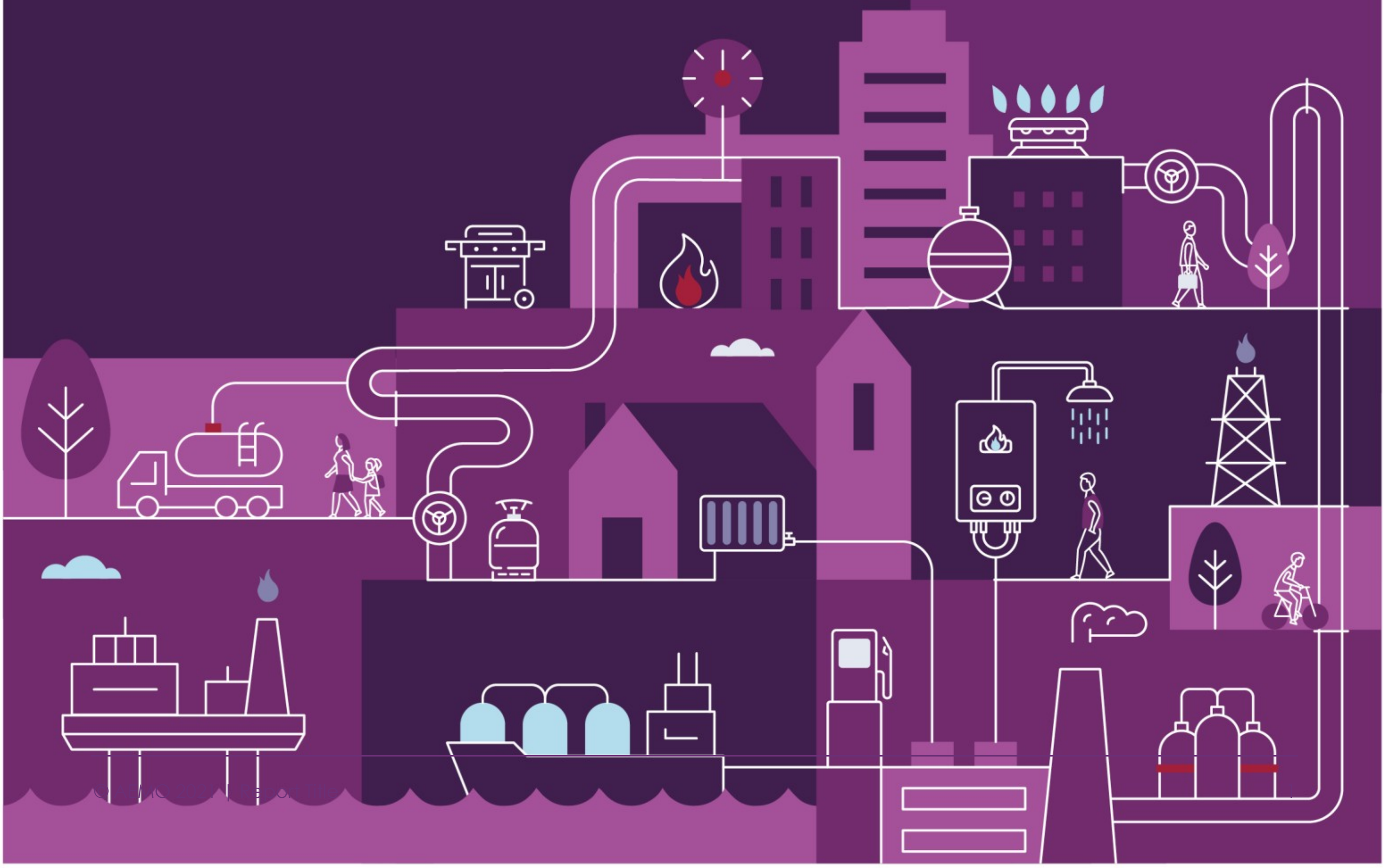
Quarterly Energy Dynamics Q2 2026

July 2026



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.

AEMO Group is proud to have launched its Innovate Reconciliation Action Plan in June 2026. Pictured left and featuring on the cover of the Innovate RAP is Wiradjuri artist Lani Balzan's 'Journey of unity: AEMO's Reconciliation Path', a visual representation of 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 2026 (1 April to 30 June 2026). This quarterly report compares results for the quarter against other recent quarters, focusing on Q2 2025 and Q1 2026. 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

Mild weather and consumer energy resources reshaped demand patterns

- Underlying demand across National Energy Market (NEM) regions remained broadly unchanged year-on-year, increasing by 0.2% to average 24,220 megawatts (MW). Distributed photovoltaic (PV) output increased by 6.9% to 2,520 MW, contributing to a 0.5% fall in operational demand to 21,700 MW.
- NEM-wide operational demand grew in daytime hours as increased home battery charging, industrial demand and data centre load outpaced distributed PV output growth. This reshaped the daily demand profile, with demand shifting away from the evening peak as more home batteries supplied household consumption after sunset and milder weather reduced heating requirements.

Higher wind output lifted renewable generation to a new Q2 high

- Wind generation reached a new Q2 high of 4,198 MW, up 20% from Q2 2025, driven by availability growth at new and commissioning facilities and improved wind conditions across all NEM regions. Queensland contributed the largest increase, with average wind generation in the region rising 80% to a new all-time high of 842 MW.
- Grid-scale solar generation increased by 12% to average 1,860 MW, with increased availability at new and commissioning facilities offsetting the impact of lower solar exposure in the southern regions during periods of increased cloud cover across the quarter.
- Total coal-fired generation fell to a new Q2 low at 13,158 MW, down 5.0% from Q2 2025, with a small year-on-year increase in brown coal-fired generation (+1.3%), offset by a 7.3% reduction in black coal-fired generation.
- Gas-fired generation recorded its lowest Q2 average since 2003, at 1,050 MW, 30% lower than in Q2 2025. Output was low for most of the quarter before reaching its highest daily average of 3,328 MW on 22 June during an extended period of low wind speeds across southern NEM regions.
- These supply changes lifted the renewable share of NEM generation to a new Q2 high of 42.1%, up from 37.1% in Q2 2025. NEM total emissions reduced to a new Q2 low of 27.1 million tonnes of carbon dioxide equivalent (MtCO2-e), down 6.4% from Q2 2025, with an emission intensity of 0.57 tonnes of carbon dioxide equivalent per megawatt hour (tCO2-e/MWh), down 6.0%.

Grid-scale battery storage increasingly shifted energy and influenced price outcomes

- Growing grid-scale battery capacity more than tripled the volumes of energy shifted from daytime periods of high solar output into the evening peak, as daytime (1000 hrs to 1600 hrs) charging increased by 1,009 MW (+211%) and evening (1600 hrs to 2100 hrs) discharge increased by 1,066 MW (+228%) year-on-year.
- The increasing role of grid-scale batteries also changed price-setting outcomes, with battery charging and discharging setting prices in 36% of dispatch intervals, up from 17% in Q2 2025. All mainland NEM regions recorded a greater influence of batteries on price setting, particularly New South Wales and Queensland.

Wholesale electricity prices fell across the NEM

- NEM-average wholesale spot prices averaged $74/MWh, down $66/MWh (-47%) from Q2 2025, and the lowest Q2 average since 2020. Increased renewable generation, higher grid-scale battery discharge during peak periods, and reduced evening peak demand contributed to lower wholesale prices and a flatter intraday price profile.
- South Australia was the only region to experience any material price volatility this quarter. On 21 and 22 June, cold and still conditions increased demand and reduced wind output, while transmission constraints restricted imports from neighbouring regions and increased reliance on gas-fired generation. While high prices on these two days contributed $13/MWh to the region's quarterly average price of $86/MWh, it was still a 38% year-on-year decrease.
- All other NEM regions also experienced lower average wholesale spot prices than in Q2 2025. Victoria recorded the lowest average price at $56/MWh, down 60% year-on-year, followed by Queensland at $67/MWh (-44%), New South Wales at $75/MWh (-53%) and Tasmania at $86/MWh (-39%).

East coast gas prices fall to their lowest level since Q2 2021 driven by lower domestic demand

- East coast wholesale gas prices averaged $9.08 per gigajoule (GJ) for the quarter, lower than Q2 2025, which averaged $12.36/GJ. This made Q2 2026 the lowest average for any quarter since Q2 2021, which averaged $8.20/GJ. At the same time, international liquefied natural gas (LNG) spot prices were materially higher than prices observed in the east coast gas market, amid ongoing heightened supply risks linked to the conflict in the Middle East.
- Gas demand decreased by 3% in aggregate from Q2 2025, driven by the lowest gas-fired generation demand in Q2 since 2003 (-10 petajoules [PJ]), and lower AEMO markets demand (-7 PJ). At the same time, Queensland LNG exports increased to their highest Q2 on record (+3 PJ). Continuing the trend observed throughout 2025 and Q1 2026, Victoria experienced the largest demand decrease, with continued reduction in industrial, commercial and residential usage, exacerbated by above average temperatures, which decreased requirements for heating.
- Iona underground gas storage (UGS) was unutilised for most of the quarter and remained at capacity until 22 June, when higher demand – mainly related to gas-fired generation – saw the storage balance decline to 22.3 PJ at the end of June, only marginally lower than the highest end-June balance, recorded in 2023.

Western Australia electricity and gas highlights

Wholesale Electricity Market (WEM) demand increased and lower wind and coal-fired generation increased reliance on gas-fired generation

- Lower temperatures and higher heating demand lifted WEM underlying demand by 1.6% year-on-year. Growth in distributed PV output (+3.4%) only partially offset this increase, with grid-supplied unscheduled demand rising by 1.4%.
- Wind generation decreased by 54 MW (-13%), due to a major outage associated with a wind farm expansion and generally lower wind speeds, while coal-fired generation fell by 137 MW (-17%), reflecting planned and forced outages and the retirement of Muja C Unit 6. These reductions increased reliance on gas-fired generation, which rose by 216 MW (+27%), while the renewable share of generation declined from 33.6% to 32.0%.
- Total WEM emissions were 2.40 $MtCO_2$-e, broadly unchanged from Q2 2025, while emissions intensity declined by 16% to 0.50 tCO2-e/MWh, as coal-fired generation accounted for a smaller share of the generation mix.

WEM energy prices reached record highs while Essential System Service (ESS) costs fell

- The average real-time energy price increased by $27.41/MWh (+30%) year-on-year to $117.87/MWh this quarter, a new WEM record. This was driven by lower wind and coal-fired generation (combined down 191 MW year-on-year), increasing reliance on higher-cost gas generation to meet higher unscheduled operational demand (+28 MW) and battery charging (+87 MW).
- Overall, normalised WEM costs increased by $31.87/MWh to $175.53/MWh, primarily driven by the increase in energy costs. Increases in Non-Co-Optimised ESS (NCESS) costs (+$6.18/MWh) and Reserve Capacity costs (+$3.83/MWh) also contributed, while lower Frequency Co-Optimised Essential System Services (FCESS) and Uplift costs partially offset these increases.
- Grid-scale batteries increased their share of contingency and regulation FCESS markets to 89% of enabled volume following the accreditation of four additional battery systems since Q2 2025. Greater competition contributed to FCESS enablement costs falling by 92% to $1.5 million and total ESS costs including uplift declining from $26.5 million to $9.6 million.

Western Australia's domestic gas consumption and production decreased

- Western Australia's domestic gas consumption was 100.3 PJ, a decrease of 9.4 PJ (-8.5%) compared with Q2 2025. Production was 99.7 PJ, which represented a 6.2 PJ (-8.5%) decrease. Net storage withdrawals of 2.1 PJ were recorded, compared to 4.9 PJ in Q2 2025.
- Linepack Capacity Adequacy (LCA) flags were observed during the quarter, reflecting operational constraints and maintenance related disruptions. The Dampier to Bunbury Natural Gas Pipeline experienced multiple periods of Amber conditions associated with cyclone recovery impacts and upstream facility outages.

Contents

1 Weather

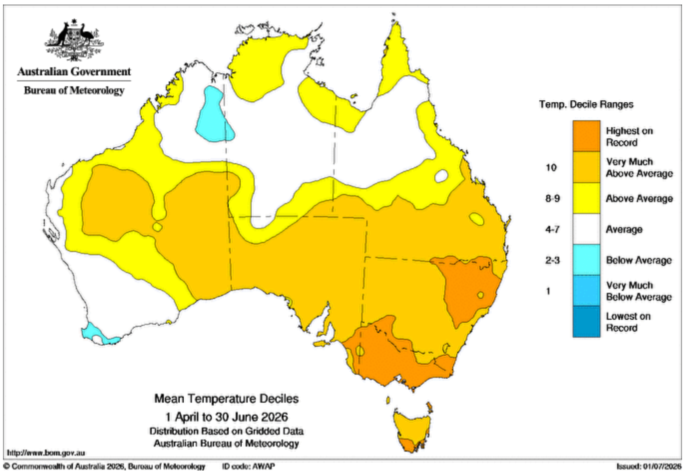
In Q2 2026, Australia experienced persistently warmer-than-average conditions, with above-average temperatures recorded across most parts of the country throughout April, May and June (**Figure 1**). April was generally warmer than average, with South Australia recording its fifth-warmest April on record, while May saw Tasmania, Victoria and New South Wales each record their second-warmest May. Warm conditions persisted into June, with all states and territories except Western Australia and the Northern Territory recording one of their 10 warmest Junes on record.

Rainfall was more variable, with April generally much drier than average, including New South Wales recording its second-driest April on record. Heavy rainfall associated with a series of low-pressure troughs in late May brought above-average rainfall and increased cloud cover to parts of central and eastern Australia, reducing solar exposure, particularly in Victoria and South Australia. Drier-than-average conditions then returned across much of southern and eastern Australia in June.

In Q2 2026, heating degree day (HDD)[1] trends across Australia's major capital cities diverged between the east and west coasts relative to Q2 2025 (**Figure 2**). Warmer-than-average conditions yielded lower HDDs across all major east-coast cities, particularly in Brisbane and Sydney, with more modest reductions in Victoria, Adelaide and Hobart. In contrast, Perth recorded higher HDDs, particularly in May and June, indicating greater heating requirements than last Q2.

Figure 1 Warmer than long-term average temperatures across most parts of Australia

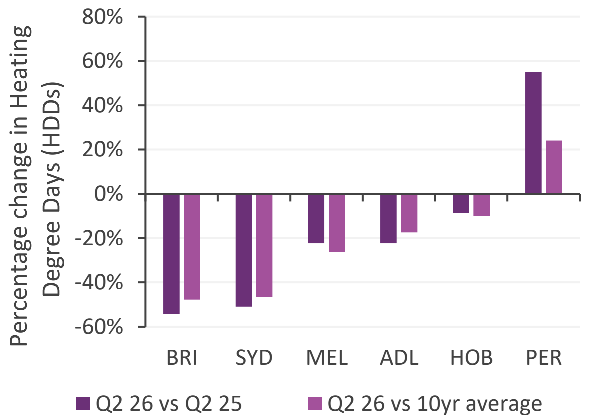
Q2 2026 mean temperature deciles for Australia



Source: Bureau of Meteorology (BOM)

Figure 2 Lower heating requirements across most capital cities in east coast, higher in Perth

Percentage change in quarterly HDDs by capital city – Q2 2026 vs Q2 2025



[1] 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).

2 NEM market dynamics

2.1 Electricity demand

NEM-wide underlying demand[2] reached a new Q2 high of 24,220 MW in Q2 2026, marginally exceeding (+0.2%) the previous high of 24,174 MW set in Q2 2025 (**Figure 3**). Warmer weather's impact on heating requirements in May and June was offset by demand increases driven by ongoing electrification, population growth and data centre loads.

Operational demand[3] averaged 21,700 MW, down 117 MW (-0.5%) year-on-year and the lowest Q2 average since 2020. Growth in distributed PV[4] output exceeded the increase in underlying demand (**Figure 4**), with NEM-wide distributed PV generation reaching a record Q2 average of 2,520 MW, up 162 MW (+6.9%) year-on-year. However, this quarter recorded the slowest year-on-year growth in distributed PV output since at least Q2 2017, reflecting lower solar exposure, particularly across Victoria and South Australia in May (see Section 1).

Figure 3 Underlying demand increased despite warmer conditions

NEM average underlying and operational demand – Q2s

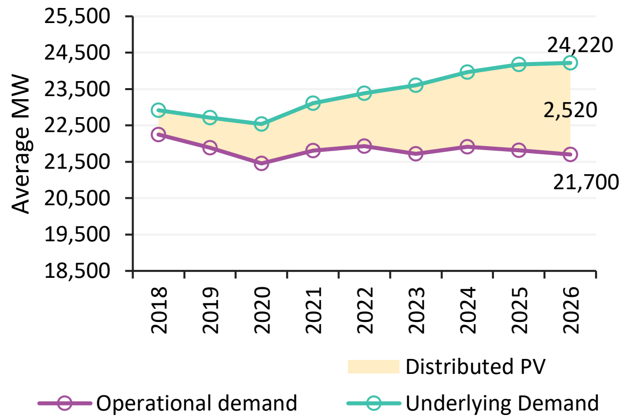
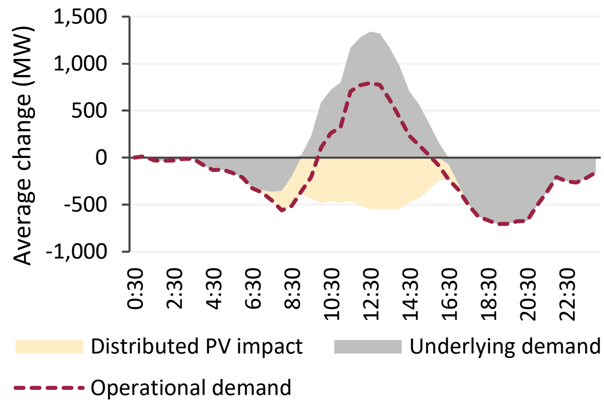


Figure 4 Increased daytime operational demand as home batteries shifted demand from evening peaks

Average changes in NEM demands and distributed PV output by time of day – Q2 2026 vs Q2 2025



NEM-wide operational demand increased notably during daytime hours as rising home battery charging activity, together with growing industrial and data centre loads, outpaced the growth in distributed PV output. As a result, operational demand shifted away from the evening peak, with home batteries supplying part of household consumption after sunset, alongside reduced heating requirements due to warmer weather. This trend was evident across most regions, highlighting the growing influence of home batteries and other load-shifting programs on the demand profile.

[2] Underlying demand is calculated by adding estimated production from distributed PV to operational demand.

[3] 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.

[4] Data from AEMO's Australian Solar Energy Forecasting System (ASEFS) phase 2: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-solar-energy-forecasting-system.

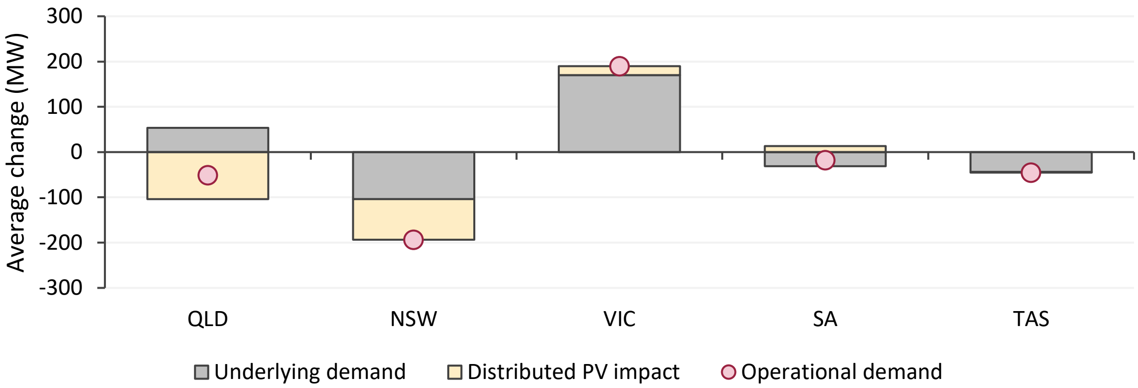
Underlying demand decreased in New South Wales, South Australia and Tasmania, particularly outside daylight hours. In contrast, underlying demand increased year-on-year in Victoria and Queensland, with higher industrial load in both regions.

Distributed PV output reached new Q2 highs in Queensland, New South Wales and Tasmania, while reduced solar exposure led to declines in southern states of Victoria and South Australia.

Victoria saw the only increase in operational demand (**Figure 5**), with higher data centre demand, industrial load and ongoing electrification, which shifted some heating demand from gas to electricity (see **Figure 91** in Section 3.2.2), offsetting the impacts of warmer temperatures. All other regions saw declines in operational demand, particularly during the evening period, as growing uptake of home batteries shifted demand from evening to daytime periods (see **Figure 8** in Section 2.1.2).

Figure 5 Operational demand decreased in all regions except Victoria

Changes in average demand components by region – Q2 2026 vs Q2 2025



Comparing quarterly average outcomes in Q2 2026 with Q2 2025:

- In **Queensland**, underlying demand increased slightly by 53 MW (+0.8%) to average 6,977 MW, with lower heating demand and higher industrial load. Distributed PV output averaged 926 MW, up 104 MW (+13%), driven by higher solar exposure and increased installed PV capacity. This growth more than offset the increase in underlying demand, reducing operational demand to an average of 6,051 MW (-51 MW, -0.8%).
- **New South Wales** saw a decline in underlying demand, down 104 MW (-1.2%) to average 8,487 MW. The reduction was driven by warmer conditions during May and June, which lowered heating demand, although this was partially offset by continued growth in data centre demand, which averaged 451 MW (+35% year-on-year). Distributed PV output reached a Q2 record of 865 MW, up 90 MW (+12%), supported by increased installed distributed PV capacity. As a result, operational demand dropped 194 MW (-2.5%) to average 7,623 MW.
- **Victoria**'s underlying demand increased by 170 MW (+2.9%) to an average of 5,944 MW, supported by higher industrial load and data centre demand, with the latter nearly doubling from 104 MW in Q2 2025 to average 204 MW this quarter. Warmer than average temperatures in May and June reduced heating requirements, while electrification shifted some heating load from gas to electricity, partially offsetting this decline. Distributed PV output fell 20 MW (-4.2%) to 452 MW, driven by lower solar exposure levels, despite higher installed PV capacity. As a result, operational demand increased by 190 MW (+3.6%) to average 5,492 MW.

- In **South Australia**, underlying demand decreased to average 1,650 MW this quarter, down 31 MW (-1.8%) from Q2 2025, with warmer weather conditions through May and June. Distributed PV decreased marginally to an average of 246 MW, down 14 MW (-5.3%). Operational demand decreased by 17 MW (-1.2%) to average 1,404 MW, with a notable drop outside daylight hours.
- **Tasmania**'s underlying demand decreased by 44 MW (-3.6%) to average 1,162 MW this quarter, largely due to lower industrial demand. Distributed PV output reached a record Q2 high, averaging 31 MW, up 1 MW (+5.0%). Operational demand averaged 1,131 MW, a decline of 45 MW (-3.8%).

2.1.1 Maximum and minimum demands

In this quarter, NEM-wide **maximum operational demand** reached 30,697 MW for the half-hour ending 1830 hrs on Monday 22 June, 1,984 MW (-6.1%) below last Q2's maximum. With warmer conditions across the quarter, maximum operational demands were lower than Q2 2025 levels in all regions (**Figure 6**).

NEM-wide **minimum operational demand** reached 12,670 MW on Sunday 19 April for the half-hour ending 1300 hrs. Victoria and South Australia set new Q2 records for minimum operational demand (**Figure 7**), with minimum demands occurring during periods of high distributed PV output, mild weather conditions, and relatively low underlying demand during daytime hours. Victoria's operational demand fell to 1,986 MW on Saturday 4 April for the half-hour ending 1330 hrs, a notable reduction of 247 MW (-11%) from the minimum in Q2 2025. South Australia also recorded a new Q2 minimum operational demand of 57 MW for the half-hour ending 1330 hrs on Saturday 18 April, down 100 MW (-64%) from the previous record of 157 MW set in Q2 2023.

Figure 6 Maximum operational demand dropped in all regions

Maximum operational demand for mainland regions – Q2s

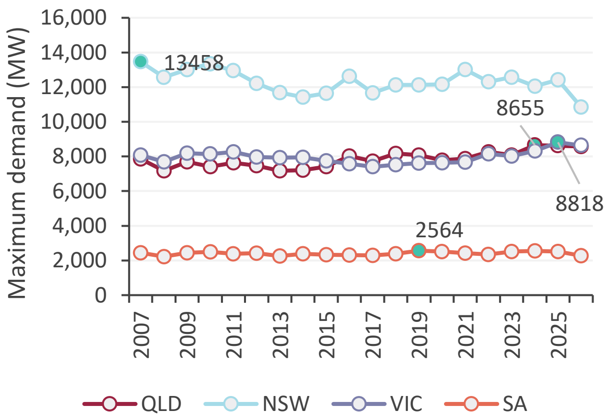
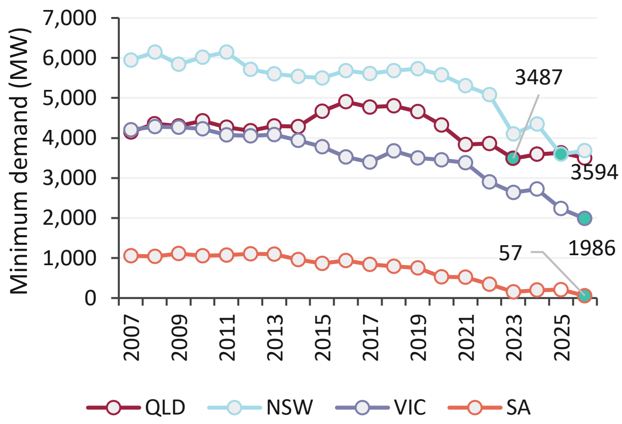


Figure 7 Victoria and South Australia set new Q2 lows for minimum operational demand

Minimum operational demand for mainland regions – Q2s



2.1.2 Consumer energy resources (CER)

Cumulative CER solar capacity continued to expand across the NEM during Q2 2026, rising from 25.7 gigawatts (GW) at the end of Q1 2026 to 26.4 GW by quarter end[5] (**Figure 8**). This growth was accompanied by an increase in CER solar installations, which reached 3.9 million. Capacity additions were recorded in all regions, with New South Wales reaching 9.0 GW, followed by Queensland at 8.0 GW, and Victoria and South Australia at 5.9 GW and 3.0 GW, respectively. Growth in Tasmania remained comparatively smaller and reached 0.4 GW.

The introduction of the Australian Government's Cheaper Home Batteries Program[6] supported continued growth in household battery adoption, with cumulative NEM-wide CER battery capacity under the program reaching 11,321 MWh and installations reaching 389,137 from 1 July 2025 to the end of June 2026[7].(**Figure 9**). Relative to end of Q1 2026, cumulative CER battery capacity across the NEM increased by 3,283 MWh (+41%) with more than 35% growth in every region by the end of Q2 2026. New South Wales recorded 4,865 MWh of installed capacity, followed by Queensland at 2,570 MWh and Victoria at 2,508 MWh. South Australia and Tasmania reached 1,288 MWh and 91 MWh, respectively.

Figure 8 CER solar capacity increased with growth in installations

Cumulative CER solar capacity and installations by region

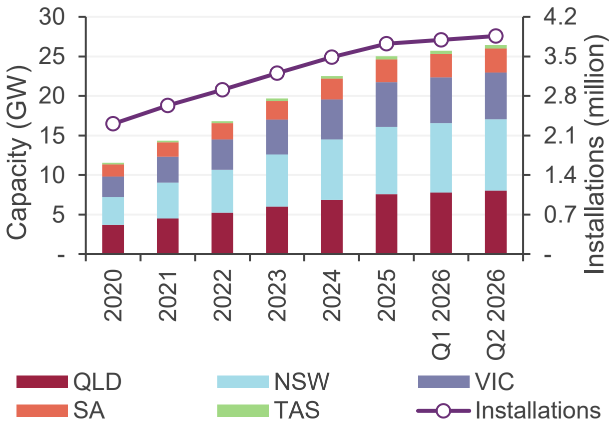
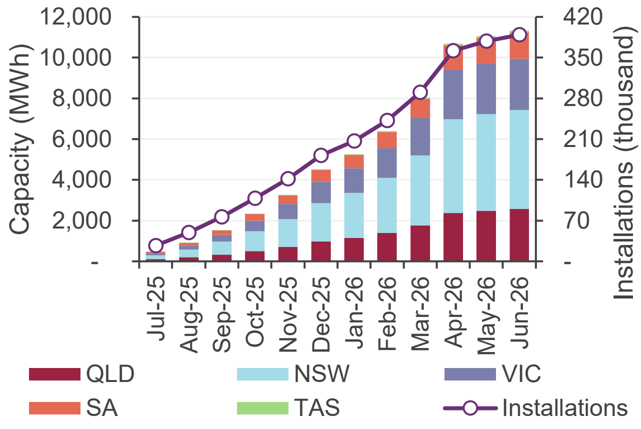


Figure 9 Continued growth in CER battery capacity and installations across the NEM

Cumulative CER battery capacity and installations by region



Source: Clean Energy Regulator

Emerging patterns in household PV and battery behaviour are reflected in intraday demand profiles, derived from demand data sourced from National Metering Identifier (NMI)[8] sample datasets of households with rooftop PV only and those with both PV and battery systems.

Figure 10 shows separate import and export profiles for samples of PV-only households and households with PV and battery systems across the NEM during Q2 2026.

[5] Data from Clean Energy Regulator: https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data. Data current as of 30 June 2026, noting that a 12-month creation period for registration persons to create small-scale technology certificates applies, so figures for the previous 12-month period will continue to rise.

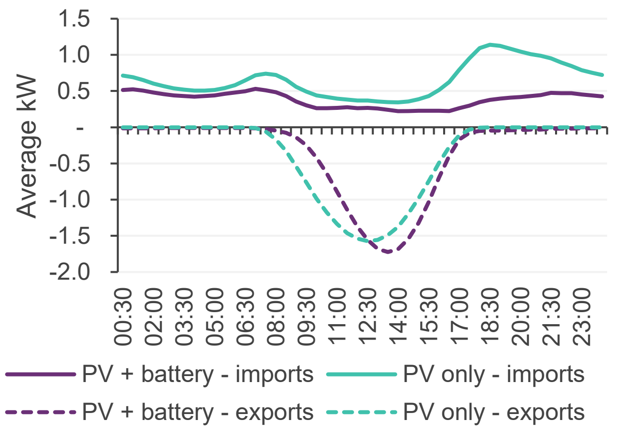
[6] See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.

[7] Solar battery postcode data is only available from 1 July 2025, when solar batteries became eligible under the Small-scale Renewable Energy Scheme, up until 30 June 2026. Postcode data only includes installations that have had their application for small-scale technology certificates approved. It does not include installations with pending applications.

[8] Households included in the sample are houses/detached dwellings with installed PV system capacity below 20 kilowatts (kW). For battery households, only battery systems installed from 1 July 2025 to 1 December 2025 are included. Each sample set includes 10,000 households.

Figure 10 Households with PV and battery shift exports later and reduce imports during peaks

Average household PV and battery import and export kW (Q2 26) – NEM



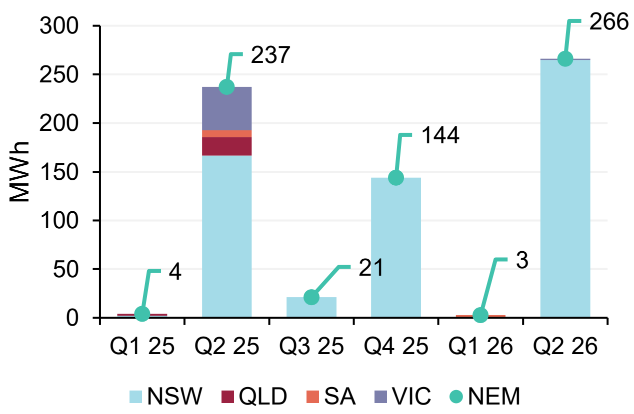
On average, households with battery systems transitioned to net exports later in the morning than PV-only households, consistent with charging before surplus PV was exported to the grid. During the evening peak (1600 hrs to 2100 hrs), households with PV and battery systems continued exporting for longer and recorded lower net grid imports than PV-only households, reflecting battery discharge supporting both household demand and the grid. Across the NEM, average evening peak net imports reduced by 0.7 kilowatts (kW) per household sampled, equivalent to 73% reduction relative to PV-only households across the quarter, with reductions across mainland regions of 0.9 kW in Queensland, 0.7 kW in New South Wales, and 0.5 kW in Victoria and South Australia.

2.1.3 Wholesale demand response (WDR)

WDR dispatch increased to 266 MWh in Q2 2026, an increase of 29 MWh compared to Q2 2025 and a sharp increase from 3 MWh in Q1 2026 (**Figure 11**).

Figure 11 Increase in WDR dispatch

Total quarterly WDR energy dispatch



WDR activity was concentrated in New South Wales, which accounted for 265 MWh across 99 dispatch intervals, 59% higher dispatch than Q2 2025. The highest level of dispatch occurred on 16 June, when 23 dispatch intervals contributed 124 MWh at an average dispatch price of $78/MWh, primarily reflecting the dispatch of WDR capacity offered at the Market Floor Price (MFP) of -$1,000. Further activity was recorded on 17 June and 18 June, with 63 MWh across 35 intervals and 73 MWh across 28 intervals, respectively.

