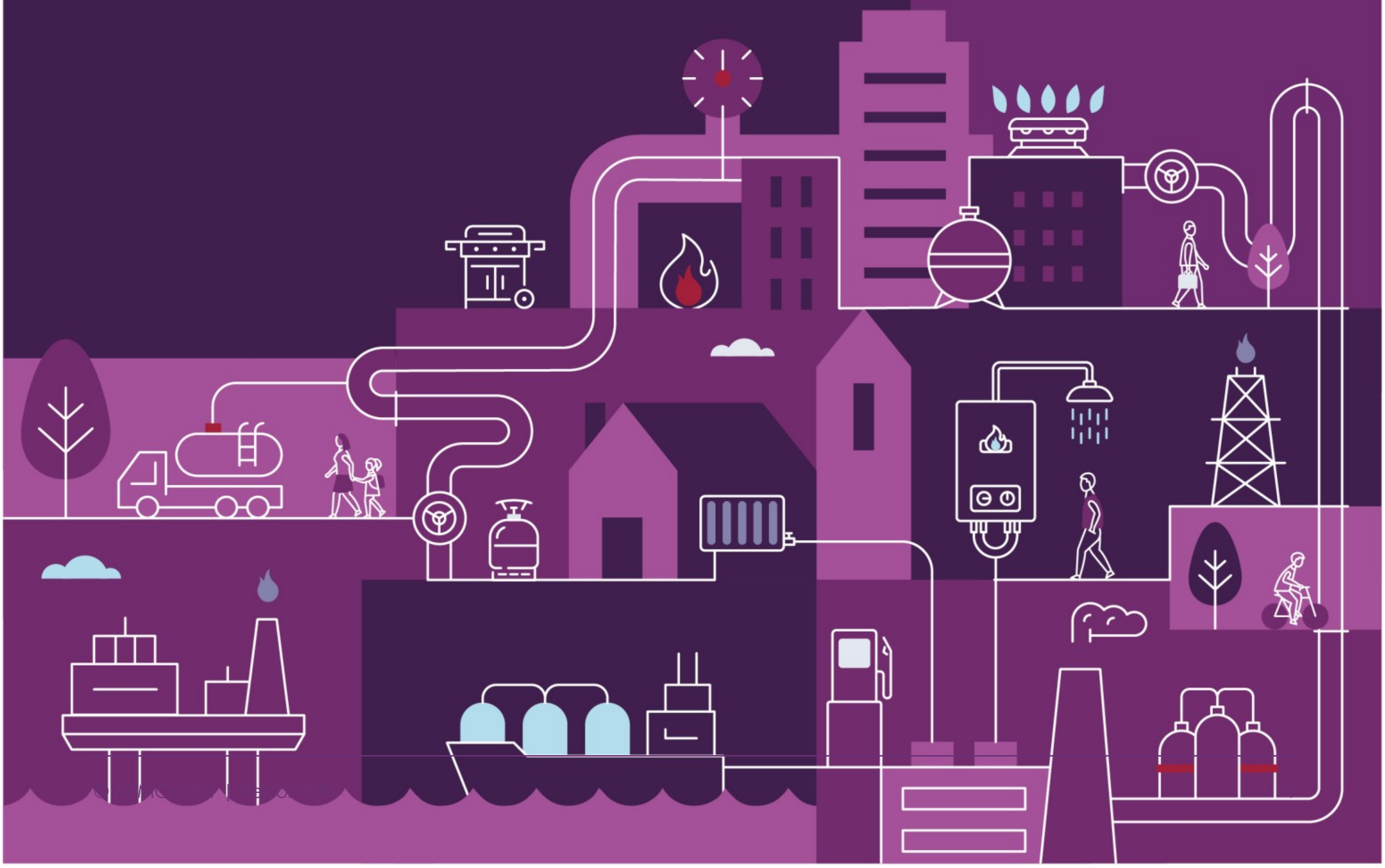
AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

Quarterly Energy Dynamics Q2 2025

July 2025



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

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 Q2 2025 (1 April to 30 June 2025). This quarterly report compares results for the quarter against other recent quarters, focusing on Q2 2024 and Q1 2025. 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; and
- the gas markets operating in Queensland, New South Wales, Victoria and South Australia.

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Executive summary

East coast electricity and gas highlights

High distributed PV output offset underlying demand growth

- Underlying demand across the National Electricity Market (NEM) regions averaged 24,118 megawatts (MW) in Q2 2025, up 156 MW (+0.7%) and a new high for a Q2. Distributed photovoltaic (PV) output reached new Q2 highs in all regions, up 307 MW (+15%) to 2,358 MW across the NEM, leading to a 151 MW (-0.7%) reduction in NEM operational demand to 21,760 MW.
- Near the start of the quarter, on 5 April 2025, new lows for Q2 minimum demand were set for the NEM overall (12,270 MW), New South Wales (3,594 MW) and Victoria (2,233 MW) as warm sunny conditions reduced underlying demand and supported high distributed PV output.
- Then late in the quarter, cold, wet and windy conditions on 25 June 2025 drove a new Q2, and winter, maximum operational demand record in Victoria of 8,818 MW in the half-hour ending 1800 hrs, up 490 MW (5.9%) from the previous Q2 record set last June.

Variable renewable energy (VRE) and battery output reached new highs

- VRE generation reached new Q2 highs, with wind generation increasing by 31% to average 3,492 MW and grid-scale solar generation increasing by 17% to average 1,662 MW. This drove a significant increase in the overall supply share met by renewables, with the quarterly average renewable contribution reaching 37.9%, up from 32.2% in Q2 2024, and reduced emissions intensity to a new Q2 low. Total emissions were 28.9 million tonnes of carbon dioxide equivalent ($MtCO_2$-e) in Q2 2025, down 5.9% from Q2 2024, and emissions intensity averaged 0.61 tonnes of carbon dioxide equivalent (tCO_2-e)/MWh, down 6.4%.
- Peak VRE output records were also set, and reset, during the quarter, driven by growing installed capacity and high wind periods. Wind generation set a new output record of 9,472 MW in the half hour ending 2230 hrs on 23 June 2025, 13% higher than the record before this quarter commenced (8,375 MW in Q2 2024). Combined wind and grid-scale solar output also reached an all-time high of 12,516 MW in the half hour ending 0930 hrs on 25 June 2025.
- Battery discharge increased to a new all-time high quarterly average of 162 MW, up 119% from Q2 2024 driven by the significant increase in battery capacity, with a total of 3,116 MW/6,415 MWh of new battery capacity entering the NEM since the end of Q2 2024. Peak battery discharge reached a new high of 1,756 MW in the half hour ending 1800 hrs on 12 June 2025. Battery charge also set a new high, reaching 1,221 MW in the half-hour ending 1300 hrs on 20 June 2025.

Gas-fired generation provided support on days of high NEM demand and low wind availability

- Gas-fired generation across the NEM decreased on a quarterly average basis, down 12% to average 1,502 MW, but within the quarter rose sharply from 1,040 MW in April to 2,157 MW in June as winter conditions set in. This rise was most evident in Victoria, which recorded its highest June average since 2007 at 533 MW after averaging only 29 MW in April.

- Across the east coast gas markets, gas demand for gas-fired generation reached new daily highs on those June days when cold winter conditions combined with low wind availability. East coast gas demand for gas-fired generation totalled 1,049 TJ on 26 June 2025, setting a new winter record and the fourth highest daily total on record for any time of year. Victorian gas demand for gas-fired generation also set a new winter record of 382 TJ on the same day.

Isolated periods of cold and still winter conditions increased NEM wholesale spot prices

- Wholesale spot prices averaged[1] $140 per megawatt hour (MWh) across all NEM regions in Q2 2025, 5% higher than Q2 2024's $133/MWh. The quarterly average price was strongly influenced by the onset of cold winter conditions in June, with prices averaging $93/MWh and $97/MWh in the relatively warm and sunny months of April and May, before rising to $232/MWh in June.
- Price volatility (spot prices above $300/MWh) contributed $37/MWh, or 26%, to the quarterly spot price average, with $32/MWh of this occurring on just three days in June. Cold and still conditions on these days increased heating demands and reduced wind generation, resulting in a greater reliance on gas-fired generation and batteries to meet peak demand. As a result, 12 June 2025 recorded the highest daily NEM-wide price since market start, and 26 June 2025 the fourth highest.

East coast gas prices ease compared to Q2 2024 as supply/demand balance eases

- East coast wholesale gas prices averaged $12.36 per gigajoule (GJ) for the quarter, lower than Q2 2024 which averaged $13.66/GJ.
- Gas demand decreased by 3% from Q2 2024 across all sectors, with AEMO markets demand falling by 7 petajoules (PJ), lower gas-fired generation (-3 PJ), and Queensland liquified natural gas (LNG) exports falling (-2 PJ). Continuing the trend observed in Q1 2025, Victoria experienced the largest market decrease, with continued reduction in industrial, commercial and residential demand.
- While projects associated with Queensland LNG exports reduced supply into the domestic market, Victorian production increased, with higher Otway Gas Plant Q2 production (+2.5 PJ), as well as the Orbost Gas Plant continuing to increase supply in Q2 (+1.4 PJ), while Longford production fell slightly (-0.3 PJ).
- Iona Underground Gas Storage (UGS) was heavily utilised in June to support higher gas-fired generation demand, and the last week of June recorded the highest seven-day drawdown for Iona storage inventory on record, coinciding with record winter daily gas-fired generation demand. Despite this, Iona storage inventory still finished the quarter 2.2 PJ higher than at the end of Q2 2024 due to starting June almost full.

[1] Calculated as the time-weighted average, which is the simple average of regional wholesale spot prices over each five-minute dispatch period over the quarter. The Australian Energy Regulator (AER) reports volume-weighted average spot prices, which are weighted using native regional demands.

Western Australia electricity and gas highlights

Cooler temperatures and batteries increase underlying demand, offset by more distributed PV

- Cooler temperatures in Q2 2025 compared to Q2 2024, combined with an increase in average battery charging of 51.8 MW (+469%) and organic demand growth resulted in an average underlying demand increase of 195 MW (+8.6%) compared with the same quarter last year.
- This increase in average underlying demand was partially offset by an 84.1 MW (+31.1%) increase to average estimated distributed PV generation and a 20.9 MW (+1,028%) increase to embedded generation. Overall, this resulted in average operational demand increasing by 87.4 MW (+4.4%) to 2,088 MW.

Renewable contributions increase in meeting energy demand, batteries dominate Frequency Co-Optimised Essential Systems Service (FCESS)

- The increase in distributed PV to represent 14.4% of underlying demand coupled with a 16.5% contribution of wind resulted in a Q2 high of 35.1% renewable contribution in Q2 2025. The Wholesale Electricity Market (WEM) also registered a new peak Q2 renewable contribution record of 78.8% on 21 April 2025 during the 12:20 interval.
- The increase in generation from renewable sources drove a reduction in emissions intensity compared to Q2 2024 by 5.5% to 0.525 tCO_2-e/MWh. This resulted in a reduction in overall emissions by 1.3% to 2.39 $MtCO_2$-e despite the 4.4% year on year increase in operational demand.
- For the first time in the WEM, batteries provided the majority of regulation and contingency FCESS markets, at 61% of enabled volume. Gas facilities provided 21%, down from 76% in Q2 2024. The Rate of Change of Frequency (RoCoF) control service market is still served only by gas and coal facilities. Gas provided 62.9% and coal 37.1% of the RoCoF market.

Energy market clearing prices increased, FCESS costs decreased

- The average energy price for Q2 2025 was $90.46/MWh, an increase of $11.67/MWh over Q2 2024, driven by a combination of increased operational demand and changes to the FCESS Uplift framework resulting in fewer committed facilities during the middle of the day. Notably, the daily energy price profile is demonstrably flatter than Q2 2024, as a consequence of batteries seeking to charge during lower priced periods and discharge during higher priced periods.
- Total ESS and Uplift costs fell to $34.2 million in Q2 2025, down $86.7 million (-72%) from $121.0 million in Q2 2024, driven by rule changes which reduced FCESS Uplift costs and increased competition which put downward pressure on FCESS enablement costs. On a MWh normalised basis this meant direct FCESS enablement costs were $4.41/MWh (-59%) and FCESS Uplift costs were $1.43/MWh (-91%).
- Overall, normalised WEM costs increased by $9.52/MWh on Q2 2024 to $147.78/MWh. This was primarily due to the increase in energy market costs (+$11.67/MWh), an increase in reserve capacity costs (+$12.22/MWh) and an increase in Non-Co-Optimised Essential System Services (NCESS) costs (+$5.20/MWh). This was offset by the reduction in FCESS Uplift (-$14.59/MWh) and FCESS enablement costs (-$6.24/MWh).

Q2 2025 saw a reduction both production and consumption of Western Australia domestic gas

- Western Australia's domestic gas consumption registered 94.3 PJ, which was a decrease of 4.6 PJ (-4.6%) compared to Q2 2024. Production was 105.9 PJ, a marginal decrease of 1.5 PJ (-1.4%) compared to Q2 2024. Storage continued its net withdrawal trend to record an increase of 4.3 PJ (+239%) net withdrawal compared to Q2 2024.

Contents

1 Weather

Q2 2025 was characterised by persistently warm and dry conditions across much of Australia (Figure 1), with notable variability introduced in June due to a series of cold fronts. April and May were dominated by above-average temperatures and below-average rainfall across the NEM states and Western Australia. Victoria recorded its warmest April on record, and temperatures were above the long-term average across Tasmania, most of New South Wales and South Australia, large parts of Western Australia and coastal parts of eastern Queensland across the autumn months.

June saw a shift in weather patterns with multiple cold fronts traversing southern Australia, bringing bursts of cooler air, widespread showers, and elevated wind speeds. Despite the frontal activity, temperatures remained above the long-term average across most of Australia, with Tasmania, South Australia and Western Australia recording some of their warmest June temperatures on record.

On a quarterly average basis, maximum temperatures were higher than the 10-year average in all capitals apart from Brisbane, ranging from 1.3°C higher in Adelaide to 0.2°C higher in Sydney (Figure 2). Maximum temperatures in Perth were 0.6°C lower compared to last year, with both April and May 2024 being exceptionally warm months.

Figure 1 Warmer than average temperatures across most of Australia

Q2 2025 mean temperature deciles for Australia

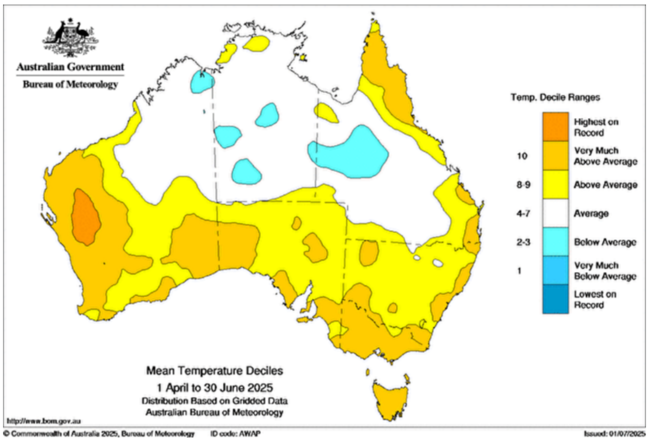
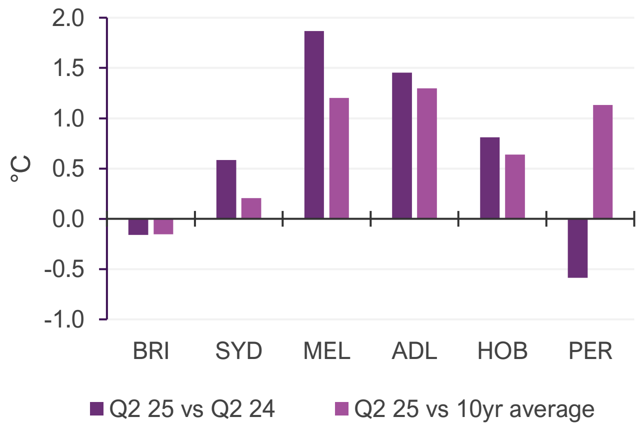


Figure 2 Significantly warmer than long-term average temperatures in southern capital cities

Average quarterly maximum temperature variance by capital city



Source: Bureau of Meteorology (BOM)

The warmer than average temperatures led to decreased heating requirements, as represented by heating degree days (HDDs)[2] in the southern NEM capitals. Compared to Q2 2024, HDDs fell by 18% in Melbourne, 15% in Adelaide, 10% in Sydney, and 4% in Hobart (Figure 3). In Perth, HDDs were higher in April and May, and marginally reduced in June, leading to a 28% increase in HDDs across the quarter. HDDs also increased in Brisbane, up 10%, with the increase driven by cooler weather during June.

[2] A "heating degree day" (HDD), which is based on the average daily temperature, is a measurement used as an indicator of outside temperature levels below what is considered a comfortable (base) temperature (18°C), where a higher HDD indicates that the weather is colder. HDD value is calculated as max (0, base temperature – average temperature).

Average wind speeds across Victoria, South Australia, New South Wales and Tasmania recovered from the low levels experienced over Q2 2024 (Figure 4). Victoria and South Australia experienced the largest increases in quarterly average wind speed, up by 14% and 11% from Q2 2024 levels. Increases were less significant in New South Wales (+4%) and Tasmania (+2%).

These dynamics led to an overall increase in quarterly wind generation across the NEM, with some particularly high-wind events leading to new wind generation records. However, there were also some isolated periods during the quarter where high-pressure fronts led to wind lulls, most noticeably during June (see Section 2.3.4).

Figure 3 Reduced heating requirements in southern NEM capitals and increased requirements in Perth

Change in monthly HDDs by capital city – Q2 2025 vs Q2 2024

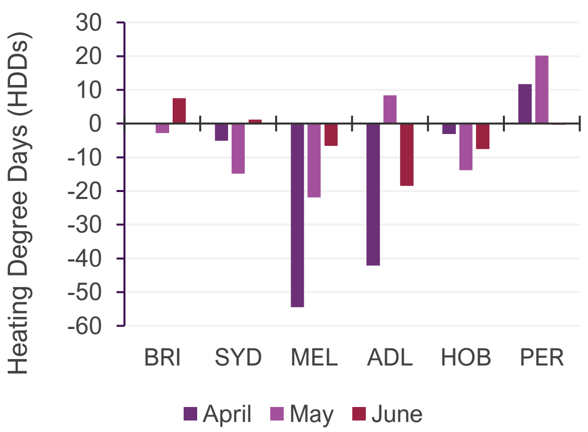
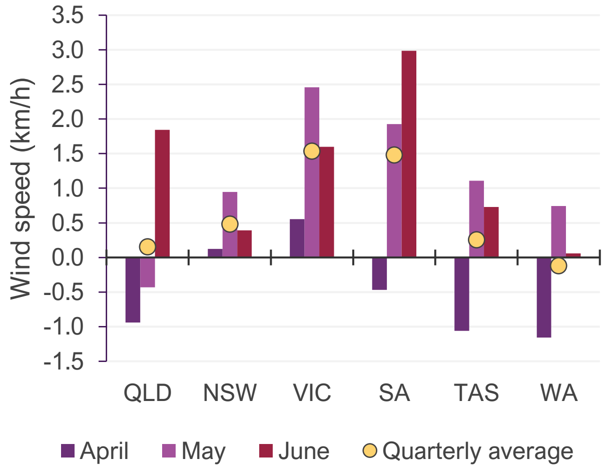


Figure 4 Significant increase in wind speed across southern NEM regions

Change in average wind speed by region[3]– Q2 2025 vs Q2 2024



[3] Wind speeds are calculated as the average of wind speed observations from all stations (capable of measuring wind speed) across each region.

2 NEM market dynamics

2.1 Electricity demand

In Q2 2025, NEM-wide underlying demand[4] averaged 24,118 MW, an increase of 156 MW (+0.7%) from Q2 2024 and a new high for a Q2 (Figure 5). This year-on-year growth in underlying demand occurred despite warmer temperatures across the quarter (see Section 1), reflecting broader trends in population growth, electrification of heating, increased use of electric vehicles and rising demand from data centres[5].

Sunny conditions over most of the quarter, and ongoing growth in installations, saw all regions reach new highs for Q2 distributed PV output, with NEM-wide distributed PV output increasing by 307 MW (+15%) to average 2,358 MW. This distributed PV output offset underlying demand growth across the daytime hours and led to an overall reduction in operational demand (Figure 6). NEM-wide operational[6] demand averaged 21,760 MW, a reduction of 151 MW (-0.7%) from Q2 2024.

Figure 5 Underlying demand reached new Q2 high, offset by distributed PV output

NEM average underlying and operational demand – Q2s

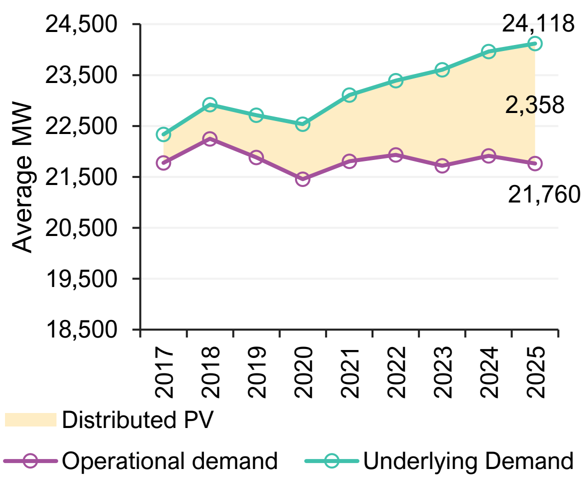
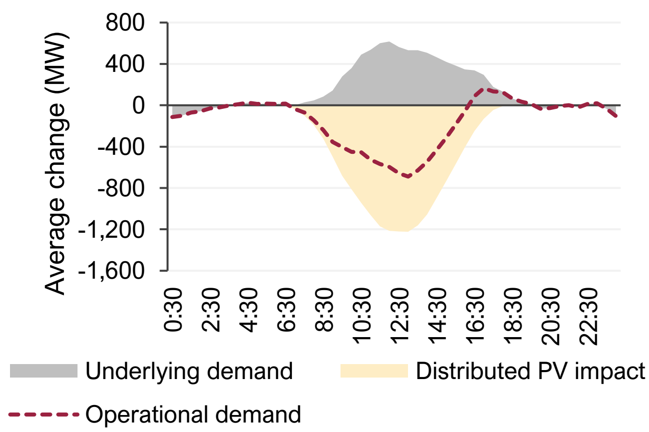


Figure 6 Record Q2 high distributed PV output reduced operational demand across the daytime hours

Average changes in NEM operational and underlying demand and distributed PV output – Q2 2025 vs Q2 2024



On a regional basis, underlying demand increased in New South Wales, Victoria and South Australia, but significant growth in distributed PV output saw operational demand decrease in all regions apart from South Australia (Figure 7).

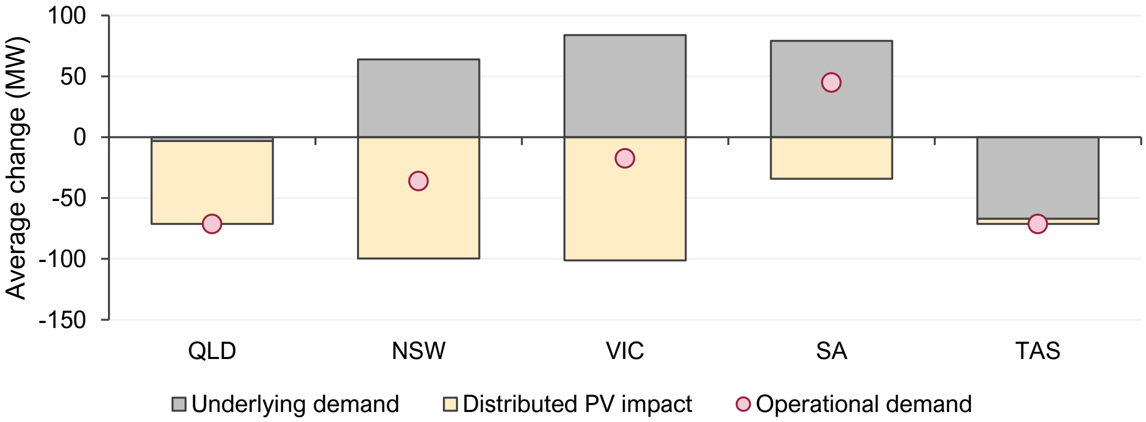
4 Underlying demand is calculated by adding estimated production from distributed PV to operational demand, to yield an estimate of total electricity generated.

5 Refer to AEMO's 2025 Input and Assumptions consultation for details on population, electrification, data centres and electric vehicle projections here: https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

6 Operational demand in a region is demand that is met by local scheduled generation, semi-scheduled generation, non-scheduled wind and solar generation of aggregate capacity >=30 MW, and by generation imports to the region, excluding the demand of local scheduled loads and including Wholesale Demand Response.

Figure 7 Operational demand reduced year-on-year in all regions apart from South Australia

Changes in average underlying and operational demand as well as distributed PV – Q2 2025 vs Q2 2024



Comparing Q2 2025 with Q2 2024:

- **Queensland's** underlying demand decreased marginally to average 6,867 MW, with higher June demand from cooler weather offset by mild conditions and reduced demand in April and May. Average distributed PV output rose 9% to 822 MW, with most of this growth occurring in April and May. Operational demand fell 71 MW (-1.2%) to average 6,045 MW, with declines across all hours except the evening peak.
- In **New South Wales**, average underlying demand rose 0.7% to 8,591 MW, but a 15% increase in distributed PV output (to an average of 775 MW) resulted in the region's lowest recorded Q2 operational demand average of 7,816 MW, down 36 MW (-0.5%). Higher distributed PV output reduced midday operational demand, offsetting underlying demand increases in the morning and evening periods.
- Underlying demand in **Victoria** increased by 1.5% to average 5,773 MW, with increases across all hours of the day. However, with Victoria recording the highest growth in distributed PV out of all NEM regions, at 27% to average 472 MW, operational demand decreased by 0.3% to 5,301 MW.
- **South Australia** was the only NEM region where both underlying and operational demand increased. Underlying demand grew by 4.9% to average 1,681 MW, representing a new Q2 high in underlying demand for the region. This increase was partly attributed to the Lonsdale desalination plant's operation in response to low reservoir levels in South Australia. Operational demand increased by 3.3% to average 1,422 MW with a 15% increase in distributed PV output (to an average of 259 MW), only partially offsetting the growth in underlying demand.
- **Tasmanian** underlying demand decreased by 5.3% to average 1,206 MW with the reduction mainly driven by lower industrial demand. Distributed PV output increased to 30 MW (+16%), and operational demand reduced by 5.7% to average 1,176 MW, with reductions across all hours of the day.

Maximum and minimum demands

In Q2 2025, NEM-wide **maximum operational demand** reached 32,681 MW in the half-hour ending 1830 hrs on 16 June 2025. This represented a 359 MW (+1.1%) increase from Q2 2024's maximum and was the highest for a Q2 since the standing Q2 record of 32,759 MW set back in 2007[7].

In Victoria, cold, wet and windy conditions on 25 June 2025 drove a new Q2, and winter, maximum operational demand record of 8,818 MW in the half-hour ending 1800 hrs, up 490 MW (5.9%) from the previous Q2 record set last June (Figure 8). Additionally, this was 206 MW (2%) higher than the previous winter record set last year on 15 July 2024, which in turn had broken a 17-year Victorian winter demand record of 8,351 MW set back on 17 July 2007.

New South Wales's maximum demand rose from Q2 2024, up 371 MW (+3.1%), but Queensland's reduced by 33 MW (-0.4%), South Australia's reduced by 34 MW (-1.3%) and Tasmania's reduced by 22 MW (-1.4%), with all regions' maximums occurring in June.

The NEM-wide **minimum operational demand** of 12,270 MW was recorded near the start of the quarter on 5 April 2025, during a period of low demands and high distributed PV output due to warm and sunny weather in south-eastern Australia. This was a new low for a Q2, 1,226 MW below (-9.1%) the previous low recorded in 2024. On the same day, New South Wales and Victoria also set new lows for Q2 minimum operational demand, at 3,594 MW and 2,233 MW respectively (Figure 9).

Figure 8 New winter maximum operational demand record in Victoria

Maximum operational demand for mainland regions – Q2s

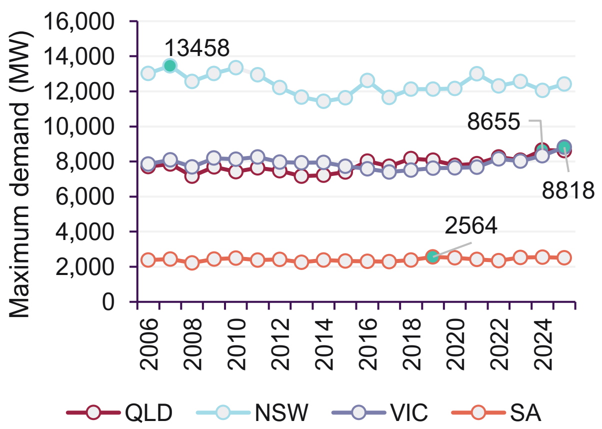
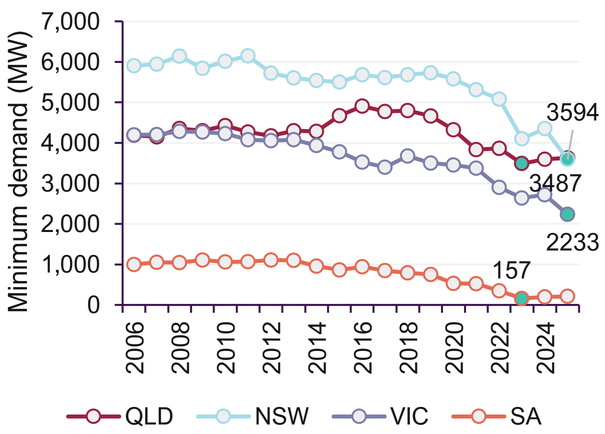


Figure 9 New South Wales and Victoria recorded new lows for Q2 minimum operational demand

Minimum operational demand for mainland regions – Q2s



Queensland demonstrated a wide range of demand conditions in two weeks in mid-June. The region's minimum operational demand for Q2 2025 of 3,626 MW was set at 1230 hrs on 8 June 2026, only 33 MW (+0.9%) above last year's Q2 low. This was driven by warmer weather and sunny conditions boosting distributed PV output, and lower Sunday demand.

[7] The start date for operational demand records in the NEM is 1 May 2006 to align with the connection of Tasmania to the mainland NEM via Basslink

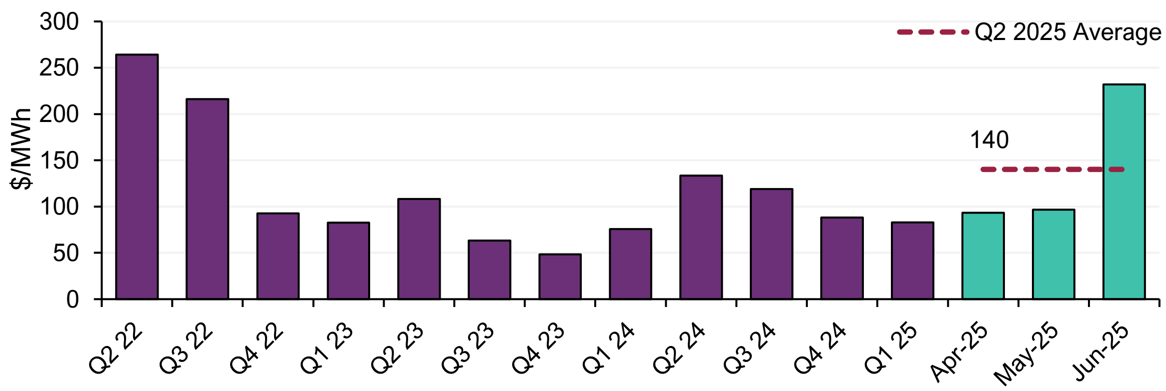
The next day, colder conditions swept in, with each weekday between 9 and 18 June 2025 recording maximum operational demands in the top 20 highest Q2 demands, with the quarter's maximum of 8,622 MW at 1900 hrs on 12 June 2025 being the second highest maximum operational demand recorded for a Q2. Also in this period, on 10 June, the intra-day demand swing in Queensland (the difference between the daily maximum and minimum demand) reached a new high for a Q2 at 4,303 MW.

2.2 Wholesale electricity prices

In Q2 2025, wholesale electricity prices averaged $140/MWh[8] across the NEM, an increase of 5% from $133/MWh in Q2 2024 (Figure 10). Relatively warm and sunny conditions during the autumn months of the quarter resulted in NEM-wide wholesale prices averaging $93/MWh and $97/MWh in April and May. However, colder conditions in June led to higher demands and periods of high-priced volatility, with NEM-wide wholesale spot prices averaging $232/MWh for the month.

Figure 10 Year-on-year increase (+5%) in NEM average wholesale spot prices

NEM average wholesale electricity spot prices – quarterly since Q2 2022



The energy component[9] of wholesale prices decreased in all regions, with the NEM-wide average energy price reducing from $121/MWh in Q2 2024 to $103/MWh (-15%) in Q2 2025 (Figure 11). The largest reductions were in the NEM southern regions, where low wind and rainfall conditions in Q2 2024 had previously driven energy prices upwards.

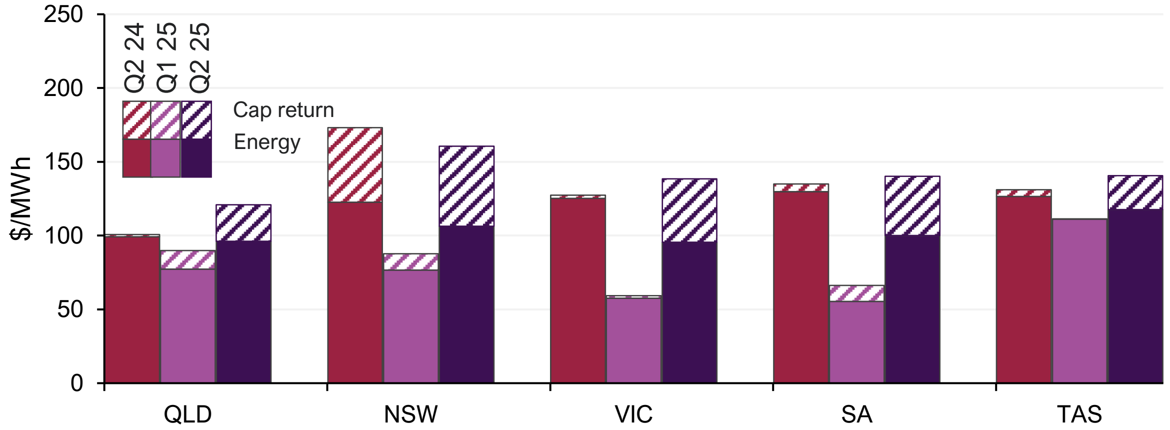
Price volatility increased in all regions, with the NEM-wide average cap return increasing from $13/MWh in Q2 2024 to $37/MWh (+191%) in Q2 2025. These increases were driven by a series of days in June (11, 12 and 26 June) where cold fronts followed by high-pressure systems caused low temperatures and reduced wind speeds. The total NEM-wide cap return accrued on these three June days was $32/MWh, representing over 85% of the quarter's total cap return, and 12 June 2025 experienced the highest NEM-wide daily average price since the NEM started.

[8] Time weighted average – simple average of regional wholesale electricity spot prices over each five-minute dispatch period over the quarter.

[9] The price analysis divides the average spot electricity price into two components: the **energy component**, which is the average spot price capped at $300/MWh, and the **cap return component (also referred to as volatility)**, which reflects the contribution to the quarterly average from any excess of spot prices above $300/MWh. Since the introduction of Five-Minute Settlement (5MS) on 1 October 2021, both energy prices and cap returns are calculated on a five-minute basis.

Figure 11 Volatility drove Q2 spot prices higher in all regions except New South Wales

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



By region:

- **Queensland** recorded the lowest average wholesale spot prices across the NEM at $121/MWh, despite the greatest year-on-year increase of $20/MWh (+20%) from Q2 2024. Queensland was the least impacted region during Q2 2024's wind and hydro drought, and energy prices remained relatively unchanged year-on-year, reducing by $3/MWh (-3.0%) to $96/MWh. The cap return component increased from just $1/MWh in Q2 2024 to $25/MWh this quarter, with $19/MWh accrued on 11-12 June.
- **New South Wales** was the only region to experience a year-on-year reduction in wholesale spot prices, averaging $161/MWh across Q2 2025, down $12.5/MWh (-7.2%) but remained the NEM's highest-priced region. Reduced operational demand and increased VRE output in the region contributed to a 13% reduction in energy prices to $106/MWh. The cap return component increased marginally from its Q2 2024 level of $50/MWh (elevated due to market events in May 2024 which led to a period of Administered Pricing) to $54/MWh, with $40/MWh accrued on 11-12 and 26 June.
- **Victoria's** wholesale spot prices averaged $138/MWh, up $11/MWh (+8.7%) from Q2 2024. This increase was driven by the cap return component, which increased from $2/MWh in Q2 2024 to $43/MWh, driven by the events on 11-12 and 26 June, which contributed $40/MWh to this total. As in New South Wales, lower operational demand and increased VRE output, in particular wind generation, reduced energy prices by $30/MWh (-24%) from Q2 2024 to average $95/MWh this quarter.
- Wholesale spot prices in **South Australia** averaged $140/MWh, up $5/MWh (+3.9%) from those in Q2 2024, also driven by the cap return component. This rose from $5/MWh in Q2 2024 to $40/MWh, with the events on 11-12 and 26 June contributing $38/MWh. Despite an increase in operational demand, increased wind generation helped reduce energy prices by $30/MWh (-23%) to average $100/MWh across the quarter.
- **Tasmanian** wholesale spot prices averaged $141/MWh, $10/MWh (+7.4%) higher than Q2 2024's prices. Despite the lower operational demand, energy prices only decreased by $9/MWh (-7.1%), with Tasmanian hydro generation at its lowest level since 2008. The cap return component increased from $4/MWh in Q2 2024 to $23/MWh this quarter, with $15/MWh accruing on the 11-12 June.

On a time-of-day basis, the increase in NEM wholesale prices was driven by the evening peak hours, when increased operational demand, and isolated periods of low wind output drove high priced volatility during June

(Figure 12). Warmer temperatures and increased wind generation this quarter saw lower prices overnight and in the morning peak when compared to Q2 2024, while greater distributed PV and VRE output lowered prices across the daytime hours.

The time-of-day energy price profiles for Q2 2025, show that price separation was most evident between Tasmania and mainland regions during daytime hours when Basslink's import capacity was often fully utilised (Figure 13). Price separation was also observed between the southern and northern NEM regions around the evening peak when system normal export limits on the Victoria – New South Wales Interconnector (VNI) were frequently reached (see Section 2.4).

Figure 12 NEM average prices increased during the evening peak and decreased in other hours

NEM average spot price by time of day – Q2 2025 vs Q2 2024

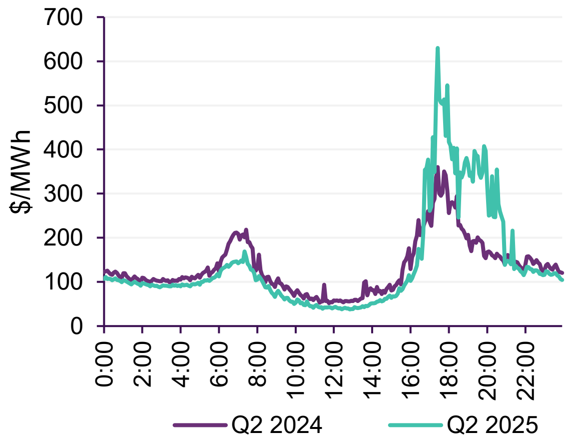
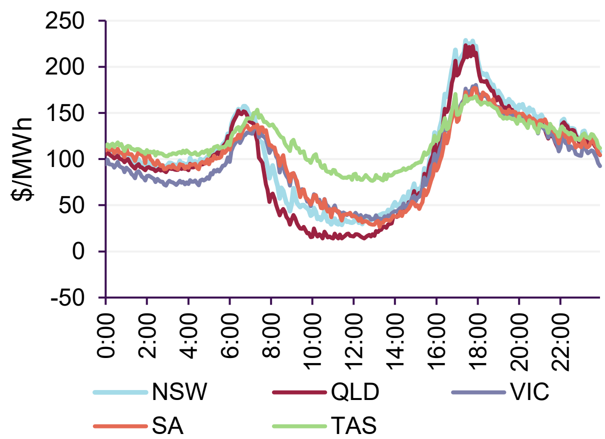


Figure 13 Daytime price separation between Tasmanian and mainland NEM regions

Average regional energy price by time of day – Q2 2025



2.2.1 Wholesale electricity price drivers

Table 1 summarises the main drivers of price changes in the NEM during this quarter, with further analysis and discussion referred to relevant sections of this report.

