energy consumed decreased by -$6.72/MWh to $100.15/MWh.
- Hedging of pricing outcomes using the Short Term Energy Market (STEM) continued, with an increased premium placed on certainty against Real Time Market outcomes compared to the Balancing Market.

Net withdrawals of gas from storage resumed

- A total of 97.2 PJ was consumed in the Western Australian domestic gas market in Q1 2024, an increase compared to both to Q1 2023 (up 6.2%), and the previous quarter (up 0.7%), mainly due to higher demand for gas-fired electricity generation.
- Despite some supply disruptions, domestic gas production in Q1 2024 was 100.3 PJ, an increase of 11.3 PJ (12.7%) compared to Q1 2023, which was also impacted by gas supply disruptions. Consistent with previous years, in Q1 2024 gas production decreased by 5.2 PJ compared to Q4 2023.
- After one quarter of net injections into storage in Q4 2023, Q1 2024 saw a return of the recent trend of net withdrawals from storage.

Contents

1 NEM market dynamics

1.1 Electricity demand

1.1.1 Weather

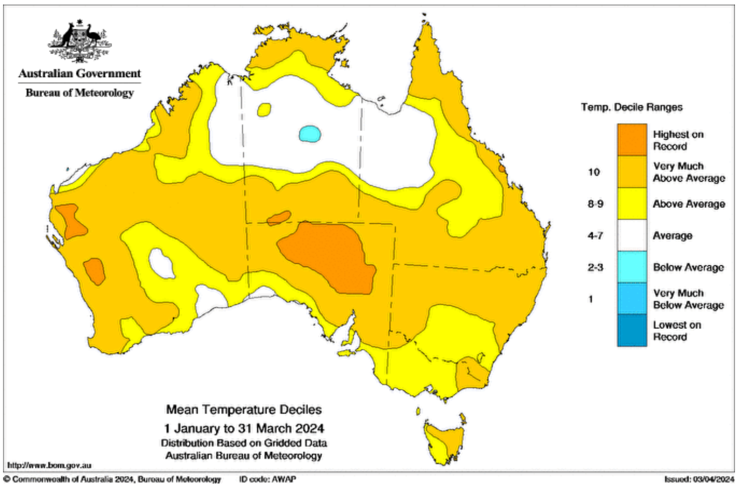
In Q1 2024, warmer weather conditions continued, with average **mean temperatures** above historical averages across most regions (Figure 1).

January and February stood out, marking Australia's third-warmest January and fourth-warmest February on record since 1910.

The national area-averaged mean temperature was 1.54°C higher in January than the 1961–1990 average, then 1.71°C higher in February and 1.11°C higher in March.

Figure 1 Warmer than average temperatures across Australia

Q1 2024 mean temperature deciles for Australia



Average **minimum temperatures** were elevated in many parts of the country, with warm overnight temperatures across the quarter (Figure 2).

In January and February, night-time temperatures were the highest on record for parts of New South Wales and Queensland. Compared to Q1 2023, Brisbane and Sydney experienced notable increases of 0.8°C and 0.6°C in minimum temperatures, respectively. Adelaide experienced a 0.8°C increase, with much of this rise occurring in March.

In this quarter, Cooling Degree Days (CDDs)[1] rose in all major mainland cities except for Melbourne, increasing cooling requirements (Figure 3). Brisbane experienced a notable increase in CDDs in January, nearly doubling the 2023 level, while February saw a 24% increase. Similarly, Sydney observed large increases, more than doubling the previous Q1 levels in both January and February. Adelaide, despite reduced CDDs in January and February, saw a significant year-on-year increase of 51 in March, up from just 2 in 2023.

February and March 2024 were extremely dry for the southern NEM regions, with Melbourne recording its driest March on record and Adelaide and Hobart recording one of their lowest March rainfall totals on record.

[1] A "cooling degree day" (CDD), which is based on the average daily temperature, is a measurement used as an indicator of outside temperature levels above what is considered a comfortable (base) temperature. CDD value is calculated as max (0, average temperature – base temperature).

Figure 2 Minimums warmer than 10-year average in most mainland capital cities

Average quarterly minimum temperature variance by capital city

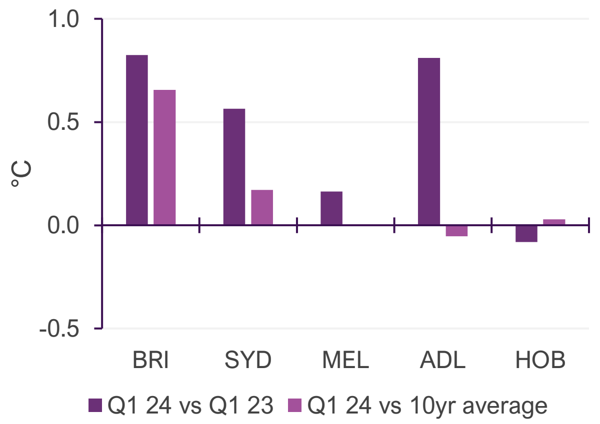
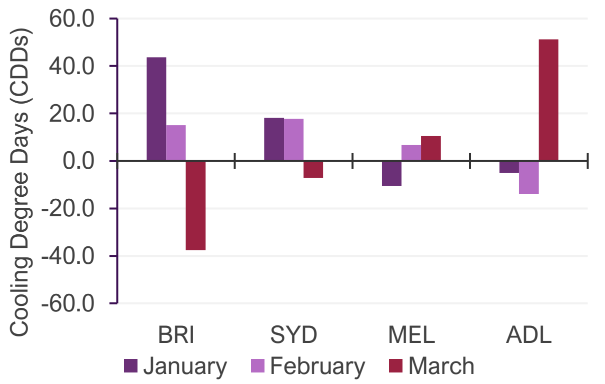


Figure 3 January and February saw higher CDDs in northern regions while March saw higher CDDs in southern regions

Change in monthly Cooling Degree Days (CDDs) by capital city – Q1 2023 vs Q1 2024



1.1.2 Demand outcomes

In Q1 2024, NEM operational demand averaged 21,552 MW, the highest Q1 average since 2020, and a 1.7% increase from Q1 2023. Underlying demand increased by 679 MW (+2.8%) to reach a record Q1 average of 24,822 MW. This uptick was partially offset by the rise in distributed PV output, which averaged 3,270 MW this quarter, a 10% increase on Q1 2023, and the second highest quarterly average after 2023 Q4 (Figure 4).

Figure 4 Record underlying demand partially offset by higher distributed PV output

NEM average underlying and operational demand – Q1s

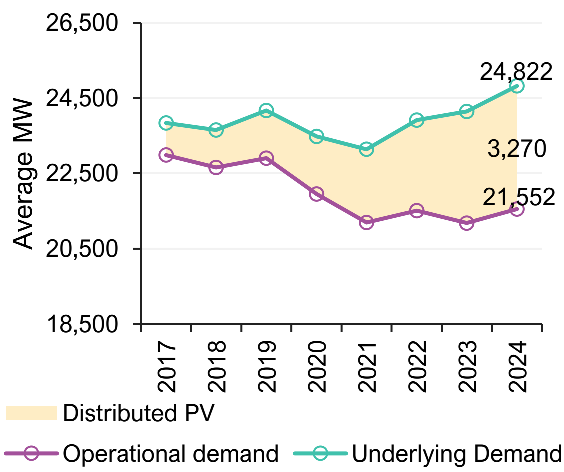
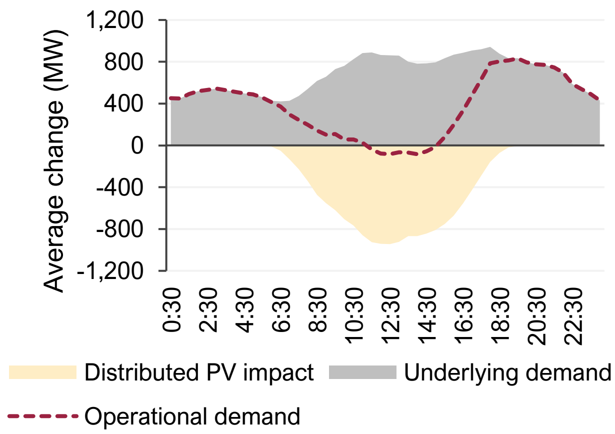


Figure 5 Significant increases in underlying demand drove higher operational demand

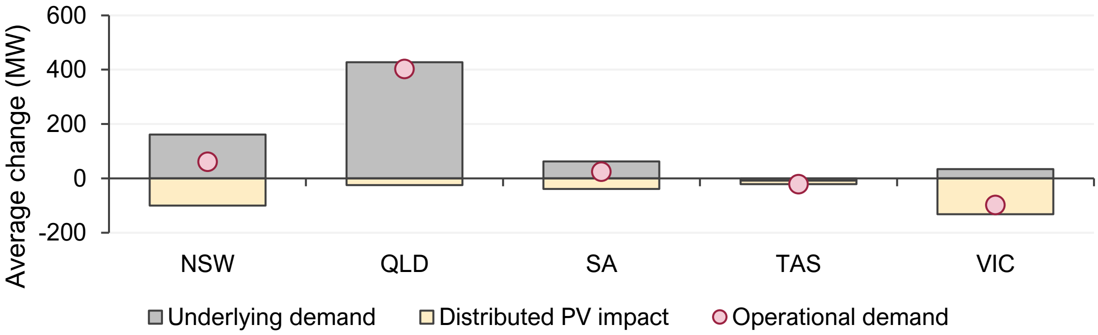
Changes in operational demand – Q1 2024 vs Q1 2023



The increase in operational demand was evident across nearly all hours, particularly outside daytime hours (Figure 5). **Queensland** accounted for most of the increase, with a rise of 403 MW (+6.2%) to reach its second highest quarterly average at 6,917 MW (Figure 6). **New South Wales**'s operational demand averaged 7,658 MW, up by 62 MW (+0.8%) from the previous Q1, while **South Australia** averaged 1,269 MW, a 24 MW (+2.0%) increase. **Victoria** and **Tasmania** experienced reductions of 98 MW (-2.1%) and 21 MW (-1.9%) respectively. Notably, Victoria's average of 4,600 MW was a record low for Q1.

Figure 6 Northern regions drove the NEM's operational demand increase

Changes in average demand components by region – Q1 2024 vs Q1 2023



Underlying demand growth during summer period

Underlying demand surged in **Queensland** and **New South Wales** due to heightened cooling requirements (Section 1.1.1), resulting in respective increases of 428 MW (+5.8%) and 162 MW (+1.9%). Queensland's average underlying demand of 7,848 MW was its highest level recorded for any quarter. Demand growth was particularly evident during the summer months (November to February), with December 2023 and January 2024 witnessing significant year-on-year increases of 16% and 12% respectively in Queensland, and 10% and 5% respectively in New South Wales. As Figure 7 and Figure 8 show, the pace slowed in February before a decline in March, with New South Wales' and Queensland's monthly averages decreasing by 181 MW (-2.1%) and 93 MW (-1.2%) respectively.

Figure 7 Significant increase in Queensland's underlying demand during summer months

Change in monthly underlying demand vs same month previous year – Queensland

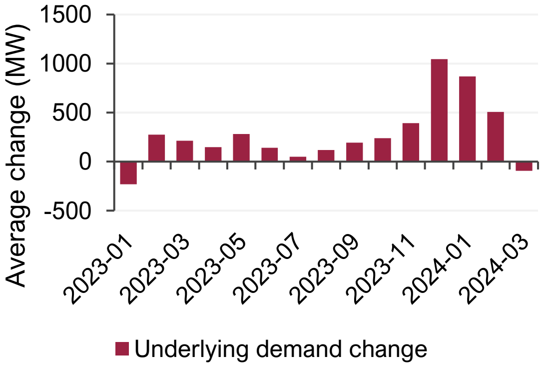
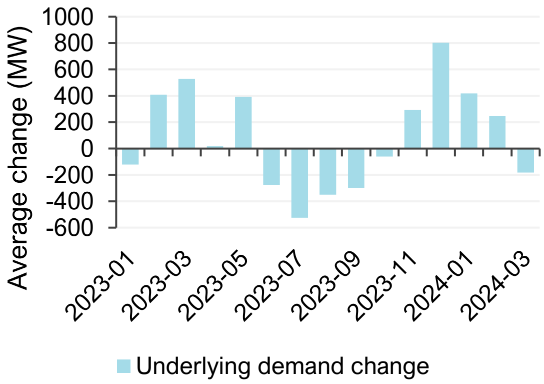


Figure 8 Significant increase in New South Wales' underlying demand during summer months

Change in monthly underlying demand vs same month previous year – New South Wales



Distributed PV growth

Average quarterly distributed PV output hit record highs in **Victoria** (787 MW), **South Australia** (445 MW) and **Tasmania** (58 MW), while **Queensland** (931 MW) and **New South Wales** (1,050 MW) witnessed their highest Q1 outputs. Despite a 10% increase in the NEM average compared to Q1 2023, growth decelerated from the previous levels of over 30% seen in Q2 and Q3 2023. Queensland saw minimal year-on-year growth at 3%, while Victoria and Tasmania exhibited significantly higher growths of 20% and 29% respectively. New South Wales and South Australia witnessed moderate growths of 11% and 9% respectively (Figure 9).

The slower distributed PV output growth in the northern regions was driven by a notable decline in average incident sunlight levels (Figure 10). Brisbane and Sydney experienced reduced average solar exposure this quarter, with decreases of 10% and 6% respectively from Q1 2023. In contrast, Melbourne and Hobart observed increases of 10% and 6% respectively, leading to comparatively higher distributed PV year-on-year Q1 growth rates. Despite a slowdown in average output growth, the upward trajectory of peak distributed PV output persisted (see Section 1.3.5, Figure 56), driven by a continuous rise in small-scale (<100 kilowatts (kW)) PV installations in recent quarters[2].

Figure 9 Significant drop in Queensland's distributed PV growth while Victoria and Tasmania saw increases

Distributed PV year on year growth (%) by region – Q1s

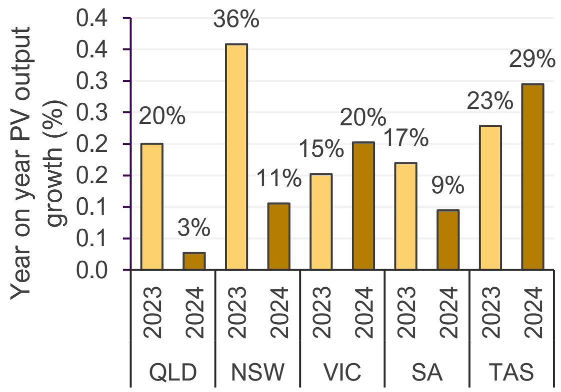
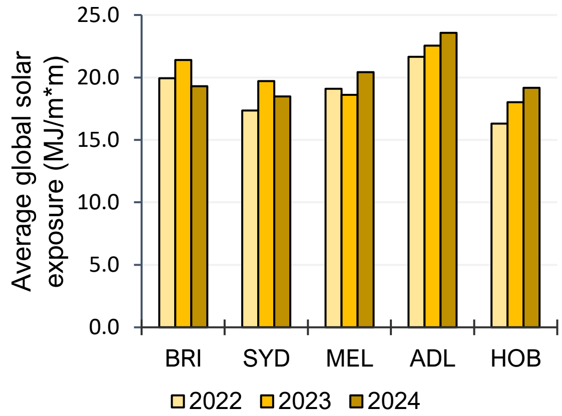


Figure 10 Incident sunlight levels fell in northern regions

Quarterly average global solar exposure by capital city – Q1s

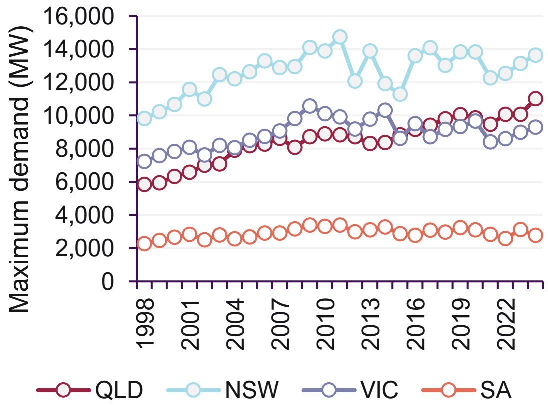


Maximum demand

In this quarter, NEM operational demand reached a maximum of 32,973 MW for the half-hour ending 1730 hrs on Thursday 22 February, marking the highest level since 31 January 2020. In Queensland, the maximum operational demand reached an all-time high of 11,005 MW for the half-hour ending at 1700 hrs on Monday 22 January, recording a 935 MW (9.3%) increase from the previous record set on 17 March 2023 (Figure 11). At this time, distributed PV output stood at 1,000 MW, constituting 8.3% of Queensland's total underlying demand, while grid-scale variable renewable energy (VRE) accounted for 16.6%. Throughout the quarter, the operational demand in Queensland surpassed the previous record of 10,070 MW on three occasions.

Figure 11 Maximum demand reached all-time high in Queensland

Q1 maximum operational demands for mainland regions



2 https://pv-map.apvi.org.au/postcode

Minimum demand

This quarter saw the lowest Q1 minimum operational demand in the NEM since Tasmania joined in 2005 (Figure 12), reaching 13,119 MW in the half-hour ending at 1230 hrs on Saturday 30 March 2024.

This was 1,256 MW (-8.7%) lower than the previous Q1 low set on 21 January 2023. At this time, distributed PV accounted for 45.5% of the NEM underlying demand while grid-scale VRE contributed 21.2%. Throughout the quarter, the NEM operational demand reached below 14,000 MW on three occasions.

New Q1 lows were also set for New South Wales, South Australia, and Victoria (Table 1).

Figure 12 Minimum demands fell to Q1 lows in New South Wales, Victoria, and South Australia

Q1 minimum operational demands for mainland regions

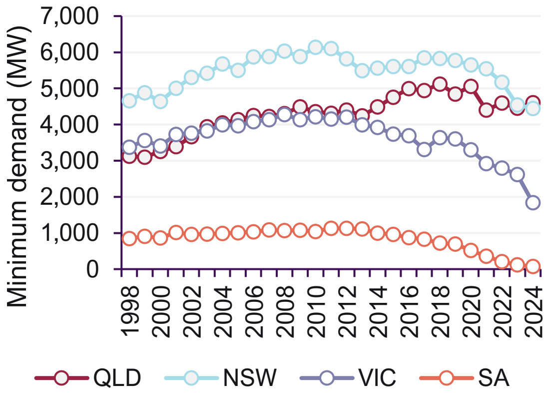


Table 1 Q1 2024 minimum operational demand records

Region	New Q1 minimum demand record	Change from the previous Q1 low
NEM	13,119 MW (1230 hrs on Saturday 30 March 2024)	1,256 MW (-8.7%) below the previous low set on 21 January 2023
New South Wales	4,449 MW (1200 hrs on Saturday 30 March 2024)	96 MW (-2.1%) below the previous low set on 8 January 2023
South Australia	76 MW (1330 hrs on Saturday 24 February)	41 MW (-35.0%) below the previous low set on 5 February 2023
Victoria	1,837 (1130 hrs on Monday 1 January 2024)	786 MW (-30.0%) below the previous low set on 13 March 2023

Daily swing in operational demand

As well as the demand records discussed above, the NEM experienced increased intraday swings between daily minimum and maximum demands this quarter. Managing these swings requires increased operational focus on factors such as system ramping capability and capacity commitment.

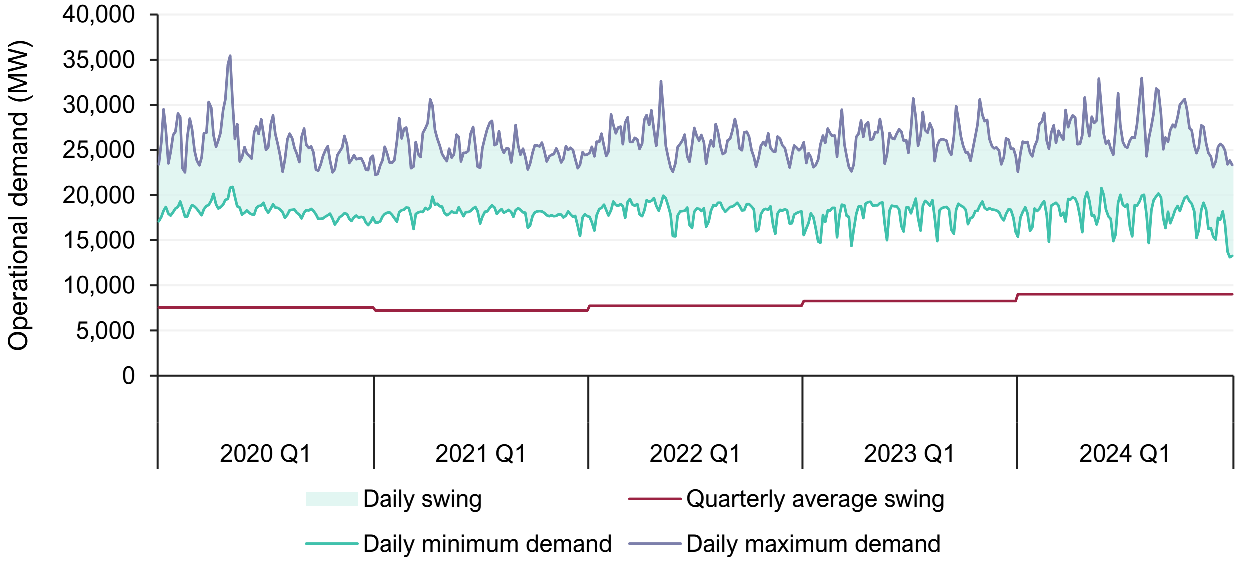
Figure 13 illustrates the NEM-wide daily minimum and maximum operational demands, along with the quarterly average for Q1s since 2020.

The quarterly average of these daily swing values shows an upward trajectory, attributed to the growing impact of distributed PV and heightened underlying demand. The average quarterly swing reached 9,023 MW this quarter, marking a 770 MW increase (+9.3%) from the previous year's Q1.

In Q1 2024, there was also a notable increase in the maximum daily swing, reaching 15,317 MW on 4 February 2024 from Q1 2023's maximum of 11,954 MW. On this day, maximum demand reached 32,907 MW while minimum demand dropped to 17,590 MW.

Figure 13 Operational demand intra-day difference continued to rise

Daily maximum and minimum operational demand in NEM – Q1s

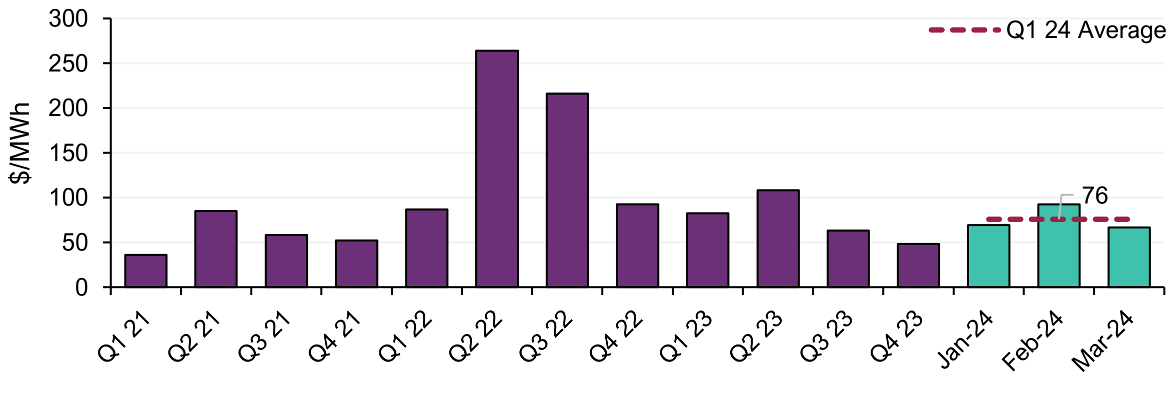


1.2 Wholesale electricity prices

In Q1 2024, wholesale spot prices across the NEM averaged $76/MWh[3], a reduction of $7/MWh (-8%) from Q1 2023 but an increase of $28/MWh (57%) from Q4 2023. Notably, the energy[4] component of the average price saw a decline of $17/MWh compared to the same period last year but the cap return component (averaged across regions) increased by $11/MWh to $17MW/h, contributing 23% to the quarterly average. Monthly average prices rose in January and February, averaging $69/MWh and $92/MWh respectively, before dropping to $67/MWh in March (Figure 14).

Figure 14 Average NEM spot prices down by 8% on Q1 2023, but up by 57% on Q4 2023

NEM average wholesale electricity prices – quarterly since Q1 2021



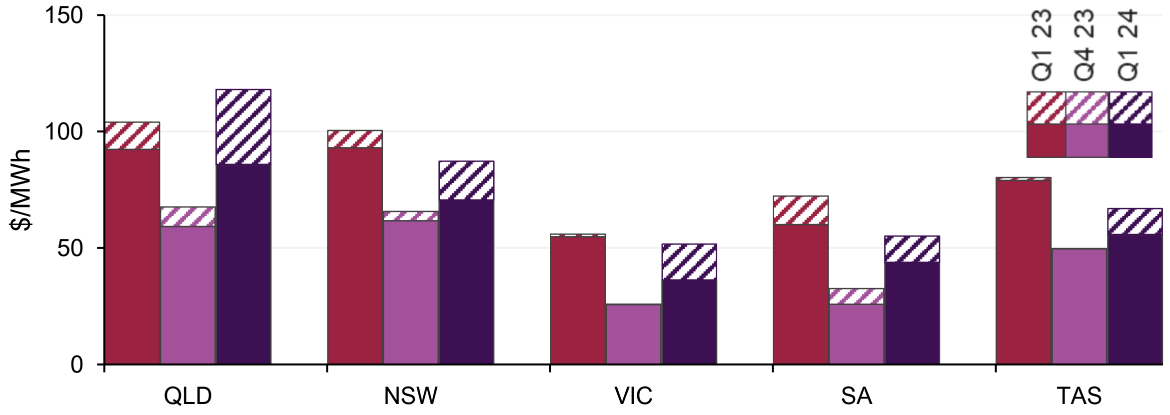
3 Time weighted average – simple average of regional wholesale electricity spot prices over each 5-minute dispatch period over the quarter.

4 Energy price calculation in the analysis of average spot electricity prices truncates the impact of volatility (that is, any excess component of spot prices above $300/MWh, also known as "cap return"). Since commencement of Five Minute Settlement (5MS) on 1 October 2021, energy prices and cap returns are calculated on a 5-minute basis.

All NEM regions, except Queensland, experienced a reduction in quarterly averages compared to Q1 last year, characterised by lower energy price components offset by higher cap returns. Regional average prices for this quarter varied from $52/MWh in Victoria to $118/MWh in Queensland. This quarter's trends continued to reflect a divide between higher average spot prices in the northern regions of Queensland and New South Wales, and lower prices in the southern regions of Victoria and South Australia (Figure 15). The drivers behind this divide are discussed in Section 1.4.

Figure 15 All regions except South Australia saw increased cap returns on Q1 2023

Average wholesale electricity spot price by region – energy and cap return components for selected quarters



By region:

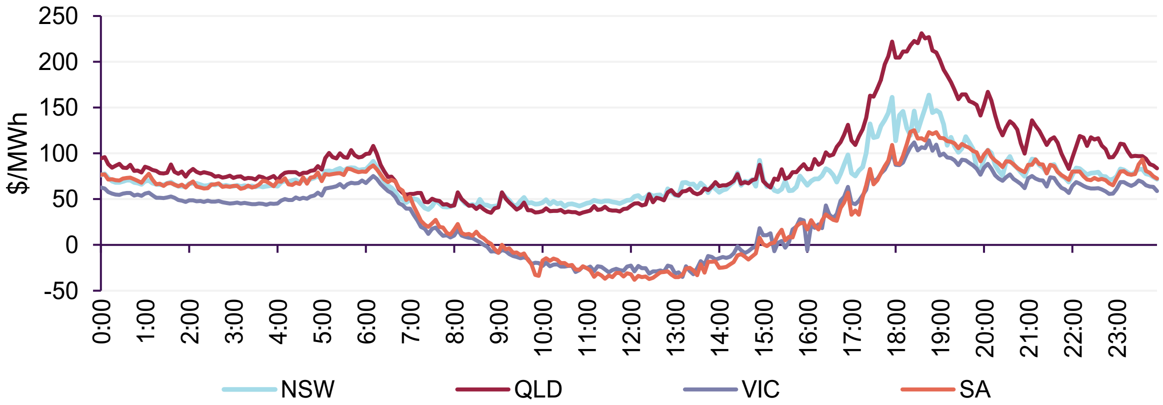
- **Queensland'**s wholesale spot prices averaged $118/MWh this quarter, marking a $14/MWh (13%) increase compared to Q1 2023 and a significant $50/MWh (+75%) increase compared to Q4 2023. While the energy component experienced a decrease of $6/MWh compared to the same period the previous year, the cap return component surged by $20/MWh to average $32/MWh, driven by numerous high-temperature and high-demand events that triggered price spikes throughout January and February (as discussed in Section 1.2.2). Notably, Queensland witnessed 797 intervals with prices exceeding $300/MWh during this quarter, compared to 465 intervals in Q1 2024.
- In **New South Wales,** the average price was at $87/MWh, a $13/MWh (-13%) reduction from Q1 2023 and a $22/MWh (+33%) increase compared to Q4 2023. Similar to Queensland, the energy component of New South Wales' average price experienced a reduction of $22/MWh, while the cap return component increased by $9/MWh (averaging $17/MWh), with 246 intervals recording prices above $300/MWh. The high-price events in January and February that contributed to the overall rise in the cap return component of the quarterly average are discussed in Section 1.2.2
- In this quarter, **Victorian** spot prices averaged $52/MWh, which was a $4/MWh (-8%) reduction from Q1 2023. The energy component of the quarterly average decreased by $19/MWh, partially offset by a $14/MWh increase in the cap return component, which averaged $15/MWh this quarter. The storm-related events on 13 February (discussed in Section 1.2.2) had a significant impact on the Victorian power system. This single event accounted for almost all of Victoria's Q1 cap return. In total, Victoria experienced 112 intervals above $300/MWh this quarter, compared to 62 in Q1 2023.

- **South Australian** spot prices averaged $55/MWh this quarter, a drop of $17/MWh (-24%) compared to Q1 2023. Almost all this decline was due to a lower energy price component, which decreased by $16/MWh. The cap return component remained relatively stable, with only a $1/MWh reduction.
- In **Tasmania**, spot prices averaged $67/MWh this quarter, decreasing by $13/MWh (-17%) compared to Q1 2023. Similar to other regions, Tasmania also saw a reduction in energy component (-$23/MWh) which was partially offset by a significant increase in cap return component (+$10/MWh). Tasmania was also impacted by the series of storm-related events in Victoria on 13 February, resulting in 15 intervals of prices at market cap ($16,600/MWh) and a $9/MWh uplift in cap return component in a single day.

Continuing the trend observed in recent quarters, Q1 2024 also saw a notable price separation between the NEM's northern regions (Queensland and New South Wales) and the southern regions of Victoria and South Australia (Figure 16). This was more pronounced during daytime hours, when the Victoria – New South Wales Interconnector (VNI) export limit frequently binds, causing large price separation between southern and northern regions (Section 1.4). Between 0900 hrs and 1500 hrs, Victorian and South Australian energy prices averaged -$22/MWh, whereas Queensland and New South Wales averaged $52/MWh.

Figure 16 Price separation between northern and southern regions widened in daytime hours

Average regional energy price by time of day – Q1 2024



This quarter also saw an emerging price gap between Queensland and New South Wales, particularly during the evening peak hours (Figure 16). New South Wales black coal generators offered additional volume priced below $200/MWh (Figure 17), while increased volume offered by Queensland black coal generators was priced above $300/MWh (Figure 18). This, coupled with strong demand growth in Queensland, caused a rise in net flow towards the north and a higher price outcome for Queensland. Additionally, during the evening period, network constraints resulted in a reduction in the Queensland – New South Wales Interconnector (QNI) export limit, causing it to bind for 32% of dispatch intervals between 1600 hrs and 2100 hrs (Section 1.4). This resulted in larger price separation between New South Wales and Queensland, particularly during evening peak period and overnight hours.