Additionally, Victoria contributed just 1 MWh during the quarter, a significant decline compared to 45 MWh in Q2 2025.

2.2 Wholesale electricity prices

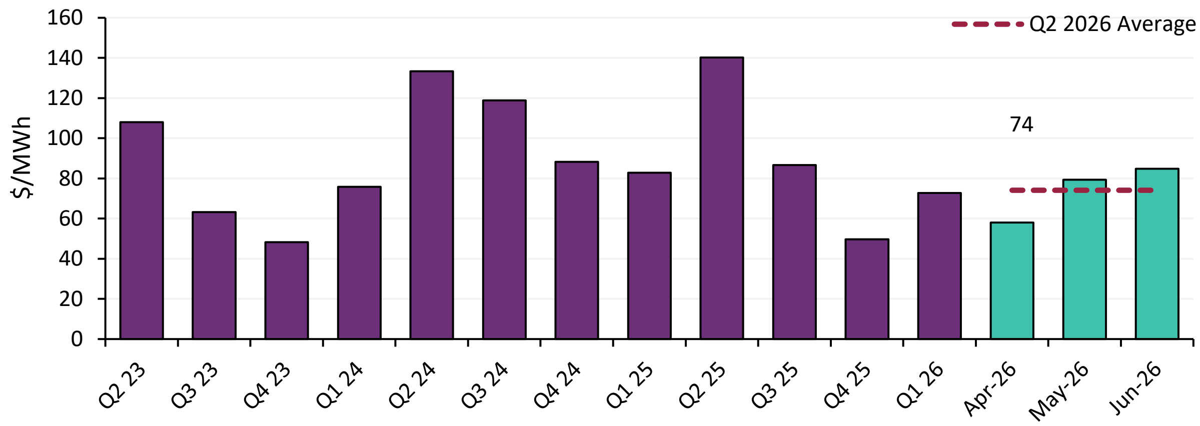
In Q2 2026, NEM-wide wholesale spot prices averaged $74/ MWh[9], down $66/MWh (-47%) from Q2 2025 and up just $1/MWh (+1.9%) from Q1 2026 (**Figure 12**). Monthly averages rose through the quarter, averaging $58/MWh in April, $79/MWh in May, and $85/MWh in June.

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

The NEM-wide average was the second lowest Q2 average since 2016, following $38/MWh in Q2 2020. All mainland regions saw their lowest Q2 averages since 2020, except South Australia where this Q2's average was the lowest since 2021.

Figure 12 Average NEM spot prices fell 47% year-on-year

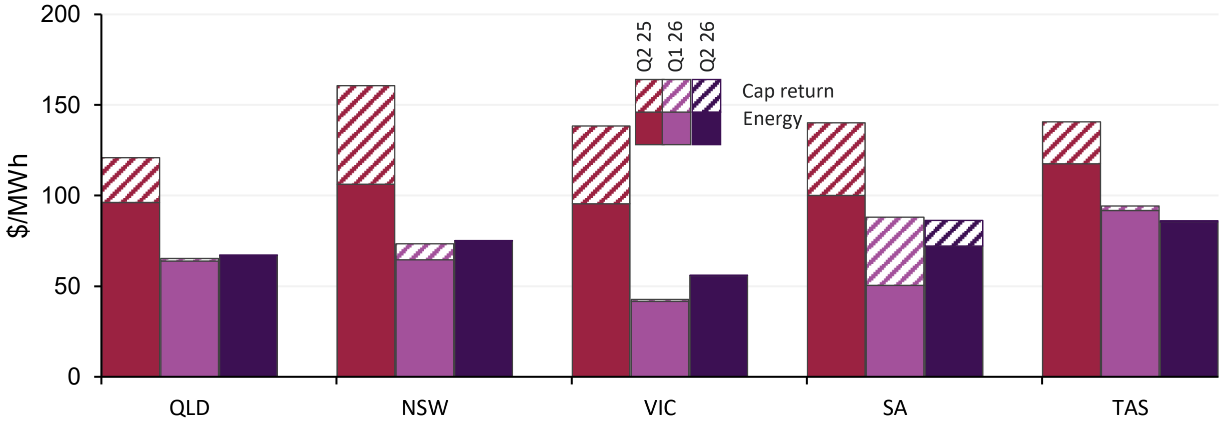
NEM average wholesale electricity spot prices – quarterly since Q2 2023



The cap return[10] component of the NEM average price fell to just $3/MWh in Q2 2026, down 92% from $37/MWh in Q2 2025 (**Figure 13**). South Australia accounted for most of the quarter's cap returns following high-priced events on 21-22 June (see Section 2.2.2). The energy component averaged $71/MWh, a decrease of $32/MWh (-31%) compared with Q2 2025, with all NEM regions recording lower energy prices.

Figure 13 Year-on-year declines in both energy and cap return prices across all regions

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



[10] The price analysis divides the average spot 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 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.

By region:

- **Queensland's** wholesale spot price averaged $67/MWh in Q2 2026, down $54/MWh (-44%) year-on-year. Increased renewable output, higher battery discharge during peak periods, warmer-than-average weather, and lower demand contributed to the cap return component falling to near zero and a $29/MWh (-30%) decline in energy prices.
- **New South Wales** recorded the largest year-on-year decline in wholesale spot prices, falling $86/MWh (-53%) to average $75/MWh. The cap return component fell to near zero from $54/MWh in Q2 2025. Lower operational demand, higher battery discharge during peak periods, and increased renewable output contributed to a $31/MWh (-29%) reduction in energy prices.
- **Victoria** recorded the lowest average wholesale spot price in the NEM at $56/MWh, down $83/MWh (-60%) from Q2 2025. The cap return component fell to near zero from $43/MWh a year earlier. The energy component averaged $56/MWh, down $40/MWh (-42%), as higher renewable and battery output more than offset higher operational demand across most hours.
- **South Australia** recorded the highest average wholesale spot price in the NEM this quarter at $86/MWh, despite declining by $54/MWh (-38%) year-on-year. It was the only mainland region to record a material cap return component for the quarter, averaging $14/MWh following high-price events in June. This was 65% lower than the $40/MWh recorded in Q2 2025. The energy component declined by $28/MWh (-28%) to average $72/MWh.
- **Tasmania's** wholesale spot price averaged $86/MWh, a year-on-year decline of $54/MWh (-39%). The cap return component fell to $1/MWh from $23/MWh a year earlier, while the energy component declined $32/MWh (-27%) to average $85/MWh.

In Q2 2026, NEM average spot prices exhibited a much flatter time of day profile, with levels over the evening peak period well below those observed last Q2, while morning peak and overnight prices also declined (**Figure 14**). This reflected lower operational demand, higher wind output displacing coal generation, and increased grid-scale battery discharge, which displaced higher-cost gas-fired-generation. Lower Basslink transfers into Tasmania across all hours (see Section 2.6) also left more generation available to supply mainland demand, further contributing to lower mainland prices.

In contrast, daytime prices remained relatively unchanged, as higher daytime operational demand (see **Figure 4** in Section 2.1), increased battery charging activity (see **Figure 56** in Section 2.4), and a reduction in negative price outcomes (see Section 2.2.3) offset downward price pressures.

This quarter, energy price separation across the mainland NEM regions was less pronounced than in previous quarters, with some divergence between Queensland and New South Wales during daylight hours and between Victoria and other mainland regions during overnight hours (**Figure 15**). Price separation between Tasmania and the mainland persisted throughout the day, with Tasmanian energy prices averaging $84/MWh between 10:00 and 16:00, $46/MWh higher than in Victoria. These outcomes were largely driven by higher-priced Basslink capacity offers, which reduced inter-regional flows (see Section 2.6).

Figure 14 Flatter intraday price profile with lower evening peak prices

NEM average spot price by time of day – Q2 2026 vs Q2 2025

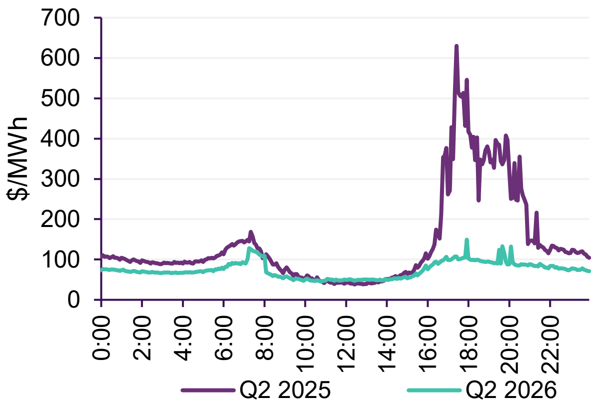
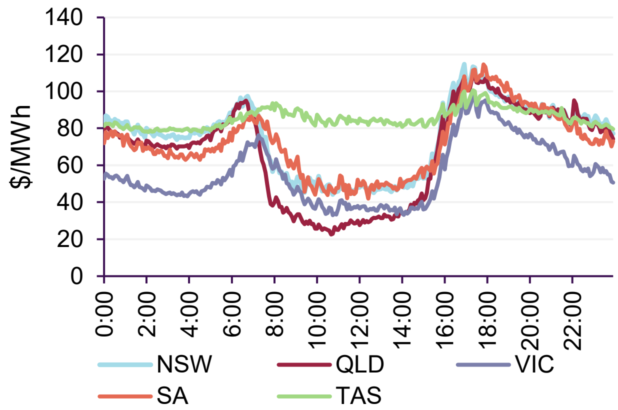


Figure 15 Continued daytime price separation between Tasmania and the mainland regions

Average regional energy price by time of day – Q2 2026



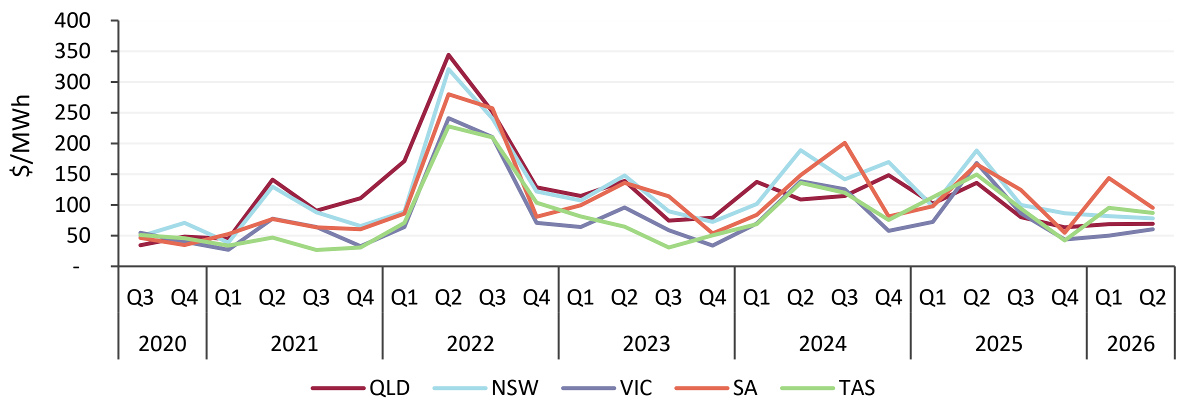
Volume-weighted average price (VWAP)

The VWAP[11] reflects the average value of energy supplied in the spot market, weighted by demand in each region and trading interval. By comparison, the time-weighted average price (TWAP) represents the simple average of trading interval prices and does not account for variations in demand or generation. As spot prices generally increase during periods of higher operational demand, particularly during evening peaks, VWAP is typically higher than TWAP. Periods of increased price volatility can further widen the difference between the two measures.

This quarter, regional VWAPs ranged from $60/MWh in Victoria to $95/MWh in South Australia, with Queensland, New South Wales and Tasmania averaging $69/MWh, $78/MWh and $87/MWh, respectively (**Figure 16**). Compared to Q2 2025, VWAP declined across all regions, with the largest reductions in New South Wales (-$111/MWh, -59%) and Victoria (-$108/MWh, -64%).

Figure 16 Volume-weighted average prices below Q2 2025 in all regions

Volume-weighted average prices by region – quarterly since Q3 2020



[11] The VWAP is calculated by weighting regional prices by INITIALSUPPLY + TOTALINTERMITTENTGENERATION. INITIAL SUPPLY represents the scheduled demand in a region that is met by local scheduled and semi-scheduled generation, by generation from scheduled bidirectional units, and by generation imports to the region. TOTALINTERMITTENTGENERATION represents metered output of significant non-scheduled generators.

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 2026

Shift towards higher daytime operational demand and lower evening peak demand	The NEM demand profile continued to shift from the evening peak towards daytime hours in Q2 2026. Increased home battery charging, together with growing industrial and data centre loads, lifted daytime operational demand, more than offsetting growth in distributed PV output (see Section 2.1). In the evening, home battery discharging and warmer weather's impact on heating requirements reduced operational demand. This pattern was evident across most regions, contributing to a flatter intraday spot price profile, with daytime prices broadly unchanged and evening peak prices well below those observed in Q2 2025.
Increased grid-scale battery activity influencing price-setting outcomes	Between Q2 2025 and Q2 2026, grid-scale battery capacity in the NEM increased by 4,640 MW/12,353 MWh, more than doubling installed capacity to over 9,000 MW by the end of the quarter. Reflecting this expansion, average battery discharge rose to a record 476 MW in Q2 2026, almost triple the 162 MW recorded in Q2 2025. Battery charging increased by 371 MW, primarily during daytime and early morning hours, to average 574 MW this quarter (see Section 2.4.1). The rapid growth in battery participation had a material impact on market outcomes. Battery charging and discharging became the NEM's most frequent price-setting technology when combined, setting spot prices in 36% of dispatch intervals (see Section 2.2.4), and reduced the frequency of price-setting by coal, gas and hydro generation (see **Figure 25** in Section 2.2.4). Increased battery discharge, combined with lower operational demand during the evening peak contributed to lower peak prices and less price volatility across most regions (see **Figure 14** in Section 2.2). This quarter, NEM-wide average cap return fell to just \$3/MWh, from \$37/MWh in Q2 2025. Battery charging growth overlaid stronger daytime operational demand, leading to fewer negative price intervals (see Section 2.2.3). Together, these changes resulted in a significantly flatter intraday price profile than in Q2 2025.
Higher renewable generation	This quarter, variable renewable energy (VRE) average output reached a record Q2 high of 6,058 MW, up 903 MW (+18%) from Q2 2025. Wind generation increased by 706 MW (+20%) year-on-year to average 4,198 MW, while grid solar output rose by 197 MW (+12%) to average 1,860 MW, with both reaching new Q2 highs (see Section 2.3.4). Higher VRE output placed sustained downward pressure on wholesale prices across the NEM, particularly overnight, where stronger wind generation displaced coal-fired generation (see **Figure 32** in Section 2.3) and contributed to lower spot prices (see **Figure 14** in Section 2.2). This shifted the overall price distribution, with the share of dispatch intervals priced below \$100/MWh increasing from 48% in Q2 2025 to 79% in Q2 2026. Higher overnight wind output also contributed to a marked rise in negative price occurrence in Victoria and South Australia.

2.2.2 Wholesale electricity price volatility

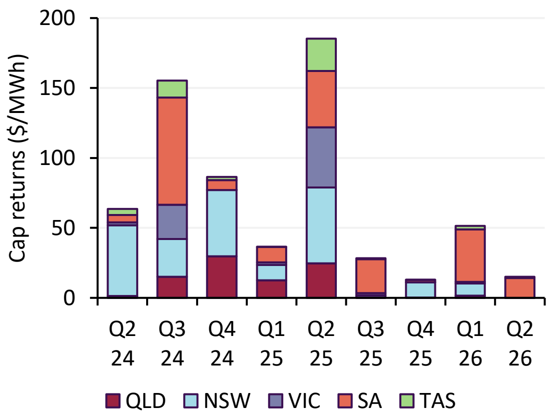
In Q2 2026, aggregated regional cap returns, representing spot price outcomes above \$300/MWh, fell sharply to \$15/MWh, down from \$185/MWh in Q2 2025 (**Figure 17**).

South Australia accounted for almost all of this total, averaging \$14/MWh, driven by the high-price events on 21-22 June.

Tasmania contributed a further \$1/MWh, while all other regions recorded negligible cap returns, averaging close to zero over the quarter.

Figure 17 Cap returns fell sharply, with South Australia the only contributor

Cap returns by region – quarterly



South Australia's high price event on 21 and 22 June

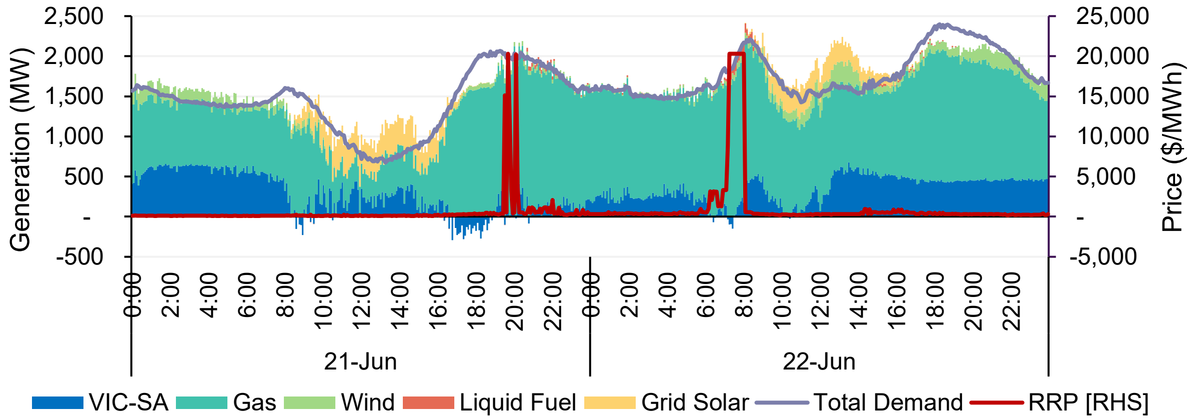
South Australia experienced significant price volatility on 21-22 June, with sustained prices above $300/MWh from the evening peak on 21 June through to the morning peak on 22 June, contributing $13/MWh to the region's quarterly cap return. Prices exceeded $10,000/MWh in four dispatch intervals between 1935 hrs and 2010 hrs on 21 June, including one interval close to the market price cap (MPC) of $20,300/MWh. On 22 June, prices reached the MPC for 10 dispatch intervals between 0720 hrs and 0805 hrs, following a further 12 dispatch intervals above $1,000/MWh in the early morning.

During the evening peak on 21 June, South Australian total demand[12] exceeded 2,000 MW as temperatures across Adelaide fell below 5°C. This coincided with a three-day wind lull in South Australia between 21-23 June, during which daily average wind capacity factors fell below 5% (see **Figure 49** in Section 2.3.4). As grid solar generation and distributed PV output fell away, wind generation also declined to around 50 MW (**Figure 18**), while imports from Victoria were constrained following a reduction in the X3 Balranald–Buronga 220 kilovolts (kV) line rating[13]. To avoid overloading the X3 line, the constraint[14] restricted flows from Victoria into South Australia across both interconnectors: V-SA, which comprises Heywood and Project EnergyConnect Stage 1 (PEC-1)[15], and Murraylink. This limited additional transfers from Victoria to offset the decline in local wind output. As a result, gas and liquid fuel generation was required to supply a very high share of the region's demand.

The reduced transfer capability also lowered reserve levels in South Australia, resulting in the Pre-Dispatch Projected Assessment of System Adequacy (PD PASA) forecast showing a Lack of Reserve (LOR) 2 condition in South Australia between 2030 hrs and 2100 hrs[16]. However, AEMO assessed the risk as temporary and expected evolving market conditions to resolve the reserve shortfall through normal dispatch processes and therefore did not declare a LOR 2 condition.

Figure 18 Low wind and reduced interconnector imports during South Australia's price volatility on 21-22 June

South Australia regional reference price (RRP), total demand, net interconnector flows and generation by fuel type 21-22 June



12 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 WDR.

13 AEMO issued Market Notice 144283 (https://www.aemo.com.au/market-notices?marketNoticeQuery=144283&marketNoticeFacets=) advising of a reduction in the X3 Balranald–Buronga 220 kV line rating.

14 Constraint CA_SYDS_594882A3.

15 PEC-1 comprises a new transmission line between Bundey in South Australia and Buronga in south-west New South Wales, with a spur connection to Victoria at Red Cliffs. The transfer capability provided by PEC-1 to and from South Australia is represented as an increase in the capacity of the existing Heywood interconnection with Victoria.

16 See Market Notice 144305 (https://www.aemo.com.au/market-notices?marketNoticeQuery=144305&marketNoticeFacets=).

With prices remaining above $300/MWh over the evening of 21 June, South Australia's batteries discharged nearly all of their stored energy through the evening peak (**Figure 19**). As the fleet's state of charge (SOC) fell to well below 200 MWh or around 10% of storage capacity, prices spiked above $10,000/MWh for four dispatch intervals, with a further two intervals above $3,000/MWh.

Low wind output and reduced interconnector flows persisted overnight, keeping prices above $300/MWh in most intervals, including a further nine intervals above $1,000/MWh. Most batteries avoided charging at these elevated overnight prices (**Figure 20**), leaving South Australia's battery fleet SOC low at around 200 MWh going into the Monday morning peak.

This, combined with continued low wind and solar output and constrained imports, drove prices above $1,000/MWh for 22 dispatch intervals between 0620 hrs and 0805 hrs on 22 June, including 10 consecutive intervals at the MPC of $20,300/MWh.

The tight supply-demand conditions also resulted in PD PASA forecasting a LOR 3 condition in South Australia[17]. However, AEMO assessed that involuntary load shedding was unlikely, as post-contingent actions were available to increase transfer capability into South Australia and improve reserve levels if required, and therefore did not declare a LOR3 condition.

High prices eased later that morning when the X3 line was de-energised[18] and the associated transfer restrictions were relaxed, increasing import capability into South Australia. To enable the outage, AEMO directed a participant[19] to disconnect after it was unable to meet inverter limitations required for secure operation of the network, allowing X3 to be taken out of service while maintaining power system security.

Figure 19 Low battery state of charge before the morning peak on 22 June

Battery SOC and RRP (Right Hand Side [RHS]) on 21 -22 June – South Australia

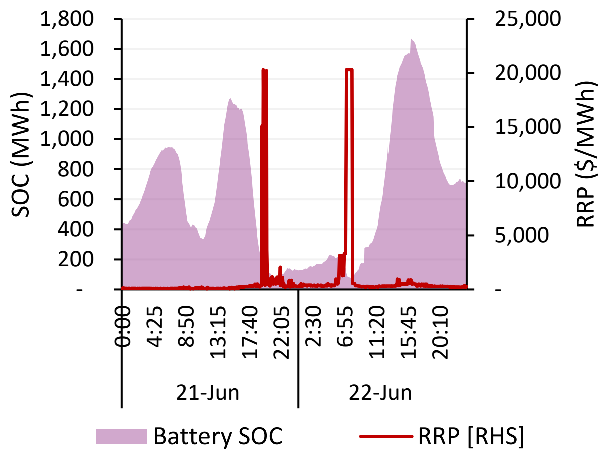
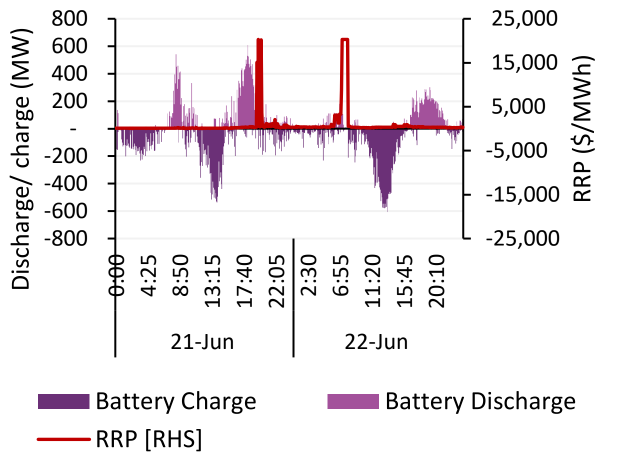


Figure 20 Limited battery charging activity in most South Australian batteries overnight

Battery charge, discharge and RRP [RHS] on 21-22 June – South Australia



[17] Market Notice 144315: https://www.aemo.com.au/market-notices?marketNoticeQuery=144315&marketNoticeFacets=.

[18] Constraint set N-BABU invoked. This constraint set limits the inverter counts of several solar and wind farms in the area to maintain power system security during an outage of the X3 line.

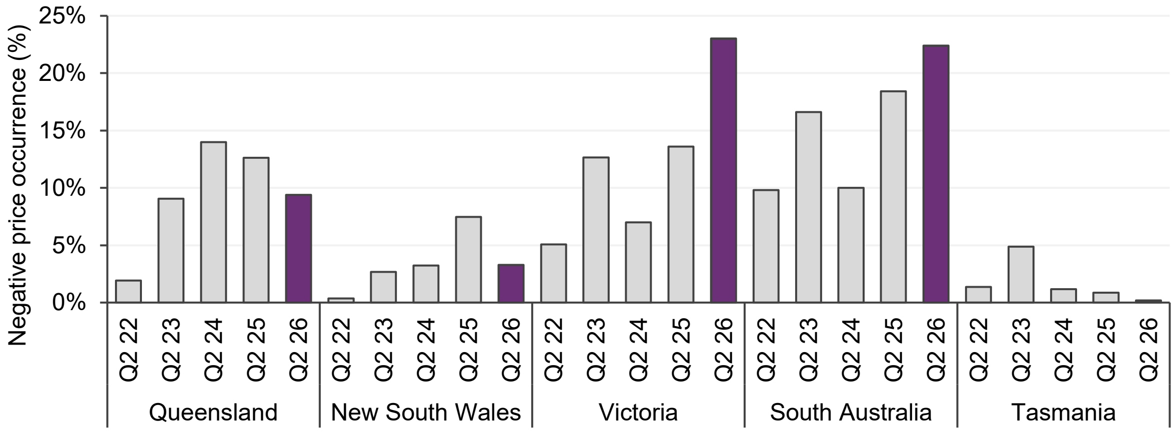
[19] AEMO issued Market Notice 144313 (https://www.aemo.com.au/market-notices?marketNoticeQuery=144313&marketNoticeFacets=) advising that it had directed a participant in New South Wales.

2.2.3 Negative wholesale electricity prices

In Q2 2026, negative or zero prices occurred in 11.7% of dispatch intervals across the NEM, up 1.1 percentage points (pp) from Q2 2025 (**Figure 21**). Regional outcomes diverged, with negative price occurrence increasing across the southern mainland regions while declining in the northern regions. Victoria and South Australia recorded the largest increases, with negative prices occurring in 23.0% (+9.4 pp) and 22.4% (+4.0 pp) of dispatch intervals, respectively. In contrast, negative price occurrence fell to 9.4% (-3.2 pp) in Queensland and 3.3% (-4.2 pp) in New South Wales. Tasmania also recorded a decline, with negative prices occurring in just 0.2% of intervals (-0.7 pp).

Figure 21 Negative price occurrence increased in Victoria and South Australia, decreased in other regions

Negative price occurrence in NEM regions – Q2s



In this quarter, lower daytime negative price occurrence, particularly in the northern states of Queensland and New South Wales, was offset by increases in overnight occurrence in Victoria and South Australia (**Figure 22**). During the daytime period (0900 hrs to 1700 hrs), negative price occurrence declined significantly in the northern regions, falling to 9% of dispatch intervals in New South Wales (-10 pp) and 25% in Queensland (-8.0 pp) compared to Q2 2025. These reductions were consistent with higher middle of day operational demand (see **Figure 4** in Section 2.1) and battery charging levels in both regions (see **Figure 56** in Section 2.4).

In contrast, daytime negative price occurrence remained elevated in South Australia, occurring in 33% of dispatch intervals, and increased to 31% (+4.0 pp) in Victoria. Victoria and South Australia were also the only regions to record higher overnight (2200 hrs to 0600 hrs) negative price occurrence, increasing to 26% (+16 pp) and 23% (+10 pp) of dispatch intervals, respectively. This reflected higher wind output and reduced exports into Tasmania.

The distribution of negative prices shifted markedly towards lower magnitudes in Q2 2026. Prices between -$10/MWh and $0/MWh accounted for 89% of all negative price intervals, up from 21% in Q2 2025 (**Figure 23**). This shift was consistent with the decline in large-scale generation certificate (LGC) prices, which averaged $3/certificate this quarter, down from $20/certificate in Q2 2025. As a result, the average spot price during negative price intervals increased from -$20.1/MWh to -$4.8/MWh.

Reflecting both the lower frequency and reduced magnitude of negative prices, negative price impact declined across all NEM regions year-on-year. NEM-wide negative price impact fell to $0.6/MWh this quarter, from $2.1/MWh in Q2 2025.

Figure 22 Negative price occurrence led by Victoria and South Australia

Negative price occurrence by time of day – Q2 2026

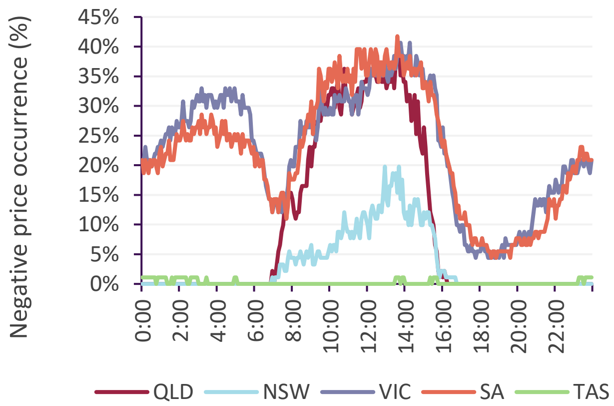
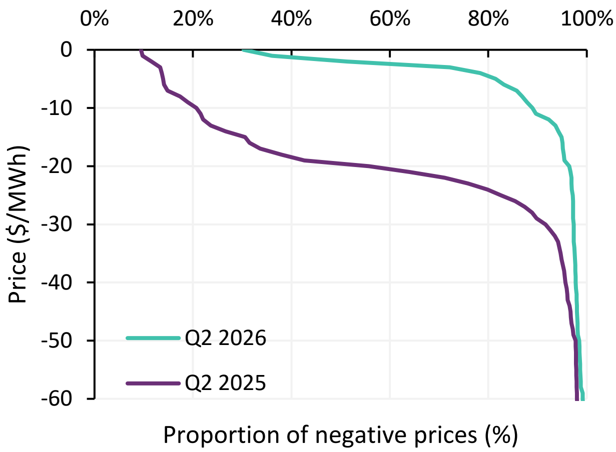


Figure 23 Impact of negative prices decreased in Q2 2026

Cumulative distribution of negative prices – Q2 2026 vs Q2 2025



2.2.4 Price-setting dynamics

This quarter, batteries remained the most frequent price-setting[20] technology across the NEM, further increasing their influence on market outcomes. Battery discharge and charge each increased their price-setting frequency by 9 pp year-on-year, setting prices in 17% and 19% of dispatch intervals, respectively, for a combined percentage of 36% compared to 17% in Q2 2025. Wind's price-setting frequency also increased to reach 10% (+5.0 pp). In contrast, all other fuel types set prices less frequently than in Q2 2025. Hydro recorded the largest decline, falling 14 pp to 22% of intervals, as the higher transfer prices offered by Basslink meant that Tasmania's hydro generators set mainland prices much less frequently than in Q2 2025.

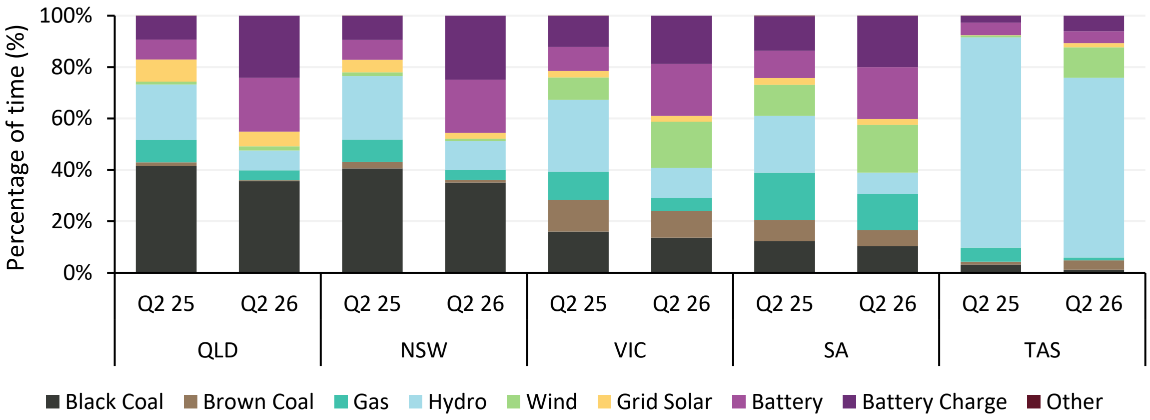
All mainland NEM regions experienced a shift in price-setting dynamics towards batteries, particularly New South Wales and Queensland (**Figure 24**). In Queensland, battery charge and discharge set prices in 24% and 21% of dispatch intervals, respectively, while in New South Wales they set prices in 25% and 21% of intervals. This coincided with a decline in price-setting by hydro and thermal generation, with hydro falling to just 8% of intervals in Queensland and 11% in New South Wales. Grid solar also set prices less frequently, with higher daytime operational demand and battery charging absorbing more grid-solar output and lessening its role as the marginal supplier. This also resulted in reduced negative price occurrence in both regions (see Section 2.2.3).