Table 1 Wholesale electricity price drivers in Q2 2025

Price volatility events	June 2025 saw significant price volatility events, driven by cold temperatures driving high heating demands and high-pressure systems reducing wind speeds and availability (see Section 2.2.2). This price volatility led to June 2025 recording the highest NEM-wide average prices for a calendar month since July 2022. During the quarter there were 2,614 intervals across the five NEM regions where spot prices exceeded $300/MWh, with almost half of these (46%) occurring on 11, 12 and 26 June. Overall price volatility (spot prices above $300/MWh) contributed $37/MWh, or 26%, to the NEM-wide quarterly average spot price of $140/MWh, with price volatility on 11, 12 and 26 June contributing $32/MWh or 23%.
Increased renewable energy output	In Q2 2025, VRE output reached a record Q2 average of 5,154 MW, up 27% from Q2 2024, with wind generation driving this year-on-year increase (see Section 2.3.4). Wind conditions improved after the lows of Q2 2024, and this combined with increased availability from new and commissioning facilities, saw a 31% year-on-year increase in wind output. Additionally, sunny conditions particularly over the first two months of the quarter drove a 15% year on year increase in distributed PV output, and a 17% increase in grid-scale solar generation. This renewable energy contributed to lower wholesale prices across most hours of the day, and the energy component of the NEM-wide wholesale price reduced by 15% year on year to average $103/MWh.

2.2.2 Wholesale electricity price volatility

In Q2 2025, aggregate regional cap returns across the NEM – representing the contribution of any excess of spot price above $300/MWh – totalled $185/MWh, almost three times higher than Q2 2024's $64/MWh (Figure 14). Q2 2025's quarterly cap return was the third highest for any quarter, only lower than Q2 2022 and Q3 2022. Additionally, the aggregate cap return for the month of June was the second highest ever for a calendar month, after July 2022.

All regions contributed to the elevated cap returns, with New South Wales the highest at $54/MWh due to isolated volatility in May adding to the volatility experienced across all regions in June (Figure 15). However, New South Wales experienced the lowest year-on-year increase in cap returns, from $50/MWh in Q2 2024 which was driven by a series of high-priced events in May 2024 (as discussed in the QED for Q2 2024).

Figure 14 Cap return increased year-on-year in all regions

Cap returns by region – quarterly

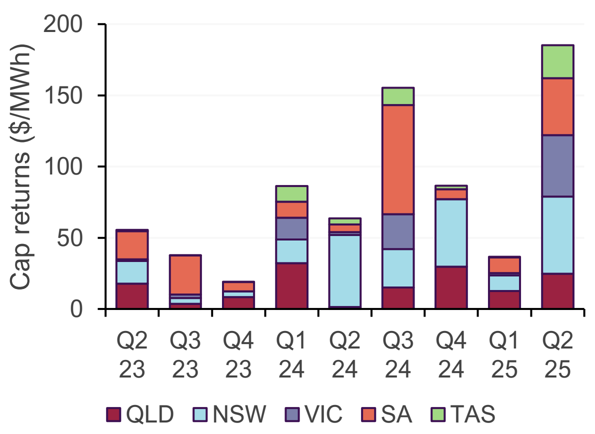
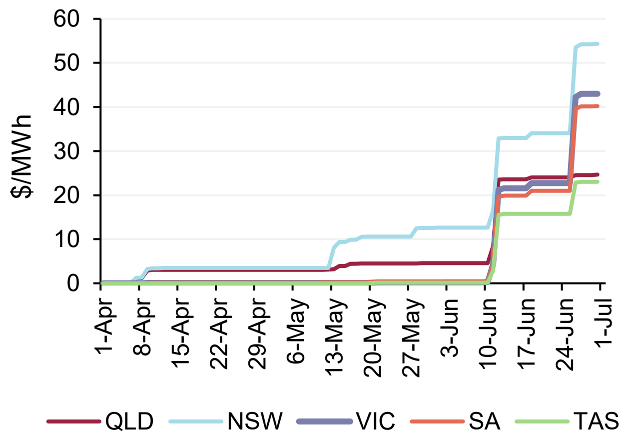


Figure 15 Cap return driven by volatility events in June

Cumulative cap return by region – Q2 2025



June 2025 price volatility

On 11 and 12 June, all NEM regions experienced a series of high prices, with the average daily NEM-wide price on 12 June reaching $1,610/MWh, the highest recorded daily price in NEM history. On these two days, all NEM regions experienced a series of cold fronts, with minimum temperatures well below June averages, driving high heating demands. During the evening peaks on these days, between 1700 and 2100 hrs, NEM-wide total demand[10] averaged over 30,000 MW and NEM-wide prices exceeded $10,000/MWh in 29 intervals (Figure 16).

A number of coal units were offline over these periods, with six units offline across the NEM (representing 2,865 MW of capacity) from the start of 11 June until late on 12 June. An additional unit with 405 MW capacity went offline at 1535 hrs on 12 June, so that 3,270 MW in total was offline.

[10] 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.

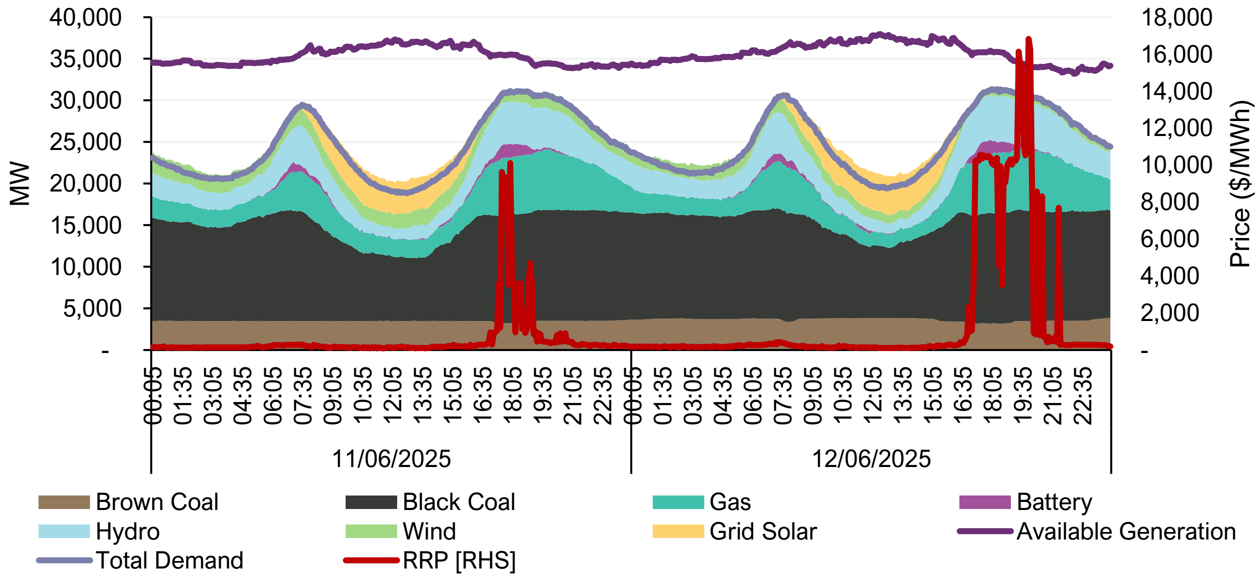
However, system reserves remained adequate over this period with Queensland the only region to register any lack of reserve (LOR) instances, namely an actual LOR1[11] from 1900 to 1945 hrs on 11 June and another between 0630 and 0725 hrs on 12 June.

Driving the high-priced volatility was a reduction in low-priced available generation during the evening peaks, with solar generation reducing to close to zero, due to the time of day. With a high-pressure system across eastern Australia following the cold fronts, NEM-wide wind generation between 1700 and 2100 hrs averaged 1,641 MW on 11 June (12% of capacity[12]) and just 953 MW (7% of capacity) on 12 June. Gas-fired and battery output lifted to meet the peak demands, with gas-fired generation averaging 6,887 MW and 7,096 MW, and battery discharge averaging 763 MW and 890 MW across those same hours on 11 and 12 June respectively.

Battery discharge set prices in around half of the high-price intervals on these two days (those with regional wholesale spot prices above $10,000/MWh) while black coal-fired and hydro generation set prices about equally in the remainder.

Figure 16 NEM-wide price spikes on 11 and 12 June

NEM output per fuel type, NEM total demand, NEM availability and NEM-wide wholesale spot prices during 11 and 12 June 2025



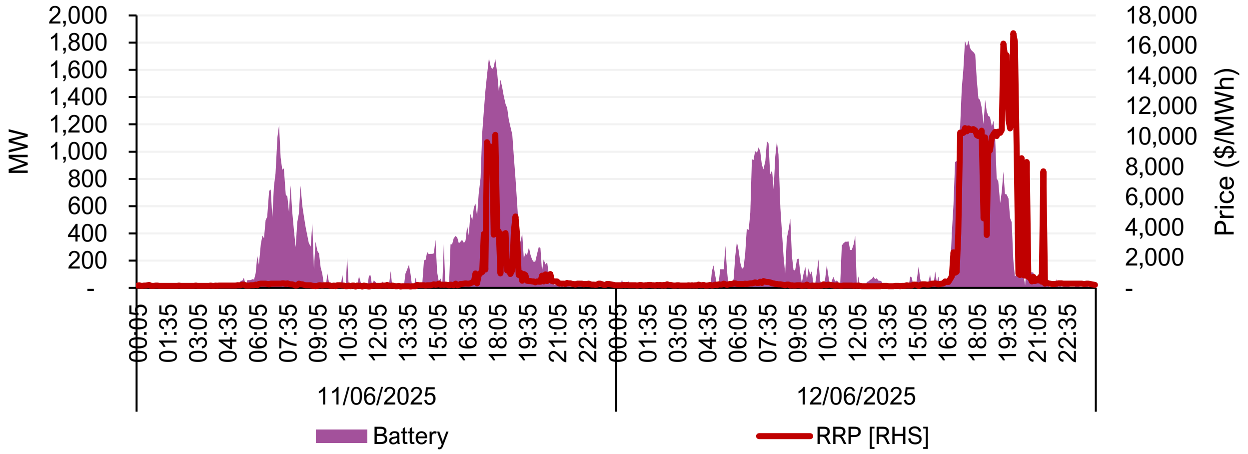
NEM-wide battery discharge reached a new high of 1,631 MW in the half-hour ending 1800 hrs on 11 June, which was then surpassed in the half-hour ending 1800 hrs on 12 June 2025, with a new record of 1,756 MW. However, battery discharge fell as price volatility extended over the evening, reducing to close to zero during later intervals as batteries' stored energy reserves depleted (Figure 17).

[11] LOR1 condition exists when reserve levels are lower than the two largest supply resources in a region. See https://aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf?la=en.

[12] Maximum capacity of all registered wind farms, including those undertaking commissioning activities.

Figure 17 Battery discharge during price spikes on 11 and 12 June

NEM battery discharge and NEM-wide wholesale spot prices during 11 and 12 June 2025



Prices were also volatile on 26 June, particularly in the southern NEM regions, after a cold front followed by a high-pressure system across south-eastern Australia drove elevated heating demand and low wind speeds. All regions apart from Queensland experienced high prices in both the morning peak and evening peak on 26 June (Figure 18), with the daily average price of $1,408/MWh making this the fourth highest price day in NEM history. NEM-wide total demands averaged 30,606 MW over the evening peak period between 1700 and 2100 hrs, and seven coal units were offline (representing 3,490 MW of capacity).

Figure 18 Price spikes on 26 June

NEM output per fuel type, NEM total demand, NEM availability and NEM-wide wholesale spot prices on 26 June 2025

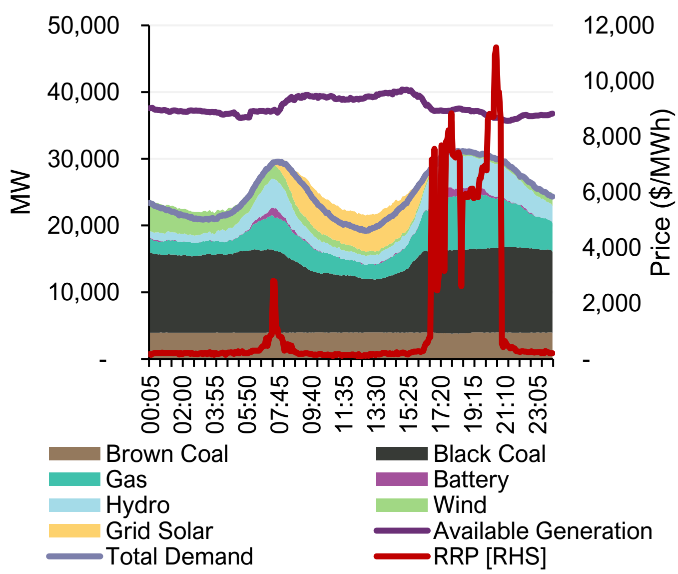
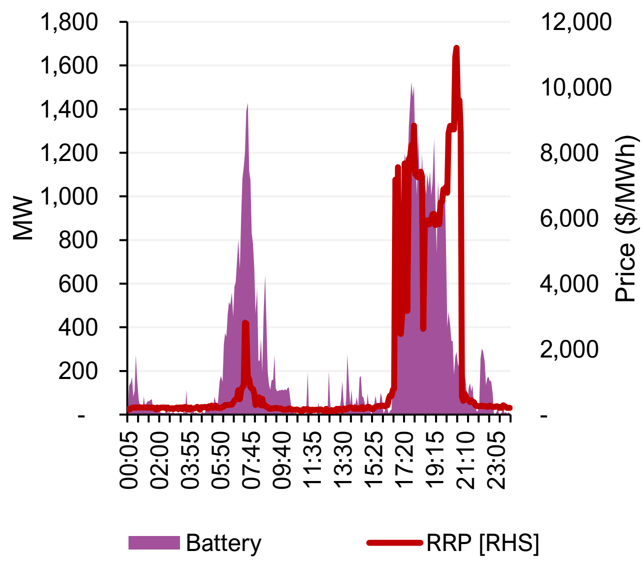


Figure 19 Battery discharge on 26 June

NEM battery discharge and NEM-wide wholesale spot prices on 26 June 2025



Available generation was on average 6,360 MW higher than demand during the evening peak periods, although 2,948 MW of this was located in Queensland, and was limited in supporting the southern regions due to the Queensland – New South Wales Interconnector (QNI) reaching its system normal transfer limits. There were no actual LOR events on this day.

However, low-priced generation was limited with NEM-wide wind generation averaging 806 MW over the evening peak, just 6% of installed capacity, falling below NEM-wide battery discharge, which averaged 878 MW over the same period. Gas-fired generation lifted to average 7,857 MW over the evening peak.

Battery discharge set prices around 80% of the high-price intervals (those with regional wholesale spot prices above $10,000/MWh), followed by gas-fired generation in around 13% of intervals and black coal-fired in the remainder, as battery discharge decreased sharply as the evening volatility period extended (Figure 19).

Table 2 summarises events of significant high-priced volatility during Q2 2025.

Table 2 Significant price volatility events in Q2 2025

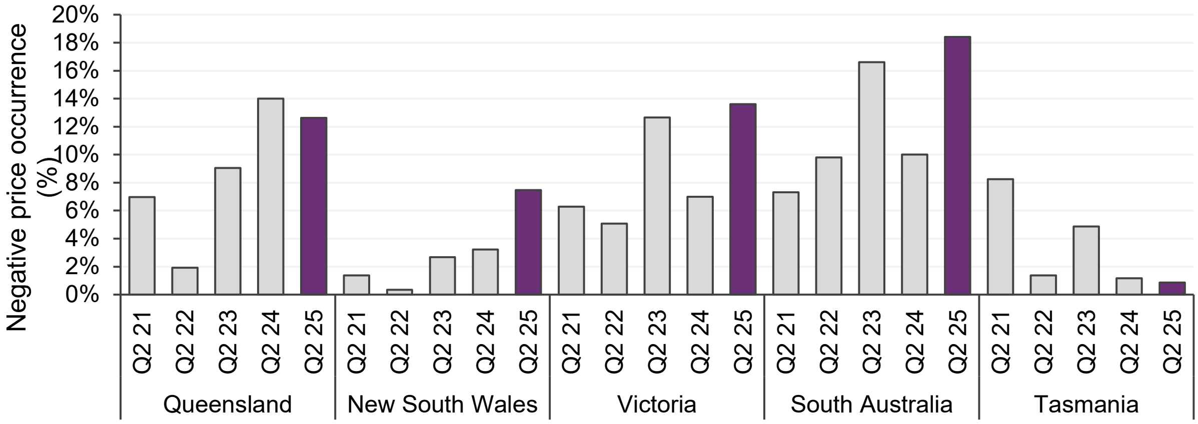
Date	Region	Contribution to quarterly regional cap return ($/MWh)	Drivers
26 June 2025	Victoria	19.5	Cold and still conditions on this day led to high demands and low wind availability causing price volatility in both the morning and evening peaks, with prices exceeding $10,000/MWh in all regions apart from Queensland (see section above for more details). The NEM-wide average price exceeded $10,000/MWh in two (2) intervals and the aggregate regional cap return across the NEM totalled $65.1/MWh.
	New South Wales	19.5	
	South Australia	18.6	
	Tasmania	7.1	
	Queensland	0.5	
12 June 2025	Victoria	16.9	On this day, cold and still conditions again limited wind availability and pushed up demand particularly during the evening peak period (see section above for more details). All NEM regions experienced price volatility, with regional spot prices exceeding $10,000/MWh in multiple dispatch intervals starting from 17:15 – ranging from seven intervals in Tasmania, 14 in Queensland, 16 in South Australia and 33 in Victoria to 34 in New South Wales. The NEM-wide average price exceeded $10,000/MWh in 28 intervals and the aggregate regional cap return across the NEM totalled $76.5/MWh.
	New South Wales	16.3	
	South Australia	15.5	
	Queensland	15.1	
	Tasmania	12.7	
13 May 2025	New South Wales	4.6	On this day, low wind availability, reduced availability of black coal generation (including partial deratings due to plant issues), and network outages impacting supply from Victoria, Queensland, and south-west New South Wales. combined to cause price volatility during the evening peak period. There were eight dispatch intervals with prices over $10,000/MWh peak between 16:35 and 17:30, including four consecutive intervals with prices over $17,000/MWh starting from 16:45.
11 June 2025	Victoria	4.0	Conditions on this day were similar to 12 June, with slightly lower demand, higher black coal availability and higher wind generation during the evening peak period (see section above for more details). All NEM regions experienced price volatility and the NEM-wide average price exceeded $10,000/MWh in one dispatch interval. The aggregate regional cap return across the NEM totalled $18.3/MWh.
	New South Wales	4.0	
	Queensland	3.9	
	South Australia	3.7	
	Tasmania	2.7	

2.2.3 Negative wholesale electricity prices

This quarter saw 10.6% of dispatch intervals record negative or zero prices, a record high for a Q2, and 3.5 percentage points (pp) higher than last Q2. South Australia, Victoria and New South Wales all saw Q2 record high levels of negative price occurrence (Figure 20).

Figure 20 Record high Q2 negative price occurrence in South Australia, Victoria and New South Wales

Negative price occurrence in NEM regions – Q2s



Negative price occurrence is most frequent in daytime hours when operational demand falls due to distributed PV output, and large-scale VRE generation output is higher. Between 0900 and 1700 hrs, negative prices occurred 34% and 27% of the time in South Australia and Victoria, increases of 18 pp and 14 pp respectively on Q2 2024 (Figure 21). Overnight negative price occurrence in South Australia and Victoria also rose significantly, due to increased wind output, reflecting those regions' larger shares of wind capacity. Between 2200 and 0600 hrs, negative prices occurred 12% and 9% of the time in South Australia and Victoria, up 6 pp and 4 pp respectively. In contrast, negative price occurrence in Queensland and New South Wales was concentrated in the daytime hours, and reached 33% in Queensland (down 4 pp from Q2 2024) and 19% in New South Wales (up 10 pp from Q2 2024), between 0900 and 1700 hrs.

Figure 21 Negative prices observed overnight and during daytime in South Australia and Victoria

Negative price occurrence by time of day – Q2 2025

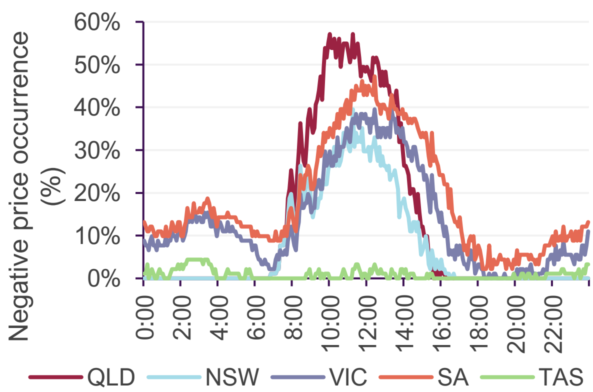
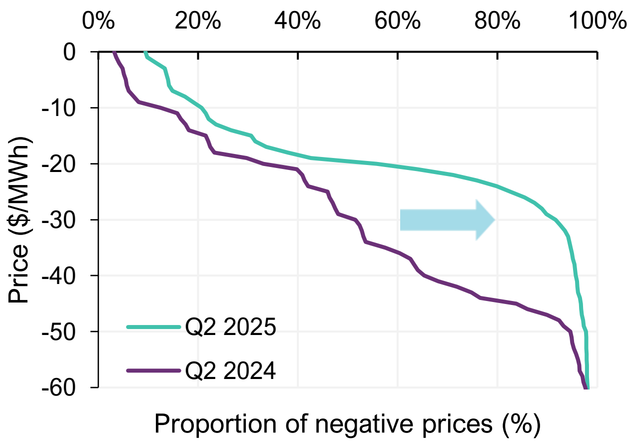


Figure 22 Increase in proportion of negative prices between -$30/MWh and $0/MWh

Cumulative distribution of negative prices – Q2 2025 vs Q2 2024



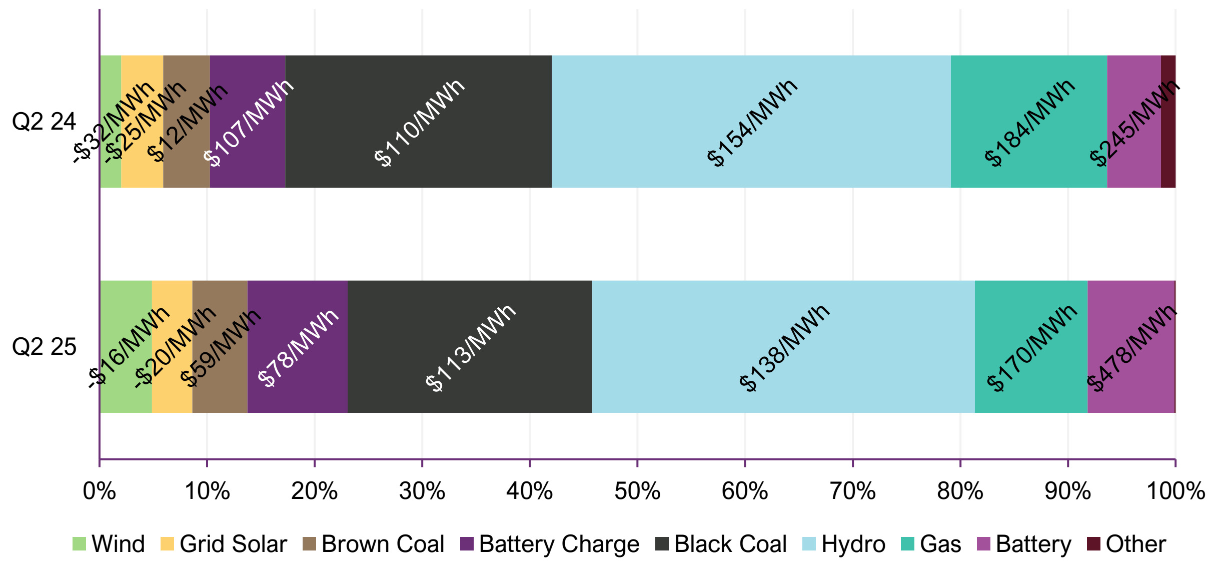
Although negative prices were more frequent this Q2, their magnitude was notably smaller. A much greater proportion of negative spot prices fell between -$30/MWh and $0/MWh in Q2 2025, rising from 51% in Q2 2024 to 92% this quarter (Figure 22). This trend aligned with a decline in large-scale generation certificate (LGC) prices, which averaged $20/certificate this quarter compared to $46/certificate in Q2 2024. As a result, the average spot price during negative price intervals increased to -$20/MWh in Q2 2025, up from -$30/MWh in Q2 2024. This caused a slight fall in the NEM-wide negative price impact[13] – reflecting the combined effect of negative price levels and frequencies on quarterly average price – which reduced from $2.2/MWh in Q2 2024 to $2.1/MWh this quarter.

2.2.4 Price-setting dynamics

Most fuel types saw increases in the average price set when marginal this quarter (Figure 23). An exception was hydro generation, with a 10% year-on-year reduction in average prices set from $154/MWh in Q2 2024 to $138/MWh in Q2 2025, reflecting an increase in volume offered at lower prices this quarter (see Section 2.3.3). As hydro generation remained the most frequent price setter across the NEM, at 36% of intervals in Q2 2025, this reduction helped contribute to the year-on-year decrease in the energy component of spot prices.

Figure 23 Significant year-on-year increase in prices set by battery discharge when marginal

NEM price-setting frequency and average spot price when price-setter by fuel type – Q2 2025 vs Q2 2024



Gas-fired generation also saw a reduction in prices set when marginal, down from $184/MWh in Q2 2024 to $170/MWh this quarter. This was combined with reduced price setting frequency, down from 15% of intervals to 10% as gas generators offered relatively more volume at prices above other price-setting fuel types (see Section 2.3.2) and less frequently became the marginal energy source. In turn, battery discharge was more frequently marginal, particularly over evening peaks, and increased its price-setting frequency from 5% in Q2 2024 to 8% this quarter, with a significant increase in average prices set. Battery discharge set prices at an average of $478/MWh this quarter, almost double its $245/MWh average in Q2 2024.

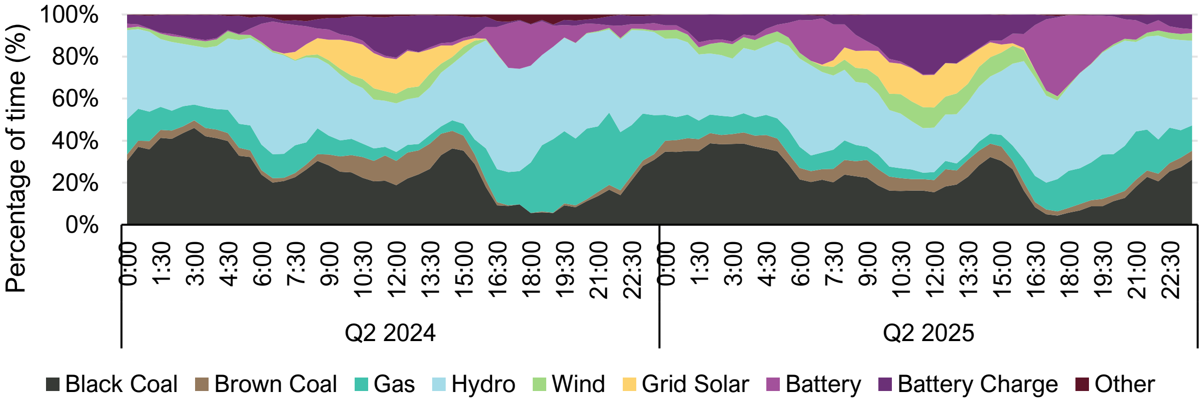
[13] Negative price impact is defined as the increase in regional average spot price that would result from replacing all negative spot price values with $0/MWh.

Price-setting by time of day

On a time of day basis, the drop in gas fired generation's price-setting frequency was most evident in the evening peak, reducing from an average of 36% of intervals between 1700 and 2100 hrs in Q2 2024 to 20% this quarter (Figure 24). Battery discharge price-setting frequency increased in those same hours, up from 12% in Q2 2024 to 24% this quarter. Smaller increases in price-setting frequency over the evening peak were also observed for black coal generation (13% to 17%) and hydro (36% to 38%).

Figure 24 Reduction in gas price-setting in evening peak offset by an increase in battery discharge price-setting

NEM price-setting frequency by fuel type and time of day – Q2 2024 and Q2 2025

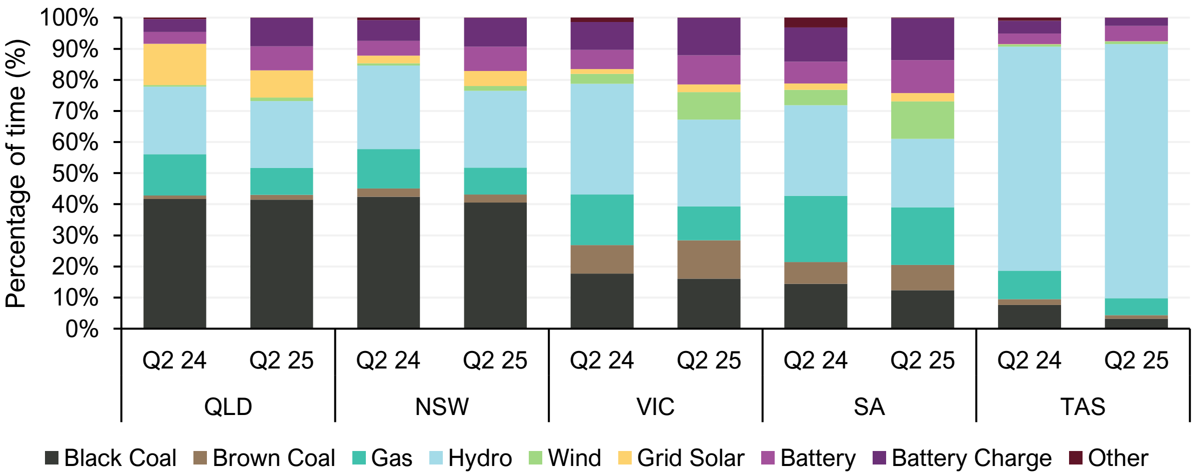


Regional price-setting trends

Year-on-year changes in price-setting frequency were largely consistent across NEM regions (Figure 25).

Figure 25 Reduction in gas price-setting frequency and increase in battery discharge price frequency evident across all regions

Regional price-setting frequency by fuel type – Q2 2025 vs Q2 2024



Two exceptions were hydro generation in Tasmania and grid-scale solar in Queensland. Tasmania was the only region in which hydro generation increased its price-setting frequency, rising from 72% of intervals in Q2 2024 to 82% this quarter. This increase in price-setting frequency acted to offset a reduction in average prices set by hydro in Tasmania (from $125/MWh to $113/MWh) to have an overall upwards impact in wholesale prices in that region.

Queensland was the only mainland region in which grid-scale solar price-setting frequency reduced, down from 13% in Q2 2024 to 9% in Q2 2025. This was matched with an increase in battery charge price-setting frequency driven by expanding battery capacity in the region.

2.2.5 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.

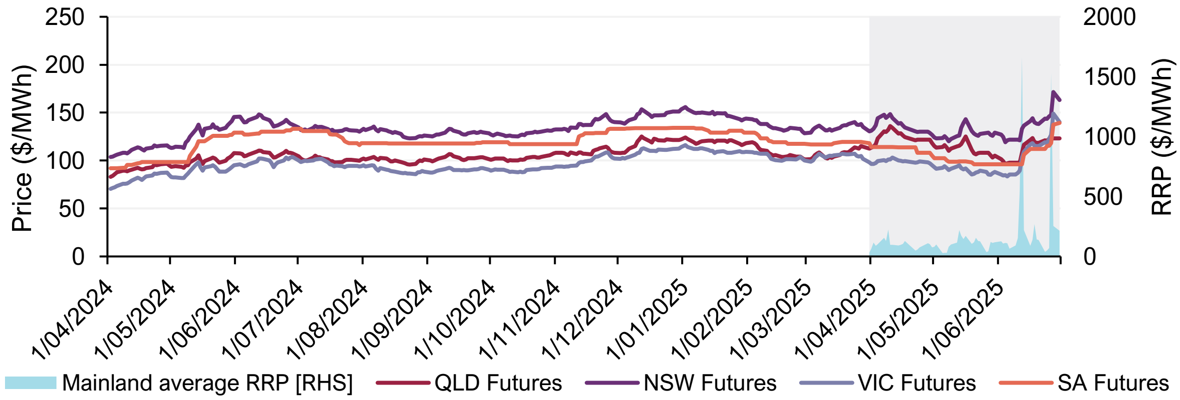
Figure 26 illustrates Australian Securities Exchange (ASX) daily prices for Q2 2025 base contracts across NEM mainland regions. Final settlement prices for such current quarter contracts are set at quarter end to the time weighted quarterly average wholesale price for the relevant region, but prior to this "delivery quarter" their traded prices reflect market expectations. During the delivery quarter, traded prices were influenced by both quarter-to-date wholesale price levels and expectations for the balance of quarter, ultimately converging to the final settlement price.

ASX contract prices for Q2 2025 rose steadily through May and June 2024, reflecting upward pressure on wholesale spot prices during the period driven by low wind and rainfall. Prices stabilised in the second half of 2024 but began climbing again in early November, reflecting high volatility in spot prices across key regions.

At the start of 2025, Q2 contract prices began to ease, as actual volatility over the quarter was lower than previously anticipated. Victorian Q2 2025 prices consistently remained below those in the northern regions. However, contract prices spiked sharply again in mid-June, following high-price volatility, with a further jump at the end of the month - particularly in response to volatile market conditions on 26 June.

Figure 26 Q2 2025 base futures surged in June amid spot price volatility after easing through most of the quarter

ASX Energy – Regional daily Q2 2025 base future prices and daily average spot price for mainland regions

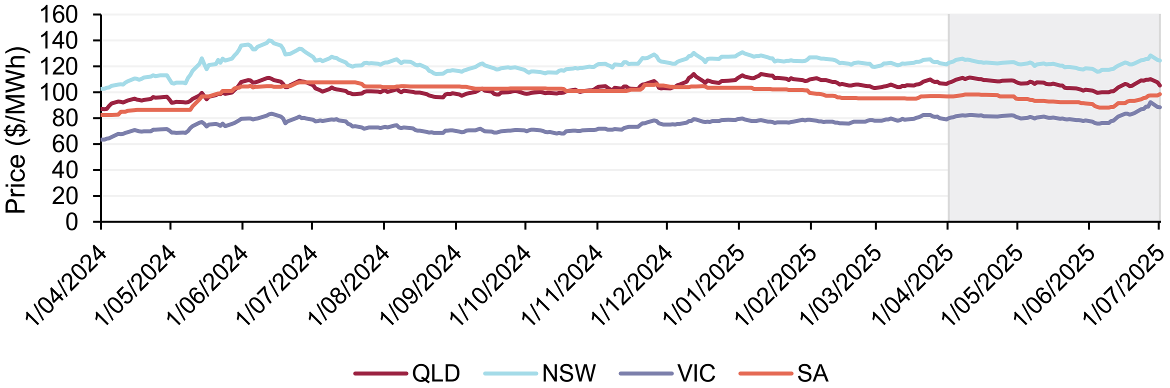


ASX base contract prices for the 2025-26 financial year (FY26) averaged $101/MWh across mainland regions in Q2 2025, slightly below the $102/MWh average in Q1 2025, but $3/MWh higher than Q2 2024 (Figure 27). Prices eased through most of the quarter before lifting in June amid high spot price volatility, ending Q2 slightly above

Q1 levels. All regions recorded increases, with average prices across mainland regions rising by an average of $4/MWh (4%), closing the quarter at $105/MWh, up from $101/MWh at the start.

Figure 27 Slight increase in mainland FY26 futures across the quarter

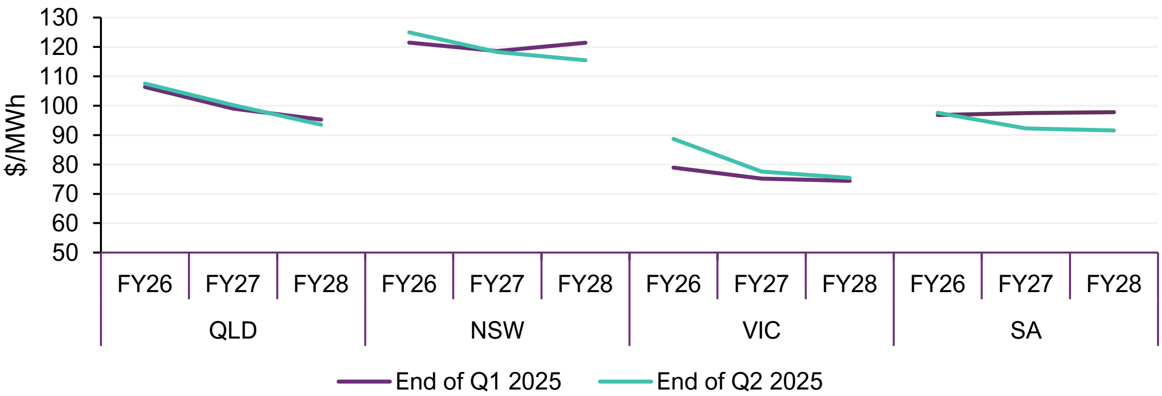
ASX Energy – Daily FY26 base futures by region



Longer-dated contract prices continued to trend lower in all NEM mainland regions (Figure 28). FY27 prices ended Q2 2025 broadly in line with Q1 levels in all regions except Victoria, which closed the quarter slightly higher. FY28 prices declined across all regions except Victoria, where prices remained steady compared to the end of Q1 2025.

Figure 28 Forward financial year contracts continued downward trend across all NEM mainland regions

ASX Energy – Financial year contract prices in mainland NEM regions – end of Q1 2025 and end of Q2 2025



2.3 Electricity generation

In Q2 2025, total NEM generation[14] increased by an average of 357 MW (+1.5%) to 24,721 MW. This growth was primarily driven by higher underlying demand and increased supply requirements for battery charging (+112 MW). The impact of rising renewable output was evident, leading to declines in gas and coal-fired generation.

[14] Generation calculation is inclusive of AEMO's best estimates of generation from distributed PV. Generation also includes supply from certain non-scheduled generators and supply to large market scheduled loads (such as pumped hydro and batteries) which are excluded from the operational and underlying demand measures discussed in Section 2.1.

Figure 29 illustrates the changes in NEM generation by fuel type compared to Q2 2024, and Table 3 presents the supply mix by fuel type. The overall renewable contribution increased by 5.7 pp, rising from 32.2% in Q2 2024 to 37.9% in Q2 2025, reflecting a significant shift in the generation mix.

Comparing the changes in generation by fuel type of Q2 2025 with Q2 2024:

- VRE output reached new Q2 quarterly highs. Grid-scale solar averaged 1,662 MW (+17%) and distributed PV average output increased to 2,358 MW, a 15% increase year-on-year. Average wind output was 3,492 MW, up by 835 MW (+31%) from Q2 2024. Grid-scale solar increases were largely from new and commissioning assets, while wind output also reflected higher wind speeds this quarter after the low levels of Q2 2024. Increases in available VRE output were partially offset by higher economic offloading and network curtailment.
- Battery discharge reached an all-time high this quarter, averaging 162 MW (+119%) and accounted for 0.7% of total NEM generation. Hydro generation also rose by 66 MW with an average output of 1,673 MW (+4.1%), contributing 6.8% to overall NEM generation.
- Gas-fired generation declined by 200 MW year-on-year to average 1,502 MW (-12%) in Q2 2025. The decline was evident in April and May, before a sharp increase in June driven by higher demand and days of low wind output.
- Coal-fired generation declined overall, with black coal-fired output decreasing by 798 MW to an average of 10,059 MW (-7.4%) and brown coal-fired output averaging 3,787 MW, a decrease of 160 MW (-4.1%) from Q2 2024. This contributed to a combined reduction of 4.8 pp in coal-fired generation share in NEM, contributing substantially to the decrease in NEM emissions this quarter.