Figure 17 Higher black coal offer volumes between $30/MWh and $200/MWh in New South Wales

New South Wales black coal bid supply curve – Q1 2024 vs Q1 2023

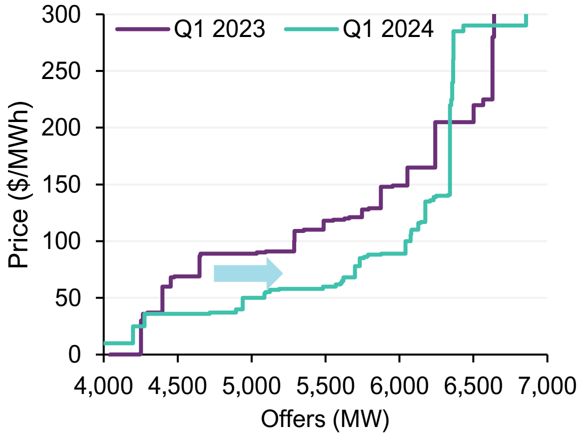
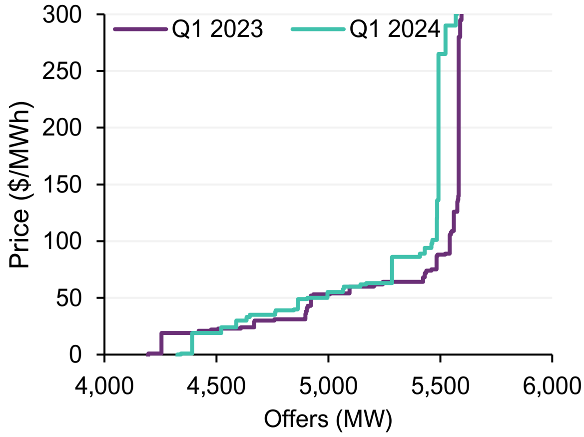


Figure 18 Lower black coal offer volumes between $25/MWh and $300/MWh in Queensland

Queensland black coal bid supply curve – Q1 2024 vs Q1 2023



1.2.1 Wholesale electricity price drivers

Key factors influencing the movement of prices throughout Q1 2024 are summarised in Table 2, with further analysis and discussion referred to relevant sections elsewhere in this report.

Table 2 Wholesale electricity price levels: Q1 2024 drivers

Increased operational demand	In this quarter, NEM-wide operational demand reached its highest Q1 average since 2020 (Section 1.1.2). This was driven by a significant uplift in underlying demand across the NEM. Although growth in distributed PV output partially offset higher underlying demand, every mainland region except Victoria witnessed increased operational demand. Notably, Queensland experienced a 6.2% increase from Q1 2023, reaching its second highest quarterly average. Queensland also saw an all-time maximum half-hourly operational demand of 11,005 MW, surpassing the previous record by over 900 MW. Throughout the quarter, operational demand in Queensland exceeded 10,000 MW on three occasions, amid numerous other high-demand days, resulting in upward pressure on prices.
Price volatility events	During the quarter, there were 1,470 intervals across all five NEM regions where spot prices exceeded $300/MWh, resulting in the aggregate cap return rising to $86/MWh from the previous Q1's $34/MWh (Section 1.2.2). Apart from South Australia, all NEM regions saw increases in cap return, exerting upward pressure on quarterly average prices. The storm events on 13 February were primarily responsible for almost all Victoria's cap return for the quarter and over 80% of Tasmania's cap return. Queensland, New South Wales, and South Australia also experienced several events contributing significantly to their cap return throughout the quarter, driven by high demand (Section 1.2.2, Table 3).
Black coal offer prices	The government policies that were introduced in December 2022 and capped domestic thermal coal prices continued to be in place throughout Q1 2024, and despite the closure of Liddell power station in late April 2023, black coal generators as a group offered increased volumes at lower price bands driven by reduced outages (Section 1.3.1). Much of these increased volumes came from New South Wales black coal generators between $30/MWh and $200/MWh (Figure 17 above), contributing to a higher frequency of black coal price-setting but at a lower average price set when marginal (Section 1.2.4). New South Wales coal generation offered an additional 780 MW below $100/MWh this quarter. Conversely, despite increased availability, Queensland generators offered lower volumes between $25/MWh and $300/MWh, and higher volumes above $300/MWh, particularly during afternoon and evening hours, contributing to a higher average price (Figure 18 above). Below $100/MWh, Queensland offered 80 MW less than in the previous Q1.
Price separation between regions	In Q1 2024, continuing the trend from previous quarters, there was a notable price difference between New South Wales and Victoria, particularly during daytime hours due to frequent binding of VNI's export limit (Section 1.4, Figure 69). This quarter also witnessed an emerging price separation between Queensland and New South Wales, especially during the evening peak period. The increase in demand in Queensland coupled with reduced offers of local black coal at lower price bands resulted in increased net flow northward. However, during the evening period, network constraints caused QNI's export limit to bind for 32% of dispatch intervals between 1600 hrs and 2100 hrs (Section 1.4) reducing exports from New South Wales and causing price separation.

Growing solar and wind output	Wind and solar generation (including distributed PV and grid-scale solar) grew by 791 MW this quarter, with the majority of this growth from wind and grid-scale solar in Queensland and New South Wales (Section 1.3). Both these sources set prices for a similar proportion of intervals to Q1 2023, while the average prices set by these fuel sources also remained largely unchanged. However, the higher volume of VRE offers below $0/MWh contributed to an overall reduction in energy prices. Grid-scale solar and wind offered an additional ~500 MW below $0/MWh this quarter, compared to the previous Q1.

1.2.2 Wholesale electricity price volatility

In Q1 2024, the cap return – which represents the contribution of spot prices in excess of $300/MWh to the quarterly average aggregated across all five NEM regions – increased to $86/MWh from the previous Q1's $34/MWh (Figure 19). Queensland witnessed the most significant increase in cap return component, rising by $20/MWh to an average of $32/MWh, driven by numerous high-demand events resulting in price spikes, particularly during January and February. New South Wales also experienced a $9/MWh increase in cap return, averaging $17/MWh. Victoria and Tasmania saw substantial increases of $14/MWh and $10/MWh respectively from the previous Q1's $1/MWh in both regions. The series of price spikes on February 13, contributed significantly to these increases in cap returns in Victoria and Tasmania, resulting in a surge in cumulative cap return (Figure 20). On February 13, Victoria and Tasmania recorded 24 and 15 intervals respectively of prices hitting the market cap of $16,600/MWh. Cap return in South Australia totalled $11/MWh, a reduction of $1/MWh.

During the quarter, 1,470 intervals (aggregated across all five NEM regions) recorded spot prices exceeding $300/MWh. All NEM regions saw an increase in occurrences above $300/MWh except South Australia, which saw only 252 intervals compared to 609 intervals in Q1 2023.

Figure 19 Increased Q1 cap returns across all NEM regions except South Australia

Cap returns by region – quarterly

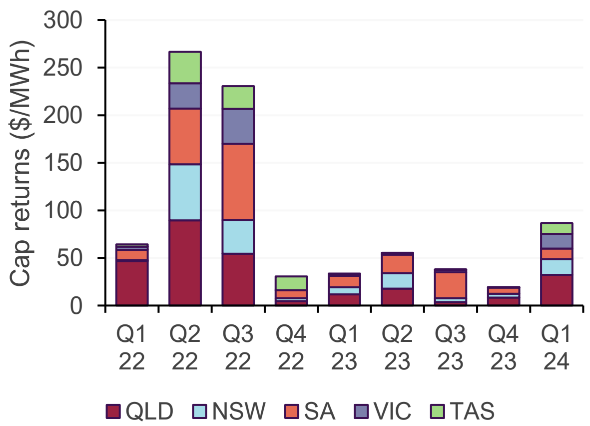
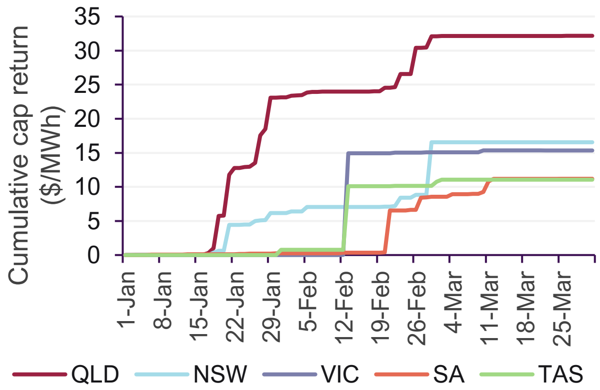


Figure 20 Northern regions saw high volatility events across the quarter, contrasted by a surge in Victoria and Tasmania on 13 February

Cumulative cap return by region – Q1 2024



Transmission system event in Victoria on 13 February 2024

On Tuesday 13 February 2024, a severe storm with intense wind gusts in Victoria damaged six 500 kilovolt (kV) towers, leading to the tripping of the Moorabool (MLTS) – Sydenham (SYTS) 500 kV lines at 1308 hrs. This event, along with the subsequent disconnection of all four Loy Yang A generating units, Dundonnell Wind Farm, and Yaloak South Wind Farm, caused a significant impact on the Victorian market operation. AEMO has published a preliminary report[5] relating to this operating incident in Victoria, covering the period from the initial event at 1308 hrs until 1515 hrs. A detailed report into this incident will be produced in due course.

On the same day, separate to this transmission system event:

- Storm activity across Victoria caused significant damage to the distribution networks, impacting more than 500,000 residential and business.
- At 1543 hrs there was a separate incident involving trip of the Hazelwood Terminal Station (HWTS) – Jeeralang Terminal Station (JLTS) 220 kV No. 2 line and the offloading of the HWTS 500/220 kV No. 1, No. 2, No. 3 and No. 4 transformers.

Prior to the event, Victorian demand[6] sustained above 7,500 MW in the interval ending at 1305 hrs, with VNI flow of 97 MW into New South Wales. At the end of trading interval (TI) 1310, VNI flowed into Victoria, reaching an actual physical flow of 178 MW, and VNI flow then surged to 1,246 MW at the end of TI 1315.

For the next interval, TI 1320, the market dispatch process had registered the total loss of output from Loy Yang A and the price in Victoria surged to the market price cap (MPC), while the actual flow into Victoria from New South Wales increased to 1,328 MW. During the same interval, the price in Tasmania reached the MPC, with Basslink actual flow into Victoria at 253 MW. In this interval, multiple constraints were violated in Victoria and Tasmania (resulting in over-constrained dispatch), this triggered automated constraint relaxation procedures, which allowed AEMO to resolve spot prices by adjusting the limits in the violating constraints, without changing the physical (MW) dispatch. Automated constraint relaxation procedures continued from TI 1320 to TI 1430, until demand in Victoria reduced to the extent that constraints no longer violated. The MPC persisted for 15 intervals in Tasmania until TI 1425.

At 1420 hrs, an actual Lack of Reserve 3 (LOR3) condition was declared, and AEMO instructed AusNet to shed 300 MW of load to manage the loading of in-service network elements. AEMO subsequently instructed Load restoration at 1450 hrs and at 1510 hrs. Prices remained at the MPC for 24 intervals in Victoria until the actual LOR3 was cancelled at 1515 hrs.

This single event contributed to a $14.9/MWh increase in Victoria's cap return (of the total $15/MWh for Q1), and $9.3/MWh rise in Tasmania's cap return (of the total $11/MWh for Q1) during the day.

Figure 21 shows the Victorian regional price, total demand and generation by fuel type during the events on 13 February.

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5 AEMO, *Preliminary Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf?la=en.

6 Demand refers to the five-minute regional total demand, that is met by local scheduled generation and semi-scheduled generation, and by generation imports to the region, excluding the demand of local scheduled loads, and including Wholesale Demand Response.

Figure 21 Victoria saw 24 intervals of prices hitting the market cap of $16,600/MWh on 13 February

Victoria Regional Reference Price (RRP), total demand and generation by fuel type – 13 February 2024

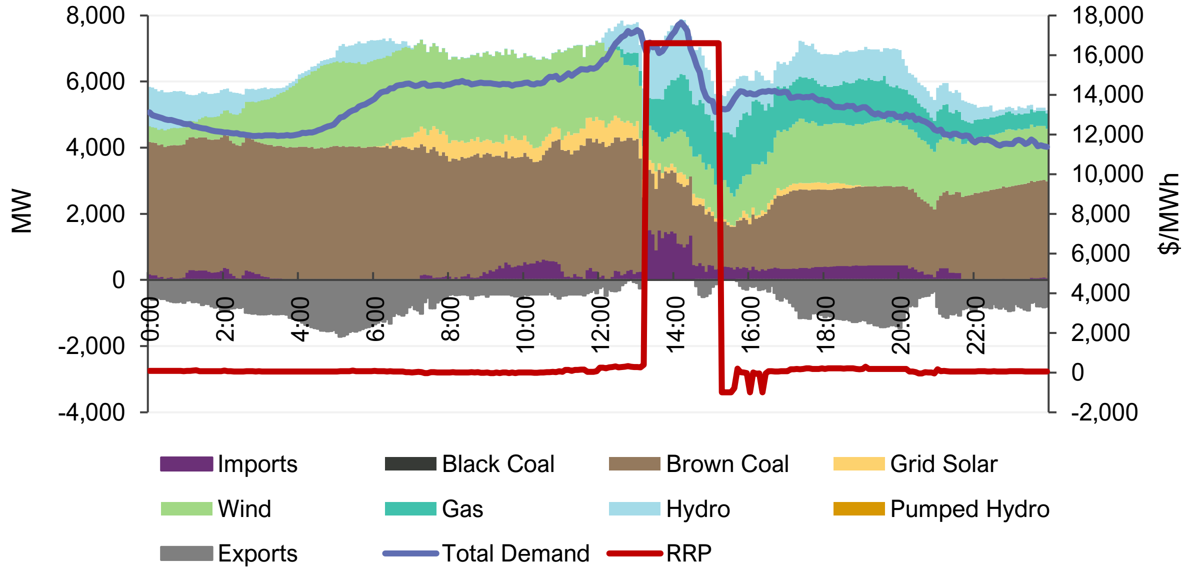


Table 3 summarises events of significant spot price volatility during Q1 2024.

Table 3 Significant volatility events in Q1 2024

Date	Region	Contribution to quarterly cap return ($/MWh)	Drivers
13 February	VIC	14.9	On this day, Victoria and Tasmania experienced a series of price spikes with 24 and 15 intervals at MPC ($16,600/MWh) respectively. The market impact of the incident is summarised in the transmission system event in Victoria on 13 February 2024 section above.
	TAS	9.3	
29 February	NSW	7.7	Both Queensland and New South Wales experienced high temperatures on this day, exceeding 31°C of average maximum temperature in Sydney and Brisbane. At the TI ending 1510 hrs, New South Wales price hit the market cap ($16,600/MWh) with ~250 MW drop in grid-scale solar availability. At this time, flow on VNI was constrained to 0 MW due to network constraints. As demand surged above 13,000 MW during peak hours in New South Wales, constraints on VNI's export limit persisted. With dwindling grid-scale solar availability and escalating demand, New South Wales experienced significant price spikes with 10 intervals above $14,000/MWh between 1625 hrs and 1800hrs. During this time, in Queensland, demand surged above 9,200 MW, accompanied by a decline in grid-scale solar availability. Queensland also encountered three intervals with prices exceeding $11,000/MWh, leading to a $1.7/MWh contribution to cap return. During this time, approximately 700-900 MW flowed into New South Wales via QNI.
21 February	SA	6.1	South Australia experienced nine intervals at the MPC of $16,600/MWh between 1810 hrs and 1850 hrs on this day. The average maximum temperature exceeding 35°C in Adelaide caused high evening peak period demand above 2,400 MW. During this time, reduced solar generation coincided with Heywood flowing ~100-400 MW into Victoria due to network constraints, causing price separation between Victoria and South Australia.

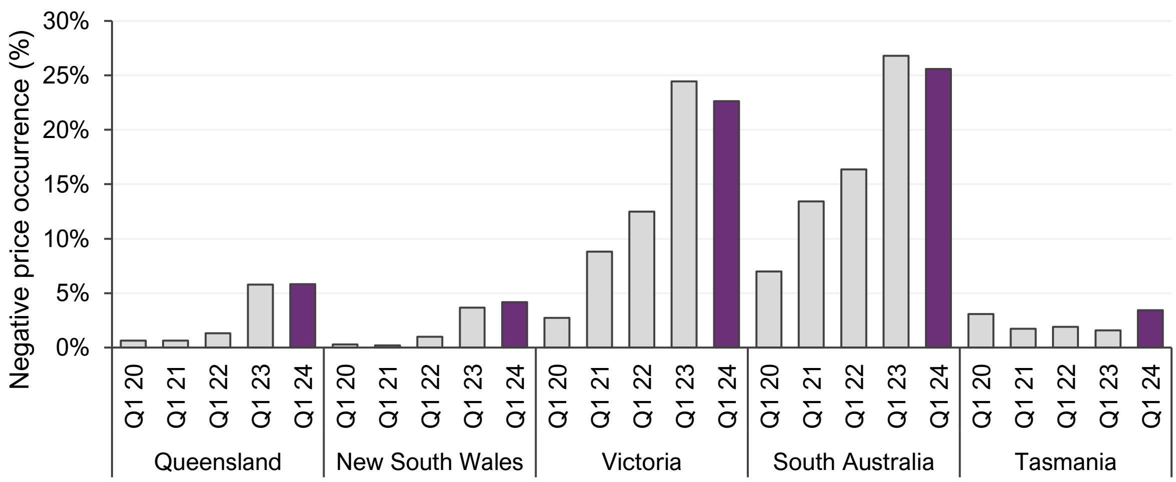
Date	Region	Contribution to quarterly cap return ($/MWh)	Drivers
21 January	QLD	6.0	High temperatures exceeding an average maximum of 33°C in Brisbane and Sydney caused extremely high demand during evening peak period, with Queensland reaching ~10,000 MW and New South Wales above 12,000 MW. Dwindling grid-scale solar generation coincided with the network constraints for most dispatch periods between 1730 and 2210 hrs, causing price spikes in both Queensland and New South Wales. Between 1755 hrs and 1840 hrs, Queensland experienced 11 intervals exceeding $8,000/MWh with two intervals at MPC. New South Wales also saw 10 intervals above $5,000/MWh during the evening peak while transfer on QNI was averaging 200-300 MW into New South Wales.
	NSW	3.8	
19, 27, 29 January, 26 February	QLD	4.7 (19 January), 4.6 (29 January), 4.0 (27 January), 3.8 (26 February)	Queensland experienced high demand on these days (~10,000 MW) coinciding with network constraints causing reduced export limits on QNI and counter-price flows into New South Wales at times in afternoon and evening periods, resulting in price spikes.

1.2.3 Negative wholesale electricity prices

In this quarter, 12.3% of dispatch intervals across the NEM experienced negative or zero prices, slightly lower than the 12.5% recorded in the previous year's Q1. This marks the first year-on-year reduction in quarterly negative price occurrences since Q3 2022. In Victoria and South Australia, the occurrences averaged 23% and 26%, respectively, showing reductions of 2 percentage points (pp) and 1 pp. Queensland and New South Wales saw minimal changes, remaining largely unchanged at 6% and 4%, respectively (Figure 22).

Figure 22 Negative price occurrence dropped in Victoria and South Australia and remained largely unchanged in other NEM regions

Negative price occurrence in NEM regions – Q1s



Negative prices persisted predominantly during daylight hours, with Victoria and South Australia experiencing notably higher occurrences compared other regions in the NEM (Figure 23). This trend mirrored the heightened price divergence observed during daytime periods due to increased demand in Queensland and New South Wales, alongside continuing constraints on northward energy transfers across VNI.

After reaching record high levels in the second half of 2023, negative price occurrences across all NEM mainland regions this quarter retreated towards levels of Q1 2023. Figure 24 shows Queensland's negative price occurrences by time of day, falling back to levels similar to Q1 2023 across daylight hours. This decline followed a significant rise in daytime negative price occurrences during the latter half of 2023.

Figure 23 Significantly higher negative price occurrence in Victoria and South Australia

Regional negative price occurence by time of day – Q1s

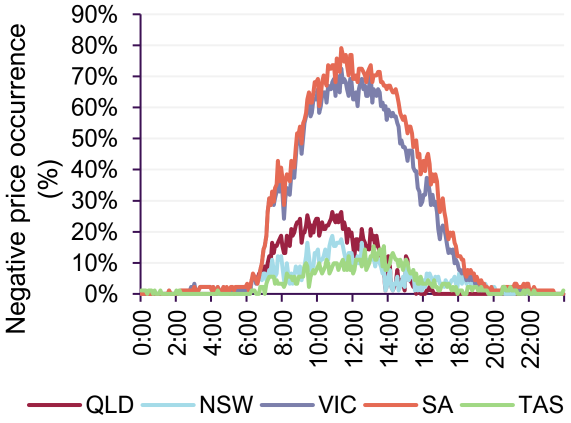
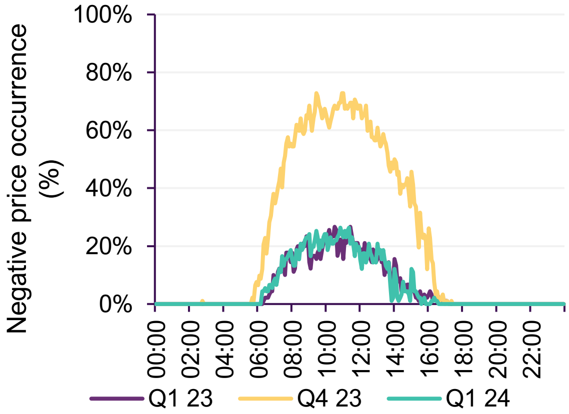


Figure 24 Negative price occurrence in Queensland returned to Q1 2023 levels

Negative and zero price occurrence in Queensland – Q1 2023, Q4 2023 and Q1 2024



In Q1 2024, NEM-wide negative prices averaged -$49.2/MWh, a significant decrease of $7.2/MWh from the previous Q1's average of -$42.0/MWh. This drop was driven by a greater proportion of negative prices falling into lower-priced ranges. In this quarter, 15% of negative prices were below -$60/MWh, nearly double the 8% observed in Q1 2023.

As a result, all NEM regions excluding Queensland saw increased negative price impacts[7] this quarter compared to Q1 2023. The NEM-wide negative price impact rose by $0.8/MWh, averaging $6.1/MWh for the quarter. Victoria and South Australia experienced negative price impacts of $12.2/MWh and $13.6/MWh, respectively, increasing by $2/MWh and $1/MWh compared to 2023 Q1. New South Wales saw its negative price impact rise by $0.6/MWh, averaging $1.9/MWh this quarter. Conversely, Queensland's negative price impact decreased by $0.6/MWh, averaging $0.9/MWh this quarter.

1.2.4 Price-setting dynamics

In Q1 2024, black coal set prices in 34% of intervals across the NEM, with a 3 pp increase from the previous Q1. Batteries saw a 2 pp increase in price-setting frequency for both load and generation, and set prices in 6% of intervals combined. Grid-scale solar also experienced a 1 pp increase, averaging 5% this quarter.

In contrast, gas and hydro witnessed their largest year-on-year drop in price-setting frequency, each decreasing by 2 pp. Hydro generation had the highest price-setting share at 35%, while gas set price in 7% of intervals. The frequency of price-setting for brown coal and wind decreased by 1 pp each, averaging 8% and 5% respectively.

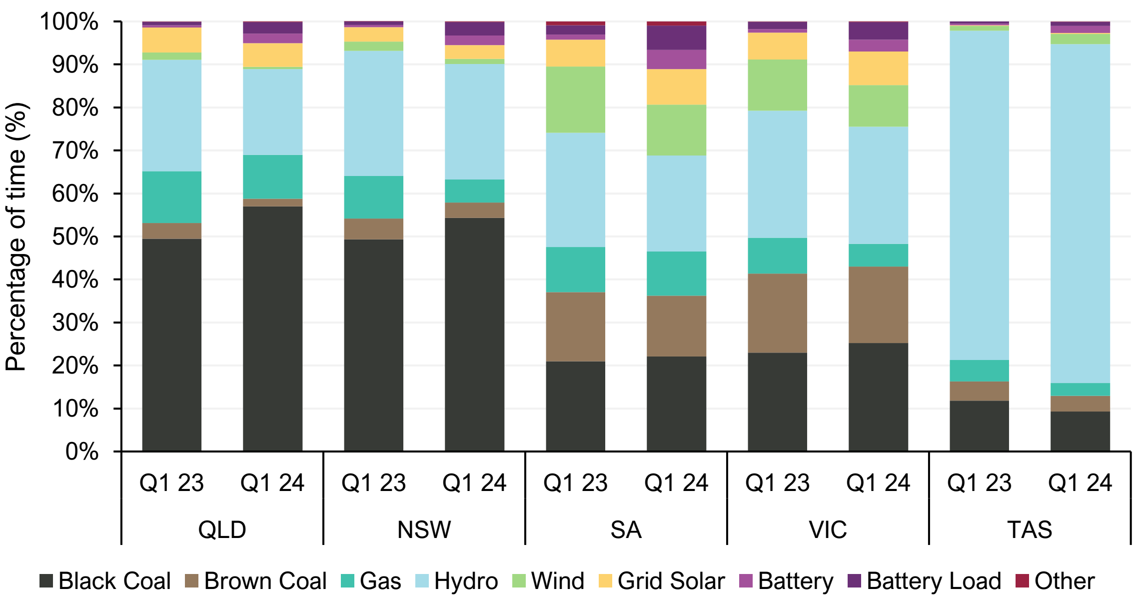
By region (Figure 25):

[7] 'Negative price impact' quantifies the effect of negative prices in reducing the overall quarterly average spot price

- **Queensland** showed a notable 7 pp increase in the proportion of spot prices set by black coal generators, accounting for the highest share of intervals at 57%. Hydro experienced a drop of 6 pp, averaging 20% this quarter. The proportion of time wind generation set prices reduced to almost 0% this quarter, with a 1 pp decline. Battery generation and load set prices 2% and 3% of time respectively, each increasing by 2 pp.
- In **New South Wales**, black coal set prices in 54% of the intervals, accounting for the largest share, with a notable 5 pp increase. Batteries also experienced increased price-setting frequency, generation and load each increasing by 2 pp. Gas saw the largest year-on-year reduction in Q1, decreasing by 5 pp to 5%.
- **South Australia** saw a rise in the proportion of spot prices set by batteries, with generation and load increasing by 3 pp and 4 pp respectively to set prices in 10% of the intervals combined.
- **Victoria** also experienced an increase in the time battery generation and load set prices, each increasing by 2 pp from the previous Q1 to reach 3% and 4% respectively. Black coal set prices in 25% of the intervals with a year-on-year Q1 increase of 2 pp, while gas saw a drop of 3 pp to average 5%.
- **Tasmania** was the only region which saw an increased hydro price-setting frequency, averaging 79% this quarter with a rise of 2 pp from the previous Q1. In contrast, black coal saw a 3 pp reduction and set prices in only 9% of the intervals this quarter.

Figure 25 Black coal set prices more frequently across the NEM mainland

Price-setting frequency[8] by fuel type – Q1 2023 vs Q1 2024



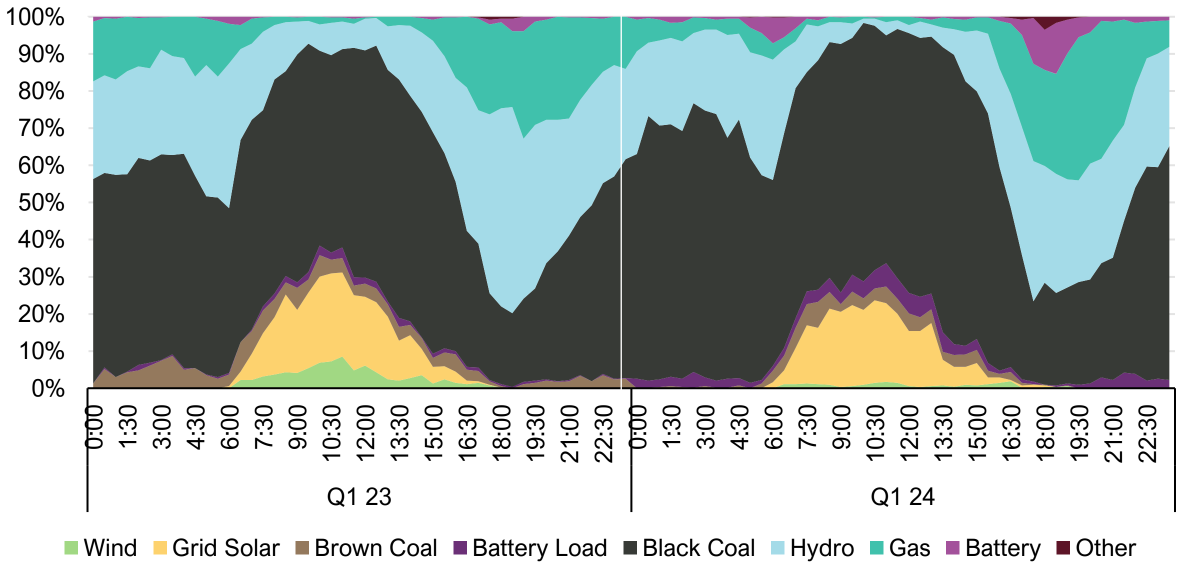
This quarter saw a notable increase in the daytime price-setting frequency of black coal generation in Queensland (Figure 26). Between 1000 hrs and 1400 hrs, black coal set the Queensland spot price 69% of the time in Q1 2024 compared to 59% in Q1 2023. During these hours, the price-setting frequency of hydro generation dropped by 6 pp, while wind and grid-scale solar reduced by 4 pp and 2 pp respectively.

[8] Price-setting data excludes the over-constrained dispatch and the Value of Lost Load (VoLL) override pricing period between 1320 hrs and 1515 hrs on 13 February.

Battery generation saw a significant increase in price-setting frequency in Queensland during evening peak period, with a 9 pp rise to set price 10% of the time between 1700 hrs and 1900 hrs. During this time, the most notable reduction came from hydro price-setting frequency, which reduced by 14 pp to 34%.

Figure 26 Significant increases in black coal daytime and battery evening peak period price-setting frequency in Queensland

Queensland price-setting frequency by fuel type and time of day – Q1 2023 and Q1 2024

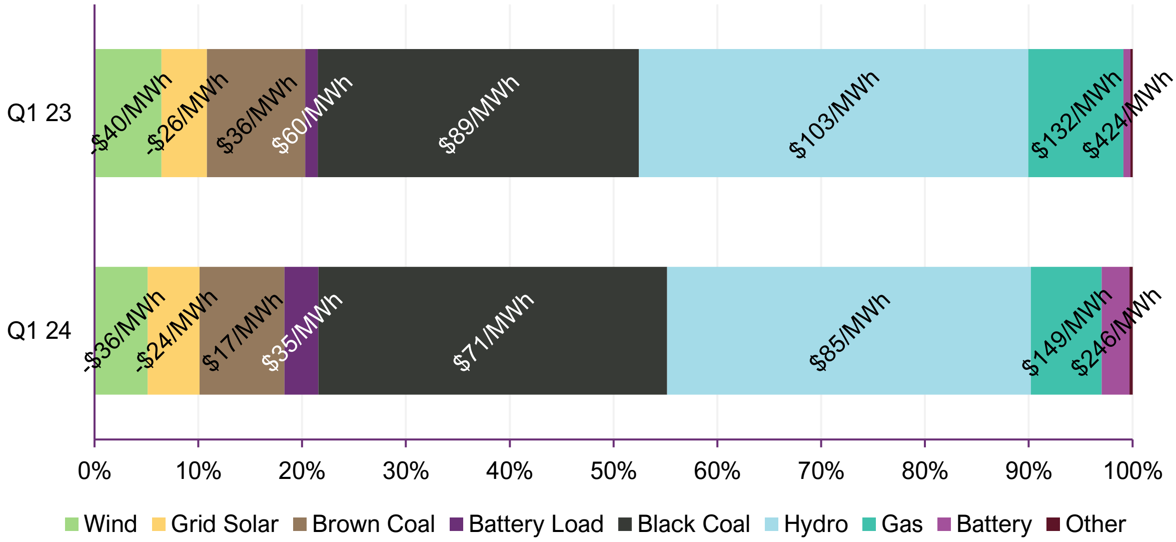


While black coal and batteries saw increased price-setting frequencies across the NEM, both fuel types witnessed lower average prices when they were the marginal supplier this quarter (Figure 27). The average price set by black coal (when marginal) decreased from $89/MWh in Q1 2023 to $71/MWh in Q1 2024, driven by increased offer volumes in lower price bands, particularly during the evening peak period (Section 1.2.1). Similarly, battery load set prices at $35/MWh compared to $60/MWh in the previous Q1. Hydro, being most frequent price-setter across the NEM, set average prices at $85/MWh, reducing by $18/MWh from Q1 2023. Brown coal also saw a $19/MWh reduction, averaging $17/MWh this quarter.