Victoria and South Australia also recorded increased battery price-setting, with battery charge and discharge together accounting for 39% and 40% of price-setting intervals, respectively. Across both regions, thermal and hydro generation set prices less frequently than a year earlier, while wind increased its price-setting frequency and grid solar remained largely unchanged.

[20] The price-setting fuel type for each five-minute dispatch interval and region are determined by identifying the marginal price-setting Dispatchable Unit Identifier (DUID) (and station). Where multiple stations contribute to setting the price, the marginal station is selected as the one with an incremental dispatch contribution closest to 1 MW, and its associated fuel type is assigned as the price-setting fuel type for that interval.

Figure 24 Shift in price-setting outcomes across NEM regions

Price-setting frequency by region and fuel type – Q2 2026 vs Q2 2025



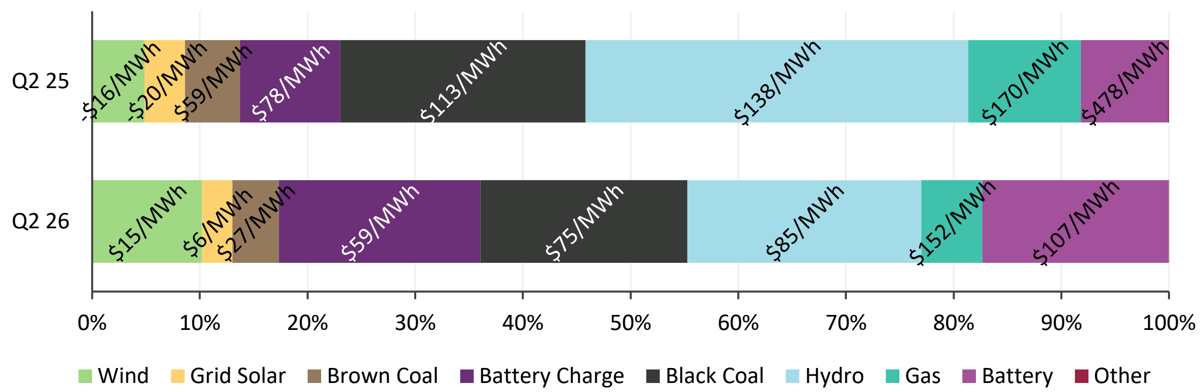
Average price set while marginal increased for wind and grid solar, decreasing for all other technology types (**Figure 25**). Wind and grid-scale solar recorded year-on-year increases of \$32/MWh and \$26/MWh, respectively, to average prices of \$15/MWh and \$6/MWh. These increases were largely driven by higher Tasmanian prices set by mainland wind and solar, which incorporate the cost of higher-priced Basslink transfer offers when these sources are marginal for Tasmanian supply, as discussed in the following section.

Battery discharge recorded the largest decline in average prices set while marginal, which fell from \$478/MWh in Q2 2025 to \$107/MWh in Q2 2026. This reflected the drop in NEM volatility this Q2 and batteries setting prices across a much broader range of market conditions, rather than predominantly during high-price events.

Average prices set by gas declined by \$18/MWh to \$152/MWh, with reductions across all regions except South Australia, where periods of price volatility lifted average outcomes. Hydro also recorded lower average prices, declining from \$138/MWh to \$85/MWh, with decreases across all regions. Black coal and brown coal likewise set prices at lower average levels than a year earlier.

Figure 25 Increased battery price setting reshaped market outcomes in Q2 2026

NEM price-setting frequency and average spot price when price-setter by fuel-type – Q2 2026 vs Q2 2025



Impact of Basslink on price-setting

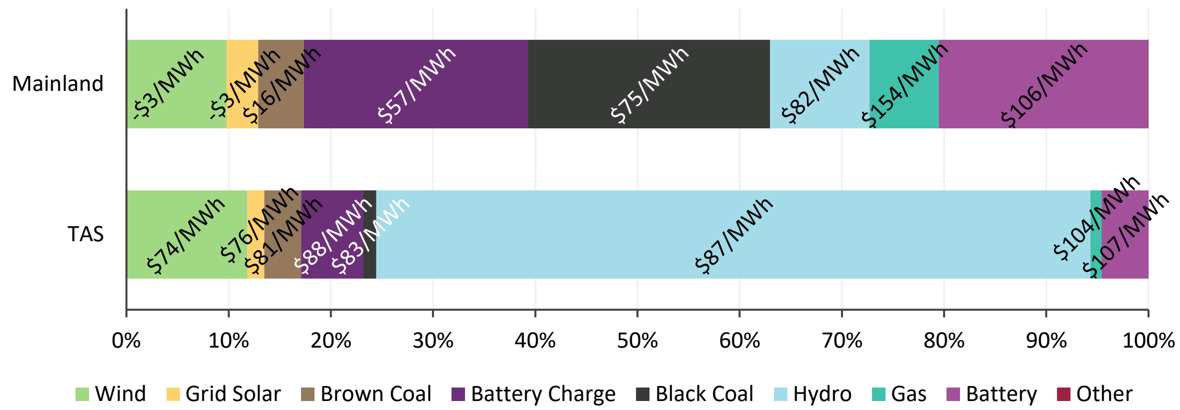
In Q2 2026, Basslink operated as a non-regulated Market Network Service Provider (MNSP), with inter-regional transfers between Victoria and Tasmania scheduled through market offers, before transitioning to being a Transmission Network

Service Provider (TNSP) on 1 July 2026. These offers are incorporated into dispatch outcomes and influence price-setting dynamics across NEM regions. Since the increase in Basslink offer prices from Q3 2025, these transfer offers have contributed to elevated Tasmanian spot prices relative to mainland regions, in addition to lower Basslink transfers (see Section 2.6).

In Q2 2026, Basslink imports to Tasmania set prices in 23% of dispatch intervals at an average transfer price of $78/MWh, contributing approximately $18/MWh to Tasmania's quarterly average spot price. As a result, average prices set while marginal were higher in Tasmania for most fuel types than on the mainland (**Figure 26**). The difference was most pronounced for renewable generation, with wind and grid solar setting average prices of $74/MWh and $76/MWh in Tasmania, compared with negative average prices on the mainland.

Figure 26 Price-setting outcomes remained higher in Tasmania than on the mainland across most fuel types

NEM price-setting frequency and average spot price when price-setter by fuel type – Mainland vs Tasmania in Q2 2026

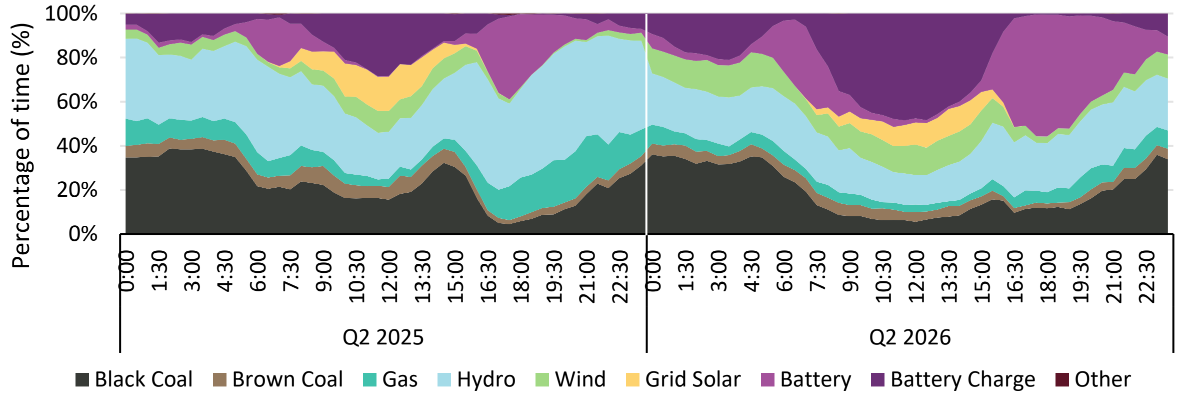


Price-setting by time of day

Throughout the quarter, batteries played a substantially larger role in price setting across all hours of the day, displacing other fuel types (**Figure 27)**.

Figure 27 Battery charge and discharge drove time of day price-setting shifts in Q2 2026

NEM price-setting frequency by fuel type and time of day – Q2 2026 and Q2 2025



Gas and hydro set prices less frequently across most trading hours, with the largest reductions occurring during the evening peak (1600–2100 hrs), where hydro price-setting fell by 21 pp year-on-year to 25%, while gas declined by 10 pp to 7%. Black coal also played a smaller role during daylight hours (1000–1600 hrs), with its price-setting frequency falling by 13 pp to 8% during this time. These reductions were largely offset by increased battery participation. During the evening peak, battery discharge became the dominant price setter, with its frequency increasing by 24 pp to 46% in Q2 2026. During daylight hours, battery charging set prices in 41% of dispatch intervals, up 21 pp year-on-year, further reducing the price-setting of other energy sources. Wind also set prices more frequently, particularly overnight, consistent with the higher occurrence of negative prices during these periods.

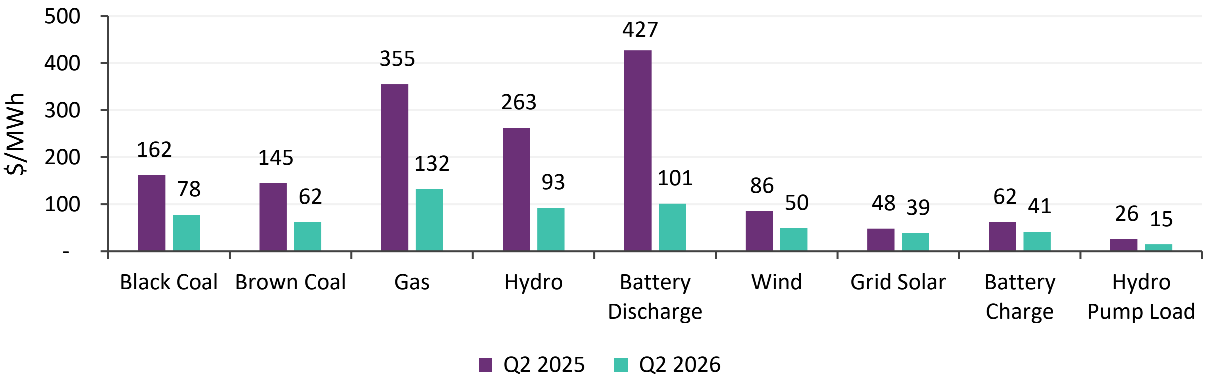
2.2.5 Volume-weighted average prices by fuel type

Figure 28 shows the average spot prices earned[21] or incurred by different fuel types across the NEM, derived as volume-weighted averages based on their generation or load volumes in each dispatch interval. In Q2 2026, volume-weighted average prices declined for all fuel types compared to Q2 2025.

Black coal and brown coal earned average VWAPs of $78/MWh (-$85/MWh) and $62/MWh (-$83/MWh), respectively, while hydro fell to $93/MWh (-$170/MWh). Lower evening peak prices particularly reduced average prices received by flexible generation, with gas and battery discharge VWAPs declining to $132/MWh (-$223/MWh) and $101/MWh (-$326/MWh), respectively. Wind and grid solar also recorded lower average VWAPs, decreasing by $36/MWh and $9/MWh to $50/MWh and $39/MWh, respectively. Overall, the decline across fuel types reflected lower average pricing outcomes across the NEM.

Figure 28 All fuel types earned lower average spot prices

Volume weighted average prices by fuel type – Q2 2026 vs Q2 2025



2.2.6 Electricity futures markets

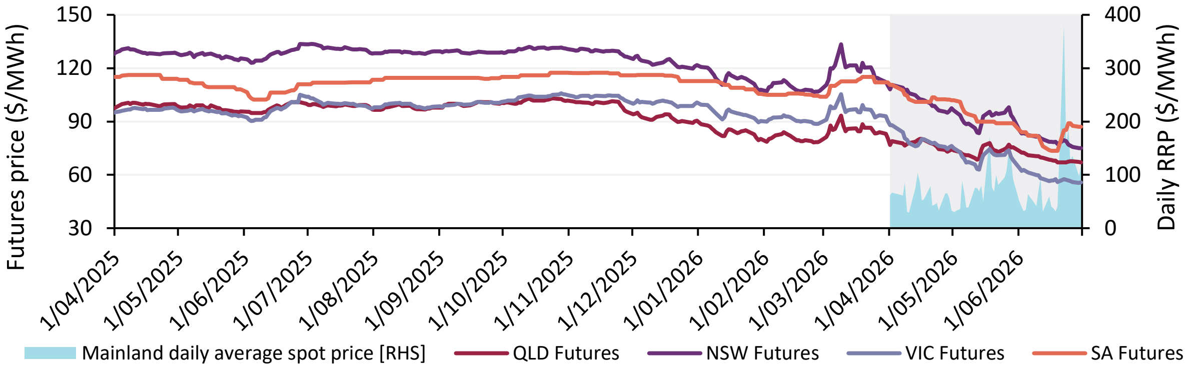
Electricity futures markets are centralised exchanges offering standardised forward financial contracts for electricity. AEMO does not administer these exchanges. Information presented in this section is to allow a holistic view of both spot electricity outcomes and electricity futures pricing. **Figure 29** shows Australian Securities Exchange (ASX) daily prices for Q2 2026 base contracts across 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.

[21] This does not reflect the full revenue earned by generators, which also includes earnings from other sources such as impact of derivative (hedging) contracts or power purchase agreements.

ASX contract prices across all mainland regions trended lower throughout Q2 2026, extending the decline from Q1 2026 as lower spot prices and the absence of price volatility softened market expectations. New South Wales, Queensland and Victoria recorded a gradual decline over the quarter, interrupted only by a brief rise in mid-May before continuing lower through to quarter-end. South Australia followed a similar pattern, with contract prices declining from $111/MWh at the start of the quarter to $74/MWh by 19 June. The high-price events on 21–22 June subsequently lifted contract prices to $85/MWh on 22 June, with prices remaining elevated to finish the quarter at $86/MWh.

Figure 29 Q2 2026 base futures declined through the quarter across all regions

ASX Energy – Regional daily Q2 2026 base future prices and daily average spot price for mainland regions



ASX base contract prices for the 2026-27 financial year (FY27) averaged $81/MWh across the mainland regions in Q2 2026, down $5/MWh (-6.2%) from Q1 2026 and $15/MWh (-16%) from Q2 2025 (**Figure 30**). Following the sharp runup in March driven by heightened geopolitical tensions in the Middle East, contract prices declined steadily throughout Q2 2026 across all mainland regions as wholesale spot prices and price volatility eased. Compared with the end of Q1 2026, New South Wales recorded the largest decline over the quarter, finishing Q2 at $83/MWh (-26%), followed by Victoria at $60/MWh (-24%), Queensland at $72/MWh (-22%) and South Australia at $79/MWh (-15%).

Longer-dated ASX futures for FY28 and FY29 also declined from the end of Q1 2026 for most regions, but by less than the drop in FY27 prices, leaving the forward curve in each region with a rising profile by the end of the quarter, reflecting expectations of gradually increasing longer-term prices (**Figure 31**).

Figure 30 FY27 futures saw a sharp drop through Q2 2026

ASX Energy – Daily FY27 base futures by region

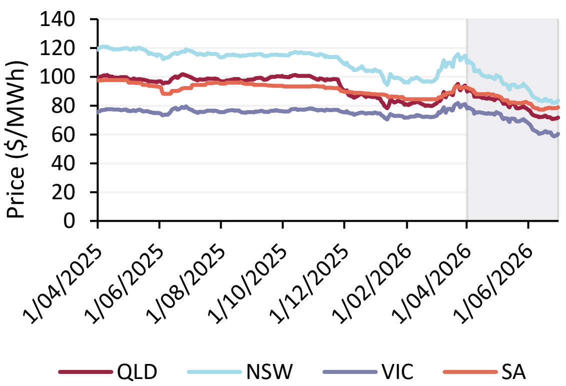


Figure 31 Future financial year contracts lower across most regions at the end of Q2 2026

ASX Energy – Financial year futures contract prices in mainland NEM regions – end of Q1 2026 and end of Q2 2026

2.3 Electricity generation

This section focuses on changes in electricity generation by fuel type, with batteries and pumped hydro considered separately in Section 2.4 as storage rather than primary generation. In Q2 2026, total electricity generation[22] across the NEM averaged 24,523 MW, increasing by 113 MW (+0.5%) from Q2 2025 (**Figure 32**). Renewable energy sources[23] comprised 42.1% of total generation, a new Q2 high, and an increase from 37.1% (+5.0 pp) the same period last year.

Figure 32 Shift in supply mix driven by higher renewable output

Change in NEM supply by fuel type – Q2 2026 vs Q2 2025

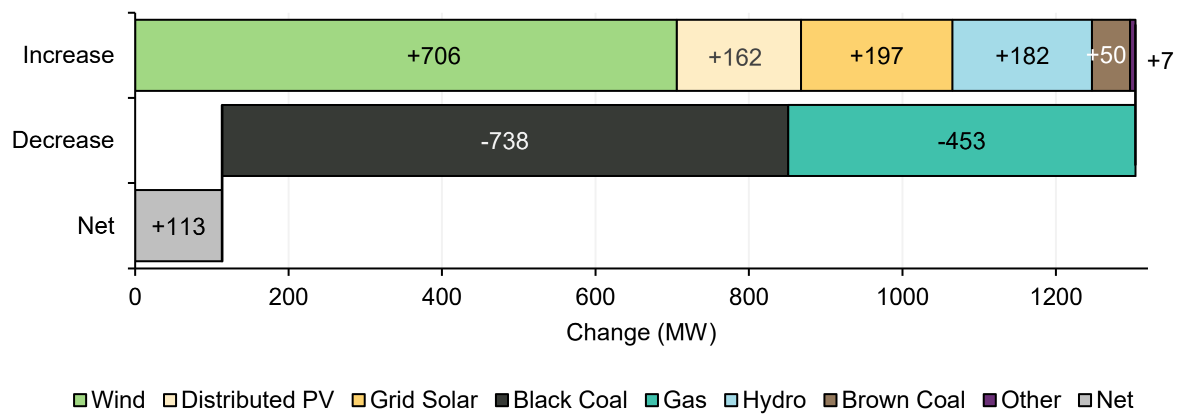


Table 2 NEM supply mix contribution by fuel type

Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Biomass
Q2 25	41.2%	15.5%	6.2%	0.01%	9.7%	14.3%	6.8%	6.2%	0.1%
Q2 26	38.0%	15.6%	4.3%	0.01%	10.3%	17.1%	7.6%	7.0%	0.1%
Change	-3.2 pp	0.1 pp	-1.9 pp	0.00 pp	0.6 pp	2.8 pp	0.8 pp	0.7 pp	0.0 pp

Comparing Q2 2026 with Q2 2025:

- Variable renewable energy (VRE) generation, comprising wind and grid-scale solar, reached a new Q2 high of 6,058 MW, an increase of 903 MW (+18%), with growth largely driven by new connections and projects progressing through commissioning. Wind generation had a notable year-on-year increase, recording a new Q2 high of 4,198 MW, up by 706 MW (+20%) and increasing its supply share to 17.1% from 14.3% (**Table 2**). Grid-scale solar also recorded a new Q2 high of 1,860 MW, up 197 MW (+12%) from Q2 2025, with its share increasing to 7.6% from 6.8%.
- Distributed PV output reached a Q2 high of 2,520 MW, up 162 MW (+6.9%) year-on-year, increasing its share to 10.3% (+0.6 pp).

[22] 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

[23] Renewable energy share measures the renewable proportion of total generation but excludes battery discharge and pumped hydro production from both renewable and total generation quantities. Pumped hydro production for Tumut 3 was estimated by multiplying its pumping load by round-trip efficiency (78%), while for Wivenhoe and Shoalhaven actual generation was used.

- Hydro generation (excluding pumped hydro) rose by 182 MW from Q2 2025 to 1,705 MW, increasing its share of total generation by 0.7 pp to 7%. The increase was predominantly driven by higher hydro output in Tasmania.
- Biomass recorded an increase of 8 MW year-on-year to 32 MW, although its generation share remained the same at 0.1%.
- Coal-fired generation declined to a new Q2 low of 13,158 MW, decreasing by 688 MW (-5.0%) year-on-year. Black coal fell by 738 MW (-7.3%), while brown coal increased by 50 MW (+1.3%). Black coal and brown coal recorded generation shares of 38% (-3.2 pp) and 15.6% (+0.1 pp), respectively.
- Gas-fired generation decreased substantially to 1,050 MW (-453 MW, -30%), with its share reducing to 4.3% (-1.9 pp). The fossil fuel share of total supply fell from 62.9% to 57.9% in Q2 2026.

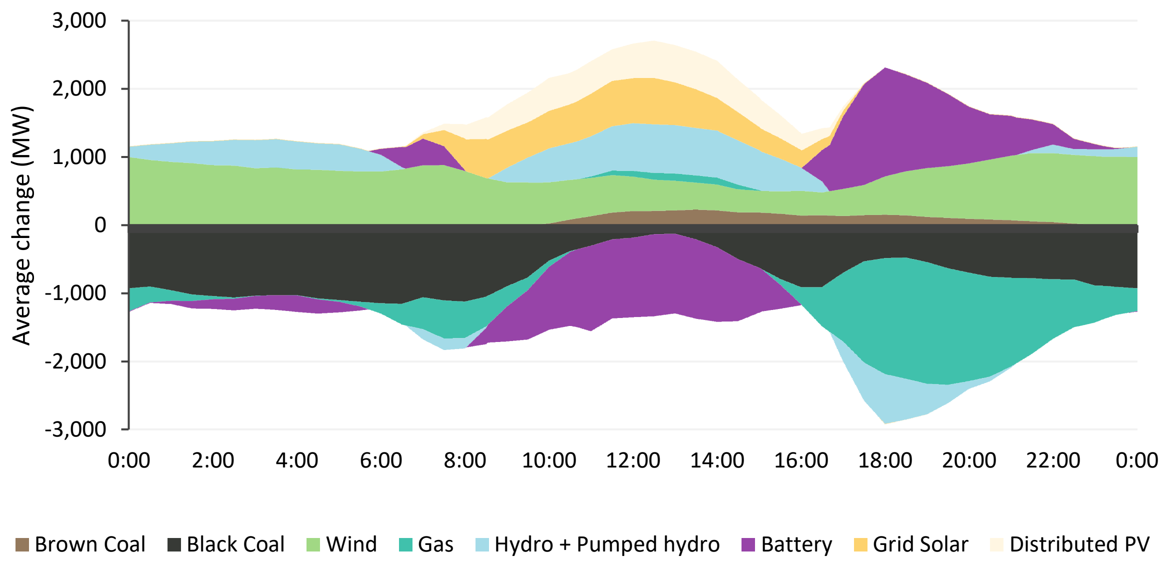
Figure 33 shows how the time-of-day generation profile for the NEM changed from Q2 2025 to Q2 2026. Storage technology changes are presented on a net basis to show how shifts in generation patterns across the day were underpinned by increased storage participation.

On average, wind generation increased across all hours of the day, displacing coal- and gas-fired generation. Black coal-fired output fell in all periods, particularly in overnight and morning hours, while the small middle-of-day increase in brown coal-fired output reflected its reduced dispatch flexibility this quarter.

During the day between 1000 hrs and 1600 hrs, grid-scale solar and distributed PV output rose by 516 MW (+11%) and 466 MW (+6.4%), respectively, while battery charging increased by 1,009 MW (+211%). This additional charging contributed to a 1,066 MW (+228%) increase in battery discharge during the evening peak period (1600 hrs to 2100 hrs). Together with higher wind output during the peak (+649 MW, +19%), this reduced the need for gas-fired generation, with average gas output in these hours declining by 1,441 MW (-45%).

Figure 33 Renewables and batteries continued to displace thermal generation during peak periods

Change in NEM generation and storage by time of day – Q2 2026 vs Q2 2025



Note: Storage technology changes are presented on a net basis where increases in supply (battery discharging and pumped hydro generation) are positive and increases in load (battery charging and hydro pumping) are negative. The chart series show the net change for each technology type, with pumped hydro incorporated within the hydro total.

2.3.1 Coal-fired generation

Black coal-fired fleet

Average black coal-fired generation in Q2 2026 fell to a new Q2 low, at 9,322 MW, a 738 MW (-7.3%) decrease from Q2 2025, despite a 302 MW (+2.5%) increase in availability (**Figure 34**). This increase in availability was due to both a 184 MW (-5.9%) decrease in fully offline capacity and a reduction in partial outages.

As **Figure 35** shows, fully offline capacity is classified into planned and unplanned maintenance/repair outages, or units being offline for market and operational reasons, referred to as economic withdrawals[24]. Fewer planned outages reduced fully offline capacity in New South Wales by 592 MW (-39%), partially offset by an increase of 407 MW (+26%) in Queensland, where planned outages and economic withdrawals were higher than in Q2 2025.

Figure 34 NEM black coal-fired output reached new Q2 low

Quarterly average black coal-fired generation and availability by region – Q2s

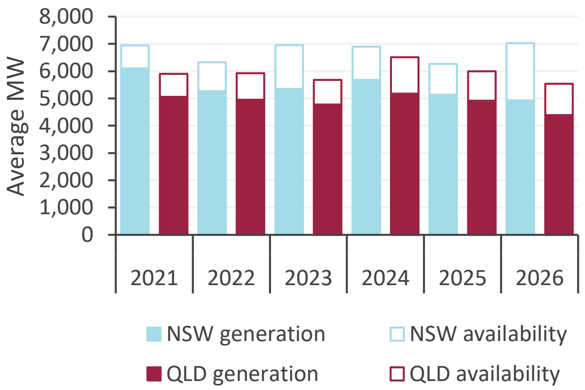


Figure 35 Coal-fired capacity on outage declined, driven by New South Wales

Average coal-fired capacity fully offline – Q2 2026 vs Q2 2025

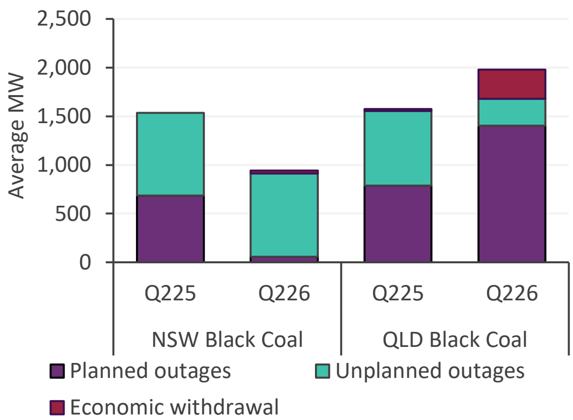
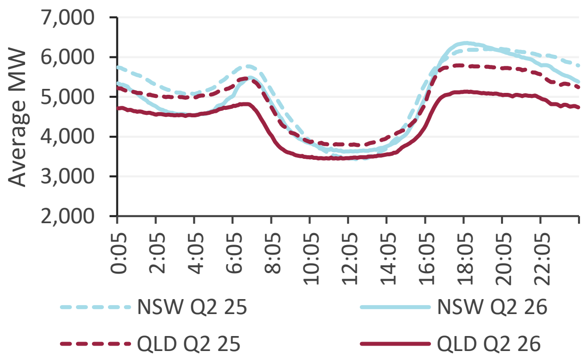


Figure 36 Reduced black coal-fired output across all hours in Queensland

Black coal-fired output by time of day – Q2s



In both New South Wales and Queensland, average black coal-fired generation fell to the lowest Q2 levels recorded.

In New South Wales, output fell by 213 MW (-4.1%), despite availability increasing by 760 MW (+12%) with the reduction concentrated in overnight and early morning hours.

In Queensland, a 458 MW (-7.6%) decline in availability contributed to a 525 MW (-11%) fall in output, with generation lower across all hours of the day (**Figure 36**).

[24] Economic withdrawals refer to periods where coal units are offline (generation below 5 MW) but are not undergoing planned or unplanned repair or maintenance work. This includes units classified under the Medium Term Projected Assessment of System Adequacy (MT PASA) as "Inactive Reserve", as well as intervals where a unit's market bid availability is zero, but non-zero PASA availability indicates that it could come online if required.

Figure 37 shows availability, generation and utilisation rates for New South Wales black coal-fired power stations. With higher availability and reductions in New South Wales operational demand, utilisation rates reduced at all stations. At Mt Piper, a 19 pp reduction in utilisation offset a 459 MW (+61%) increase in availability, with output increasing by 120 MW (+21%). Bayswater was the only other station to record higher generation, up 197 MW (+12%) year-on-year. Eraring recorded the largest decrease in output, decreasing by 399 MW (-20%), followed by Vales Point (-130 MW, -15%).

Figure 37 Lower utilisation across the New South Wales black coal-fired fleet

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q2 2026 vs Q2 2025

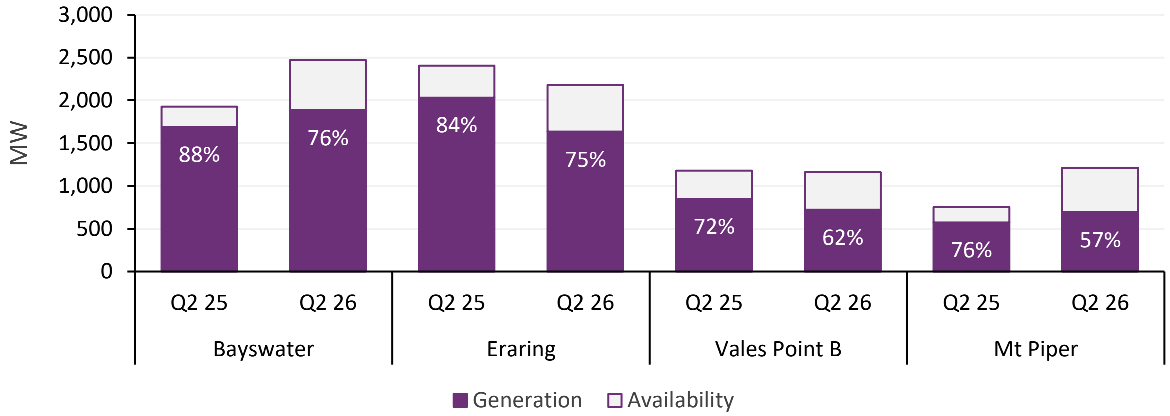
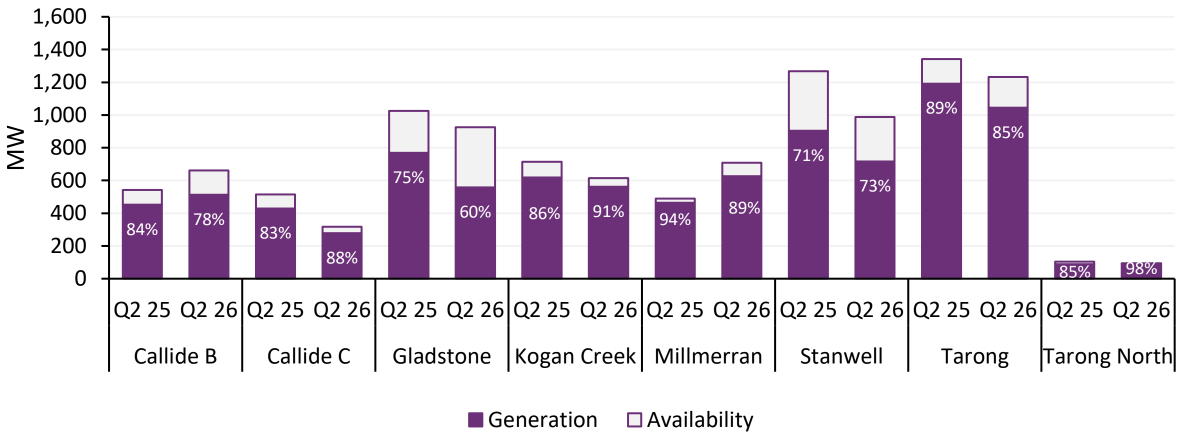


Figure 38 shows availability, generation and utilisation rates for Queensland black coal-fired power stations. Lower availability across most of the fleet contributed to lower output. Millmerran and Callide B were the only stations to record increases in availability, contributing to output increases of 164 MW (+35%) and 61 MW (+13%), respectively. The largest output decrease was at Gladstone, where lower availability and a 15 pp drop in utilisation yielded a 210 MW (-27%) reduction in generation. Stanwell (-187 MW, -21%), Callide C (-151 MW, -35%) and Tarong (-148 MW, -12%) also recorded notable reductions in output. Availability and generation at Tarong North remained relatively unchanged, but at lower than normal levels, with the unit offline for planned maintenance over most of Q2 in both 2025 and 2026.

Figure 38 Lower availability and generation across the Queensland black coal-fired fleet

Average quarterly availability and generation for Queensland black coal-fired power stations – Q2 2026 vs Q2 2025



Brown coal-fired fleet

Average brown coal-fired generation was 3,836 MW in Q2 2026, a year-on-year increase of 50 MW (+1.3%) following a 177 MW (+4.2%) increase in availability due to fewer outages across the quarter (**Figure 39**). Capacity on full outage decreased by 244 MW (-39%), partially offset by a higher level of partial outages.

Yallourn W drove the increase in brown coal-fired generation, with higher availability and lower fully offline capacity contributing to a 191 MW (+21%) increase in output (**Table 3**). Yallourn's intraday swing also reduced substantially, from 235 MW to 73 MW, indicating a flatter operating profile across the day. Consistent with this, brown coal-fired generation was higher during the middle of the day and across the evening peak in Q2 2026 (**Figure 40**).