Figure 29 Shift in supply mix driven by higher renewable output

Change in NEM supply by fuel source – Q2 2025 vs Q2 2024

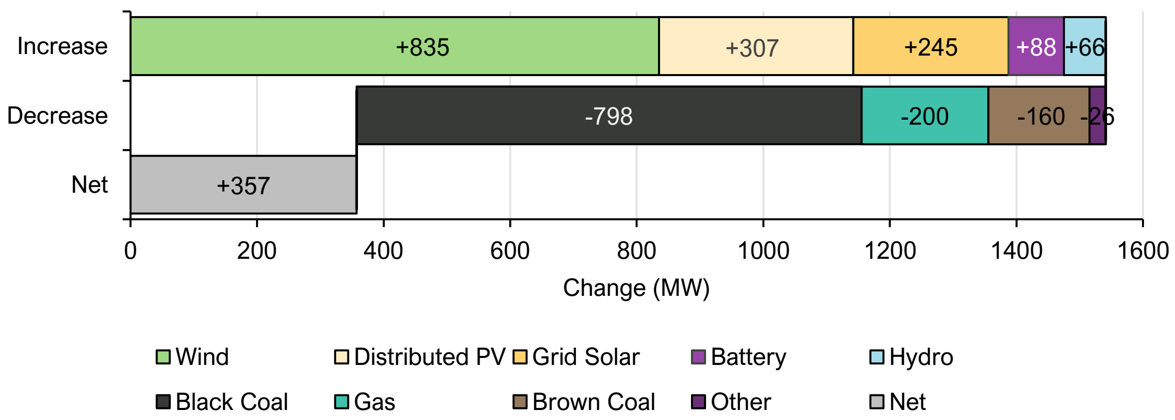


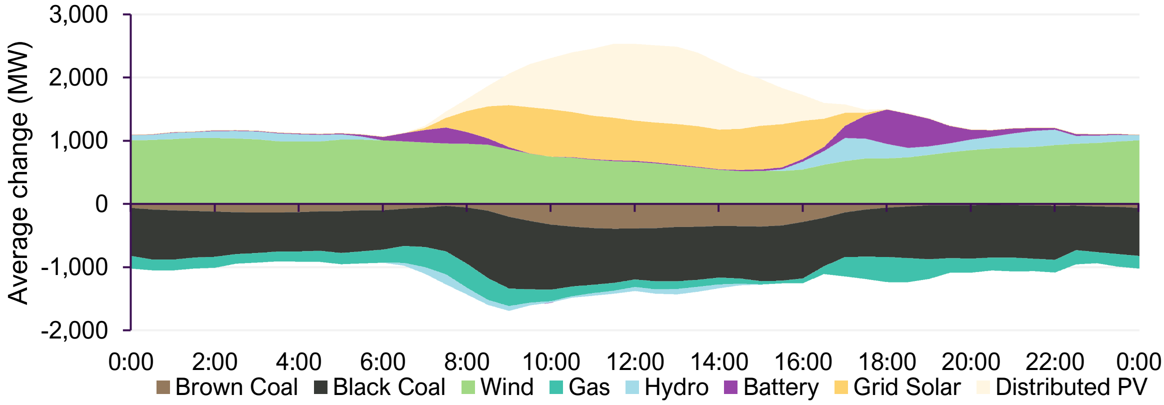
Table 3 NEM supply mix contribution by fuel type

Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Biomass	Battery
Q2 2024	44.6%	16.2%	7.0%	0.1%	8.4%	10.9%	5.8%	6.6%	0.1%	0.3%
Q2 2025	40.7%	15.3%	6.1%	0.0%	9.5%	14.1%	6.7%	6.8%	0.1%	0.7%
Change	-3.9%	-0.9%	-0.9%	-0.1%	1.1%	3.2%	0.9%	0.2%	0.0%	0.4%

Figure 30 shows the changes in generation from Q2 2024 to Q2 2025 by time of day. On average, wind generation increased across all times of day due to higher average wind speeds (see Figure 4 in Section 1). Battery and hydro output grew during morning and evening periods and combined with higher VRE output to reduce coal-fired and gas generation.

Figure 30 Decreases in gas and coal-fired output as VRE output grows across the day

NEM generation changes by time of day – Q2 2025 vs Q2 2024



2.3.1 Coal-fired generation

Black coal-fired fleet

In Q2 2025, average black coal-fired generation across the NEM declined to 10,059 MW, a year-on-year decrease of 798 MW (-7.4%) and the lowest Q2 output since NEM start (Figure 31). The decline in generation was observed across both New South Wales and Queensland, with average output reductions of 539 MW (-9.5%) and 259 MW (-5.0%) respectively.

Availability also fell significantly, down by 1,150 MW (-8.6%) to 12,264 MW. This was primarily due to increased planned and unplanned full unit outages in New South Wales (+579 MW) and Queensland (+284 MW), which combined with partial outages to reduce availability by 636 MW (-9.2%) and 514 MW (-7.9%) respectively (Figure 32).

Figure 33 shows availability, generation and utilisation rates for the New South Wales black coal-fired power stations.

In New South Wales, Eraring recorded a significant year-on-year generation increase of 197 MW (+11%). Eraring availability rose by 372 MW (+18%), but its utilisation declined by 6 pp. Vales Point had a generation increase of 9 MW (+1%), but a 107 MW (+10%) increase in availability, with utilisation also down by 6 pp.

The utilisation rate for Bayswater increased (+6 pp), but this was more than offset by a 581 MW (-23%) drop in availability, resulting in a 352 MW (-17%) decline in generation this quarter. Mt Piper experienced the most significant decline in generation compared to Q2 2024, with outages increasing by 581 MW. The average generation for Mt Piper this quarter was 573 MW, representing a 41% year-on-year decrease.

Figure 31 Lowest Q2 black coal fired generation output on record

Quarterly average black coal-fired generation– Q2s

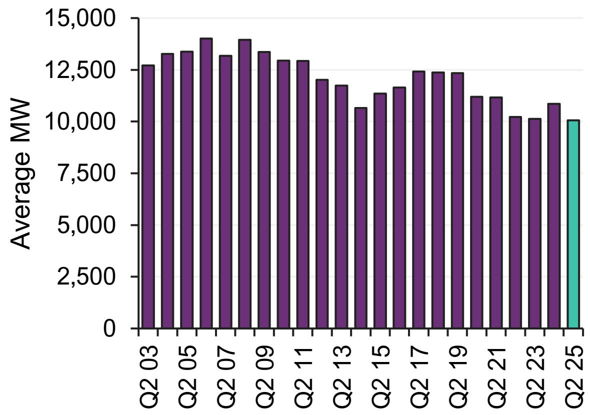


Figure 32 More black coal-fired capacity on full unit outages

Average coal-fired capacity on full outage[15] – Q2 25 vs Q2 24

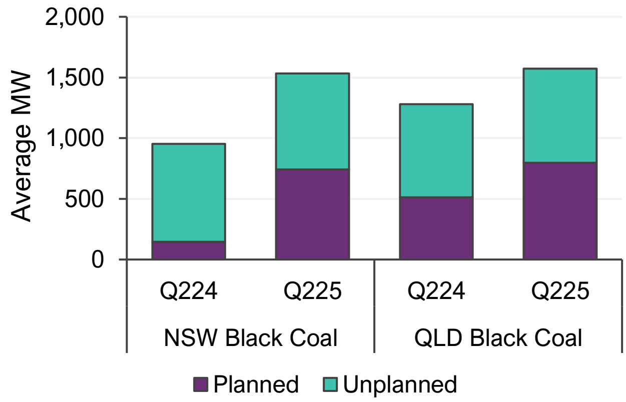


Figure 33 Lower output at Mt Piper and Bayswater offset increased output at Eraring and Vales Point for an overall decline in New South Wales black coal-fired generation

Average quarterly availability, generation and utilisation for New South Wales black coal-fired power stations – Q2 2025 vs Q2 2024

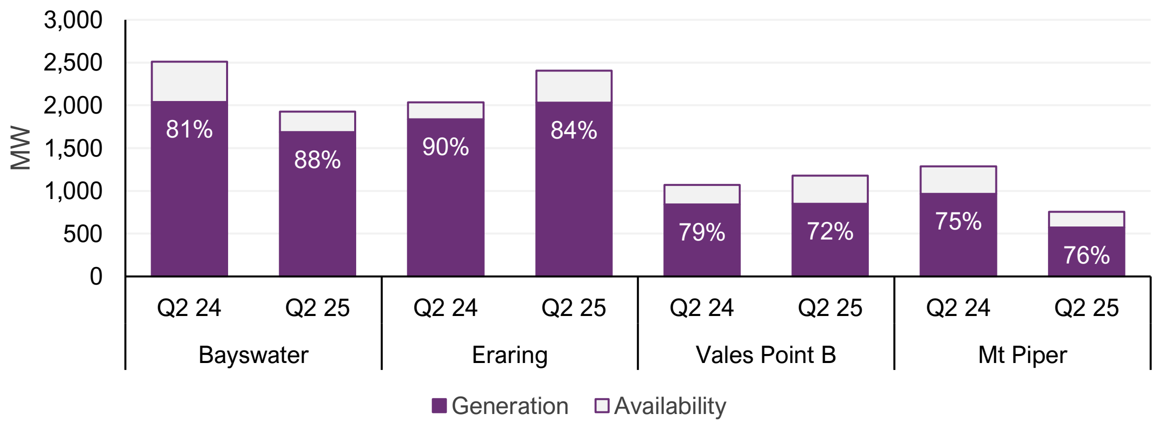
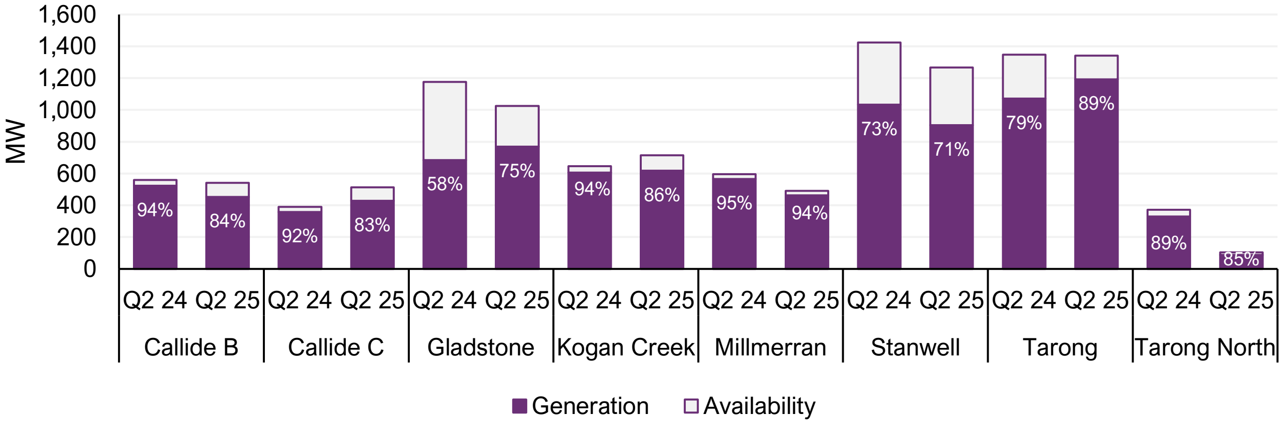


Figure 34 shows availability, generation and utilisation rates for the Queensland black coal-fired power stations. In Queensland, Tarong, Gladstone and Callide C recorded notable increases in generation. Tarong increased by 122 MW (+11%) with a 9 pp rise in utilisation, while Gladstone rose by 83 MW (+12%) with a 17 pp increase in utilisation. Callide C also saw a generation increase of 70 MW (+20%) and a 123 MW (+31%) rise in availability, although its utilisation declined by 8 pp. Kogan Creek output was marginally higher, up 12 MW (2%) while its utilisation fell by 7 pp. Other Queensland stations experienced year-on-year declines in both generation and utilisation. Tarong North saw a 242 MW (-73%) drop in generation and a 267 MW (-72%) decline in availability due to a planned outage during the quarter. Millmerran and Callide B generation decreased by 103 MW (-18%) and 71 MW (-14%) respectively.

[15] Classification of full unit outages into planned and unplanned in the Quarterly Energy Dynamics (QED) is primarily based on Medium Term Projected Assessment of System Adequacy (MT PASA) unit status. For Q2 2024, some outages have been reclassified since the publication of Q2 2024 QED. This includes reclassifying around 490 MW of New South Wales outages and around 225 MW of Queensland outages from planned to unplanned.

Figure 34 Overall decline in Queensland black coal-fired generation

Average quarterly availability, generation and utilisation for Queensland black coal-fired power stations – Q2 2025 vs Q2 2024



Black coal-fired generation decreased across all hours of the day in Q2 2025 compared to Q2 2024, reversing the temporary uplift observed last year due to reduced wind and hydro output. In New South Wales, the intra-day swing in black coal generation declined slightly by 94 MW from 2,871 MW in Q2 2024 to 2,777 MW this quarter (Figure 35). Bayswater recorded the largest reduction in intraday swing, down by 354 MW, with lower availability reducing generation during morning and evening peak periods to a greater extent than during the middle of the day. In contrast, Eraring and Vales Point had increases in intraday swing of 349 MW and 54 MW respectively, with year-on-year increases in generation concentrated in morning and evening peak periods.

In Queensland, intra-day flexibility from black coal generation increased marginally by 51 MW (Figure 36). Reductions in intraday output variability at Gladstone, Kogan Creek, Millmerran, and Tarong North were offset by increases at Callide B and Callide C, contributing to the overall rise.

Figure 35 New South Wales black coal-fired generation declined across the day

New South Wales black coal-fired generation by time of day– Q2s

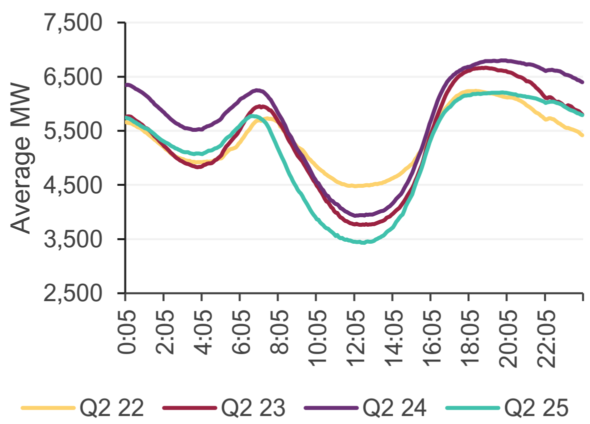
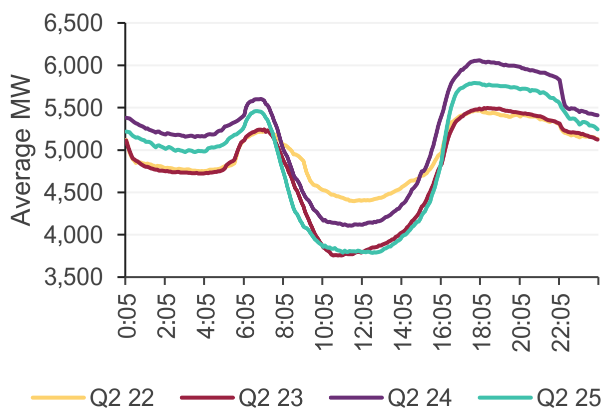


Figure 36 Queensland black coal-fired generation decreased across the day

Queensland black coal-fired generation by time of day– Q2s



Brown coal-fired fleet

Brown coal-fired generation decreased by 160 MW (-4.1%), averaging 3,787 MW in Q2 2025 (Figure 37). This was despite a slight increase in availability of 79 MW (+1.9%) year-on-year to average 4,180 MW this quarter. Capacity on full unit outages at brown coal-fired stations was down by 90 MW (-13%) as compared to last year, slightly offset by an increased level of partial outages.

Availability increased at Loy Yang B (+11%) and Yallourn W (+3.6%) but only Loy Yang B, where capacity on full unit outage reduced by 113 MW, increased its average output, up by 38 MW (+3.8%) (Table 4).

Average brown coal-fired generation declined across the day in Q2 2025, with intra-day swing in output increasing significantly, up by 341 MW from 547 MW in Q2 2024 to 888 MW this quarter (Figure 38). This trend was consistent across all brown coal generators, Yallourn W recorded the largest year-on-year increase, with a 143 MW rise compared to Q2 2024. Higher intraday swing meant that utilisation rates fell for all brown coal-fired stations, with Loy Yang A down to 90%, and both Loy Yang B and Yallourn W at 91%.

Figure 37 Decline in brown coal-fired generation despite increased availability in Q2 2025

Quarterly average brown coal-fired generation and availability (including decommissioned units) – Q2s

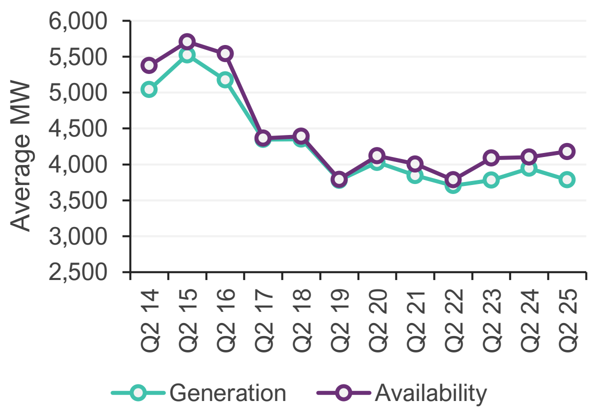


Figure 38 Brown coal-fired generators displayed increased swing year-on-year

Brown coal-fired generation by time of day– Q2s

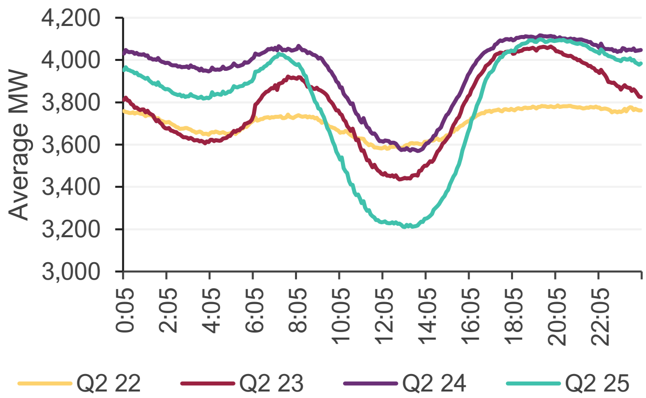


Table 4 Brown coal availability, output, utilisation, outage, and intraday swing – Q2 2025 vs Q2 2024

Generator	Availability (MW)		Output (MW)		Utilisation		Outage (MW)		Intraday swing (MW)	
	Q2 24	Q2 25	Q2 24	Q2 25	Q2 24	Q2 25	Q2 24	Q2 25	Q2 24	Q2 25
Loy Yang A	2,107	2,034	2,001	1,838	95%	90%	79	142	354	440
Loy Yang B	1,021	1,137	994	1,032	97%	91%	133	20	109	242
Yallourn W	973	1,009	952	917	98%	91%	499	458	91	235

2.3.2 Gas-fired generation

Gas-fired generation in the NEM declined in Q2 2025, averaging 1,502 MW. This represents a reduction of 200 MW (-12%) compared to Q2 2024 (Figure 39). However, monthly outcomes varied, with low average generation in April (1,040 MW) and May (1,316 MW) before a significant increase in June (2,157 MW). This increase was primarily driven by colder weather conditions and associated cold fronts that elevated demand, coupled with periods of low wind output and coal-fired outages during June. These conditions, alongside increased price volatility in June, led to higher monthly gas-fired generation.

Quarterly average gas-fired generation fell in all regions except New South Wales, where it rose 39 MW (+15%) year-on-year to 302 MW. South Australia contributed most significantly to the NEM-wide fall with its average gas-fired generation of 478 MW down by 104 MW (-18%) from the same quarter last year. In Victoria, gas-fired generation averaged 231 MW, down 55 MW (-19%) from Q2 2024. Despite this decline in quarterly average, Victoria recorded a June monthly average of 533 MW, its highest June level since 2007, after averaging only 29 MW in April. In Tasmania, average gas-fired generation fell to 21 MW in Q2 2025, a decline of 64 MW (-76%) from Q2 2024. In Q2 2024, elevated output was driven by reduced hydro availability in Tasmania, which led to more reliance on gas-fired generation. Queensland contributed marginally to the overall reduction in gas-fired generation this quarter, with average output down by 17 MW (-3.4%) to 471 MW.

Average gas offer volumes were stable compared to Q2 2024, up by just 43 MW to 6,206 MW in Q2 2025. However, there was a noticeable shift in offer prices, with the average volume of gas-fired generation offers reduced by around 200 MW at offer prices up to $500/MWh, and by a greater margin in higher price bands (Figure 40).

Figure 39 Gas-fired generation grew across Q2 2025

Average gas-fired generation by region – Q2s

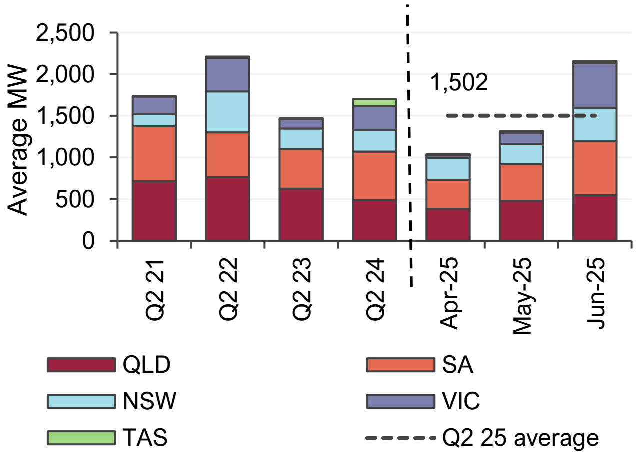


Figure 40 Gas offer volumes decreased

Gas-fired generation bid supply curve – Q2 2025 vs Q2 2024

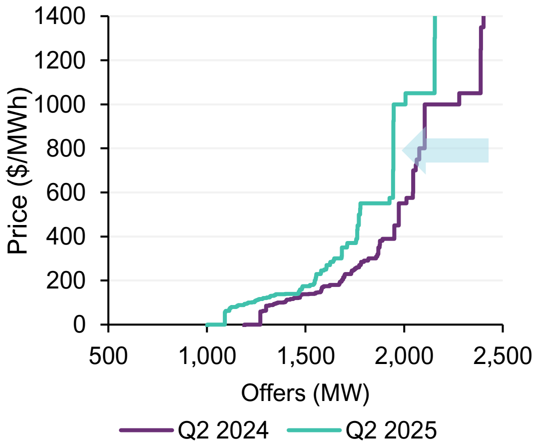


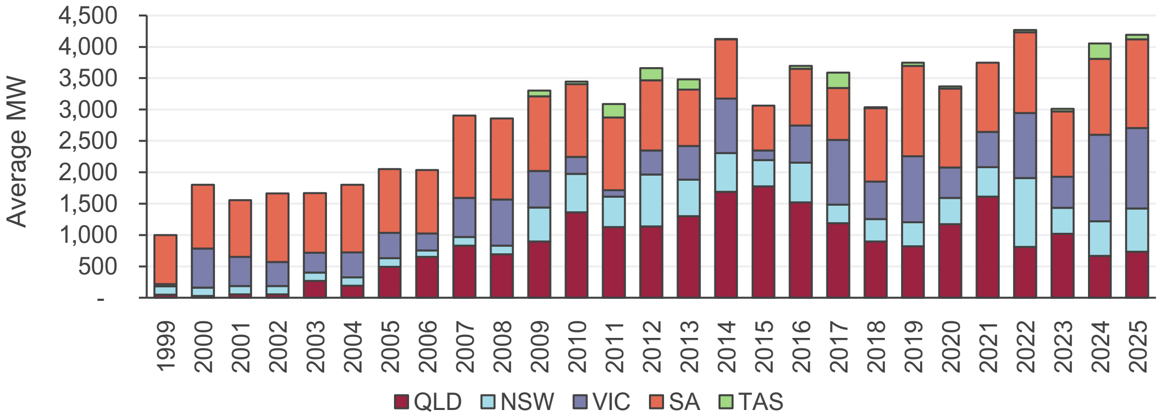
Figure 41 shows the peak daily average level of gas-fired generation recorded in each Q2 since 1999. In Q2 2025, daily average gas-fired generation peaked at 4,193 MW on Thursday, 26 June 2025, the second-highest value recorded for any Q2, surpassed only in Q2 2022 (4,268 MW). This high generation level, the result of widespread cold weather and low wind conditions, led to a new winter record for daily[16] gas demand for power generation on the east coast gas system[17] (see Section 3.2.1).

[16] Daily gas demand for the east coast gas system is based on a 'gas day' which runs from 6.00 am to 6.00 am. NEM daily gas generation is based on a calendar day.

[17] Gas demand for the east coast gas system excludes Yabulu Power Station.

Figure 41 Peak day gas-fired output reached second-highest Q2 level

Maximum daily average gas-fired generation by region – Q2s



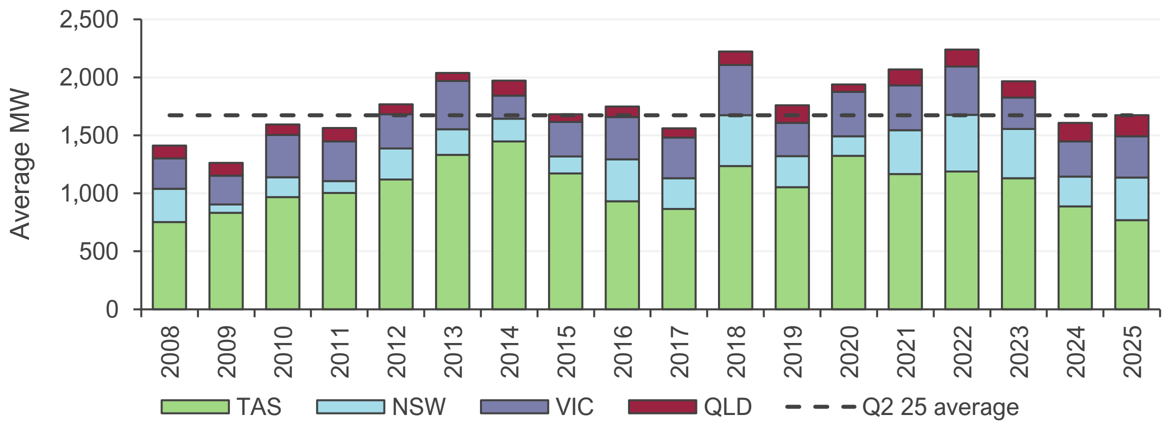
2.3.3 Hydro

During this quarter, NEM hydro generation[18] increased 66 MW (+4.1%) from Q2 2024 to an average of 1,673 MW in Q2 2025 (Figure 42).

Hydro generation increased across most NEM regions, led by New South Wales and Victoria. In New South Wales, average hydro output rose by 111 MW (up 43% year-on-year) to 368 MW, driven by higher generation at Upper Tumut (+88 MW) and Tumut 3 (+24 MW). Victoria also recorded a notable increase, with average hydro output rising by 54 MW (up 18%) to 355 MW, primarily due to higher generation at Dartmouth (+87 MW). Queensland's hydro output increased by 21 MW to 181 MW, marking the state's highest Q2 average since the start of the NEM. This reflected higher generation at Barron Gorge (+24 MW) and Wivenhoe (+4 MW), partially offset by a reduction at Kareeya (-8 MW).

Figure 42 Significant hydro generation decrease in Tasmania

Average hydro output by region – Q2s



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

In contrast, Tasmania experienced a significant decline in hydro generation with an average output of 768 MW in Q2 2025, reducing by 119 MW (-13%) from Q2 2024. This represents the lowest Q2 average hydro generation for Tasmania since 2008, which can be partially attributed to the 71 MW fall in average operational demand in Tasmania this Q2. Energy in storage across Tasmania's hydro systems was at 33.1% of full capacity at the end of Q2 2025, compared to 31.5% at the end of Q2 2024 and 40.5% at the end of Q2 2023 (Figure 43).

During the evening peak period between 1600 and 2000 hrs, Queensland recorded a year-on-year increase of 121 MW in hydro output, while New South Wales saw a larger increase of 194 MW. Storage levels at Snowy Hydro's three main storages were down when compared to 2024 levels, with Lake Eucumbene 33% full at end of June, down from 49% at end of Q2 2024. There was an overall increase in volume of hydro generation offered in the market, with an increase of around 300 MW offered at prices less than $300/MWh (Figure 44).

Figure 43 Hydro storage levels in Tasmania finish the quarter at 33.1%

Month end Tasmania energy storage levels in percentage compared to prudent storage level (PSL) and high reliability level (HRL)[19]

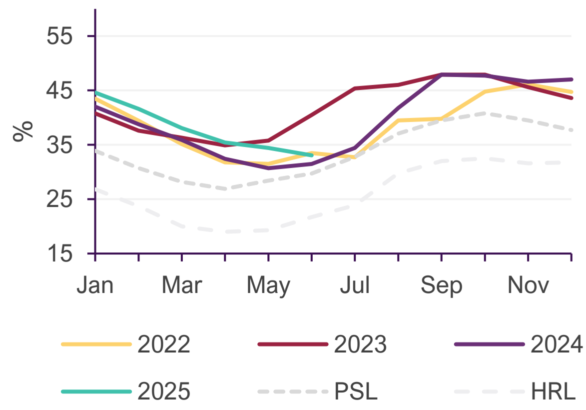
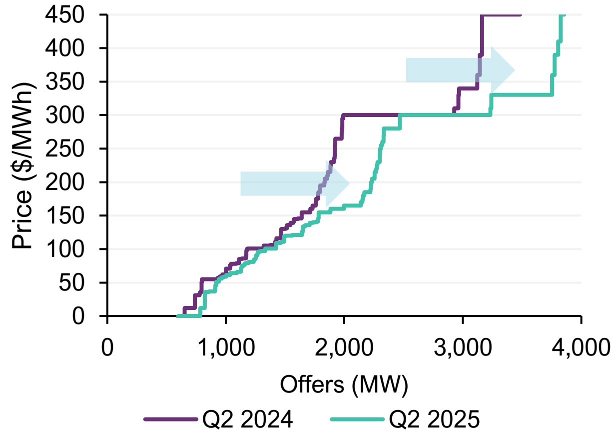


Figure 44 Increased hydro generation offer volumes

Hydro generation bid supply curve – Q2 2025 vs Q2 2024



2.3.4 Wind and grid-scale solar

In Q2 2025, output from grid-scale VRE reached a record Q2 average of 5,154 MW, a 1,080 MW (+27%) increase year-on-year (Figure 45). This was primarily driven by an 835 MW (+31%) increase in wind generation compared to Q2 2024, while grid-scale solar contributed an additional 245 MW (+17%). The result reflected a return to steady output growth after the very low wind conditions experienced in Q2 2024.

Wind generation increased across all regions with the most substantial growth observed in Victoria, where average output rose by 412 MW (+44%), from 940 MW in Q2 2024 to 1,352 MW this quarter (Figure 46). Grid-scale solar output also increased across most regions, except for South Australia. New South Wales led the grid-scale solar increase, reaching 720 MW in Q2 2025, a 124 MW (+21%) increase compared to the same quarter last year.

[19] Month-end storage levels are based on the first Monday after the end of the month. See https://www.economicregulator.tas.gov.au/about-us/energy-security-monitor-and-assessor/tasmanian-energy-security-monthly-dashboard.

Figure 45 VRE growth continued

Average quarterly VRE generation by fuel type – Q2s

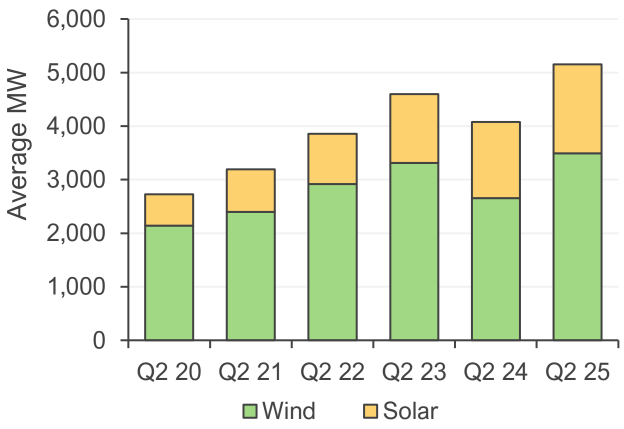
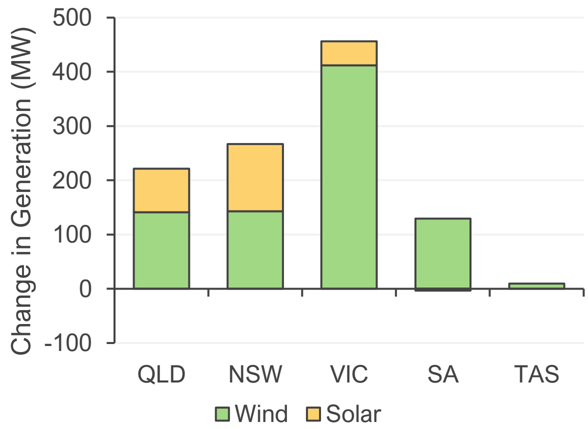


Figure 46 VRE increases led by Victorian wind

Average MW change in output Q2 2025 vs Q2 2024



Grid-scale solar

Increased VRE generation in the NEM can arise from both newly connected facilities and those progressing through their commissioning processes, which can extend over 12 months or longer. These growth sources contributed a 270 MW increase in average quarterly solar availability from Q2 2024 (Figure 47). Much of this increase was in New South Wales, with contributions from Wellington North (+70 MW), Stubbo (+59 MW), Walla Walla (+47 MW) and Wollar (+25 MW). There were a few new additions in Victoria as well, with Girgarre (+14 MW) and Wunghnu (+14 MW) the major sources. Queensland recorded a total increase of 23 MW from Aldoga (+14 MW) and Kingaroy (+9 MW).

Network curtailment and economic offloading both increased in Q2 2025 compared to the same quarter last year, reducing potential large-scale solar generation output by 47 MW across the NEM. Higher network curtailment of grid-scale solar entirely reflected outcomes in New South Wales with an average of 37 MW this quarter, a 22 MW increase year-on-year. In contrast, Victoria saw a slight decrease of 2 MW, leading to a net increase of 20 MW in curtailment across the NEM. Economic offloading increased across most regions in Q2 2025, with New South Wales again recording the largest rise, averaging 33 MW, a 30 MW year-on-year increase. South Australia and Victoria followed with increases of 12 MW and 4 MW respectively. Queensland was the only region with lower economic offloading, with a 19 MW reduction. Overall, these changes resulted in a net increase in offloading of 27 MW.

Established[20] grid-scale solar facilities recorded higher volume-weighted available capacity factors in all regions except New South Wales, with the NEM-wide capacity factor increasing by 0.4 pp to 19.2% this quarter (Figure 48). Queensland solar farms had the highest regional capacity factor at 21.3%, a 1.2 pp increase from Q2 2024. This was followed by South Australia at 19.5% with a rise of 1.3 pp year-on-year.

[20] Existing (or established) capacity in this section refers to the grid-scale solar and wind facilities that were fully commissioned prior to the start of Q2 2025. These facilities may also appear in the "New Capacity or "Commissioning" categories in Figure 47 and Figure 49 if they were connected or exhibited ramping capacity between Q2 2024 and Q2 2025 respectively.

Figure 47 Contribution of new capacity to year-on-year grid-scale solar growth

Change in grid-scale solar generation – Q2 2025 vs Q2 2024

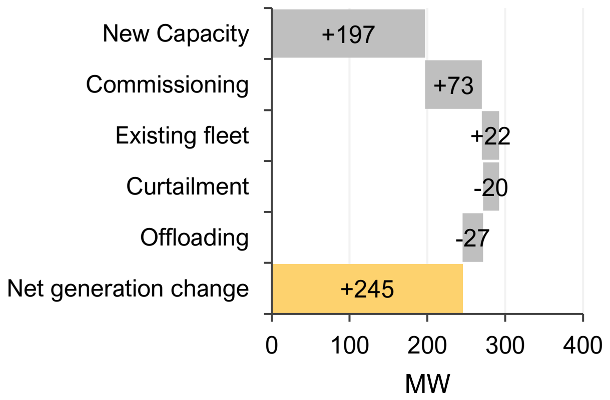
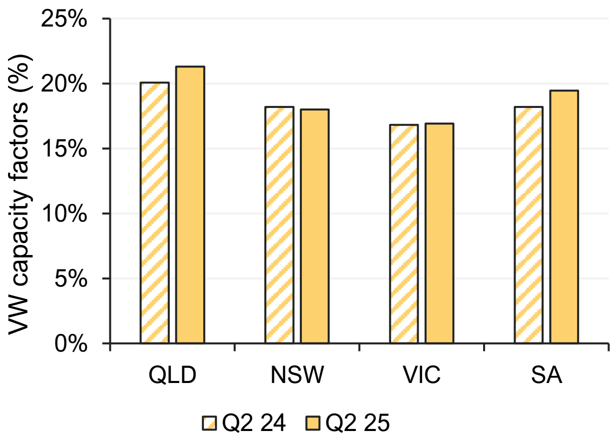


Figure 48 Increased grid-scale solar availability across all regions

Volume-weighted grid-scale solar available capacity factors[21] – Q2s



Wind

Newly connected wind farms and those progressing through commissioning contributed a 546 MW increase in wind availability compared to Q2 2024, while improved capacity factors at established wind facilities contributed availability growth of 445 MW (Figure 49). Growth from new and commissioning facilities was primarily driven by new capacity installed since Q2 2024. In Victoria, the contributors were Ryan Corner (+70 MW), Golden Plains (+122 MW) and in Queensland, Clarke Creek (+58 MW) and MacIntyre (+85 MW). In South Australia, availability at the two stages of Goyder South (+115 MW) grew compared to last year. New South Wales also had increased availability from commissioning wind farms Rye Park Renewable Energy (+24 MW) and Flyers Creek (+23 MW) over the quarter.

Offsetting the overall increase in wind availability, network curtailment and economic offloading reduced potential wind output growth in Q2 2025 by an average of 156 MW. Higher network curtailment accounted for output decreases of 33 MW compared to Q2 2024, driven primarily by curtailment in Victoria (+19 MW) and South Australia (+11 MW). Economic offloading accounted for a further 123 MW reduction in average wind output, with the largest changes in offloading observed in Victoria (+63 MW) and South Australia (+52 MW).

Established wind facilities showed increases in quarterly volume-weighted available capacity factors across all NEM regions, resulting in the NEM-wide average rising by 4.5 pp to 29.8% this quarter (Figure 50). The overall increase reflected wind conditions in Q2 2024 having been well below average, reducing available wind energy across the NEM. Victoria led the increases in quarterly volume-weighted available capacity factor this Q2 at 29.8%, an increase of 6.8 pp compared to Q2 2024. Queensland recorded the highest regional result at 33.6% though its year-on-year increase was the smallest among regions, at just 0.3 pp.

[21] 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 solar or wind resource levels. Available capacity factors for each established facility are weighted by maximum installed capacity to derive a regional weighted average.

Figure 49 Output increased from existing and new wind farms

Change in wind generation – Q2 2025 vs Q2 2024

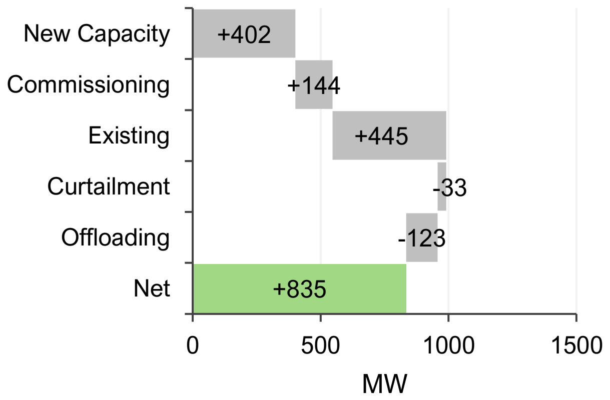


Figure 50 Increased wind availability across all regions

Volume-weighted wind available capacity factors – Q2s

During Q2 2025, Victoria recorded the highest number of consecutive days where the daily average wind capacity factor[22] fell below 5%. Notably, it was the only region to experience a lull covering four consecutive days, with the capacity factor averaging 2.8% during that period. In contrast, New South Wales, Tasmania, and South Australia experienced fewer wind lulls, typically limited to one or two days (Figure 51). Compared to Q2 2024, the total number of wind lull days was lower overall, with fewer longer duration events.