In contrast, the average spot price set by grid-scale solar and wind slightly increased by $1/MWh and $5/MWh respectively to average -$24/MWh and -$36/MWh, due to increased offer volumes in price bands above -$40/MWh, in line with the reduction witnessed in Large-scale Generation Certificate (LGC) prices this quarter. The average spot price set by gas generation also increased by $17/MWh to average $149/MWh, driven by increased gas volumes offered at higher prices bands (see Section, 1.3.2, Figure 43).

Figure 27 Average prices set by coal and batteries dropped but rose for VRE and gas

NEM price-setting frequency and average price when price-setter by fuel type – Q1 2023 vs Q1 2024



1.2.5 Electricity futures markets

Electricity futures markets are centralised exchanges offering standardised forward financial contracts for electricity. AEMO does not administer these exchanges. Information presented in this section is to allow a holistic view of both spot electricity outcomes and electricity futures pricing.

In this quarter, ASX base contract prices for the 2024-25 financial year (FY25) averaged $84/MWh across all mainland NEM regions, reflecting an 11% decrease from their average of $95/MWh over the previous quarter and a 12% decrease from Q1 2023's average of $96/MWh. While all regions experienced declines from Q4 2023, South Australia saw the most significant decrease, with a 17% drop to $86/MWh. New South Wales and Victoria both saw declines of 11%, averaging $98/MWh and $64/MWh, respectively. Queensland showed a relatively smaller decrease of 6%, averaging $90/MWh this quarter (Figure 28).

Figure 28 FY25 futures rebounded following a drop in January but closed the quarter at lower levels to Q4 2023.

ASX Energy – Daily FY 2024-25 base future by region

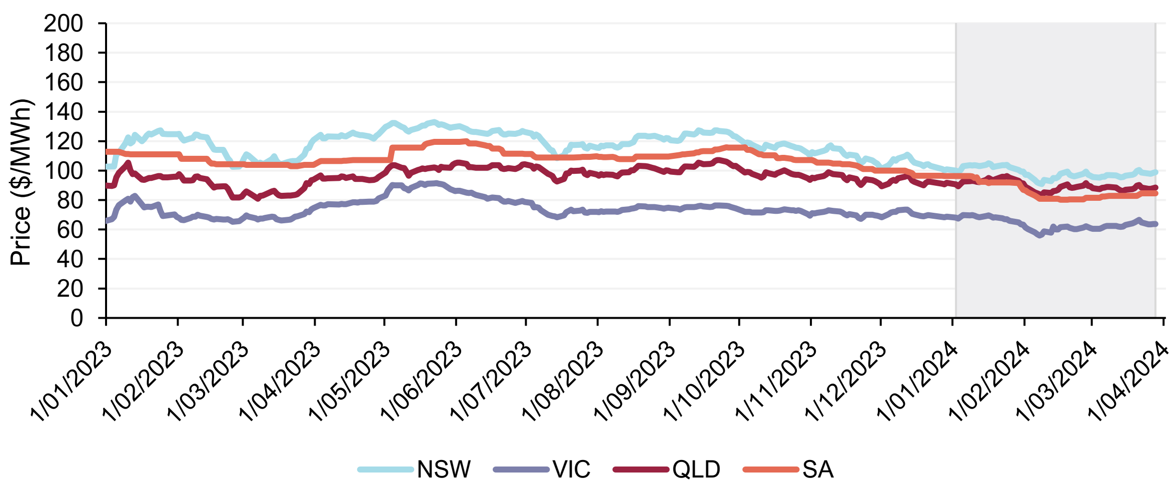


Figure 29 and Figure 30 illustrate ASX daily prices for Q1 2024 base contracts in Queensland and Victoria, respectively. Final settlement prices for such current quarter contracts are set at quarter end to the time-weighted quarterly average spot price for the relevant region, but prior to this "delivery quarter" their traded prices reflect market expectations. During the delivery quarter, traded prices are influenced by both quarter-to-date spot price levels and expectations for the balance of quarter, ultimately converging to the final settlement price.

These contract prices exhibited a strong upward trend in the first half of 2023, driven by factors such as the Liddell closure and anticipation of a hot El Nino summer. However, during the second half of the year, prices for all regions declined, influenced by weaker-than-expected spot prices. This pattern of contract prices closely following spot prices continued into Q1 2024, with spot market outcomes in Queensland during January and February (Section 1.2.2) pushing contract prices upward. Queensland prices surged to above $140/MWh in late January due to high volatility in spot prices but recovered to previous levels during February. Futures prices experienced another jump in early March amid persistent volatility in Queensland, closing the quarter slightly higher than their end of Q4 2023 levels.

In Victoria, lower operational demand and benign spot prices saw Q1 2024 futures prices in a strong downward trend throughout the first part of the quarter. However, the 13 February storm-related events (discussed in Section 1.2.2) caused high spot volatility. The impact of this volatility and immediate uncertainty surrounding the event led to a surge in futures prices from $31/MWh on 12 February to over $80/MWh on 13 February. Prices dropped to around $50/MWh the following day and remained around that level until the end of quarter, closing the quarter $15/MWh lower than the start of quarter, but $20/MWh above pre-13 February levels.

Figure 29 High spot price volatility drove Queensland contract prices

ASX Energy – Daily Q1 2024 base future price and spot price in Queensland

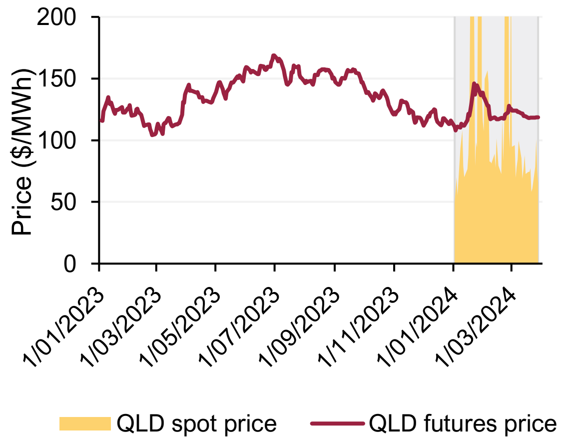
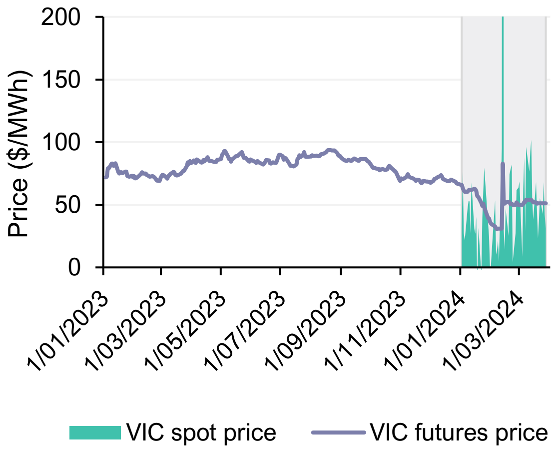


Figure 30 Victorian contract prices jumped on the back of volatility event on 13 February

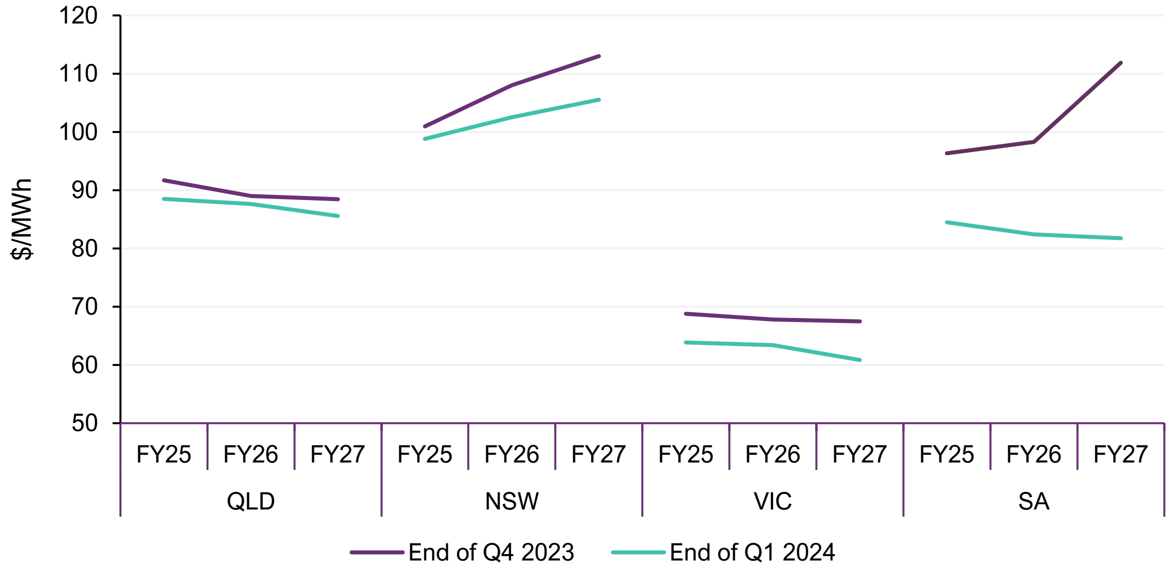
ASX Energy – Daily Q1 2024 base future price and spot price in Victoria



Despite the high volatility, FY25 prices concluded the quarter at lower levels across all regions. New South Wales saw a reduction of $2/MWh from the end of Q4 2023, ending the quarter at $99/MWh for FY25. Queensland ended the quarter $3/MWh lower at $89/MWh. Meanwhile, Victoria and South Australia closed at comparatively lower levels of $64/MWh and $84/MWh, respectively. Longer-term prices for FY26 and FY27 also closed the quarter significantly lower for all mainland regions (Figure 31).

Figure 31 Future financial year contracts significantly lower in all regions

Financial year contract prices in mainland NEM regions – end of Q4 2023 and end of Q1 2024

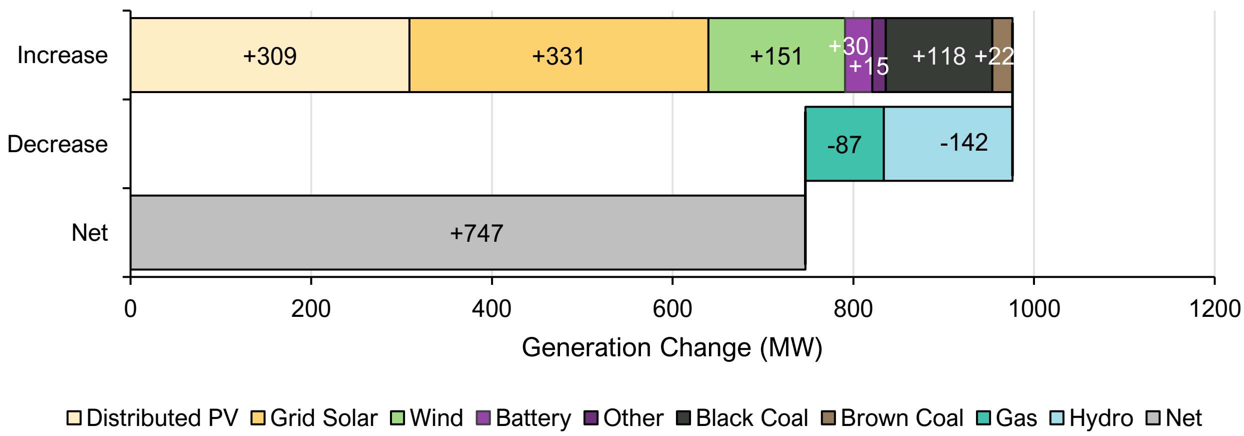


1.3 Electricity generation

During Q1 2024, total NEM quarterly average generation increased by 747 MW, up 3.1% from 24,396 MW in Q1 2023 to 25,143 MW this quarter. This change in overall NEM generation along with the changes for each fuel type, relative to Q1 2023, is shown in Figure 32.

Figure 32 All fuel types saw increased output, except gas and hydro

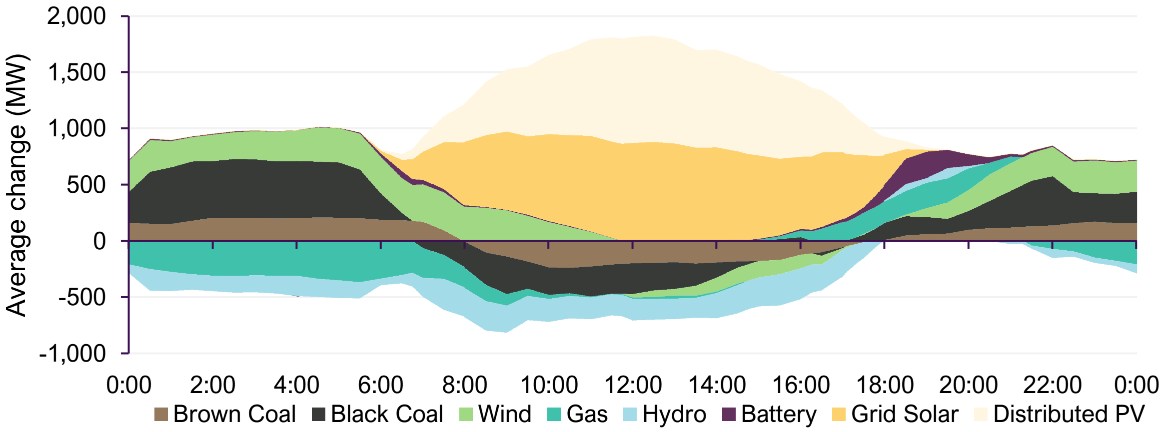
Change in NEM supply by fuel type – Q1 2024 vs Q1 2023



Higher generation in Q1 2024 was driven by the increase in NEM underlying demand discussed in Section 1.1.2. The time-of-day characteristics of changes in generation are shown in Figure 33 for each fuel type. Grid-scale solar and distributed PV output increased in line with increased capacity, with output from other fuel types decreasing during the middle of the day in response. All fuel types lifted output during the evening peak to meet the increasing demand, while overnight periods saw output reductions from the higher cost sources of gas and hydro while coal and wind output increased.

Figure 33 VRE output increased during the day, pushing down gas, coal, and hydro output

NEM generation changes by time of day – Q1 2024 vs Q1 2023



Comparing Q1 2024 with Q1 2023:

- Distributed PV, grid-scale solar, and wind saw an aggregate increase of 791 MW, with grid-scale solar having the highest year-on-year increase at 331 MW, followed by distributed PV and wind at 309 MW and 151 MW, respectively (Figure 32). New and commissioning wind and grid-scale solar in Queensland and New South Wales accounted for the majority of this increase. The majority of uplift in wind generation happened outside the solar peak (Figure 33).
- Batteries saw a 30 MW increase in quarterly average generation, reflecting the additional battery capacity installed since Q1 2023. Batteries increased their contribution to the evening peak demand, between 1800 hrs and 2100 hrs, with an average generation of 217 MW.
- Black coal-fired generation output saw an uplift of 118 MW relative to Q1 2023, which occurred during evening and overnight hours. This increase was mainly driven by New South Wales black coal-fired generators offering lower priced volumes (Section 1.2). Brown coal-fired generation also increased by 22 MW year-on-year, mainly outside daytime periods.
- Although gas-fired generation saw an uplift in its output during the evening peak, this was more than offset by the reduction overnight, leading to 87 MW less output than during Q1 2023.
- With NEM prices reducing from Q1 2023, hydro saw a reduction in its output of 142 MW. This reduction was seen at all times of the day except evening peak hours where hydro increased output to capture price spikes (hitting an average of 2,555 MW between 1800 hrs and 2100 hrs).

Table 4 summarises changes in the NEM generation shares by fuel type. Despite the absolute increase in black and brown coal-fired output relative to Q1 2023, their percentage contributions to NEM supply reduced year-on-year. This was driven by the increased contribution of renewables, which accounted for an aggregate share of 39.0%, up from 37.4% in Q1 2023.

Table 4 NEM supply mix contribution by fuel type

	Fossil fuels				Renewables					
Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Battery	Biomass
Q1 2023	43.0%	15.0%	4.6%	0.02%	12.1%	11.6%	7.5%	6.1%	0.1%	0.02%
Q1 2024	42.2%	14.6%	4.1%	0.05%	13.0%	11.8%	8.6%	5.3%	0.2%	0.05%
Change	-0.8%	-0.4%	-0.5%	0.03%	0.9%	0.3%	1.1%	-0.7%	0.1%	0.03%

1.3.1 Coal-fired generation

Black coal-fired fleet

During Q1 2024, black coal-fired quarterly average generation increased by 118 MW (1.1%) over last year's Q1 average (10,495 MW), reaching 10,613 MW, partly driven by the increase in underlying demand. Black coal generation in New South Wales increased from 5,124 MW in Q1 2023 to 5,415 MW this quarter, while Queensland saw black coal generation dropping from 5,370 MW in Q1 2023 to 5,198 MW this quarter (Figure 34). These shifts reflected New South Wales black coal-fired generators offering more volume in lower price ranges, relative to Q1 2023, while Queensland black coal-fired stations reduced their offer volumes at the same price levels (see Section 1.2.1).

With Liddell being retired in April 2023, black coal-fired availability in New South Wales this quarter reduced by 329 MW year-on-year to an average of 7,411 MW, indicating that the lost availability of Liddell (averaging 921 MW in Q1 2023) was largely offset by increased availability at other New South Wales stations. This increase was driven by a significant reduction in outages in the region, from 1,211 MW in Q1 2023 to 359 MW this quarter (Figure 35). Queensland saw an increase in quarterly average availability from 6,172 MW in Q1 2023 to 6,451 MW this quarter, a 280 MW (+5%) increase year-on-year.

Figure 34 Black coal-fired generation reduced in Queensland, but increased in New South Wales

Quarterly average black coal-fired generation and availability by region (including decommissioned units) – Q1s

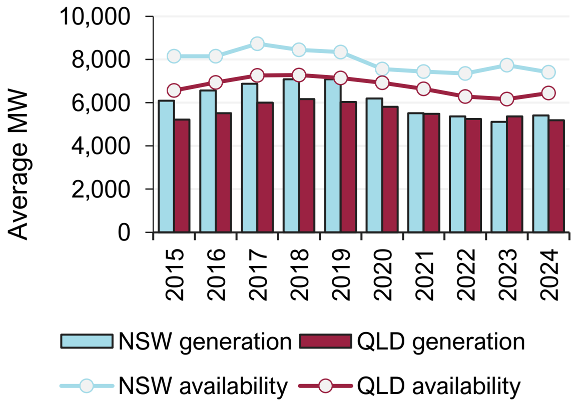


Figure 35 Coal-fired capacity on outage declined, mostly driven by New South Wales

Average coal-fired capacity on outages – Q1 2024 vs Q1 2023

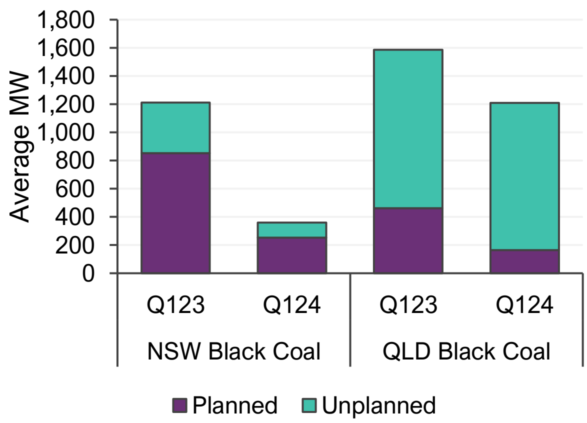
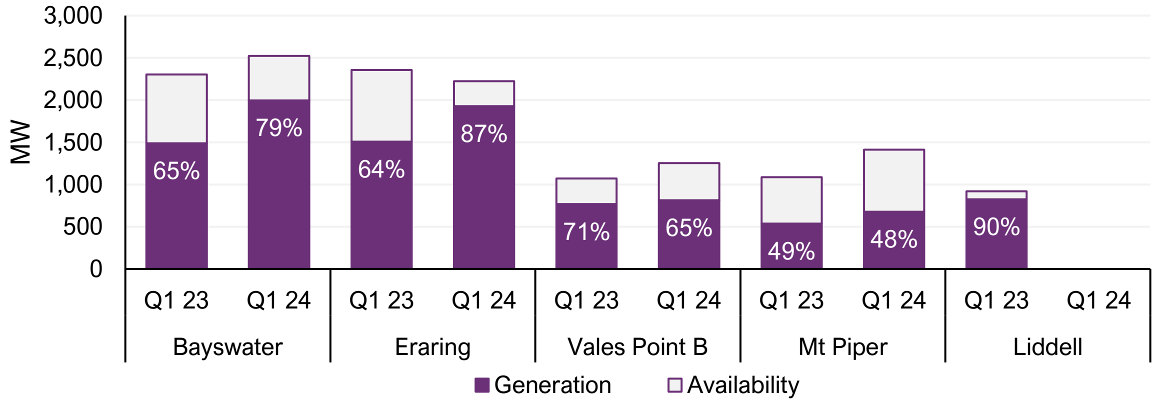


Figure 36 shows the availability, generation and utilisation rate for New South Wales black coal-fired power stations.

Figure 36 Increased output from all remaining black coal-fired generators in New South Wales

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q1 2024 vs Q1 2023



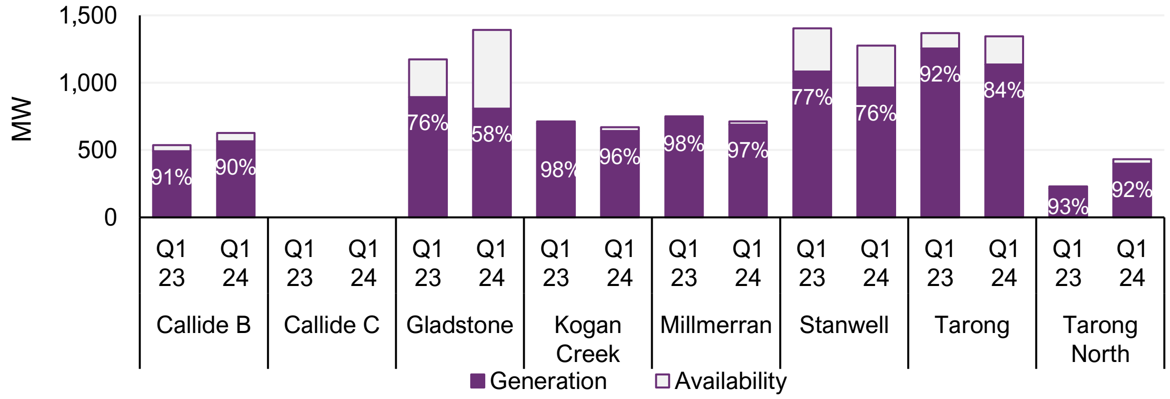
In particular:

- Bayswater saw a 218 MW increase in availability, reaching 2,523 MW this quarter due to reduced outages, relative to Q1 2023. Generation increased from 1,487 MW in Q1 2023 to 1,995 MW this quarter, pushing Bayswater's utilisation to 79%, up from 65% in Q1 2023.
- Although Eraring availability reduced slightly (-132 MW), its generation increased by 419 MW year-on-year. This resulted in an increase of 23 pp in its utilisation rate, from 64% in Q1 2023 to 87% this quarter.
- With minimal outages this quarter (15 MW), Vales Point increased its availability by 179 MW from 1,072 MW last Q1 to 1,252 MW. Generation, however, only increased by 49 MW, reaching 816 MW during the quarter. This resulted in a noticeable drop in its utilisation rate from 71% to 65% year-on-year.
- Mt Piper saw both availability and generation increasing by 326 MW, and 141 MW reaching 1,413 MW and 677-MW, respectively, resulting in a 48% utilisation rate, almost matching its previous Q1 level of 49%.

While demand in Queensland increased strongly in Q1, the region's black coal-fired stations apart from Callide B and Tarong North reduced output (Figure 37). This was mainly driven by slightly higher offer pricing by most black coal-fired generators in Queensland and significantly reduced pricing by New South Wales generators as discussed in Section 1.2.1, as well as higher VRE output in Queensland, relative to Q1 2023, leading to noticeably lower Queensland coal-fired output in daytime hours.

Figure 37 All Queensland black coal generators saw reduced output except Callide B and Tarong North

Average quarterly availability, generation and utilisation for Queensland black coal-fired power stations – Q1 2024 vs Q1 2023



Both quarterly average availability and generation increased for Callide B year-on-year. With 626 MW of availability and 564 MW of generation, Callide B saw its quarterly utilisation rate at 90%, almost matching its previous Q1 level of 91%. During Q1 2023, Tarong North experienced 18 days of complete outage and had almost 50% of its capacity on partial outage for the majority of the quarter. With only 4 MW outage during this quarter (80 MW reduction year-on-year) it saw increases in both quarterly average availability and generation by 202 MW and 184 MW, resulting in a quarterly utilisation rate of 92% for this quarter.

Gladstone had the highest increase in availability, from 1,173 MW in Q1 2023 to 1,392 MW this quarter (+220 MW). However, its generation reduced by 85 MW from 893 MW in Q1 2023 to 808 MW this quarter, which was driven by upward repricing of its offers, relative to Q1 2023. All other generators saw reductions in both availability and generation, relative to Q1 2023.

With commencement of Unit C3's long-term forced outage in October 2022, Callide C produced no output this quarter, however CS Energy advised the market of Unit C3's return to service on 1 April 2024[9]. The target return date for the rebuilt C4 unit's full capacity is still 31 July 2024, with 50% capacity expected from 30 June 2024[10].

Intraday swing for black coal-fired generation increased in Queensland from 1,389 MW in Q1 2023 to 1,762 MW this quarter, a 373 MW increase year-on-year (Figure 38). New South Wales saw a very small increase in generation intraday swing, from 2,816 MW in Q1 2023 to 2,851 MW this quarter (Figure 39).

Figure 38 Queensland black coal generation down in daytime hours, up in evening peak

Queensland black coal-fired output by time of day – Q1s

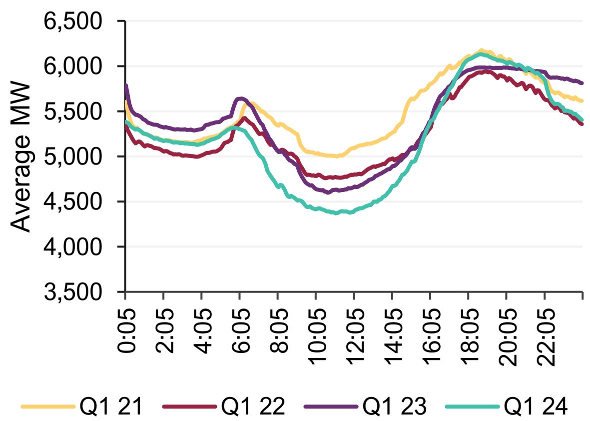
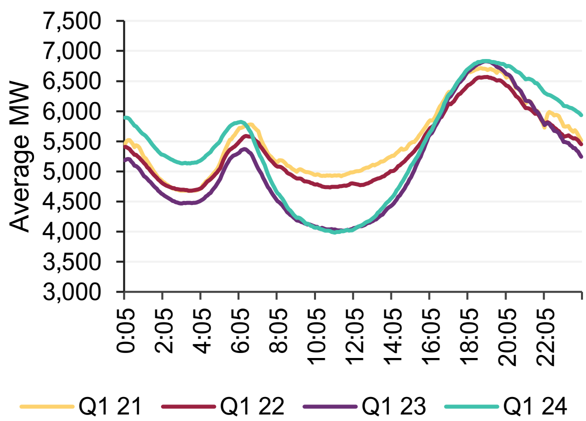


Figure 39 Black coal-fired generation increased overnight in New South Wales

New South Wales black coal-fired output by time of day – Q1s



Brown coal-fired fleet

During Q1 2024, brown coal-fired average availability increased by 95 MW from 4,108 MW in Q1 2023 to 4,203 MW this quarter. Quarterly average generation increased 22 MW (0.6%) from 3,653 MW in Q1 2023 to 3,675 MW this quarter (Figure 40). Loy Yang A was the main driver of this increase in availability and generation.

9 See https://www.csenergy.com.au/news/callide-unit-c3-returns-to-service.

10 See https://www.csenergy.com.au/news/update-on-callide-unit-c3-return-to-service-mar23.

Brown coal generation continued to drop during the day but increased during evening peak and overnight, with intraday swing in brown coal-fired generation increasing by 331 MW (+33%), from 1,000 MW in Q1 2023 to 1,331 MW this quarter (Figure 41). All brown coal-fired generation contributed to this increased swing.

Figure 40 Increase in brown coal-fired generation availability and output

Quarterly average generation and availability (including decommissioned units) – Q1s

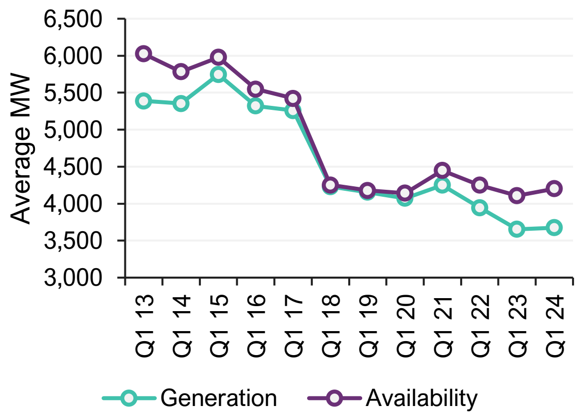
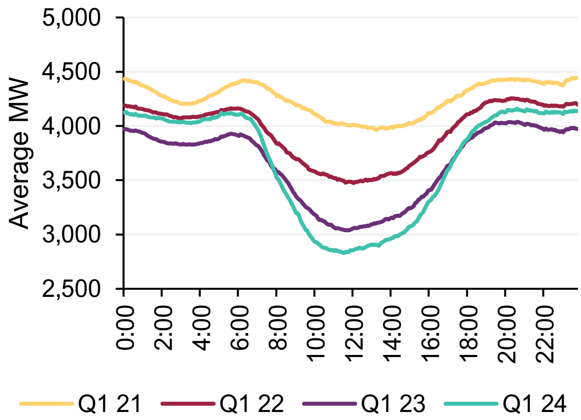


Figure 41 Increased swing in brown coal-fired generation output

Brown coal-fired output by time of day – Q1s from 2021 to 2024



Following a significant reduction in outages, all brown coal-fired generators saw increased availability, with Loy Yang A having the largest uplift, relative to Q1 2023 (Table 5). However, only Loy Yang A saw increased output in this quarter. Loy Yang B and Yallourn experienced a reduction in generation, resulting in 1 pp and 6 pp reductions in their utilisation rates, respectively.

Table 5 Brown coal availability, output, utilisation, outage, and intraday swing by generator – Q1 2023 vs Q1 2024

Generator	Availability (MW)		Output (MW)		Utilisation		Outage (MW)		Intraday swing (MW)	
	Q123	Q124	Q123	Q124	Q123	Q124	Q123	Q124	Q123	Q124
Loy Yang A	1,922	2,013	1,653	1,744	86%	87%	278	182	565	677
Loy Yang B	1,134	1,137	987	976	87%	86%	18	1	332	408
Yallourn W	1,052	1,053	1,014	955	96%	91%	362	343	112	253

1.3.2 Gas-fired generation

During Q1 2024, gas-fired generation across the NEM reduced by 87 MW (-8%) from 1,113 MW in Q1 2023 to 1,026 MW this quarter (Figure 42). This reduction was driven by lower spot prices during the quarter, along with higher priced volumes offered by gas generators to the market, relative to previous Q1 (Figure 43). Gas generation still saw an increase in output during the evening peak, but this was more than offset by the reduction at other times of the day (see Figure 33).

While total NEM gas-fired generation reduced, Queensland saw a 3% uplift from its previous Q1 level at 562 MW to 580 MW this quarter. This was mainly driven by the significant increase in Queensland evening peak prices. Darling Downs saw the largest year-on-year increase from 127 MW in Q1 2023 to 207 MW this quarter.

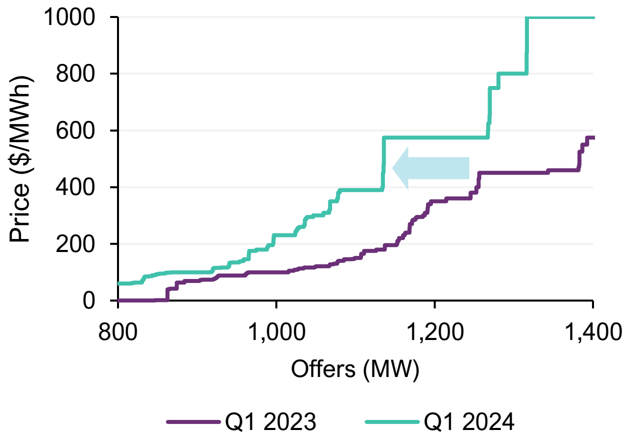
Gas output in New South Wales reduced by 53 MW, with lower output from Tallawarra A (14 MW in Q1 2024 compared to 125 MW in Q1 2023). The region also saw first generation from Tallawarra B (320 MW capacity), averaging 27 MW during this quarter. Gas output in South Australia saw a reduction of 30 MW year-on-year. Pelican Point had the largest output reduction, from 204 MW in Q1 2023 to 127 MW this quarter.