Figure 39 Brown coal-fired availability and generation increased

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

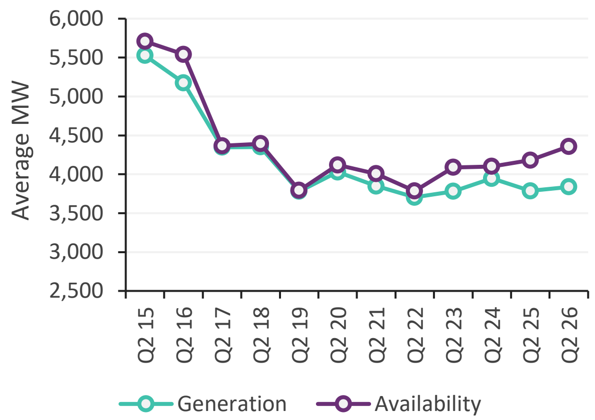


Figure 40 Higher brown coal-fired output across the middle of the day and the evening peak

Brown coal-fired output by time of day – Q2s

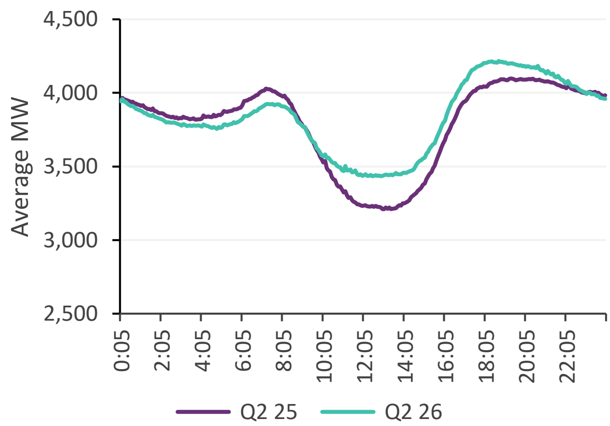


Table 3 Brown coal availability, output, utilisation, offline capacity, and intraday swing – Q2 2026 vs Q2 2025

Generator	Availability (MW)		Output (MW)		Utilisation		Fully offline capacity (MW)		Intraday swing (MW)	
	Q2 25	Q2 26	Q2 25	Q2 26	Q2 25	Q2 26	Q2 25	Q2 26	Q2 25	Q2 26
Loy Yang A	2,034	2,032	1,838	1,707	90%	84%	142	142	440	508
Loy Yang B	1,137	1,149	1,032	1,021	91%	89%	20	3	242	212
Yallourn W	1,009	1,176	917	1,108	91%	94%	458	231	235	73

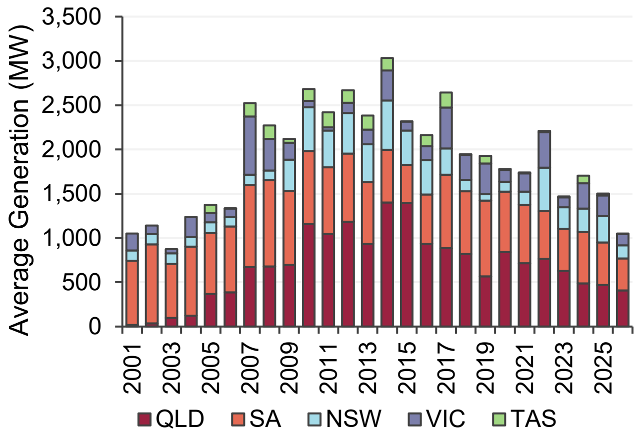
2.3.2 Gas-fired generation

Gas-fired generation across the NEM averaged 1,050 MW in Q2 2026, 453 MW (-30%) lower than Q2 2025 and the lowest Q2 average recorded since 2003 (**Figure 41**). Daily average output was low for most of the quarter before peaking at 3,328 MW on 22 June during a wind lull across southern NEM regions (see **Figure 50** in Section 2.3.4).

Gas-fired output declined in all regions, with the largest reduction occurring in New South Wales, where average generation fell by 155 MW (-51%) year-on-year. The decrease was most evident during the evening peak period (1600 hrs to 2100 hrs), when average output was 442 MW lower than Q2 2025. Most gas-fired generators in the region recorded lower production, led by Tallawarra A (-84 MW), Colongra (-32 MW) and Uranquinty (-28 MW).

Figure 41 Lowest Q2 gas-fired output across the NEM since 2003

Average gas-fired generation by region – Q2s



In South Australia, gas-fired generation averaged 363 MW, 115 MW (-24%) below Q2 2025 and the lowest Q2 level on record. The largest reductions were recorded at Torrens Island (-42 MW), Pelican Point (-28 MW) and Barker Inlet (-22 MW).

Gas-fired generation averaged 127 MW in Victoria, a decrease of 104 MW (-45%) year-on-year, with Newport (-64 MW) and Laverton (-34 MW) accounting for most of the decline.

In Queensland, gas-fired generation averaged 408 MW, 63 MW (-13%) lower than Q2 2025. Reductions across most stations were partially offset by higher output at Yarwun (+48 MW), Swanbank (+17 MW) and Yabulu (+5 MW).

2.3.3 Hydro

This section discusses hydro generation, excluding pumped hydro output, which is covered in Section 2.4.2.

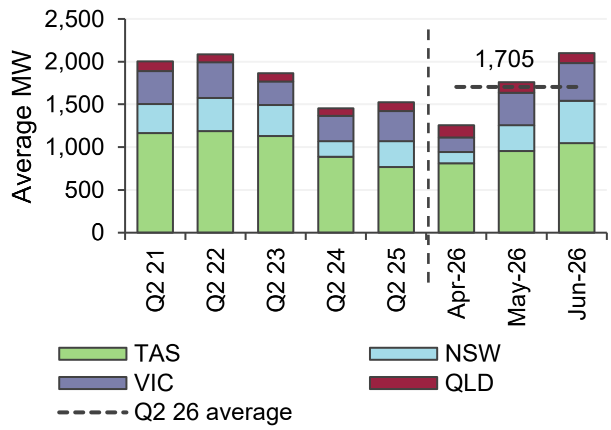
Hydro generation[25] across the NEM averaged 1,705 MW in Q2 2026, 182 MW (+12%) higher than Q2 2025 (**Figure 42**).

Tasmania accounted for most of the increase, with its average hydro generation 170 MW (+22%) above Q2 2025. The increase reflected higher output at most stations and lower imports into Tasmania (see Section 2.6), leading to greater utilisation of hydro generation despite lower operational demand.

Additionally, hydro storage levels in the region improved, with energy in storage reaching 43.0% of full capacity at the end of Q2 2026, compared with 33.1% at the end of Q2 2025 and 31.5% at the end of Q2 2024[26].

Figure 42 Hydro generation increased year-on-year

Average hydro generation by region – Q2s



On the mainland, hydro generation was higher in both Queensland and New South Wales compared to Q2 2025. Queensland averaged 26 MW (+25%) above the previous year, primarily driven by higher output from Barron Gorge (+22 MW), while New South Wales recorded a modest increase of 10 MW (+3.2%). This increase was partially offset by lower hydro generation in Victoria, where average output declined by 23 MW (-6.5%) year-on-year.

[25] Hydro generation excludes output from hydro pumped storage and does not net off electricity consumed by pumping at these facilities. When excluding pumped hydro generation, the pumped hydro production for Tumut 3 was estimated by multiplying its pumping load by round-trip efficiency (78%), while for Wivenhoe and Shoalhaven actual generation was used.

[26] 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.

2.3.4 Wind and grid-scale solar

Average VRE generation in the NEM reached a new Q2 high of 6,058 MW, a year-on-year increase of 903 MW (+18%). Wind generation led this growth, accounting for 706 MW (+20%), while grid-scale solar contributed a 197 MW (+12%) increase from Q2 2025 (**Figure 43**).

Queensland's wind generation reached a record average output of 842 MW, up 375 MW (+80%) from Q2 2025, supported by the commissioning of new wind farms and stronger wind conditions (**Figure 44**). Average output also increased in Victoria (+177 MW, +13%), South Australia (+102 MW, +14%), Tasmania (+20 MW, +11%) and New South Wales (+32 MW, +4.1%). Grid-scale solar growth was also led by Queensland, with a year-on-year increase of 145 MW (+22%) to reach a new quarterly high of 793 MW. New South Wales recorded a moderate increase of 66 MW (+9.1%) year-on-year, while Victoria recorded a slight increase of 15 MW (+7.6%), but this growth was partially offset by a 29 MW (-29%) decrease in South Australia.

Figure 43 Growth in VRE output

Average quarterly VRE generation by fuel type – Q2s

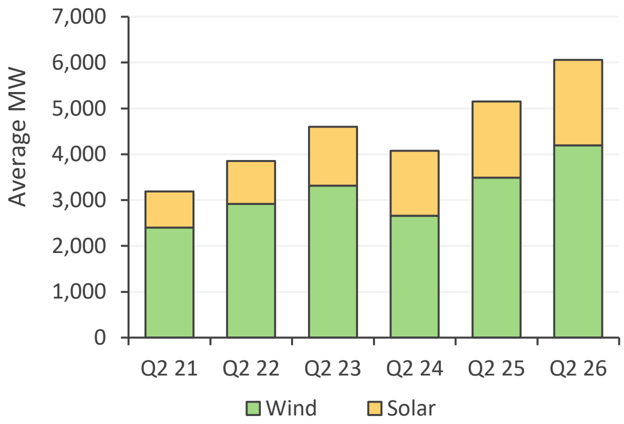
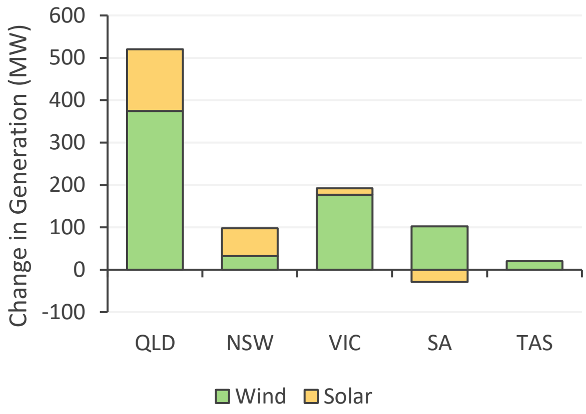


Figure 44 Queensland led renewable increases

Average MW change in output Q2 2026 vs Q2 2025



Grid-scale solar

Grid-scale solar output across the NEM reached a new Q2 high of 1,860 MW (+197 MW, +12%) in 2026. New connections and projects progressing through the commissioning process resulted in an increase of 366 MW in average quarterly solar availability compared to Q2 2025 (**Figure 45**). Availability growth was led by Aldoga in Queensland (+80 MW), Culcairn in New South Wales (+61 MW), and Goorambat East in Victoria (+35 MW).

Offsetting these increases, available output from existing[27] facilities fell by 148 MW, due to lower volume-weighted capacity factors[28] year-on-year, averaging 18% (-1.2 pp). Queensland recorded the highest available capacity factor at 22% (+0.3 pp), followed by New South Wales at 17% (-1.2 pp) (**Figure 46**). Victorian and South Australian solar farms had the lowest availability across NEM regions this quarter at 14%, falls of 2.8 pp and 5.9 pp, respectively, driven by lower solar exposure and increased cloud cover (see Section 1).

Network curtailment for grid-scale solar increased by 33 MW year-on-year, while economic offloading decreased by 12 MW.

[27] Existing (or established) capacity here means wind and grid-scale solar facilities that were fully commissioned prior to the start of Q2 2026. These facilities may also appear in the "New Capacity" or "Commissioning" categories in **Figure 45** and **Figure 47** if they were connected or exhibited ramping activity between Q2 2025 and Q2 2026, respectively.

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

Figure 45 New and commissioning capacity led the year-on-year grid-scale solar growth

Changes in grid-scale solar generation – Q2 2026 vs Q2 2025

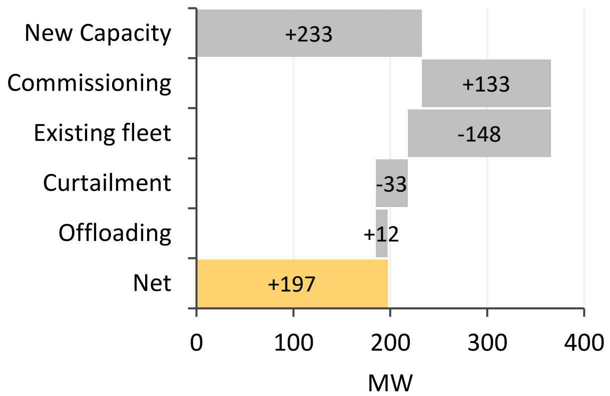
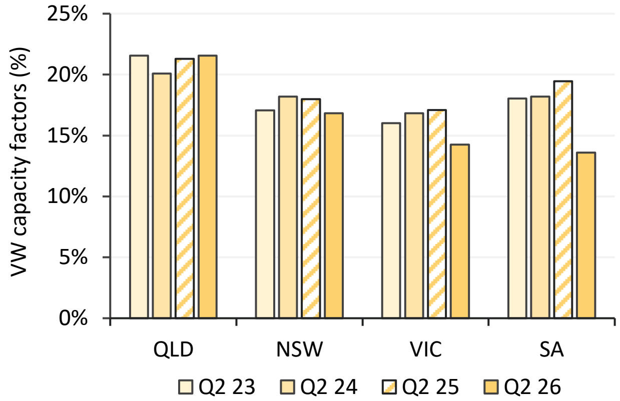


Figure 46 Reduced grid-scale solar availability in all NEM regions except Queensland

Volume-weighted grid-scale solar available capacity factors[29] – Q2s



Wind

In Q2 2026, wind generation reached a new Q2 high of 4,198 MW, a year-on-year increase of 706 MW (+20%). Quarterly availability increased by 567 MW, due to new and commissioning wind farms (**Figure 47**). Most growth was in Queensland, with added availability from Clarke Creek (+138 MW), MacIntyre (+97 MW) and Wambo (+95 MW). Further increases occurred in Victoria, from Golden Plains East (+120 MW) and Golden Plains West (+67 MW), and in South Australia, from Goyder South (+48 MW).

At existing wind farms, availability was up by 271 MW from Q2 2025. The NEM-wide quarterly volume-weighted capacity factor for wind rose to 33% (+3.0 pp) and was higher in all regions (**Figure 48**). Queensland's increase of 7.0 pp was the most notable due to stronger wind conditions, yielding the highest regional average capacity factor of 41%, followed by Tasmania at 35% (+3.5 pp), South Australia at 33% (+3.6 pp) and Victoria at 32% (+2.4 pp). New South Wales had the lowest average capacity factor of 29%, recording a slight year-on-year increase of 0.9 pp.

Figure 47 Increased output from commissioning and existing wind farms

Changes in wind generation – Q2 2026 vs Q2 2025

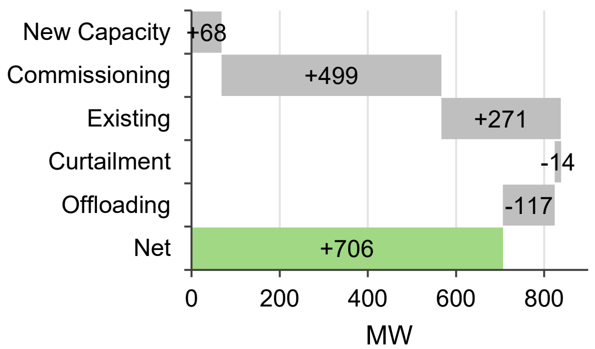
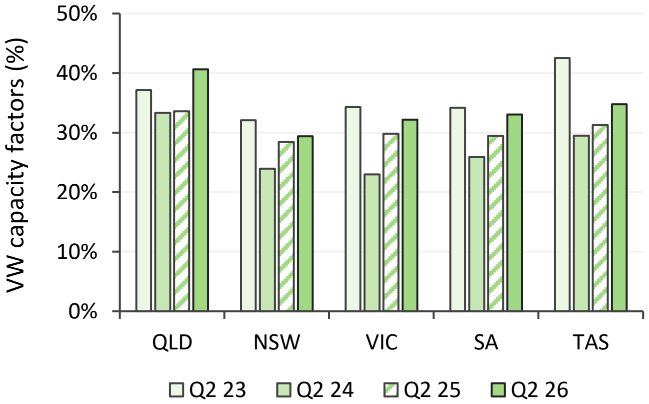


Figure 48 Wind availability up in all NEM regions

Volume-weighted wind available capacity factors – Q2s



29 Available capacity factors for each established facility are weighted by maximum capacity to derive a regional weighted average.

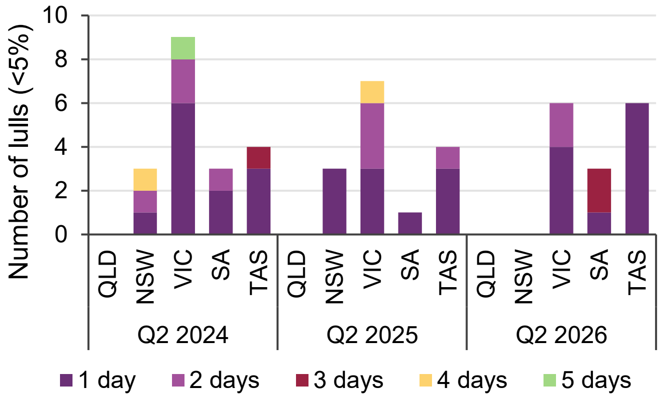
Network curtailment for wind generation increased by 14 MW compared to this time last year, while economic offloading rose by 117 MW.

Figure 49 shows the number of Q2 wind lull events across NEM regions.

In Q2 2026, South Australia had the longest runs of consecutive days with daily average wind capacity factors[30] below 5%, and was the only region to experience lulls of three days (over 13-15 April and 21-23 June). The available wind capacity factor in South Australia averaged 3.7% across 13-15 April and 3.4% across 21-23 June. The June wind lull was one of the factors contributing to the tight supply-demand conditions during the South Australian high-price event discussed in Section 2.2.2.

Figure 49 Fewer multi-day wind lulls in Q2 2026.

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

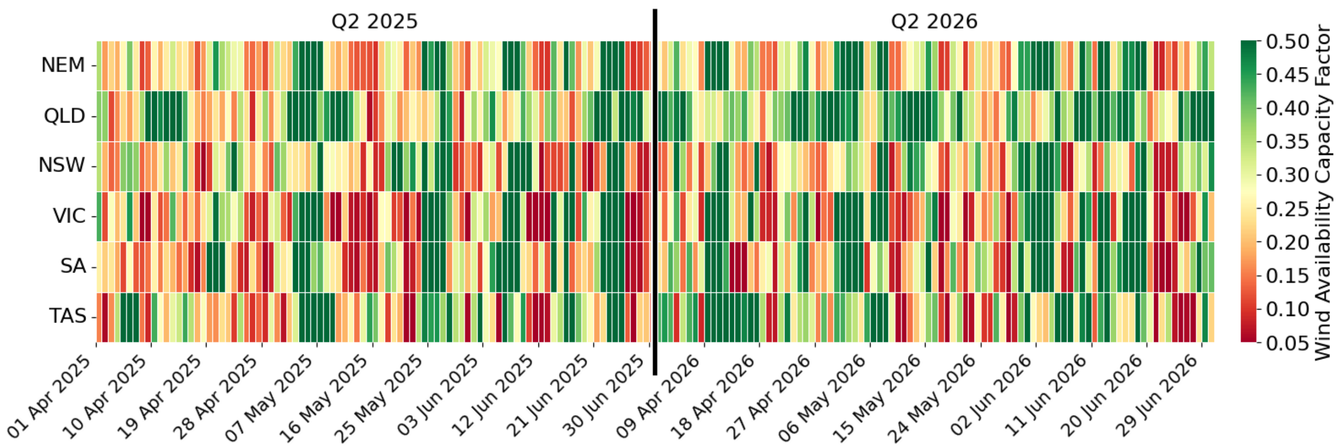


In contrast, the other NEM regions experienced fewer multi-day events. Victoria and Tasmania recorded fewer two-day wind lulls than in Q2 2025, but more single days with availability below 5%. Queensland and New South Wales had no days with availability below 5% this Q2.

Figure 50 further illustrates daily wind available capacity factors for Q2 2025 and Q2 2026.

Figure 50 Fewer lows in wind availability across Q2 2026

Daily wind availability capacity factor – Q2 25 and Q2 26



In April and May 2026, the number of days with wind available capacity factor below 5% increased year-on-year to four days (+1 day) and eight days (+2 days), respectively. The increase in April was driven by a three-day wind lull in South Australia, while in May, several one-day low wind events in Tasmania contributed to the higher count. In June 2026, South Australia again recorded more low-wind days due to a second three-day lull. However, fewer and shorter wind lull events in

[30] Available capacity factors are calculated using the available energy divided by the maximum capacity. The use of availability instead of generation output removes the impact of economic offloading or curtailment to better capture in-service plant capacity and underlying wind resource levels. Wind farms are included in the capacity factor calculation from the first day of the quarter after they reach full output.

New South Wales, Victoria and Tasmania reduced the monthly total to nine days, compared to 13 days in June 2025. Overall, this quarter recorded 21 days with wind available capacity factor less than 5%, one day fewer than in Q2 2025. Despite similar numbers of low-wind days, these events were less clustered across the NEM regions this Q2 than in 2025.

Economic offloading

Total economic offloading[31] for wind and grid-scale solar averaged 349 MW in Q2 2026, a year-on-year increase of 105 MW (+43%) (**Figure 51**). Economic offloading was highest in Victoria (199 MW, predominantly wind), followed by South Australia (85 MW, again mostly wind), Queensland (52 MW, largely grid-solar), then New South Wales (13 MW), driven by more frequent negative price occurrences (see Section 2.2.3).

Grid-scale solar economic offloading decreased by 12 MW (-13%), to average 81 MW, with offloading as a percentage of average solar availability also decreasing to 4% (-1.0 pp) from the previous year. Year-on-year reductions in grid-scale solar economic offloading were concentrated in New South Wales (-21 MW, -64%) and South Australia (-5 MW, -29%) (**Figure 52**). This was partially offset by increases in Victoria (+9 MW, +160%) and Queensland (+4 MW, +12%).

In contrast, wind economic offloading grew notably by 117 MW (+78%), to average 268 MW this quarter, with offloading as a share of average wind availability rising 2 pp to 6%. Victoria recorded the largest increase (+103 MW, +128%), followed by South Australia (+12 MW, +19%) and Queensland (+6.5 MW, +179%). Economic offloading remained negligible in Tasmania, and fell in New South Wales (-4 MW, -75%).

Figure 51 Economic offloading increased for wind and decreased for solar farms

Average MW offloading and as percentage of availability by fuel type

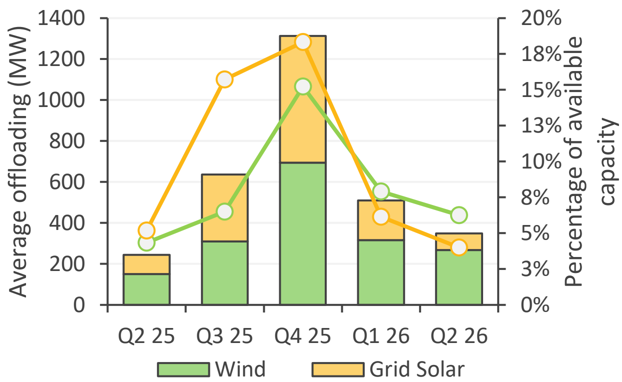
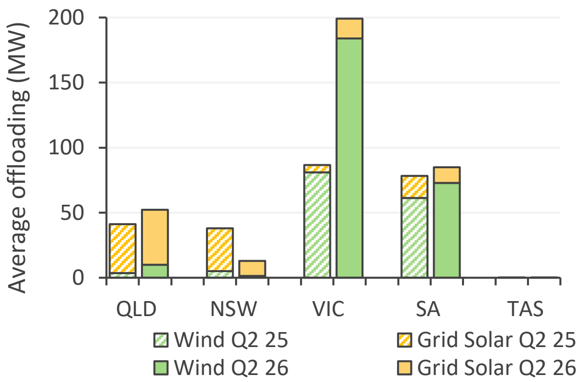


Figure 52 Queensland and Victoria saw higher economic offloading

Average MW offloading by region – Q2s



Network curtailment

Total network curtailment of wind and solar generation averaged 142 MW in Q2 2026, up 48 MW from the same time last year (**Figure 53**). Grid-scale solar curtailment grew by 33 MW, with average curtailed output of 81 MW this quarter. As a percentage of average solar availability, curtailment was up 1.3 pp from Q2 2025 to 4.0% this Q2. Increases were led by New South Wales, where curtailment rose 22 MW (+60%), followed by Queensland (+11 MW, +540%) (**Figure 54**). In Victoria and South Australia, grid-scale solar curtailment was unchanged year-on-year, at 8 MW and 0.2 MW, respectively.

[31] Economic offloading refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price (RRP); that is, it was undercut by competitors offering their output at a lower price.

Figure 53 Curtailment increased for solar farms and remained the same for wind farms

Average MW network curtailment and as percentage of availability by fuel type

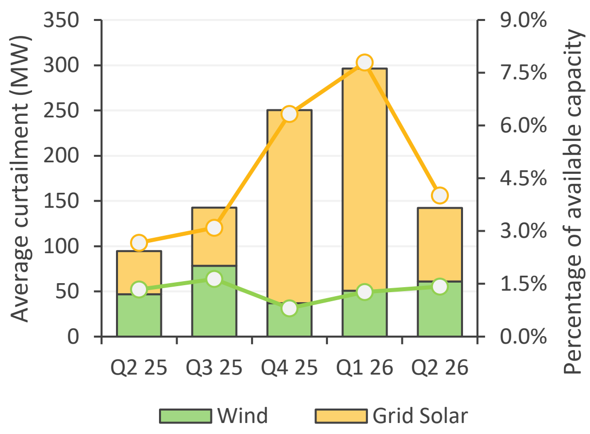
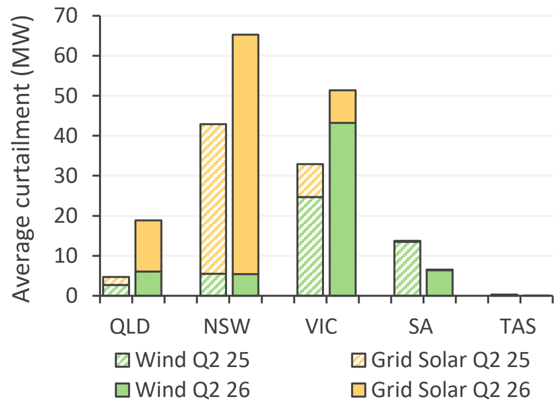


Figure 54 Curtailment was higher in New South Wales for grid solar and higher in Victoria for wind

Average MW network curtailment by region – Q2s



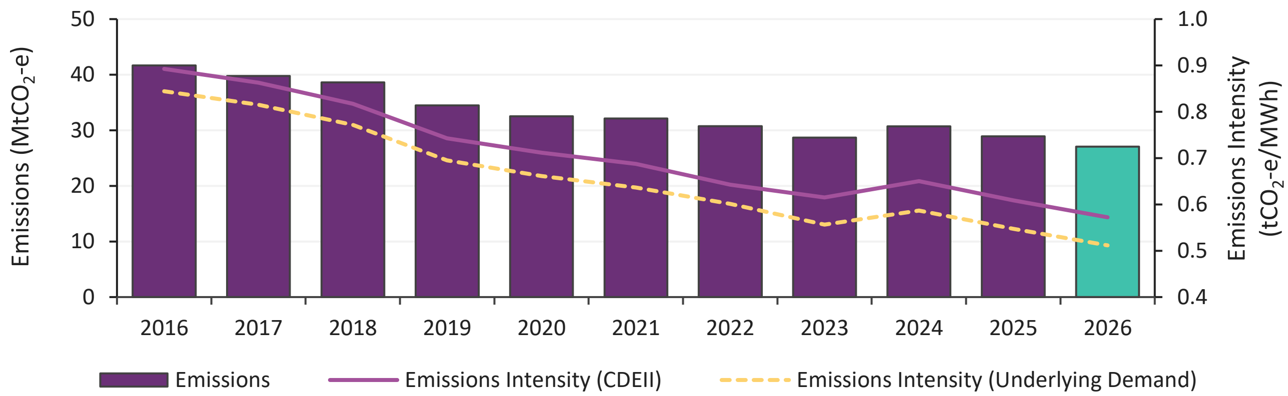
Average curtailment[32] of wind generation also increased by 14 MW, up to 61 MW, with curtailment as a percentage of average wind availability rising 0.1 pp from the previous year to 1.4%. Victoria and Queensland recorded increases of 19 MW (+75%) and 3.3 MW (+124%), respectively. However, these rises were partially offset by lower curtailment in South Australia (-7.1 MW, -53%).

2.3.5 NEM emissions

In Q2 2026, NEM total emissions reduced to a new Q2 low of 27.1 MtCO2-e, down 1.9 MtCO2-e (-6.4%) from Q2 2025 (**Figure 55**).

Figure 55 NEM total emissions and emission intensity fell to Q2 lows

Quarterly NEM emissions and intensity – Q2s



This reduction was driven by lower operational demand and lower emissions intensity of grid-scale generation. The Carbon Dioxide Equivalent Intensity Index (CDEII) emissions intensity is measured by combining sent out metering data with

[32] 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.

publicly available generator emission and efficiency data to provide a NEM-wide CDEII[33]. This emissions intensity excludes generation from distributed PV, considering only sent out generation from market generating units. This quarter, CDEII emissions intensity averaged 0.57 tCO_2-e per MWh, down 6.0% year-on-year, and setting a new Q2 low, reflecting increased grid-scale renewable generation and lower output from coal-fired and gas-fired generators. Continued growth in distributed PV output further reduced emissions intensity associated with underlying demand,[34] which reduced 6.6% year-on-year to average 0.51 tCO_2-e per MWh this quarter.

2.4 Storage and renewable contribution

2.4.1 Batteries

Between the end of Q2 2025 and Q2 2026, the installation of numerous battery energy storage systems (BESS) saw a significant increase in battery capacity in the NEM, with a combined capacity of 4,640 MW/12,353 MWh beginning commissioning. Of this total, 951 MW/2,753 MWh came online in Q2 2026 (**Table 4**). Total installed battery capacity in the NEM, including both fully commissioned facilities and projects still in their commissioning phase, exceeded 9,000 MW by the end of the quarter.

Table 4 New battery systems commenced commissioning in the NEM in Q2 2026

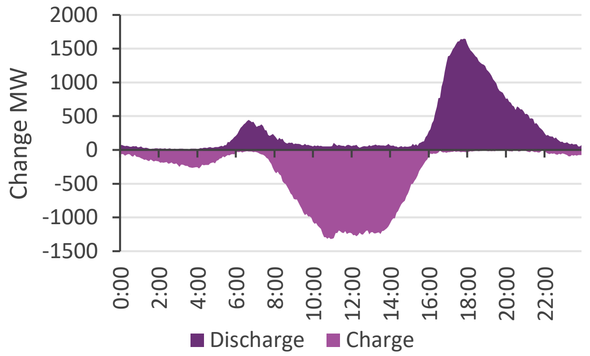
Battery	Region	Maximum Capacity
Lincoln Gap Wind Farm BESS	South Australia	9 MW/10 MWh
Mornington BESS	Victoria	240 MW/590 MWh
Broadsound Energy Park	Queensland	180 MW/360 MWh
Stanwell BESS	Queensland	300 MW/1200 MWh
Woolooga BESS	Queensland	222 MW/593 MWh

Battery discharge increased substantially in Q2 2026 to average 476 MW (+314 MW), almost triple the 162 MW recorded last Q2, to reach a new quarterly high. Average charging increased by 371 (+182%) MW year-on-year to 574 MW, concentrated in daytime (1000 hrs to 1600 hrs) and early morning periods (0200 hrs to 0600 hrs).

Early morning charging rose by 188 MW (+91%), storing energy to support higher discharge over the morning peak, while daytime charging increased by 1,009 MW (+211%), supporting higher discharge across evening peak demand hours (**Figure 56**).

Figure 56 Increased daytime charging and stronger evening discharge

Change in average battery discharge/ charge by time of day – Q2 2026 vs Q2 2025



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

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

Peak battery charging reached 3,653 MW this quarter on 7 June 2026 during the half-hour ending 1300 hrs, surpassing the previous record of 2,834 MW set in Q4 2025 by 819 MW (+29%). Peak battery discharging also set a record at 3,759 MW during the half-hour ending 1800 hrs on Friday 26 June 2026. This was 203 MW (+5.7 %) higher than the previous record of 3,556 MW set in Q1 2026.

Battery revenue

In Q2 2026, estimated revenue[35] for grid-scale batteries in the NEM averaged $57.5 million, a decline of $73 million from Q2 2025 (**Figure 57**). This reflected lower net revenue from arbitrage, which at $52.8 million was $68.1 million (-56%) lower than Q2 2025, driven by shrinkage in the price spreads earned by batteries across the NEM.

Frequency control ancillary services (FCAS) revenue also declined by $5.0 million (-51%) to $4.8 million this quarter. Despite this decrease, FCAS accounted for a slightly larger share of total battery revenue, rising by 0.8 pp year-on-year to 8.3% (**Figure 58**).