Figure 51 Consecutive days with very low wind conditions highest in Victoria in Q2 2025

Count of wind lulls (<5%) by region – Q2s

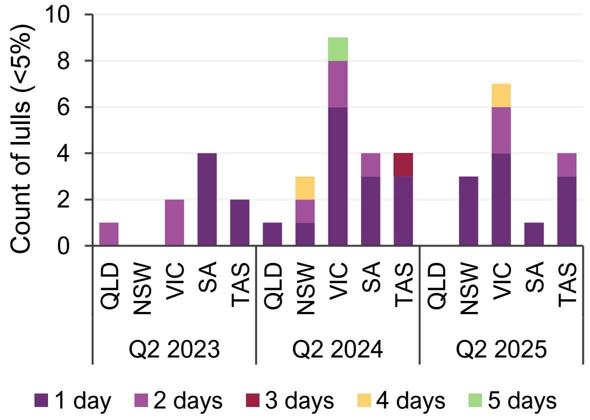
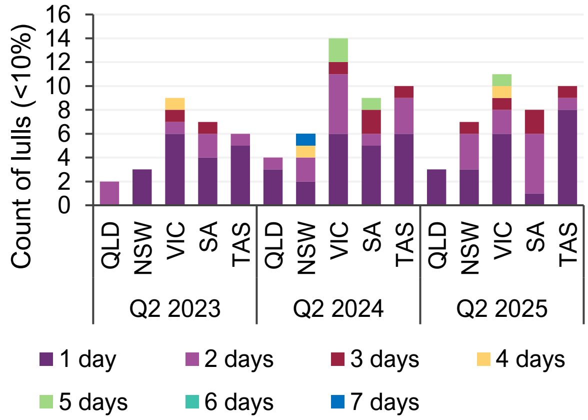


Figure 52 Year-on-year reduction in consecutive days with low wind conditions

Count of wind lulls (<10%) by region – Q2s



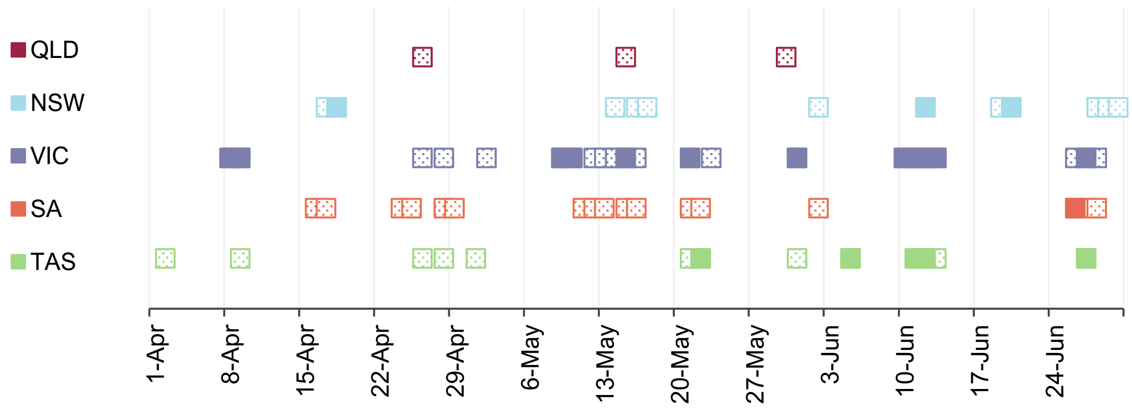
The number of consecutive days with daily average capacity factor under 10% also decreased this quarter compared to Q2 2024 (Figure 52). In Q2 2024, New South Wales experienced a seven-day period with daily capacity average factor under 10%, compared to a maximum of three days with the same conditions this quarter.

[22] Capacity factors are calculated using average dispatched energy divided by maximum installed capacity. Wind farms are included in the capacity factor calculation from the first day of the quarter after they reach full output.

Figure 53 shows the quarterly profile of days with daily average wind capacity factor under 5% and 10% in each NEM region. This highlights the wind lulls that occurred across multiple regions in June, with Victoria experiencing a four-day period with capacity factor less than 5% starting from 10 June 2025. This period overlapped with low wind conditions in Tasmania (two days at less than 5%, followed by one at less than 10%) and New South Wales (one day less than 5%). Similar conditions were experienced in late June, with wind also low in South Australia.

Figure 53 Regional alignment of very low wind days in June 2025

Quarterly profile with daily wind capacity factor below 5% (solid) and 10% (dotted) by region – Q2 2025



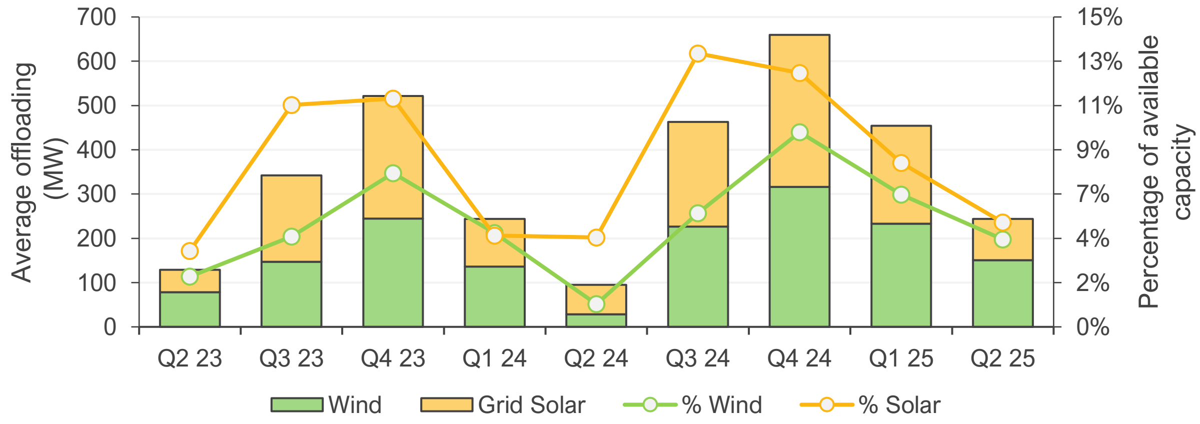
Economic offloading

In Q2 2025, total economic offloading of wind and grid-scale solar generation averaged 244 MW, a 149 MW (+158%) increase compared to Q2 2024 (Figure 54). For wind generation, economic offloading rose sharply from 28 MW in Q2 2024 to 151 MW this quarter, an increase of 123 MW (+434%). As a percentage of average wind availability, offloading grew from 1.1% to 4.3% year-on-year. This higher offloading was concentrated in Victoria (+63 MW) and South Australia (+52 MW) reflecting these regions' larger shares of wind capacity and higher available capacity factors this Q2, as well as their higher incidence of negative spot prices (Section 2.2.3).

Grid-scale solar offloading also increased, rising from 67 MW to 93 MW, with offloading as a percentage of average solar availability growing from 4.4% in Q2 2024 to 5.2% in Q2 2025.

Figure 54 Increased economic offloading of wind and grid-scale solar generation

Average MW offloading and as percentage of availability by fuel type

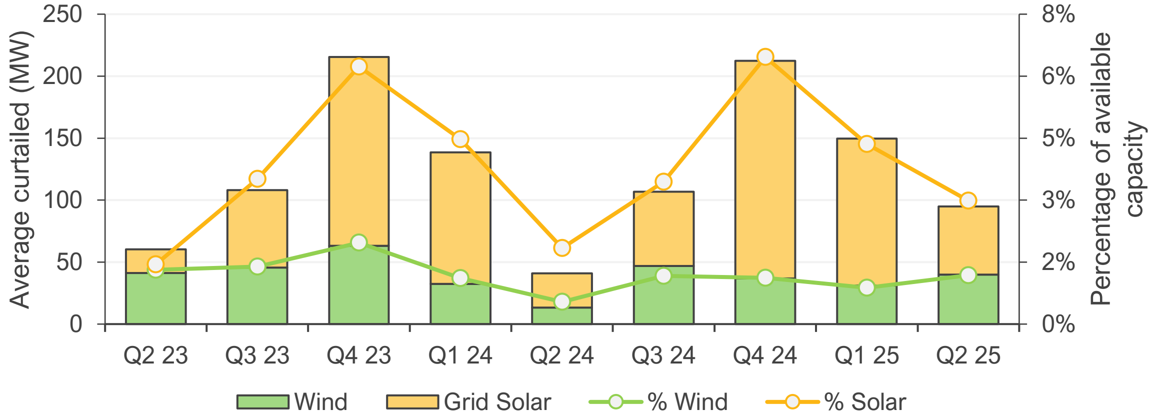


Curtailment

This quarter, average curtailment[23] of wind generation increased by 33 MW, rising to 47 MW, which represents a 248% increase on Q2 2024, but a similar level to Q2 2023 (Figure 55). Curtailment as a percentage of average wind availability rose to 1.3%, up 0.8 pp year-on-year. Grid-scale solar curtailment also increased, with average curtailed output rising from 28 MW to 48 MW. As a percentage of average solar availability, curtailment rose from 1.8% in Q2 2024 to 2.7% in Q2 2025.

Figure 55 Curtailment of wind and grid-scale solar generation increased year-on-year

Average MW curtailment and percentage of availability by fuel type



2.3.5 Renewables contribution

Peak renewable contribution

Peak renewable contribution[24] in the NEM reached 71.3% this quarter, recorded for the half-hour ending 1200 hrs on Saturday, 5 April 2025 (Figure 56). This represents a 4.1 pp increase compared to Q2 2024. The primary driver for this increase was distributed PV, accounting for 46% of total generation in the peak half-hour, a 12.4 pp increase year-on-year. VRE including wind and solar generation, contributed a combined 24% of total supply at this time. Maximum renewable potential[25] for this quarter reached 93.7%, a 15.4 pp increase from 78.4% in Q2 2024.

Figure 57 shows the range of minimum and maximum renewable contribution for the quarter. In Q2 2025, the maximum contribution increased year-on-year to 71.3% and the minimum renewable contribution was 11.9%, recorded on Tuesday, 29 April 2025 during the half hour ending at 0300 hrs, 3.9 pp higher than same quarter last year. The range between maximum and minimum remained similar to last year with a 59.4 pp swing this quarter compared to 59.1 pp in Q2 2024. During Q2 2025, both New South Wales and South Australia achieved new

[23] Curtailment refers to a generator being dispatched below its economic availability (output available at offer prices below the regional reference price) due to the operation of network- or security-related constraints.

[24] Peak renewable contribution is calculated using the NEM renewable share of total generation. This 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 discharge and distributed PV, and excludes battery charging and hydro pumping. Total generation = NEM generation + estimated PV generation.

[25] 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.

records for renewable generation contribution[26]. New South Wales reached a peak of 82.9% during the half hour ending at 1200 hrs on 5 April 2025, while South Australia recorded a peak contribution of 97.8% during the half hour ending at 1300 hrs on 4 June 2025 (Figure 58).

Figure 56 Peak renewable contribution increased year-on-year

Percentage of NEM supply from renewable energy sources at time of peak renewable contribution

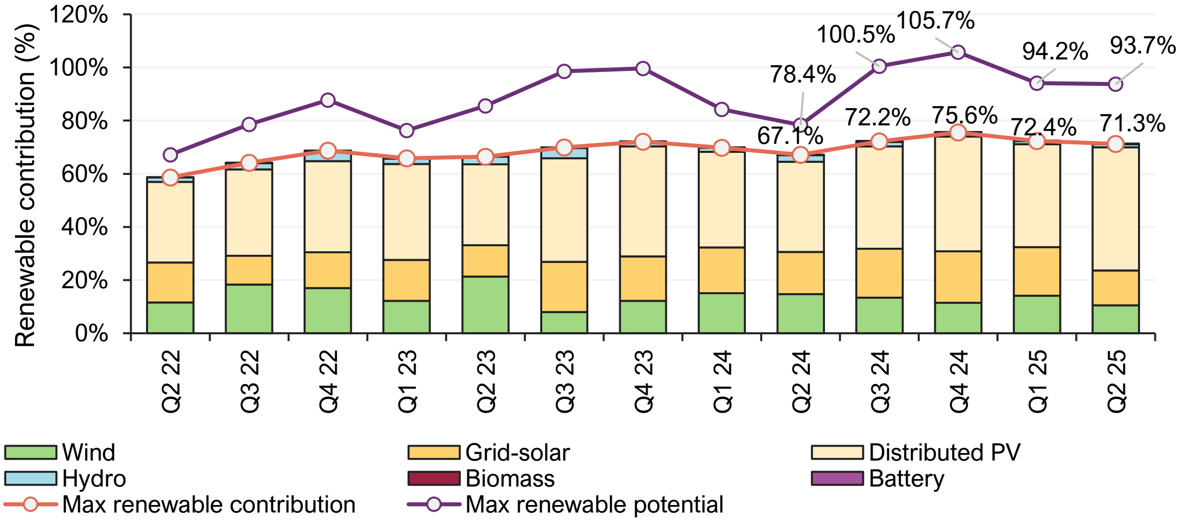


Figure 57 Increased maximum renewable contribution

Range of NEM supply share from renewable energy sources – Q2s

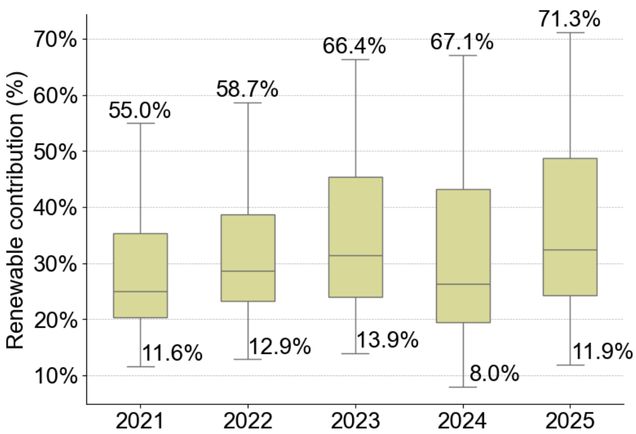
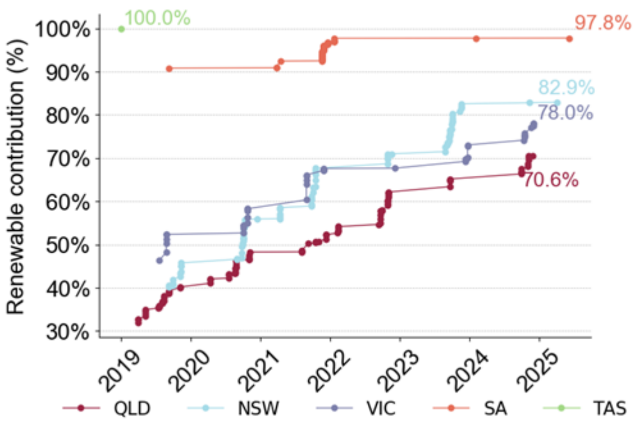


Figure 58 Record high renewable contribution in New South Wales and South Australia

Change in peak renewable contribution record by region



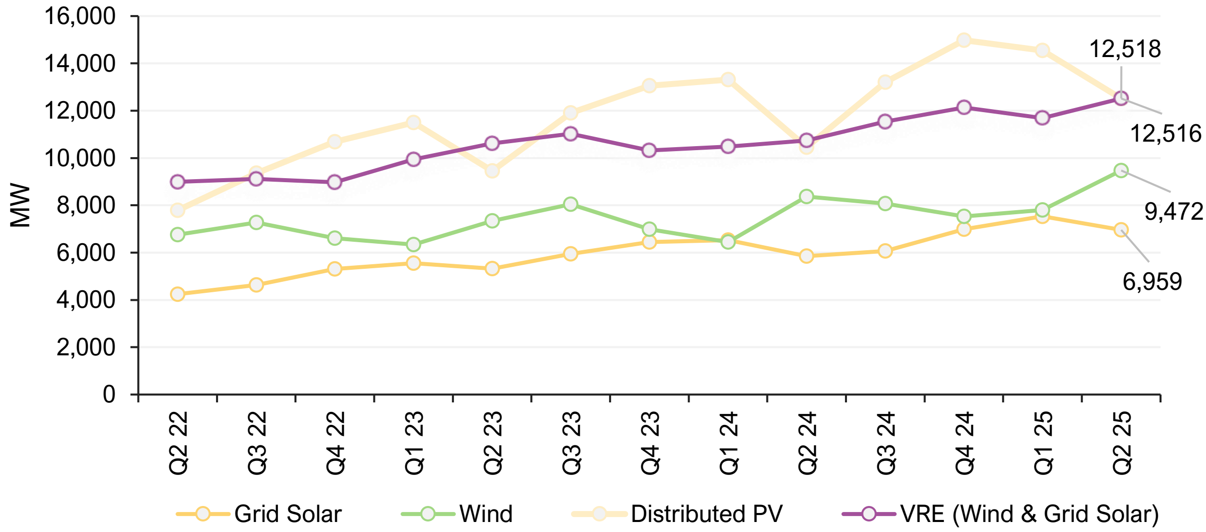
[26] Regional renewable contribution is calculated using the renewable share of total generation in a region. As per peak renewable contribution, this measure is calculated on a half-hourly basis. Renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery discharge and distributed PV, and excludes battery charging and hydro pumping. Regional total generation = regional generation + estimated regional distributed PV generation, and regional renewable contribution = regional renewable generation / regional total generation.

Maximum peak renewable output

Figure 59 shows the highest quarterly peak half-hourly outputs for grid-scale solar, wind, and distributed PV since Q2 2022. During Q2 2025, wind generation set a peak instantaneous output record of 9,472 MW for the half hour ending 2230 hrs on Monday, 23 June 2025. This represents a 13% increase compared to the prior record of 8,375 MW set in Q2 2024, which was also surpassed earlier this quarter with 9,221 MW on Monday, 26 May 2025. VRE generation, comprising wind and grid-scale solar also achieved an all-time high of 12,516 MW on Wednesday, 25 June 2025 for the half hour ending 0930 hrs, a 3.2% increase compared to the record before this quarter commenced, of 12,133 MW set in Q4 2024. VRE generation was supplying 40.5% of the total supply mix at the time of the new record.

Figure 59 Record highs for peak VRE and wind output

Maximum quarterly peak (half-hourly) generation by fuel type



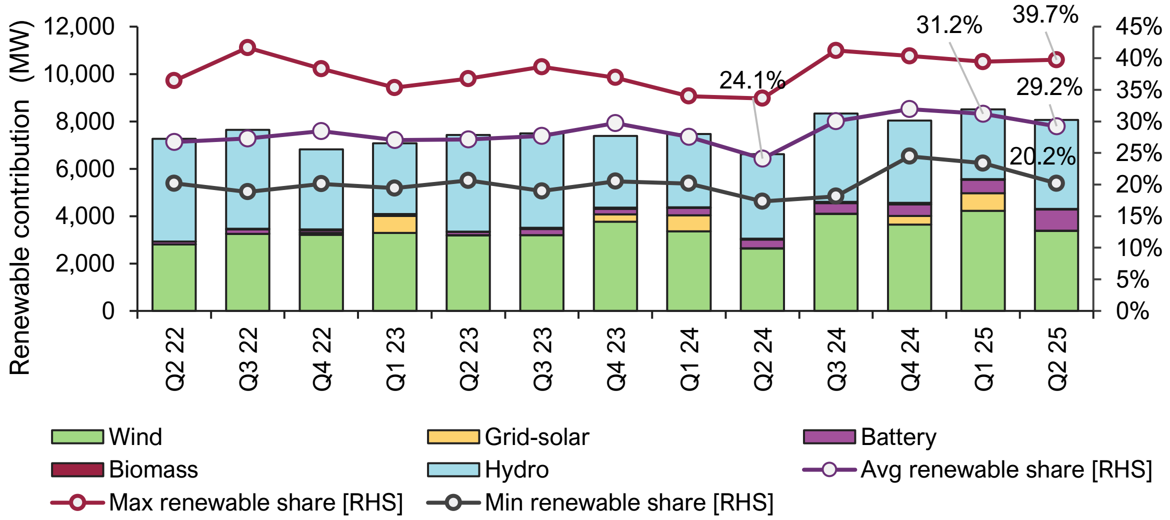
Renewable contribution to maximum demand

Figure 60 shows the contribution of large-scale renewable generation to meeting daily maximum operational demand, averaged across all days in each quarter since Q2 2022[27]. This quarter, the average renewable contribution supplying daily maximum operational demand was 29.2%, a 5.1 pp increase from Q2 2024. The minimum daily value for this measure in Q2 2025 was 20.2%, a 2.8 pp increase year-on-year.

[27] 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.

Figure 60 Year-on-year growth in renewable contribution at daily maximum demand

Maximum, minimum and average renewable share (%) and average renewable contributions (MW) at time of daily maximum operational demand – Quarterly

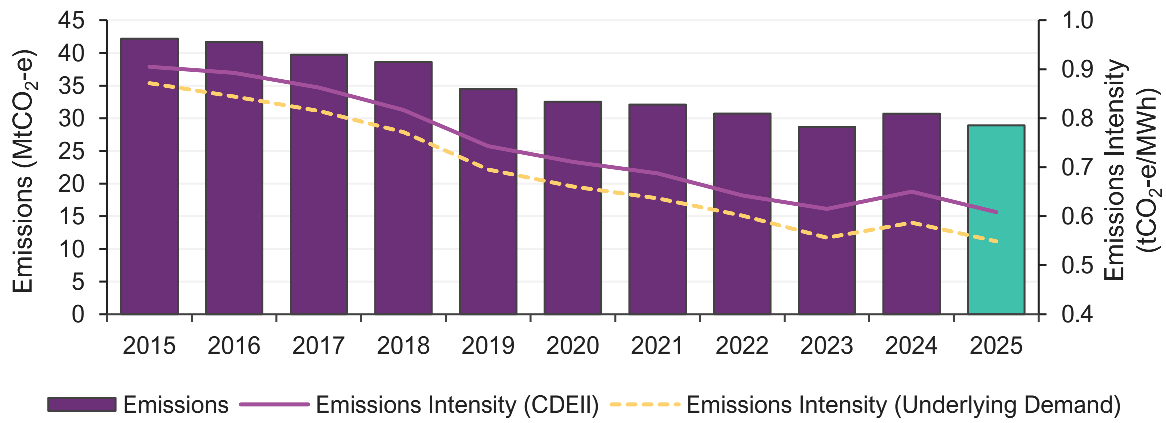


2.3.6 NEM emissions

During Q2 2025, NEM total emissions fell to 28.9 MtCO_2-e, down 1.8 MtCO_2-e (-5.9%) compared to Q2 2024 levels (Figure 61) driven by lower operational demand and lower emissions intensity.

Figure 61 Emissions and emissions intensity decreased compared to Q2 2024

Quarterly NEM emissions and intensity – Q2s



The Carbon Dioxide Equivalent Intensity Index (CDEII) emissions intensity combines sent out metering data with publicly available generator emission and efficiency data to provide a NEM-wide CDEII[28]. This emissions intensity excludes generation from distributed PV, taking into consideration only sent out generation from market generating units. This quarter, CDEII emissions intensity averaged 0.61 tCO_2-e per MWh, a 6.4% decline from 0.65 tCO_2-e per MWh in Q2 2024, and setting a new Q2 quarterly low. The reduction in emission intensity was

[28] https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/carbon-dioxide-equivalent-intensity-index

primarily due to increased grid-scale renewable generation and lower output from coal-fired and gas-fired generators. Emission intensity associated with underlying demand[29] also declined to 0.55 tCO_2-e per MWh, 0.04 tCO_2-e/MWh lower than the same quarter last year.

2.3.7 Storage

Batteries

In Q2 2025, estimated net revenue from grid-scale batteries in the NEM totalled $130.6 million, a significant $89.4 million (+217%) increase from Q2 2024 (Figure 62). Growth in battery capacity and availability both contributed to this increase, in combination with higher levels of spot price volatility this quarter (see Section 2.2.2).

Energy arbitrage[30] net revenue rose sharply to $120.8 million, up $95.5 million (+377%) year-on-year, and accounted for 93% of total net revenue. Estimated revenue from energy discharge reached $148.1 million, a year-on-year increase of $107.6 million (+266%). Energy costs (charging above $0/MWh) increased by $13.3 million (+80%) to reach $29.8 million, while revenue from charging at negative prices increased by $1.2 million (84%) to $2.6 million.

In contrast, frequency control ancillary services (FCAS) revenue declined to $9.8 million (-39%) from $15.9 million in Q2 2024, reducing its share of total net revenue from 39% in Q2 2024 to 7% this quarter (Figure 63).

Figure 62 Significant net battery revenue increase driven by energy arbitrage

Quarterly net revenue from NEM battery systems by revenue stream

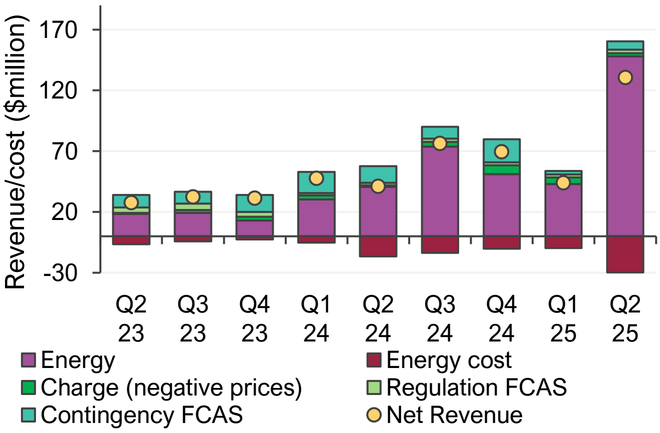
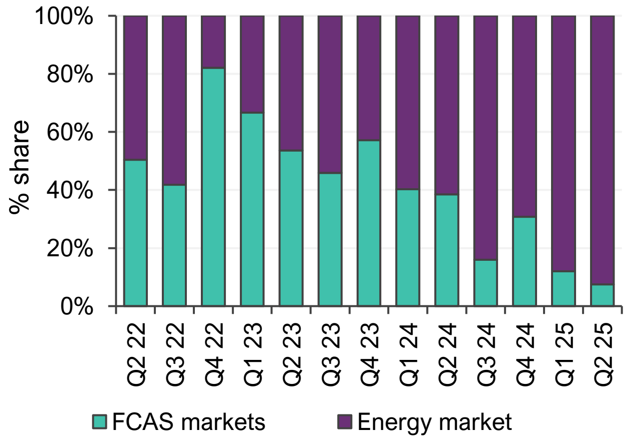


Figure 63 Proportion of battery revenue from FCAS markets decreased

Percentage share of battery net revenue – energy vs FCAS markets



Between the end of Q2 2024 and the end of Q2 2025[31], the following major battery systems with a total capacity of 3,116 MW/6,415 MWh have entered the NEM and either reached full operation or are undergoing commissioning (Table 5).

[29] Total emissions from NEM electricity generation including distributed PV, divided by underlying demand.

[30] Energy arbitrage revenue for batteries includes three components: 1) revenue from discharging (selling energy), 2) revenue from recharging during negative priced intervals, and 3) cost of recharging at non-negative prices (buying energy).

[31] Also in Q2 2025, the Melbourne Renewable Energy Hub (400 MW/800 MWh) in Victoria was registered into the NEM market systems but did not commence commissioning.

Table 5 New battery systems in the NEM

Battery	Region	First quarter of generation	Capacity
Greenbank	Queensland	2025 Q1	200 MW / 400 MWh
Tarong	Queensland	2025 Q2	300 MW / 600 MWh
Ulinda Park	Queensland	2025 Q2	155 MW / 298 MWh
Western Downs	Queensland	2024 Q3	255 MW / 510 MWh
Eraring	New South Wales	2025 Q1	460 MW / 1073 MWh
Waratah	New South Wales	2024 Q3	850 MW / 1679 MWh
Blyth	South Australia	2024 Q3	200 MW / 400 MWh
Mannum	South Australia	2025 Q2	100 MW / 200 MWh
Templers	South Australia	2025 Q2	111 MW / 285 MWh
Koorangie	Victoria	2025 Q1	185 MW / 370 MWh
Latrobe Valley	Victoria	2025 Q2	100 MW / 200 MWh
Rangebank	Victoria	2024 Q4	200 MW / 400 MWh

With this growth in battery capacity, NEM-wide average quarterly battery discharge availability increased by 801 MW (+81%) from 985 MW in Q2 2024 to 1,786 MW this quarter, and average battery discharge in the NEM increased to 162 MW, more than doubling the average of 74 MW observed in Q2 2024.

Battery storage set a new peak discharge record this quarter, reaching 1,756 MW for the half hour ending 1800 hrs on Thursday, 12 June 2025. This represents a 60% increase compared to the prior quarterly record of 1,099 MW, set in Q1 2025. Battery charge also reached a new high, at 1,221 MW in the half-hour ending 1300 hrs on 20 June 2025.

The NEM-wide price spread[32] for batteries rose to $342/MWh this quarter, up from $157/MWh in Q2 2024, reflecting higher price volatility year-on-year (Figure 64). Average NEM battery discharge and charge increased across most all hours of the day (Figure 65). Significantly, average battery discharge during the evening peak period between 1600 and 2000 hrs increased by 300 MW from Q2 2024, while average battery charge during the day between 1000 and 1600 hrs also increased, up 270 MW year-on-year.

[32] The battery price spread represents the arbitrage revenue per MWh of generation, calculated as arbitrage revenue/generation.

Figure 64 Year-on-year rise in NEM battery discharge and price spread

Average quarterly battery discharge (MW) and price spread ($/MWh)

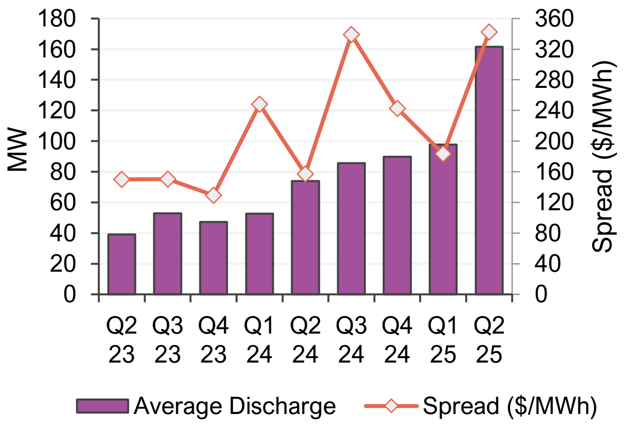


Figure 65 Increased battery contribution across all hours of the day

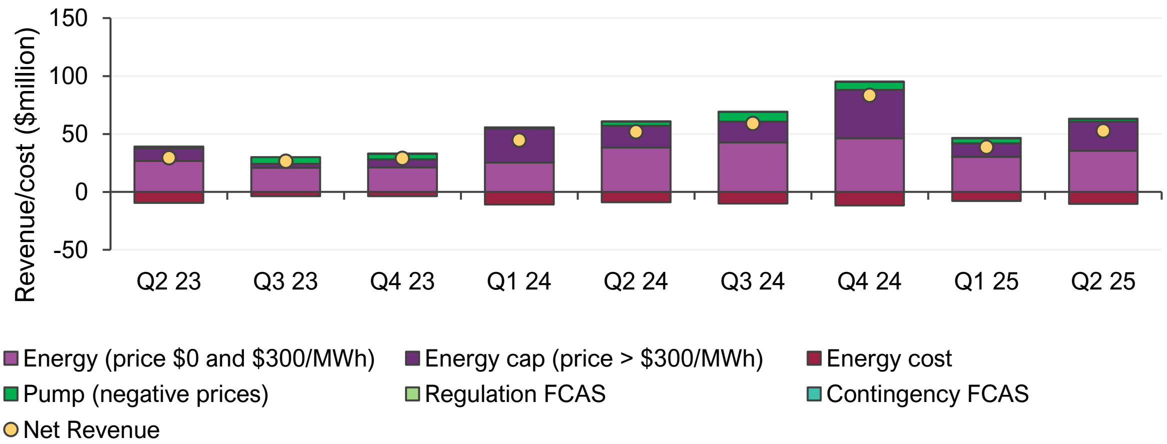
Average battery charge and discharge (MW) by time of day

Pumped hydro

Estimated net pumped hydro revenue was $52.6 million (+1.3%) in Q2 2025, up slightly from $51.9 million in Q2 2024 (Figure 66). The uplift was due to increased net revenue at Wivenhoe totalling $41.8 million this quarter, up $14.3 million from the same quarter last year. This growth was largely attributable to heightened spot price volatility in Queensland, with revenue from prices exceeding $300/MWh rising by $16.7 million to reach $17.5 million. In contrast, Shoalhaven's net revenue declined by $13.7 million, totalling $10.8 million in Q2 2025 due to partial outages limiting availability throughout the quarter. Shoalhaven's revenue from prices above $300/MWh fell by $10.5 million to $7.6 million, and revenue from prices at or below $300/MWh also dropped 40% to $5.3 million this quarter.

Figure 66 Pumped hydro revenue rose slightly from Q2 2024

Quarterly revenue from NEM pumped hydro by revenue stream



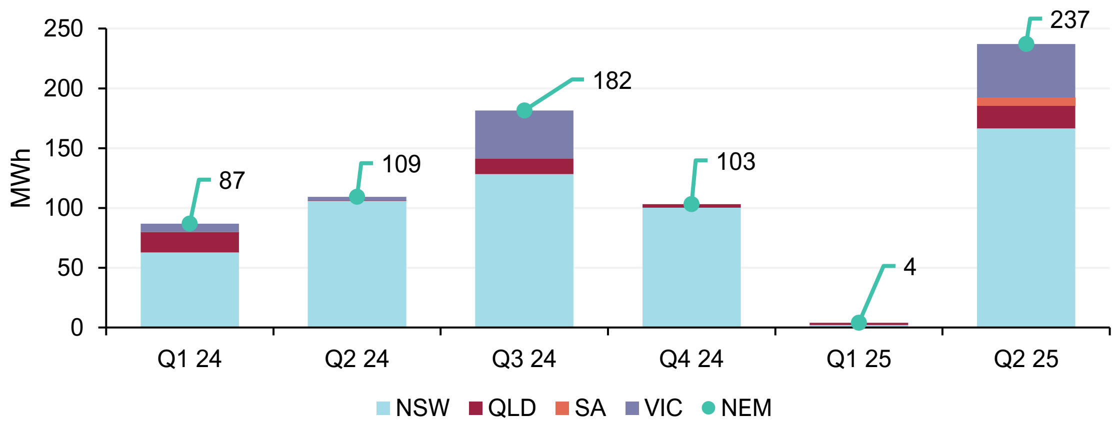
2.3.8 Demand side flexibility

In Q2 2025, wholesale demand response (WDR) dispatch rose sharply to 237 MWh, more than doubling from 109 MWh in Q2 2024 and surging from just 4 MWh in Q1 2025 (Figure 67). This marked the highest quarterly dispatch since Q2 2022, driven by increased price volatility across all regions.

New South Wales contributed the majority of WDR activity, accounting for 166 MWh, or 70% of the total volume for the quarter. This was a 57% increase from 106 MWh in Q2 2024. Other states also recorded strong year-on-year growth. Queensland increased from 1 MWh to 19 MWh, South Australia from zero to 7 MWh, and Victoria from 3 MWh to 45 MWh.

Figure 67 Increased wholesale demand response dispatched year-on-year

Total quarterly WDR energy dispatch

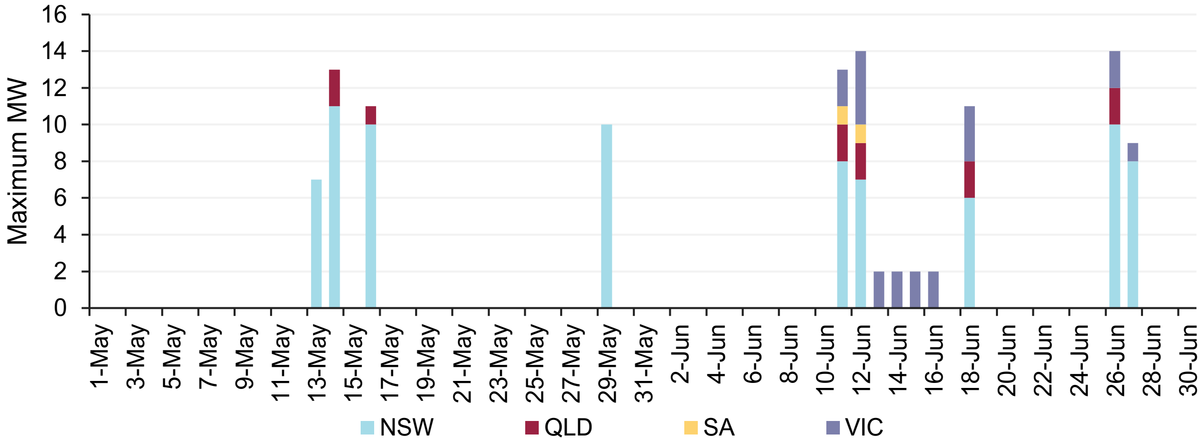


In New South Wales, WDR was dispatched across 398 dispatch intervals. The most significant activity occurred on 12 June 2025, when 159 intervals accounted for 40 MWh (Figure 68). During these periods, wholesale spot prices in the region averaged $2,953/MWh, with a peak WDR output of 7 MW. On the same day, Queensland recorded 7 MWh of dispatch across 55 intervals, South Australia dispatched 5 MWh over 56 intervals, and Victoria delivered 9 MWh across 46 intervals.

Another major dispatch event occurred on 26 June 2025. New South Wales dispatched 41 MWh with a peak output of 10 MW, while average spot prices during the 53 dispatch intervals reached $9,184/MWh. Victoria also saw elevated activity on the same day, dispatching 8 MWh with a peak output of 2 MW at an average spot price of $9,912/MWh over 47 intervals.

Figure 68 Active participation from wholesale demand response across May and June

Maximum WDR dispatch by day – May and June 2025



2.3.9 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[33] monitored by AEMO to track the progress of projects going through the connections process include application, proponent implementation, registration, commissioning, and model validation.

The increased volume of connection applications approved over the past two financial years are now starting to connect to the NEM and reach their full operating capacity. This is reflected in both the full output capacity (Figure 69) and the capacity currently in commissioning (Figure 70). The elevated rate of application approvals has remained steady for the past six quarters which should enable the steady flow of projects through to full output if investment conditions continue to remain stable.

During the past year there has been an increase in standalone battery projects, which now make up 44% of the capacity of projects in the end-to-end connections process.

During Q2 2025:

- 6.5 gigawatts (GW) of applications were approved across 18 projects.
- 1.5 GW of plant across nine projects were registered and connected to the NEM.
- 1.5 GW of plant across 10 projects progressed through commissioning to reach full output: Wollar Solar Farm (280 MW), Stubbo Solar Farm 2 (198 MW), Wunghnu Solar Farm (75 MW), Mannum 2 Solar Farm (29.99 MW), Kerang Solar Farm (29.9 MW), Greenbank Battery Energy Storage System (200 MW), Koorangie Energy Storage System (185 MW), Latrobe Valley Battery Energy Storage System (100 MW), Goyder South 1A Wind Farm (201 MW), and Goyder South 1B Wind Farm (196 MW).

[33] Application stage establishes technical performance and grid integration requirements. In proponent implementation 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.

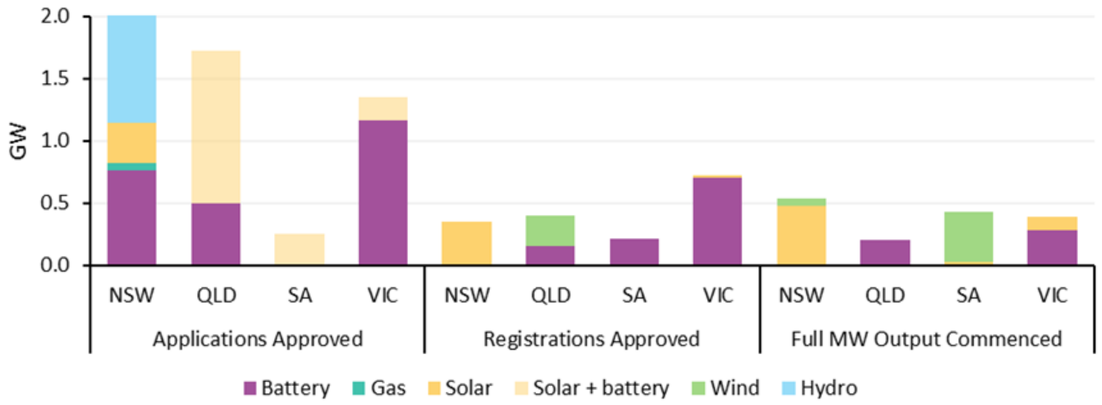
Please refer to the Connections Scorecard[34] for further information.

At the end of Q2 2025, AEMO's snapshot of connection activities in progress shows that:

- There was 53.0 GW of new capacity progressing through the end-to-end connection process from application to commissioning, 39% more than at the same time last year when 38.1 GW was in-progress.
- The capacity of battery projects in the end-to-end connection process increased 83% over the year, from 12.6 GW to 23.1 GW. Solar projects increased by 6% from 9.8 GW to 10.4 GW. Hybrid solar with battery increased 68% from 4.6 GW to 7.7 GW. Wind increased 9% from 7.1 GW to 7.7 GW, hybrid wind with battery was steady at 0.4 GW. Hydro was steady at 2.6 GW and gas increased 10% from 0.8 GW to 0.9 GW.
- The total capacity of in-progress applications remains steady, currently 17.5 GW.
- 23.1 GW of new capacity projects are finalising contracts and under construction (proponent implementation), compared with 14.6 GW a year ago (58% increase).
- Registration project capacity has been steady, currently 5.6 GW.
- There was 6.9 GW of new capacity in commissioning, compared to 2.1 GW at the same time last year (228% increase). The commissioning measure considers all plant in commissioning up to the plant reaching its full output.