Figure 42 Gas-fired generation reduced to its lowest Q1 level since 2004

Average gas-fired generation by region – Q1s

Figure 43 Gas volumes were offered at higher price bands

Gas-fired generation bid supply curve – Q1 2024 vs Q1 2023



1.3.3 Hydro

With the southern NEM regions experiencing very low rainfall (see Section 1.1.1) and average prices lower this Q1 than in Q1 2023, quarterly average NEM hydro generation[11] reduced by 142 MW (10%) from 1,486 MW in Q1 2023 to 1,344 MW this quarter (Figure 44). Similar to gas generation, NEM hydro output reduced at all times of the day, except during evening peak.

Figure 44 Hydro generation dropped in all regions, except Victoria

Average hydro output by region – Q1s

By region, New South Wales saw the largest year-on-year drop in hydro generation, from 359 MW in Q1 2023 to 276 MW this quarter, a 23% reduction (-84 MW). This was followed by Tasmania and Queensland which had year-on-year reductions of 59 MW and 30 MW, reaching 649 MW and 150 MW, respectively. While Kareeya and

[11] Hydro generation includes output from hydro pumped storage generators and does not net off electricity consumed by pumping at these facilities.

Wivenhoe saw increases of 22 MW and 11 MW, respectively, this was more than offset by the outage of Barron Gorge in December 2023 due to flooding. The generator is expected to return to service by June 2024[12]. Victoria was the only region with an increase in hydro output, of 30 MW, reaching 270 MW this quarter. This increase in Victorian hydro output was mostly seen during evening and overnight hours.

1.3.4 Wind and grid-scale solar

In Q1 2024, grid-scale VRE reached 5,136 MW, a 482 MW (+10%) increase from Q1 2023's 4,654 MW (Figure 45). The majority (69%) of this VRE output growth was from grid-scale solar which increased 331 MW year-on-year from 1,833 MW in Q1 2023 to 2,164 MW this quarter (+18%) – an all-time record for quarterly average grid-scale solar output in the NEM. Wind also reached 2,971 MW, a 151 MW (+5%) increase from 2,820 MW in Q1 2023.

Grid-scale solar output increased in all mainland regions, with the majority of this increase in New South Wales and Queensland at 179 MW and 114 MW, respectively, while South Australia and Victoria only saw marginal increases of 18 MW and 20 MW (Figure 46). Likewise, the majority of increased output in wind generation occurred in New South Wales and Queensland (up by 68 MW and 84 MW respectively).

Figure 45 Steady VRE growth continued

Average quarterly VRE generation by fuel type – Q1s

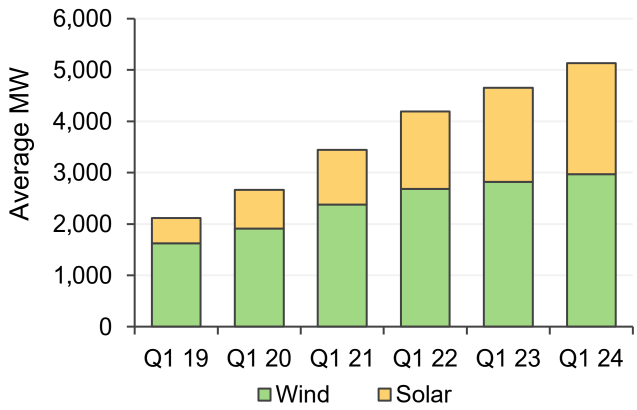
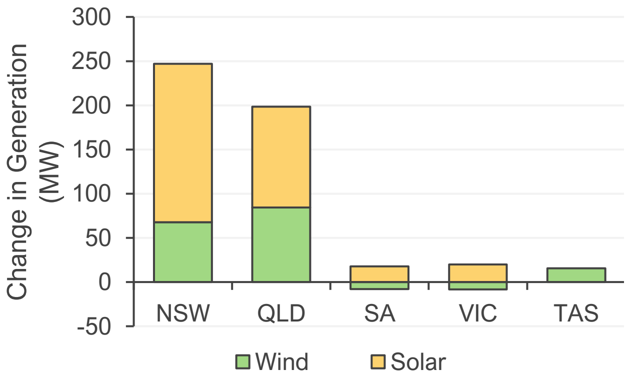


Figure 46 VRE increases led by Queensland and New South Wales

Average MW change in output – Q1 2024 vs Q1 2023



Increases in VRE output in Q1 2024 were driven by new facilities connected after Q1 2023, and those progressing through their commissioning processes[13], as shown in Figure 47 and Figure 48.

Relative to Q1 2023, new and commissioning grid-scale solar capacity offered additional availability of 245 MW and 179 MW respectively, while availability from existing generators reduced by 72 MW. With an 8 MW reduction in network curtailment, and an increase of 30 MW in offloading, grid-scale solar generation increased by a net 331 MW, year-on-year.

Wind availability increased relative to Q1 2023 by 151 MW due to newly connected facilities, and by 74 MW from capacity continuing its commissioning. Existing wind capacity saw a reduction of 51 MW in availability. With an additional 8 MW curtailment and 14 MW offloading of wind in this quarter, overall wind output increased by 151 MW, year-on-year.

[12] See https://cleancoqueensland.com.au/kuranda-weir-recovery-project/.

[13] New capacity is the capacity that connected to the grid between Q1 2023 and Q1 2024, while commissioning capacity is the capacity that connected to the grid before Q1 2023 and is showing ramping behaviour as it has not reached its full capacity yet (this can extend over 12 months or longer).

Figure 47 Growth in new and commissioning capacity year-on-year

Changes in grid-scale solar generation – Q1 2024 vs Q1 2023

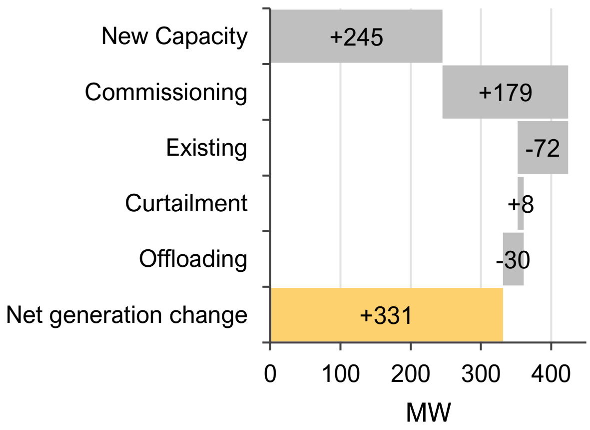
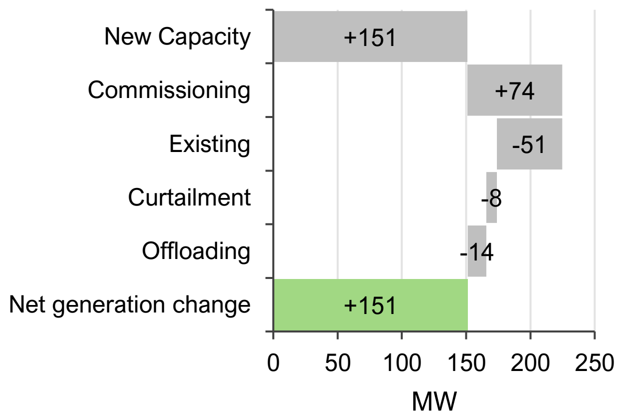


Figure 48 Increased availability in new and commissioning wind capacity

Changes in wind generation – Q1 2024 vs Q1 2023



New and commissioning capacity

- 424 MW of increased grid-scale solar availability arose from new and commissioning facilities, with the largest contributions from Avonlie Solar Farm (+68 MW), New England Solar Farm 1 (+61 MW) and New England Solar Farm 2 (+47 MW) in New South Wales. Edenvale Solar Park (+39 MW) and Wandoan Solar Farm (+36 MW) in Queensland and Tailem Bend Stage 2 Solar Project (+30 MW) in South Australia and Glenrowan Solar Farm (+27 MW) in Victoria also contributed to the increased availability.
- 225 MW of increased wind availability arose from new and commissioning facilities, with the largest contributions from Rye Park Wind Farm (+75 MW) in New South Wales and Dulacca Wind Farm (+61 MW) in Queensland.

Existing capacity[14]

- Established wind capacity in Tasmania saw an uplift of 3.0 pp in quarterly volume-weighted available capacity factor[15], which was offset by reductions in other regions, relative to Q1 2023 (Figure 49), resulting in 0.8 pp reduction in NEM-wide wind capacity factor year-on-year, from 30.5% in Q1 2023 to 29.7% in Q1 2024.
- New South Wales was the only region to experience a reduction in quarterly volume-weighted available capacity factor for existing grid-scale solar, with a 1.5 pp decrease year-on-year (Figure 50). South Australia saw the largest increase at 1.8 pp year-on-year, followed by Victoria and Queensland at 0.7 pp and 0.2 pp, respectively. NEM-wide capacity factor reduced from 30.5% in Q1 2023 to 29.6% in Q1 2024.

[14] Existing (or established) capacity in this section refers to the wind and grid-scale solar facilities that were fully commissioned prior to the start of Q1 2024. These facilities may also appear in the "New Capacity" or "Commissioning" category in Figure 47 and Figure 48 if they were connected or exhibited ramping capacity between Q1 2023 and Q1 2024, respectively.

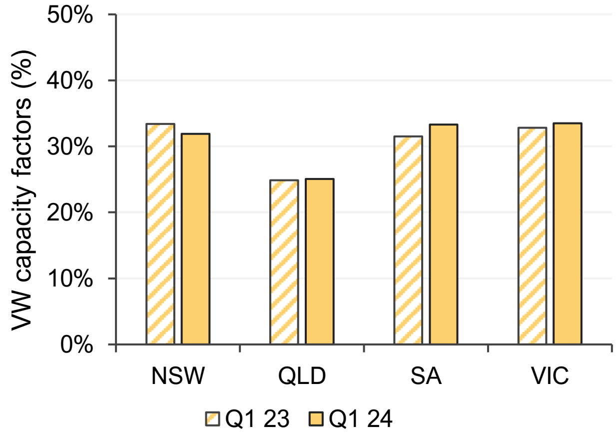
[15] Available capacity factors are calculated using average available energy divided by maximum installed capacity. The use of availability instead of generation output removes the impact of any economic offloading or curtailment and better captures in-service plant capacity and underlying wind or solar resource levels.

Figure 49 Noticeable increase in wind availability in Tasmania

Volume-weighted wind available capacity factors[16] – Q1s

Figure 50 Grid-scale solar availability rose in all regions except New South Wales

Volume-weighted grid-scale solar available capacity factors – Q1s

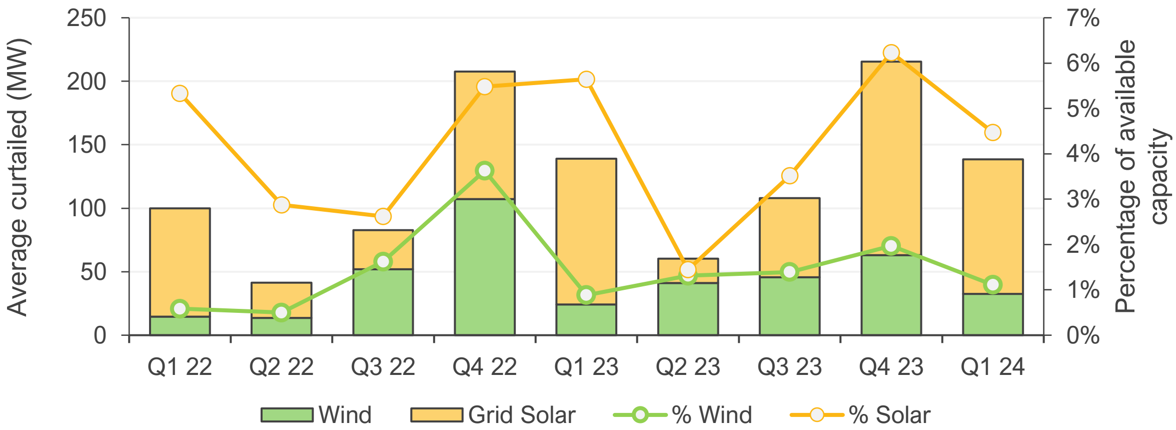


Curtailment

- Wind curtailment averaged 32 MW, an 8 MW (+34%) increase year-on-year, and wind curtailment as a percentage of quarterly average availability increased from 0.9% in Q1 2023 to 1.1% in Q1 2024 (Figure 51).
- Grid-scale solar average curtailment reduced from 115 MW in Q1 2023 to 106 MW this quarter, and as a percentage of quarterly average availability reduced from 5.6% in Q1 2023 to 4.5% this quarter.

Figure 51 Curtailment increased in wind but reduced for solar farms year-on-year

Average MW curtailment and percentage of availability by fuel type

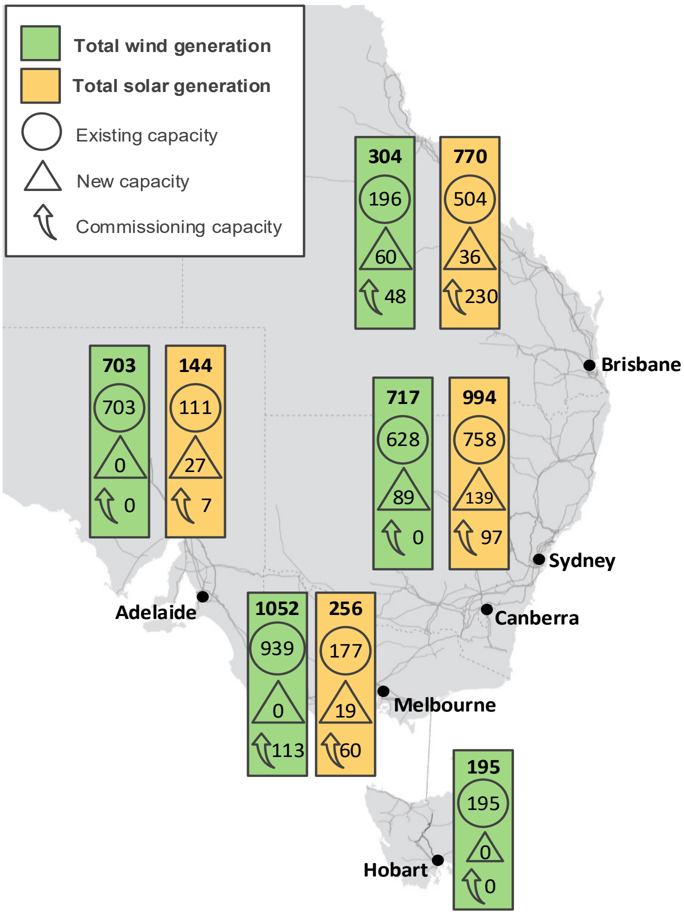


The map in Figure 52 shows a summary representation of VRE output during Q1 2024. Numbers presented in this map are in megawatts and are calculated on a quarterly average basis.

[16] Available capacity factors for each established facility are weighted by maximum installed capacity to derive a regional weighted average.

Figure 52 Regional VRE generation summary during Q1 2024

Quarterly average generation (MW) by fuel type and region



1.3.5 Renewables penetration

Instantaneous renewable penetration

During the half-hour ending 1230 on Saturday 9 March 2024, the maximum instantaneous share of renewable energy generation[17] in the NEM reached a new Q1 high of 69.9%, a 4.1 pp increase compared to Q1 2023 (Figure 53). Relative to the record level of 72.1% set in Q4 2023, this was a reduction of 2.2 pp, due to the seasonal increase in underlying demand between Q4 2023 and Q1 2024. Distributed PV was the largest contributor to Q1 2024's maximum instantaneous renewable share at 36% of total supply, similar to its Q1 2023 share. The year-on-year increase in instantaneous renewable penetration was mainly driven by increases in grid-scale solar and wind contributions from 15% and 12% in Q1 2023 to 17% and 15% respectively this quarter.

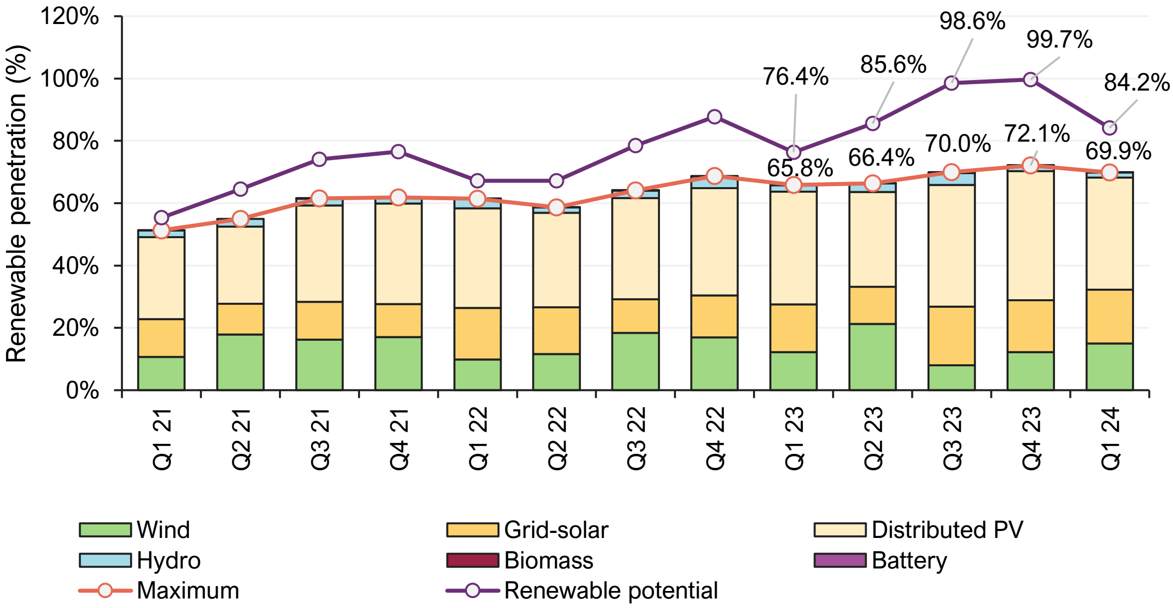
Renewable potential[18] also saw an increase from 76.4% in Q1 2023 to 84.2% this quarter, but reduced relative to its Q4 2023 level of 99.7%, again reflecting seasonally higher underlying demand in Q1.

[17] Instantaneous renewable penetration is calculated using the NEM renewable generation share of total generation. The measure is calculated on a half-hourly basis, because this is the granularity of estimated output data for distributed PV. Renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Total generation = NEM generation + estimated distributed PV generation.

[18] Renewable potential in an operating interval refers to the total available energy from VRE sources, even if not necessarily dispatched, and actual output from dispatchable renewables, expressed as a percentage of the total NEM supply requirement.

Figure 53 Instantaneous renewable penetration reduced with an increasing contribution from wind

Percentage of NEM supply from renewable energy sources at time of peak instantaneous renewable energy output

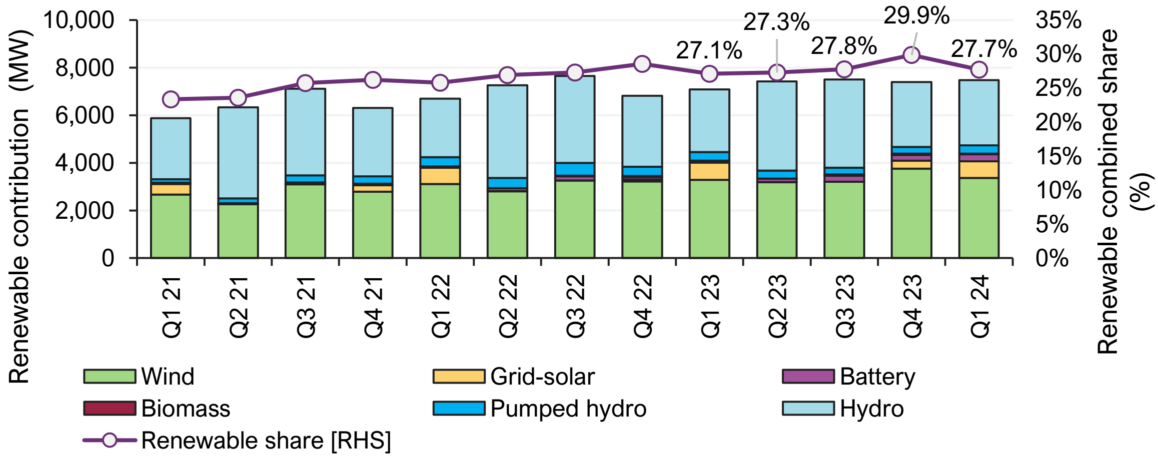


Renewable contribution to maximum demand

Figure 54 illustrates the contribution of large-scale renewable generation in meeting daily maximum NEM operational demand, computed as an average across all days in each quarter[19]. In Q1 2024, the average renewable contribution to supplying daily maximum operational demand reached 27.7%, with wind and hydro being the dominant renewable sources at 12.5% and 10.2% respectively. With summer daylight hours extending into the evening peak demand period, Q1 2024 also saw an average 2.6% contribution from grid-scale solar.

Figure 54 Year-on-year increase in renewable contribution to meeting daily maximum demand

Average renewable contributions (MW) and combined share (%) at time of daily maximum operational demand – Quarterly



[19] For every day in each quarter, the half-hour of maximum NEM operational demand is found along with large-scale renewable sources' contribution to meeting that demand. These quantities are then averaged over all days in the quarter to compute renewables' average contribution to supplying peak demand.

Renewable penetration range and peak outputs

Renewable penetration range shows the minimum and maximum instantaneous renewable penetration in meeting NEM demand during the quarter. As seen in Figure 55, the renewable penetration range has continuously increased over time. The maximum renewable penetration (also discussed in instantaneous renewable penetration – Figure 53) and minimum renewable penetration for this quarter were 69.9% and 13.3%, respectively. This range shows 56.6% quarterly swing for renewable penetration. The minimum renewable penetration occurred during the half-hour ending 0300 on Wednesday 10 January 2024.

Figure 55 Instantaneous renewable penetration range increased

Percentage range of NEM supply from renewable energy sources

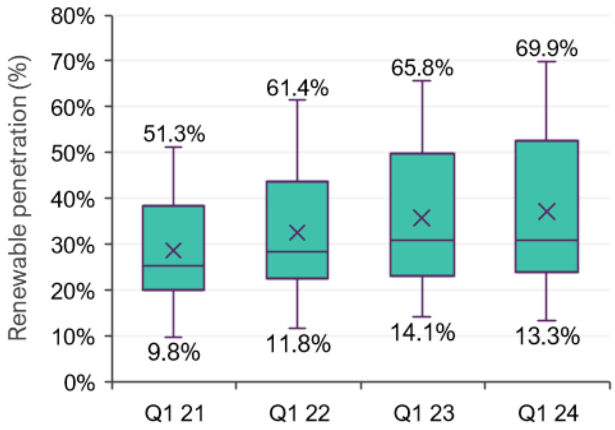


Figure 56 Record high instantaneous generation from grid-scale solar and rooftop solar in Q1 2024

Maximum quarterly instantaneous generation by fuel type

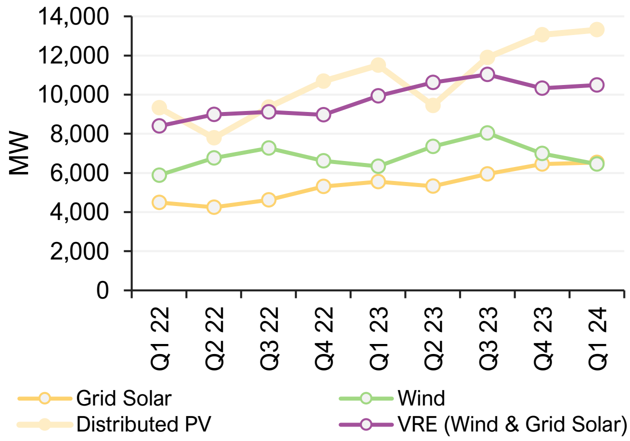


Figure 56 shows the instantaneous maximum outputs reached by grid-scale solar, wind and distributed PV output for all quarters since Q3 2019. In this quarter, both distributed PV and grid-scale solar reached record instantaneous highs of 13,311 MW and 6,531 MW representing 16% and 18% increases year-on-year. This increase was driven by the increase in new and commissioning grid-scale solar capacity. Wind instantaneous maximum output reduced from 6,983 MW in Q4 2023 to 6,446 MW this quarter, in line with previous seasonal trends, but increased 105 MW (+2%) from Q1 2023 due to additions to wind capacity over the year.

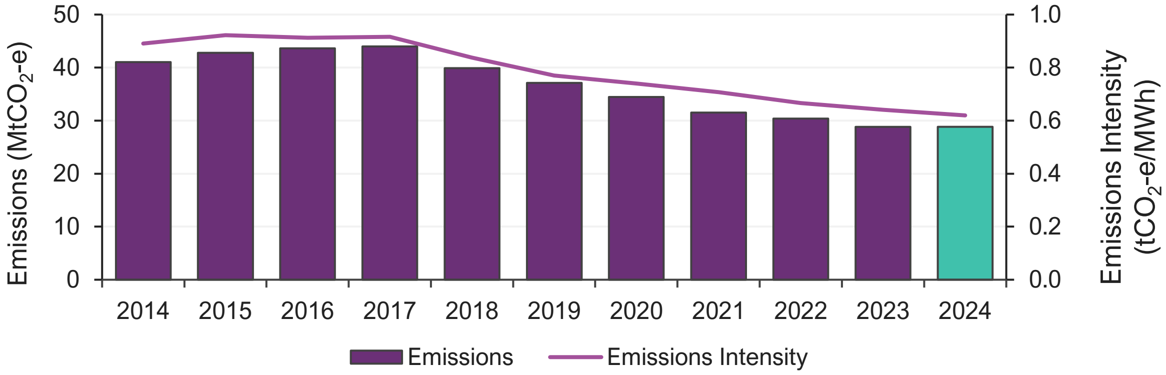
1.3.6 NEM emissions

During Q1 2024, NEM total emissions marginally increased by 0.01 million tonnes of carbon dioxide equivalents ($MtCO_2$-e) on Q1 2023 levels, reaching 28.84 $MtCO_2$-e (Figure 57). Emissions intensity, however, reduced to a new Q1 low of 0.62 tonnes of carbon dioxide equivalents per megawatt hour (tCO_2-e/MWh), a 0.02 tCO_2-e/MWh reduction year-on-year. Emissions intensity excludes generation from distributed PV, taking into consideration only sent out generation from market generating units[20]. The marginal increase in total emissions reflected higher output from thermal generating units due to the strong increase in operational demand during the quarter. With the increased share of renewables this Q1 (Section 1.3, Table 4), emissions intensity continued to fall.

[20] Sent out generation derived from metering data is combined with publicly available generator emission factors to provide a NEM-wide Carbon Dioxide Equivalent Intensity Index calculated on a daily basis. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/carbon-dioxide-equivalent-intensity-index.

Figure 57 Marginal increase in emissions (0.01 $MtCO_2$-e), but reduction in emission intensity

Quarterly NEM emissions and intensity – Q1s



1.3.7 Storage

Batteries

In Q1 2024, total net revenue for NEM grid-scale batteries reached $47.8 million, a 129% increase year-on-year from $20.9 million in Q1 2023, and a 52% increase from the previous quarter, Q4 2023, which saw $31.5 million in net revenue (Figure 58). The majority of the net revenue during this quarter was from energy arbitrage[21] which grew from $7.0 million in Q1 2023 to $28.5 million this quarter.

The main driver for the increased net revenue was an increase in quarterly average battery capacity, increasing 74% year-on-year from 947 MW in Q1 2023 to 1,652 MW this quarter, with a corresponding increase in quarterly average battery availability (from 348 MW in Q1 2023 to 819 MW this quarter). Batteries also offered more volume in lower price ranges across the quarter (Figure 59), resulting in a 134% year-on-year increase in quarterly average battery generation (from 23 MW in Q1 2023 to 53 MW this quarter).

Figure 58 Battery revenue up from Q1 2023 with increased revenue from energy and contingency FCAS markets

Quarterly revenue from NEM battery systems by revenue stream

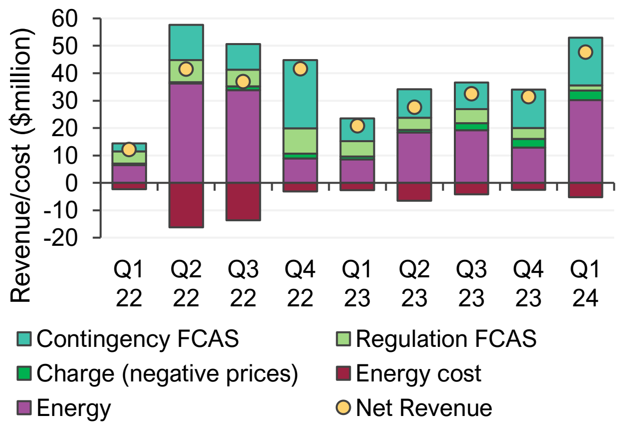
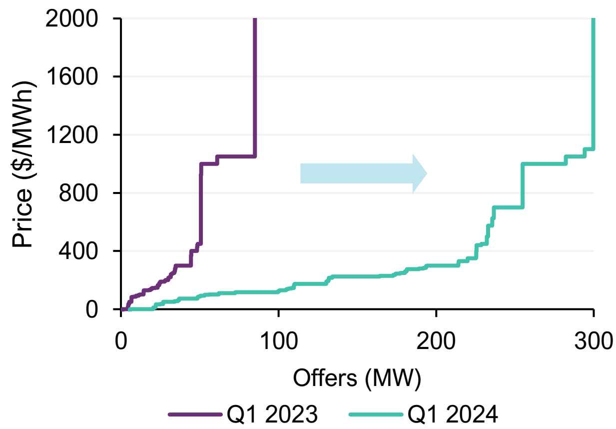


Figure 59 Batteries offered more volume in all price ranges

Battery generation bid supply curve – Q1 2024 vs Q1 2023



[21] Energy arbitrage revenue for batteries includes three components: 1) revenue from discharging (selling energy), 2) any revenue from recharging during negative priced intervals, and 3) cost of recharging at prices higher than $0/MWh.

NEM FCAS revenue increased by $5.3 million from $13.9 million in Q1 2023 to $19.2 million this quarter. Q1 2024 saw a significant share of total FCAS revenue (52%) being captured from the Very Fast Raise Contingency (R1SE) market at $9.9 million, a significant increase from $4.4 million in the previous quarter Q4 2023. The Very Fast Lower Contingency (L1SE) market provided the lowest revenue with significantly lower prices during the quarter (see Section 1.5).

Battery revenue from charging at negative prices (included in energy arbitrage earnings) increased year-on-year as more battery capacity was exposed to these prices. Charging at negative prices accounted for $3.5 million of total net revenue during the quarter, an increase of 220% relative to $1.1 million in Q1 2023.

The majority of battery revenue was captured by South Australian batteries at $20.4 million, including $8.7 million from energy and $11.7 million from FCAS markets. This represented the largest year-on-year increase in net revenue for any NEM region, more than doubling from $9.3 million in Q1 2023, and was predominately driven by increased battery capacity with the connection of Torrens Island Battery Energy Storage System (BESS). The region also saw the largest revenue from charging at negative prices at $1.7 million.

Queensland batteries had the next highest increase in net revenue, with a $7.2 million increase from Q1 2023 to $10.4 million in Q1 2024, with nearly all this quarter's net revenue arising from energy arbitrage at $9.7 million.