Figure 57 Decreases in FCAS and battery arbitrage revenue

Quarterly net revenue from NEM battery systems by revenue stream

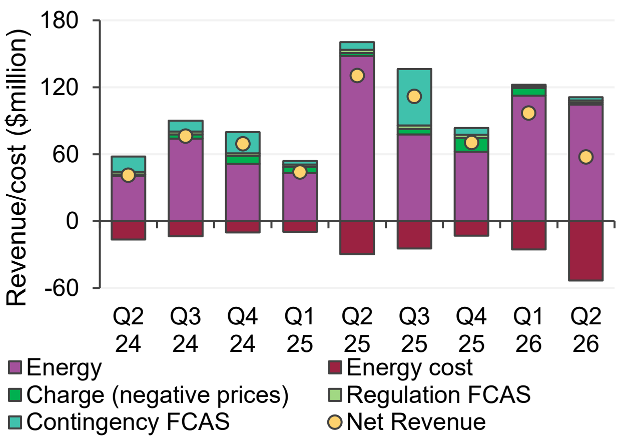
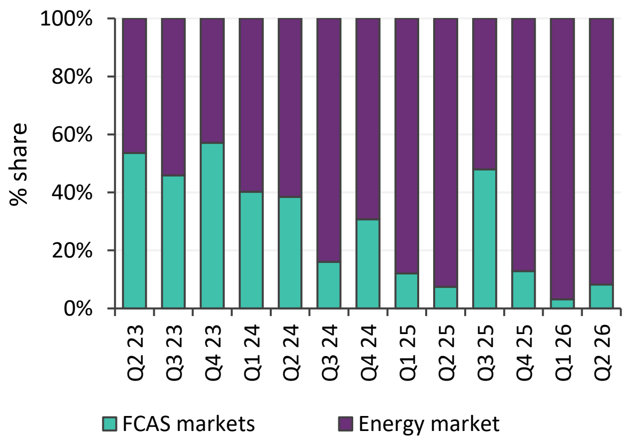


Figure 58 Battery revenue share from FCAS markets slightly increased

Percentage share of battery net revenue – energy vs FCAS markets



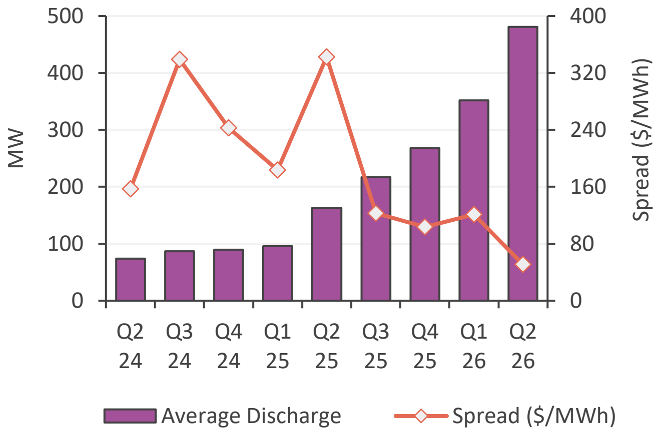
Lower energy arbitrage revenue, including revenue earned from charging at negative prices, was driven by a decline in gross energy revenues, which fell by $44.5 million to $106.2 million. This was compounded by an increase in energy charging costs, from $29.8 million to $53.4 million, a rise of $23.6 million (+79%). As a result, net energy arbitrage revenue declined by $68.1 million (-56%) to $52.8 million.

Despite substantial increases in charge and discharge volumes, energy arbitrage revenue fell this Q2 as lower intra-day price differences reduced the value captured from energy shifting. NEM-wide battery price spreads fell sharply from $342/MWh to $51/MWh (**Figure 59**), reflecting lower price volatility and a narrowing gap between charging and discharging prices (see **Figure 28** in Section 2.2.5).

[35] Battery revenue comprises revenue from energy arbitrage – calculated as revenue from energy discharged (including charging at negative prices) net of charging costs – and revenue earned from frequency control ancillary services (FCAS). This measure excludes FCAS costs incurred by batteries and Frequency Performance Payment (FPP) outcomes for batteries.

Figure 59 NEM-wide battery price spread

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



All NEM regions experienced this decline in average price spreads. The largest decreases were in New South Wales and Victoria, where spreads fell by $381/MWh (-90%) to $41/MWh and by $350/MWh (-88%) to $50/MWh, respectively. South Australia and Queensland also recorded substantial year-on-year declines, with respective spreads decreasing by $232/MWh (-80%) to $59/MWh and $211/MWh (-79%) to $57/MWh.

Energy arbitrage revenue declined in all NEM regions, with the largest reduction in Victoria (-$32.7 million). South Australia and New South Wales recorded declines of $17.8 million and $13.5 million, respectively, while arbitrage in Queensland decreased by $4.0 million.

2.4.2 Pumped hydro

This section discusses pumped hydro generation, covering the Shoalhaven and Tumut 3 stations in New South Wales and Wivenhoe in Queensland. Revenue calculations include Shoalhaven and Wivenhoe only, with Tumut 3 excluded.

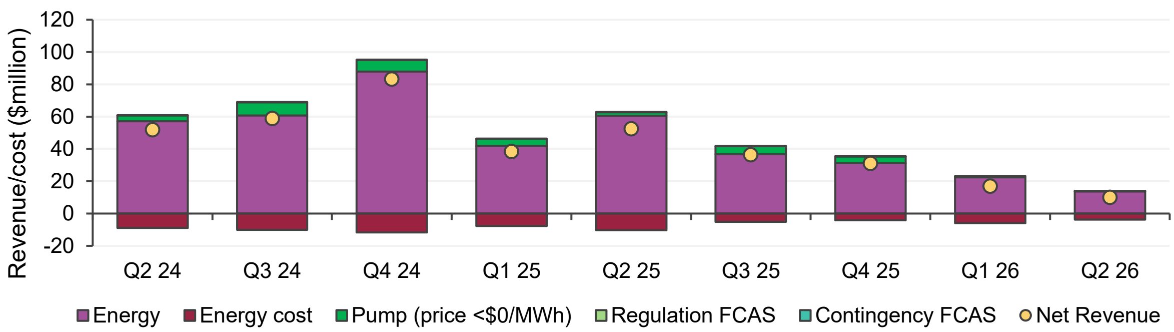
Pumped hydro generation[36] averaged 91 MW in Q2 2026, a year-on-year decline of 59 MW (-39%). This was driven by decreases at all three pumped hydro facilities in the NEM, with the largest decline at Tumut 3 (-32 MW, -58%). Wivenhoe and Shoalhaven fell by 23 MW (-28%) and 4 MW (-33%), respectively.

Pumped hydro revenue[37]

Estimated net pumped hydro revenue decreased to $10.1 million this quarter, a $42.5 million decline from this time last year (**Figure 60**), driven primarily by lower wholesale spot prices. In Queensland, Wivenhoe's revenue fell by $33 million (-79%) to $8.8 million, while in New South Wales, Shoalhaven's revenue by $9.5 million (-88%) to $1.3 million.

Figure 60 Pumped hydro revenue decreased year-on-year

Quarterly revenue from NEM pumped hydro by revenue stream



[36] Pumped hydro production for Tumut 3 was estimated by multiplying its pumping load by round-trip efficiency (78%), while for Wivenhoe and Shoalhaven actual generation was used.

[37] Pumped hydro revenue calculations include Shoalhaven and Wivenhoe only, with Tumut 3 excluded.

2.4.3 Peak renewable and storage contribution

This section examines renewable and storage contribution to demand at a 30-minute level, reflecting the combined role of renewable generation and battery discharge in meeting demand at any point in time. Peak renewable and storage contribution[38] in the NEM reached a Q2 high of 73.9% during the half-hour ending 1230 hrs on 11 April 2026. This was 2.6 pp higher than in Q2 2025, although it remained 4.8 pp below the all-time record of 78.6% set in October 2025 (**Figure 61**). At the time of the peak, distributed PV provided 38.4% of total generation, while grid-scale solar and wind contributed 16.2% and 17.0%, respectively.

Figure 61 Peak renewable and storage contribution increased from Q2 2025 but was below Q4 2025's record high

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

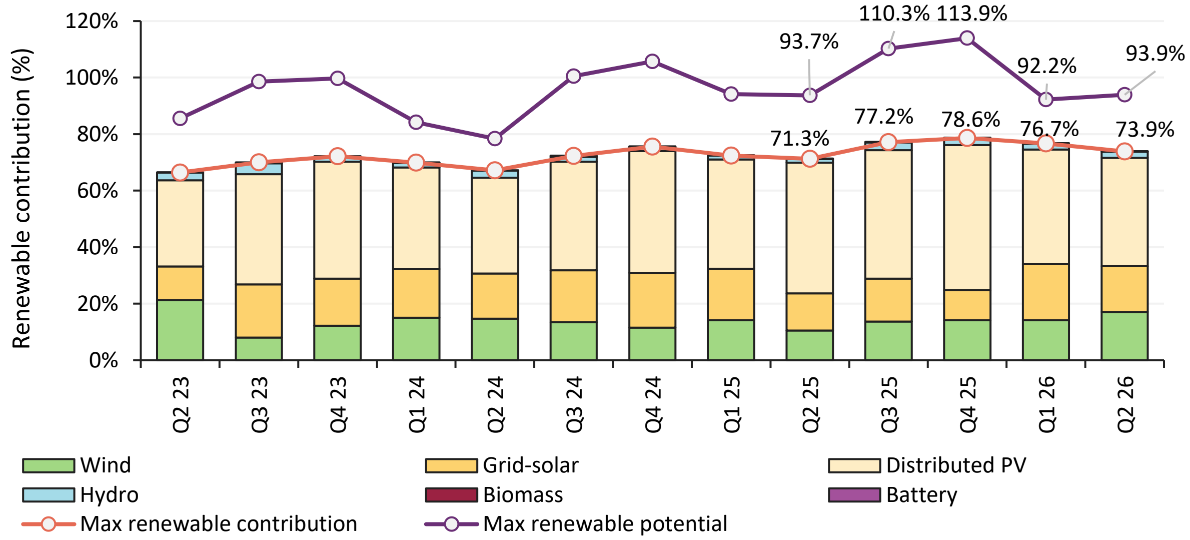
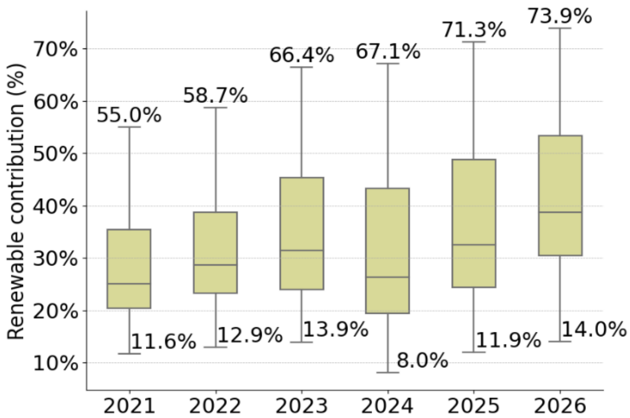


Figure 62 Higher maximum and minimum renewable storage contribution

Range of NEM supply share from renewable sources and storage – Q2s



Renewable and storage contribution varied substantially throughout Q2 2026, ranging from a quarterly low of 14.0% to a high of 73.9%, a spread of 59.9 pp (**Figure 62**). The minimum occurred in the half-hour ending 0230 hrs on 22 June 2026, and was 2.0 pp higher than the lowest level recorded in the same quarter last year. By region, Queensland recorded a new high for renewable and storage contribution this quarter, reaching 71.1% during the half hour ending 1130 hrs on 9 April 2026. This record was subsequently exceeded several times throughout the quarter, with a new all-time high of 72.2% achieved during the half-hour ending 1130 hrs on 31 May 2026. The new record was 1.6 pp higher than the previous peak set in November 2024.

[38] Peak renewable and storage contribution is calculated using the renewable share of total generation (either NEM-wide or regional). 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 (including pumped hydro), biomass, battery discharge and distributed PV. Total generation = large-scale generation + estimated PV output.

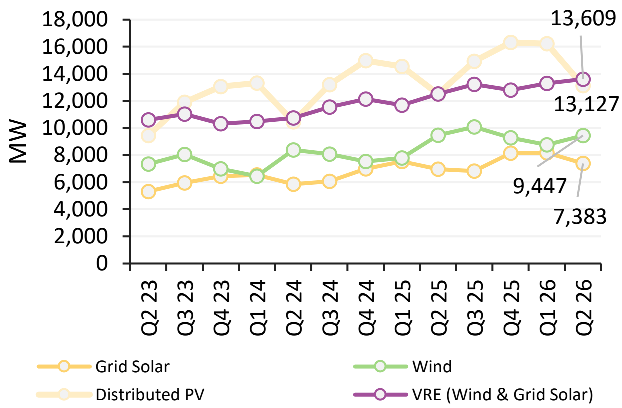
Maximum renewable output

Figure 63 highlights the highest quarterly peak half-hourly generation for grid-scale solar, wind, and distributed PV since Q2 2024. In Q2 2026, grid-scale solar reached 7,383 MW in the interval ending 1000 hrs on 28 April 2026. This was 424 MW (+6.1%) higher than in Q2 2025. Peak wind generation was marginally down this Q2 at 9,447 MW (-25 MW).

Peak VRE output, comprising wind and grid-scale solar, reached a new all-quarter record this Q2, at 13,609 MW in the half-hour ending 1230 hrs on 7 May 2026. This was 315 MW (+2.4%) higher than the previous record set in Q1 2026.

Figure 63 Record highs for combined VRE generation

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

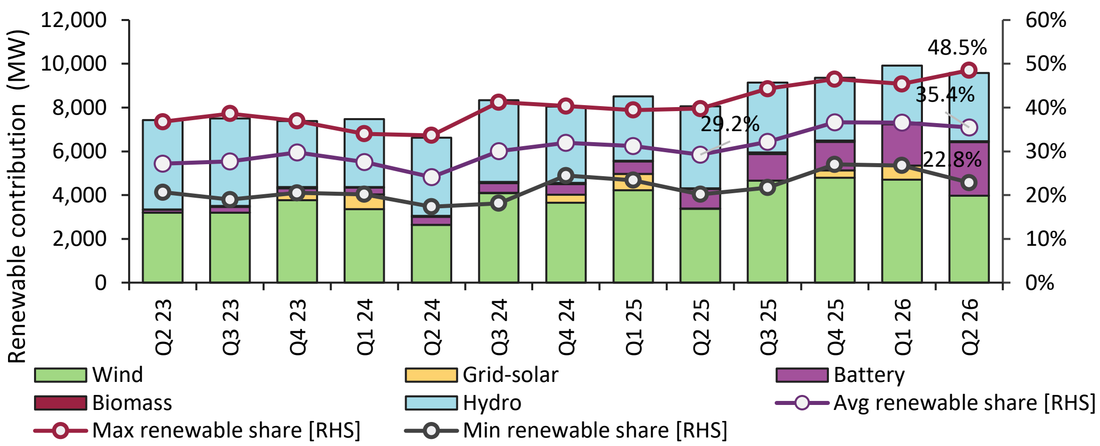


Renewable and storage contribution to maximum demand

Figure 64 shows the average share of large-scale renewable generation and storage in meeting daily maximum NEM operational demand, aggregated across all days in each quarter since Q2 2023[39].

Figure 64 Renewable and storage contribution increased at time of daily maximum demand

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



The average renewable and storage contribution at the time of daily maximum demand reached 35.4% in Q2 2026, increasing by 6.2 pp compared with Q2 2025. This reflected strong growth in the average contribution of battery discharge, up by 5.8 pp to 9.1%. Wind displaced hydro as the largest contributor, meeting an average 14.7% (+2.5 pp) of maximum daily demand. Over the quarter, daily maximum demand contributions ranged from 22.8% to 48.5%, reflecting variability in renewable resource availability, dispatch volumes, and demand.

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

2.5 New grid connections

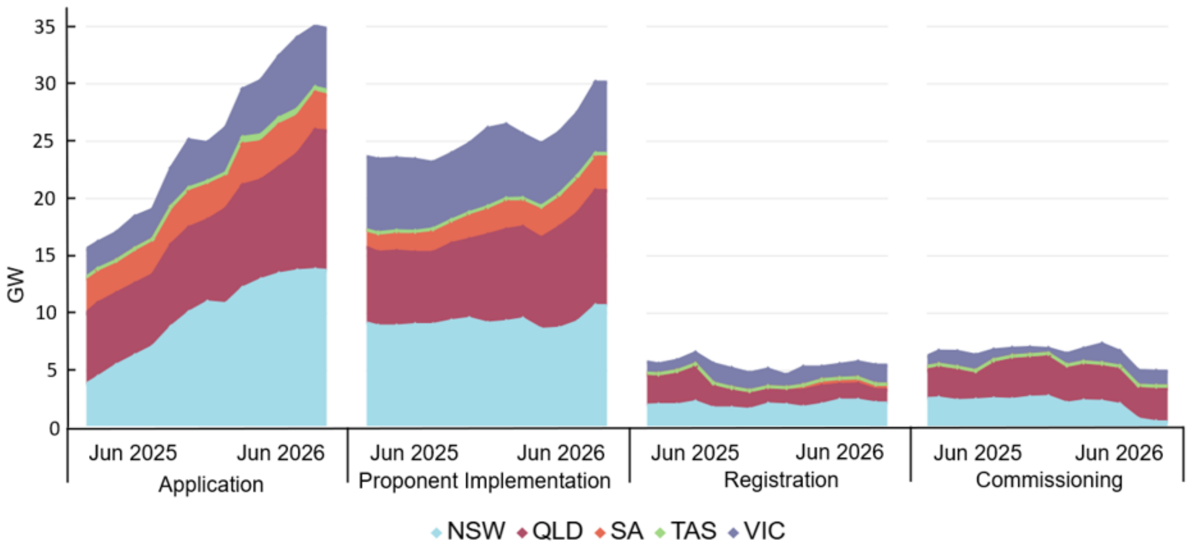
Generation and storage connections

Connecting new generation and storage projects to the NEM involves coordinated work between project proponents, network service providers (NSPs), original equipment manufacturers (OEMs) and AEMO. Before a formal connection application is submitted to AEMO, proponents work with the relevant NSP through an enquiry phase to assess connection requirements. Once a connection application has been submitted, AEMO and the NSP assess and negotiate performance standards for connecting assets to ensure the stable and secure performance of the power system. AEMO is only involved in assessing performance standards that fall under AEMO advisory matters. AEMO also monitors progress across the key stages of the connection process[40], including application, proponent implementation, registration, commissioning and model validation.

Generation and storage project capacity in the pipeline has grown 42% in the past year, from 53.0 GW to 75.4 GW. Growth came from batteries (71% increase), wind (41% increase), hydro (41% increase), and solar and solar hybrid (13% increase). This growth was largely driven by new applications, with the application pipeline more than doubling in FY26, from 17.5 GW to 35.3 GW (**Figure 65**).

Figure 65 Increased capacity progressing through application stage driven by recent Queensland applications

12-month trend of connection capacity in progress



Note: charts are based on current data, and therefore some variances may exist compared to previously reported capacity in progress.

During Q2 2026, AEMO and the relevant NSPs approved a record 6.9 GW of new generation and storage connection applications. In this quarter, battery projects accounted for the largest share of approved application capacity at 3.6 GW, followed by 1.8 GW hybrid solar plus battery projects, 1.3 GW wind and 0.2 GW solar.

[40] Application stage establishes technical performance and grid integration requirements. In proponent implementation stage, contracts are finalised and the plant is constructed. AEMO is not involved in this stage. 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.

Commissioning activity was strong in Q2 2026, continuing the momentum observed across FY26. A total of 3.9 GW of generation and storage capacity reached full output during the quarter, double the previous quarterly record. This comprised 2.7 GW of battery capacity, 0.5 GW of solar plus battery capacity, 0.4 GW of solar capacity and 0.2 GW of wind capacity.

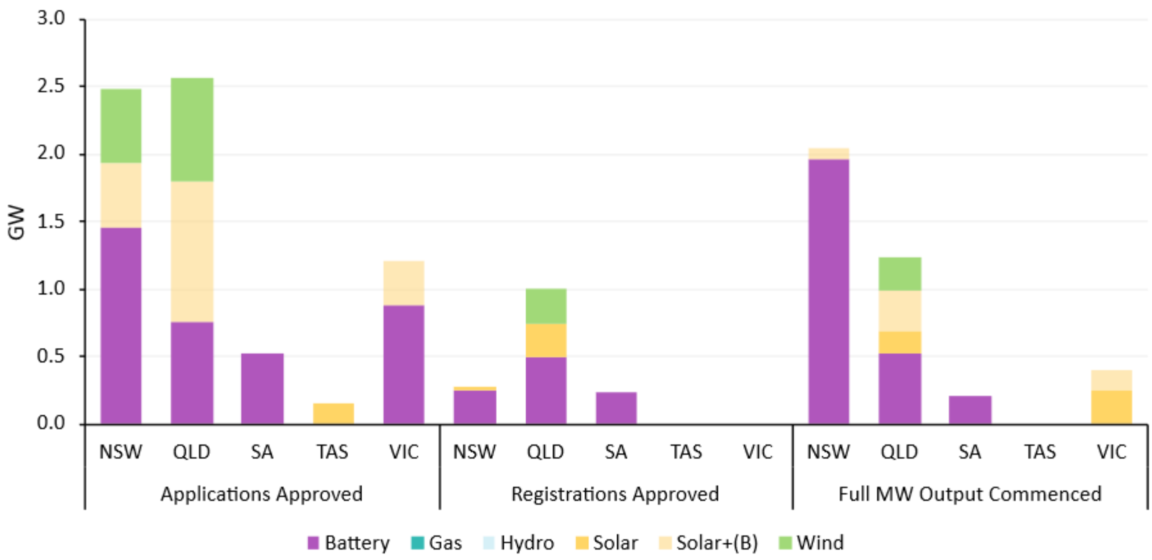
Projects in proponent implementation – a developer-led stage that sits outside AEMO's role in the connection process – increased 30% to 30.1 GW in the last year. There has been a throughput challenge for progression of projects to registration stage. While 14.4 GW of projects progressed from application into proponent implementation, only 6.4 GW exited the stage. Projects are taking longer to progress through proponent implementation, with the median duration increasing from 14 months to 18 months over the year. Nearly one-third of projects in this stage have now been there for more than two years, with the majority of these being solar projects. Reasons for this include design changes (adding batteries to solar, change of equipment) and sale of projects. Extended financing and commercial readiness activities are also contributing to longer proponent implementation durations. Post application approval, the average time to execute connection agreements increased from two months in FY22 to eight months in FY26.

During Q2 2026:

- 6.9 GW of applications were approved across 32 projects (**Figure 66**).
- 1.5 GW of plant across eight projects were registered and connected to the NEM.
- 3.9 GW of plant across 14 projects progressed through commissioning to reach full output.

Figure 66 Strong quarter for application approvals and commissioning

Application approved, registrations and plant commissioned to full output during Q2 2026



At the end of Q2 2026, AEMO's snapshot of connection activities in progress shows that:

- 75.4 GW of new capacity is progressing through the end-to-end connection process from application to commissioning, made up of batteries (53%), solar and solar hybrid (27%), wind (15%), hydro (5%), and gas (1%).
- Battery remains the leading technology in the pipeline and is progressing through project stages faster than any other technology. Of the 39.6 GW of the battery capacity in the pipeline, 32.9 GW is grid-forming, 6.5 GW is grid-following and 0.2 GW is compressed air storage.

- Battery projects are increasingly providing longer-term storage. 31% of battery projects in the pipeline in June 2026 are medium storage batteries, increased from 16% in June 2025
- There are currently 36 wind projects, totalling 11.5 GW, in the pipeline. During FY26 a record 5.2 GW in wind applications, across 12 projects, were received. This is the highest volume of wind applications recorded in a single year.
- The capacity of applications in the pipeline more than doubled in FY26, from 17.5 GW to 35.3 GW, with the number of projects increasing by about 44%, indicating a greater proportion of larger projects on average.
- During the quarter 30 applications were received, totalling 10.5 GW of capacity. More than half of this new application capacity is for Queensland – battery (2.9 GW), wind (1.7 GW), hydro (0.8 GW), solar hybrid (0.2 GW) and gas (0.1 GW).

Please refer to the Connections Scorecard[41] for further information.

Data centre loads with connection applications submitted to AEMO

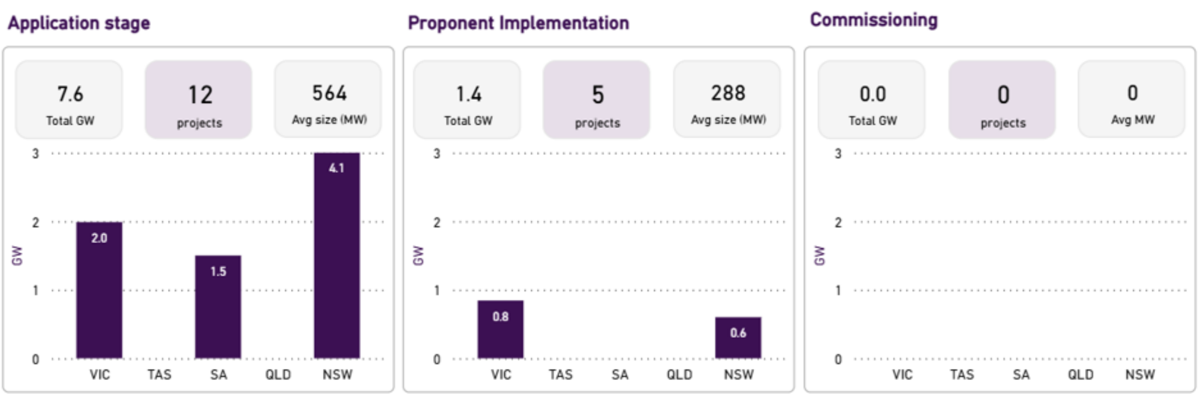
AEMO does not currently have a formal role in connecting data centre loads that are less than 5 MW and do not demonstrate potential for inverter control instability. However, AEMO does track progress through the connection process, which is managed by NSPs. The key stages monitored by AEMO to track progress of data centre load connections include application[42], proponent implementation and commissioning.

In Q2 2026, there are 17 data centres with a combined maximum connection capacity of 9.0 GW working through the transmission network connection process (**Figure 67**). Of these:

- 52% of the capacity is in New South Wales, 31% in Victoria and 17% in South Australia.
- 12 projects (7.6 GW) are currently in the application stage.
- Five projects (1.4 GW) are in proponent implementation stage.

Figure 67 Data centre load connection projects submitted to AEMO

Number and connection capacity of data centre load connection applications submitted to AEMO



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

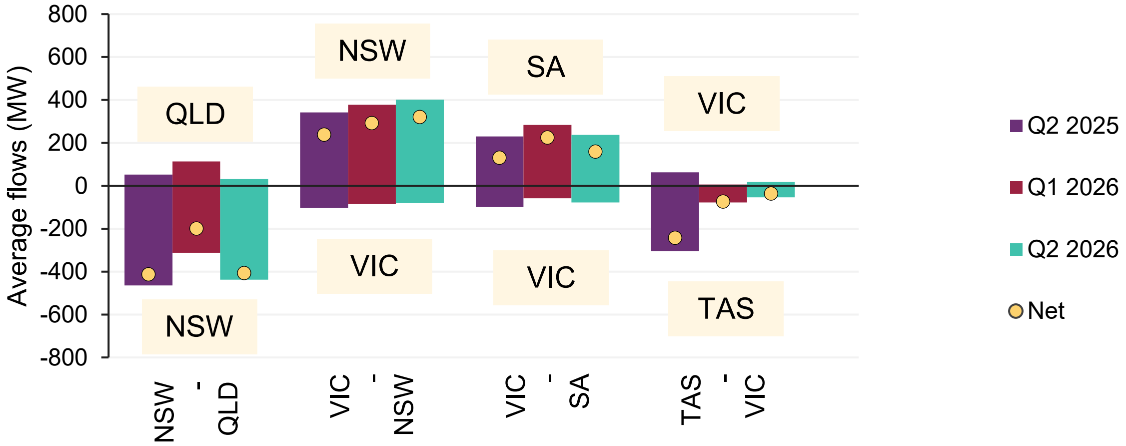
[42] Only projects with an officially submitted connection application package to AEMO are reported. AEMO and NSPs are also supporting multiple proponents across New South Wales, Victoria, South Australia and Tasmania to prepare their project connection applications.

2.6 Inter-regional transfers

Total inter-regional transfers were 2,924 gigawatt hours (GWh) in Q2 2026, equivalent to 6.2% of operational demand, and a reduction of 19% from 3,618 GWh in Q2 2025. The decline was primarily driven by lower net transfers between Victoria and Tasmania, which decreased by 646 GWh (-80%) year-on-year, alongside decreased net transfers between Queensland and New South Wales, down 107 GWh (-9%) (**Figure 68**). This was partially offset by increased net transfers between Victoria and New South Wales.

Figure 68 Inter-regional transfers declined in Q2 2026

Quarterly inter-regional transfers



Compared to Q2 2025, average net transfers on Basslink decreased by 205 MW (-85%), with transfers from Victoria to Tasmania declining from an average of 305 MW to just 54 MW. This reduction was observed across all hours of the day (**Figure 69**) and reflected changes in Basslink bidding behaviour since 1 July 2025[43]. In Q2 2026, Basslink capacity to Tasmania was predominantly priced between $75 and $150/MWh, accounting for 76% of average transfer capacity, with the remaining 24% offered between $35 and $75/MWh (**Figure 70**). Capacity to Victoria was more broadly distributed across price ranges, with 35% offered between $15 and $35/MWh. A further 28% was offered in the $75 to $150/MWh price range and 25% offered between $35 and $75/MWh, with the remaining capacity offered at higher prices.

Compared to Q2 2025, transfers from Victoria to New South Wales rose by 60 MW (+17%), with the increase mainly overnight from 2200 hrs to 0600 hrs, when average spot prices in New South Wales were $30/MWh above Victoria. Transfers from Victoria into South Australia also increased slightly (+9 MW), with higher flows concentrated during daytime hours between 0900 hrs and 1700 hrs, when spot prices in South Australia averaged $14/MWh higher than Victoria.

[43] Basslink has transitioned its network service classification from an MNSP to a TNSP on 1 July 2026. Coinciding with this, first settlement residue auctions (SRAs) for Basslink interconnector residues were held in June 2026.

Figure 69 Basslink transfers to Tasmania reduced across all hours

Average Basslink flow by time of day

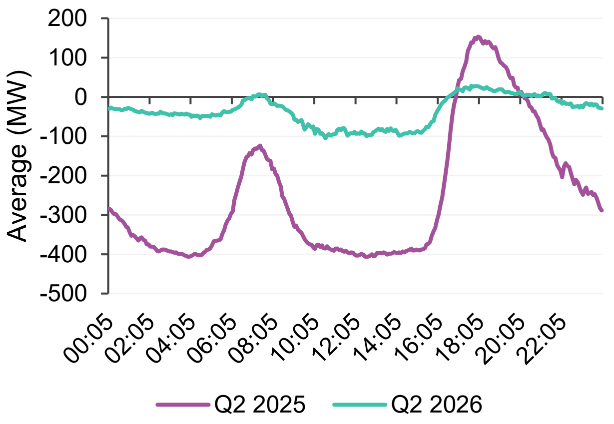
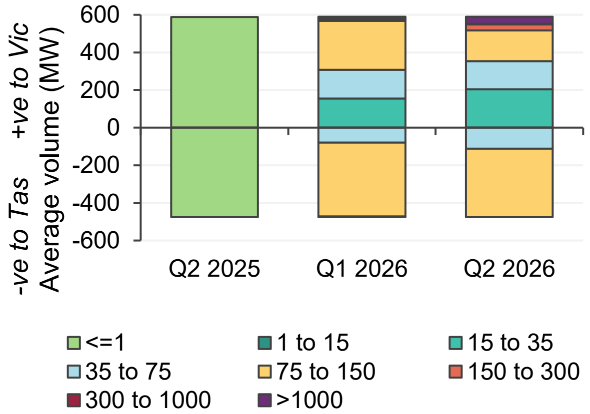


Figure 70 Majority of Basslink capacity to Tasmania offered at prices $75-$150/MWh

Basslink MNSP offers, average transfers capacity (MW) offered by price range ($/MWh)



2.6.1 Inter-regional settlement residue (IRSR)

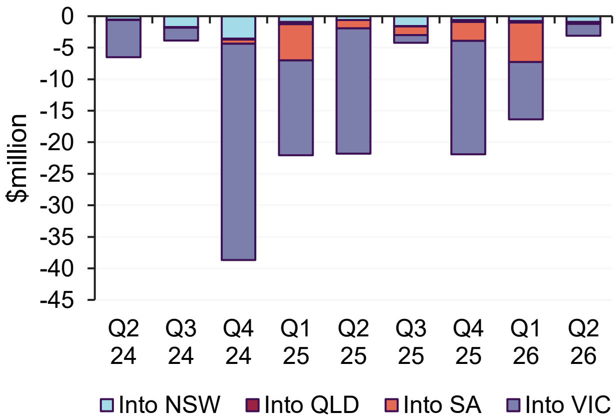
Positive IRSR totalled $70 million this quarter, representing a year-on-year decrease of $67 million (-49%) (**Figure 71**). The reduction was primarily driven by lower residues into New South Wales from Queensland, which totalled $15 million, down $77 million (-83%) compared to the same period last year, reflecting reduced price volatility in New South Wales this quarter (see **Figure 17** in Section 2.2.2).

Figure 71 Significant decrease in positive IRSR into New South Wales

Quarterly positive IRSR by region

Figure 72 Negative IRSR decreased year-on-year

Quarterly negative IRSR by region



Negative IRSR declined from $22 million in Q2 2025 to $3.1 million this quarter, largely reflecting lower residues into Victoria from New South Wales after transmission outage-related constraints contributed to elevated negative IRSR in Q2 2025 (**Figure 72**).