Figure 69 Steady progress of application approvals and strong quarter for registrations in Q2 2025

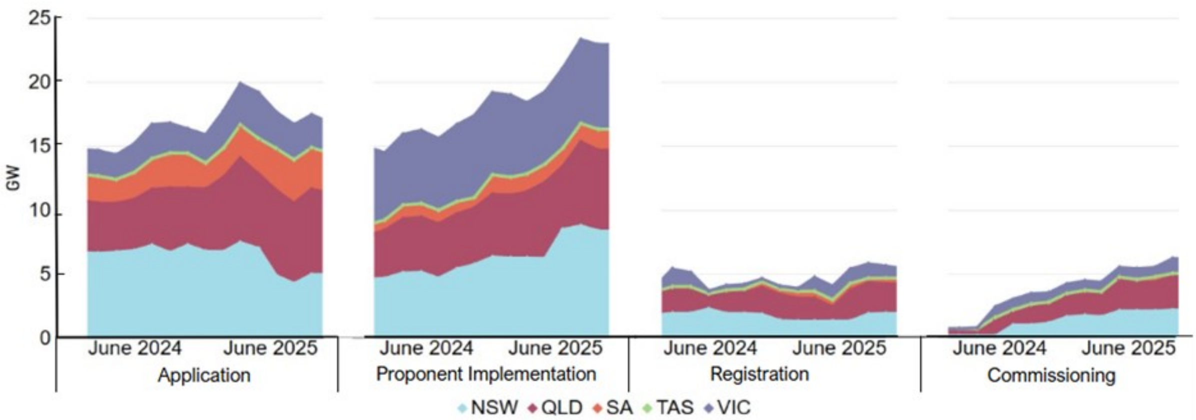
Application approved, registrations and plant commissioned to full output during Q2 2025



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

Figure 70 Increased capacity progressing through Proponent Implementation and Commissioning stages of the connections pipeline over the year

12 months trend of connection capacity in progress



2.4 Inter-regional transfers

Total inter-regional transfers reached 3,618 GWh in Q2 2025, a 12.6% increase from 3,212 GWh in Q2 2024. Transfer volumes were equivalent to 7.6% of NEM operational demand for the quarter.

Flow out of Victoria to other regions saw the most significant year-on-year changes, particularly across VNI, where average net northward flows rose sharply from 68 MW in Q2 2024 to 239 MW in Q2 2025 (Figure 71). Transfers from Victoria to South Australia also increased, from an average of 94 MW to 131 MW.

Meanwhile, Tasmania continued to import heavily from Victoria via Basslink, with average net southward flows rising to 242 MW this quarter, up from 144 MW in the same quarter last year.

Figure 71 Increased flows from Victoria to other regions

Quarterly inter-regional transfers

Compared to Q2 2024, net flows across the Victoria to New South Wales interconnector were higher in most hours of Q2 2025, supported by a $23/MWh price premium in New South Wales over Victoria. The increase in northward transfers was partly due to the low baseline in Q2 2024, which had seen reduced flows driven by lower wind generation in Victoria (Figure 72).

As a result of higher flows across VNI, export limits were binding in 27% of dispatch intervals in Q2 2025, up from 17% in Q2 2024 (Figure 73). This was particularly evident during evening peak and overnight hours, contributing to a wider price separation between the two regions compared to the same quarter last year.

Figure 72 Victoria – New South Wales transfers bounced after a significant drop in Q2 2024

Victoria to New South Wales transfers – Q2s

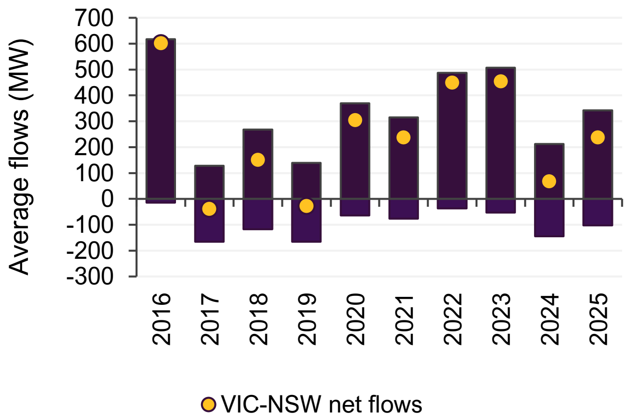
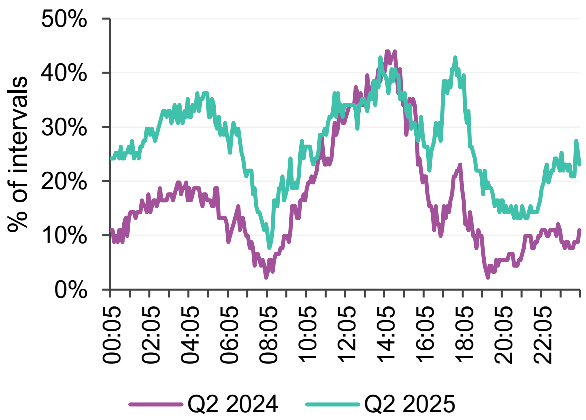


Figure 73 Increased VNI binding during evening peak and overnight period

Average VNI export limit binding percentage – Q2s



2.4.1 Inter-regional settlement residue (IRSR)

Positive IRSR totalled $137.1 million in Q2 2025, down $6.3 million (-4.4%) from Q2 2024. The main driver of this decline was lower positive residue on flows from Queensland into New South Wales, which fell from $103.0 million in Q2 2024 to $91.9 million this quarter (Figure 74), due to reduced imports into New South Wales. Imports across QNI averaged 465 MW in Q2 2025, 42 MW lower than the 507 MW recorded in Q2 2024. This decline was partly driven by a narrower price gap between the two regions, which fell from $73/MWh in Q2 2024 to $40/MWh in Q2 2025. Positive IRSR into Victoria also fell by $4.6 million, primarily due to reduced flows from New South Wales – down from an average of 145 MW in Q2 2024 to 103 MW in Q2 2025.

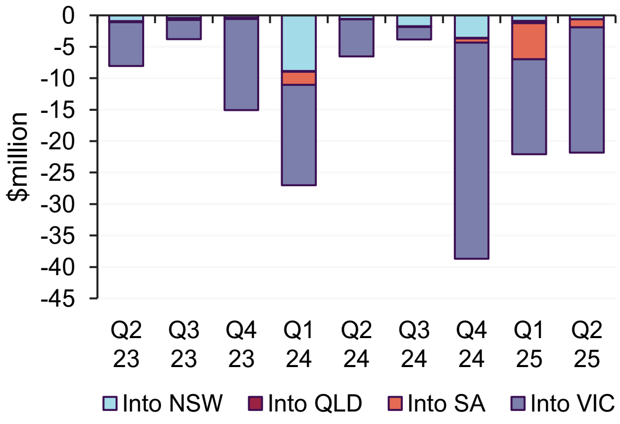
Negative IRSR increased significantly in Q2 2025, growing from -$6.5 million in Q2 2024 to -$21.8 million (Figure 75). The main contributor was higher negative IRSR on flows into Victoria from New South Wales, which totalled -$19.1 million this quarter, compared to just -$5.8 million in the same period last year. This was largely driven by constraints associated with transmission outages in New South Wales forcing southward flows on VNI at times of price volatility in New South Wales.

Figure 74 Slight reduction in positive IRSR

Quarterly positive IRSR by region

Figure 75 Negative IRSR increased, particularly into Victoria from New South Wales

Quarterly negative IRSR by region



2.5 Frequency control ancillary services

Total FCAS costs reached $23 million in Q2 2025, representing approximately 0.3% of the total cost of consumed energy for the quarter. This marks a $21 million decrease compared to the same period last year.

While cost reductions were recorded across all mainland NEM regions, the majority came from Queensland, where FCAS costs fell by $20.6 million - from $29.7 million in Q2 2024 to just $9 million this quarter (Figure 76). This sharp decline was primarily driven by a reduction in contingency lower 6-second (L6SE) prices in Queensland, which dropped to $5.9/MWh after reaching a high of $48.2/MWh in Q2 2024, when prices were elevated due to transmission constraints requiring local sourcing of FCAS capability on several occasions.

Raise regulation (RREG) was the largest contributor to FCAS costs this quarter, accounting for $8.0 million, or 34% of the total (Figure 77). It also saw the largest year-on-year increase, rising by $4.2 million. The L6SE service incurred the second-highest cost at $4.9 million (21% of total FCAS costs), but dropped substantially (-$19.1 million) from Q2 2024 when QNI outages had led to L6SE price volatility in Queensland. Contingency raise 6-second (R6SE) costs followed closely, at $4.7 million or 20% of total FCAS costs.

Figure 76 Notable reduction in FCAS costs

Quarterly FCAS costs by region

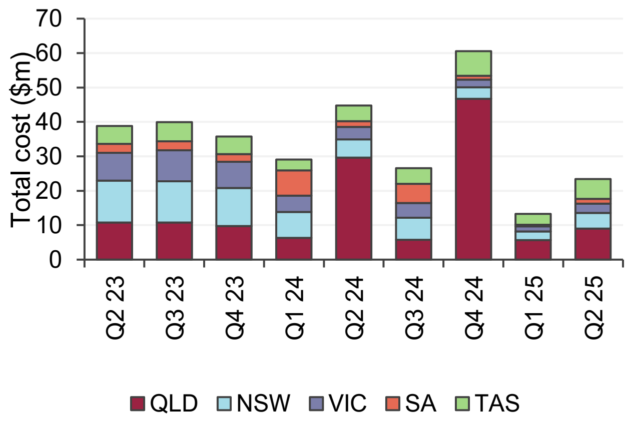
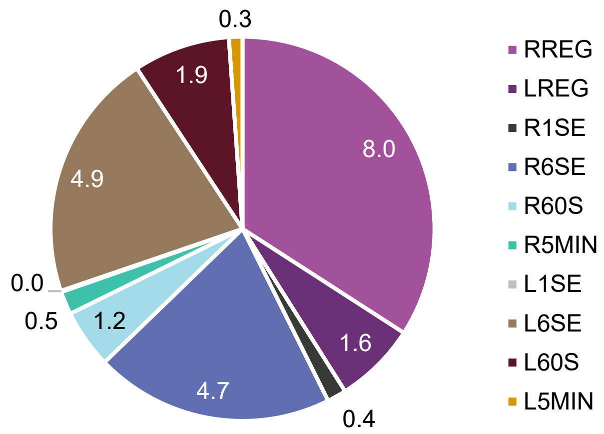


Figure 77 High share for regulation FCAS costs

NEM quarterly FCAS cost per service – Q2 2025 ($m)



Batteries remained the dominant source of FCAS provision in Q2 2025, accounting for 54% of total enablement volume (Figure 78). This was supported by a 42 MW increase in average battery enablement compared to Q2 2024. Demand response (DR) and virtual power plants (VPPs) also recorded strong year-on-year growth, with increases of 78 MW and 20 MW, respectively (Figure 79). In contrast, black coal and hydro saw the largest declines in enablement, particularly for contingency services.

Figure 78 Batteries dominated FCAS market share

FCAS volume market share by technology – Q2 2025

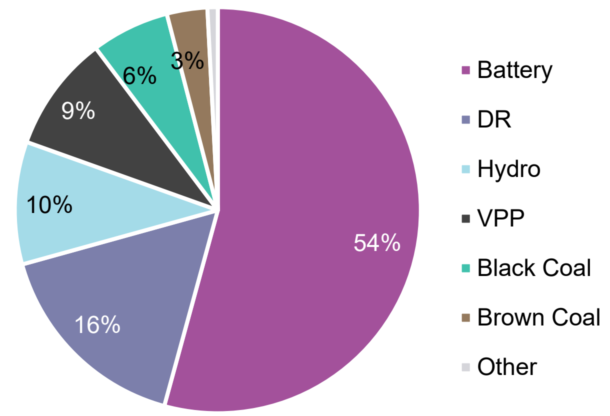
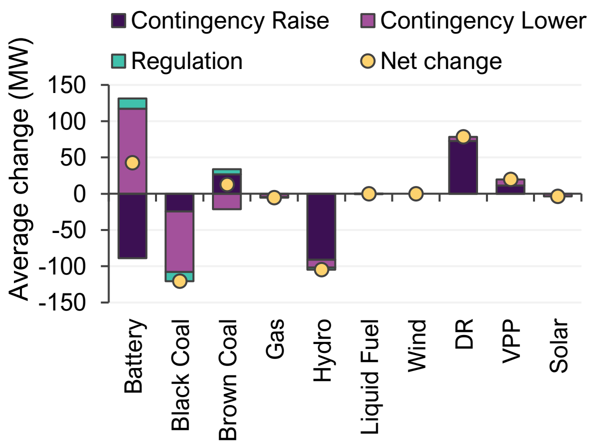


Figure 79 Reduction in black coal and hydro FCAS enablement, growth in demand response and batteries

Change in FCAS enablement by technology – Q2 2025 vs Q2 2024



2.6 The Frequency Performance Payment (FPP) Reform

The Frequency Performance Payment (FPP) arrangements officially commenced on Sunday, 8 June 2025, under the Primary Frequency Response Incentive Arrangements rule[35]. This reform introduced new incentive and

[35] Refer AEMO's Frequency Performance Payments project at https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/frequency-performance-payments-project.

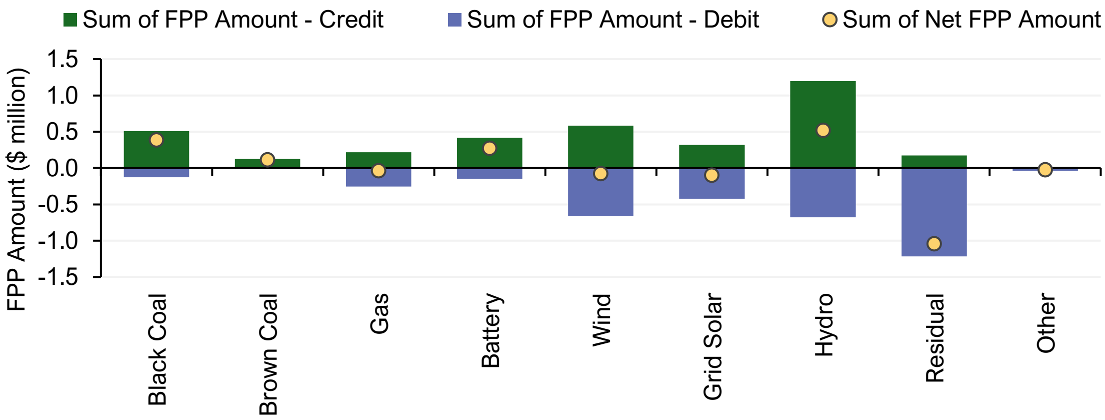
payment arrangements for electricity generators, large loads, and batteries based on how their active power deviations affect system frequency.

Under the new FPP framework, incentive payments (credits) are allocated to units that contribute positively and calculated using the Requirement for Corrective Response (RCR) and individual units' Contribution Factor (CF). To fund these incentives, payments (debits) are charged to units whose deviations move system frequency further from the target. Any leftover deviations after adding up all the measured deviations are assigned to the Residual. Combined, the payments form a zero-sum system in each five-minute trading interval.

Figure 80 shows net FPP outcomes by fuel type including the sum of credits, debits, and net payments over the 23-day period from the FPP's commencement (8 June 2025) to the end of Q2 (30 June 2025).

Figure 80 Hydro, black coal and batteries received highest net credits while the residual incurred largest net debits under new FPP arrangement

Sum of Frequency Performance Payment (FPP) Amounts by fuel type - 8 June to 30 June



During this period, total incentive payments of $3.6 million were credited, with $1.4 million occurring on 12 June 2025 driven by the high marginal cost of providing regulation FCAS services that day.

Early settlement data shows that the Residual category, which includes the sites without appropriate metering to calculate individual contribution factors, incurred the largest share of debit charges. The Residual group recorded $1.2 million in debits, representing 34% of the total funds distributed through FPP, resulting in a net debit of $1.0 million. Wind and solar units each recorded net debits of approximately $0.1 million by the end of the period. While some intervals delivered credits, these were outweighed by larger debits in others.

On the credit side, hydro generators received the highest share of incentives, totalling $1.2 million, or 34% of all credits distributed during the period.

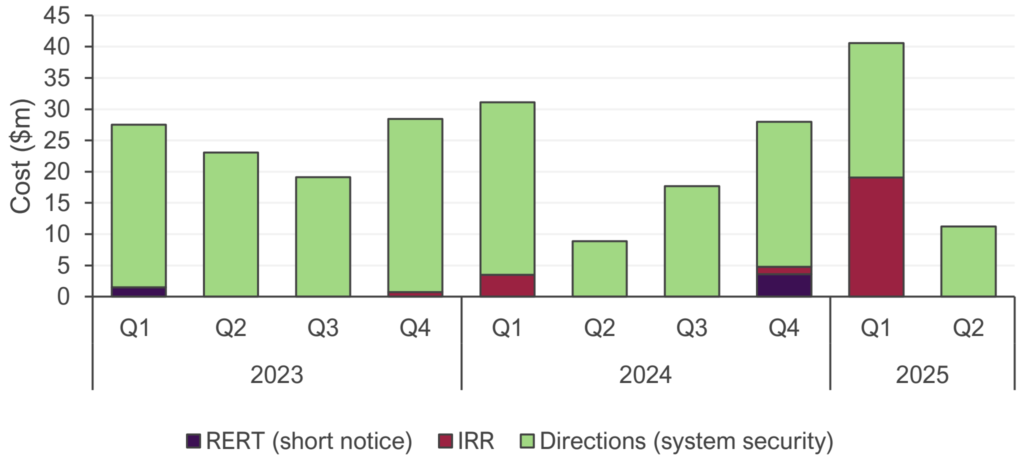
The reform also introduced a new method for recovering costs associated with Regulation FCAS, replacing the Causer Pays approach.

2.7 Power system management

Power system management costs were estimated at $11.2 million in Q2 2025 (Figure 81), representing approximately 0.1% of the total cost of consumed energy for the quarter. This reflects an increase of $2.4 million compared to Q2 2024, but a much larger drop of $29.3 million from Q1 2025, when costs were significantly higher due to the inclusion of a $19.1 million interim reliability reserve (IRR) payment.

Figure 81 System security direction costs down year-on-year

Estimated quarterly system security costs by category

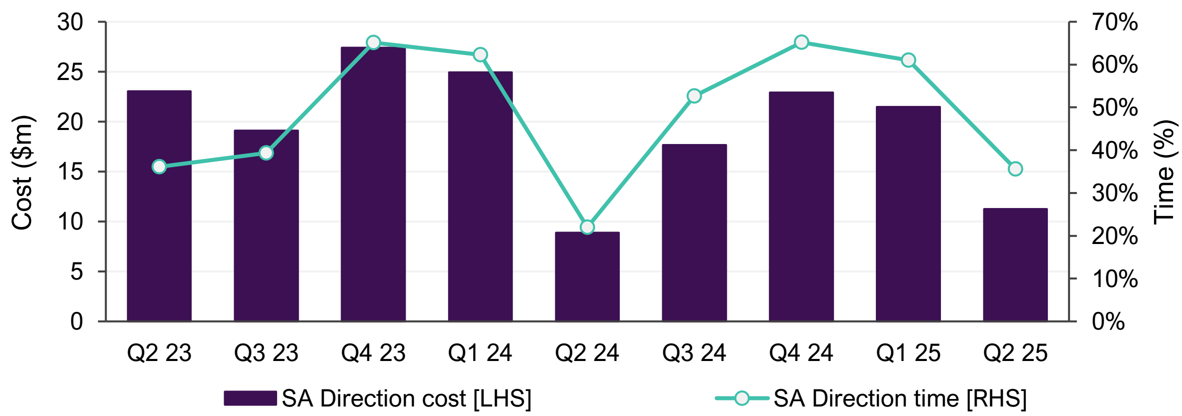


2.7.1 System security energy directions

System security directions were issued in South Australia during 36% of dispatch intervals in Q2 2025, up from 22% in Q2 2024 (Figure 82). The volume of gas-fired generation directed in South Australia also rose, averaging 23 MW for the quarter, 7 MW higher than the same period last year. The share of directed gas generation as a portion of South Australia's total gas-fired output increased from 3% to 5%. This increase in average MW directed, combined with a 20% rise in the estimated average compensation price[36] for South Australia (from $179/MWh in Q2 2024 to $214/MWh in Q2 2025), resulted in a 26% increase in direction costs to $11.2 million.

Figure 82 Direction frequency of South Australian generators was slightly higher year-on-year

Time and cost of energy only system security directions – South Australia Q2 2023 to Q2 2025



[36] Directed generators receive a compensation price calculated as the 90th percentile of spot prices over a trailing 12-month window. Directed participants may also make a claim for additional compensation to cover loss of revenue and net direct costs minus trading amounts for energy and market ancillary services and minus any compensation for directed services that has already been determined by AEMO.

3 Gas market dynamics

3.1 Wholesale gas prices

Quarterly wholesale gas prices decreased from Q2 2024 and were also 7% lower than Q1 2025. The average price across all AEMO markets was $12.36/GJ compared to $13.66/GJ in Q2 2024 (Table 6).

Table 6 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q2 2025	Q1 2025	Q2 2024	Change from Q2 2024
Victoria Declared Wholesale Gas Market (DWGM)	11.60	12.18	13.60	-15%
Adelaide	12.90	13.51	13.86	-7%
Brisbane	12.40	13.64	13.66	-9%
Sydney	12.59	13.33	13.94	-10%
Gas Supply Hub (GSH)	12.31	13.63	13.21	-7%

Key factors influencing the movement of prices throughout Q2 2025 are summarised in Table 7, with further analysis and discussion referred to relevant sections elsewhere in this report.

Table 7 Wholesale gas price levels: Q2 2025 drivers

Lower offer prices into DWGM and Short Term Trading Market (STTM) in May and June	Q2 2025 saw average prices in May 20% lower and June 16% lower than Q2 2024, due to an increase in the proportion of volumes offered into the domestic market at prices below $14/GJ which led to a reduction in the average price for the whole quarter (Figure 84). May 2025 offers were influenced by an increase in supply from Queensland to southern markets, and an increase in Longford available capacity, combined with lower AEMO markets and gas-fired generation demand compared to May 2024.
Increase in Victorian supply, Longford capacity and Iona storage inventory ending Q2 2025 higher than Q2 2024	Victorian supply was 4.1 PJ higher than Q2 2024, with increased production at the Otway, Bass Gas and Orbost facilities. Additionally, while Longford produced similar volumes to Q2 2024, it had an additional 6.2 PJ of capacity offered into the market, mainly due to the unplanned offshore maintenance issues in June 2024. This increase in southern states supply combined with lower AEMO market demand led to Iona storage inventory ending Q2 2025 2.2 PJ higher than Q2 2024.

International prices reversed the upward trend observed in Q1 2025 and Q2 2024. This decrease was reflected in downward movements in the Australian Competition and Consumer Commission (ACCC) netback price to June 2025, with corresponding forward prices then slightly higher at between $16.13/GJ and $17.17/GJ over the next six months (Figure 83). Drivers for international prices are discussed in Section 3.1.1.

Prices in April 2025 were consistent with those recorded in Q1 2025, averaging $13.08/GJ for the month. From 1 May, increased supply from Queensland to the domestic market, combined with mild weather and subdued gas-fired generation demand, resulted in lower prices across both the Short Term Trading Market (STTM) and the Declared Wholesale Gas Market (DWGM). For the first time since January 2024, prices at all locations fell below $10/GJ during the month.

In contrast, the second half of June 2025 saw a sharp price increase, peaking at $19.70/GJ in Brisbane and $18.04/GJ in the DWGM on 18 June 2025. This surge was primarily driven by elevated gas-fired generation, which spiked from mid-June and led to record winter gas-fired generation demand on 26 June 2025 (see Section 3.2.1).

The heightened demand triggered a significant drawdown of Iona storage inventory and a substantial uptick in supply from Queensland to southern markets. Nonetheless, prices remained below June 2024 levels, which experienced even greater storage drawdowns and record supply from Queensland to southern markets. This is reflected in market participants increasing bid volumes below $14/GJ (Figure 84).

Figure 83 Domestic prices lower mainly due to lower prices in May 2025

ACCC netback and forward prices[37], DWGM and Short Term Trading Market (STTM) Brisbane average gas prices by month

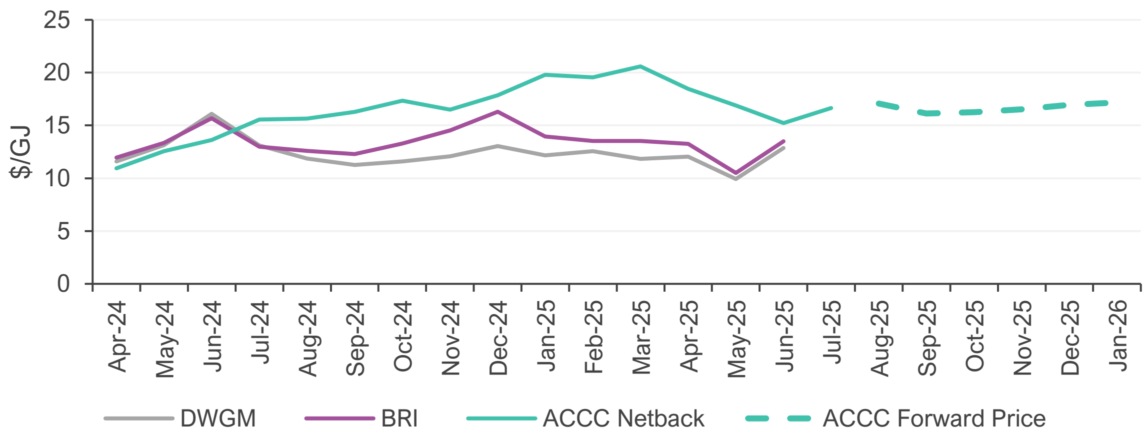
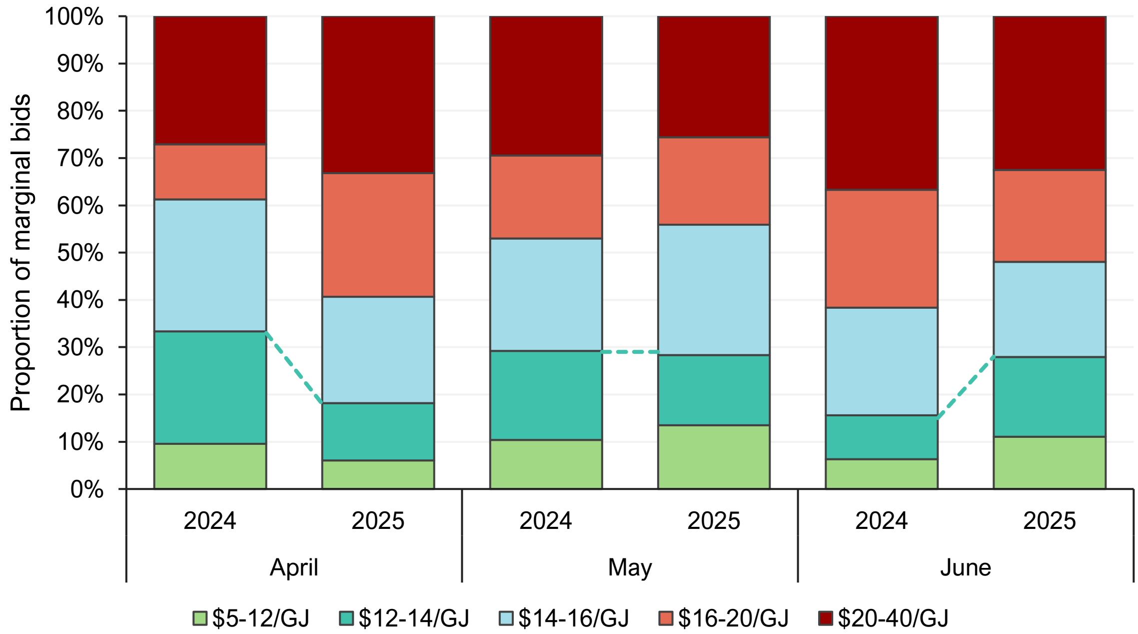


Figure 84 Increased proportion of DWGM bids in June at lower prices compared to 2024

DWGM – proportion of marginal bids by price band – Q2 2025 vs Q2 2024 by month



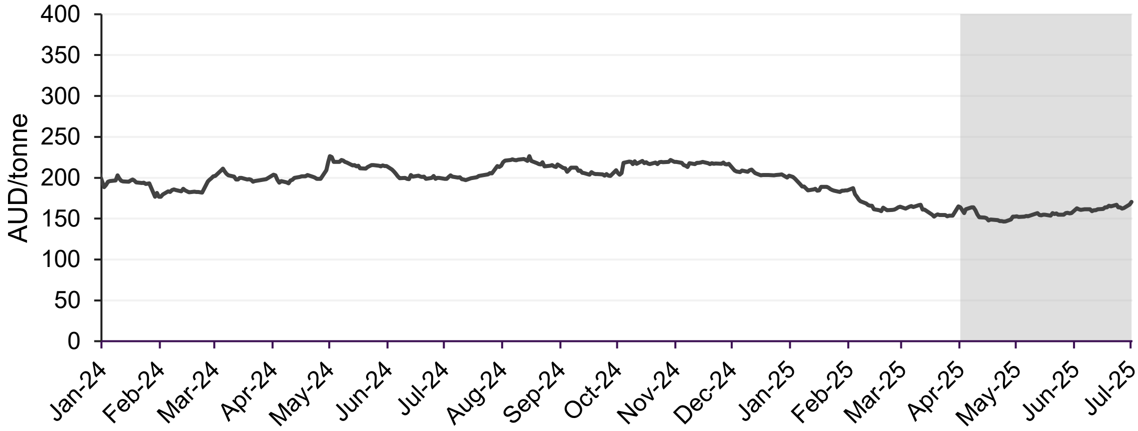
[37] ACCC, LNG netback price series published on 1 July 2025, https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

3.1.1 International energy prices

Newcastle export coal prices averaged $157/tonne this quarter, a reduction from $171/tonne in Q1 2025, and $207/tonne in Q2 2024 (Figure 85). This represented the lowest quarterly average price since Q2 2021, with weaker global demand due to increased domestic coal output in India and China and rising renewable energy adoption among key importers[38].

Figure 85 Traded thermal coal prices at lowest quarterly average since Q2 2021

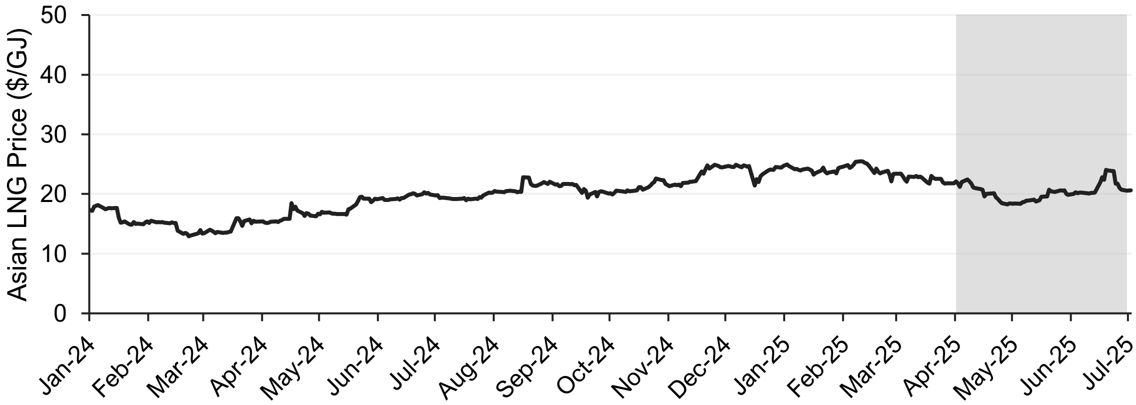
Newcastle 6,000 kcal/kg thermal coal price in A$/Tonne daily



Source: Bloomberg ICE data

Figure 86 Volatility in Asian spot LNG prices during the quarter

Asian LNG price in A$/GJ daily



Source: Bloomberg ICE data

Asian spot LNG prices ended the quarter slightly lower, despite significant volatility that saw prices swing both above and below the mean (Figure 86). In the first half of the quarter, prices dropped to as low as A$17.30/GJ (delivered to North Asia), primarily driven by ongoing trade tensions between the United States and China coupled with higher than average storage inventories across North Asia[39].

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[38] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly June 2025, at https://www.industry.gov.au/publications/resources-and-energy-quarterly-june-2025.

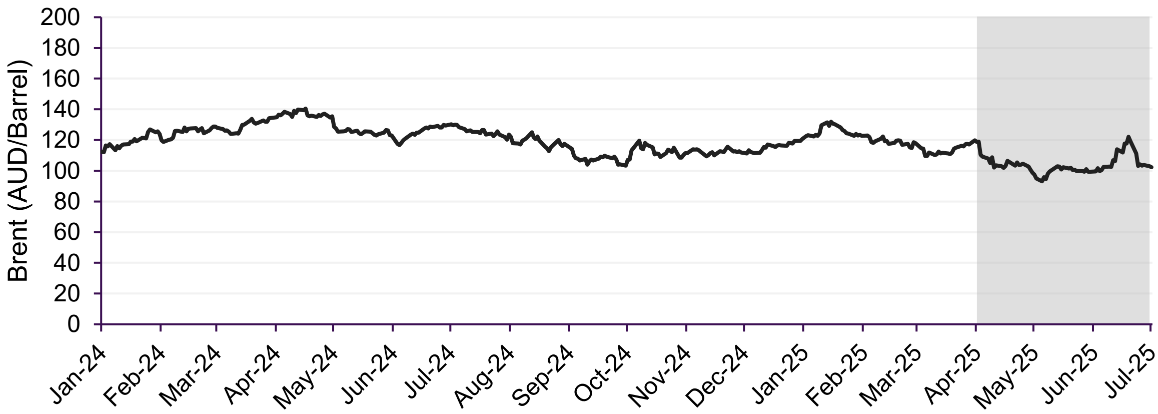
[39] Reuters, April 2025: https://www.reuters.com/business/energy/asian-spot-prices-slip-8-month-low-weak-demand-recession-concerns-2025-04-11/

Prices then stabilised until mid-June, when tensions in the Middle East escalated. These events led to fears over a potential closure of the Strait of Hormuz (where approximately 20% global LNG is supplied from – specifically Qatar and Iran). This triggered a sharp spike in Asian LNG spot prices, however, as these geopolitical tensions eased toward the end of the quarter, prices subsided as quick as they rose, resulting in an overall reduction in average price for the quarter[40].

A new development in the Asian LNG market was the entry of LNG Canada, which began exports from its Kitimat facility in British Columbia[41]. With an expected capacity of up to 14 million tonnes per annum (MTPA), the project is expected to supply LNG primarily to Asian markets, further diversifying regional supply sources and could put downward pressure on both Asian LNG and global gas prices.

Figure 87 Brent Crude oil prices averaged A$104/barrel

Brent Crude Oil in A$/Barrel daily



Source: Bloomberg ICE data

The Brent crude oil markets followed a similar trend to Asian LNG prices (Figure 87). As noted above, the price spike in mid-to-late June was as a result of the tensions in the Middle East, which quickly subdued before the end of the quarter. Prices averaged A$104/barrel for the quarter, down A$15/barrel from Q1 2025. This decline was largely attributed to the continued rollback of voluntary production cuts by OPEC+[42], as well as record global electric vehicle (EV) adoption. The International Energy Agency (IEA) notes that EVs now account for approximately one in 10 cars on the road in China and one in 20 in Europe[43].

3.2 Gas demand

Total east coast gas demand decreased by 3% compared to Q2 2024 (Figure 88 and Table 8). AEMO markets saw the largest fall in overall demand (-7 PJ), with the largest decrease of 6.6 PJ in Victoria's DWGM due to a combination of lower industrial, commercial and residential demand, and warmer temperatures. This decline continues the trend in commercial and industrial demand discussed in the Q1 2025 QED report, and is discussed

[40] Reuters, June 2025: https://www.reuters.com/business/energy/oil-hits-five-month-high-after-us-hits-key-iranian-nuclear-sites-2025-06-23/.

[41] Reuters, June 2025: https://www.reuters.com/business/energy/lng-canada-produces-first-liquefied-natural-gas-export-sources-say-2025-06-22/.

[42] IEA, Oil Market Report May 2025: https://www.iea.org/reports/oil-market-report-may-2025.

[43] IEA, Global EV Outlook, May 2025: https://www.iea.org/reports/global-ev-outlook-2025/trends-in-electric-car-markets-2.

further in Section 3.2.2. Despite a new record daily winter demand in June, gas-fired generation decreased by 3 PJ overall, and Queensland LNG production saw a small decrease of 2 PJ.

Figure 88 Lower gas demand across all sectors

Components of east coast gas demand change – Q2 2025 to Q2 2024

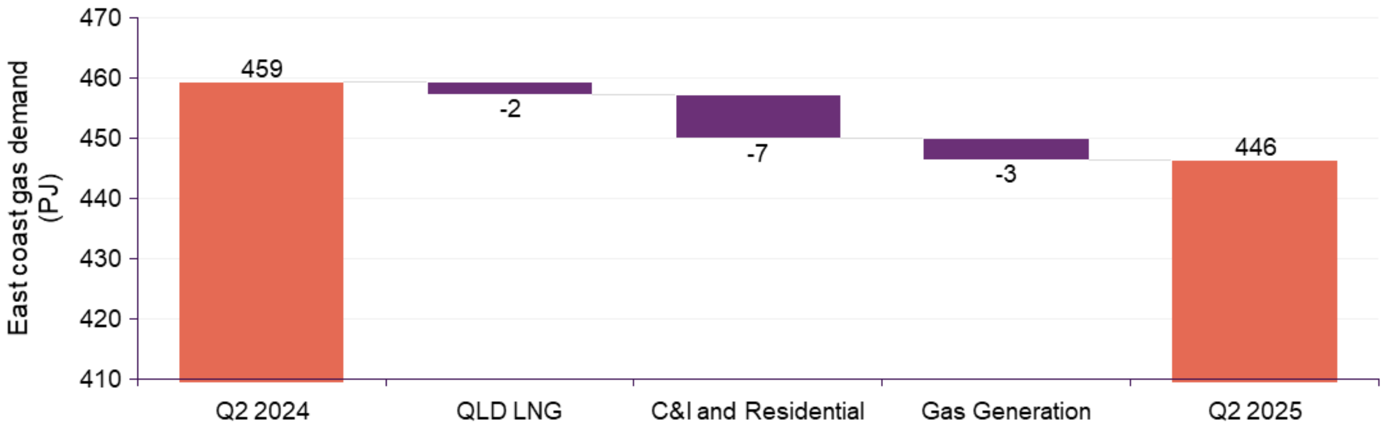


Table 8 Gas demand – quarterly comparison

Demand (PJ)	Q2 2025	Q1 2025	Q2 2024	Change from Q2 2024
AEMO markets *	77.0	45.0	84.3	-9%
Gas-fired generation **	30.5	17.8	34.0	-10%
Queensland LNG	338.9	366.0	341.0	-1%
Total	446.4	428.9	459.3	-3%

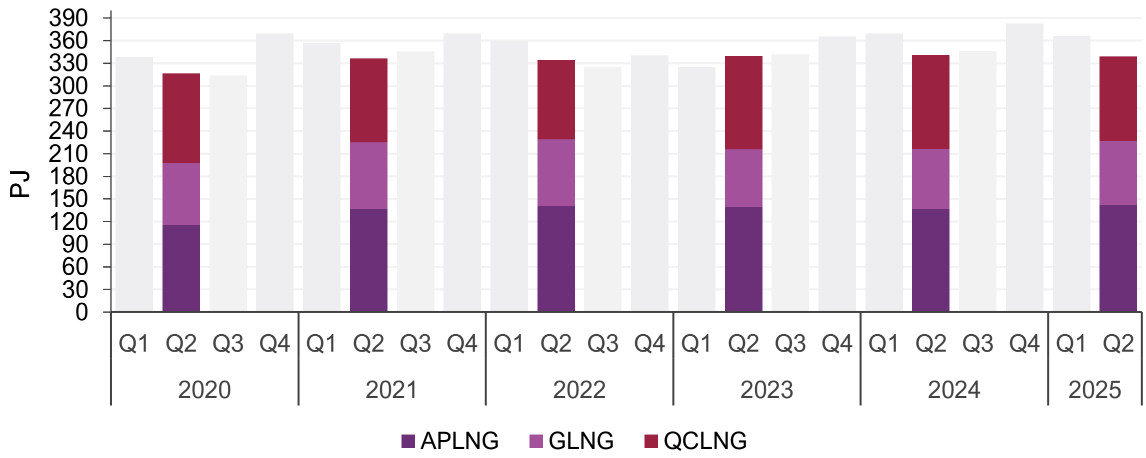
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand slightly decreased compared to Q2 2024 solely due to a decrease in QCLNG demand, offset by increases in APLNG and GLNG demand. The QCLNG decrease was due to a planned maintenance outage from 16 May to 10 June, which also impacted Woleebee Creek and Ruby Jo plant production. The combined total demand of 339 PJ is the third highest LNG export demand for Q2, with the record set in Q2 2024 (Figure 89).

By participant, in comparison to Q2 2024, QCLNG demand decreased by 12 PJ, while APLNG increased by 5.1 PJ and GLNG increased by 4.7 PJ. There were 86 cargoes exported during the quarter, down from 87 cargoes in Q2 2024.