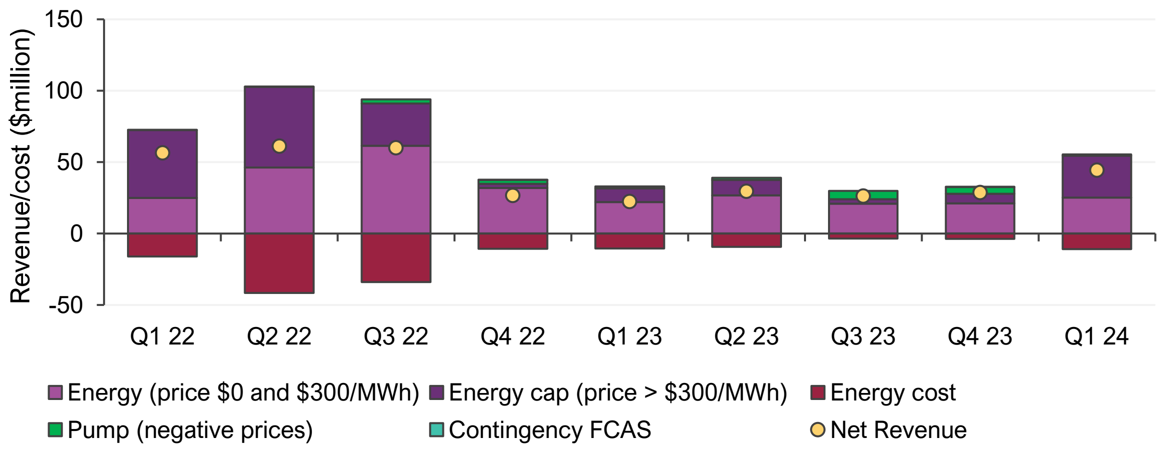
Pumped hydro

During Q1 2024, pumped hydro reached $44.5 million net revenue, which accounted for a 97% increase year-on-year from $22.6 million in Q1 2023 (Figure 60). Pumped hydro earned an estimated $54.5 million revenue from generating energy ($25.2 million captured from energy component of the spot price and $29.4 million revenue from cap return component of spot price). These were significant increases on corresponding figures of $22.1 million and $9.6 million during Q1 2023.

Queensland's Wivenhoe saw the majority of the year-on-year increase in net revenue, up $21.3 million from $17.9 million in Q1 2023 to $39.2 million this quarter, driven predominantly by the region's higher price volatility (Section 1.2.2). Shoalhaven in New South Wales saw a $0.6 million increase, from $4.7 million in Q1 2023 to $5.2 million this quarter.

Figure 60 Pumped hydro revenue increased from Q1 2023 with increased revenue from cap returns

Quarterly revenue from NEM pumped hydro by revenue stream



1.3.8 Demand side flexibility

Consumer energy resources (CER) continue to be installed at high rates, resulting in record high instantaneous distributed PV generation in Q1 2024. In line with this, AEMO continues to facilitate and prioritise initiatives to maximise the value of available assets and infrastructure such as demand side flexibility to smooth a transition from a one-way energy supply chain to a decentralised, two-way energy system. This includes initiatives that enable CER and demand response to provide energy and contingency services.

Since the establishment of the wholesale demand response (WDR) mechanism in October 2021, the number of registered demand response units has increased from three WDR units in Q4 2021 to 15 units this quarter (Figure 61). Following the increase in the number of registered demand response units, WDR capacity has also increased from 17.2 MW in Q4 2021 to 65.0 MW in Q1 2024. There is one participant registered to provide WDR. Since Q1 2023, Victoria saw one new unit register, which increased the total NEM WDR capacity registered by 4 MW from 61 MW in Q1 2023.

During Q1 2024, WDR saw a total of 87 MWh of energy dispatched over the quarter, an increase of 18 MWh from Q1 2023 (Figure 62) in line with the increased operational demands and spot price volatility experienced over this quarter.

The majority of WDR was from units in New South Wales, with 63 MWh dispatched in response to price volatility on two days in the quarter, reaching a peak dispatch level of 15 MW. A total of 17 MWh of WDR was dispatched in Queensland, at a peak dispatch level of 2 MW, on six days over the quarter – aligning with the price volatility periods in mid-late January and late February (see Section 1.2.2, Table 3). The majority of the 7 MWh dispatched in Victoria occurred during the storm events on 13 February with a peak dispatch level of 8 MW.

Figure 61 Increase in registered WDR units and capacity since establishment

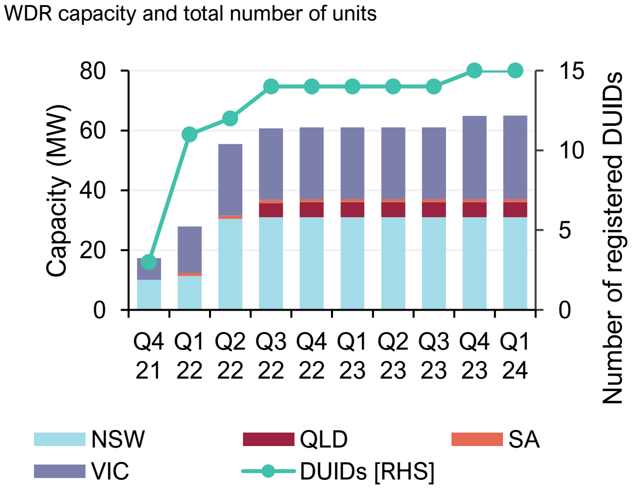
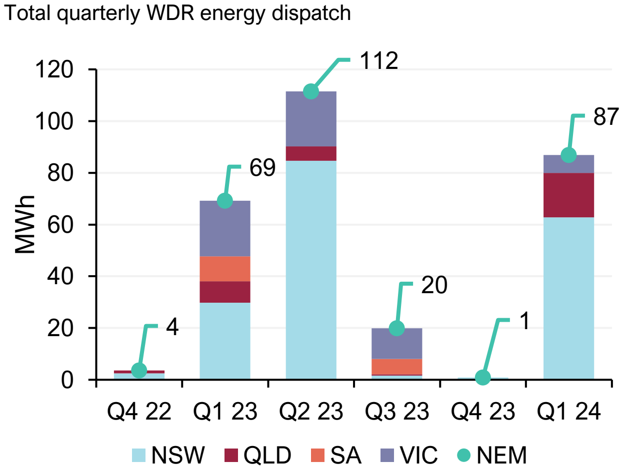


Figure 62 Increase in WDR dispatch occurrence in line with increased price volatility



Demand flexibility also plays a large role in the FCAS markets, with 13 participants registered to provide demand response (DR) ancillary services, and DR supplying 20% of the combined contingency raise services over Q1 2024 with 369 MW average enablement over the quarter. This included 54 MW average enablement, towards the new R1SE providing 25% of the total market share for this service.

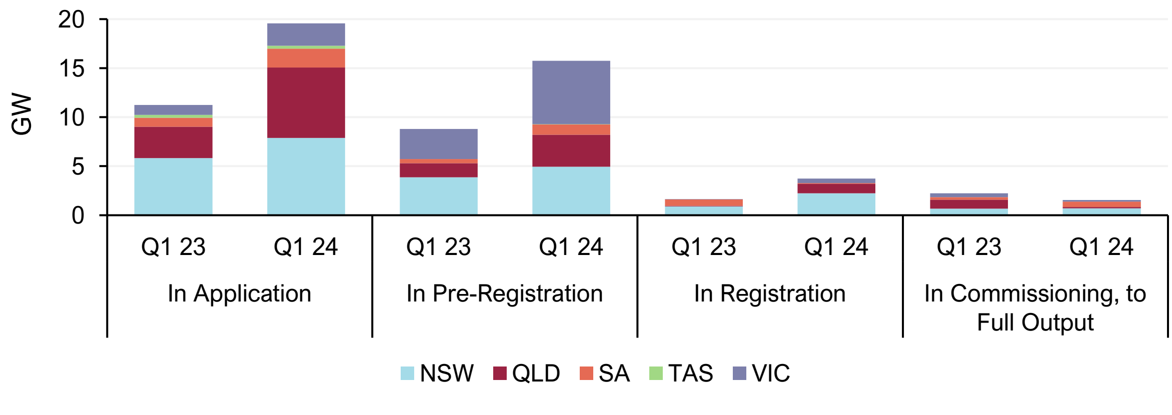
1.3.9 New grid connections

New grid connections to the NEM follow a process which involves the applicant, network service provider (NSP) and AEMO. Prior to submission of a connection application with AEMO, the applicant completes a pre-feasibility and enquiry phase where the connecting NSP is engaged in the process. The key stages[22] monitored by AEMO to track the progress of projects going through the connections process include application, pre-registration, registration, commissioning, and model validation. At the end of Q1 2024, AEMO's snapshot of connection activities in progress shows that:

- There was 41 gigawatts (GW) of new capacity progressing through the end-to-end connection process from application to commissioning, 70% increase in capacity compared to 24 GW at the end of Q1 2023 (Figure 63). Around 40% of this capacity is in New South Wales, 28% in Queensland, and 23% in Victoria.
- The majority (87%) of projects are in the early stages of development, in either application or pre-registration stages. Connections projects in these early stages are 43% solar, 31% battery, 18% wind and 7% hydro.
- The total capacity of in-progress applications was 19.6 GW, compared with 11.3 GW at the same time last year. Of the current capacity in application stage, 40% are New South Wales projects, 37% Queensland, 12% Victora, 10% South Australia, and 1% Tasmania.
- An additional 15.7 GW of new capacity projects are finalising contracts and under construction (pre-registration), with 40% of this capacity in Victoria, 30% in New South Wales, 20% in Queensland and 7% in South Australia. This compares to 8.8 GW at the end of Q1 2023. In Victoria, the majority (70%) of projects currently in the pipeline are in pre-registration stage, when contracts and construction are underway.
- There were 22 projects totalling 3.7 GW progressing through registration, with nine of these being registrations received during Q1. At the end of Q1 2024, there was 80% more capacity progressing through registration than at the end of Q1 2023. The majority (60%) of this 2024 capacity was in New South Wales.
- There was 1.6 GW of new capacity in commissioning to full output, compared to 2.2 GW at the end of Q1 2023. This commissioning measure considers all plant in commissioning up to the plant reaching its full output.

Figure 63 Increase in connection applications and projects under construction (pre-registration)

Connections snapshot as at end Q1 for 2023 and 2024



22 Application stage establishes technical performance and grid integration requirements. In pre-registration stage, contracts are finalised, and the plant is constructed. Registration stage reviews the constructed plant models for compliance with agreed performance standards. Once the plant is electrically connected to the grid, commissioning confirms alignment between modelled and tested performance.

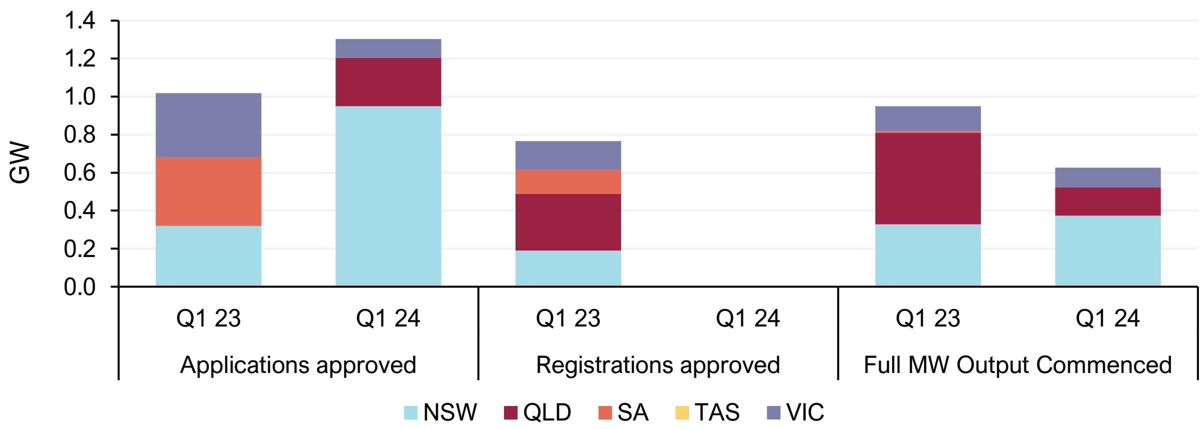
During Q1 2024:

- 1.3 GW of applications were approved across five projects (Figure 64) compared with 1.0 GW across seven projects in Q1 2023. Out of the applications approved, 73% (0.9 GW) were for three New South Wales projects.
- There were no projects registered and connected to the NEM. In comparison, five projects totalling 0.8 GW were registered and connected during Q1 2023.
- 0.6 GW of plant across five projects progressed through commissioning to reach full output. 50% of this capacity is from one project, Tallawarra B Power Station in New South Wales. In Q1 2023, 0.9 GW across seven projects reached full output, which included one 0.4 GW battery project.

The Connections Scorecard[23] is published monthly and contains further information.

Figure 64 Increase in application approvals and decrease in registrations approvals

Comparison of applications approved, registrations, and commissioning in Q1 for 2023 and 2024



1.4 Inter-regional transfers

Total gross inter-regional transfers during Q1 2024 were 3,142 gigawatt hours (GWh), a 13 GWh increase from 3,128 GWh in Q1 2023. The most significant change was a 176 GWh reduction in total transfers between New South Wales and Queensland, offset by increases in total transfers between Victoria and New South Wales (by 102 GWh), between Tasmania and Victoria (by 44 GWh) and between Victoria and South Australia (by 43 GWh).

Overall average net transfer between New South Wales and Queensland reversed from 341 MW southward in Q1 2023 to 27 MW northward in Q1 2024 (Figure 65).

Average flows northward on **QNI** more than tripled their Q1 2023 levels to 199 MW this Q1, and average flows southward more than halved to 155 MW this Q1. This increase in net flows northwards was consistent with Queensland experiencing higher wholesale spot prices than New South Wales this quarter (almost $31/MWh higher) compared to the gap of only $4/MWh in Q1 2023 (see Section 1.2). This change in flow patterns was experienced across almost all hours of the day, with the exception of the evening peak when QNI was heavily constrained (Figure 66). Overall QNI's export limit bound for 19% of dispatch intervals in Q1 2024, a significant

[23] https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard

increase from 7% in Q1 2023. Exports were most heavily limited between the hours of 1600 hrs and 2100 hrs, being constrained for 32% of intervals at an average level of 402 MW (Figure 67).

The main constraint setting QNI's export limit in these periods was a system normal constraint used to avoid overloading Bayswater to Liddell transmission (lines 33 and 34) on the loss of either of the two parallel lines. With the retirement of Liddell (on the northern end of these lines) this constraint binds more frequently as generation on the southern side of this line, including Bayswater, attempts to flow northwards to meet northern New South Wales and Queensland demand. The constraint is more restrictive over summer periods due to seasonal reduction of rated capacity for line 34.

Figure 65 New South Wales to Queensland significant increase in northward flows and decrease in southward flows

Quarterly inter-regional transfers

Figure 66 Significantly more net northward flow on QNI all day apart from evening peak

Average QNI flow (New South Wales to Queensland), by time of day

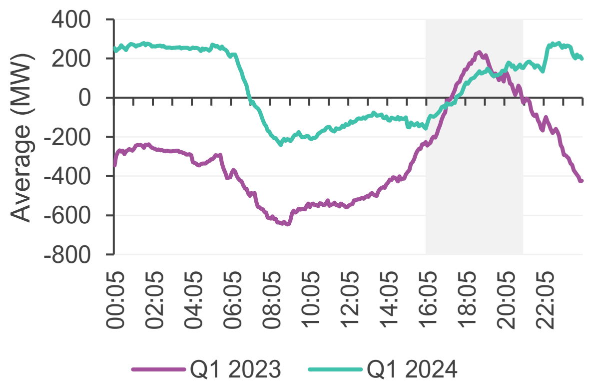
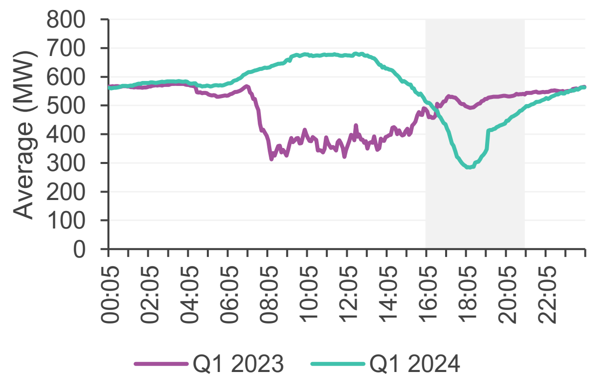


Figure 67 QNI export limit significantly reduced during the evening peak

Average QNI export limit when binding, by time of day



Average flows northward on **VNI** increased by 54 MW to 361 MW from Q1 2023 to this Q1. This increase in northward flows mainly occurred in the early hours of the day, with VNI continuing to be heavily constrained during daylight hours as discussed in the Q4 2023 QED (Figure 68). Over Q1 2024, VNI's export limit bound for 41% of dispatch intervals at an average export level of 476 MW during those binding intervals. This was an increase in binding frequency from the 39%, and a marginal decrease from the export limit of 478 MW, in Q1 2023.

However, compared to Q1 2023, VNI's export limit fell over evening periods, with the Bayswater to Liddell constraint (lines 33 and 34) at times determining this limit during the evening peak. When binding, this constraint limits the ability of northward flows on VNI as well as New South Wales generation upstream of the constrained lines to support higher demand in northern New South Wales and Queensland, leading to reduced maximum exports from Victoria to New South Wales (Figure 69).

Figure 68 Increased export to New South Wales on VNI in the mornings

Average VNI flow (Victoria to New South Wales), by time of day

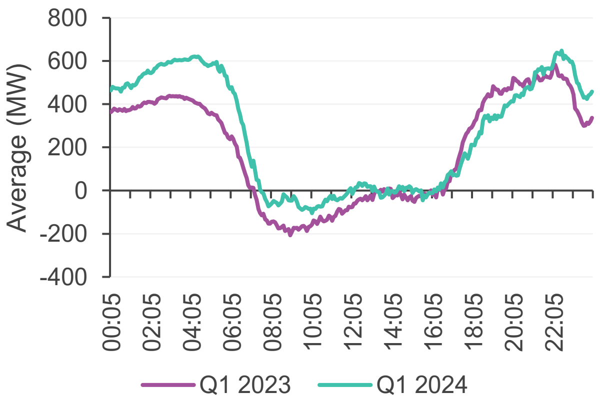
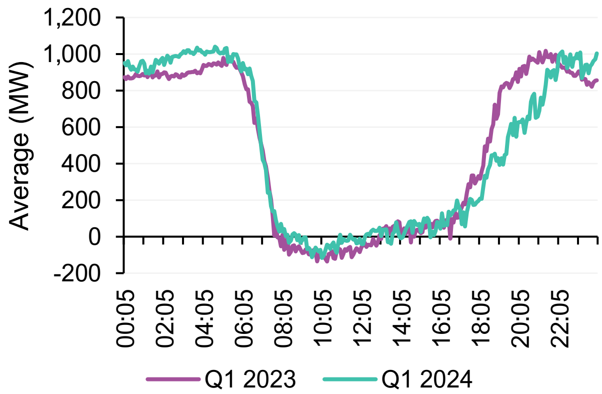


Figure 69 VNI export limit constraints extending past daylight hours

Average VNI export limit when binding, by time of day



1.4.1 Inter-regional settlement residue

Positive inter-regional settlement residue (IRSR) totalled $107 million in Q1 2024, up from the $81 million accrued over the previous Q1 (Figure 70). Approximately $23 million of this positive IRSR accrued on 13 February 2024, due to the Victorian storm-related events discussed in Section 1.2.2, including $17 million into Victoria from New South Wales and $6 million from South Australia.

Compared to Q1 2023, there was an increase in positive IRSR into Queensland of $11 million, leading to a total of $17 million over Q1 2024, driven by the price volatility events seen in Queensland over the quarter (see Section 1.2.2). The high demand day in New South Wales on 29 February 2024 contributed $17 million to the total quarterly $48 million positive IRSR into New South Wales.

Negative IRSR totalled $27 million in Q1 2024, an all-time quarterly high (Figure 71) with $5 million of this accruing on 13 February 2024. Negative IRSR into Victoria totalled $16 million, with $14 million from New South Wales driven by counter price flows on VNI, predominately caused by the network constraints in southern New South Wales discussed in the previous QED. In addition to those constraints, close to 30% of the negative IRSR accrued when the system normal constraints used to manage transmission loading between Bayswater to Liddell (lines 33 and 34) were setting VNI's export limit. The majority of $2 million negative IRSR into Victoria from South Australia accrued on 21 February 2024, when South Australia was experiencing high temperatures and high operational demands and both the Moorabool to Sydenham 500 kV lines were still out of service following the 13 February 2024 storm damage.

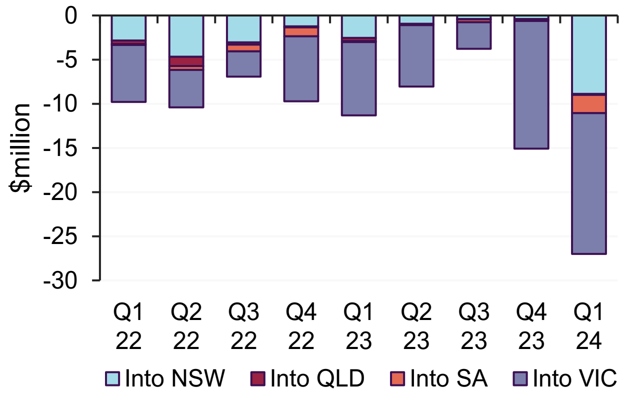
Negative IRSR into New South Wales was $9 million, with $4 million from Victoria predominately accruing on 13 February 2024. The remaining $5 million from Queensland occurred when Bayswater to Liddell constraint caused counter-price flows on QNI during periods of high evening operational demands in Queensland.

Figure 70 Significant increase in positive IRSR

Quarterly positive IRSR values

Figure 71 Highest quarterly negative IRSR on record

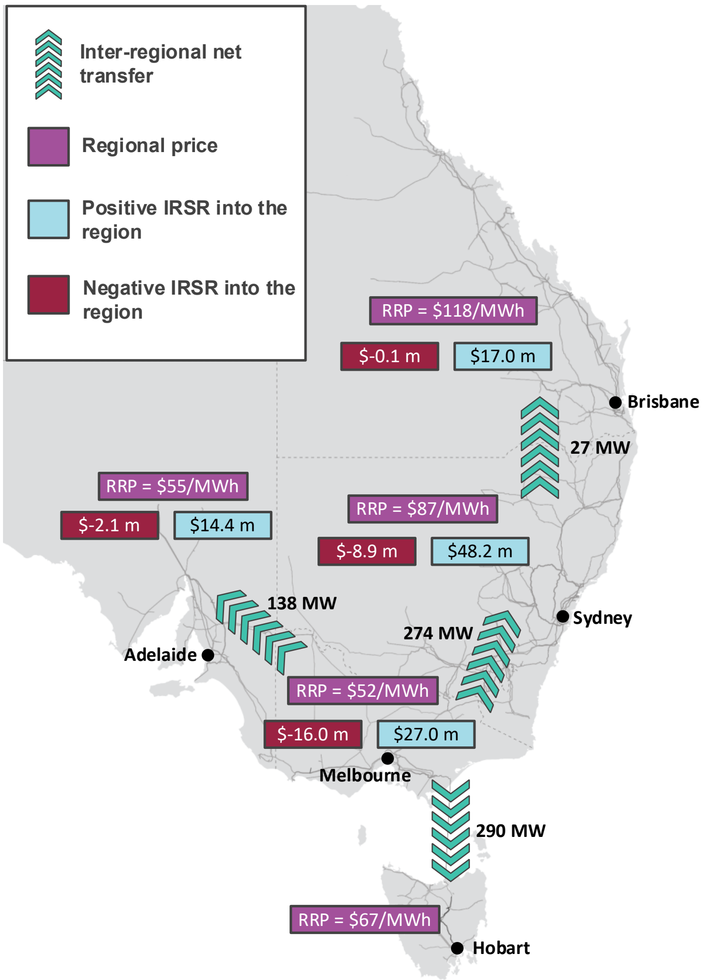
Quarterly negative IRSR values



The map in Figure 72 shows a summary representation of inter-regional exchanges during Q1 2024. Regional reference prices and the inter-regional net transfers are shown on a quarterly average basis. The positive and negative IRSR numbers refer to the total IRSR into the region from its neighbouring regions.

Figure 72 Inter-regional transfers, regional reference price, and settlement residues

Quarterly average net inter-regional transfer (MW), quarterly average regional reference price ($/MWh), and quarterly total IRSRs per region ($ million)



1.5 Frequency control ancillary services

Total FCAS costs for the quarter were $29 million, continuing the reduction from previous quarters and $9 million less than in Q1 2023 (Figure 73). South Australia was the only region to experience an increase in FCAS costs relative to Q1 2023, with a $5 million increase in contingency lower costs predominately due to the 13 February storm-related events in Victoria.

Payments for R1SE contributed $13.5 million or 47% to the total Q1 2024 costs (Figure 74) with the NEM-wide average quarterly price for R1SE significantly higher than the prices for the other FCAS services.

Figure 73 FCAS costs reduced across all regions except South Australia

Quarterly FCAS costs by region

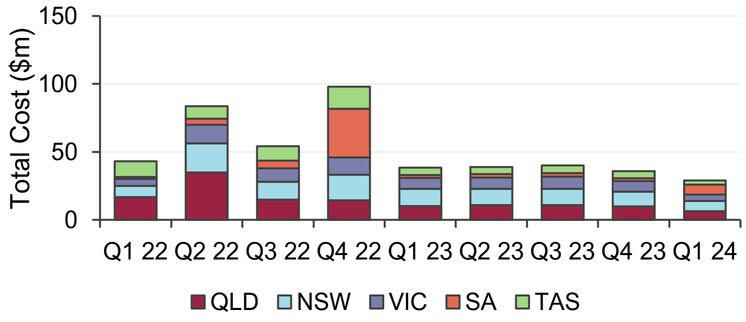
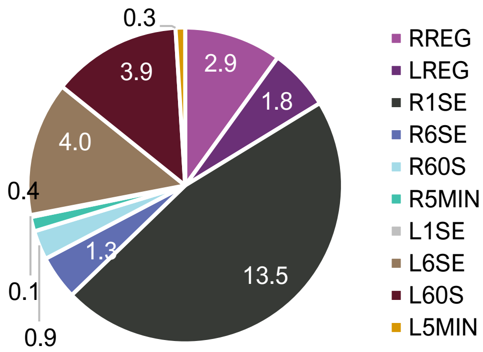


Figure 74 R1SE contributed close to half the total FCAS costs

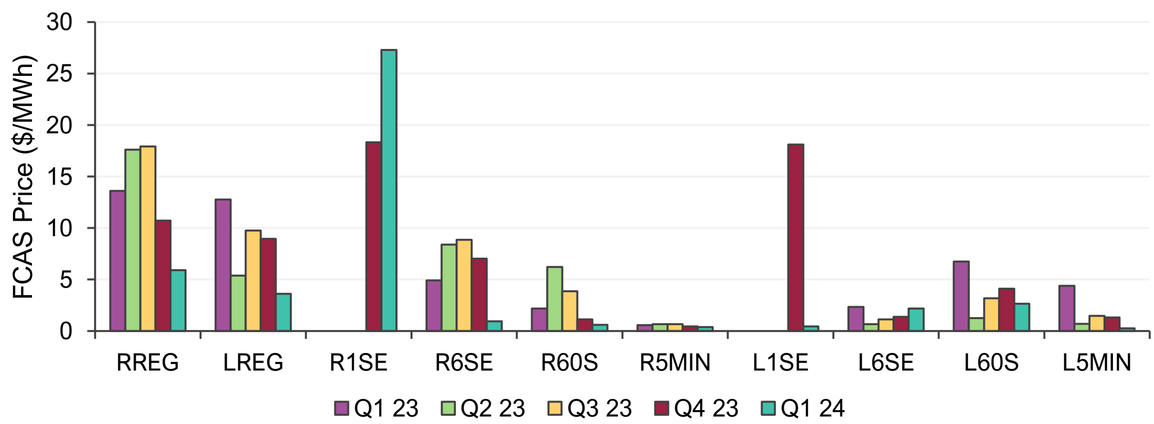
NEM quarterly FCAS cost by market – Q1 2024 ($m)



Apart from the NEM-wide average quarterly price for R1SE which increased to a quarterly average of $27/MWh, prices for the remaining FCAS services were generally lower than in preceding quarters, as shown in Figure 75.

Figure 75 R1SE average NEM price increased and L1SE decreased in the second quarter of market operation

NEM average FCAS prices by service – quarterly since Q1 2023



Batteries continued to be the dominant technology providing FCAS, with a market share of 57% (Figure 76), increasing from their 50% volume share in Q4 2023 and 38% in Q1 2023. This reflected a 632 MW increase in average enablement of batteries compared to Q1 2023 (Figure 77). The only other technologies to increase in average enablement from Q1 2023 levels were solar with a 17 MW increase, demand response (DR) with a 11 MW increase, and virtual power plant (VPP) with a 4 MW increase.

The increase in battery enablement was driven by ongoing increase in provision for the new 1 second markets, with batteries suppling 75% of the combined enablement for the R1SE and L1SE services as well increases in provision from new batteries with growth since Q4 2023 including from Hazelwood (+134 MW), Riverina (+175 MW) and Torrens Island (+127 MW).

Figure 76 Batteries further grew FCAS market share

FCAS volume market share by technology – Q1 2024

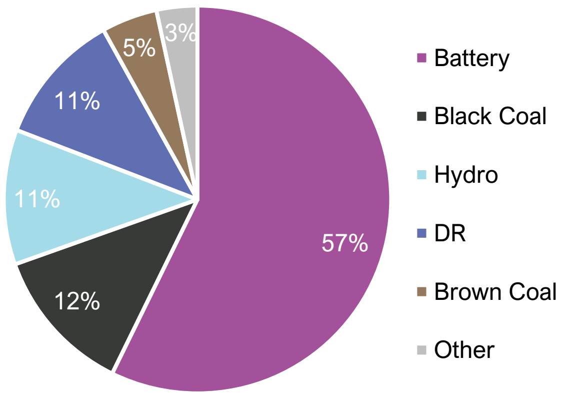
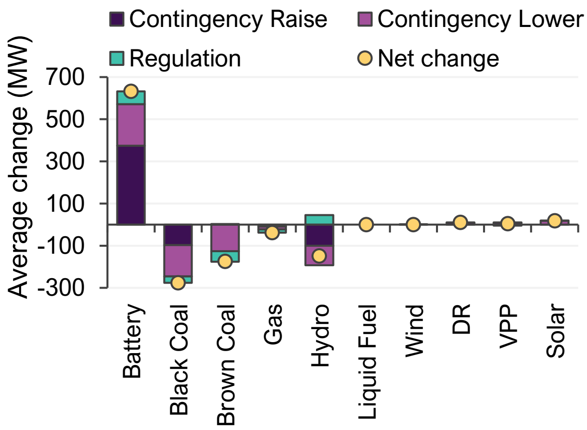


Figure 77 Increased enablement for batteries

Change in FCAS enablement by technology – Q1 2024 vs Q1 2023



Very fast frequency response market

The very fast FCAS markets commenced operation during the previous quarter on 9 October 2023 at 1:00 pm (market time) and are continuing their transition to full uncapped market operation. During Q1 2024 the cap on the L1SE requirement was increased from 100 MW to 125 MW on 12 February 2024, and the cap on R1SE requirements was increased from 225 MW to 250 MW on 18 March 2024.

Monthly NEM-wide prices for R1SE started the quarter averaging $48/MWh in January, before decreasing to an average of $9/MWh in March (Figure 78). A number of providers increased offered availability to the R1SE market between January and March 2024, including Riverina (from an average of 0 MW in January to 34 MW in March), Bouldercombe (from 0.4 MW to 21 MW) and Darlington Point (from 0 MW to 8 MW).

Figure 78 R1SE price started high and decreased over the quarter

Average R1SE cap, enablement, actual availability and price

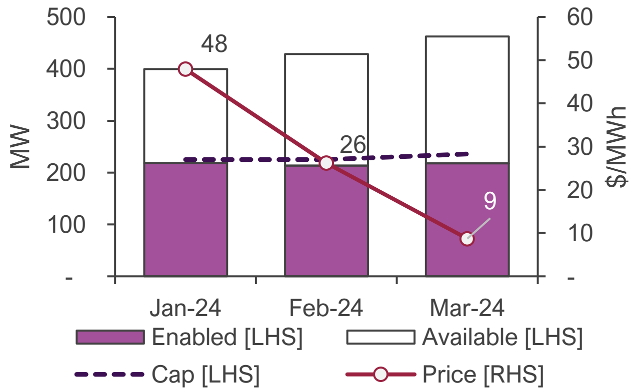
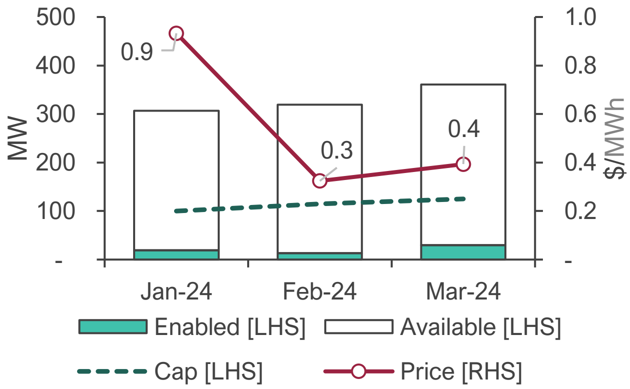


Figure 79 L1SE price remained low throughout the quarter

Average L1SE cap, enablement, actual availability and price



The uncapped underlying very fast FCAS requirements are made visible to the market via non-binding constraints, and these demonstrate that the underlying requirement for R1SE remained higher than the cap over the quarter. Monthly NEM-wide average prices for L1SE averaged below $1/MWh throughout the quarter, with the underlying requirement for L1SE remaining well under the cap (Figure 79).