2.7 Frequency control ancillary services (FCAS) and frequency performance payments (FPP)

In Q2 2026, total FCAS costs were $9.2 million, equivalent to approximately 0.3% of the cost of consumed energy[44] over this quarter. Compared to Q2 2025, total FCAS costs decreased by $14 million (-61%), with reduced costs across all regions (**Figure 73**). The reduction in FCAS costs was spread across regulation services and most contingency services. Raise regulation (RREG) comprised the largest proportion of total FCAS costs for the quarter, at $2.4 million (**Figure 74**).

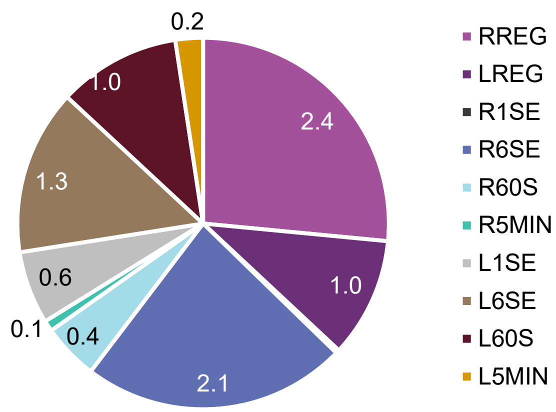
The contingency raise 6-second (R6SE) service was the next largest contributor, at $2.1 million of total FCAS costs, with costs primarily incurred in Tasmania. This reflected an increase in the number of intervals where Basslink was unable to transfer FCAS[45] due to flow levels being within its 'No-Go' zone of approximately -50 MW to 50 MW, with the share of these intervals increasing from 3% in Q2 2025 to 57% in Q2 2026.

Figure 73 FCAS costs reduced across all regions

Quarterly FCAS costs by region

Figure 74 RREG and R6SE accounted for the highest shares of total FCAS costs

NEM quarterly FCAS costs per service – Q2 2026 ($m)



Batteries remained the dominant providers of FCAS, increasing from 54% in Q2 2025 to 68% this quarter (**Figure 75**). Average battery enablement rose by 984 MW compared to Q2 2025, with highest enablement growth at Tarong (+518 MW), Melbourne Renewable Energy Hub (+311 MW), Latrobe Valley (+209 MW), Smithfield (+147 MW) and Greenbank (+141 MW). Hydro enablement increased across most contingency services, with raise and lower contingency services increasing by 34 MW and 87 MW, respectively. Enablement declined across other fuel types, with the largest reductions recorded for virtual power plants (VPPs), down 153 MW, followed by demand response (DR), down 91 MW (**Figure 76**).

Average total enablement increased by 786 MW compared to Q2 2025, driven by a 706 MW increase in Queensland lower contingency services enablement. This increase was primarily due to an increase in local requirements during the quarter associated with outages of lines out of Armidale impacting the Queensland – New South Wales interconnector (QNI).

44 Where the cost for consumed energy is the Adjusted Consumed Energy (ACE) amount, which comprises the costs for both the total consumed energy and the unaccounted-for energy allocation.

45 For additional detail on Basslink's capability to transfer FCAS, see Section 5.8 of AEMO's Constraint Formulation Guidelines: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/cfg-and-scvpf/final/constraint-formulation-guidelines-v12---final_.pdf.

Figure 75 Battery FCAS market share rose to 68%

FCAS volume market share by technology – Q2 2026

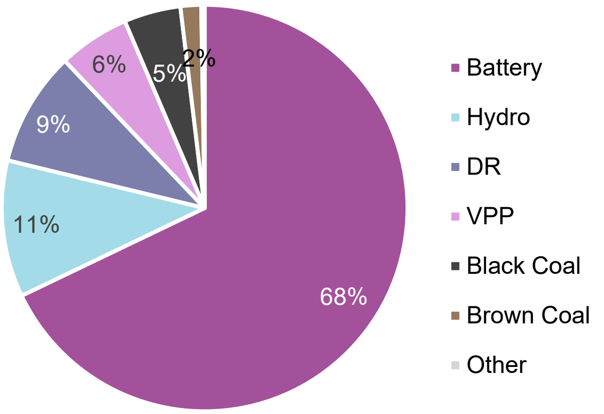
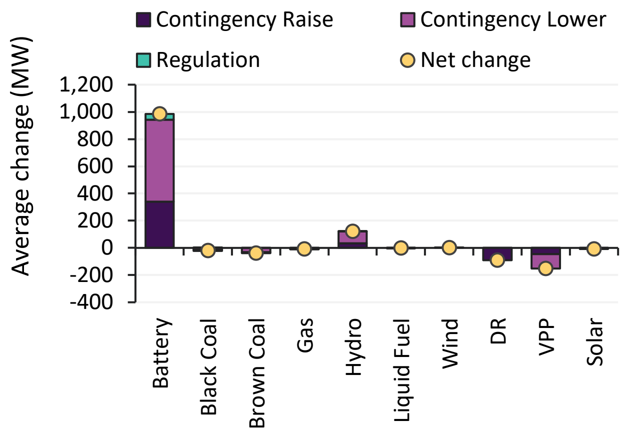


Figure 76 Battery enablement increased across all FCAS services

Change in FCAS enablement by technology – Q2 2026 vs Q2 2025

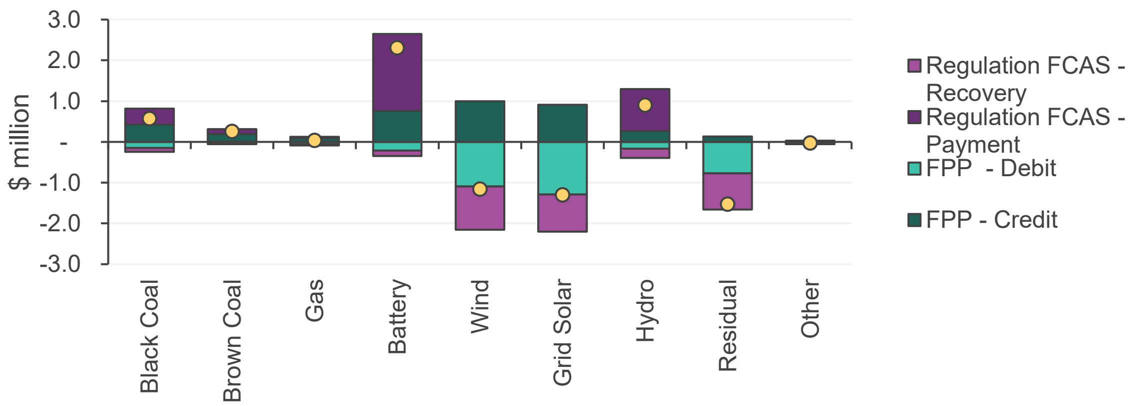


Regulation FCAS and FPP

In Q2 2026, costs for regulation FCAS were $3.5 million, down $6.4 million from Q2 2025, and a total of $3.8 million in FPP incentive payments were distributed. **Figure 77** illustrates the FPP credits and debits, and regulation FCAS payments and cost recovery by fuel type, in Q2 2026.

Figure 77 Batteries received highest share of FPP and FCAS net settlements

Sum of FPP and regulation FCAS recovery and payments by fuel type – Q2 2026



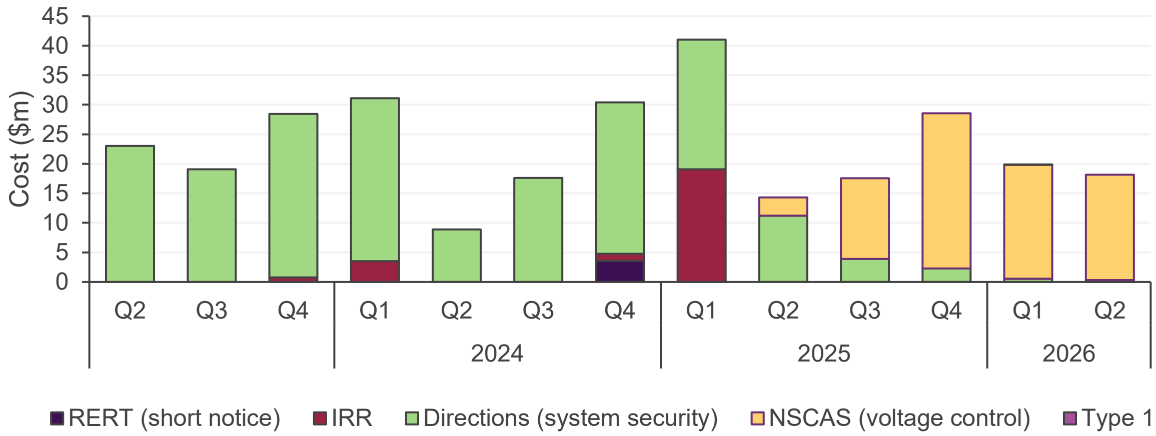
For batteries, hydro, black and brown coal-fired and gas-fired units, combined FPP credits and regulation FCAS payments offset the combined FPP debits and regulation FCAS recovery costs, with batteries receiving the large share of overall net settlements at $2.3 million. The residual category – which includes sites without appropriate metering to calculate individual contribution factors, such as small consumers and distributed resources – recorded the largest share of charges at -$1.5 million in net charges. Grid-scale solar units incurred the next largest share of charges, with -$1.3 million in total net FPP and regulation FCAS settlements, followed by wind units at -$1.2 million.

2.8 Power system management

In Q2 2026, power system management costs[46] were estimated at $18.2 million, representing approximately 0.5% of the total cost of consumed energy for the quarter, and increased by $3.9 million compared to Q2 2025 (**Figure 78**). All power system management costs were incurred in South Australia for voltage control, comprising combined costs for system security energy directions[47] and network support and ancillary services (NSCAS) costs.

Figure 78 Estimated power system management increased year-on-year

Estimated quarterly system security costs by category



2.8.1 South Australian voltage control

NSCAS services are primarily used to manage voltage control in South Australia, with directions issued only as a last resort when contracted services are insufficient. In Q2 2026, gas-fired generation was dispatched under NSCAS contracts, or directed where required, in 49% of dispatch intervals, compared with 37% in Q2 2025. This included 1.8% of intervals with directions in place (**Figure 79**). Over the same period, the share of dispatch intervals requiring two or more units simultaneously under contract or direction declined from 28% to 23%, reflecting the South Australian operating condition changes introduced in Q3 2025[48].

The volume of gas-fired generation required for voltage control through contracts or directions reached 34 MW in Q2 2026, compared with 28 MW in Q2 2025 (**Figure 80**). Dispatch for voltage control represented a 13% share of total gas-fired generation, up from 6% during the same quarter in 2025.

[46] 'Power system management costs' are those associated with Reliability and Reserve Trader (RERT), estimated compensation for system security directions for energy services, costs associated with NCSAS for voltage control, and costs associated with Type 1 transition contracts. Costs associated with reliability directions (including those to maintain a state of charge) and system security directions for other services (that is, operating as synchronous condenser) are not included because current quarter cost estimates are not available at the time this report is prepared. All direction reports are available on AEMO's website at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports.

[47] Participants directed for energy or market ancillary services receive an initial compensation amount determined using a price calculated as the 90th percentile of the relevant market 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.

[48] See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/related-resources/reduction-of-minimum-synchronous-generators-in-south-australia.pdf.

Figure 79 Decrease in two-unit requirement for voltage control

Percentage of time units simultaneously used for voltage control

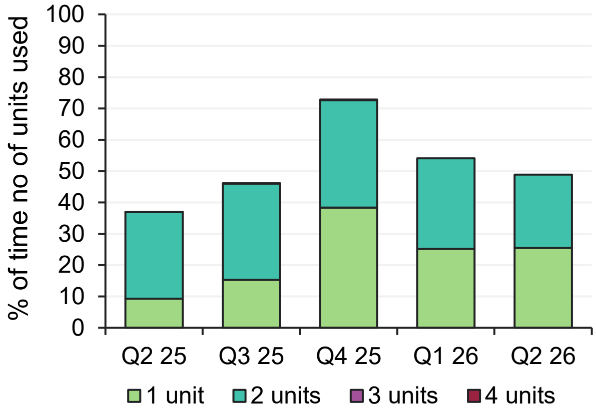
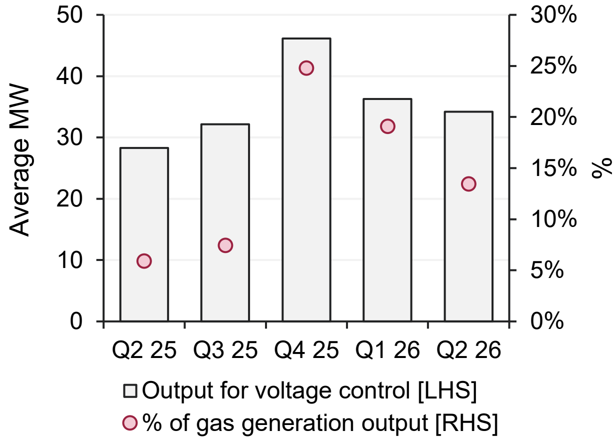


Figure 80 Increase in South Australian gas generation for voltage control

South Australian gas-fired generation for voltage control – volume and share



3 East coast gas market dynamics

3.1 Wholesale gas prices

Quarterly wholesale gas prices significantly decreased from Q2 2025, and were also 14% lower than Q1 2026. The average price across all AEMO markets was $9.08/GJ compared to $12.36/GJ in Q2 2025 (**Table 5**). This was the lowest average price for any quarter since Q2 2021.

Table 5 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q2 2026	Q1 2026	Q2 2025	Change from Q2 2025
Victoria Declared Wholesale Gas Market (DWGM)	8.39	10.50	11.60	-27%
Adelaide	9.27	10.61	12.90	-28%
Brisbane	9.32	10.56	12.40	-25%
Sydney	9.21	10.65	12.59	-27%
Gas Supply Hub (GSH)	9.18	10.63	12.31	-25%

Key factors influencing the movement of prices throughout Q2 2026 are summarised in **Table 6**, with further analysis and discussion in relevant sections elsewhere in this report.

Table 6 Wholesale gas price levels: Q2 2026 drivers

Lower offer prices into DWGM and Short Term Trading Market (STTM) in May and June	Q2 2026 saw average prices in May 15% lower and June 40% lower than Q2 2025, due to an increase in the proportion of volumes offered into the domestic market at prices below $12/GJ, which led to a reduction in the average price for the whole quarter (**Figure 82** below). June 2026 offers, in particular, were influenced by lower demand in AEMO markets and for gas-fired generation compared to June 2025.
Lowest Q2 gas-fired generation demand since 2003	As in Q4 2025 and Q1 2026, demand from gas-fired generation dropped to near record low levels due to increased wind output and battery discharge in the NEM. This put downward pressure on spot prices across all AEMO markets, particularly in June where low gas-fired generation demand combined with a change in market participant bidding behaviour.
Mild weather in June leading to decreased heating load requirements, particularly in Victoria	Above average temperatures in Victoria in Q2, but particularly in June when heating load typically increases, contributed to record low Q2 system demand in Victoria's DWGM, on top of impacts of electrification on gas demand.

International LNG spot prices were at their highest level since February 2023, reflected in an increase in the Australian Competition and Consumer Commission (ACCC) netback price to $20.84/GJ, materially higher than the average AEMO market price of $9.08/GJ.

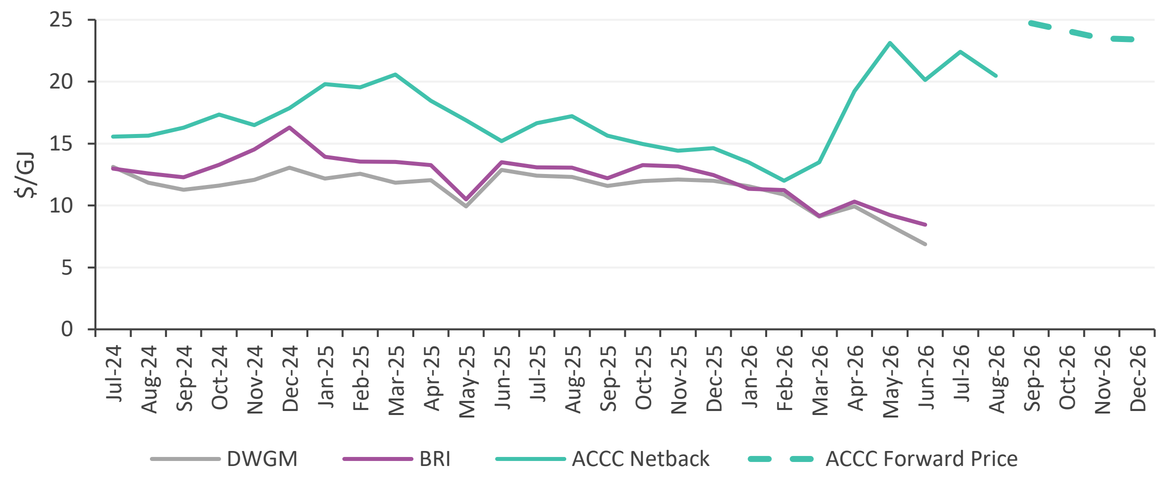
International prices began increasing at the start of March, amid heightened global supply risks linked to the conflict in the Middle East. The continuation of the conflict into April resulted in a further rapid increase in global energy prices, reflected in the sharp increase in the ACCC netback price, with corresponding forward prices ranging from $20.47/GJ to $24.73/GJ over the next six months (**Figure 81**). Drivers for international prices are discussed in Section 3.1.1 .

As observed in March 2026, AEMO domestic market prices diverged from international markets, and while April saw a small increase compared to March, prices dropped across all markets in May and especially in June, with the average price dropping to $7.96/GJ. This was the lowest average price for any month since May 2021. Prices were particularly low in the first half of June across all markets, dropping to $3.50/GJ in the Declared Wholesale Gas Market (DWGM) on 17 June, which was the lowest 6.00 am price since 7 May 2020. Lower prices reflected ample supply to the domestic market, which was experiencing low demand, particularly from gas-fired generation, but also from residential and commercial and industrial users, with the continuing impact of electrification and above average temperatures leading to decreased heating requirements, particularly in Victoria.

Prices increased in the second half of June, primarily driven by an increase in gas-fired generation with Iona storage inventory being utilised, but with demand not spiking to levels seen in 2025 or 2024, prices remained below June 2025 levels.

Figure 81 Domestic prices drop to lowest level for any quarter since Q2 2021

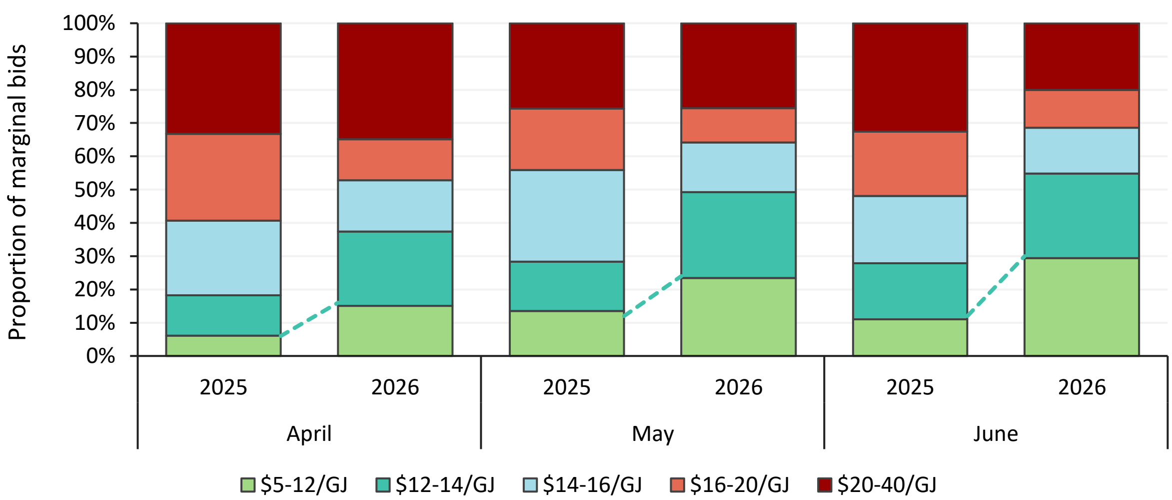
ACCC netback and forward prices, DWGM and STTM Brisbane average gas prices by month



Note: ACCC, LNG netback price series published on 16 July 2026: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

Figure 82 Increased proportion of DWGM bids in May and June at lower prices compared to 2025

DWGM – proportion of marginal bids by price band – Q2 2026 vs Q2 2025 by month

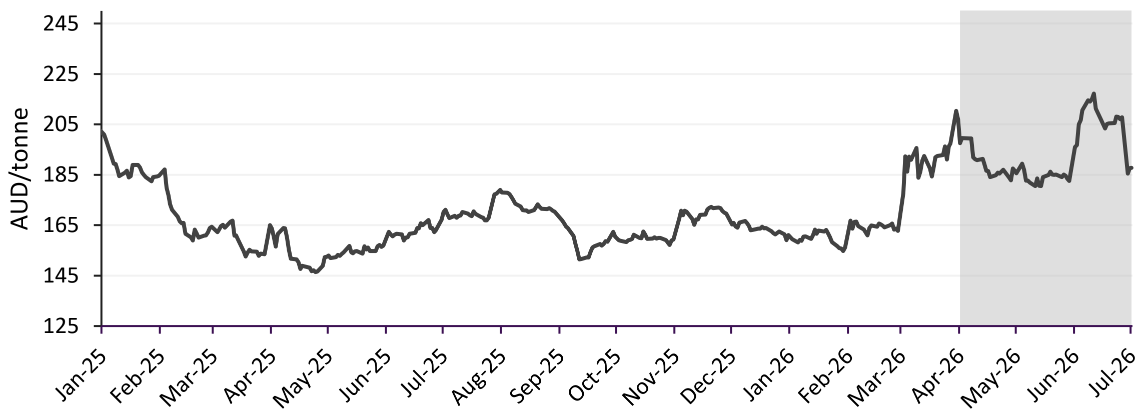


3.1.1 International energy prices

Newcastle export coal prices averaged $193/tonne in Q2 2026, increasing from $172/tonne in Q1 2026 and $157/tonne in Q2 2025 (**Figure 83**). Prices remained elevated as disruptions to shipping through the Strait of Hormuz persisted, with higher LNG prices supporting thermal coal prices through fuel-switching in markets where the two fuels can act as substitutes[49]. In mid-June, the prices rose above $215/tonne, supported by stronger demand from Japan and South Korea and concerns around coal supply from China and Indonesia[50].

Figure 83 Traded thermal coal prices remained elevated and volatile over the quarter

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



Source: Bloomberg ICE data.

Asian spot LNG prices experienced significant volatility across the Q2 2026 (**Figure 84**), largely as a residual effect of the conflict in the Strait of Hormuz that begun in Q1. The average price for the quarter jumped to a three-year high of A$23.50/GJ, up A$5.30/GJ, ending the quarter at A$22.20/GJ. The elevated LNG spot price forced some nations to look at fuel-switching to coal, hydro and nuclear power. There were also reports of some south Asian nations opting to load shed instead of importing spot LNG[51].

North Asian LNG demand reached its the highest level in five months, driven by a heatwave in Japan and an increased demand for gas from the industrial sectors in China. Domestic gas production in China declined by 2.1% (year-on-year) and storage levels were approximately 46% below the five-year seasonal average, requiring the nation to continue spot LNG purchases[52].

European gas storage injections remained behind seasonal targets, with the resulting inventory shortfall emerging as a key driver of competition for LNG cargoes between the Atlantic and Pacific basins. European Union gas storage levels entered the 2026 injection season at their lowest storage level since 2018, and by the end of the quarter had only filled to 45.1%

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[49] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly June 2026: https://www.industry.gov.au/publications/resources-and-energy-quarterly-june-2026.

[50] China mine disaster, Indonesia policy changes upend global coal market, June 2026: https://www.reuters.com/business/energy/china-mine-disaster-indonesia-policy-changes-upend-global-coal-market-2026-06-16/.

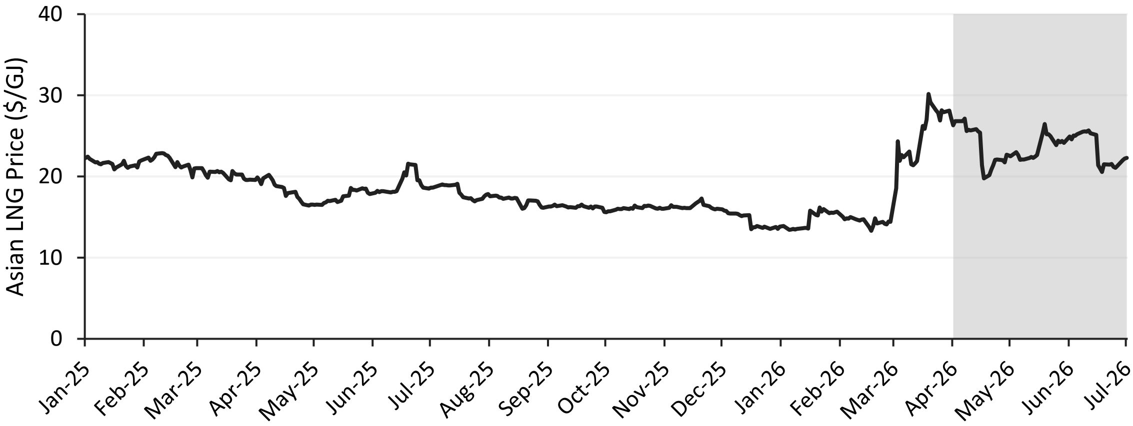
[51] Energy Connects, The Market Outlook for Gas and LNG and Asia, June 2026: https://www.energyconnects.com/opinion/features/2026/june/the-market-outlook-for-gas-and-lng-in-asia/

[52] Bloomberg, China's June LNG Imports Seen in Line with Last Year, Kpler Says, June 2026: https://www.bloomberg.com/news/articles/2026-06-29/china-s-june-lng-imports-seen-in-line-with-last-year-kpler-says.

(the lowest since 2021)[53]. At least 11 Atlantic Basin cargoes were reported to have been diverted from Europe and rerouted to Asia via the Panama Canal and Cape of Good Hope[54].

Figure 84 Asian LNG spot prices experienced significant volatility across Q2 2026

Asian LNG price in A$/GJ daily



Source: Bloomberg ICE data.

Similar to LNG spot markets, Brent Crude Oil prices faced volatile periods in April and May (**Figure 85**). Brent averaged A$136/barrel across Q2 2026 and prices began to decline sharply towards quarter end (falling to A$106/barrel) as a Memorandum of Understanding (MoU) was agreed to for a ceasefire[55]. This allowed for increased vessel movements through the Strait of Hormuz, with daily transits reaching 57 vessels on 24 June[56]. However, tensions escalated, which saw drone attacks on container ships and crude oil tankers leading to reduced transit volumes to around 25 vessels per day in the final days at the end of Q1.

Movement through the Strait of Hormuz continued to be well below pre-conflict levels of 125-140 commercial vessel transits per day[57]. Another factor adding to softening prices in June was increased non-OPEC+[58] production, particularly from the Americas, which added downward pressure to Brent crude oil prices by supporting greater Atlantic Basin crude exports to Asia. Strategic petroleum reserve releases also helped ease some of the supply disruption associated with the ongoing conflict in the Persian Gulf. Notably, Organisation for Economic Co-operation and Development (OECD) government oil inventories fell by 163 million barrels during May (equivalent to 1.8 million barrels per day), reaching their lowest level since December 1990[59].

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[53] Swiss Federal Office of Energy, June 2026: https://energiedashboard.admin.ch/gas/eu-gasspeicher.

[54] NGI, US Shipping More LNG to Asia, Setting Stage for Supply Battle With Europe Later in Year, June 2026: https://naturalgasintel.com/news/us-shipping-more-lng-to-asia-setting-stage-for-supply-battle-with-europe-later-in-year/.

[55] CNN, US releases official agreement with Iran. Read the 14-point text, June 2026: https://edition.cnn.com/2026/06/17/middleeast/us-iran-war-mou-text-intl

[56] Strait of Hormuz vessel numbers sourced from Bloomberg ICE data.

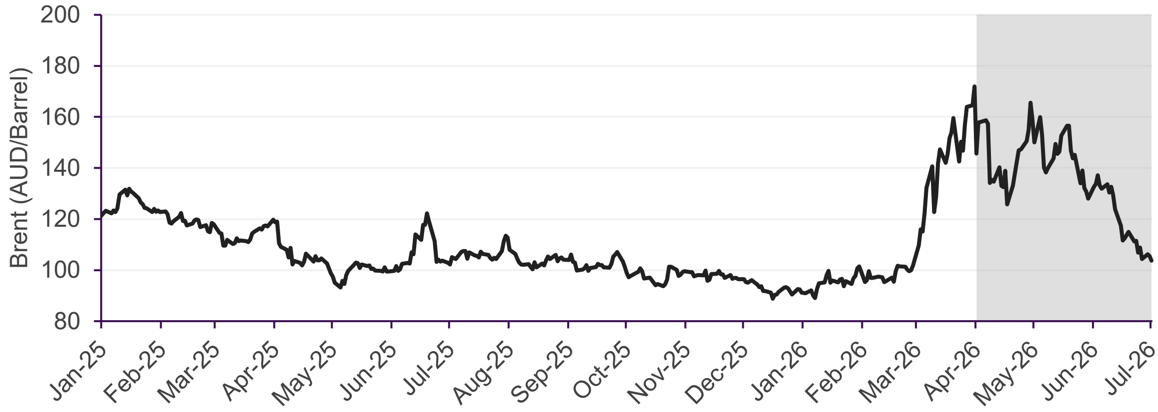
[57] Aljazeera, US launches second night of strikes on Iran after ship hit by drone, June 2026: https://www.aljazeera.com/news/2026/6/27/us-launches-second-night-of-strikes-against-iran-after-ship-struck-by-drone

[58] OPEC+ comprises OPEC and a broader alliance of non-OPEC oil-producing countries.

[59] International Energy Agency (IEA), Oil Market Report, June 2026: https://www.iea.org/reports/oil-market-report-june-2026

Figure 85 Brent Crude prices volatile in the first half of the quarter, began to soften by the end

Brent Crude Oil in A$/Barrel daily



Source: Bloomberg ICE data.

3.2 Gas demand

Total east coast gas demand decreased by 3% compared to Q2 2025 (**Figure 86** and **Table 7**). Gas-fired generation saw the largest fall in demand (-10 PJ), with AEMO markets demand also declining (-7 PJ). The majority of the AEMO market demand decrease occurred in Victoria's DWGM (-6 PJ), due to a combination of lower industrial, commercial and residential demand, and warmer temperatures. This decline continued the trend in commercial and industrial demand discussed in *Quarterly Energy Dynamics* (QED) reports throughout 2025 and Q1 2026, and is discussed further in Section 3.2.2. Queensland LNG production saw a small increase of 3 PJ.

Figure 86 Large reduction in market demand and gas-fired generation

Components of east coast gas demand change – Q2 2026 to Q2 2025

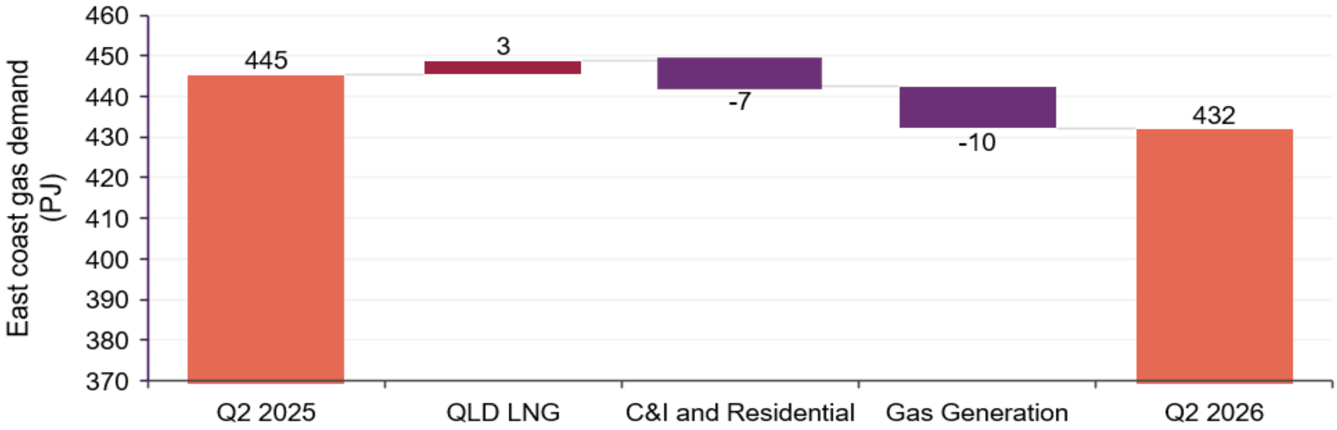


Table 7 Gas demand – quarterly comparison

Demand (PJ)	Q2 2026	Q1 2026	Q2 2025	Change from Q2 2025
AEMO markets *	69.5	45.5	76.0	-7 (-9%)
Gas-fired generation **	20.3	13.3	30.5	-10 (-33%)
Queensland LNG	342.4	364.6	338.9	3 (1%)
Total	432.2	423.3	445.5	-13 (-3%)

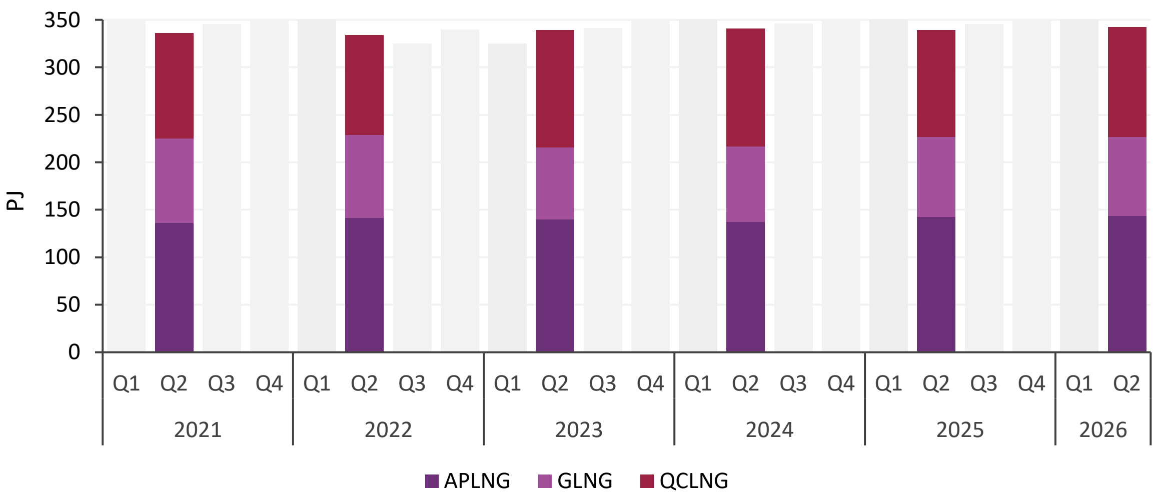
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand increased compared to Q2 2025, due to increases in Queensland Curtis LNG (QCLNG) and Australia Pacific LNG (APLNG) demand, offset by a small decrease in Gladstone LNG (GLNG) demand. The increases can be attributed to slightly shorter planned maintenance durations compared to Q2 2025. Although only a modest increase from Q2 2025, the combined total demand of 342.4 PJ is a record for LNG export demand for Q2, surpassing the previous record of 341.0 PJ set in Q2 2024 (**Figure 87**). While a record for Q2, higher export volumes have typically occurred during Q1 and Q4.