Figure 89 Queensland LNG production decreased due to maintenance at QCLNG

Total quarterly pipeline flows to Curtis Island

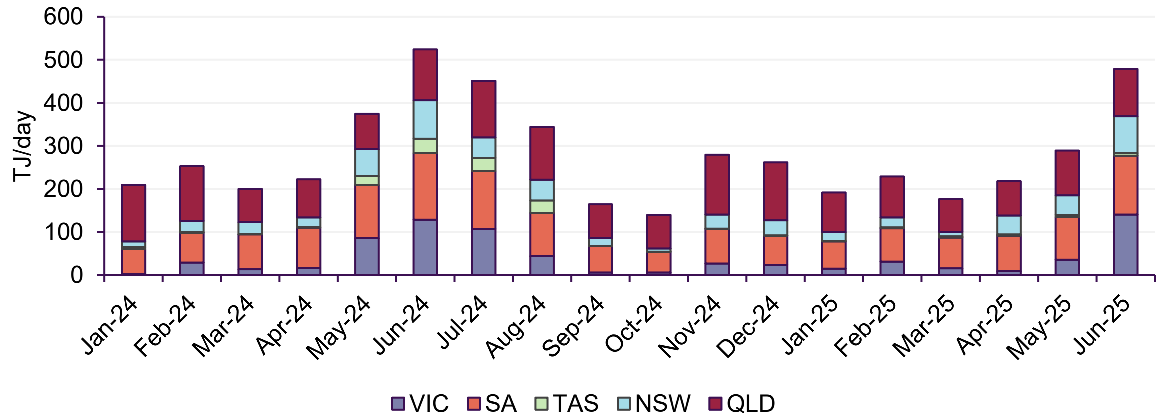


3.2.1 Gas-fired generation

While demand from gas-fired generation increased significantly in June 2025 compared to April and May 2025, total gas-fired generation demand across all regions was still lower than June 2024 (Figure 90).

Figure 90 Large increase in gas-fired generation demand in June but slightly below 2024 levels

Average daily gas-fired generation demand by state



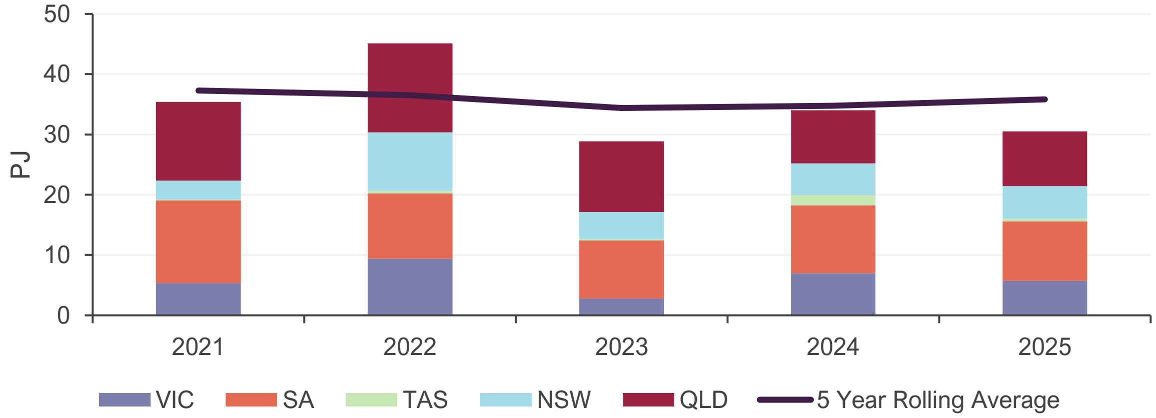
Total gas-fired generation demand across the east coast reached 1,049 TJ on 26 June 2025 setting a new winter record and the fourth highest daily total on record for any time of year. Five of the top ten winter gas-fired generation demand days on the east coast in the last ten years occurred in June 2025, with three of those occurring in the last week of June. The factors contributing to this increase in demand are discussed in Section 2.2.1.

Victoria recorded a new winter peak on 26 June 2025 with daily demand reaching 382 TJ, surpassing the previous winter record of 356 TJ set in June 2024. This marked the fourth highest daily demand ever recorded in the state, regardless of season. Notably, five of Victoria's top ten winter days for gas-fired generation demand occurred in June 2025.

The significant increase in June gas-fired generation, after lower-than-average generation in April and May, increased the gas-fired generation demand for the quarter to be comparable to Q2 2023 (+1.6 PJ), while slightly lower than Q2 2024 (-3.5 PJ) (Figure 91).

Figure 91 Decrease in Q2 gas-fired generation demand compared to Q2 2024

Q2 total gas-fired generation demand by state 2021-2025



3.2.2 Victorian DWGM demand

In the Victorian DWGM, Tariff D customers are defined as large commercial and industrial users that consume more than 10 TJ/year or more than 10 GJ/hour of gas. These customers typically have flat consumption profiles across a year, with their gas consumption often linked to economic conditions. They are also generally less sensitive to weather conditions than residential and small commercial gas users (known as Tariff V customers).

Continuing the trend observed in Q1 2025, Q2 2025 saw the largest decrease in Tariff D demand for any Q2 since the DWGM began in March 1999, with demand decreasing from 14.6 PJ in Q2 2024 to 13.4 PJ in Q2 2025, an 8% decrease (Figure 92).

Figure 92 Victorian industrial and large commercial demand continued Q1 trend and remained at lowest level since at least the DWGM began

Q2 DWGM Tariff D demand

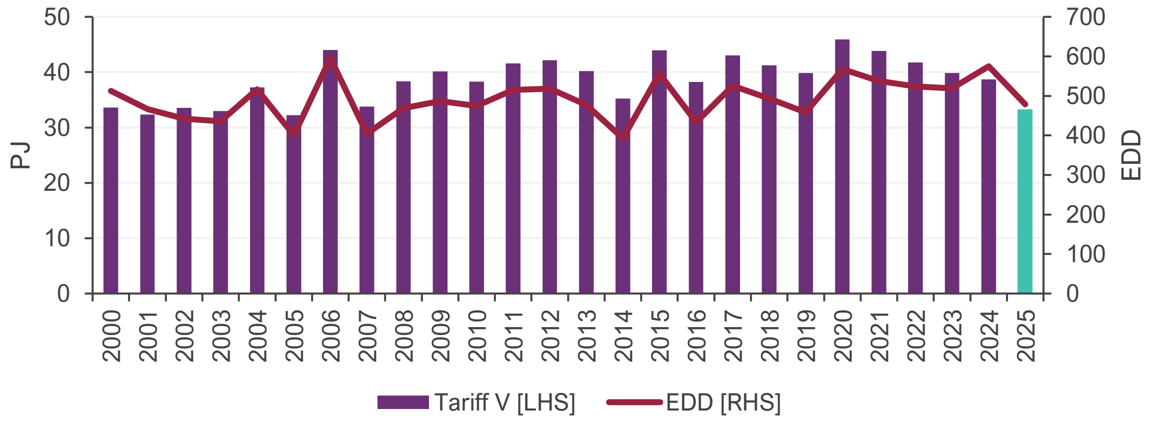
As reported in the Q1 2025 QED report, the 2025 *Victorian Gas Planning Report* (VGPR)[44] notes that Victoria has seen significant declines in manufacturing from 2021 to 2024, including closures in large heavy industries such as Qenos, the Mobil Altona refinery, Oceania Glass, as well as dairy, food manufacturing and paper industries.

Tariff V demand fell to the lowest level in Q2 since 2005 (Figure 93). As much of Tariff V demand is typically used for heating, it can vary from year to year depending on weather conditions. To capture the impact of weather on demand, AEMO uses a measure known as the Effective Degree Day (EDD), which considers the temperature profile, average wind speed, sunshine hours, and the season for the gas day. The higher the EDD, the higher the likely gas use. The cumulative EDD in Q2 2025 of 479 was the lowest since 2019, which was 459. Despite Q2 2019 recording a lower EDD total (therefore warmer), Q2 2025 Tariff V demand was 6.6 PJ lower.

The 2025 VGPR notes that Tariff V consumption has continued a downward trend, which AEMO believes is due to a combination of electrification of gas loads, cost of living pressures and reduced commercial activity, though at this stage AEMO cannot quantify each of these components.

Figure 93 Victorian Tariff V demand declined to its lowest level since 2005

Q2 DWGM Tariff V demand and EDD

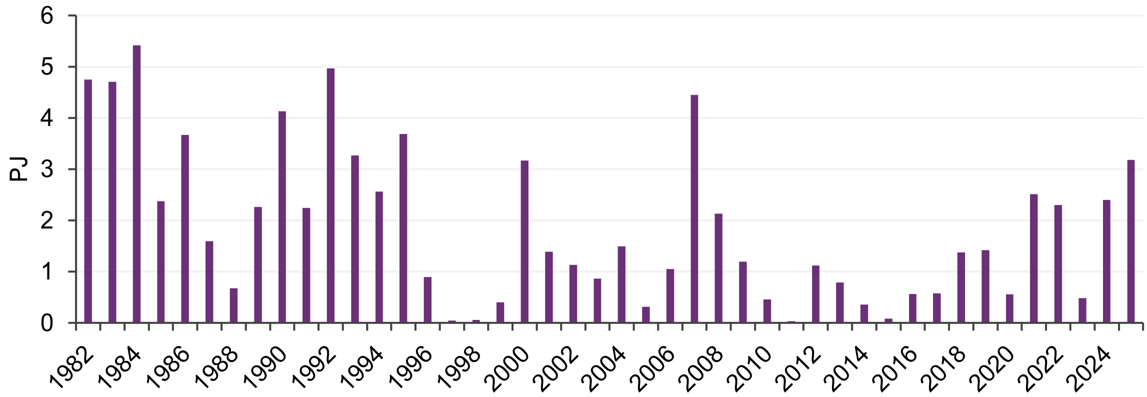


Monthly gas-fired generation demand for June 2025 in the DWGM reached its highest level in any June since 2007 (Figure 94). The elevated demand in June 2007 was largely driven by drought conditions, which reduced hydro generation due to water conservation measures. Between 2008 and 2020, gas-fired generation in June remained relatively low, but has steadily increased since 2021 except for June 2023, when above average temperatures and strong renewable generation moderated gas-fired generation demand.

[44] 2025 VGPR, Section 1.1 https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

Figure 94 Highest DWGM gas-fired generation monthly demand for June since 2007

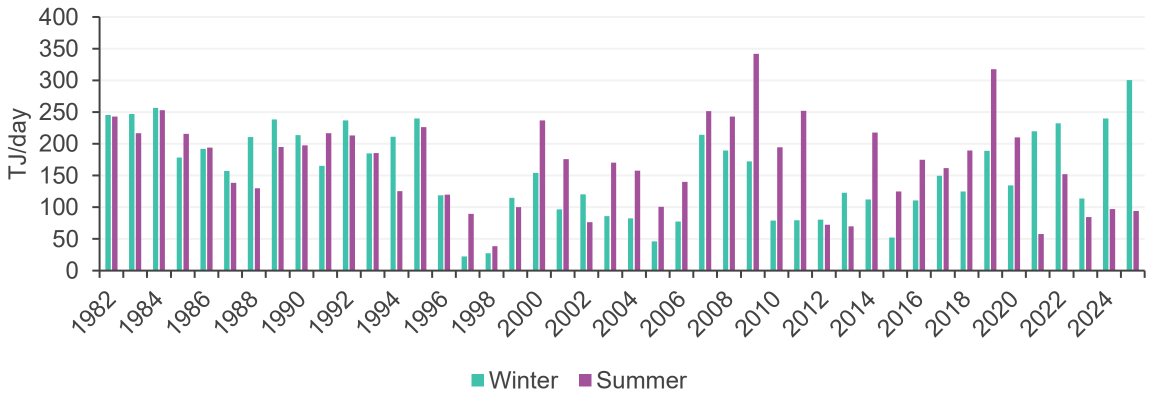
DWGM gas-fired generation[45] aggregate June demand 1982-2025



Since 1997, seasonal peak demand for gas-fired generation in the DWGM has typically occurred during summer. However, since 2021 this trend has shifted, with peak demand now occurring in winter (Figure 95). Notably, a new daily winter record was set on 26 June 2025, reaching 301 TJ and surpassing the previous record of 256 TJ that had stood since 6 June 1984, noting that this excludes Mortlake and Bairnsdale stations as while they are in Victoria, they are located outside the boundaries of the DWGM.

Figure 95 Victoria DWGM gas-fired generation peak day demand has switched to winter peaking since 2021

Highest DWGM gas-fired generation demand in summer and winter[46] 1982-2025



3.3 Gas supply

3.3.1 Gas production

East coast gas production decreased by 15.0 PJ (-3%) compared to Q2 2024 (Figure 96). Key changes included:

- Queensland production decreased by 15.2 PJ, with assets operated by QCLNG decreasing by 10.1 PJ, GLNG operated assets by 4.4 PJ, and APLNG operated assets by 1.3 PJ. Gas demand for Queensland LNG exports

45 DWGM gas-fired generation excludes Mortlake and Bairnsdale stations as these stations while in Victoria are outside the Declared Transmission System (DTS) which form the DWGM boundary. While the Victorian Gas Market began in March 1999, this chart represents gas-fired generation demand from inside the DTS.

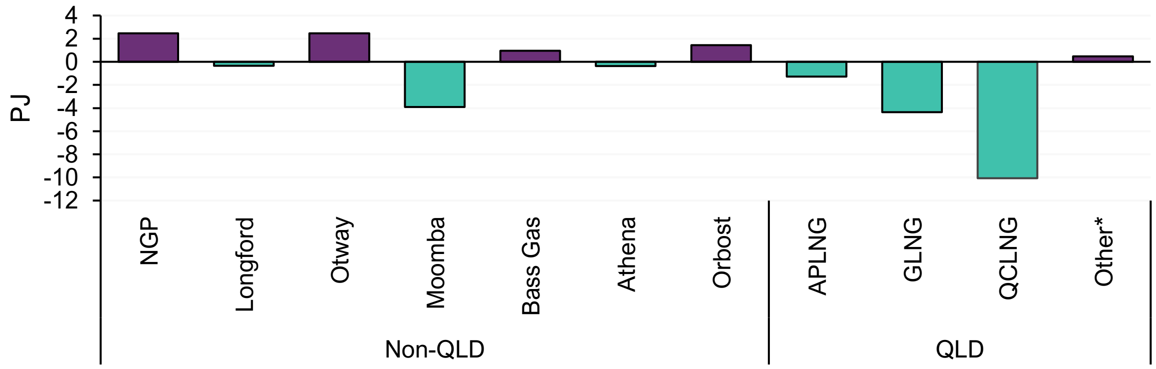
46 Summer is defined as December to February and winter is defined as June to August

decreased by 2.1 PJ, resulting in 13.1 PJ less supply associated with Queensland LNG projects entering the domestic market compared to Q2 2024, marking the lowest Q2 level since Q2 2022 (Figure 97). This decrease was mostly due to planned maintenance.

- Moomba production fell by 3.9 PJ, impacted by widespread flooding in far northern South Australia in mid-April. Average daily output dropped from 252 TJ/day in Q2 2024, to 209 TJ/day in Q2 2025.
- Northern Gas Pipeline (NGP) supply increased by 2.5 PJ, following the resolution of upstream issues in the Northern Territory earlier in the quarter. However, new production issues emerged on 24 June 2025, causing flows to Queensland to cease again. This is discussed in more detail in Section 3.3.2.

Figure 96 Production fell mostly due to lower Queensland and Moomba output

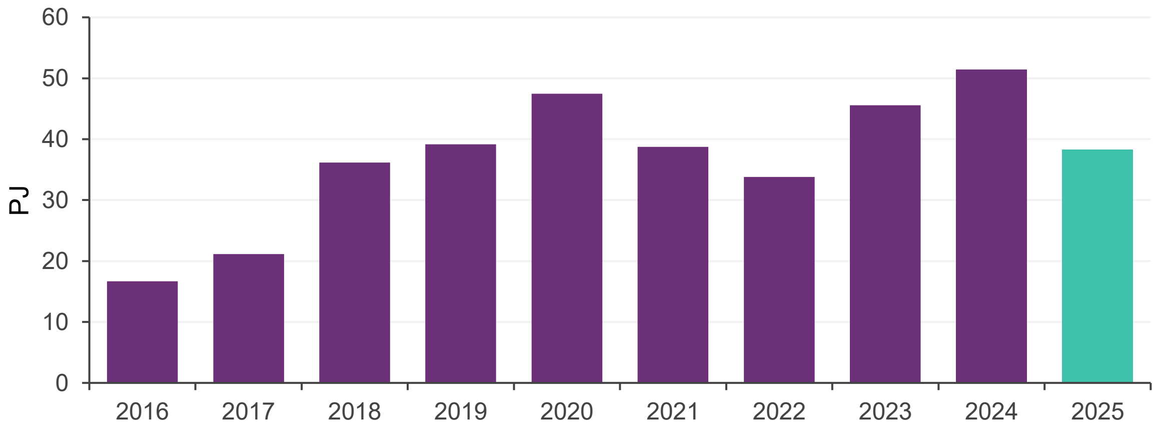
Change in east coast gas supply – Q2 2025 vs Q2 2024



*Other QLD supply is calculated by total QLD production minus production associated with QLD LNG export projects

Figure 97 Queensland Q2 2025 net domestic supply decreased to lowest level since 2022

Queensland net domestic supply during Q2



3.3.2 Northern Territory supply

On 24 June 2025 AEMO was notified that the Northern Territory (NT) was unable to be supplied from the Ichthys LNG plant until mid-July due to planned pipeline maintenance. NT demand was being supported by supply from the Yelcherr Gas Plant (Blacktip), as well as gas plants in southern NT.

This in turn caused the Northern Gas Pipeline (NGP), which had resumed flows to Queensland from 10 April 2025, to cease flows from 28 June due to insufficient gas flow to meet minimum flow requirements.

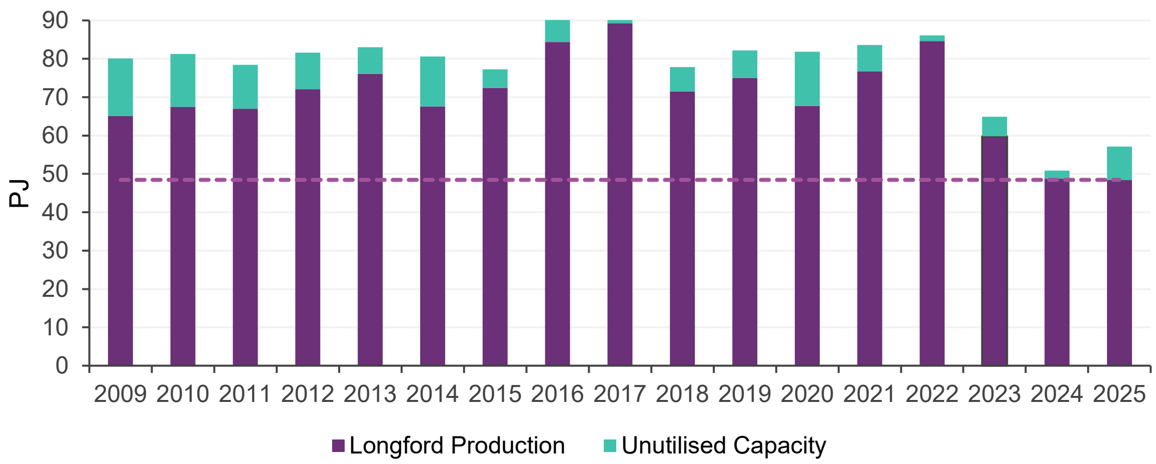
AEMO continued to monitor NT supply due to the risk of an unplanned outage of the Blacktip offshore facility, which supplies the Yelcherr Gas Plant. The NGP does have the capability to reverse flow from Queensland into the NT if there is insufficient supply in the NT, but this requires a lead time to configure the reverse flow.

3.3.3 Longford production and capacity

Longford's gas production in Q2 2025 was largely in line with the same period in 2024, reaching 48.4 PJ compared to 48.8 PJ. However, available production capacity rose to 57 PJ, up from 51 PJ in Q2 2024, reflecting reduced maintenance-related constraints (Figure 98).

Figure 98 Longford Q2 production remained steady but available capacity increased from Q2 2024

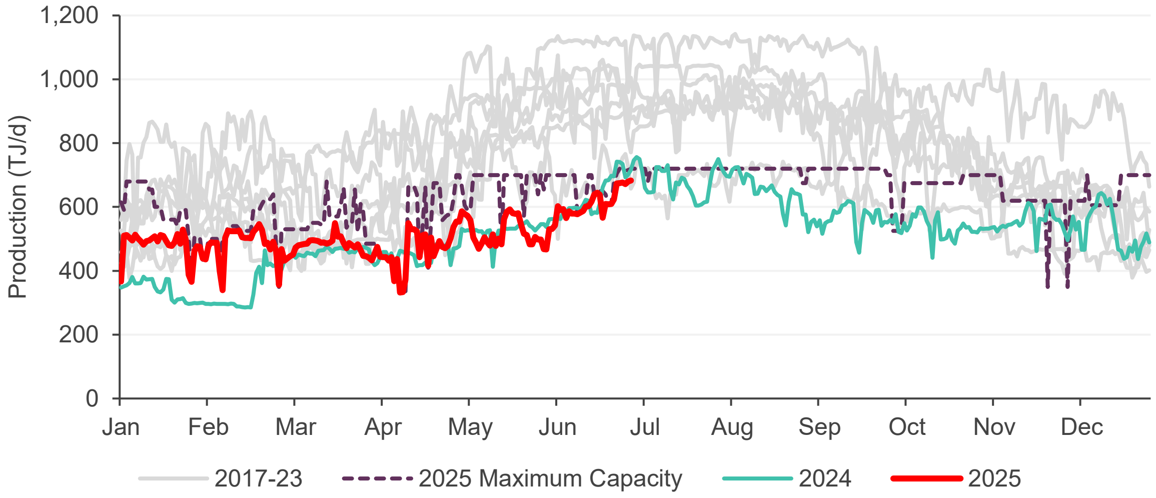
Longford Q2 production and unutilised capacity



Consistent with trends observed in recent quarters, daily production through much of Q2 remained below available capacity, particularly in April and May, with Longford operating at a capacity factor of 85% (Figure 99). This gap was largely due to Longford supply offers continuing to exceed daily price outcomes in the DWGM and Sydney STTM. On high demand days, particularly in June, this margin narrowed, coinciding with record or near-record levels of gas-fired generation.

Figure 99 Daily Longford production remained on par with 2024 levels

Daily Longford production 2017-2025, maximum capacity profile 2025



3.3.4 Gas storage

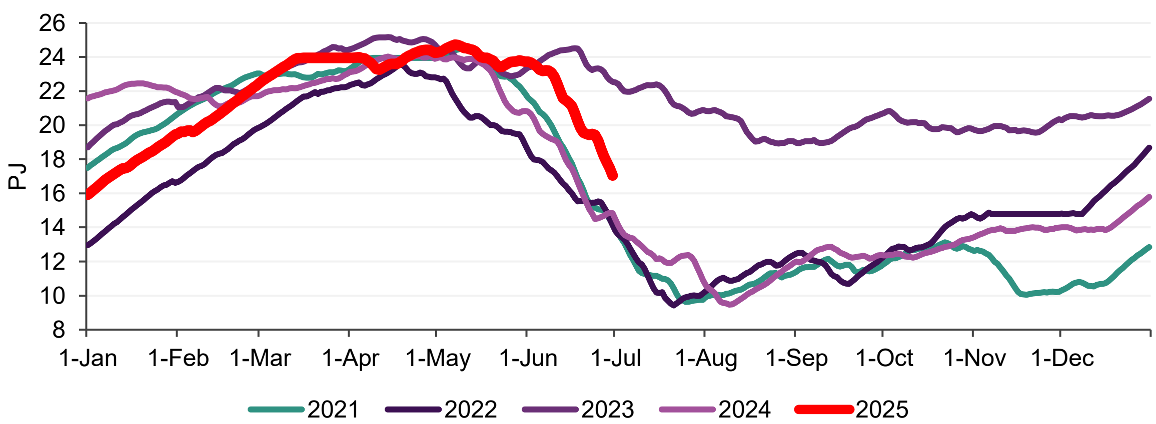
The Iona UGS facility finished the quarter with a gas balance of 17.0 PJ, 2.2 PJ higher than at the end of Q2 2024 (Figure 100) and also higher than 2021 and 2022.

Iona began June at near full levels, crucially 2.9 PJ higher than at the start of June 2024, reflecting lower demand and increased supply in April and May 2025. However, it was heavily utilised throughout June, particularly on days of high gas-fired generation. Iona emptied 6.7 PJ during June 2025, higher than June 2024 which emptied by 6 PJ, and the highest monthly drawdown since June 2021 when it emptied by 7.3 PJ.

Of note, Iona emptied by 2.4 PJ in the last week of June 2025, while it increased by 0.3 PJ for the same period in June 2024. This was the largest decrease for Iona storage inventory in a seven-day period on record, surpassing the previous highest of 2.35 PJ in June 2021. This coincides with not only a record winter GPG demand on 26 June, but the third highest winter GPG demand on 30 June, and the fifth highest on 27 June.

Figure 100 Iona storage emptied at high rates in June, but remained above the 2024 level

Iona storage levels

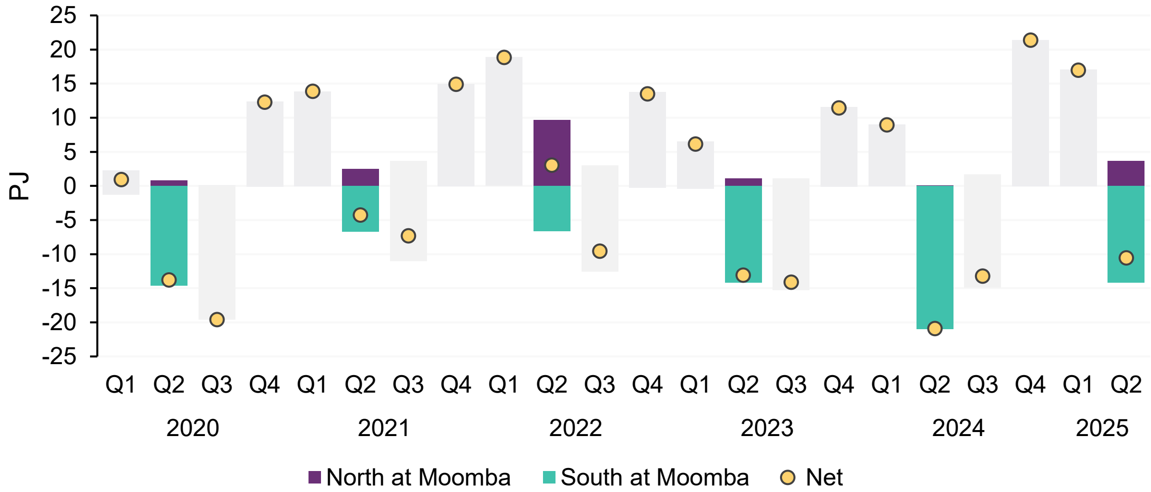


3.4 Pipeline flows

Compared to Q2 2024, there was a 10.4 PJ decrease in net transfers south to Moomba from the South West Queensland Pipeline (SWQP, Figure 101). Decreased flows south coincided with lower industrial, commercial, and residential demand in the Victorian DWGM, particularly in April and May.

Figure 101 Net Q2 flows south on South West Queensland Pipeline in Q2 2025

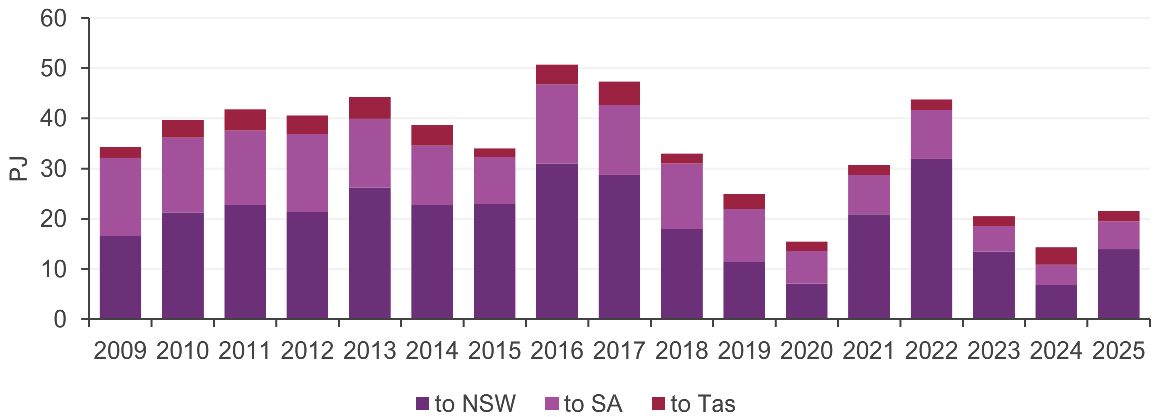
Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states increased by 10 PJ from Q2 2024 levels (Figure 102), predominantly due to an increase in flows to New South Wales. Victoria exported a net 1.2 PJ to New South Wales via Culcairn in Q2 2025, reversing the direction of flows compared to Q2 2024, when Victoria imported a net 4.8 PJ via Culcairn. Exports to New South Wales via the Eastern Gas Pipeline (EGP) increased by 3.5 PJ in comparison to Q2 2024.

Figure 102 Increase in Victorian Q2 exports to New South Wales and South Australia in 2025

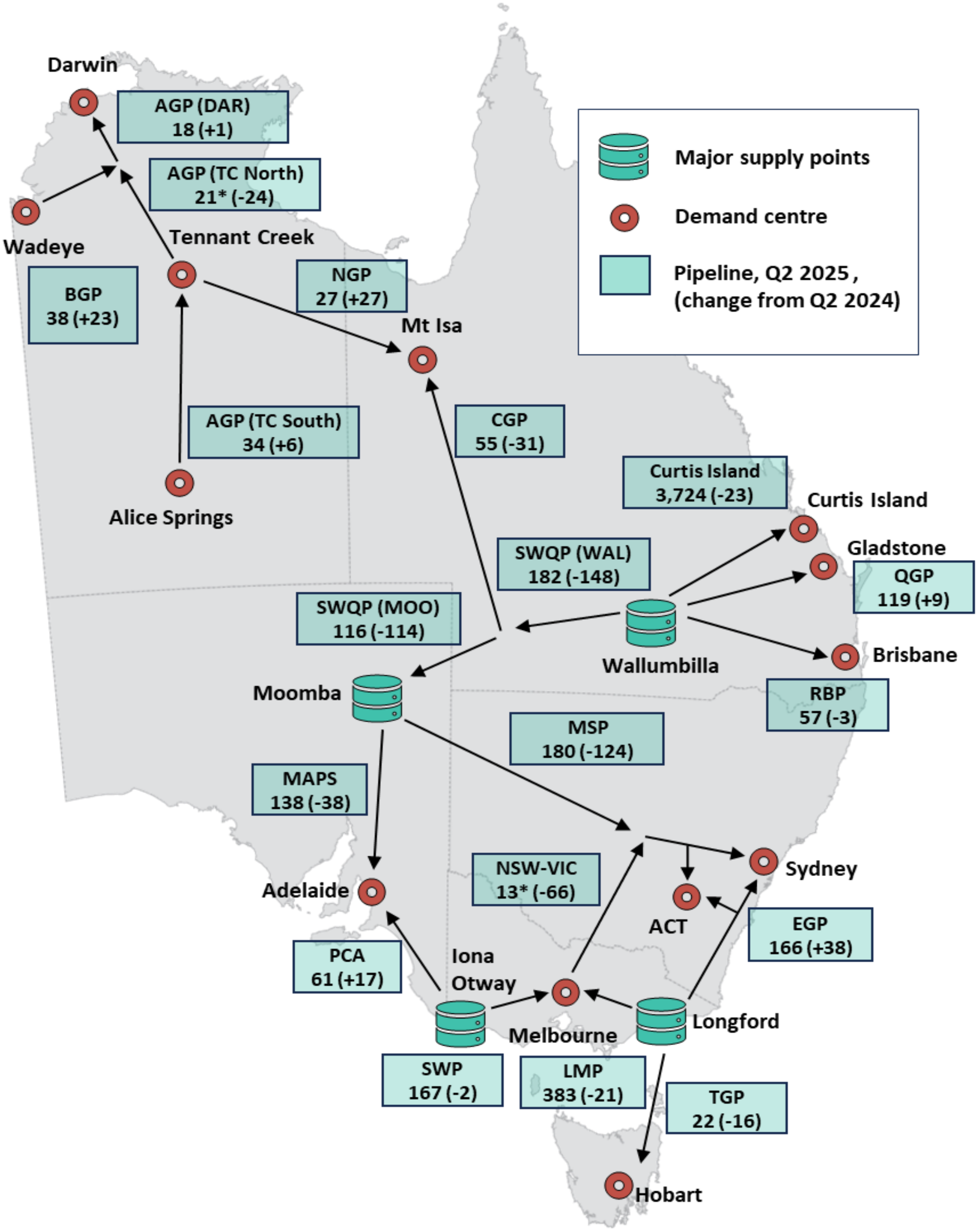
Victorian net gas transfers to other regions



Average daily pipeline flows south were lower in Q2 2025, particularly on the SWQP and the Victorian Northern Interconnect, reflecting reduced gas demand and increased Victorian supply. Curtis Island flows averaged 3,724 TJ/d in Q2 2025, down 23 TJ/d from Q2 2024. In Queensland, a significant portion of Mt Isa demand was met by the Northern Gas Pipeline (NGP) which resumed flows in April 2025 following an extended period of upstream supply issues in the Northern Territory, though upstream constraints reoccurred from 24 June impacting flows to Mt Isa for the rest of the quarter, as discussed in Section 3.3.2 (Figure 103).

Figure 103 Reduced flows south to Victoria and NGP resumed flows south

Average daily pipeline flows Q2 2025 vs Q2 2024

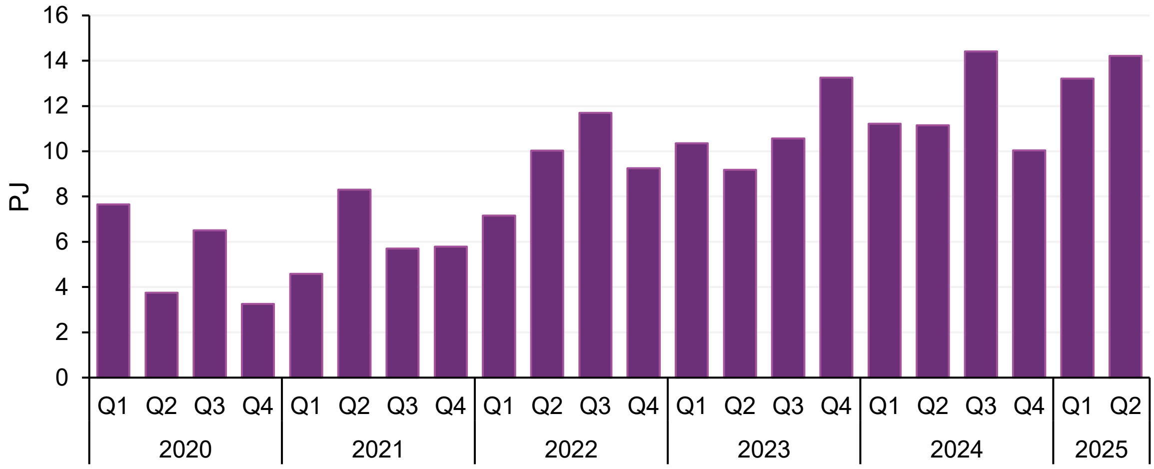


3.5 Gas Supply Hub (GSH)

In Q2 2025, traded volumes on the GSH increased by 3.1 PJ in comparison to Q2 2024 (Figure 104). The traded volume this quarter was 14.2 PJ and represented the second highest quarter traded volume since market start. June was the highest monthly traded volume for the quarter at 6.0 PJ predominantly for delivery in the same month.

Figure 104 Highest Q2 traded volumes on record

Gas Supply Hub – quarterly traded volume



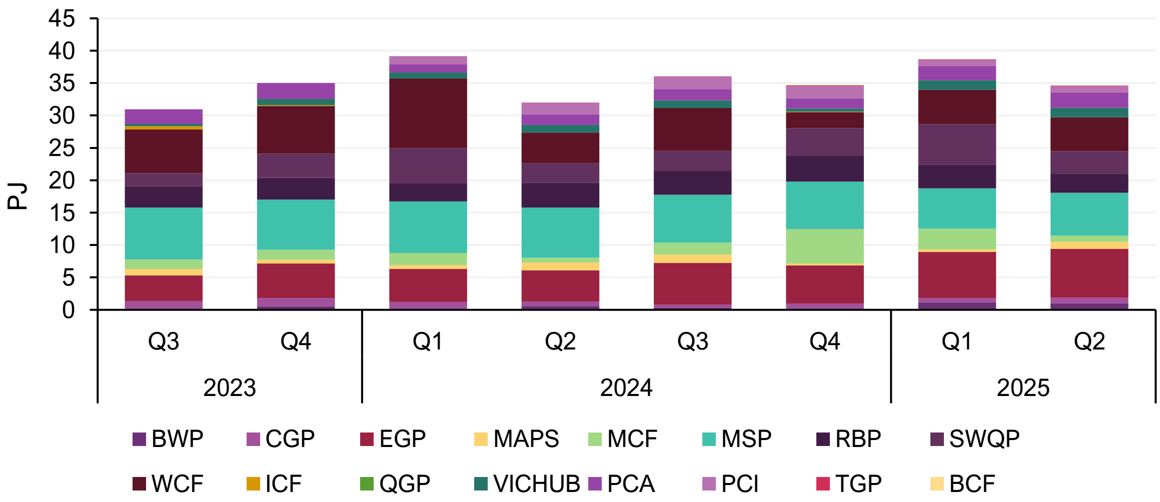
The first swap product on the GSH was traded on 8 March 2025, following its implementation on 6 March 2025. This service is facilitated by the seller who offers to receive the buyer's gas at one location and deliver it back to another location. The price for the product reflects the price that the buyer is willing to pay the seller for this service. All swap transactions so far have occurred between Wallumbilla and Wilton, with the traded volume this quarter being 128 TJ.

3.6 Pipeline capacity trading and Day Ahead Auction

Day Ahead Auction (DAA) volumes increased by 2.6 PJ in comparison to Q2 2024 and represented the highest Q2 traded quarter on record (Figure 105). Compared to Q2 2024, the largest increases occurred on the EGP (+2.7 PJ) and on the Port Campbell to Adelaide Pipeline (PCA, +0.7 PJ).

Figure 105 Highest Q2 traded volumes on record

Day Ahead Auction volumes by quarter



Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were:

- EGP North which averaged $0.50/GJ,
- Roma to Brisbane Pipeline (RBP) West which averaged $0.29/GJ and RBP East which averaged $0.14/GJ,
- SWQP Wallumbilla to Ballera which averaged $0.31/GJ, and,
- Carpentaria Gas Pipeline (CGP) South which averaged $0.17/GJ and CGP North which averaged $0.14/GJ.

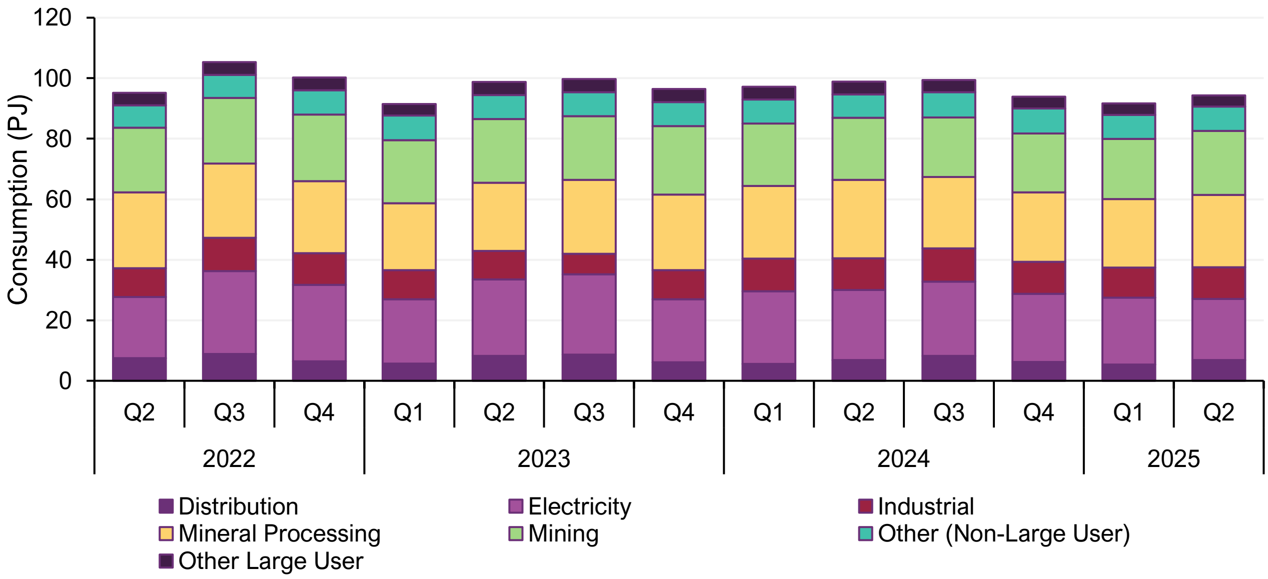
3.7 Gas – Western Australia

3.7.1 Gas consumption

A total of 94.3 PJ was consumed from registered pipelines in the Western Australian domestic gas market in Q2 2025 (Figure 106). This was a decrease of 4.6 PJ (-4.6%) compared to Q2 last year, and a slight increase of 2.6 PJ (2.9%) from Q1 2025. The largest difference compared to Q1 2025 was observed in the distribution category, which increased by 1.5 PJ (+ 24.0%). All other sectors saw a slight increase this quarter, partially offset by a 1.9 TJ (-8.8%) reduction in the electricity sector. There were also changes in consumption when reviewing geographic zones with Q1 2025; the largest increase was 1.2 PJ (+4.6%) in the South-West Zone, the Karratha zone decreased consumption by 0.2 PJ (-4.1%).