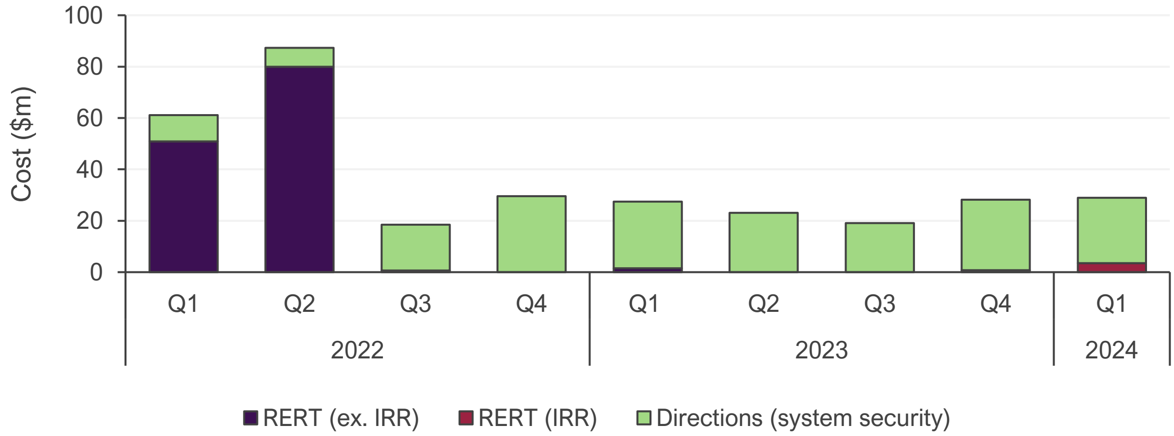
1.6 Power system management

Estimated power system management costs for system security directions and Reliability and Emergency Reserve Trader (RERT) were $29 million over Q1 2024, a $1.4 million increase from Q1 2023 (Figure 80).

RERT is a function conferred on AEMO to ensure reliability of supply by securing the availability of reserves using reserve contracts. AEMO entered into interim reliability reserve (IRR) agreements with various providers for the regions of Victoria and South Australia for the period from 1 December 2023 to 31 March 2024. IRR payments for Q1 2024 were $3.5 million. AEMO also entered into reserve contracts in response to forecast LOR conditions during two days in Q1 2024, however no reserves associated with these contracts were activated or pre-activated so no costs were incurred for these contracts[24].

Figure 80 System security costs slightly increased from Q1 2023

Estimated quarterly system costs by category



1.6.1 System security directions

Directions were in place in South Australia for 62% of dispatch intervals in Q1 2024, lower than the 65% in Q4 2023 but higher than the 50% in Q1 2023 (Figure 81). Despite an increase in the average directed output volume of South Australian gas-fired synchronous generators (from 37 MW in Q1 2023 to 46 MW in Q1 2024), estimated direction costs in South Australia were $23 million compared with $26 million in Q1 2023. This reduction in direction cost despite the increase in the frequency and volume of directions was due to a decrease in the compensation prices paid to directed participants from $349/MWh in Q1 2023 to $179/MWh in Q1 2024 in line with the reduction in spot prices[25].

Directions were in place in Victoria for 2.2% of dispatch intervals at an estimated cost of $2.7 million, the highest level of system security directions in Victoria since Q1 2020 when storm events caused the collapse of six

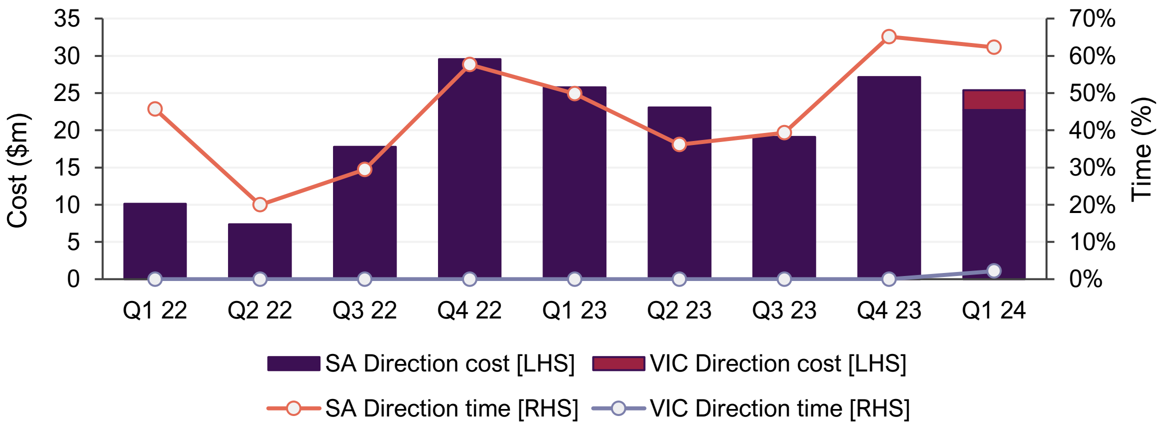
[24] AEMO, RERT Reporting, at https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

[25] Directed generators receive a compensation price calculated as the 90th percentile of spot prices over a trailing 12-month window.

transmission towers and separated the Victoria and South Australia power systems for 18 days from 31 January 2000. Following the 13 February 2024 storm-related events discussed in Section 1.2.2,, South Australia and the Alcoa Portland (APD) smelter remained connected to the NEM, however a credible contingency event (the loss of the Moorabool A1 500/220 kV transformer) would have resulted in the synchronous separation of South Australia and the APD smelter from the NEM. To manage power system security for this credible contingency event, AEMO issued a direction to a participant to maintain power system security. On 15 February 2024, AusNet reconfigured the network to eliminate this credible contingency risk.

Figure 81 Decrease in South Australia direction costs

South Australia and Victoria system security directions – time and estimated cost



2 Gas market dynamics

2.1 Wholesale gas prices

Quarterly average prices increased in all markets compared to Q4 2023 but were 3% lower than Q1 2023. The average price across all AEMO markets was $11.60/GJ compared to $11.80/GJ in Q1 2023 (Table 6).

Table 6 Average east coast gas prices - quarterly comparison

Price ($/GJ)	Q1 2024	Q4 2023	Q1 2023	Change from Q1 2023
Declared Wholesale Gas Market (DWGM)	11.19	10.40	11.53	-3%
Adelaide	11.65	11.23	12.59	-7%
Brisbane	11.80	10.92	11.81	0%
Sydney	11.71	10.82	12.05	-3%
Gas Supply Hub (GSH)	11.62	10.74	11.02	5%

Key factors influencing the movement of prices throughout Q1 2024 are summarised in Table 7, with further analysis and discussion referred to relevant sections elsewhere in this report.

Table 7 Wholesale gas price levels: Q1 2024 drivers

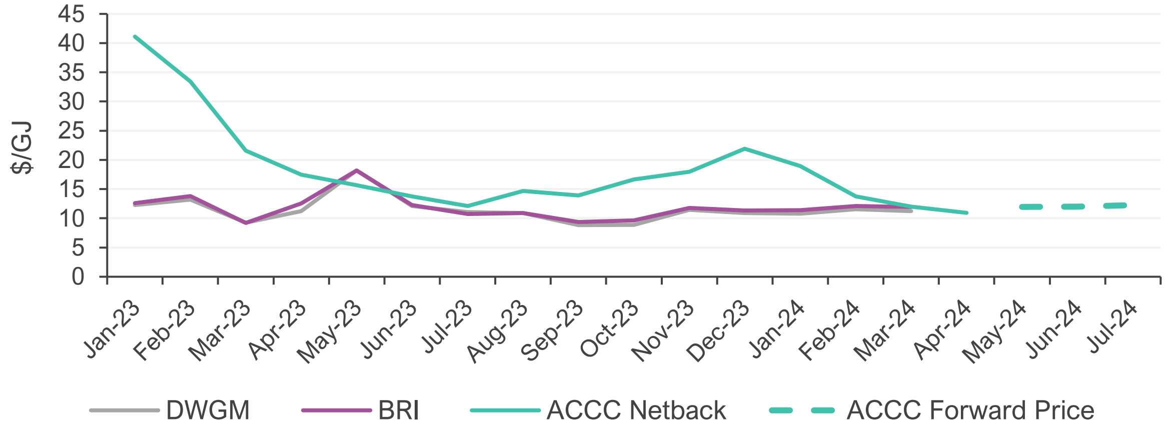
Lower offer prices into DWGM and Short Term Trading Market (STTM) in January and February	Q1 2024 saw average prices in January and February lower than Q1 2023, due to an increase in the proportion of volumes offered into the domestic spot markets at prices below $12/GJ which led to a reduction in the average price for the whole quarter (Figure 83). As noted in the Australian Competition and Consumer Commission (ACCC) Gas Inquiry[26], this has coincided with prices offered by producers continuing to trend downwards since their peak of $49/GJ in August 2022. The ACCC report states that since the introduction of the price cap on 23 December 2022, through to 8 August 2023, producers have sold gas to the domestic market under short-term contracts at or below $12/GJ. March 2023 offers were influenced by unplanned outages at QCLNG's facility which led to more volume being bid at lower prices, which did not occur in March 2024, leading to higher prices for that month compared to 2023.
Lower international prices	An increase in international LNG supply, coinciding with a mild winter in the northern hemisphere and record European storage levels has contributed to lower LNG prices across the globe (Section 2.1.1). International prices play a role in influencing the domestic price, with many domestic supply offers linked to the world price.
Reduction in domestic demand	Residential and commercial demand saw decreases in all regions, combined with a small decrease in gas-fired generation (Section 2.2).

International gas prices fell during the quarter after peaking in December 2023 at $21.91/GJ, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, falling to $10.94/GJ in early April 2024, the lowest price since June 2021 (Figure 82). Drivers for international prices are discussed in Section 2.1.1.

[26] ACCC 2024, LNG netback price series, at https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

Figure 82 International gas prices decreased while domestic prices increased marginally

ACCC netback and forward prices, DWGM and Short Term Trading Market (STTM) Brisbane average gas prices by month

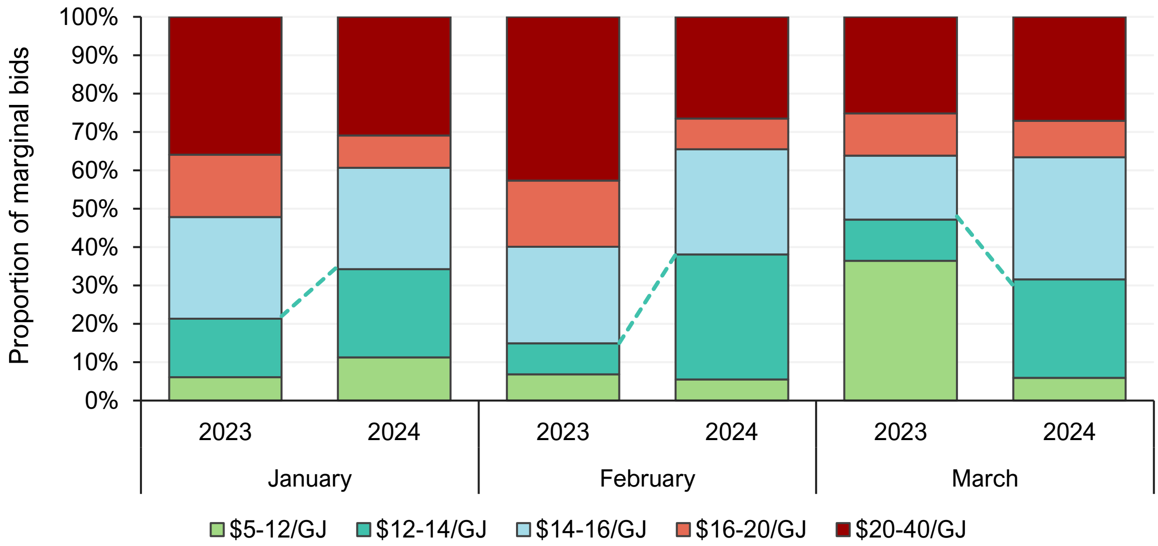


Domestic prices remained relatively flat across Q1 2024, with average prices ranging from $10.80/GJ in the Declared Wholesale Gas Market (DWGM) in January, to $12.12/GJ in Brisbane in February. There has been an absence of demand spikes or supply issues in the markets which can contribute to temporary spikes or dips in price. This is despite periods of very low Longford capacity in January, likely to have been assisted by the healthy Iona storage levels post winter 2023. While the Queensland Gas Pipeline (QGP) experienced a supply interruption that was ongoing throughout March (see Section 2.4.1), Gladstone, the major demand centre for that gas, is not part of the Brisbane Short Term Trading Market (STTM), so this event was not a factor in domestic market price outcomes.

Prices were more volatile in Q1 2023, which saw average prices peak in February at $13.70/GJ and drop to $9.43/GJ in March, due to higher gas-powered generation demand in February increasing prices, and unplanned outages at the QCLNG export facility in March 2023 causing lower prices. These factors were not repeated this quarter. This is reflected in the proportion of DWGM bid volumes below $12/GJ (Figure 83) in January and February, but not in March. Higher volumes bid below $12/GJ in January 2024 compared to January 2023 can be attributed to significantly lower international prices and lower commercial and industrial demand.

Figure 83 Larger proportion of DWGM bids at lower prices in January and February compared to 2023

DWGM – proportion of marginal bids[27] by price band – Q1 2023 vs Q1 2024 by month

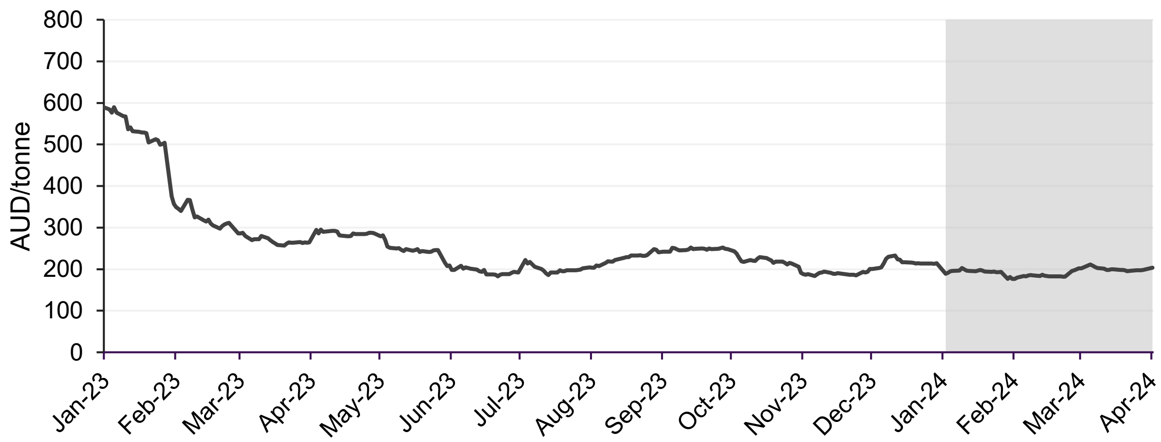


2.1.1 International energy prices

Newcastle export coal prices averaged $193/tonne this quarter, continuing the trend seen in recent quarters (Figure 84), with prices well below the 2022 peaks, but remaining higher than historical averages due to structural price pressures including low capital availability, labour shortages, rising freight costs and increased insurances[28].

Figure 84 Traded thermal coal prices remained flat over the quarter

Newcastle 6,000 kcal/kg thermal coal price in A$/Tonne daily



Source: Bloomberg ICE data

Asian spot LNG prices remained stable throughout the quarter as most of the northern hemisphere went through a mild winter (Figure 85). European LNG storage reached record high levels[29] throughout the period and even an

[27] Bids between $5/GJ and $40/GJ.

[28] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly March 2024, at https://www.industry.gov.au/publications/resources-and-energy-quarterly-march-2024.

[29] EU Gas Flow Dashboard, 2024, at https://gasdashboard.entsog.eu/.

increase in spot activity from Asia (mainly China, India and other south-east Asian nations) at the back end of the quarter did not have a material impact on global LNG prices[30].

Figure 85 Asian LNG prices stable throughout the quarter

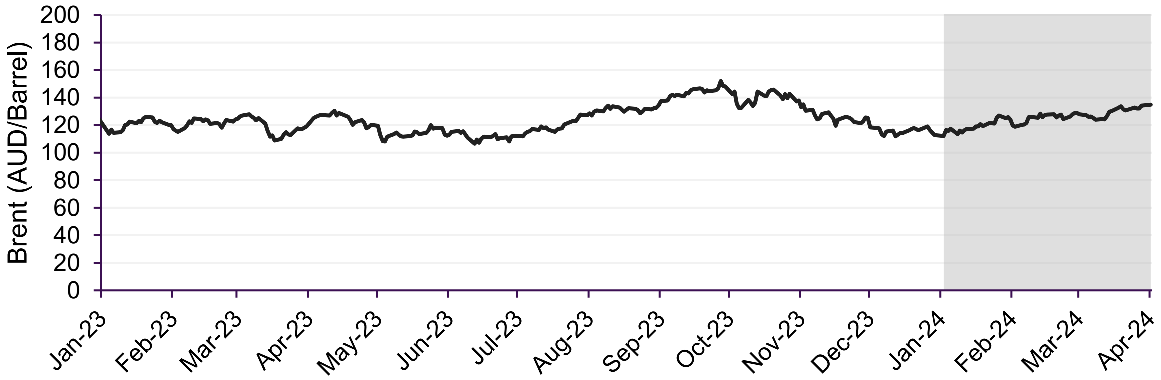
Asian LNG price in A$/GJ daily

Source: Bloomberg ICE data

The steady rise in Brent Crude oil prices is mainly attributed to ongoing conflicts in the Middle East (Figure 86). Oil tankers are having to avoid the Red Sea as Yemen's Houthi rebels continue to force vessels to take the longer route around Africa[31]. This has led to a tightening of US oil exports to Western Europe, forcing Brent crude oil prices to increase toward A$130/bbl at the end of the quarter. Consequently, medium-term LNG netback prices have also increased, to a point where Asian spot LNG prices had become more economical during the quarter[32].

Figure 86 Brent Crude oil prices increased throughout the quarter

Brent Crude oil in A$/Barrel daily



Source: Bloomberg ICE data

[30] Reuters, 2024, at https://www.reuters.com/business/energy/lower-lng-prices-trigger-surge-asian-spot-market-purchases-2024-03-21/.

[31] IEA Oil Market Report – March 2024, at https://www.iea.org/reports/oil-market-report-march-2024.

[32] ACCC LNG Netback price series, 2024, at https://www.accc.gov.au/inquiries-and-consultations/gas-inquiry-2017-30/lng-netback-price-series.

2.2 Gas demand

Total east coast gas demand increased by 10% compared to Q1 2023 (Table 8). This was solely attributed to an increase of Queensland LNG production facilities (+44 PJ), while domestic market demand decreased. The total Queensland LNG demand of 369 PJ is a record for Q1 (Figure 87).

Even though Queensland LNG production was the driving factor behind the increased gas demand on the east coast, both QCLNG and APLNG were impacted by extreme temperatures at Gladstone in January and March 2024 where temperatures reached above 36°C[33]. Such temperatures affect production and gas flows, meaning QLD LNG demand could have potentially been even higher.

Figure 87 Higher gas demand solely due to large increase in LNG exports

Components of east coast gas demand change – Q1 2023 to Q1 2024

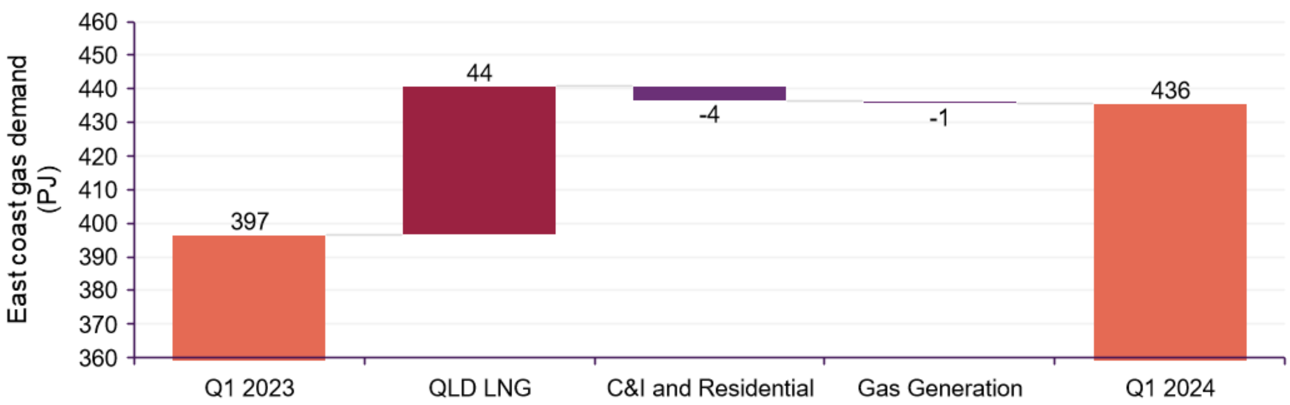


Table 8 Gas demand – quarterly comparison

Demand (PJ)	Q1 2024	Q4 2023	Q1 2023	Change from Q1 2023
AEMO markets *	46.3	57.5	50.6	-4 (-8%)
Gas-fired generation **	20.0	16.8	20.8	-1 (-4%)
Queensland LNG	369.3	365.3	325.2	+44 (14%)
Total	435.6	439.6	396.5	+38 (10%)

* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

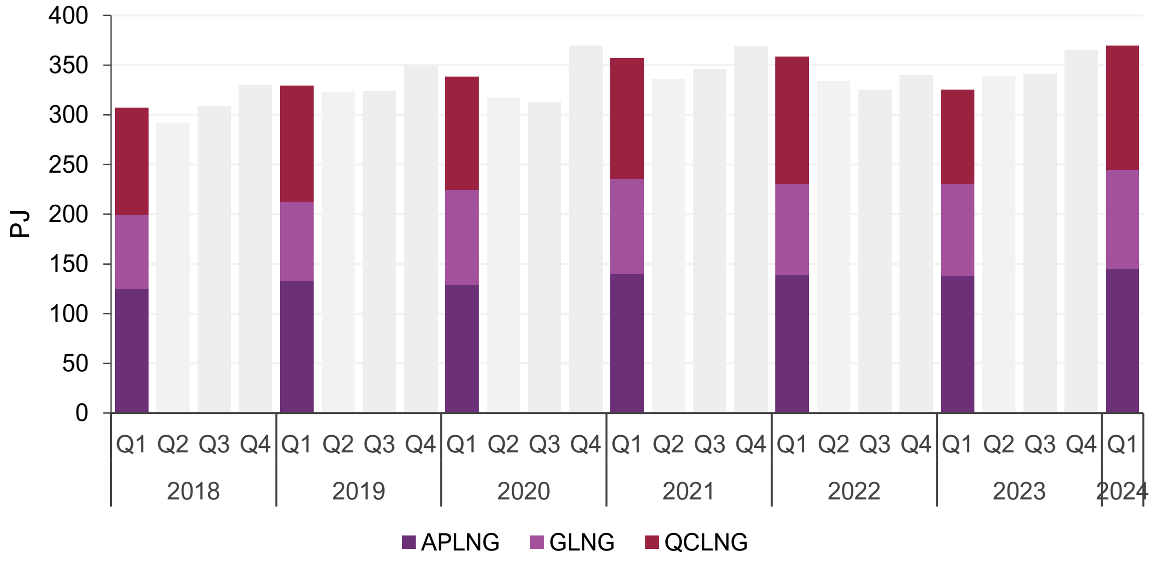
By participant, in comparison to Q1 2023, QCLNG demand increased by 31 PJ, GLNG increased by 6 PJ, and APLNG increased by 7 PJ (Figure 88). QCLNG's increase was attributable to overcoming the challenges they faced in Q1 2023, where they had one full train under maintenance for over 45 days. There were 91 cargoes exported during the quarter, up from 84 cargoes in Q1 2023.

Domestic markets saw slightly lower demand in all AEMO markets (-4 PJ) spread across the regions, and a small decrease in gas-fired generation (-1 PJ). Reduced market demand was mainly due to lower commercial and industrial demand, and the small decrease in gas-fired generation was mainly due to an increase in solar and wind generation in the NEM across all states (see Section 1.3).

[33] Gladstone Jan and Mar Daily Weather Observations, 2024, at http://www.bom.gov.au/climate/dwo/202401/html/IDCJDW4049.202401.shtml.

Figure 88 Highest Q1 on record for Queensland LNG production

Total quarterly pipeline flows to Curtis Island



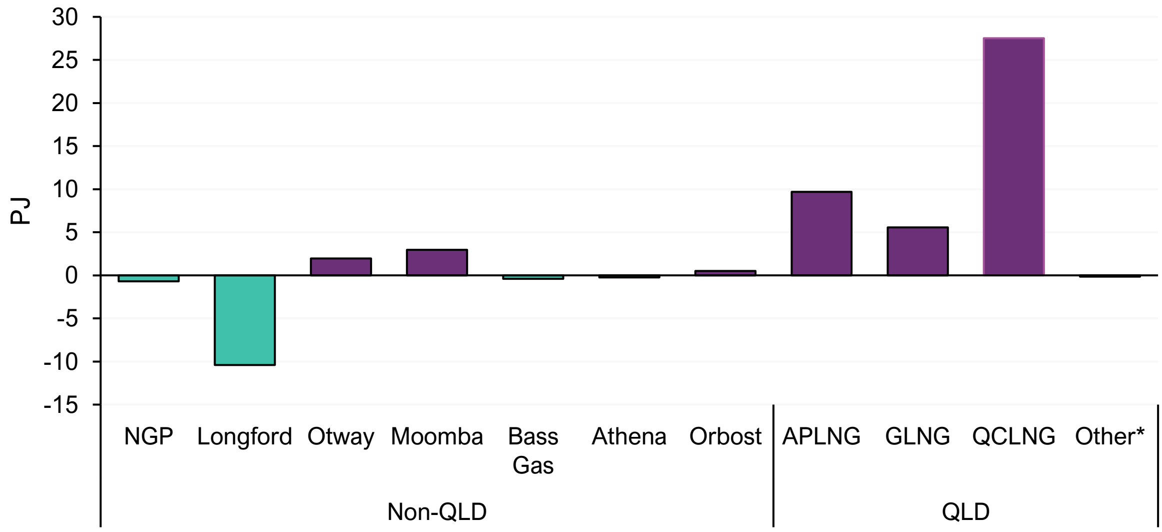
2.3 Gas supply

2.3.1 Gas production

East coast gas production increased by 36.8 PJ (9%) compared to Q1 2023 (Figure 89).

Figure 89 Production continues to fall at Longford while Queensland increases

Change in east coast gas supply – Q1 2024 vs Q1 2023



Key changes included:

- Decreased Victorian production (-8.6 PJ), mainly driven by lower production at Longford (-10.4 PJ).
- Increased Queensland production (+42.6 PJ), with assets operated by QCLNG increasing by 27.5 PJ, APLNG operated assets by 9.7 PJ, and GLNG operated assets by 5.6 PJ. Gas demand for Queensland LNG exports

increased by 44.1 PJ, meaning net supply associated with Queensland LNG projects into the domestic market was 1.5 PJ lower than in Q1 2023.

- Increased Moomba production (+3.0 PJ), continuing the trend in increases observed since Q2 2023. As previously reported, increased production has coincided with an increase in the number of wells drilled in the Cooper Basin.

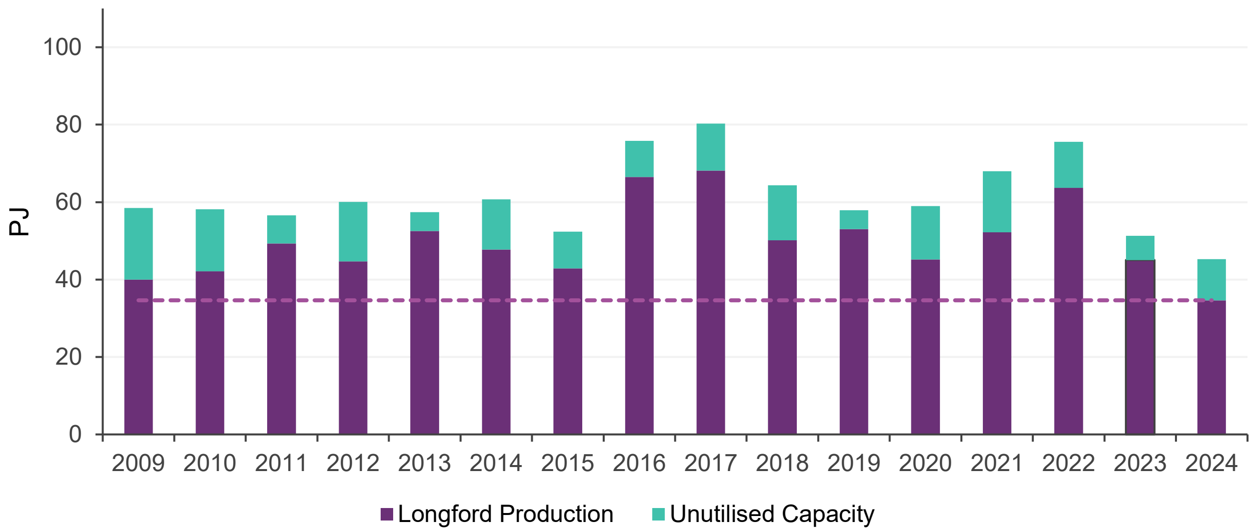
2.3.2 Longford production and capacity

Q1 continued the decline in Longford production observed throughout 2023. Longford's production of 35 PJ was the lowest Q1 since data commenced on the Gas Bulletin Board (GBB) in 2009 (Figure 90), and its available production capacity of 45 PJ was also the lowest recorded since this time.

The most recent information on Longford's declining gas reserves in Bass Strait and its future production forecasts is discussed in AEMO's 2024 *Victorian Gas Planning Report Update* and 2024 *Gas Statement of Opportunities*[34].

Figure 90 Lowest Longford Q1 production and capacity since data reporting began

Longford Q1 production versus unutilised capacity

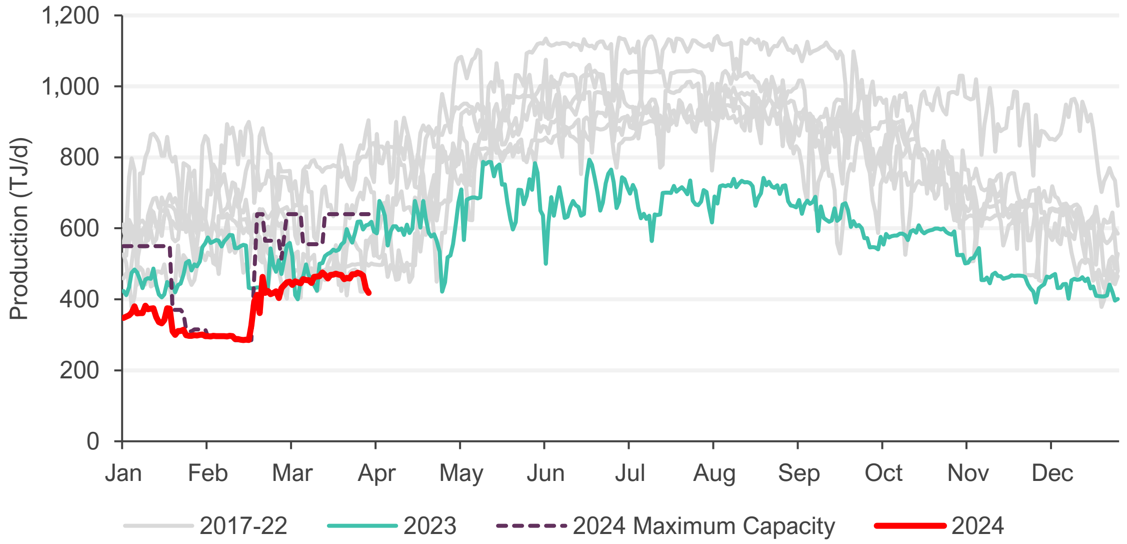


Daily production for much of January and all of March was well below available capacity (Figure 91). A planned maintenance reduction from late January to mid-February meant daily production for much of that time was at the reduced capacity level. Longford's capacity ranged from 285 – 295 TJ/day from 1 to 17 February, the lowest level since GBB reporting began in July 2008, and most likely its lowest planned level since Gas Plant 3 was commissioned in 1983.