By participant, in comparison to Q2 2025, QCLNG demand increased by 3.6 PJ, while APLNG increased by 1.6 PJ and GLNG decreased by 1.7 PJ.

Figure 87 Queensland LNG export demand increases to new Q2 high

Total quarterly pipeline flows to Curtis Island



3.2.1 Gas-fired generation

Gas-fired generation decreased by 33% compared to Q2 2025. The largest declines were in New South Wales (-3.2 PJ) and Victoria (-2.7 PJ). Similarly to Q1 2026, lower demand for gas-fired generation reflected higher wind output and battery discharge in the NEM. Consistent with previous years, June was the highest month for gas-fired generation (**Figure 88**). The significant decreases across all months led to the lowest Q2 demand for gas-fired generation since Q2 2003 (**Figure 89**).

Figure 88 Large declines in gas-fired generation demand across all mainland regions

Average daily gas-fired generation by state

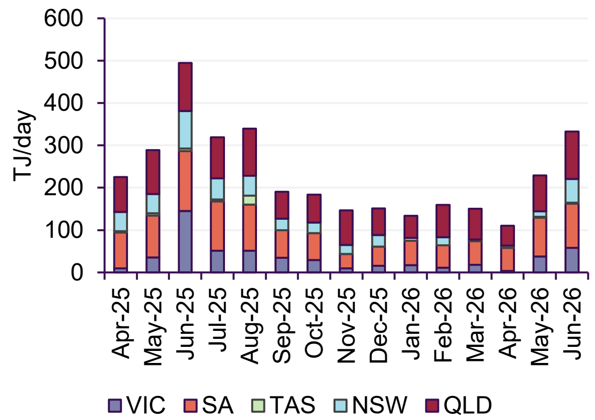
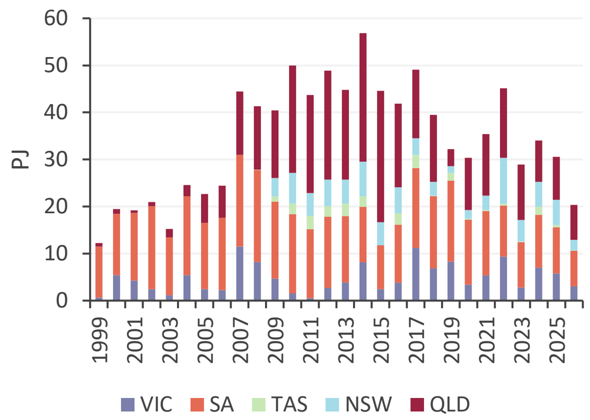


Figure 89 Lowest Q2 demand for gas-fired generation since 2003

Q2 gas-fired generation by state



3.2.2 Victorian Declared Wholesale Gas Market (DWGM) demand

In the Victorian DWGM, Tariff D customers are defined as large commercial and industrial users that consume more than 10 terajoules (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). Q2 2026 saw ongoing Tariff D demand decreases, with demand dropping from 13.7 PJ in Q2 2025 to 12.75 PJ in Q2 2026, a 7% decrease (**Figure 90**).

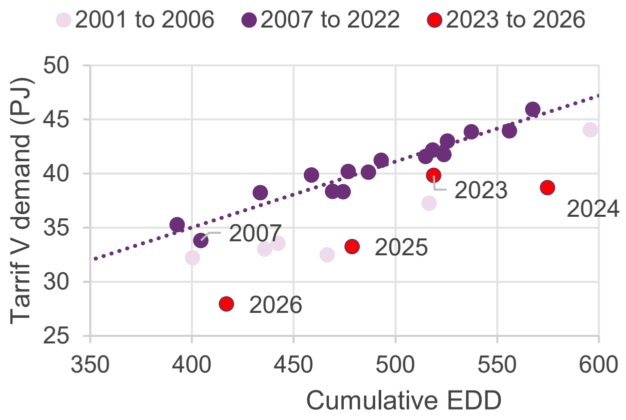
Figure 90 DWGM Tariff D demand continues to decline

Q2 DWGM Tariff D Demand

Tariff V demand fell to the lowest level since at least 2000. 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. Tariff V demand was materially lower than in previous comparable warm Q2 periods, indicating that the decline was not solely weather-driven (**Figure 91**).

Figure 91 Tariff V demand decline not solely weather driven

Q2 Tariff V demand versus cumulative EDD 2001-2026



While Q2 2026 recorded the lowest cumulative EDD total since 2007, Tariff V demand was 5.9 PJ lower than in Q2 2007, despite that quarter being warmer. The 2026 *Victorian Gas Planning Report Update*[60] noted that this was likely due to the electrification of some gas use and reduced small commercial customer demand.

Government policies are also likely to be having an impact, with Tariff V reductions in 2024 and 2025 correlating with increased registrations of Victorian Energy Efficiency Certificates (VEECs) for space heating, water heating and weather sealing applications.

3.3 Gas supply

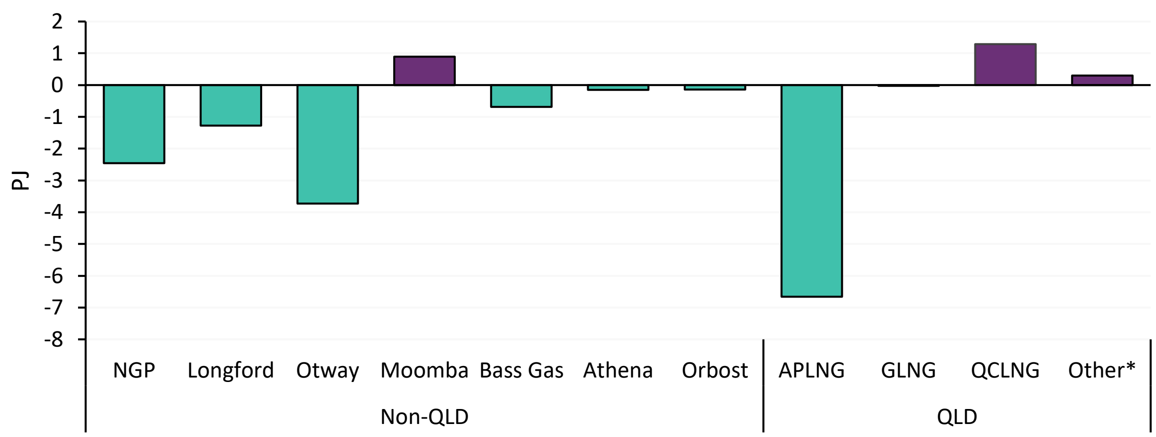
3.3.1 Gas production

East coast gas production decreased by 10.2 PJ (-2%) compared to Q2 2025 (**Figure 92**). Key changes included:

- Victorian production decreased by 6 PJ, driven by decreases at Otway (-3.7 PJ) and Longford (-1.3 PJ), and smaller decreases at Bass Gas (-0.7 PJ), Athena (-0.2 PJ) and Orbost (-0.1 PJ).
- Queensland production decreased by 5.1 PJ, with assets operated by APLNG decreasing by 6.7 PJ due to maintenance, while GLNG remained steady, and QCLNG operated assets increased by 1.3 PJ. Gas demand for Queensland LNG exports increased by 3.5 PJ, resulting in 8.6 PJ less supply associated with Queensland LNG projects entering the domestic market compared to Q2 2025, marking the lowest Q2 level since Q2 2017 (**Figure 93**).

Figure 92 Production fell due to Lower Queensland and Victoria output

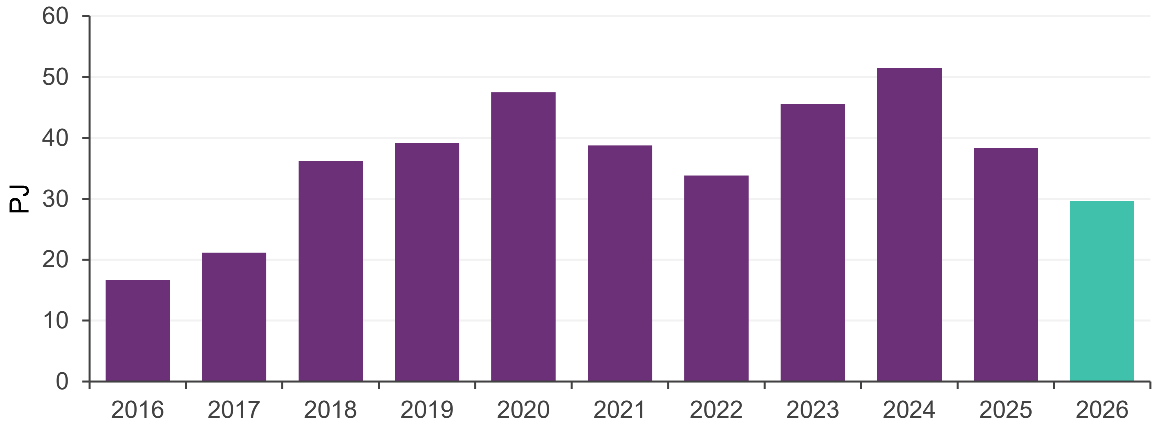
Change in east coast supply – Q2 2026 vs Q2 2025



[60] https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report

Figure 93 Queensland Q2 2026 net domestic supply decreased to lowest level since 2017

Queensland net domestic supply during Q2



3.3.2 Northern Territory supply

Northern Territory demand was supported by flows from Queensland, up to 30 TJ/day, with only limited emergency gas inflows from the Ichthys LNG facility of less than 5 TJ/day. The Yelcherr Gas Plant remained offline, following the outage at the offshore Blacktip gas field platform caused by Tropical Cyclone Fina in November 2025.

Industrial action at the Ichthys LNG facility began in early June, disrupting LNG loadings, delaying cargoes, and temporarily shutting down one LNG production train. INPEX and unions reached an in-principle agreement on 17 June, after which operations returned to normal and cargo loading resumed.

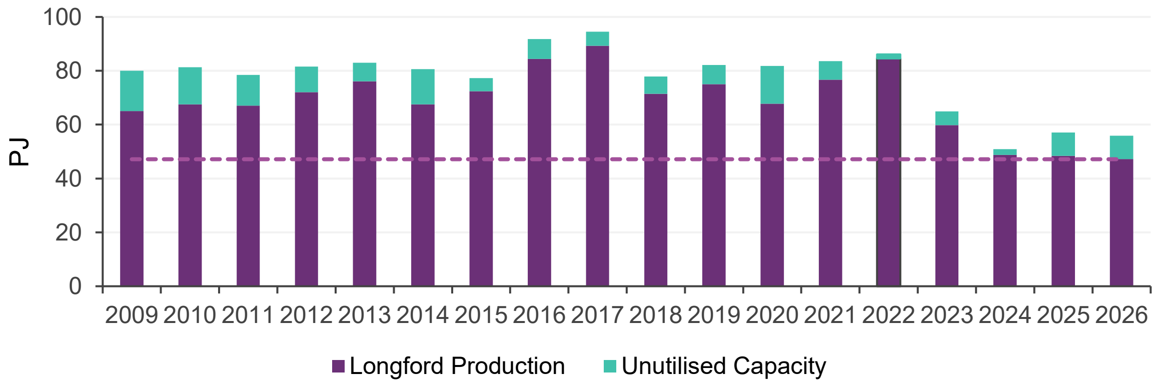
3.3.3 Longford production and capacity

Longford's gas production in Q2 2026 was largely in line with the same period in 2025, reaching 47.1 PJ compared to 48.4 PJ. Available production capacity of 55.9 PJ was slightly compared to Q2 2025, which was 57.1 PJ (**Figure 94**).

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 84%. This gap was largely due to Longford supply offers continuing to exceed daily price outcomes in the DWGM and Sydney STTM.

Figure 94 Longford Q2 production remained steady

Longford Q2 production and unutilised capacity



Longford Plant Outage

On 28 June 2026, the Longford Gas Plant experienced an unplanned outage of around 10 hours, following an internal power failure and trip of the Gas Conditioning Plant that resulted in off-specification gas being produced and the subsequent trip of Gas Plants 2 and 3 (a full plant outage) resulting in no production. AEMO issued a constraint notice for reduced Longford supply at 9.49 am, which was revised at 1.35 pm to reflect Longford being offline until 10.00 pm.

AEMO determined that sufficient linepack was available in the Declared Transmission System (DTS) to manage the event without intervention in the DWGM, although operational constraints remained.

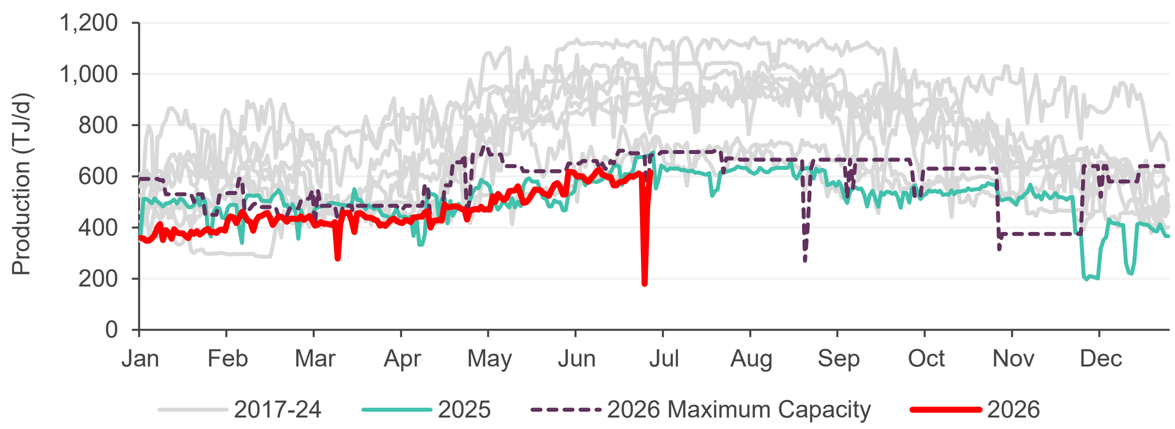
At 4.30 pm, AEMO convened an East Coast Gas System (ECGS) Gas Supply Adequacy and Reliability Conference[61]. AEMO assessed that if Longford remained unavailable for the following day, supply would be tight but manageable without supply from Dandenong LNG, although some Newcastle LNG and additional Queensland supply may be required. AEMO did not declare an ECGS supply threat but requested participants increase supply from alternative sources where possible.

Longford resumed on-specification supply into the DTS from around 7.00 pm, with steady supply from 8.00 pm. AEMO advised that no further industry conference was required. The plant continued ramping up on 29 June and returned to full capacity on 30 June. Longford production on the day was 180 TJ, compared to an average of 597 TJ/day from 1-27 June (**Figure 95**).

Both the Western Outer Ring Main (WORM), that was commissioned prior to winter 2024 along with the second Winchelsea compressor, and the full duplication of the Victorian Northern Interconnection (VNI) to Barnawartha, near Wodonga in northern Victoria, that was completed prior to winter 2018, provided additional linepack and supply capacity from Port Campbell for managing the system during the incident. These pipeline expansions were not available during the 1 October 2016 7-hour unplanned Longford full plant outage when AEMO issued a Notice of a Threat to System Security and intervened in the DWGM, resulting in over $3 million of ancillary payments and uplift. AEMO has previously highlighted increased Longford outage risk in recent *Victorian Gas Planning Reports*, including the risk of a Gas Conditioning Plant outage.

Figure 95 Longford unplanned plant outage on 28 June dropped production to 180 TJ

Daily Longford production 2017-2026, maximum capacity profile 2026



[61] https://www.aemo.com.au/energy-systems/gas/east-coast-gas-system/ecgs-reports-and-notices

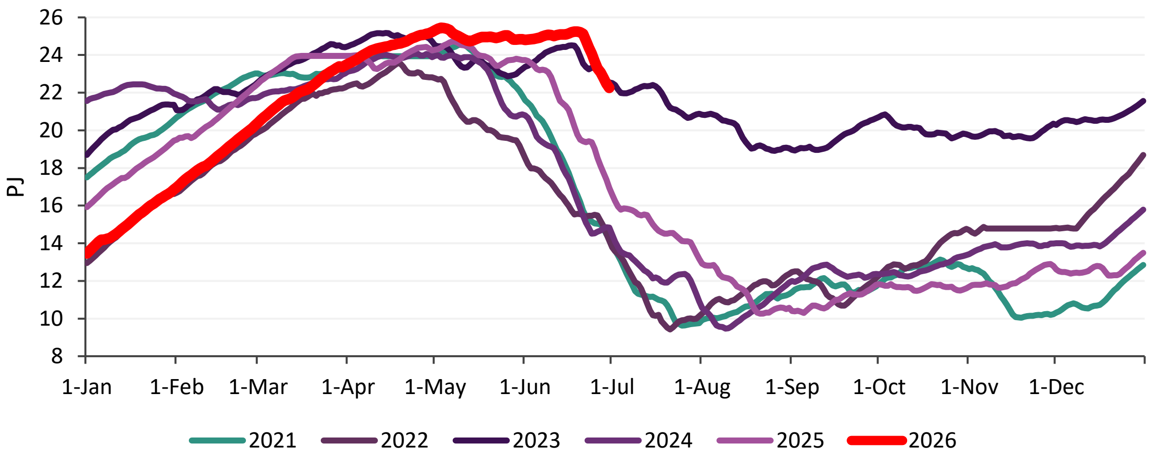
3.3.4 Gas storage

Iona UGS finished the quarter with a gas balance of 22.3 PJ, 5.3 PJ higher than at the end of Q2 2025 (**Figure 96**). The only year in which Q2 finished with a higher gas balance was 2023, which finished the quarter with 22.6 PJ.

Iona inventory began June at 24.8 PJ, higher than its reported maximum capacity of 24.4 PJ, and 1.1 PJ higher than at the start of June 2025, when storage levels were near full. This reflects lower demand in April and May 2026. Storage levels even began to increase during the month, peaking at 25.3 PJ on 19 June, reflecting mild weather, low gas-fired generation demand, and ample supply from Queensland. Higher demand from 22 June onward, particularly from gas-fired generation, saw Iona begin to draw down on its inventory.

Figure 96 Iona storage was largely unutilised until higher demand from 22 June

Iona storage levels

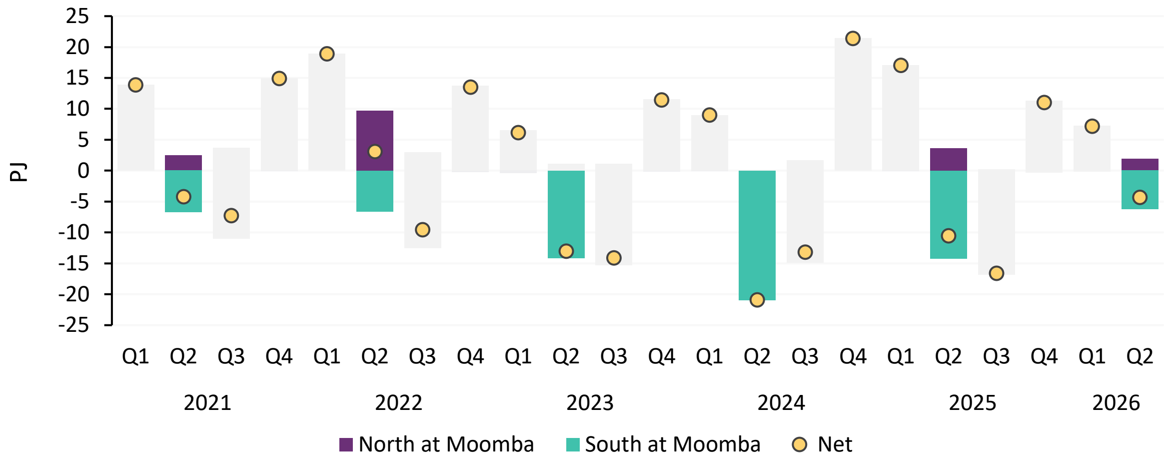


3.4 Pipeline flows

Compared to Q2 2025, there was a 6.3 PJ decrease in net transfers south to Moomba from the South West Queensland Pipeline (SWQP, **Figure 97**). This represents the lowest southerly Q2 SWQP transfer since 2021. Decreased flows south coincided with lower industrial, commercial, and residential demand (see **Figure 90** and **Figure 91** in Section 3.2.2) in the Victorian DWGM, particularly in the early and middle parts of the quarter.

Figure 97 Lowest Q2 net transfers south at Moomba from the SWQP since 2021

Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states decreased by 2.9 PJ compared to Q2 2025, due to demand reductions in AEMO markets and for gas-fired generation (**Table 7** in Section 3.2). State by state, Victoria exported 1.1 PJ less to New South Wales, 1.6 PJ less to South Australia, and 0.3 PJ less to Tasmania (**Figure 98**). Lower demand across the east coast gas system led to lower pipeline flows from Wallumbilla via Moomba to New South Wales, South Australia and Victoria, although flows to Curtis Island, Gladstone and the Northern Territory increased (**Figure 99**).

Northern Gas Pipeline (NGP) flows from Queensland into the Northern Territory averaged 9 TJ/day during the quarter. The increased utilisation reflected lack of emergency gas supply from the Ichthys LNG facility into the Wickham Point Pipeline (WPP) while industrial action involving the Offshore Alliance and INPEX remained unresolved, however the dispute was settled in late June 2026.

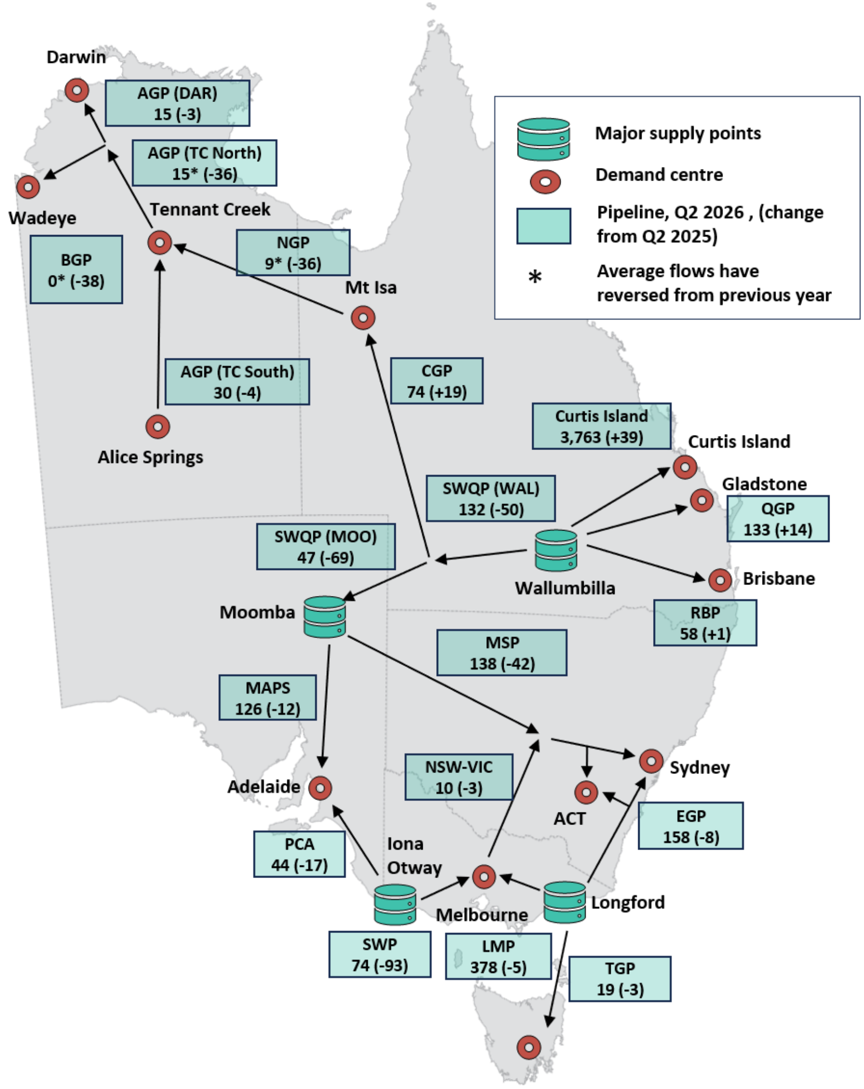
Demand at Mount Isa was supplied solely from Queensland via the Carpentaria Gas Pipeline (CGP), which increased by 1.7 PJ compared with Q2 2025, and just over 2 PJ compared with Q1 2026. Increased deliveries on the CGP were not limited to flows towards the Northern Territory, with commercial and industrial demand in central Queensland also rising by around 1.2 PJ, largely due to higher gas usage at both Phosphate Hill and Mount Isa Mines facilities compared with Q1 2026.

Figure 98 Decrease in Victorian Q2 exports to New South Wales and South Australia in 2026

Victorian net gas transfers to other regions during Q2

Figure 99 Reduced flows south to Victoria reflecting large demand decrease

Average daily pipeline flows TJ/day Q2 2026 vs Q2 2025

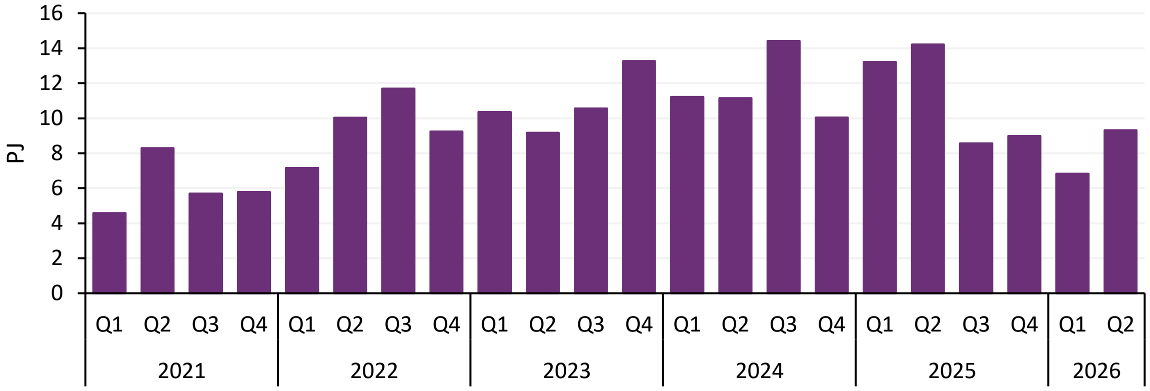


3.5 Gas Supply Hub (GSH)

In Q2 2026, traded volumes on the GSH increased by just under 2.5 PJ compared to Q1 2026 (**Figure 100**). The traded volume this quarter was 9.3 PJ, which was highest quarter traded volume since Q2 2025. GSH trading activity was notably elevated during certain periods of the quarter. The periods of elevated trading coincided during periods of reduced gas deliveries to the Curtis Island LNG facilities and higher levels of gas-fired generation across the NEM.

Figure 100 Highest quarterly traded volume since Q2 2025

Gas Supply Hub – quarterly traded volume



3.6 Pipeline capacity trading and Day Ahead Auction

Day Ahead Auction (DAA) volumes decreased by 1.8 PJ in comparison to Q2 2025 (**Figure 101**). Compared to Q1 2026, there were notable decrease on the Eastern Gas Pipeline (EGP, -1.3 PJ), SWQP (-1.2 PJ) and VicHub (-0.8 PJ).

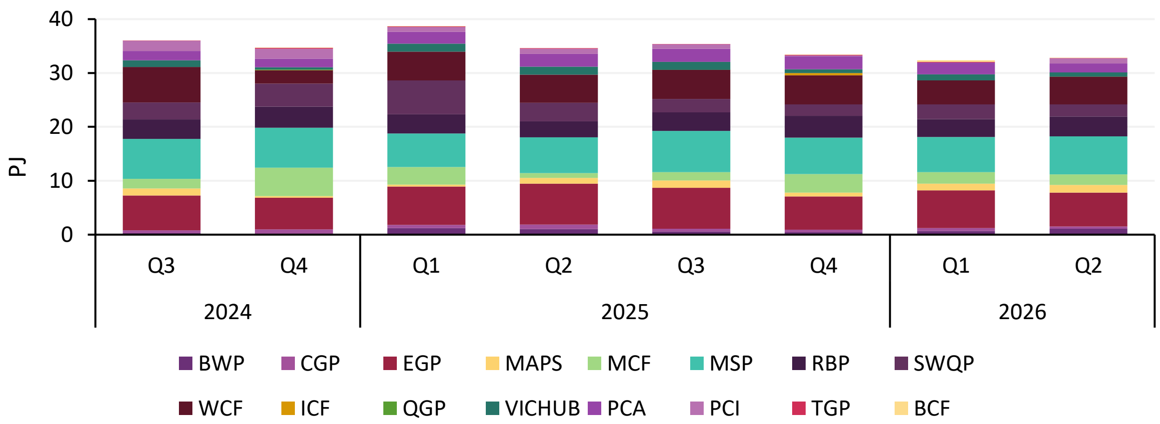
Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were:

- the EGP, which averaged $0.18/GJ,
- the SWQP, which averaged $0.15/GJ,
- the Moomba to Sydney Pipeline (MSP), which averaged $0.14/GJ, and
- the Roma to Brisbane Pipeline (RBP) and the Moomba to Adelaide Pipeline (MAPS), which both averaged $0.06/GJ.

Swap products continued to be actively traded on the GSH following their introduction in March 2025. Total swap volumes traded during Q2 2026 reached 328 TJ. While historical swap activity had been limited between Wilton and Wallumbilla, trading activity expanded beyond this product route during the quarter, with 93 TJ of Moomba to Wallumbilla swaps transacted.

Figure 101 Day Ahead Auction volumes remain steady

Day Ahead Auction volumes by quarter



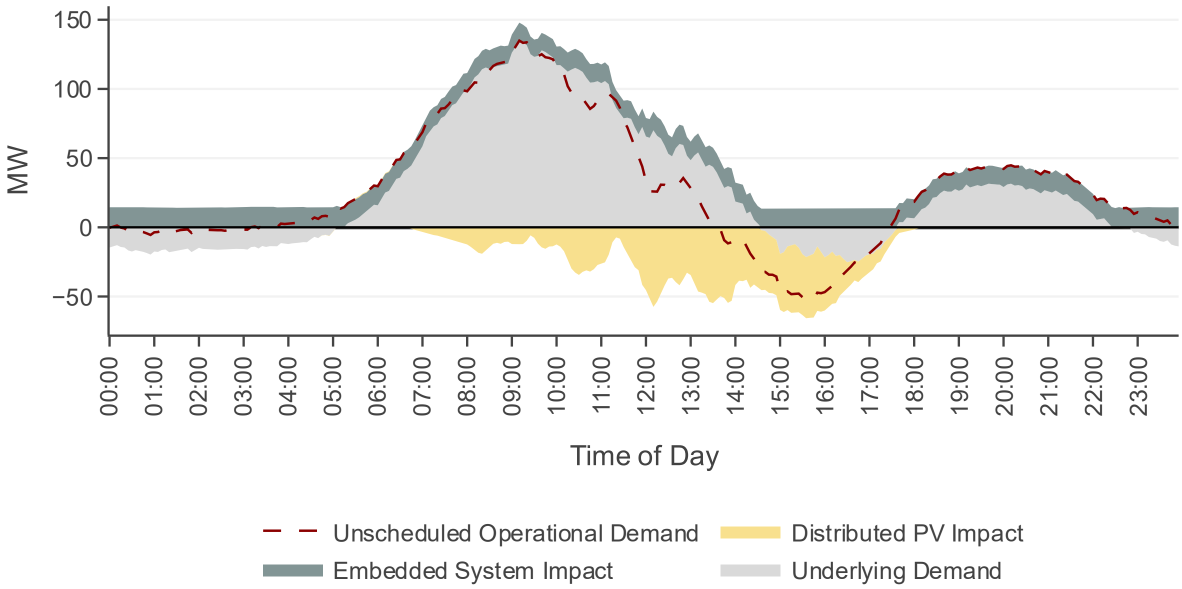
4 WEM market dynamics

4.1 Electricity demand

Average unscheduled operational demand[62] was 2,046 MW in Q2 2026, an increase of 28 MW (+1.4%) compared to Q2 2025 (**Figure 102**). This was primarily driven by an increase in average underlying demand[63] of 38 MW (+1.6%). While a decrease in average embedded system[64] impact of 14 MW (-61%) contributed to the increase in unscheduled operational demand, this was partially offset by an increase in average distributed PV[65] generation of 12 MW (+3.4%). The increase in average underlying demand can be attributed to a greater number of HDDs and lower maximum and minimum temperatures. The average daily maximum and minimum temperatures were -2.1°C and -1.6°C lower, respectively, than in Q2 2025.