Figure 106 Gas consumption in Western Australia increased slightly compared to Q1 2025

Western Australia quarterly gas consumption by sector Q2 2022 to Q2 2025



3.7.2 Gas production

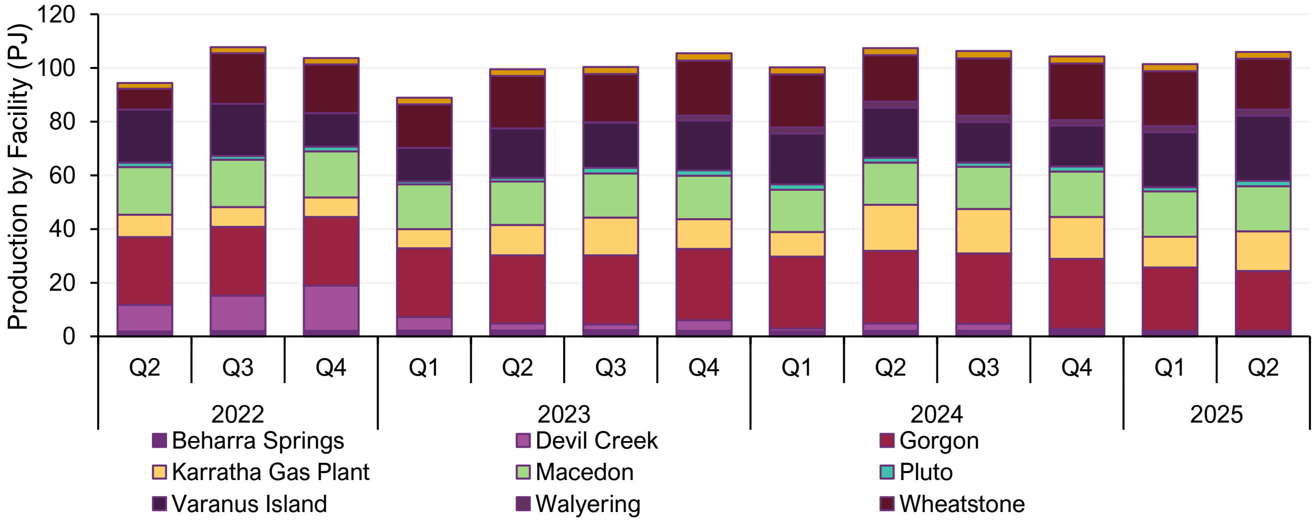
Gas production in Western Australia was 105.9 PJ, a decrease of 1.5 PJ (-1.4%) compared to Q2 2024 and an increase of 4.5 PJ (+4.5%) compared to last quarter (Figure 107)[47].

[47] Imbalance between production, consumption, and storage flows can be attributed to changes in linepack, pipeline usage, losses and other factors that are currently under investigation. See item #7 of August 2024 Gas Advisory Board (GAB) minutes, at https://www.wa.gov.au/system/files/2024-10/gab_2024_08_29_minutes.pdf.

The increase in production from Q1 2025 can be mainly attributed to increases at the Karratha Gas Plant (3.4 PJ, +30.1%), and Varanus Island (3.8 PJ, +18.5%).

Figure 107 Q2 2025 saw an increase in gas production of 4.5 PJ from Q1 2025

Western Australia quarterly gas production by facility Q2 2022 to Q2 2025

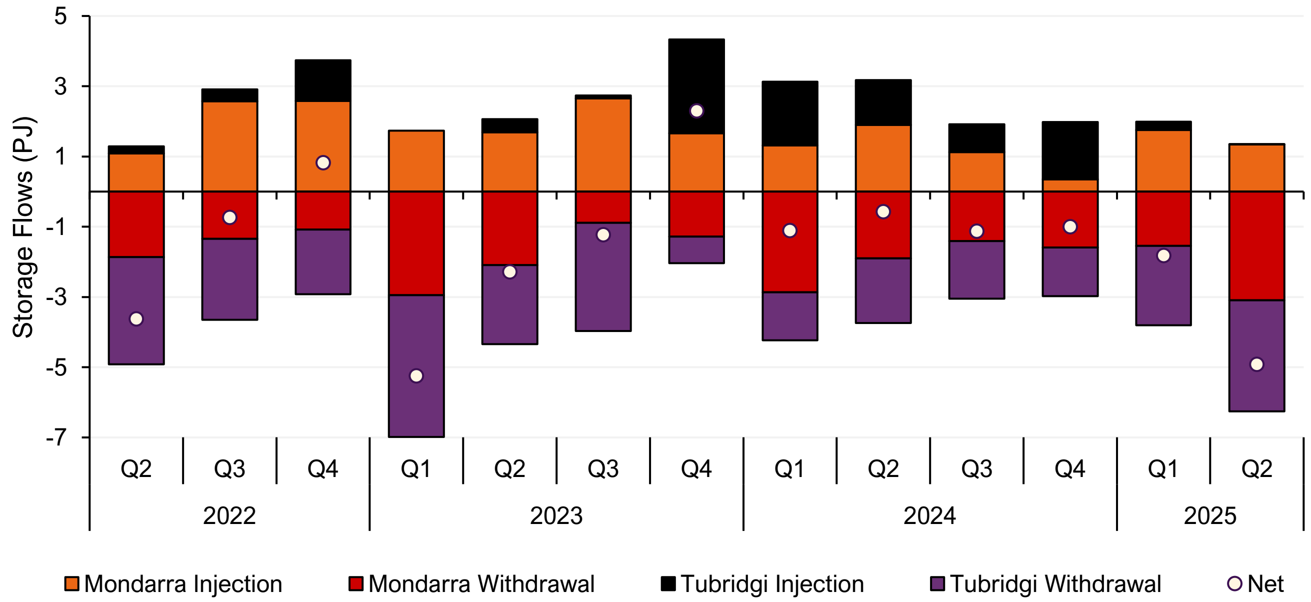


3.7.3 Storage facility behaviour

In Q2 2025, there was net withdrawal from storage facilities of 4.9 PJ (Figure 108). This is the sixth consecutive quarter of net withdrawals. Net withdrawal from storage in Q2 2025 increased by 4.3 PJ (+239%) compared to the Q2 2024. Compared to Q1 2025, withdrawals increased 3.1 PJ (170%).

Figure 108 Net withdrawals from storage continued in Q2 2025

Western Australia gas storage facility injections and withdrawals – Q2 2022 to Q2 2025



3.7.4 Linepack Capacity Adequacy (LCA)

LCA is an indication of the actual or expected capability of a pipeline to meet relevant delivery nominations, and, for a storage facility, an indication of the number of days for which supply of natural gas can be maintained at the maximum operational outlet capacity. During Q2 2025, there was a red LCA flag for the Mondarra Storage Facility on 5-9 May due to planned maintenance.

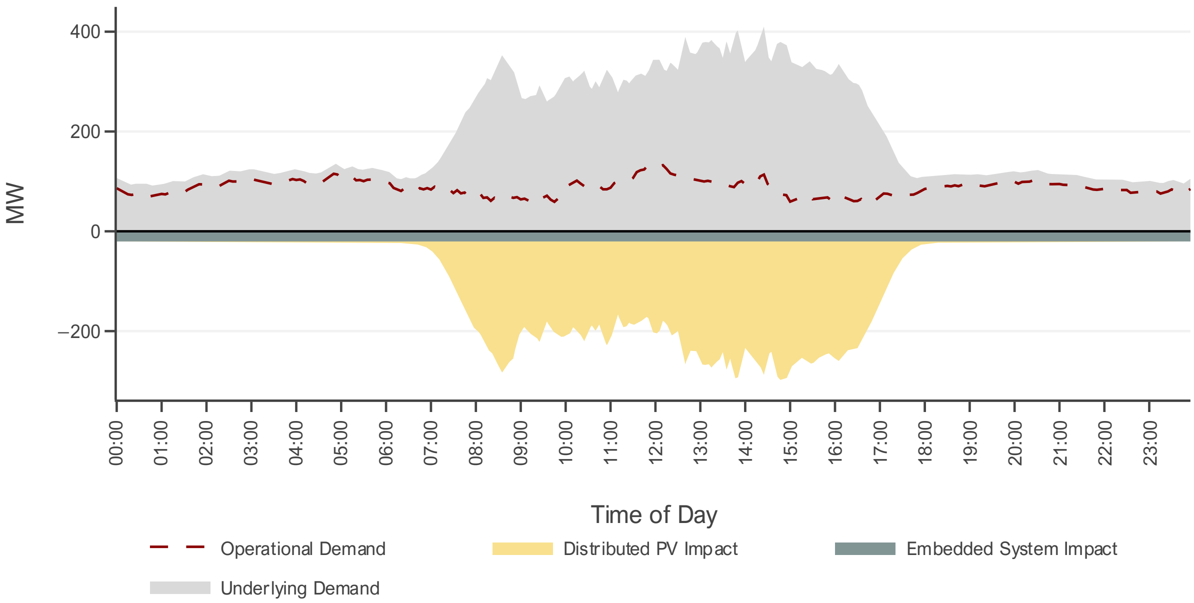
4 WEM market dynamics

4.1 Electricity demand

Average operational demand[48] was 2,088 MW, an increase of 87.4 MW (+4.4%) in Q2 2025 compared to Q2 2024. This was driven by an increase in average underlying demand of 195 MW (+8.6%) to 2,465 MW that was only partially offset by increased distributed PV (Figure 109).

Figure 109 Increases in underlying demand outpaced increase in distributed PV generation

Change in WEM average operational demand components by time of day – Q2 2024 vs Q2 2025



In addition to growth from increasing population and economic activity, increased underlying demand was due to:

- Cooler temperatures (Figure 1, Section 1) compared to Q2 2024, which resulted in 32.9 more heating degree days (Figure 3, Section 1) than the prior quarter, increasing electricity demand. See Section 1 for more details on weather.
- An increase in average battery withdrawal (charging) by 51.8 MW (+469%) compared to Q2 2024. This primarily occurred during early morning hours and during the middle of the day (Figure 111). This can be attributed to the increase in battery capacity commissioned since Q2 2024 (see Section 4.2).

Increases to underlying demand were partially offset by components that reduce operational demand:

- Distributed PV recorded an average increase of 84.1 MW[49]. This can be attributed to increasing installed capacity and higher solar exposure compared to Q2 2024. Note, some of the increase can likely be attributed

[48] Operational demand considers the total injection, in megawatts, from all scheduled facilities, semi-scheduled facilities and non-scheduled facilities that are injecting at the end of the dispatch interval. As such, it includes scheduled demand driven by charging of electric storage resources (batteries).

[49] Estimated distributed PV is an estimation based on solar irradiance data and installed distributed PV capacity data available to AEMO.

to a change in data source between Q2 2025 and Q2 2024, whereby the Q2 2024 was likely underestimating distributed PV generation compared to the Q2 2025 source and methods.

- Increases in average embedded system[50] generation by 20.9 MW (+1,028%), due to a reduction in local load served by the embedded systems.

4.2 Electricity generation

Gas and coal remained the largest contributors to the fuel mix in the WEM, supplying 32.1% and 31.9% of underlying demand in Q2 2025 respectively. All Q2 2025 contributions can be seen in Table 9 with the following key changes since Q2 2024:

- A 39 MW reduction in average gas generation was observed (Figure 110). This reduction occurred during most times of the day (Figure 111) as gas was replaced by wind overnight and during the middle of the day, and primarily by batteries during the evening peak.
- Average battery injection (discharge) increased by 44.1 MW (+469%) in Q2 2025 compared to Q2 2024, which was primarily delivered during the morning and evening peaks. This is attributable to an increase in battery capacity comprised of:
  - COLLIE_ESR1, with a capacity of 200 MW/800 MWh, which was commissioned during Q4 2024;
  - KWINANA_ESR2, with a capacity of 225 MW/900 MWh, which was commissioned during Q1 2025; and
  - COLLIE_BESS2, with a capacity of 300 MW/1200 MWh, which was undergoing commissioning during the quarter[51].
- Average coal generation increased by 44.2 MW (+6%), a reversal of the decreasing trend observed in recent quarters. Despite the retirement of Muja C Unit 6 power station (capacity 196 MW) on 1 April 2025, there was an overall increase in availability of coal capacity during the quarter (reflecting less capacity on outage).
- The hybrid fuel type also increased generation by 12.2 MW. This was an increase from 0 MW in Q2 2024 after the WEM's first hybrid type facility (the Cunderdin Hybrid Facility, a 100 MW solar/battery hybrid) completed commissioning during Q1 2025. Notably, this is less than the 22.7 MW of average hybrid generation observed in Q1 2025, which can be attributed to an increase in outage time of the facility and the reduction in solar exposure from Q1 to Q2 2025.
- Wind generation increased through the early morning and midday periods, and decreased slightly in the afternoon and evening, resulting in an average increase of 22 MW across the day between Q2 2024 and Q2 2025. This increase was mainly driven by a decrease in the curtailment of wind energy due to an increase in battery charging, which increases operational demand.

[50] An embedded system is a network connected to the South West Interconnected System (SWIS) which is owned, controlled or operated by a person who is not a Network Operator or AEMO. Net export into the grid results in a decrease to operational demand as this offsets generation required from registered facilities.

[51] Commissioning for COLLIE_BESS2 has now completed.

Figure 110 Distributed PV grew, along with batteries, coal, wind and hybrid

Change in quarterly average generation – Q2 2024 vs Q2 2025

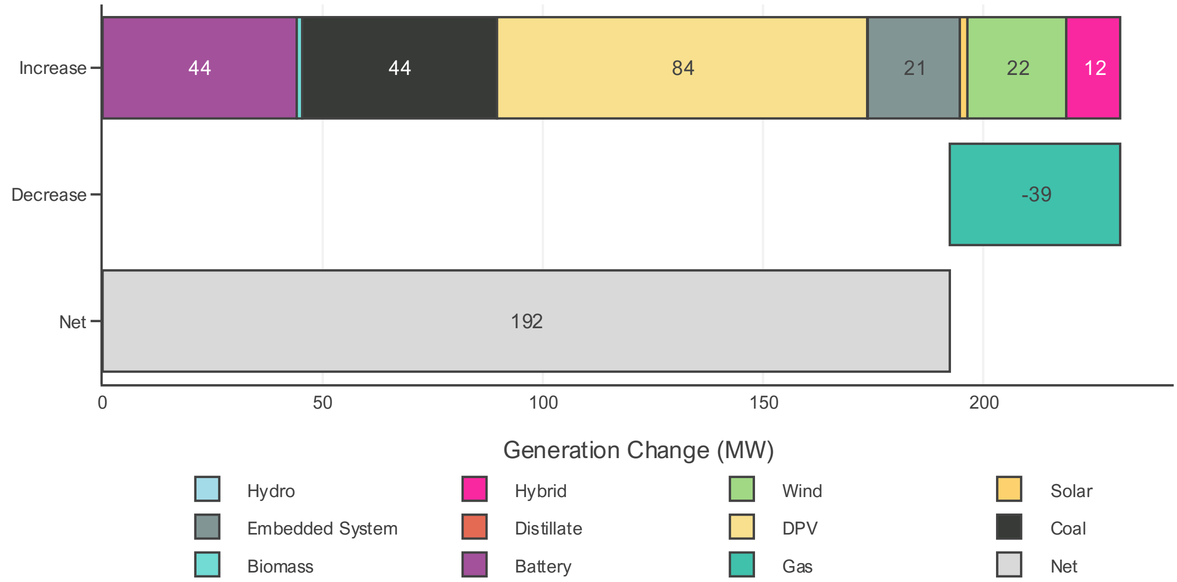


Figure 111 Gas replaced by batteries at the peak, batteries increased charging overnight and during the day

Average WEM change in fuel mix by time of day – Q2 2024 vs Q2 2025

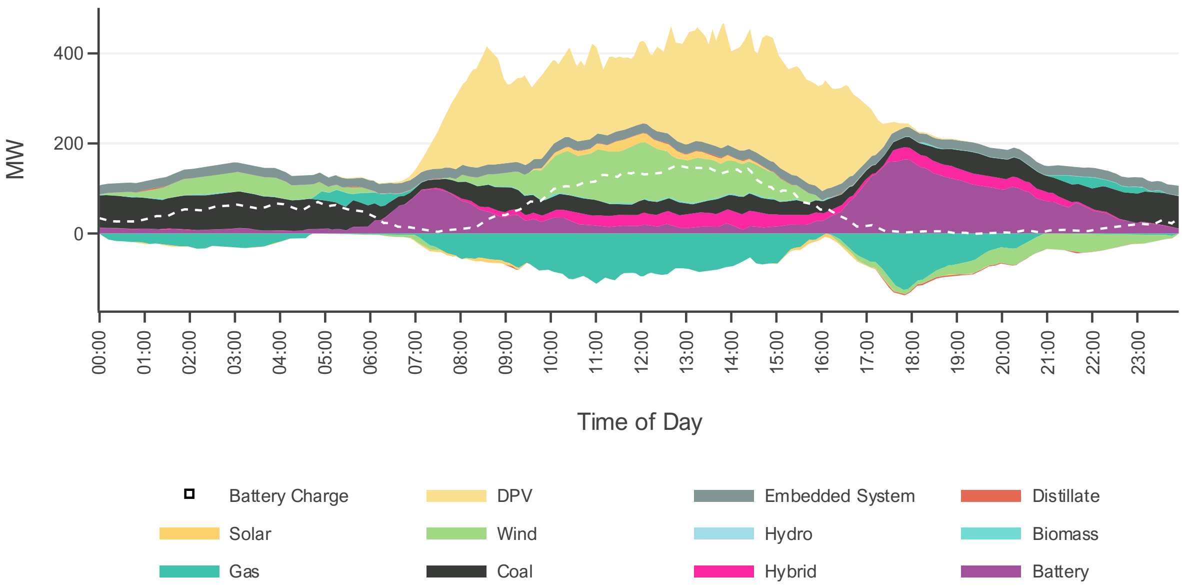


Table 9 WEM supply contributions by fuel type

Quarter	Coal	Gas	Distillate	Grid solar	Wind	Biomass	Battery	Hybrid	Hydro	Distributed PV	Embedded systems
Q2 2024	32.6%	36.5%	0.1%	1.1%	16.9%	0.4%	0.4%	0%	<0.1%	11.9%	0.1%
Q2 2025	31.9%	32.1%	0.1%	1.1%	16.5%	0.4%	2.2%	0.5%	<0.1%	14.4%	0.9%
Change	-0.7%	-4.4%	-	-	-0.4%	-	1.8%	0.5%	-	2.5%	0.8%

4.2.1 Renewable contribution

The average renewable contribution in Q2 2025 was 35.1% of underlying demand, a new record for a Q2 and exceeding Q2 2024 by 4.3 pp (Figure 112). This was largely driven by the increase in estimated distributed PV generation by 2.5 pp (to 14.4%) and hybrid output, which increased from no contribution to 0.5%. The contribution of batteries (which also increase underlying demand when charging) increased by 1.8 pp to 2.2%. Average wind contribution dropped by 0.4 pp to 16.5%; this was despite the increase in overall average wind generation by 22 MW, as it was outpaced by the increase in underlying demand.

Q2 2025 also experienced the highest Q2 peak renewable contribution on 21 April 2025 of 78.8% during the 12:20 interval (Figure 113). The primary contributors were distributed PV of 57.2% and wind of 16.3%.

Figure 112 New Q2 average renewable contribution high recorded in Q2 2025

Renewable contribution components – Q2s

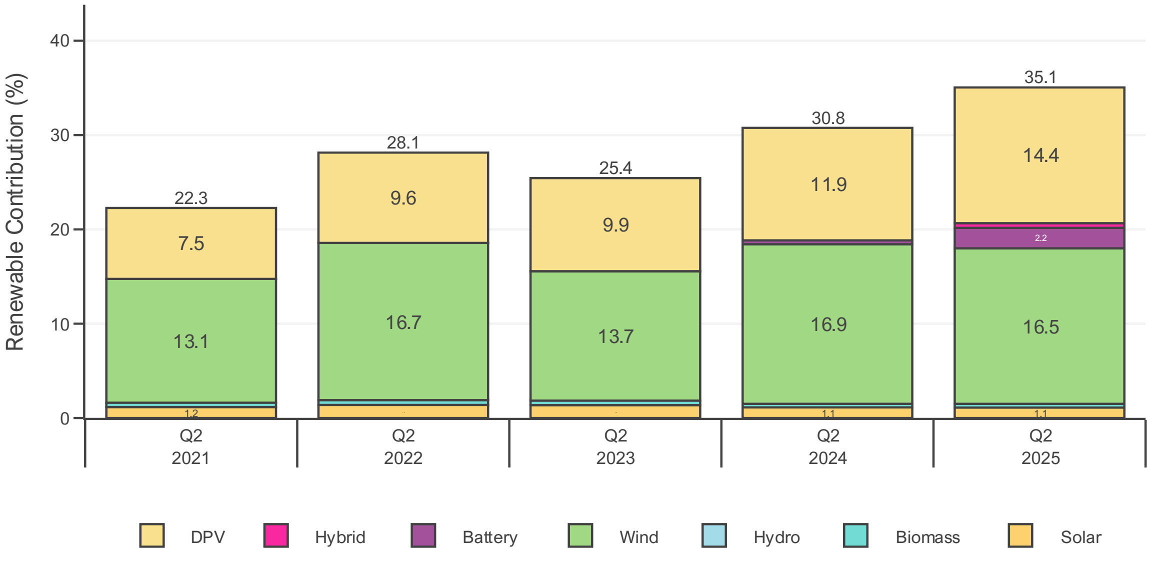
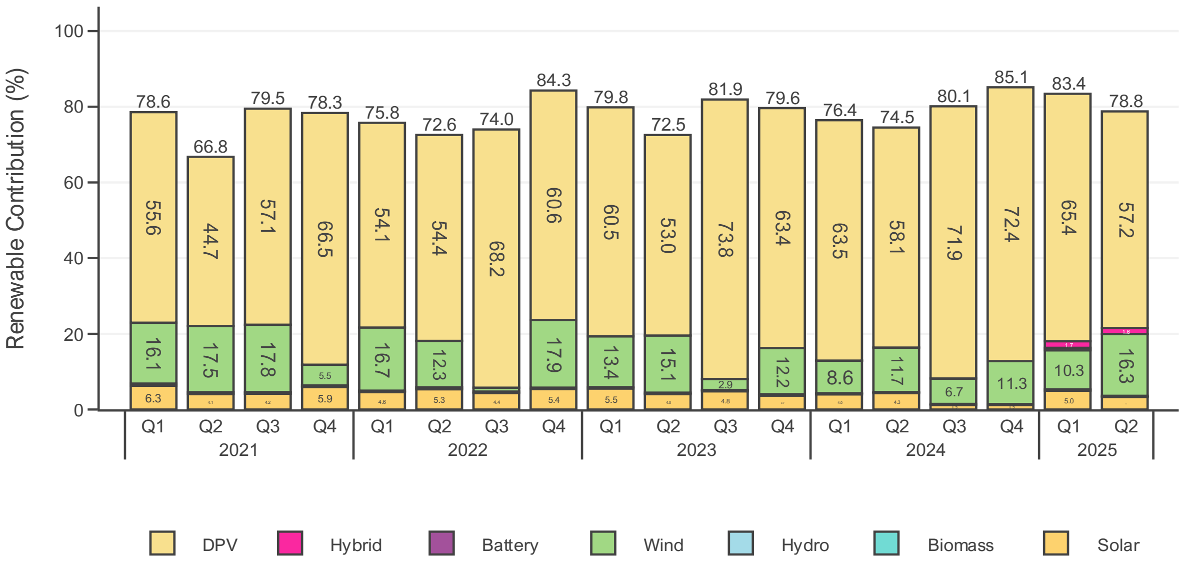


Figure 113 Q2 2025 observed the highest peak renewable contribution for Q2s of 78.8%

Percentage of WEM supply from renewable energy sources at time of peak renewable contribution

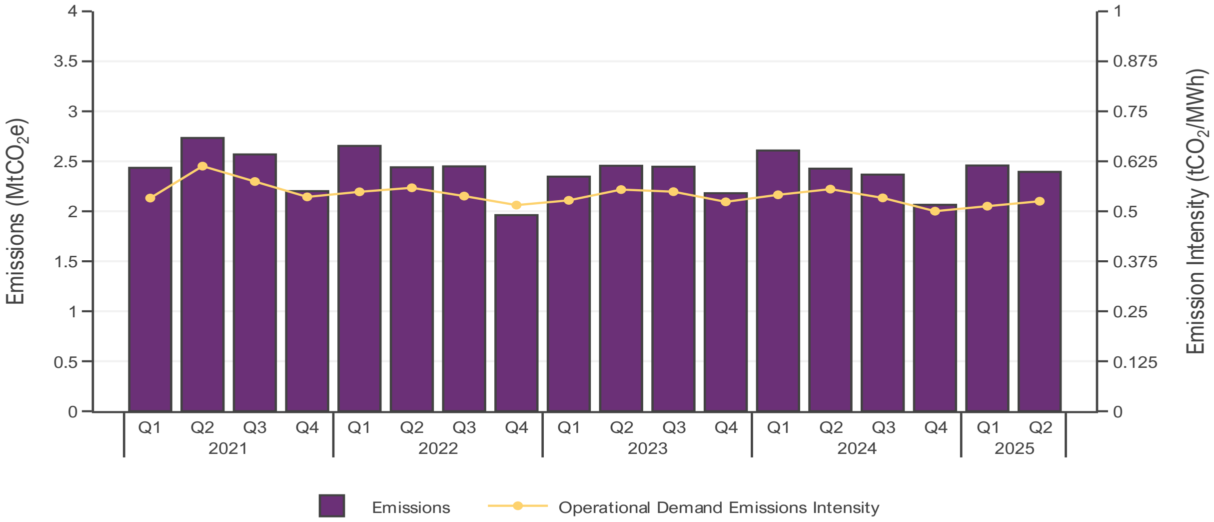


4.2.2 Carbon emissions

Total estimated WEM emissions[52] were 2.39 $MtCO_2$-e, a decrease of 0.03 $MtCO_2$-e (-1.3%) on Q2 2024 despite the increase in operational demand of 4.4% (Figure 114). The primary reason for the reduction was the decrease in emissions intensity to 0.525 tCO_2-e /MWh, down from 0.555 tCO_2-e /MWh (-5.5%), which can be attributed to renewables increasing their share in meeting operational demand.

Figure 114 Total emissions reduced despite the increase in operational demand

Quarterly WEM emissions and emission intensity – Q1 2021 to Q2 2025



4.3 Frequency co-optimised essential system services (FCESS)

Q2 2025 was the first quarter in which the battery fuel type was the majority provider of regulation and contingency services, with on average 283 MW of service enabled across these markets, capturing 61% of the market share (Figure 115 and Figure 116). This compares to 0% in Q2 2024, when the WEM had no battery facilities accredited for FCESS, with three now accredited. Gas recorded a decrease of 225 MW in average enabled quantities across all four markets, resulting in a reduction in market share from 76% in Q2 2024 to 21% in Q2 2025.

The RoCoF control service market is still served only by gas and coal facilities. Gas provided 62.9% and coal 37.1% of the RoCoF market share.

[52] Emissions intensity ratings are obtained from data published by the Clean Energy Regulator at https://cer.gov.au/node/4444 (Greenhouse and energy information by designated generation facility). Where the facility emissions intensity is not published by the Clean Energy Regulator, the average for the same fuel type of published facilities is used.

Figure 115 Batteries displaced gas in the regulation and contingency FCESS markets

Change in FCESS (regulation and contingency markets) enablement by fuel type – Q2 2024 vs Q2 2025

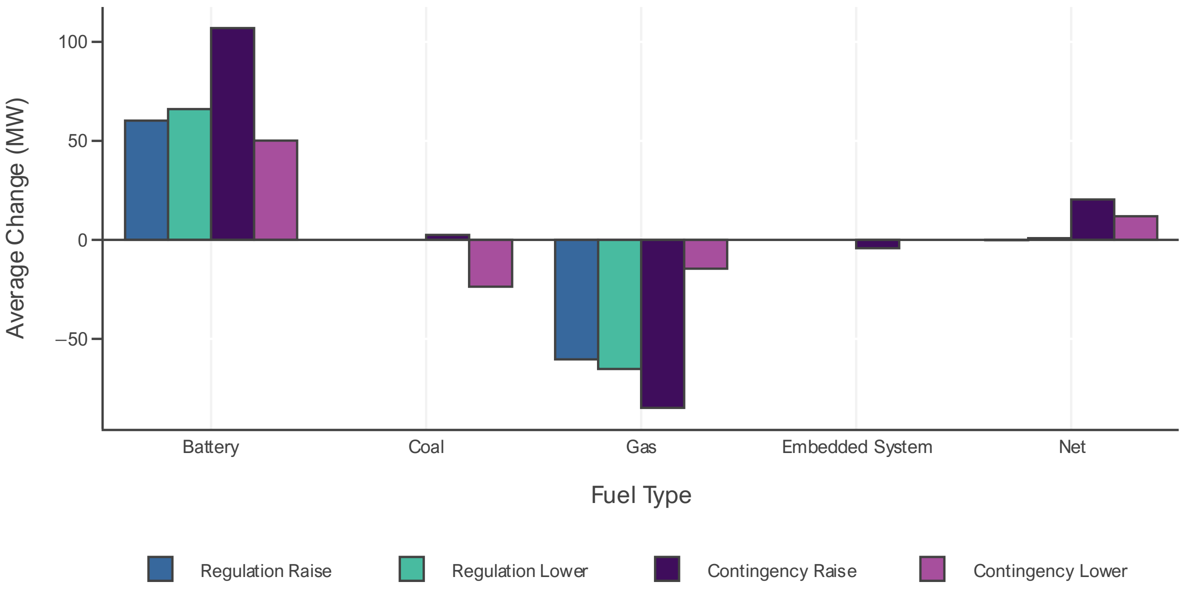
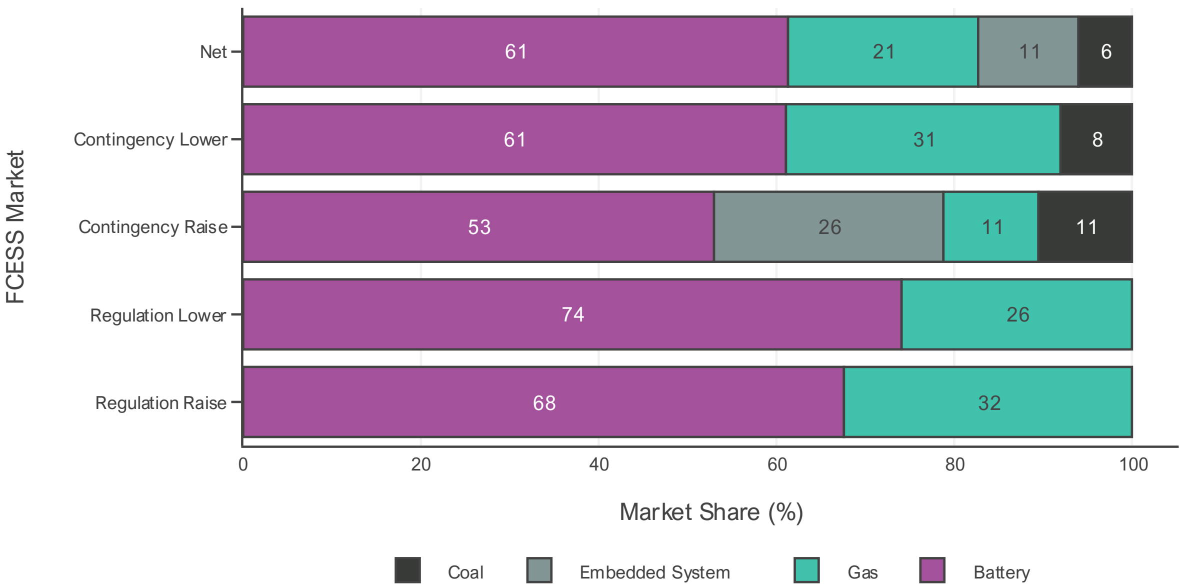


Figure 116 Batteries accounted for the majority of contingency and regulation markets

FCESS volume market share by market and fuel type, excluding. RoCoF control service – Q2 2025



4.4 WEM price outcomes

4.4.1 Real-Time Market price dynamics

The average energy price in Q2 2025 was $90.46/MWh, an increase of $11.67/MWh (+15%) compared to Q2 2024 (Figure 117). Drivers included:

- Increased operational demand due to increased battery withdrawal (charge) overnight and during the middle of the day, and cooler temperatures (Section 4.1). This was partially offset by increased battery injection (discharge) during the morning peak, evening peak, and late evening (Section 4.2) leading to lower prices during these periods (Figure 118). The effect of batteries flattening the energy price profile can be seen in the change in net withdrawal and injection in Figure 119 compared to the change in the daily price profiles seen in Figure 118.

- Changes to the FCESS Uplift payment structure leading to a reduction in the number of committed facilities during the middle of the day[53]. While this lowered overall FCESS Uplift costs significantly, it also contributed to upward pressure on energy clearing prices during that period of the day.

Figure 117 Average energy price increased in Q2 2025 compared to prior quarters

Quarterly average energy prices – Q1 2024 to Q2 2025

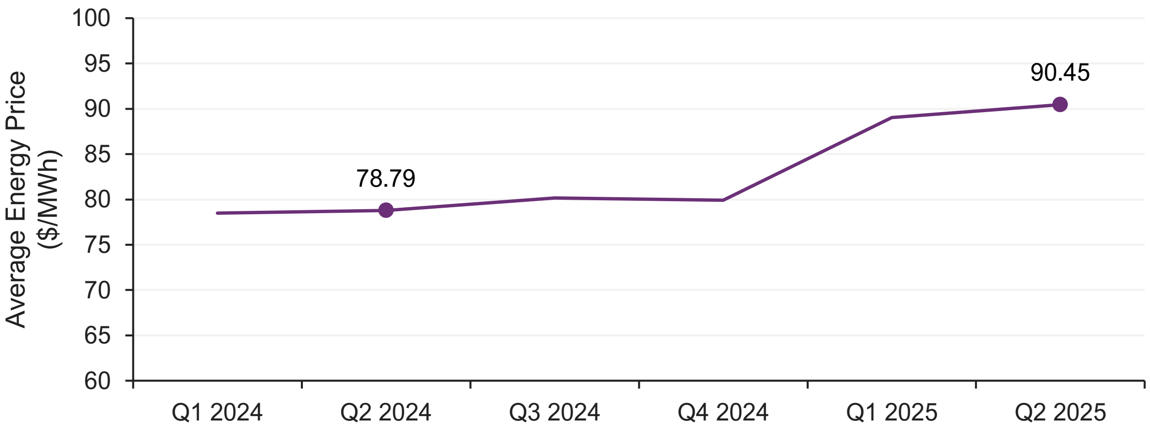
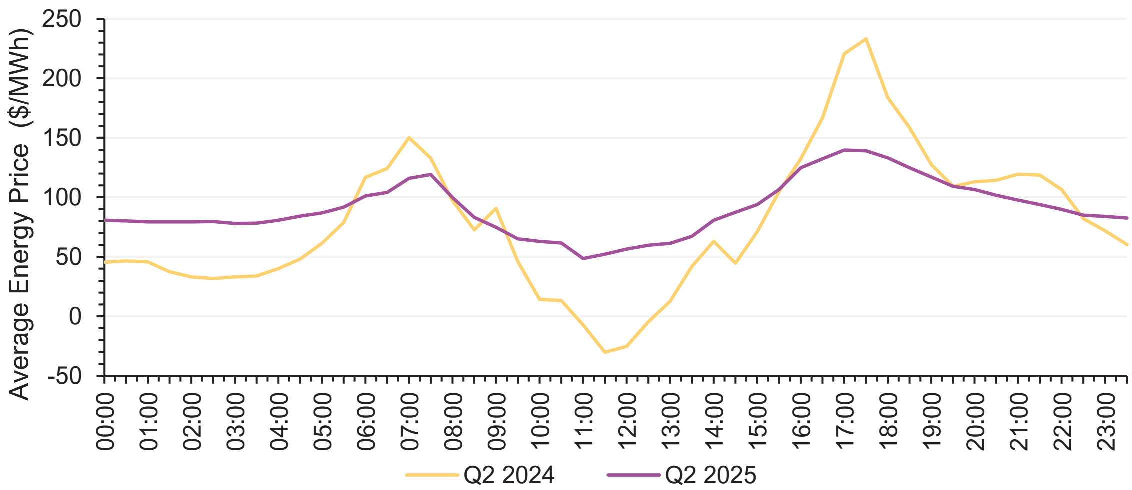


Figure 118 Impact of batteries and cooler weather on daily energy price profiles

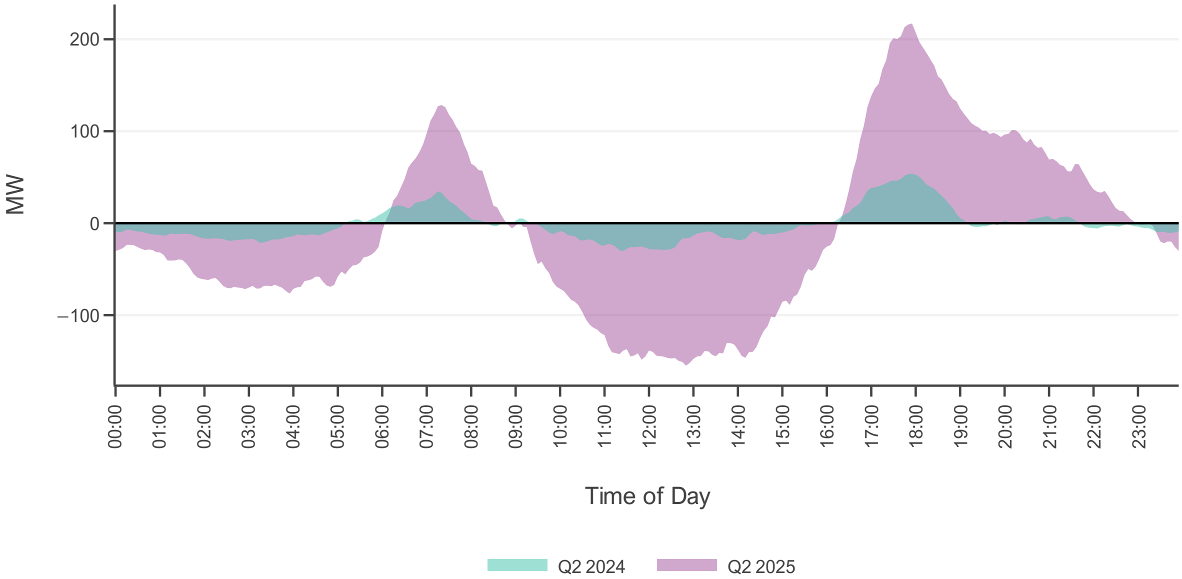
Average energy price by time of day – Q2 2024 and Q2 2025



[53] The new tie-breaking methodology introduced as part of the FCESS Cost Review in November 2024 favours facilities with lower estimated FCESS uplift costs. The prior tie-breaking methodology was a simple pro-rata dispatch based on marginal tranche quantity size, which resulted in more facilities remaining committed. More details can be found in the December WEM Real-Time Market Insights Forum slides https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/wa_meetings/real-time-market-insights-forum/2024-12-03-rtm-industry-insights-forum.pdf?la=en

Figure 119 Battery discharge and charge influenced daily price profiles

Average battery discharge and charge (MW) by time of day – Q2 2024 and Q2 2025



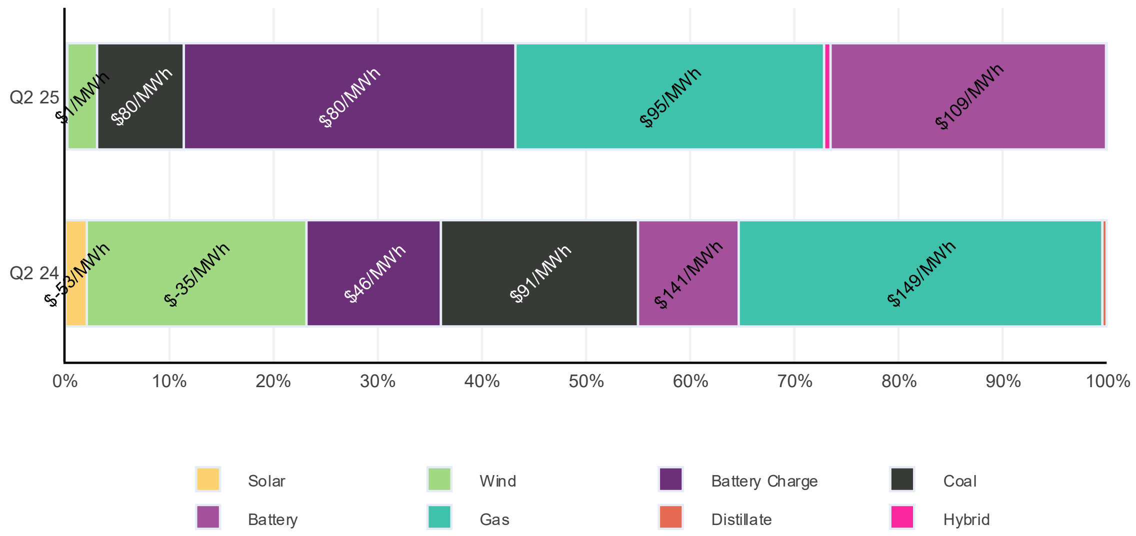
4.4.2 Price setting

Price setting dynamics have changed significantly between Q2 2024 and Q2 2025:

- Charging batteries are now the most frequent price setter, at 31.9% of intervals in Q2 2025 compared to just 12.9% in Q2 2024 (Figure 120). The average clearing price when battery charging set the price also grew from $46/MWh to $80/MWh. Batteries are dispatched to charge when their offer price is equal to (i.e. setting the price) or higher than the energy market clearing price. Therefore, as energy market clearing prices increase (as discussed in section 4.4.1), batteries must also increase their prices they are willing to charge at to ensure they are dispatched to charge. The increased capacity of batteries in Q2 2025 compared to Q2 2024 is therefore inherently a driver of both the increase in average clearing price when set by charging batteries and the frequency that it is the price setter.
- A reduction in wind facilities setting the price from 21.1% to 2.9% of the time can be attributed to the increase in operational demand.