[34] See https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report and https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Figure 91 Daily Longford production continued to decline

Daily Longford production 2017-2024, maximum capacity profile Q1 2024



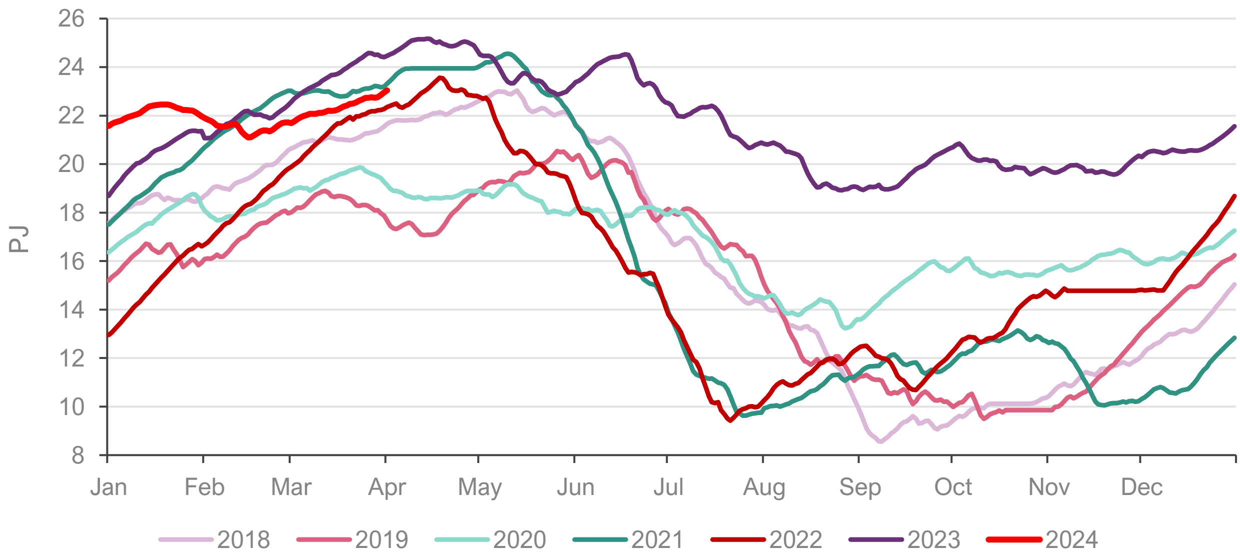
2.3.3 Gas storage

The Iona underground gas storage (UGS) facility finished the quarter with an inventory of 23.0 PJ, 1.4 PJ lower than at the end of Q1 2023 (Figure 92).

Storage inventory filled slowly during the first half of January, before emptying in the first half of February, coinciding with record low Longford capacity combined with gas flows towards Queensland from Moomba necessitating greater reliance on Iona storage to meet southern demand. Storage levels increased from late March, aided by an increase in Longford capacity, as well as lower demand.

Figure 92 Iona more heavily utilised for supply coinciding with record low Longford capacity

Iona storage levels

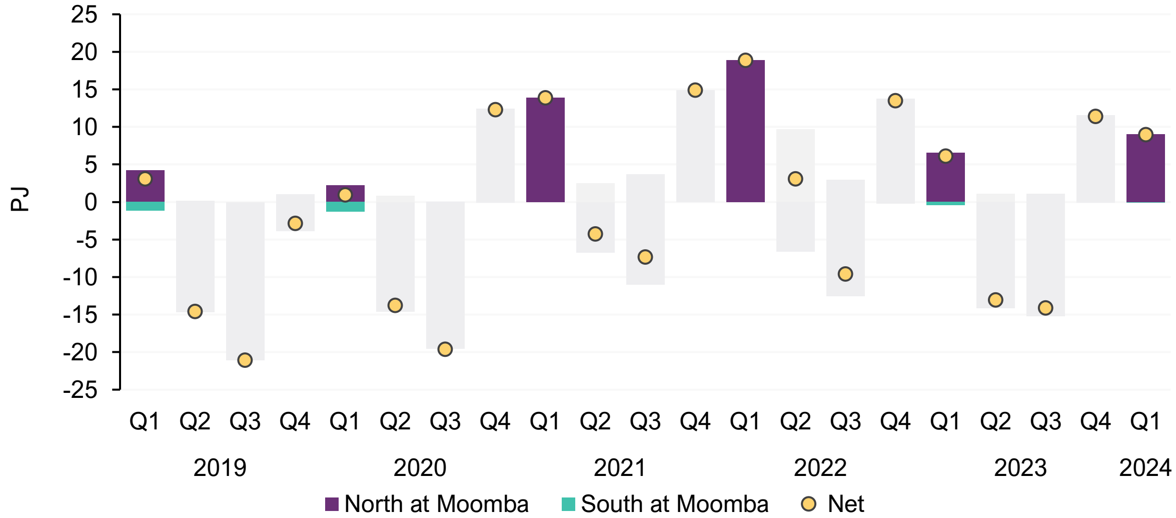


2.4 Pipeline flows

Compared to Q1 2023, there was a 2.8 PJ increase in net transfers north from Moomba on the South West Queensland Pipeline (SWQP, Figure 93). Increased flows coincided with an increase in Queensland LNG export demand, most of which was met by an increase in Queensland production.

Figure 93 Net Q1 flows north on SWQP increased in 2024

Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states decreased by 2.6 PJ from Q1 2023 levels due to reduced production at Longford alongside increased production at Moomba. This represents the second lowest export flow from Victoria for a Q1 since data reporting began (Figure 94). Net flows from Victoria to New South Wales decreased by 1.5 PJ, comprising a net decrease of 1.9 PJ via Culcairn and increase of 0.3 PJ via the Eastern Gas Pipeline (EGP). Flows from Victoria to South Australia decreased by 1.1 PJ, while there was a negligible change in flows from Victoria to Tasmania.

Figure 94 Second-lowest Victorian Q1 exports since data reporting began

Victorian net gas transfers to other regions – Q1s

2.4.1 Queensland Gas Pipeline Supply Interruption

On 5 March, a rupture occurred on Jemena's Queensland Gas Pipeline (QGP) between the Rolleston Compressor Station and Oombabeer, which severely restricted supply into Gladstone, Bundaberg and Maryborough. Only one production facility was able to supply gas downstream of the rupture, which initially restricted supply to approximately 30 TJ/day. Before the incident, average flow on QGP between 1 January and 4 March was 129 TJ/day (Figure 95).

AEMO determined that the event was a risk or threat to the adequacy or reliability of supply within the east coast gas system as it met the following criteria:

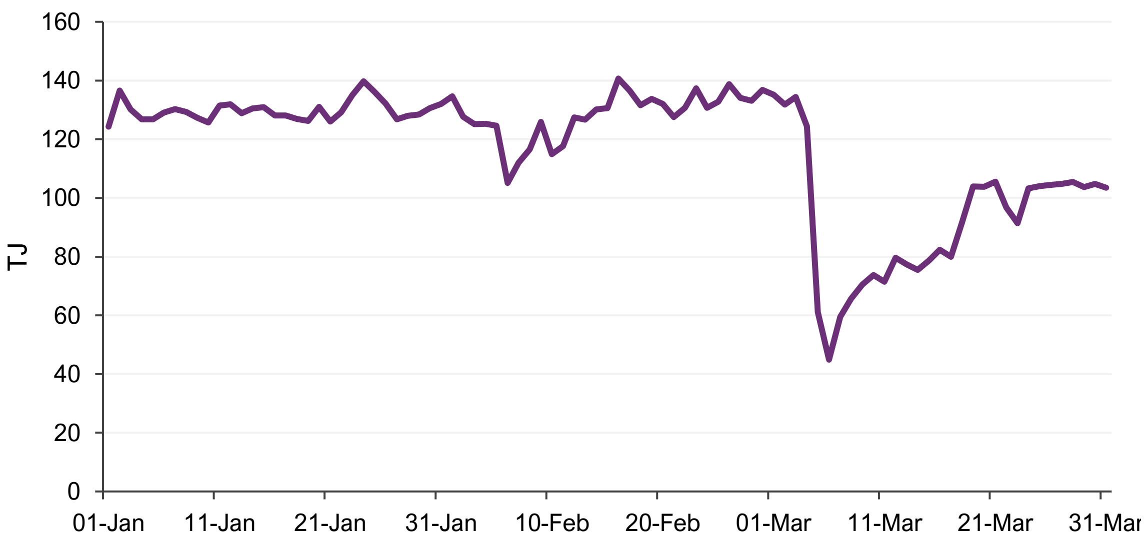
- The supply of gas in all or part of the east coast gas system may be inadequate to meet demand; and
- Alternative AEMO functions and powers such as STTM contingency gas or DWGM interventions would be insufficient to mitigate the identified risk or threat.

AEMO therefore, in consultation with Jemena and the Queensland Government, exercised its east coast gas system function and issued directions to relevant entities to prevent, reduce or mitigate the risk or threat.

AEMO worked closely with industry stakeholders and the Queensland Government as the capacity on the QGP was increased, which by 7 March was 70 TJ/day, then 85 TJ/day by 12 March, and approximately 105 TJ/day by 19 March where it remained for the rest of the month.

Figure 95 QGP flows interrupted by pipeline rupture on 5 March

QGP – daily pipeline flows Q1 2024



Directions continued for the rest of the month. AEMO will publish a report into this incident at a future date.

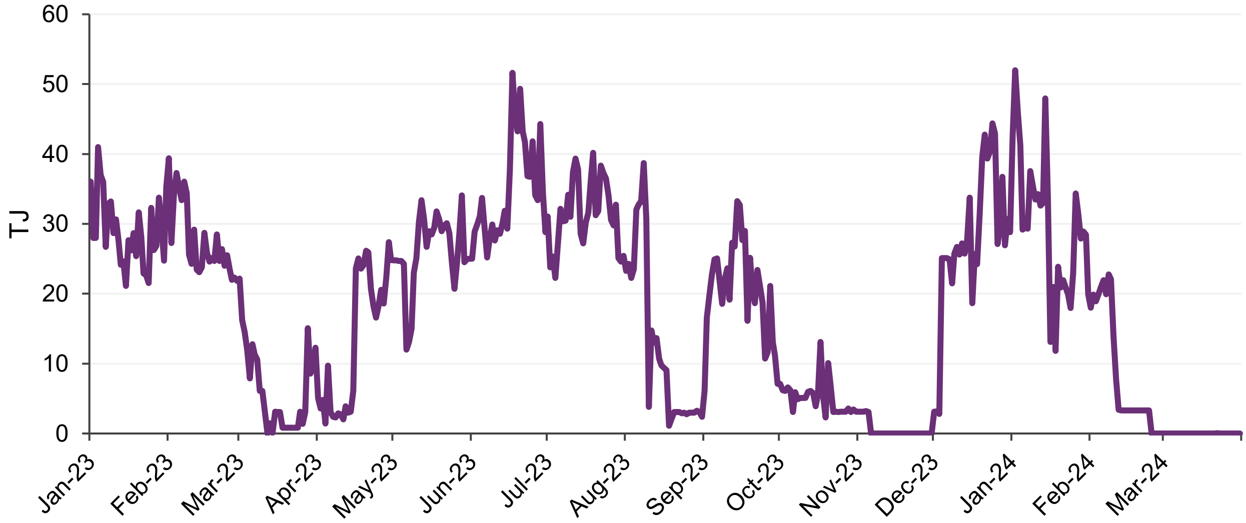
2.4.2 Gas flows on Northern Gas Pipeline ceased since late February 2024

Jemena's Northern Gas Pipeline (NGP) ceased gas flows from late February 2024 due to upstream supply issues at the Blacktip gas field in the Northern Territory. The NGP connects Tennant Creek in the Northern Territory to Mt Isa in Queensland, and has the capability of flowing up to 90 TJ/day.

Since it began commercial operations in January 2019, a majority of the gas transported via the NGP has come from the Blacktip field. However, supply issues at the gas field since early 2021 have reduced its output significantly (Figure 96). The current advice from Jemena is that pipeline flows on NGP will remain at zero until at least June 2024[35].

Figure 96 NGP flows to Queensland at zero since February due to supply issues

NGP – daily pipeline flows



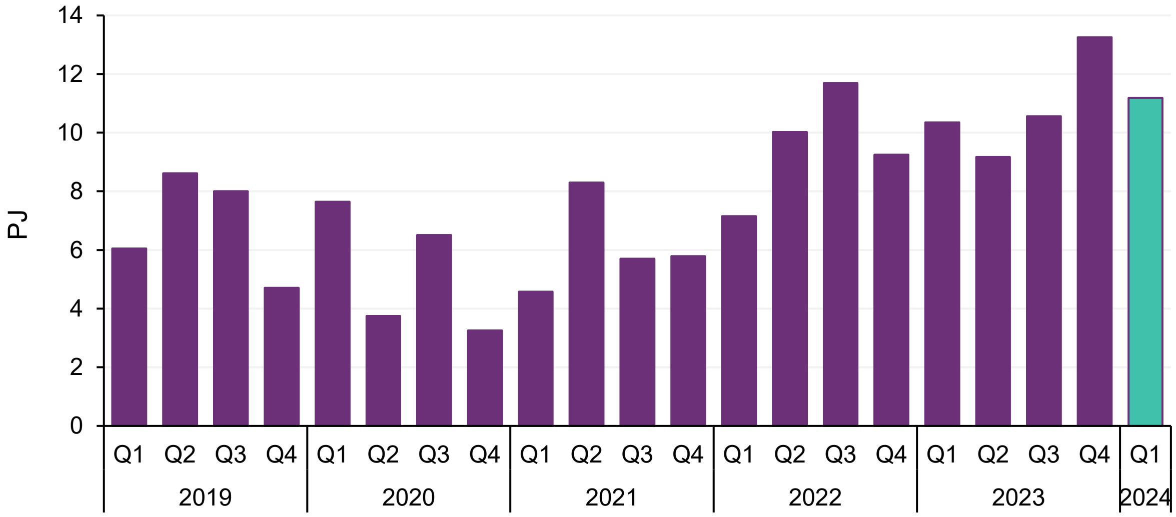
2.5 Gas Supply Hub (GSH)

In Q1 2024, traded volumes on the GSH increased by 0.8 PJ in comparison to the previous Q1 record set in 2023, setting a new Q1 record (Figure 97). The traded volume this quarter was 11.2 PJ and represented the third highest volume on record, after the record being set in Q4 2023.

[35] ABC News, 2024: Northern Gas Pipeline stops flowing from NT to east coast

Figure 97 Highest Gas Supply Hub Q1 volumes on record

Gas Supply Hub – quarterly traded volume



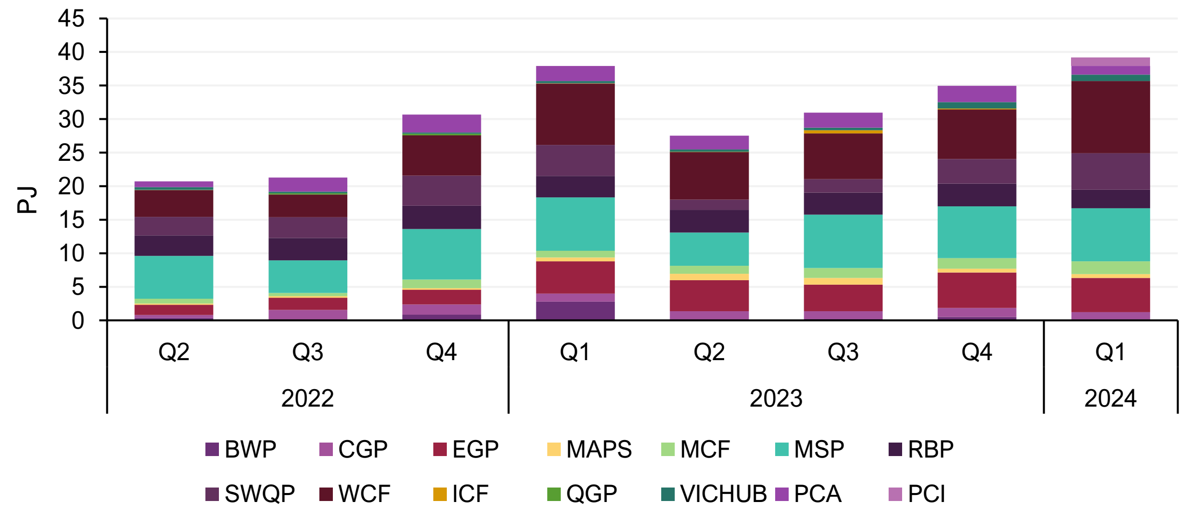
2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes traded in Q1 2024 set a record of 39.2 PJ, 1.2 PJ higher than the previous record set in Q1 2023 (Figure 98). Compared to Q1 2023, the largest increase occurred on the Wallumbilla Compression Facility (WCF, +1.6 PJ). The first DAA capacity won on the Port Campbell to Iona Pipeline (PCI) occurred in January 2024, with 1.2 PJ traded in the quarter – a majority of which was to transport gas east to Port Campbell.

Average auction clearing prices remained at or close to $0/GJ on most pipelines and compression facilities. The exceptions to this were northern haul on the Carpentaria Gas Pipeline (CGP, $0.042/GJ) and both northern haul and southern haul on the EGP ($0.027/GJ).

Figure 98 Highest Day Ahead Auction utilisation since market start

Day Ahead Auction volumes by quarter



2.7 Gas – Western Australia

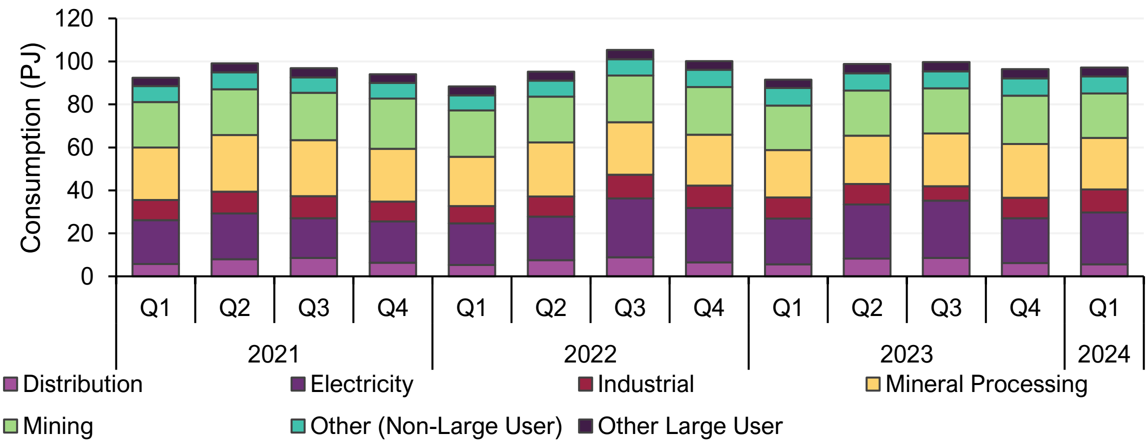
2.7.1 Gas consumption

A total of 97.2 PJ was consumed via pipeline in the Western Australian domestic gas market in Q1 2024 (Figure 99). Compared to Q1 2023, consumption increased by 5.7 PJ (+6.2%), and compared to the previous quarter, Western Australia consumed a slightly increased 0.7 PJ more gas via pipeline (+0.7%).

The main driver for the increase in consumption compared to the previous quarter and previous year was an increase in gas-fired electricity generation, with consumption by the electricity sector increasing in line with heatwaves driving higher electricity demand.

Figure 99 Western Australian domestic gas consumption in Q1 2024 increased compared to both Q1 2023 and Q4 2023

WA quarterly gas consumption by sector – Q1 2021 to Q1 2024



2.7.2 Gas production

Domestic gas production in Q1 2024 was 100.3 PJ, an increase of 11.3 PJ compared to Q1 2023 (+12.7%) which was impacted by gas supply disruptions[36]. In Q1 2024 gas production decreased by 5.2 PJ compared to Q4 2023 (-4.9%) (Figure 100).

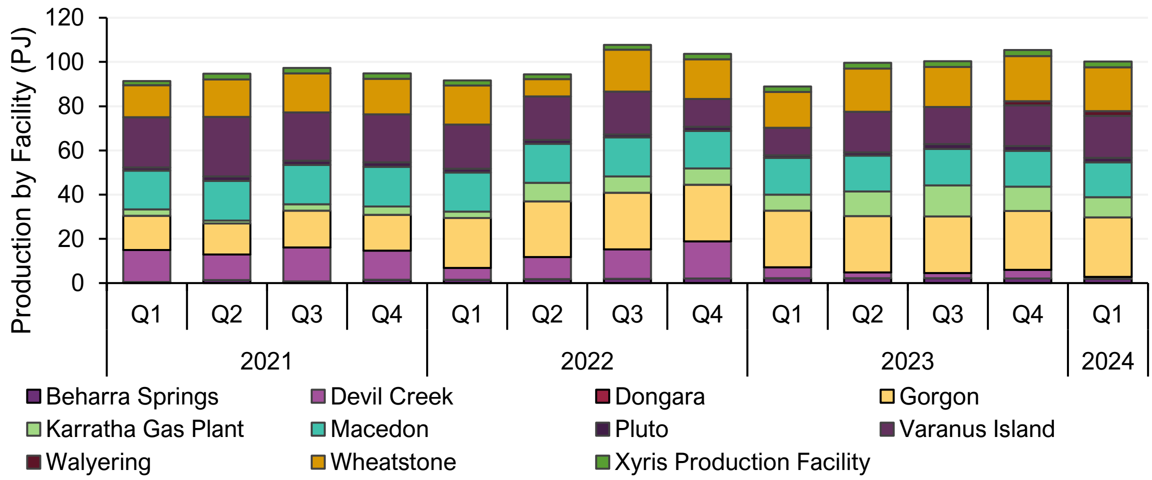
Key drivers of the changes in gas production in Western Australia compared to the previous quarter included:

- Steady production despite supply disruptions at Varanus Island in late January 2024 and Wheatstone in early February 2024.
  - On Friday 9 February, 249 TJ more gas was withdrawn from the pipelines than was injected from production facilities, resulting from the combined production disruption and consumption increase from increased gas-fired power generation. 186 TJ was withdrawn from storage.
- Quarter-on-quarter production decreases from Beharra Springs, Devil Creek, Karratha Gas Plant, Macedon and Wheatstone. These were partially offset by increased production from Gorgon and Walyering.

[36] https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q1-2023-report.pdf

Figure 100 Western Australian domestic gas production in Q1 2024 increased from Q1 2023 and decreased from Q4 2023

WA quarterly gas production by facility – Q1 2021 to Q1 2024

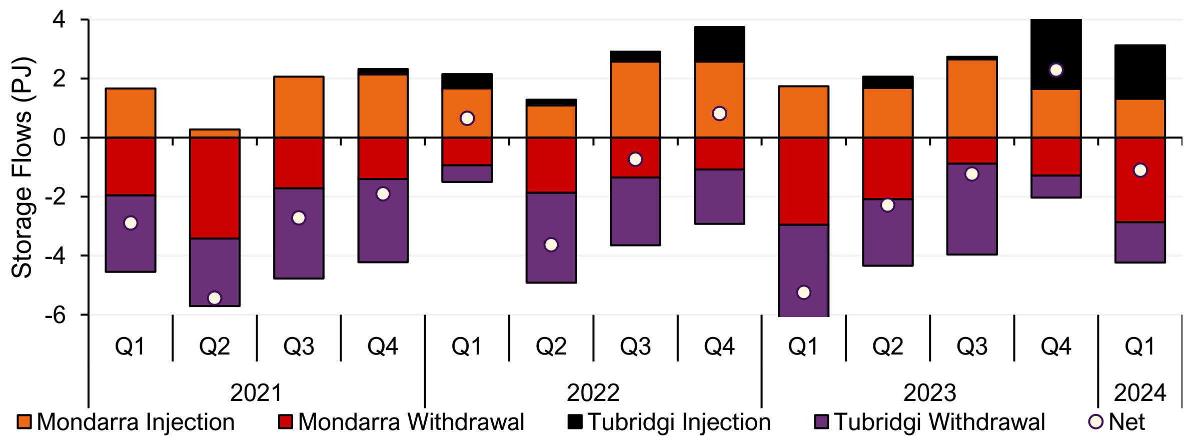


2.7.3 Storage facility behaviour

The net flow of gas was a net withdrawal of 1.1 PJ from storage, following a net injection the previous quarter. Compared to Q1 2023, this was a 4.1 PJ decrease in withdrawal (Figure 101).

Figure 101 Storage flows in Q1 2024 returned to a net withdrawal

WA gas storage facility injections and withdrawals – Q1 2021 to Q1 2024



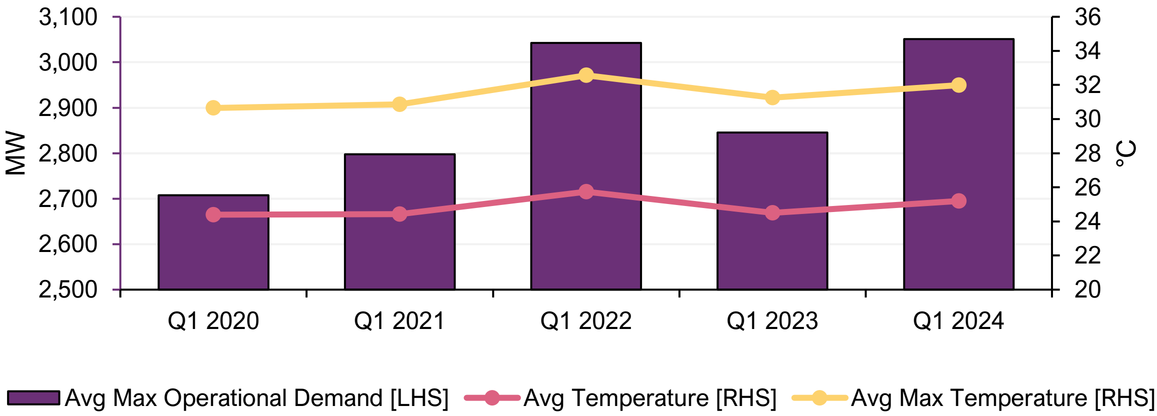
3 WEM market dynamics

3.1 Weather observations and electricity demand

Q1 2024 was characterised by an exceptionally warm February for the Perth Metro area; the mean daily maximum of 34.6°C was an equal highest record for February and 3°C higher than the long-term average. This included seven days above 40°C – in comparison, there were no days above 40°C observed in Q1 2023. January and March were also above average, experiencing mean maximum temperatures of 0.7°C and 0.6°C above the long-term average[37], respectively. Overall, this resulted in the average maximum temperature for Q1 2024 being 32°C, an increase of 0.7°C compared to Q1 2023. As Figure 102 indicates, this resulted in the average maximum demand for the quarter increasing 206 MW compared to Q1 2023, to 3,051 MW.

Figure 102 High temperatures resulted in record high maximum operational demands

Average of maximum daily operational demands with average temperature and average maximum temperature – Q1s



Q1 2024 experienced seven of the 10 highest maximum operational demands of all time[38], driven by high temperatures throughout the quarter. Demand reduction, in the form of Demand Side Programmes (DSP) and Supplementary Reserve Capacity (SRC), was activated on 14 occasions in the quarter.

A new maximum operational demand record of 4,233 MW occurred on Sunday 18 February 2024 during the 17:55 interval (Figure 103), an increase from the previous record of 4,040 MW from Q4 2023. This was driven by high temperatures (temperatures measured 39.6°C at 18:00 with a daily maximum of 43°C), which occurred during a heatwave from 17 to 21 February 2024. This is especially notable as high demands typically occur on weekdays. During the peak demand interval:

- Renewable penetration was measured at 9.2% of total average underlying demand. This was largely driven by wind generation, providing 203 MW.

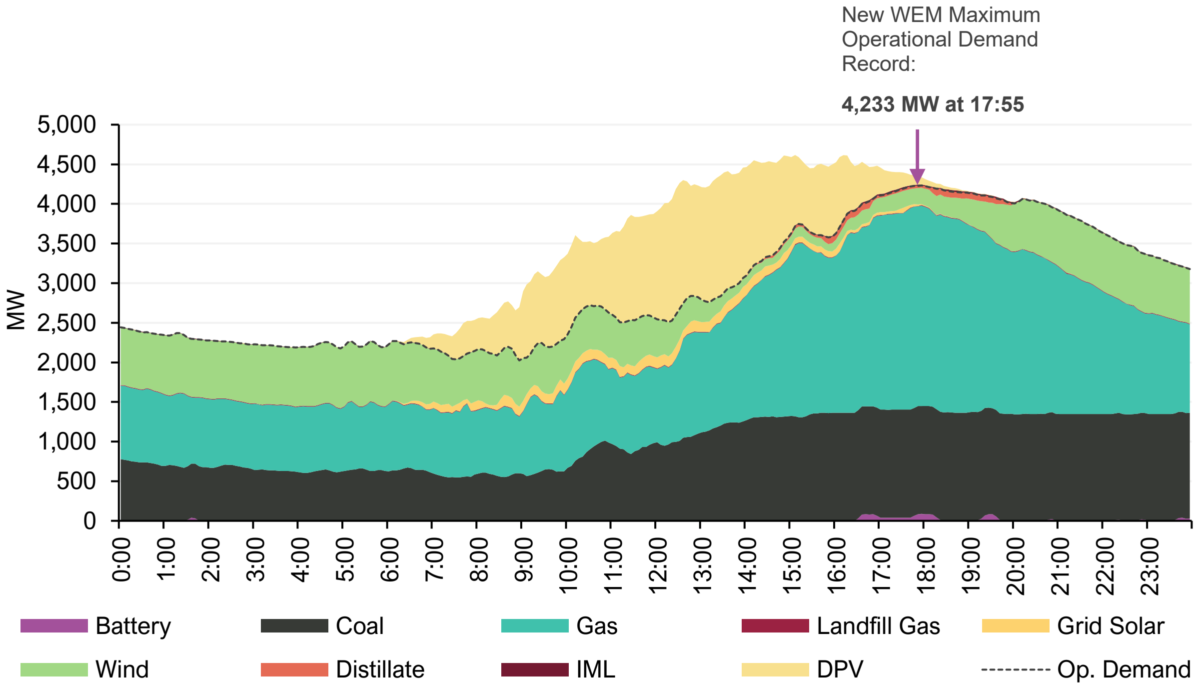
[37] http://www.bom.gov.au/climate/current/statement_archives.shtml?region=wa&period=month

[38] As measured by Average Operational Demand, which is defined as the average total injection (sent out, MW) from all registered Facilities in the WEM over a Dispatch Interval (5-minute period) based on non-loss adjusted SCADA. Note that this metric is distinct from Operational Demand as defined in the WEM Rules, which is an instantaneous, end of interval measurement used for dispatch purposes. Comparisons between average operational demand records before and after New WEM Commence (1 October 2023) are approximate, due to measurements being in 30-minute intervals prior to New WEM and 5-minute intervals post New WEM.

- The largest contributing fuel type was gas, at 2,529 MW (58.3% of total average underlying demand).
- Approximately 125 MW of demand reduction was activated through SRC.

Figure 103 All-time WEM maximum average operational demand recorded: 4,233 MW on 18 February 2024

18 February 2024, 5-Minute Average Generation by Fuel Type and Operational Demand (MW)



3.1.1 High demand led to tight operational conditions

Hot weather and high electricity demand resulted in several periods of tight operational conditions in the SWIS during the quarter. In Q1 2024, AEMO forecast LOR conditions on 15 occasions and 10 actual LOR events occurred. This compares to one forecast and no actual LOR events in Q1 2023.

In anticipation of tight conditions over summer 2023-24, during 2023 AEMO procured approximately 160 MW of SRC to provide additional capacity for the period from 1 December 2023 to 1 April 2024. As noted above, this SRC was dispatched on 14 occasions, along with DSPs procured via the WEM Reserve Capacity Mechanism, and on some occasions, additional generation and demand reduction was also provided by off-market facilities connected to the SWIS, to ensure secure and reliable power supplies for consumers.

3.2 Electricity generation

3.2.1 Change in fuel mix

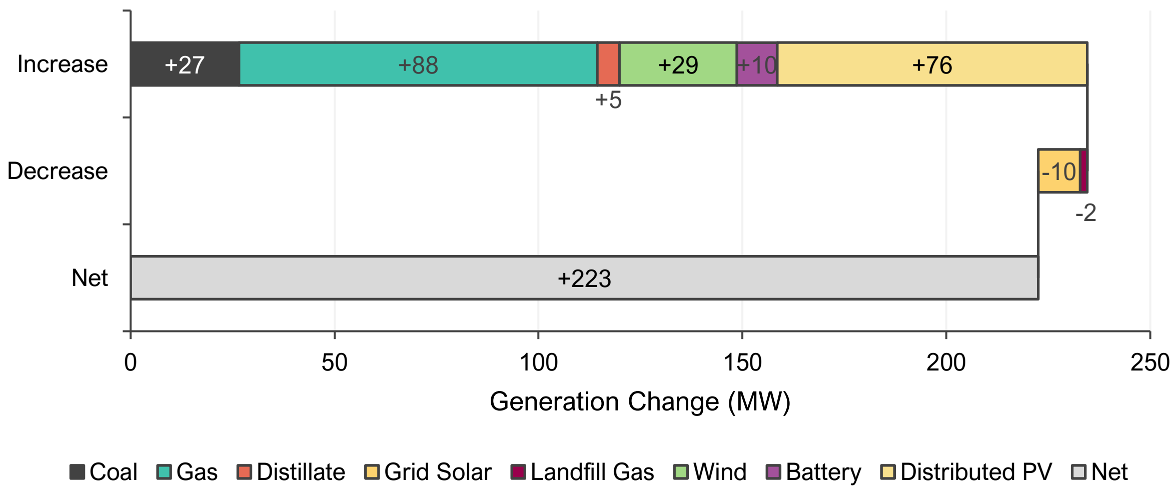
Total average generation output was 223 MW higher in Q1 2024 compared to the same quarter prior year, with an average demand for the quarter of 2,735 MW, driven by overall increases in demand (see Section 3.1). This increase was met by most fuel types, except landfill gas and grid-scale solar (Figure 104):

- Average generation from wind and distributed PV was driven by increased capacity, including Flat Rocks Wind Farm, which was registered on 23 November 2023 with a system size of 75.6 MW.

- Numerous high demand and LOR events throughout the quarter (see Section 3.1) required increased usage of peaking generation (gas and distillate).
- Increases in average gas and coal generation were there to meet the remaining average demand increases, and also driven by increased availability of these fuel types (see Section 3.4.1).

Figure 104 Decrease in grid-scale solar and landfill gas more than offset by increases in all other generation

Change in quarterly average generation – Q1 2023 vs Q1 2024



Compared to Q1 2023, distributed PV and gas generation accounted for a larger share of the fuel mix in Q1 2024, with grid-scale solar and wind generation providing a lower percentage contribution (Table 9).

Table 9 WEM fuel mix Q1 2023 and Q1 2024

Quarter	Coal	Gas	Distillate	Grid solar	Landfill gas	Wind	Battery	Distributed PV
Q1 2023	31.8%	29.6%	0.0%	2.2%	0.4%	18.0%	0.0%	18.0%
Q1 2024	30.2%	30.4%	0.2%	1.6%	0.3%	17.5%	0.4%	19.3%
Change (pp)	-1.6%	0.8%	0.2%	-0.6%	-0.1%	-0.5%	0.4%	1.3%

3.2.2 Renewable penetration

Renewable penetration increased to 39.1% of the overall generation fuel mix, an 0.5 pp increase compared to Q1 2023 (Figure 105).

The main driver was an increase in distributed PV installed capacity resulting in a penetration of 19.3% (1.3 pp increase compared to Q1 2023) and the Kwinana Battery Energy Storage System (KBESS), which registered on 26 April 2023, which contributed 0.4% to the total. While wind increased its overall generation (as seen in Section 3.2.1), it grew proportionately less than overall generation and therefore decreased to 17.5% penetration (0.5 pp decrease compared to Q1 2023), mitigating some of the increase due to distributed PV and the KBESS.

Figure 105 Renewable penetration increased to 39.1% driven by distributed PV installed capacity

Change in quarterly average renewable penetration– Q1 2020 to Q1 2024

	Q1 2020	Q1 2021	Q1 2022	Q1 2023	Q1 2024
Wind	11.1%	19.4%	18.9%	18.0%	17.5%
DPV	9.2%	12.8%	14.9%	18.0%	19.3%
Grid Solar	0.2%	2.2%	2.1%	2.2%	1.6%
Landfill Gas	0.5%	0.5%	0.4%	0.4%	0.3%
Battery	0.0%	0.0%	0.0%	0.0%	0.4%
Total	21.1%	34.9%	36.2%	38.6%	39.1%

Battery Landfill Gas Grid Solar DPV Wind

3.2.3 Intermittent generation forecasts

Between Q4 2023 and Q1 2024, inaccuracies in the Unconstrained Injection Forecast (UIF)[39], submitted by Market Participants for intermittent generators, increased on average across forecast horizons, from between 75-82 MW in Q4 to 82-86 MW in Q1. This can be seen in Table 10, which shows the mean absolute error of UIF, as compared with their actual unconstrained generation potential[40]. Comparisons between forecast horizons show marginal improvements in mean forecast accuracy between 24-hour to 30-minute forecast horizons.

Table 10 Unconstrained Injection Forecasts, mean absolute error for 30-minute, 2-hour, and 24-hour horizons

Forecast horizon	Mean absolute error (MW)	
	Q4 2023	Q1 2024
30 minutes	75	83
2 hours	76	82
24 hours	82	86

Intermittent generation forecasts trended more toward under predicting injection; see Figure 106, which shows larger negative forecast errors in Q1 2024 than the previous quarter. Figure 106 also shows larger forecast errors observed in the 30-minute forecast horizon (for Q1 2024) compared with the 24-hour and 2-hour horizons, despite the mean absolute error being lower for the 30 minute horizon (as shown in Table 10).

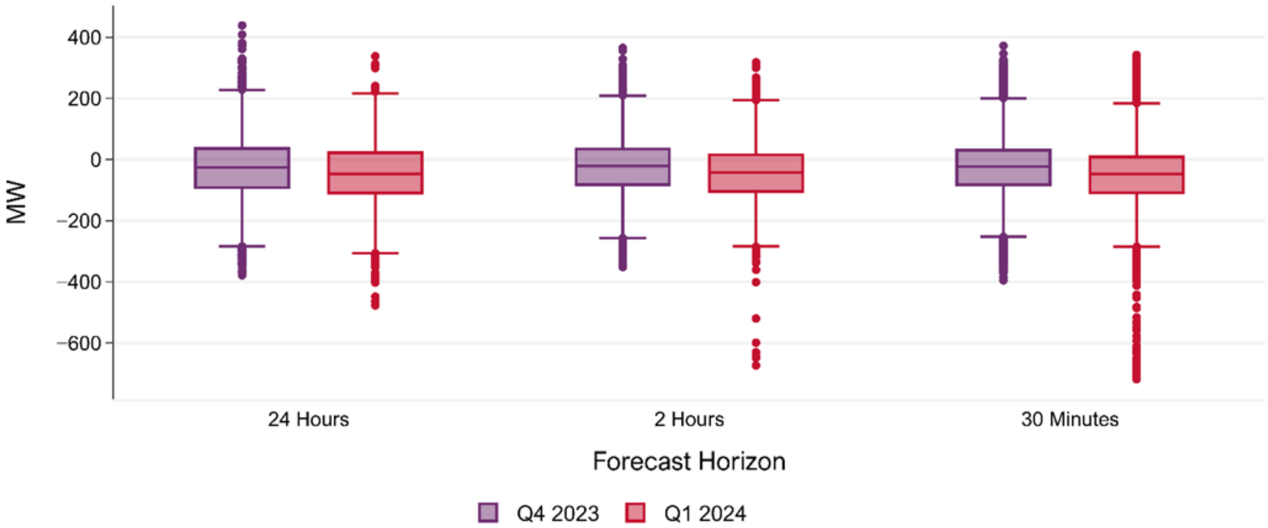
Under-forecasting of UIF generally results in upwards pressure on forecast Energy Market Clearing Price in the forecast horizon. Some inaccuracy is expected due to the intermittent nature of these Facilities' injection potential.

[39] The expected MW level of Injection at the end of a Dispatch Interval for a Semi-Scheduled Facility or Non-Scheduled Facility as submitted to AEMO in a Real-Time Market Submission, assuming that the Facility will not be subject to a Dispatch Instruction or direction from AEMO that limits its Injection, and allowing for expected conditions, commitment and control intentions and the effect of any Outages that have not been rejected for the Facility.

[40] Unconstrained generation potential is measures in real-time via the SCADA system, and represents the Facility's best estimate of MW available to export if there were no active MW setpoints limiting the output.

Figure 106 Intermittent generation forecasts trended more toward under-forecasting generation since the previous quarter

Intermittent Unconstrained Injection Forecast accuracy: 24 Hour, 2 Hour, and 30 Minute horizons

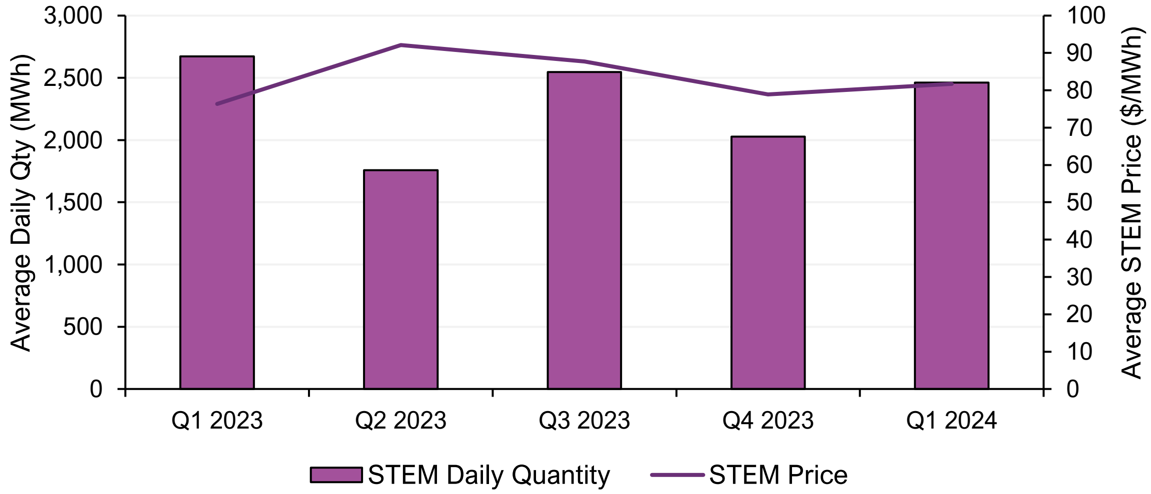


3.3 Short Term Energy Market

During Q1 2024 the average prices and quantities traded in STEM were consistent with previous quarters and trends in the Balancing (Q3 2023 and prior) and Real Time Markets (Q4 2023 and later) (Figure 107).

Figure 107 Average STEM prices and quantities are consistent with recent quarters

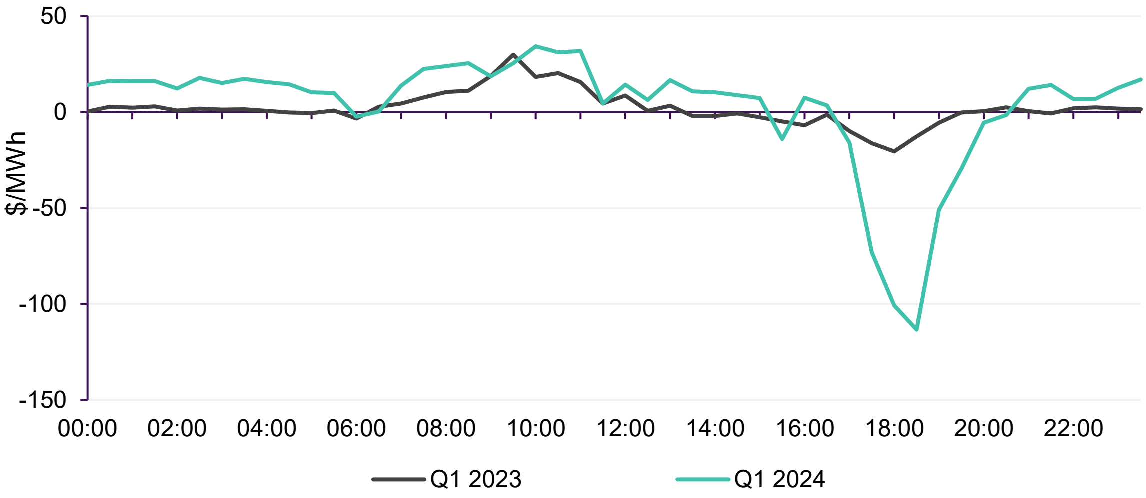
Average STEM prices ($/MWh) and daily quantities (MWh) per quarter



The price differences between the STEM and the Balancing Price (Q1 2023) and Reference Trading Price (Q1 2024), with positive values representing a higher STEM price, follow similar patterns through a trading day (Figure 108). STEM prices are, on average, similar or higher during times of lower operational demand such as overnight and during the day. During the evening peak the STEM price is, on average, lower than the Balancing or Reference Trading Price. This represents the difference between the forward price and actual price and premium paid or accepted for certainty. This trend has become more pronounced in Q1 2024, with average differences in prices increasing while following the same directional trends through the different times of day.

Figure 108 Daily trend between STEM and Balancing/Referring Trading Prices became more pronounced

Average difference between STEM and Balancing (2023) and Reference Trading Price (2024) for a Trading Interval



3.4 WEM prices

3.4.1 Real-Time Market price dynamics

The average Final Reference Trading Price in Q1 2024 was $78.49/MWh, an increase of 5% in comparison to the average Balancing Price in Q1 2023, but a 6% decrease compared to Q4 2023 (Figure 109). A key driver of the increase compared to Q1 2023 was higher operational demand (refer to Section 3.1)[41]. The average Reference Trading Price decreased by $5.17 relative to Q4 2023; this can be attributed to quantities of both coal and gas offered in the Real-Time Market:

- Average coal quantities offered increased, seeing a rightward shift of the average supply curve and an additional 159 MW of generation being offered at the floor price compared with the previous quarter (Figure 110).
- There was a shift of the average gas-fired generation supply curve to the right, from the $110/MWh price band and above. This resulted in additional lower-cost gas-fired generation being available to the market during higher demand periods, putting downwards pressure on the energy market clearing price compared to the previous quarter (Figure 111).

[41] Note, this comparison is between pre-New WEM Commencement (Balancing Price) and post-New WEM Commencement (Reference Trading Price); New WEM involved the introduction of Security Constrained Economic Dispatch and other significant changes to the market structure, potentially driving further changes in price outcomes compared with old WEM.

Figure 109 Balancing and Real Time Energy Prices decreased from Q4 2023

Quarterly Average Prices from Q1 2023 to Q1 2024

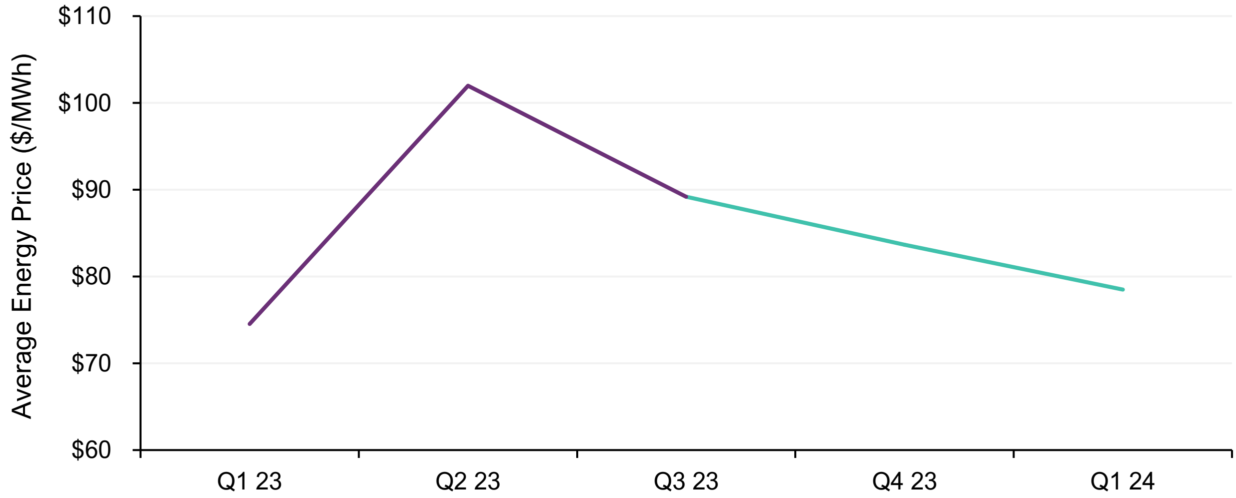


Figure 110 Increase in average quantities offered in all price brackets from coal generators

Average total coal generation supply curve, Q4 2023 to Q1 2024

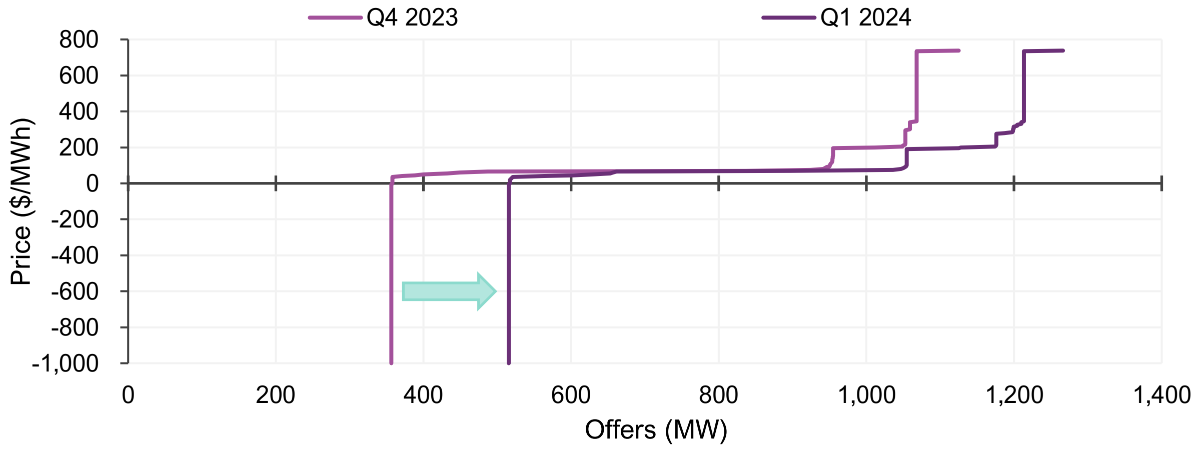
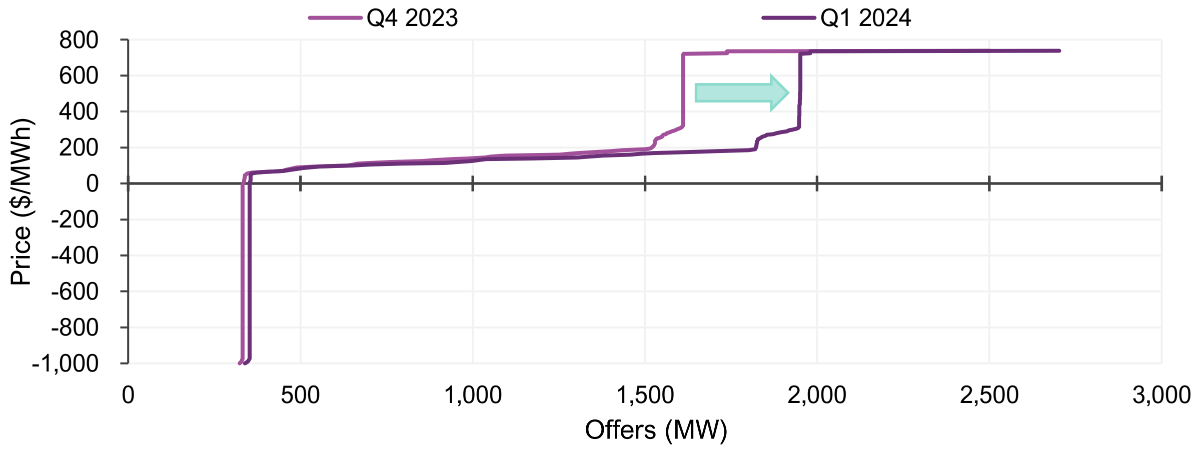


Figure 111 Increase in average quantities offered at $110/MWh and above from gas generators

Average total gas generation supply curve, Q4 2023 to Q1 2024

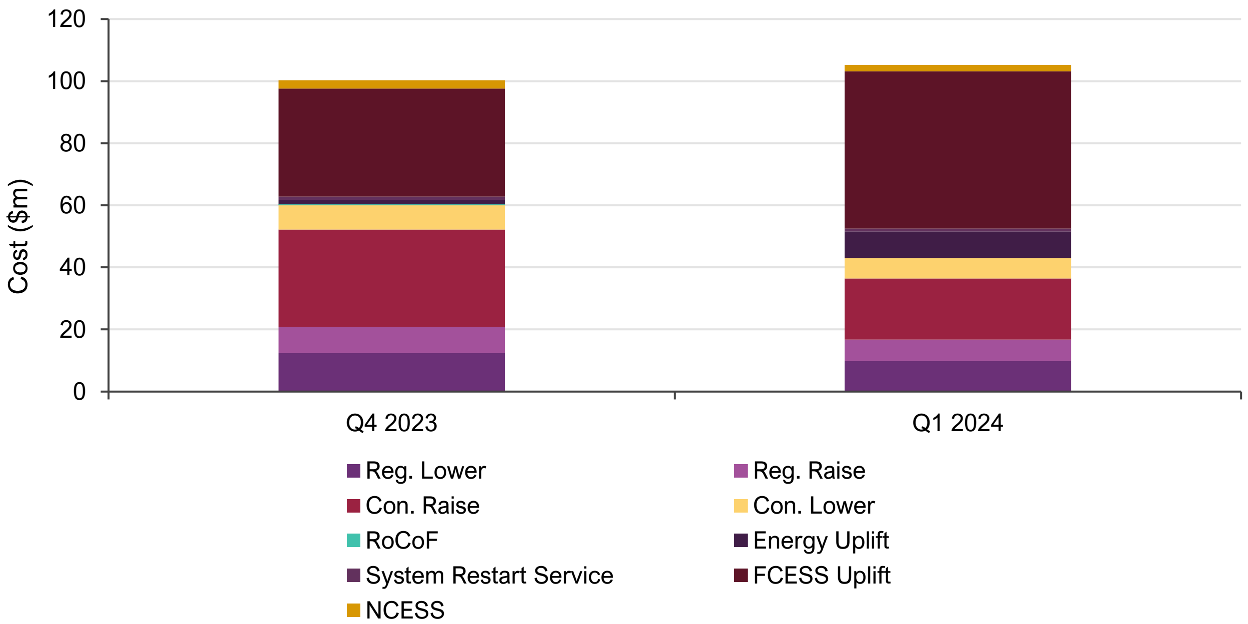


3.4.2 Essential System Services (ESS) costs

The total cost of ESS and Uplift in Q1 2024 increased by $5.0 million compared to Q4 2023 (Figure 112).

Figure 112 Total costs for Essential System Services Increased compared to Q4 2023

Total Costs ESS and Uplift Q4 2023 to Q1 2024



This was primarily driven by outcomes in both Energy and Frequency Co-Optimised Essential System Services (FCESS) Uplift payments. In contrast, each Regulation and Contingency service saw a decrease in total costs compared to the previous quarter:

- Contingency Raise and Contingency Lower combined accounted for $26.3 million of total ESS and Uplift costs over the quarter, down from $39.3 million in Q4 2023. This was primarily driven by a decrease in average prices in both markets in Q1 2024, with a 35% decrease in the average Contingency Raise price, and a 19% decrease for Contingency Lower.
- The cost of Regulation Raise and Lower in Q1 2024 decreased by 19% and 20% respectively compared to Q4 2023. Similar to outcomes in the Contingency Raise and Contingency Lower markets, this was driven by lower prices in each service, with both markets seeing a $7.5/MW/h decrease in average prices compared to last quarter.
- Rate of Change of Frequency (RoCoF) Control Service had a total cost of only $8.41 this quarter, compared to $0.2 million in Q4 2023 which had been driven almost exclusively by a single Dispatch Interval in which the Market Service cleared at $300/MWs (dollars per megawatt second). This quarter, the service cleared at $0.01/MWs in a single Dispatch Interval, and $0.00/MWs in all others.
- Energy Uplift payments totalled $8.5 million this quarter, roughly five times the cost in Q4 2023. The majority of these payments were driven by high operational demand. For example, Energy Uplift costs over the heatwave conditions that occurred between 17 February 2024 and 21 February 2024 were $2.9 million.
- FCESS Uplift accounted for close to half of total ESS and Uplift costs this quarter, and increased by 45% compared to Q4 2023. FCESS Uplift payments are likely to be higher when Final Energy Market Clearing Prices

are lower, representing greater enablement losses for facilities when dispatched for ESS. Therefore this outcome can be partly explained by a decrease in average Real-Time Energy Prices compared to Q4 2023.

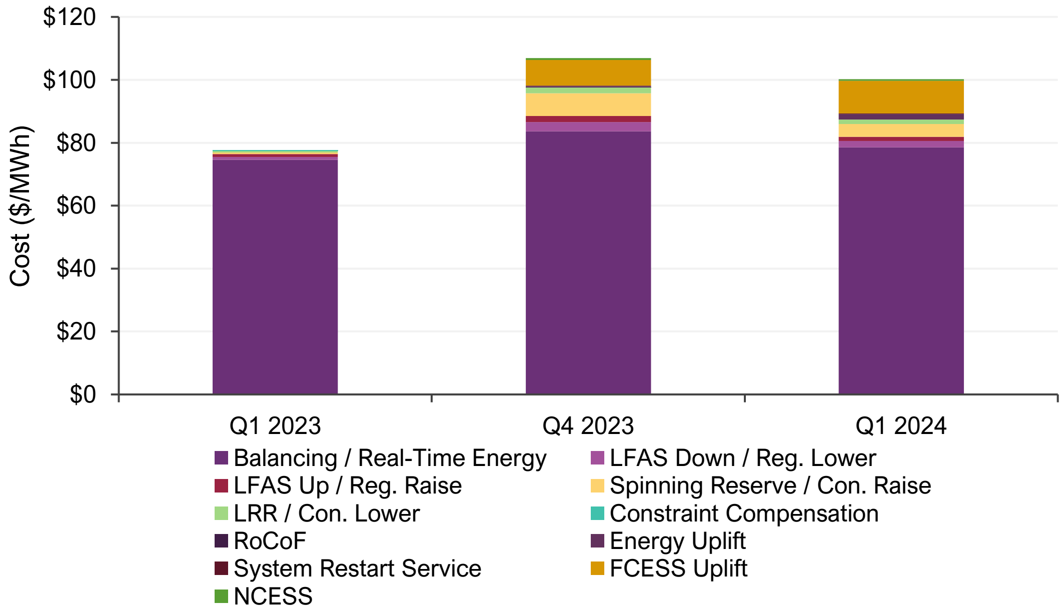
3.4.3 Real-Time Market costs

Figure 113 presents Energy and ESS costs as a price-per-MWh normalised by total energy consumed[42], enabling some comparison of costs between new and previous markets. However, given this is a new market and system, WEM outcomes are still stabilising as system performance and participant understanding improves. Therefore, more time and data are required before conclusions can be drawn around the drivers, dynamics and trends of the new market compared to the old.

The total cost of the Real-Time Market (Energy and ESS) rose from $77.64/MWh in Q1 2023, to $100.15/MWh in Q1 2024, an increase of 29%. This was driven by an increase of $3.96 in the average Energy price and an additional $18.55/MWh for ESS compared to Ancillary Services (AS). However, compared to Q4 2023 which represented the first three months of the new market, total costs decreased by $6.72/MWh. In particular, the average costs of Energy and Contingency Raise decreased by $5.17 and $3.20 respectively. Note that these costs do not include Reserve Capacity or Supplementary Reserve Capacity (SRC).

Figure 113 Total cost of Energy and ESS normalised per MWh

Normalised Energy and AS/ESS costs per MWh consumed in the WEM



42 To calculate a dollar per MWh of energy consumed, AEMO divided the total segment cost by total gross consumption in the WEM, calculated as:

- For the new market: the sum of CCQ_P_I
- For the old market: the sum of (MSNDL_P_I - ABSLOAD_P_I)/2 + min(MS_F_I of Registered Facilities, 0).

Capacity costs were excluded from this calculation.

4 Reforms delivered

AEMO, with government and industry, is delivering several energy market reforms. The reforms provide for changes to key elements of Australia's electricity and gas market design to facilitate a transition towards a modern energy system, capable of meeting the evolving wants and needs of consumers, as well as enabling the continued provision of the full range of services necessary to deliver a secure, reliable and lower emissions system at least cost.

Table 11 provides a brief description of the market settlement and transfer solutions (MSATS) reform delivered in Q1 2024.

Table 11 MSAT reform delivered in Q1 2024

Reform initiative	Description	Reform delivered
Metering Exemptions (part of MSATS Standing Data Review)	AEMO has implemented the third and final release as part of the MSATS Standing Data Review. This release saw the addition of Meter Malfunction Exemption Number (the exemption number granted by AEMO when a meter malfunction exemption is granted) and Meter Malfunction Exemption Expiry Date (the end date of the malfunction exemption) fields in MSATS as well as automation of the metering installation exemption process. These changes make it easier for Metering Coordinators to communicate with AEMO when issues arise and makes the process more transparent for all by sharing exemption data with those who need it. Reference: https://aemo.com.au/consultations/current-and-closed-consultations/metering-installation-exemption-automation-consultation	March 2023

In addition to this reform, work continues to progress on the next wave of initiatives set for release later in 2024. Table 12 below provides a brief description of those initiatives to be delivered in Q2 and Q3 2024.

Table 12 Upcoming reforms Q2 - Q3 2024

Reform initiative	Description	Reform to be delivered
Integrating Energy Storage Systems (IESS)	AEMO and industry continue to collaborate on the delivery of the third and fourth releases under the IESS project set to go-live in early June 2024. These two releases represent the final releases for the IESS project and provide for significant changes to the calculation method to be used for Non-Energy Cost Recovery, as well as the introduction of the Integrated Resource Provider (IRP) participant type and Bidirectional unit (BDU) bidding and dispatch. Reference: https://aemo.com.au/en/initiatives/major-programs/integrating-energy-storage-systems-project	June 2024
Retail Market Improvements (Net System Load Profile, Metering Substitutions)	As part of the ongoing suite of Retail Market Improvement initiatives, work continues to progress on several changes including: • September 2024 – introduction of a preferred longer-term Net System Load Profile (NSLP) Methodology providing for a more indicative NSLP shape supporting critical market settlements eliminating energy volume spikes in profile reads, and • November 2024 – implementation of various Substitution Type and Reason code changes associated with small market interval metering providing for greater insights, improved customer communication and support and more efficient processes including introduction of seven new substitution types; the obsoletion of substitution type 16; and the addition of 10 new Reason Codes. Reference: https://aemo.com.au/consultations/current-and-closed-consultations/july-2023-retail-electricity-market-procedures-consultation	September and November 2024

List of tables and figures

Tables

Figures

Abbreviations

Abbreviation	Expanded term
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
ASX	Australian Securities Exchange
BESS	Battery energy storage system
CGP	Carpentaria Gas Pipeline
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EOI	End of interval
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
FCESS	Frequency Co-Optimised Essential System Services
GJ	Gigajoule
GWh	Gigawatt hours
GLNG	Gladstone LNG
GSH	Gas Supply Hub
IRSR	Inter-regional settlement residue
LNG	Liquefied natural gas
MPC	Market price cap
MSP	Moomba to Sydney Pipeline
$MtCO_2$-e	Million tonnes of carbon dioxide equivalents
MW	Megawatts
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NCESS	Non-Co-optimised Essential System Service
NGP	Northern Gas Pipeline
pp	Percentage points
PJ	Petajoule
PV	Photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
RTM	Real Time Market
SCED	Security Constrained Economic Dispatch

Abbreviation	Expanded term
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TJ	Terajoule
UGS	Underground Storage Facility
VRE	Variable renewable energy
VNI	Victoria – New South Wales Interconnector
WEM	Wholesale Electricity Market
WEMDE	Wholesale Electricity Market Dispatch Engine
WDR	Wholesale demand response