Figure 120 Battery withdrawal (charging) has become the largest price-setter by frequency in the WEM

WEM price-setting frequency and average price when price-setter by fuel type – Q2 2025 vs Q2 2024



4.4.3 Impact of 8 June 2025 Real-Time Market suspension

On 8 June 2025, an IT systems failure resulted in an inability of the WEM Dispatch Engine (WEMDE) to create market schedules for dispatch intervals 18:40 and 19:00 to 21:45. AEMO suspended the Real-Time Market from 20:40, and resumed the Real-Time Market from 23:50 after IT systems were restored. This section outlines the key market impacts of the suspension; AEMO has published additional details on the event in a preliminary incident report available on our website[54].

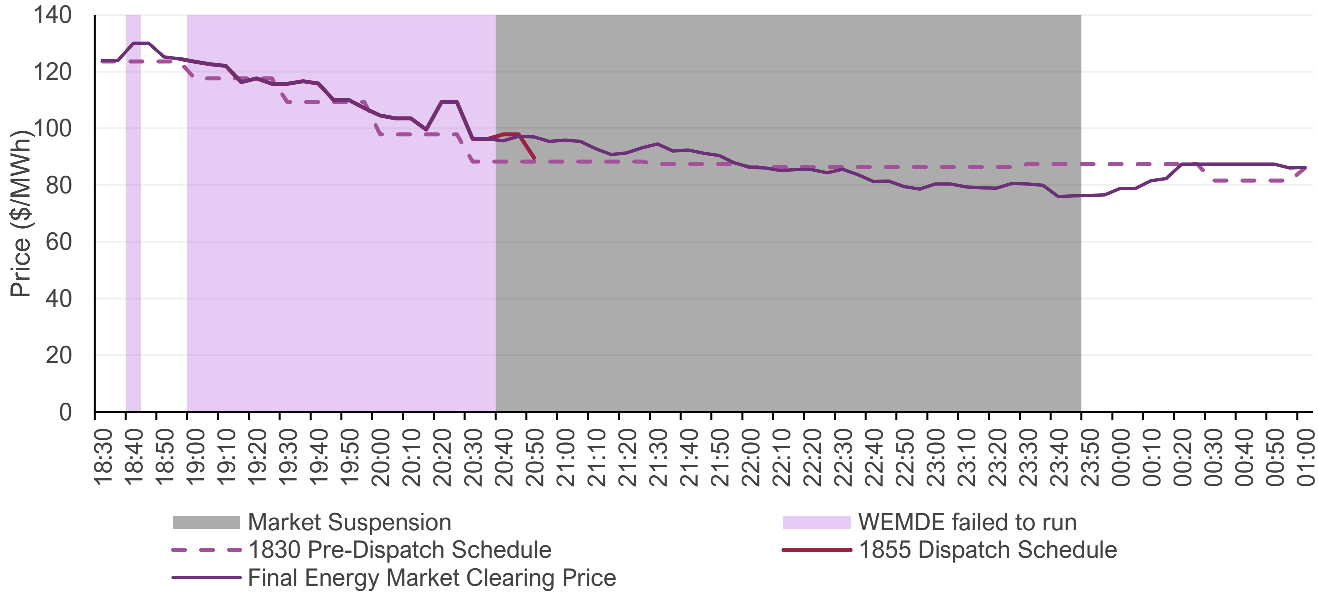
During the suspension event, AEMO was required to apply an administered pricing methodology, setting energy and FCESS prices equal to the average of the relevant prices in the equivalent intervals in the four most recently completed Trading Weeks.

Figure 121 illustrates the timeline of missed dispatch intervals, the Real-Time Market suspension period and the final (administered) market clearing prices compared to forecast market clearing prices for energy, based on the last available Dispatch or Pre-Dispatch schedule. The final energy market clearing price outcomes were relatively consistent with the last available forecast prices.

[54] AEMO, *Preliminary Report – Real-Time Market suspension on 8 June 2025*, at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-events-and-reports/incident-reports.

Figure 121 Alignment of final and forecast market clearing prices during the Real-Time Market suspension

Timeline of missed dispatch intervals, Real-Time Market suspension, and the final vs forecast clearing market prices on 8 June 2025



Furthermore, a series of adjustments to cost recovery and market charges were applied for intervals impacted by the Market suspension:

- All facilities were deemed eligible for Energy Uplift payments and ineligible for FCESS Uplift payments during affected dispatch intervals (facilities are always ineligible for FCESS Uplift payments when they are eligible for Energy uplift payments).
- Contingency reserve raise charges and additional RoCoF control service charges were reallocated using the Real-Time Market suspension share method, rather than the normal runway share.
- Facility reserve capacity deficit refunds were adjusted to reflect suspension conditions. Not-In-Service capacity, Electric Storage Resource (ESR) capacity shortfall and Real-Time Market offer shortfall quantities were deemed to be zero for all facilities.

4.4.4 Essential system services (ESS) costs

Total ESS and Uplift costs fell to $34.2 million in Q2 2025, down $86.7 million (-72%) from $121.0 million in Q2 2024 (Figure 122), driven primarily by rule changes and increased competition which impacted FCESS Uplift costs and FCESS enablement costs respectively.

Observations include:

- FCESS Uplift costs were $6.4 million in Q2 2025, a significant reduction of $63.5 million (-91%) from Q2 2024, driven primarily by changes to the FCESS Uplift payment framework implemented as part of the FCESS Cost Review in November 2024. Higher energy prices also put some downward pressure on FCESS Uplift costs.
- Three new batteries were accredited to provide FCESS market services since Q2 2024, leading to increased competition. As a result, total FCESS enablement costs were $20.0 million in Q2 2025, a $26.0 million (-56%) reduction from Q2 2024. This included KWINANA_ESR2 in Q2 2025, which was accredited for a maximum of

199.7MW in contingency reserve raise and lower, and 200 MW in regulation raise and lower markets from 6 June 2025, resulting in a decrease in FCESS enablement and uplift costs in June 2025 (Figure 123), despite an increase in the quantity of contingency reserve lower procured around the same period (Section 4.4.5).

- The regulation lower market saw the largest decrease, down to $1.9 million from $13.8 million, a decrease of 86%.
- The contingency reserve lower and regulation raise markets also saw significant decreases of $7.0 million (-80%) and $5.4 million (-72%) respectively.
- Contingency reserve raise costs continued to make up the bulk of total costs, at $14.2 million, decreasing modestly (-11%) from $15.9 million in Q2 2024.

- Provisional Non-Peak NCESS costs increased to $5.4million in Q2 2025, an increase of $2.1 million (+62%) from Q2 2024, driven by the commencement of two Non-Peak NCESS contract since Q2 2024, including one in Q2 2025. Note that NCESS costs data in this report are only available up to 15 June 2025 due to timing discrepancies in payment reconciliation at the time of reporting.
- Energy Uplift costs totalled $1.7 million in Q2 2025, an increase of $0.9 million (+108%) compared to Q2 2024. Of this, a total of $0.7 million (42%) were incurred during planned network outages in early April 2025.
  - A smaller increase was driven by changes implemented as part of the FCESS Cost Review, which introduced Energy Uplift payments for Facilities constrained on to provide RoCoF Control Service under Certain circumstances.
  - Energy Uplift payments paid during the Real-Time Market suspension totalled $59,000 (see Section 4.4.3).

Figure 122 Total ESS and Uplift cost decrease driven by FCESS Cost Review and batteries

Total ESS and Uplift cost per quarter - Q1 2024 to Q2 2025

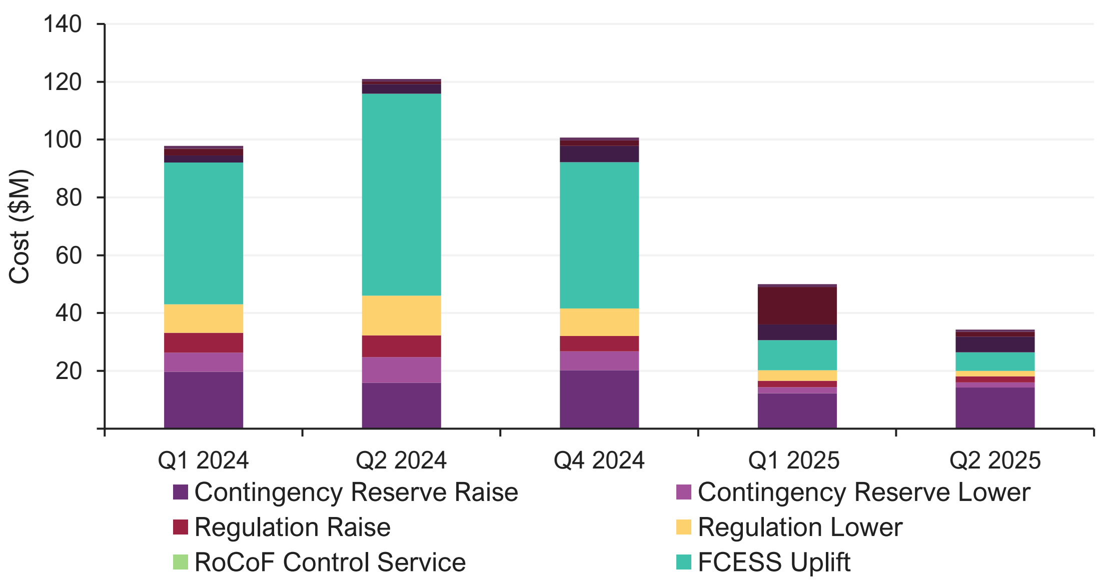
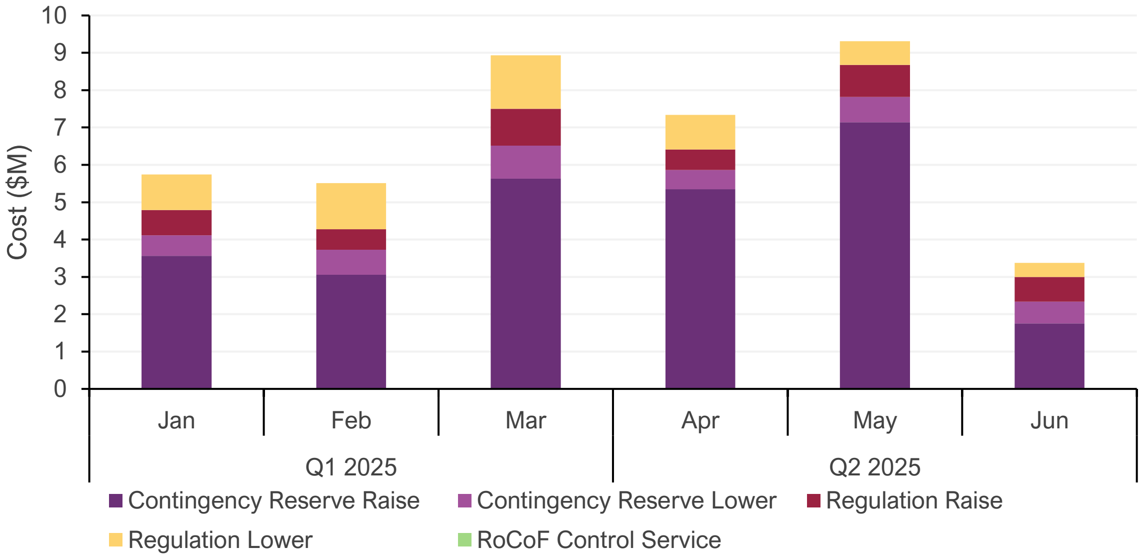


Figure 123 FCESS Enablement cost decrease driven by entry of battery in FCESS market on June 2025

Total FCESS enablement (excl. Uplift) costs per month in Q1 and Q2 2025



4.4.5 Load contingency limit increase

In response to system security risks identified by AEMO, a 200 MW load contingency limit was placed on the network prior to the commencement of Battery Energy Storage System (BESS) facilities in the WEM. However, recent connection of large-scale BESS facilities has challenged this limit due to the constraints it places on such facilities' withdrawal (charge) capacities.

A permanent upgrade to WEMDE is planned for Q4 2025 to enable co-optimisation of the Largest Credible Load Contingency (LCLC) with contingency reserve lower and RoCoF control service, which would enable larger load contingencies. To support new connections and large-scale BESS participation in the short term, several interim measures[55] to support system security have been implemented, which allowed AEMO to lift the load contingency limit from 200 MW to 300 MW from 20 May 2025.

As a result, the average contingency reserve lower (CRL) enabled quantity increased from 51.9 MW (period starting 1 April) to 109.4 MW after 20 May 2025, an increase of 57.5 MW (+111%) per dispatch interval (Figure 124). Despite this increase, contingency reserve lower prices decreased marginally by $0.76/MWh.

Shortly thereafter, the accreditation of KWINANA_ESR2 to provide FCESS services from 6 June 2025, put downward pressure on the final CRL clearing price, which fell to $18.54/MWh, a decrease of $8.04/MWh (-30%) in June 2025, despite further increases to the average CRL enabled quantity to an average of 118.9 MW per dispatch interval.

[55] Relevant measures were discussed in depth at the Real-Time Insights Forum in April 2025: slides are available at https://aemo.com.au/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/real-time-market-insights-forum

Figure 124 Average CRL clearing price decreased despite LCLC limit increase and KWINANA_ESR2 accreditation

Average CRL quantity and price per dispatch interval before and during LCLC increase, and after KWINANA_ESR2 accreditation

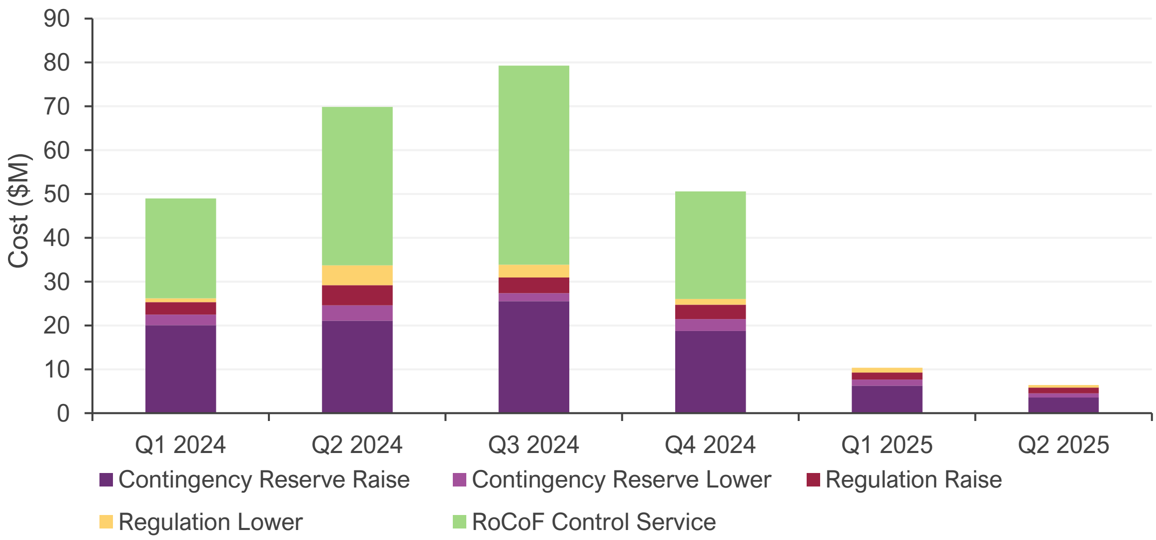
4.4.6 FCESS Uplift share costs

When a facility receives FCESS Uplift payments in a dispatch interval, those costs are assigned to an FCESS market service[56] and recovered through normal cost distribution processes for those market services.

Figure 125 provides a breakdown of the total FCESS Uplift costs assigned to each FCESS market service. This data can be combined with FCESS enablement costs to understand the total costs (enablement plus uplift) recovered in respect of each FCESS market service.

Figure 125 Total FCESS Uplift cost decreases by $63.9 million (-91%) in Q2 2025 compared to Q2 2024

Distribution of FCESS Uplift market services per quarter– Q1 2024 to Q2 2025



[56] Note that since 20 November 2024, no FCESS Uplift costs are assigned to the RoCoF Control Service market service.

The total FCESS Uplift costs recovered through the regulation and contingency market services fell by between 71% and 88% from Q2 2024 to Q2 2025, while the costs recovered through RoCoF Control Service fell to zero, primarily as a result of changes implemented as part of the FCESS Cost Review in November 2024. Slightly over half ($3.6 million or 56%) of all FCESS Uplift costs were recovered through the contingency reserve lower market.

4.4.7 Non-Co-optimised Essential System Services

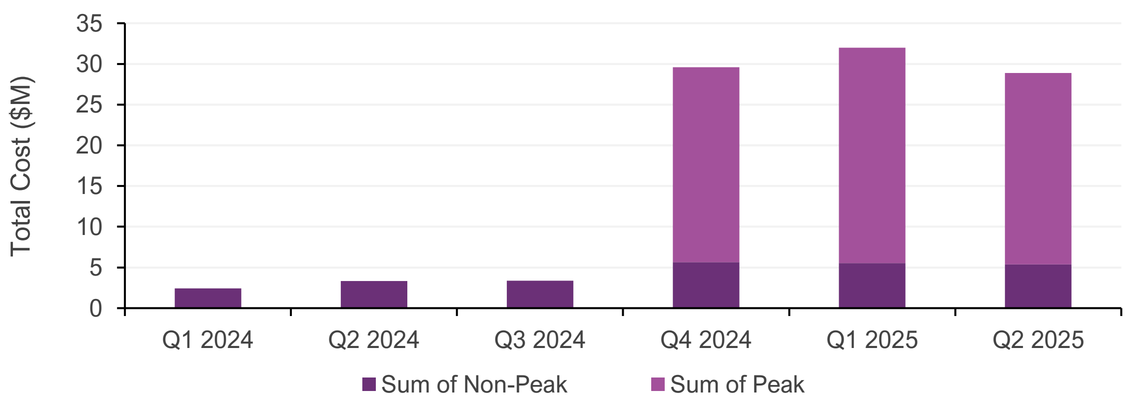
Since 7 October 2024, NCESS costs[57] are divided into two categories, with different cost-recovery mechanisms, based on the nature of the NCESS service. AEMO refers to these as “Peak NCESS” and “Non-Peak NCESS” costs, and groups these with Capacity and ESS costs respectively for reporting purposes. Prior to 7 October 2024, all NCESS costs were recovered in the same manner as Non-Peak NCESS costs and were treated as ESS costs for reporting purposes.

Note that NCESS costs data in this report are only available up to 15 June 2025 due to timing discrepancies in payment reconciliation at the time of reporting.

In Q2 2025, total NCESS costs reached $28.9 million, a $25.5 million increase compared to Q2 2024 (Figure 126). This increase was driven by commencement of 10 new Peak NCESS contracts since Q2 2024, including two which commenced in Q2 2025. Of the total NCESS cost, $23.5 million (92%) were Peak NCESS costs, while $5.4 million (8%) were Non-Peak NCESS costs. Total Non-Peak NCESS costs increased by $2.0 million (+62%) compared to Q2 2024.

Figure 126 NCESS costs increased as 10 new Peak NCESS contracts commenced since Q2 2025

NCESS costs by cost recovery mechanism (excluding NCESS costs after 15 June 2025) – Q1 2024 to Q2 2025



4.4.8 Total Wholesale Electricity Market costs

Figure 127 represents the WEM costs as a price per MWh, normalised by total energy consumed to enable better comparison of costs between periods with different demand.

In Q2 2025, the sum of all normalised costs in the WEM totalled $147.78/MWh, an increase of $9.52/MWh (+7%) from Q2 2024. Changes are outlined below and discussed further in referenced sections:

[57] NCESS costs for Q2 2025 are only available up to 15 June 2025 due to timing discrepancies in payment reconciliation at the time of reporting.

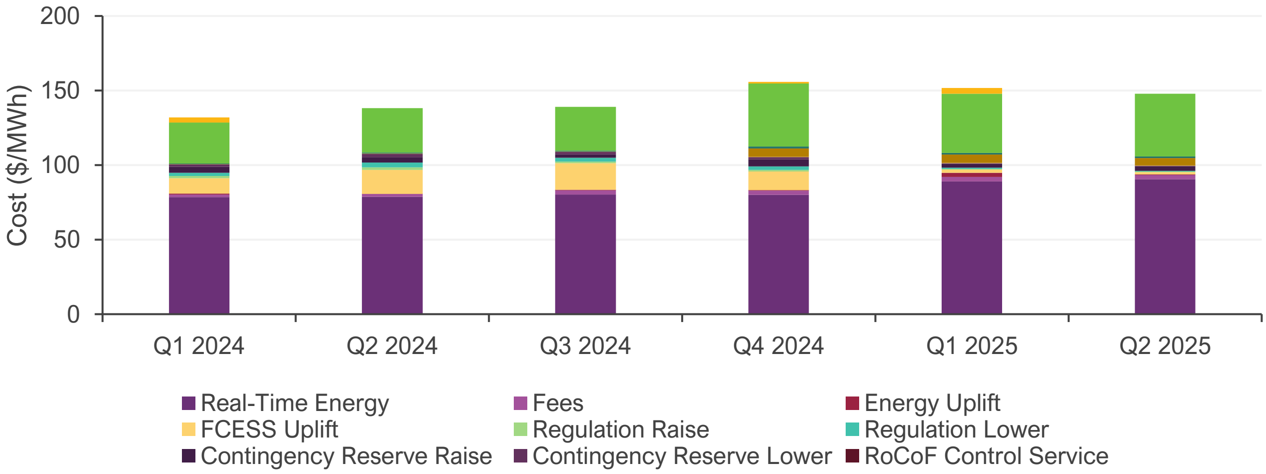
- The increase was largely attributed to a rise in the average energy price, which rose to $90.45/MWh in Q2 2025, an increase of $11.67/MWh (15%) compared to Q2 2024 (Section 4.4).
- Normalised reserve capacity costs, net of reserve capacity refunds, increased to $42.07/MWh in Q2 2025, a $12.22/MWh (+41%) increase, primarily due to a higher Reserve Capacity Price[58] set for the 2024–25 Capacity Year.
- Normalised energy uplift costs increased to $0.35/MWh, up $0.18/MWh following higher-than-average Energy Uplift costs driven by a planned network outage in early April 2025 (Section 4.4.4).
- Normalised NCESS costs were $5.96/MWh, an increase of $5.20/MWh driven by commencement of 10 new NCESS contracts since Q2 2024.

Conversely, several cost components saw decreases:

- Normalised FCESS enablement costs (excluding Uplift) fell to $4.41/MWh in Q2 2025, a reduction of $6.24/MWh (-59%) from Q2 2024 (Section 4.4.4).
- Normalised FCESS Uplift costs fell to $1.43/MWh in Q2 2025, representing a $14.59/MWh (91%) decrease compared to Q2 2024 (Section 4.4.4).

Figure 127 Wholesale Electricity Market costs increased compared to Q2 2024

Normalised Energy, ESS and Capacity costs per MWh consumed in the WEM – Q1 2024 to Q2 2025



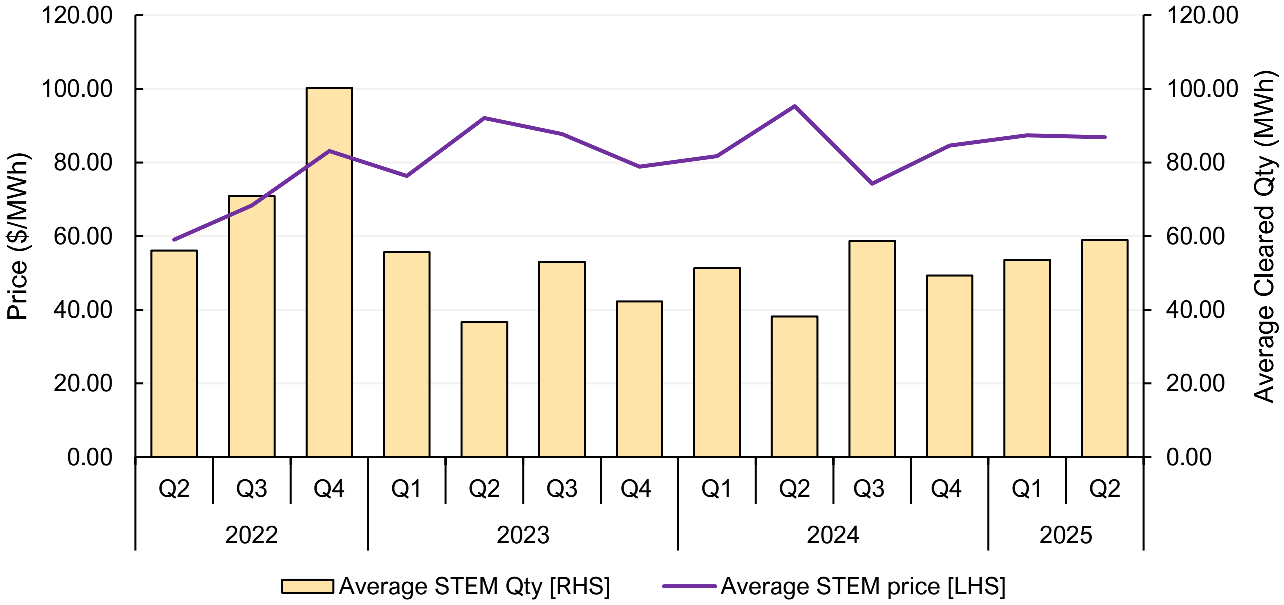
4.4.9 Short Term Energy Market (STEM)

The average STEM price for Q2 2025 was $86.87/MWh, a decrease of $0.50/MWh (-0.5%) from the previous quarter and a decrease of $8.40/MWh (-9%) compared to Q2 last year (Figure 128). The quarterly average quantity of energy cleared in the STEM per interval was 59 MWh, an increase of 5 MWh (+14%) from Q1 2025. When compared to Q2 2024, quantities cleared increased by 20 MWh (+39%).

[58] The reserve capacity price for transitional facilities, which is applicable to the majority of facilities, increased from $118,599.19/MW/yr in capacity year 2023-24 to $150,745.81/MW/yr in capacity year 2024-25, while the reserve capacity price increased from $105,949.27/MW/yr to $194,783.54/MW/yr.

Figure 128 The average STEM price decreased by 0.5% in Q2 2025

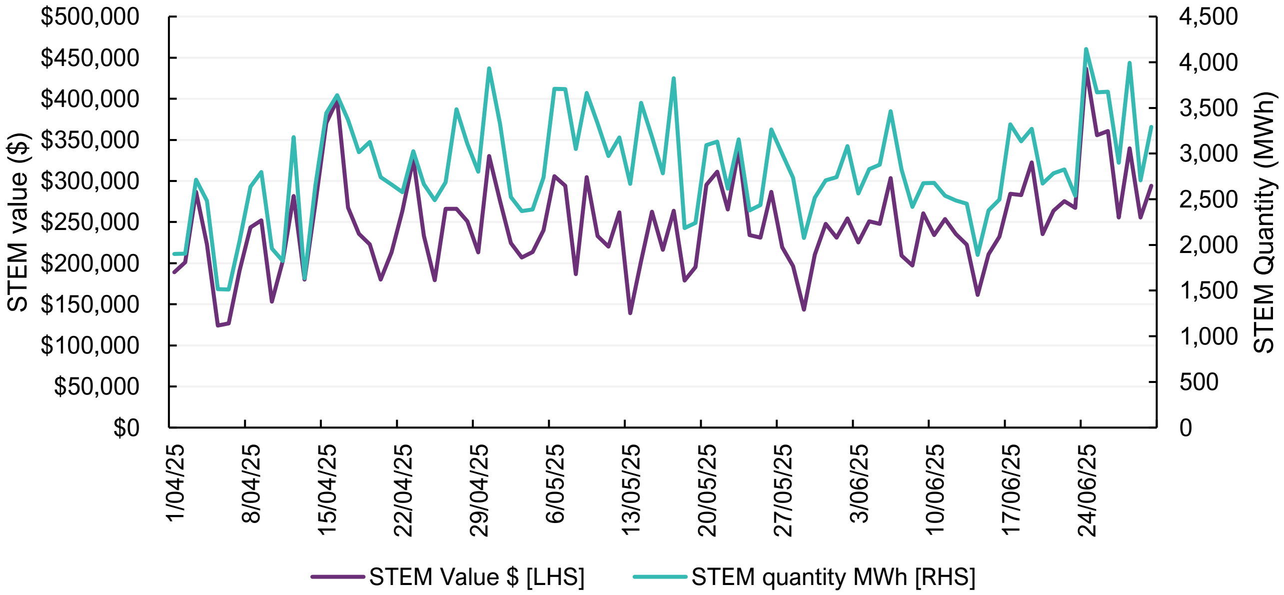
WEM average STEM price and quantity cleared in STEM – Q2 2022 to Q2 2025



The daily traded value in STEM ranged from $124,119 to $436,576 in Q2 2025, whereas the daily quantities traded varied between 1,512 MWh and 4,144 MWh (Figure 129). A $38,166 increase in minimum daily traded value from last quarter is mostly driven by the reduction in intervals clearing at a negative price. A total of 38 intervals cleared at a negative price this quarter, compared with 74 in Q1 2025.

Figure 129 Daily STEM values fluctuated between $124,119 and $436,576 in Q2 2025

Daily Quantities (MWh) and value ($) traded in STEM – Q2 2025



5 Reforms delivered

AEMO, with government and industry, continues to deliver energy market reforms across the WEM, NEM and east coast gas markets. These 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 10 provides a brief description of the reforms implemented over the last quarter.

Table 10 Reforms delivered Q2 2025

Reform initiative	Market	Description	Reform delivered
SCADA Lite	NEM	SCADA Lite (an AEMO foundational and strategic initiative under the NEM Reform Program) enables NEM non-NSP participants to establish a bi-directional connection to exchange operational information (telemetry and control) with AEMO – specifically, those requirements defined in both the Wholesale Demand Response Guidelines (Version 1.0, effective date 24 June 2021) and Power System Data Communication Standard (Version 3.0, effective date 3 April 2023). More information: https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/scada-lite	May 2025
Reserve Capacity Mechanism (RCM) Review (2025 Capacity Cycle Certification)	WEM	The 2025 WEM ESOO includes new modelling in the 10-year horizon to determine the duration required by new battery capacity and maximum dispatch requirements for demand side programmes, as included the Electricity System and Market Amendment (Tranche 8) Rules 2025. Also in the modelling is an uplift to the Peak Reserve Capacity Target arising as a result of protection provisions for the previously certified storage with a shorter duration requirement. More information: https://aemo.com.au/media/files/electricity/wem/planning_and_forecasting/esoo/2025/2025-wem-electricity-statement-of-opportunities.pdf	June 2025
Frequency Performance Payments (Financial Operation)	NEM	In accordance with the NEM Primary Frequency Response Incentive Arrangement rule change, financial operation of the new Frequency Performance Payments (FPP) system went live in June 2025. This follows an extended period of non-financial operation from December 2024 of the new FPP system to allow market participants to familiarise themselves with its operation. The FPP system and associated procedures and guidelines (including Frequency Contribution Factor Procedures) provide incentives for all facilities to operate in a way that helps maintain power system frequency within the normal operating band, at the lowest cost to consumers. More information: https://aemo.com.au/initiatives/major-programs/frequency-performance-payments-project	June 2025

In addition to these reforms, work continues to progress on the next wave of initiatives set for release later in 2025. Table 11 below provides a brief description of initiatives to be delivered in Q3 and Q4 2025.

Table 11 Upcoming implementation of reforms Q3 – Q4 2025

Reform initiative	Market	Description	Reform to be delivered
RCM Review (2025 Capacity Cycle Certification)	WEM	AEMO has scheduled further changes to its systems and processes, live on 8 July, to enable the assignment of Flexible Capacity and the determination of the Reserve Capacity Prices for the 2025 Reserve Capacity Cycle. The Peak Reserve Capacity Price and the Flexible Reserve capacity price curves have changed to reduce volatility in the price and incentivise investment. Additionally Flexible Capacity Providers will also have the option of applying for a 10-year price guarantee aligned with their year of entry. Prioritisation of firm and intermittent generation capacity in the Network Access Quantity framework will also now be considered where the WEM ESOO has identified a need for generation, rather than duration-limited capacity to meet energy shortfalls in the applicable Capacity Year. The 2025 WEM ESOO included a determination of the Flexible Reserve Capacity Target as the expected highest four-hour demand increase plus a reserve margin. More information: https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism https://aemo.com.au/media/files/electricity/wem/planning_and_forecasting/esoo/2025/2025-wem-electricity-statement-of-opportunities.pdf	July 2025
Enhancing Reserve Information (ERI)	NEM	In accordance with the Enhancing Reserve Information (ERI) rule change, the ERI reform improves the transparency of energy availability across the NEM. This will allow participants to make more informed decisions about their own behaviour, including when periods of tighter supply-demand balance are anticipated. As of Tuesday 1 July, the ERI rule commenced and AEMO now publishes: • Energy availability for batteries (by Dispatchable Unit Identifier (DUID) and for each 5-minute trading interval) at the end of the trading day for the previous trading day; • Daily energy limits (total availability) of scheduled generators and scheduled bidirectional units that are not batteries, aggregated by region; and • Energy availability of batteries (i.e. state of charge), aggregated by region, for each trading interval. More information: https://aemo.com.au/initiatives/major-programs/nem-reform-program/enhancing-reserve-information-project	July 2025
Short Term Projected Assessment of System Adequacy (ST PASA) Procedure and Recall Period	NEM	The Updating ST PASA rule change introduced a principles-based approach for AEMO to administer ST PASA. This included an obligation to publish a ST PASA Procedure, and made changes to ST PASA publication timetable, the definition of 'energy constraint' and PASA availability. The resulting system and procedural changes are to go live from 31 July 2025 and provide flexibility to participants to communicate to the market on their unit availability and outage conditions as well as support AEMO's ability to assess reliability and security conditions in the NEM as the market develops. More information: https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/st-pasa	July 2025

Reform initiative	Market	Description	Reform to be delivered
Improving Security Frameworks (ISF)	NEM	The Improving Security Frameworks for the Energy Transition Rule builds on existing tools and frameworks within the power system to enhance system security procurement frameworks, providing increased transparency on system security needs and understanding of how AEMO plans to manage system security as we transition to a secure net zero emissions power system. The rule sets forth multiple milestones, scheduled between 30 June 2024 and 2 December 2025. • A complete Security Enablement Procedure is to be published in August 2025 inclusive of methodology for enablement of system security services. • Full enablement obligations on AEMO will commence in December 2025. AEMO is implementing ISF system security enablement functions across two releases. • The first release delivers enablement functions focusing on external-facing components and reporting from 2 December 2025. • A subsequent release in mid-2026 will deliver automated enablement functionality and other non-core components of the solution. More information: https://aemo.com.au/initiatives/major-programs/improving-security-frameworks-for-the-energy-transition	August & December 2025
Contingency Reserve Lower Procurement and Recovery (Cost Allocation Review)	WEM	AEMO will deliver changes to its dispatch systems to enable the co-optimised procurement of the Largest Credible Load Contingency within the dispatch algorithm. The change to the procurement methodology will be complemented with changes to the cost recovery using a modified runway method to allocate costs based on the causer pays principle. More information: https://aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/p3109--first--final-ia202501.pdf?la=en&hash=28DF02F0CC94DD8645ABCB72E7675D48	October 2025
Metering Services Review – Package 1	NEM	The Accelerating Smart Meter Deployment (ASMD) seeks to achieve universal smart meter deployment in the NEM by 2030. There are four key changes for 2025 as part of this Rule change: • Legacy Meter Replacement Plan: a plan developed by the DNSP that provides for the replacement of all legacy (Type 5 & 6) meters at connection points on its distribution network. The program starts on 1 December 2025 to 30 November 2030. • Defect Management: Metering Coordinators are required to notify the retailer of a defect when attempting to exchange a meter as well a record the defect in Market Settlements and Transfer Solution (MSATS), including the nature of the defect. • One in All in: a new procedure for managing the replacement of meters with shared fusing. • Testing and inspection: AEMO has proposed a new Procedure for testing and inspection for all metering installations and changes to the malfunction and exemption process. A second release package (Package 2) enabling better access to power quality data (PQD) for DNSPs is to go live in July 2026. More information: https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/metering-services-review---accelerating-smart-meter-deployment	December 2025

List of tables and figures

Tables

Figures

Abbreviations

Abbreviation	Expanded term
5MS	Five-Minute Settlement
ACCC	Australian Competition and Consumer Commission
ACE	Adjusted Consumed Energy
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APLNG	Australia Pacific LNG
ASX	Australian Securities Exchange
BCF	Ballera Compression Facility
BESS	battery energy storage system
CDEII	Carbon Dioxide Equivalent Intensity Index
CF	contribution factor
CGP	Carpentaria Gas Pipeline
CRL	contingency reserve lower
DAA	Day Ahead Auction
DR	demand response
DUID	Dispatchable Unit Identifier
DWGM	Declared Wholesale Gas Market
EDD	effective degree day
EGP	Eastern Gas Pipeline
ERI	Enhancing Reserve Information
ESR	electric storage resource
ESS	essential system services
FCAS	frequency control ancillary services
FCESS	frequency co-optimised essential system services
FPP	Frequency Performance Payment
GAB	Gas Advisory Board
GBB	Gas Bulletin Board
GJ	gigajoule/s
GJ/h	gigajoules per hour
GW	gigawatt/s
GWh	gigawatt hour/s
GLNG	Gladstone LNG
GSH	Gas Supply Hub
HDD	heating degree day
IEA	International Energy Agency
IRR	interim reliability reserve
IRSR	inter-regional settlement residue
L6SE	lower 6-second (FCAS)

Abbreviation	Expanded term
LCA	Linepack Capacity Adequacy
LCLC	Largest Credible Load Contingency
LGC	large-scale generation certificate
LNG	liquefied natural gas
MTPA	million tonnes per annum
MT PASA	Medium Term Projected Assessment of System Adequacy
$MtCO_2$-e	million tonnes of carbon dioxide equivalents
MW	megawatt/s
MWh	megawatt hour/s
NEM	National Electricity Market
NCESS	non-co-optimised essential system service
NGP	Northern Gas Pipeline
NO	Network Operator
NSP	network service provider
NT	Northern Territory
pp	percentage points
PJ	petajoule/s
PV	photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
R6SE	raise 6-second (FCAS)
RBP	Roma Brisbane Pipeline
RCM	Reserve Capacity Mechanism
RCR	requirement for corrective response
RERT	Reliability and Emergency Reserve Trader
RoCoF	Rate of Change of Frequency
RREG	raise regulation
RRP	regional reference price
ST PASA	Short Term Projected Assessment of System Adequacy
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
tCO2-e	tonnes of carbon dioxide equivalent
TJ/d	terajoules per day
TJ/y	terajoules per year
UGS	Underground Storage Facility
VGPR	*Victorian Gas Planning Report*
VPP	virtual power plant
VRE	variable renewable energy

Abbreviation	Expanded term
VNI	Victoria – New South Wales Interconnector
WCF	Wallumbilla Compression Facility
WEM	Wholesale Electricity Market
WEMDE	WEM dispatch engine
WDR	wholesale demand response