Figure 102 Increased unscheduled operational demand driven by cooler temperatures

Change in WEM average unscheduled operational demand components by time of day – Q2 2025 vs Q2 2026



4.1.1 Consumer energy resources

Total WEM solar installations increased from 0.4 million at the end of 2020 to 0.6 million at the end of Q2 2026, with installed capacity increasing from 1.6 GW to 3.2 GW. Consistent with this growth trend, a further 173 MW of CER solar capacity has been installed over Q1 and Q2 of 2026 (**Figure 103**).

[62] Unscheduled operational demand sums the injection, in megawatts, from all scheduled facilities, semi-scheduled facilities and non-scheduled facilities that are injecting at the end of the dispatch interval, excluding scheduled demand driven by charging from Electric Storage Resources (ESR – batteries).

[63] Underlying demand is calculated by summing distributed PV generation and unscheduled operational demand.

[64] 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.

[65] Distributed PV generation is an estimation based on solar irradiance data and installed distributed PV capacity data available to AEMO.

Household battery uptake grew significantly since July 2025 following the introduction of the Australian Government's Cheaper Home Batteries Program and the Western Australian Residential Battery Scheme (WARBS)[66]. On 1 May 2026, significant changes[67] took effect for all new and upgraded solar and battery systems in the South West Interconnected System (SWIS) (including an increased inverter size limit of 30 kilovolt amperes [kVa]), supporting the continued uptake of these renewable technologies. Clean Energy Regulator data[68] shows that WEM household storage capacity increased by 288 MWh (+39%) over Q2 2026, reaching 1,027 MWh, with the number of installations increasing by 11,823 (+33%) to more than 47,000 systems (**Figure 104**).

Figure 103 Growth in the WEM's solar capacity and installations since 2020

Cumulative CER solar capacity and installations

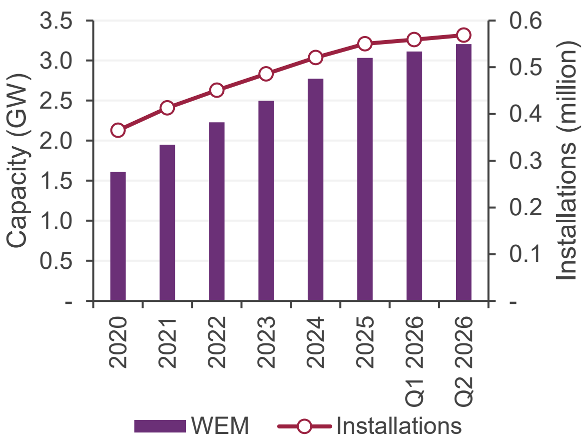
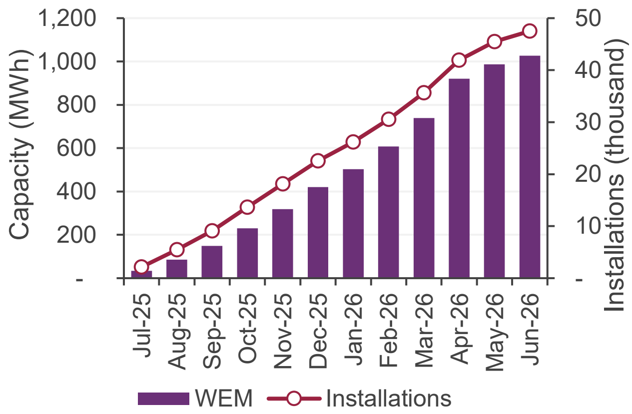


Figure 104 Growth in WEM's CER battery capacity

Cumulative CER battery capacity and installation



Source: Clean Energy Regulator

4.2 Electricity generation

Wind generation's share of the fuel mix in Q2 2026 was -2.48 pp lower than it was in Q2 2025, reflecting both major outages associated with an expansion of Warradarge Wind Farm and weaker wind conditions. Driven by periods of planned maintenance and forced outage, coal-fired generation's share of the fuel mix declined -6.11 pp. Primarily driven by these reductions in wind generation and coal-fired generation, gas-fired generation increased its share of the fuel mix by +8.30 pp. In Q2 2026 renewable generation comprised 32.0% of the fuel mix, a decline of -1.59 pp from 33.6% in Q2 2025.

Table 8 shows all Q2 2026 contributions, with average generation shown in **Figure 105**. The following key changes were observed since Q2 2025:

- Average coal-fired generation decreased by 137 MW (-17%). This was driven by reduced coal availability due to planned and forced outages, and the retirement of Muja C Unit 6 in Q2 2025.

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[66] https://www.wa.gov.au/organisation/energy-policy-wa/wa-residential-battery-scheme

[67] The new changes include increase in inverter size limit to 30 kVA (aggregate) for standard connections, requirement to enable remote disconnection and connection by the customers' electricity retailer or otherwise be export limited to 1.5 kW, and compliance requirement of all inverters with AS/NZS 4777.2:2020. See https://www.wa.gov.au/organisation/energy-policy-wa/new-requirements-small-scale-solar-and-battery-systems.

[68] Data from Clean Energy Regulator: https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data. Data current as of 30 June 2026, noting that a 12-month creation period for registration persons to create small-scale technology certificates applies, so figures for the previous 12-month period will continue to rise.

- Average wind generation reduced by 54 MW (-13%), driven by extensive planned outages associated with an expansion of Warradarge Wind Farm and weaker wind conditions.
- Average gas-fired generation increased by 216 MW (+27%).
- Average biomass generation increased 15 MW (+49%). This can be attributed to the commissioning of facility PHOENIX_KWINANA_WTE_G1, with a capacity of 43 MW, which commenced Commercial Operation in Q3 2025.
- Average embedded system impact decreased by 14 MW (-61%) due to the permanent retirement of ALCOA_KW_IL.

Table 8 WEM supply mix contribution by fuel type

Quarter	Coal	Gas	Distillate	Grid solar	Wind	Biomass	Hybrid	Hydro	Distributed PV	Embedded systems
2025 Q2	32.6%	32.8%	<0.1%	1.1%	16.9%	0.4%	0.5%	0%	14.7%	0.1%
2026 Q2	26.5%	41.1%	<0.1%	1.2%	14.4%	1%	0.5%	0%	15.0%	<0.1%
Change	-6.1 pp	8.3 pp	<0.1 pp	0.1 pp	-2.5 pp	0.6 pp	<0.1 pp	0 pp	0.3 pp	<0.1 pp

Figure 105 Higher underlying demand, and decreases in wind and coal-fired generation, were met by increased gas-fired generation

Change in quarterly average generation – Q2 2025 vs Q2 2026

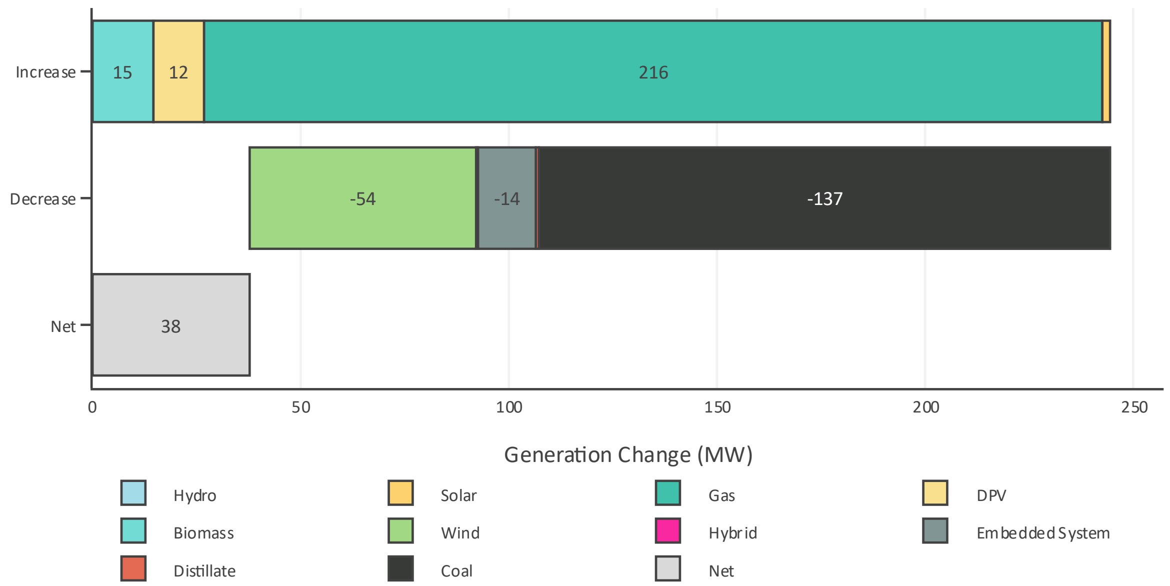
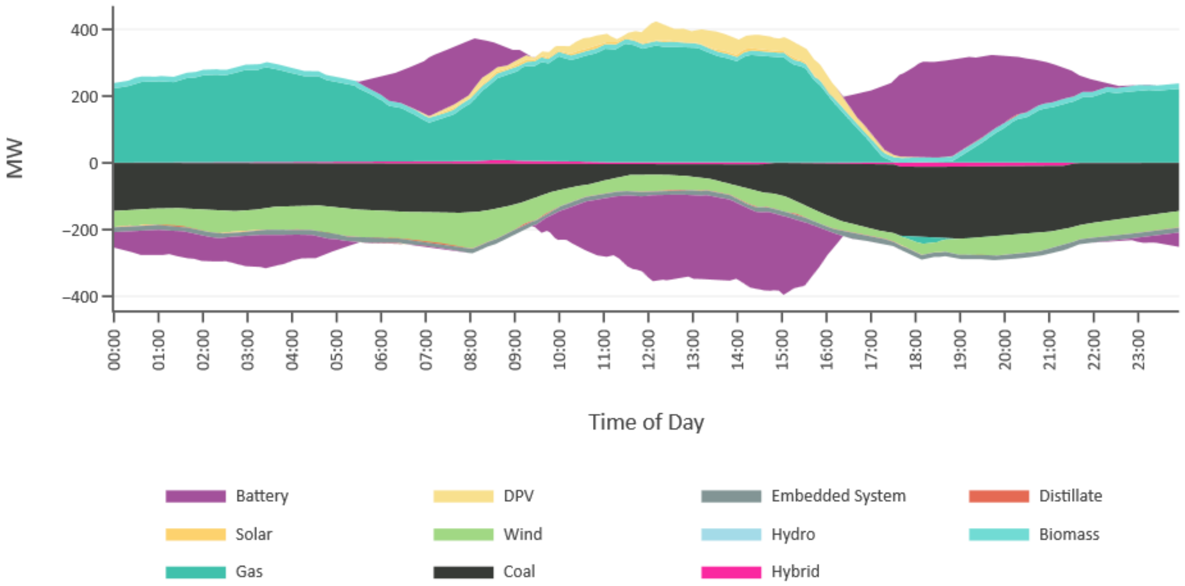


Figure 106 shows how the WEM's generation profile changed by time of day. Battery charging and discharging are included on net basis to show the storage-driven shifts that underpinned changes in generation across the day.

Figure 106 Increases in gas-fired generation and battery discharge balanced reduced wind and coal-fired generation at all times of day

Change in average WEM generation and storage by time of day – Q2 2025 vs Q2 2026

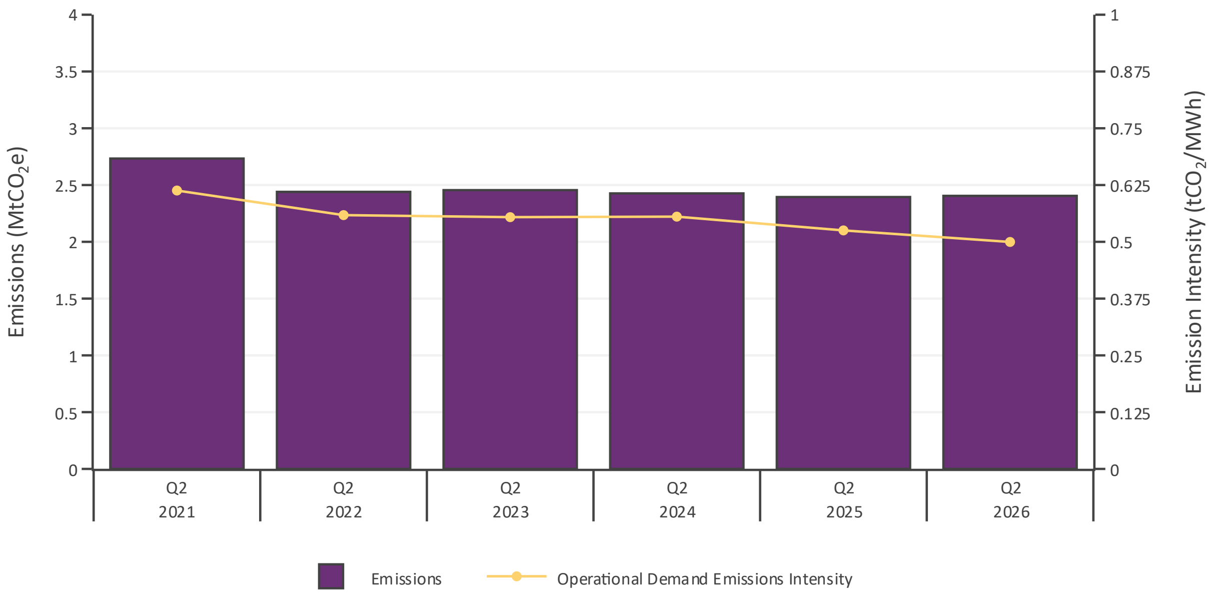


4.2.1 Carbon emissions

Total WEM emissions increased from 2.39 MtCO2-e in Q2 2025 to 2.40 MtCO2-e (+0.4%) in Q2 2026 (**Figure 107**). Despite reduced wind generation, the increase in total WEM emissions was marginal due to a reduced emissions intensity of 0.50 tCO2-e/MWh, down 0.03 tCO2-e/MWh (-16%) year-on-year, which can be attributed to the reduction in the share of the fuel mix taken by coal-fired generation.

Figure 107 Emissions remain stable Q2 on Q2 despite decreased average wind generation

Quarterly WEM emissions and emission intensity – Q2 2021 to Q2 2026

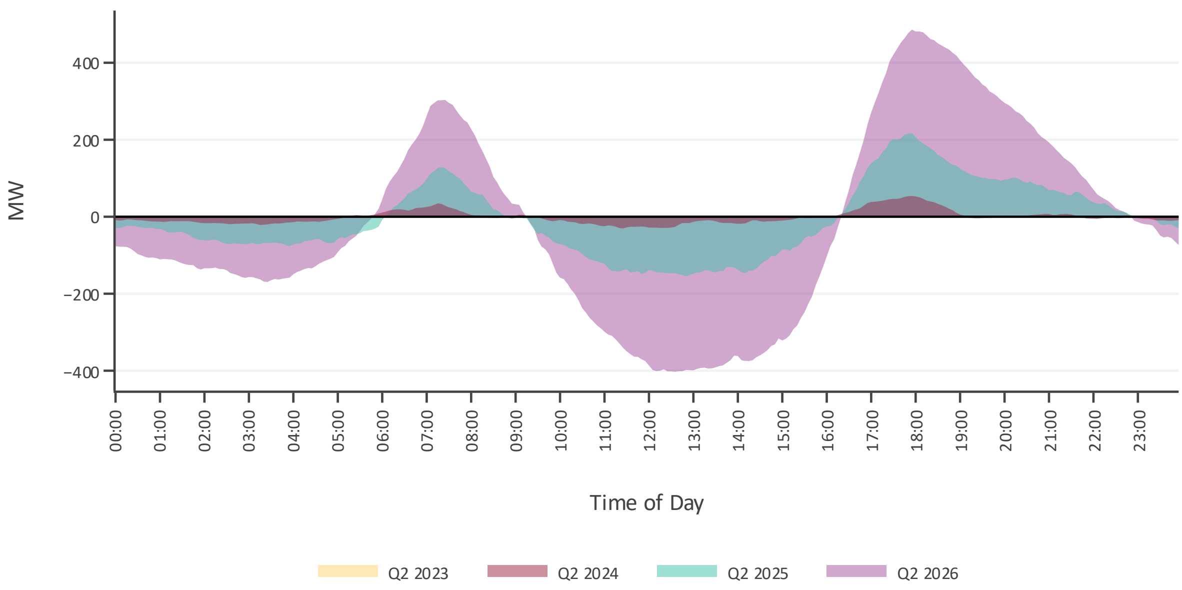


4.3 Electric Storage Resources (ESR)

In Q2 2026 average battery charging and discharging were 87 MW (+139%) and 76 MW (+142%) higher, respectively, than Q2 2025. These observations can both be attributed to an increase in battery capacity (see **Table 9** in Section 4.3.1). Batteries primarily charged during the middle of the day and discharged over the mid-morning and evening peaks (**Figure 108**). Q2 2026 saw two battery charging records, of 1,011 MW and 1,031 MW, occurring in the 28 April 1255 hrs and 3 June 1225 hrs intervals, respectively.

Figure 108 Battery discharge and charge volumes have increased year-on-year with increased battery capacity

Average battery energy injection/withdrawal, time of day – Q2s



4.3.1 ESR revenue

In Q2 2026, estimated net Real-Time Market revenue[69] for WEM grid-scale batteries, in aggregate, was $0.5 million, down $14.5 million (-97%) from Q2 2025 (**Figure 109**). Energy arbitrage revenues decreased by $4.6 million (-120%), from $3.9 million in Q2 2025 to -$0.8 million in Q2 2026. This marked the first quarter since grid-scale batteries began operating in the WEM that energy arbitrage netted a loss. FCESS revenue fell to $1.3 million in Q2 2026, a reduction of $9.9 million (-89%). Because net revenue from energy arbitrage was negative, FCESS revenue accounted for 100% of total WEM grid-scale battery revenue this quarter, up from 74% in Q2 2025 (**Figure 110**).

The reduction in FCESS revenue from Q2 2025 was driven by a significant increase in battery capacity (including FCESS-accredited battery capacity), with four battery systems having completed commissioning since Q1 2025 (**Table 9**). This led to increased competition in the FCESS markets, which resulted in lower FCESS prices, and therefore lower revenue, despite batteries taking a larger share of the FCESS markets.

[69] Battery estimated net Real-Time Market revenue comprises revenue from energy arbitrage – calculated as revenue from energy discharged (including charging at negative prices) net of charging costs – and revenue earned from FCESS. It excludes FCESS charges and other payments and charges including those relating to Energy Uplift, FCESS Uplift, Reserve Capacity (including Refunds), and NCESS. Revenue quantities are approximations based on dispatched quantities rather than metered values and do not account for Bilateral Contracts or Short Term Energy Market (STEM) trading.

Figure 109 Aggregated energy arbitrage and FCESS revenue fell year-on-year

Quarterly net revenue from WEM battery systems by revenue stream

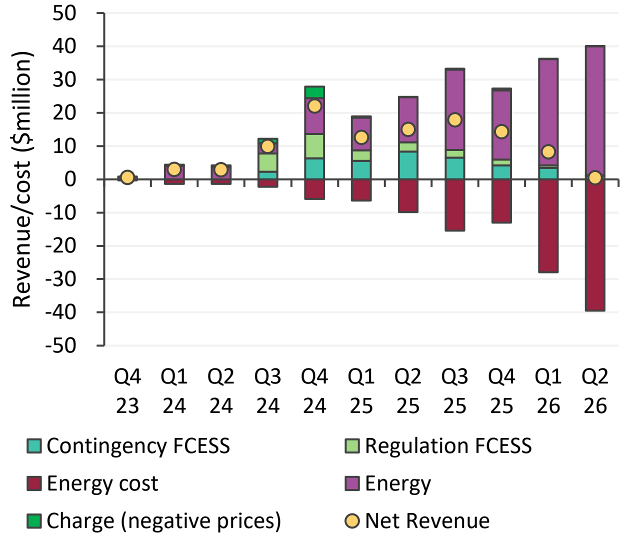


Figure 110 Despite decreasing in absolute terms, FCESS revenue rose to 100% of battery net revenue

Percentage share of battery net revenue – energy vs FCESS markets

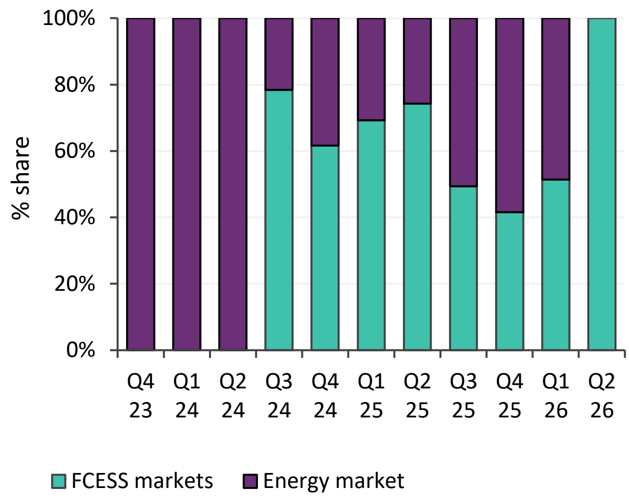


Table 9 Four new battery systems were commissioned and FCESS-accredited since Q2 2025

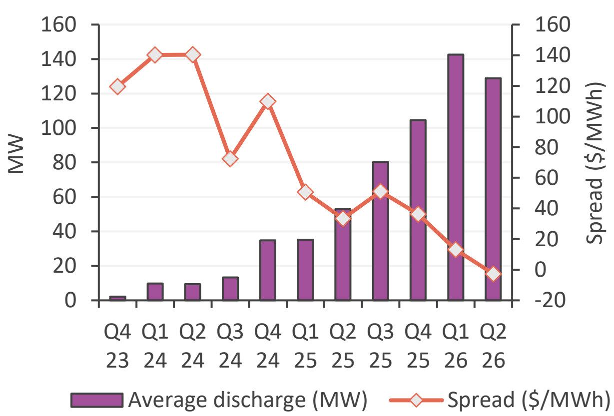
Electric Storage Resource	Capacity	Commercial Operation	FCESS Accreditation
KWINANA_ESR2	225 MW/900 MWh	Q2 2025	Q2 2025
COLLIE_BESS2	300 MW/1,200 MWh	Q3 2025	Q4 2025
COLLIE_ESR4	250 MW/1,000 MWh	Q4 2025	Q2 2026*
COLLIE_ESR5	250 MW/1,000 MWh	Q4 2025	Q2 2026

* COLLIE_ESR4 and COLLIE_ESR4 became accredited in the contingency markets in Q2 2026. As of the date of publication, they are not accredited in the regulation markets.

Between Q2 2025 and Q2 2026, total WEM battery discharge capacity increased by 1,025 MW, reaching a total of 1,275 MW (5,140 MWh), a 410% increase.

Figure 111 WEM battery price spread continued to decrease with lower price volatility

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



Lower volatility in the energy Market Clearing Price in Q2 2026 reduced the value of the arbitrage opportunities available to batteries in the WEM. This can be partly attributed to the increase in battery capacity, which raises demand, and therefore prices, during midday charging periods, while in parallel contributing to lower evening prices by increasing the availability of energy.

As a result, the WEM price spread earned by batteries declined by 108%, from $33.39/MWh in Q2 2025 to -$2.71/MWh (**Figure 111**).

4.4 Frequency co-optimised essential system services (FCESS)

In Q2 2026, batteries again increased their market share of the contingency and regulation markets, reaching 89% of total volume (**Figure 112**), an increase of 28 pp on Q2 2025 (**Figure 113**). This increase was driven by four additional batteries becoming accredited to provide FCESS since the beginning of Q2 2025 (**Table 9** in Section 4.3.1).

The average Contingency Reserve Lower requirement increased by 52 MW (+63%), which can be attributed to the commissioning of larger battery systems since Q2 2025 and regulatory changes in Q4 2025 that facilitated larger credible load contingencies. The average Contingency Reserve Raise requirement increased by 43 MW (+21%) compared to Q2 2025, with a contributing factor being the increase in the allowable contingency size via an increase to the Rate of Change of Frequency (RoCoF) Safe Limit from 26 February 2026.

Figure 112 Batteries took 89% of the contingency and regulation market volume in Q1 2026

FCESS volume market share by market and fuel type, excluding RoCoF control service – Q2 2026

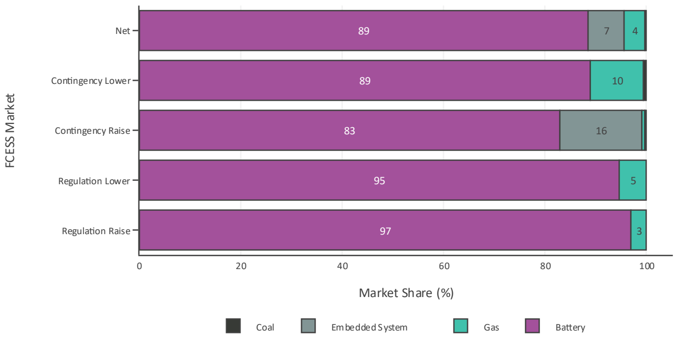
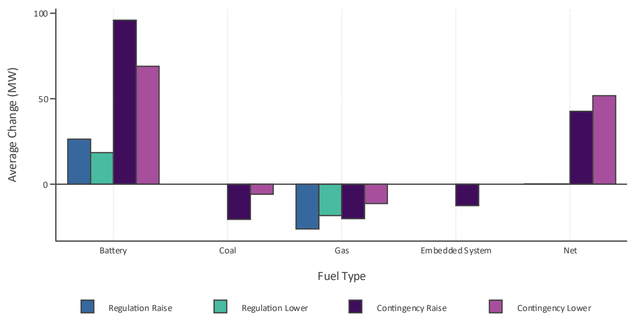


Figure 113 Batteries increased market share and contributed to higher contingency lower requirements

Change in FCESS (regulation and contingency markets) enablement by fuel type – Q2 2025 vs Q2 2026



4.5 WEM price outcomes

4.5.1 Real-Time Market price dynamics

The average real-time energy price in Q2 2026 was $117.87/MWh, an increase of $27.41/MWh (+30%) from Q2 2025 and a record high for the WEM. The Q2 2026 daily price profile was notably flatter than Q2 2025 (**Figure 114**), with average final reference trading prices ranging between $106.43/MWh to $136.73/MWh in Q2 2026, compared with $48.57/MWh to $139.73/MWh in Q2 2025.

In addition to flattening, the price profile increased throughout the day except during the 1700 hrs and 1730 hrs. This was most notable during the middle of the day and overnight, with smaller increases over the morning and evening peak.

The quarterly energy price dynamics can be attributed to:

- increased battery charging during the middle of the day and overnight, which resulted in higher operational demand (**Figure 115**), and
- reduced coal- and wind-powered generation availability, which led to a reduction in available lower-cost generation throughout the day.

Figure 114 Flatter average energy prices in the WEM in Q2 2026 compared to last year

Average Real-Time Energy prices by Trading Interval

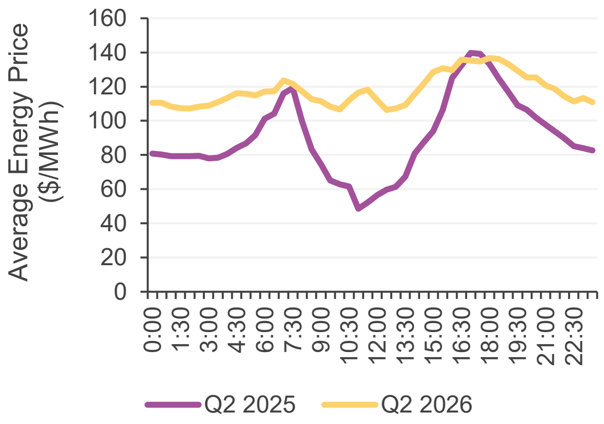
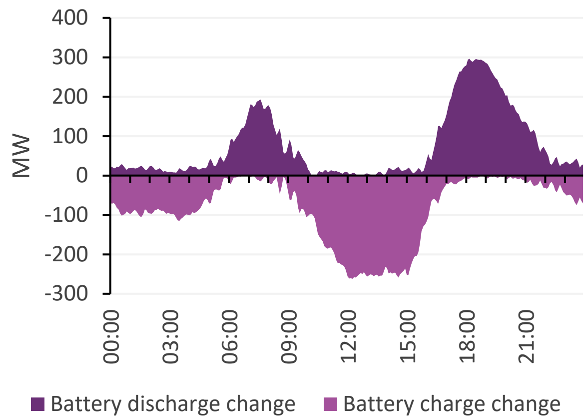


Figure 115 Batteries drove a flatter price profile

Average change in battery charge and discharge – Q2 2025 vs Q2 2026

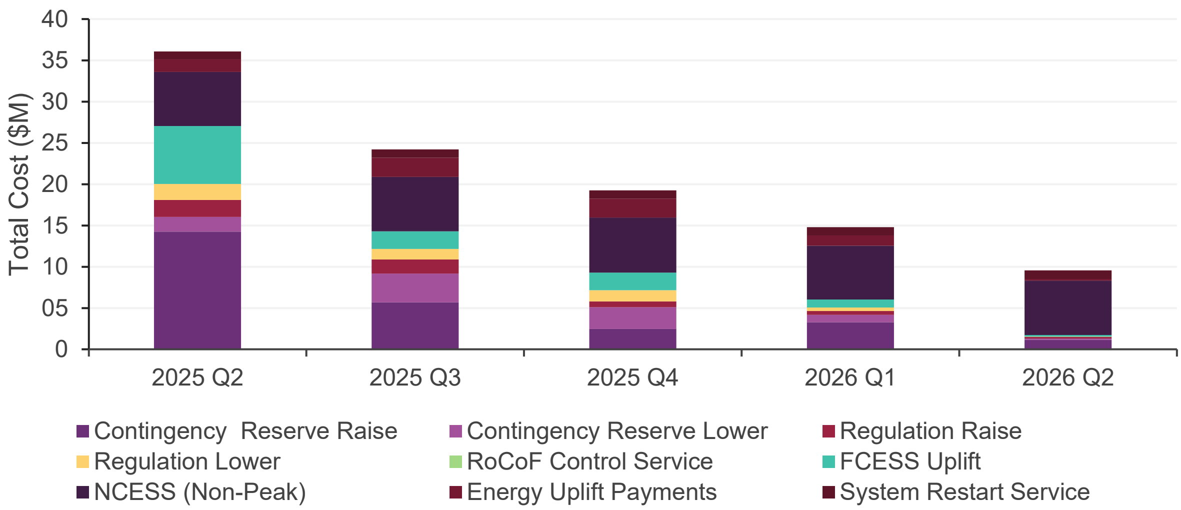


4.5.2 Essential system services (ESS) costs

Total ESS costs including Uplift costs were $9.6 million in Q2 2026, down from $26.5 million in Q2 2025 (**Figure 116**).

Figure 116 Falling ESS costs in the WEM

ESS costs are down quarter on quarter



Key observations include:

- FCESS enablement costs, which exclude FCESS Uplift, were $1.5 million in Q2 2026, a reduction of $18.5 million (-92%) compared with Q2 2025. Costs reduced across all FCESS markets services.
  - Contingency Reserve Raise costs decreased to $1.1 million, down $13.1 million (-92%) from $14.2 million in Q2 2025, but remained the largest contributor to FCESS enablement costs, accounting for 73% of Q2 2026 FCESS enablement costs.
  - Contingency Reserve Lower costs decreased by $1.6 million (-91%) to $0.2 million.

  - Regulation Raise and Regulation Lower costs also decreased materially, falling by $1.9 million each, or -90% and -97% respectively.
- FCESS Uplift costs were $0.2 million in Q2 2026, a reduction of $6.8 million (-97%) from $7.0 million in Q2 2025.
- Energy Uplift costs totalled $0.2 million in Q2 2026, down $1.3 million (-87%) from Q2 2025.
- Non-Peak NCESS costs were $6.6 million in Q2 2026, broadly unchanged from Q2 2025, increasing by only $0.1 million (+1%).
- System Restart Service costs increased slightly to $1.1 million (8%).

The decrease in FCESS enablement and Uplift costs was driven by an increase in competition in the FCESS market services, as four new battery Facilities were accredited to provide FCESS.

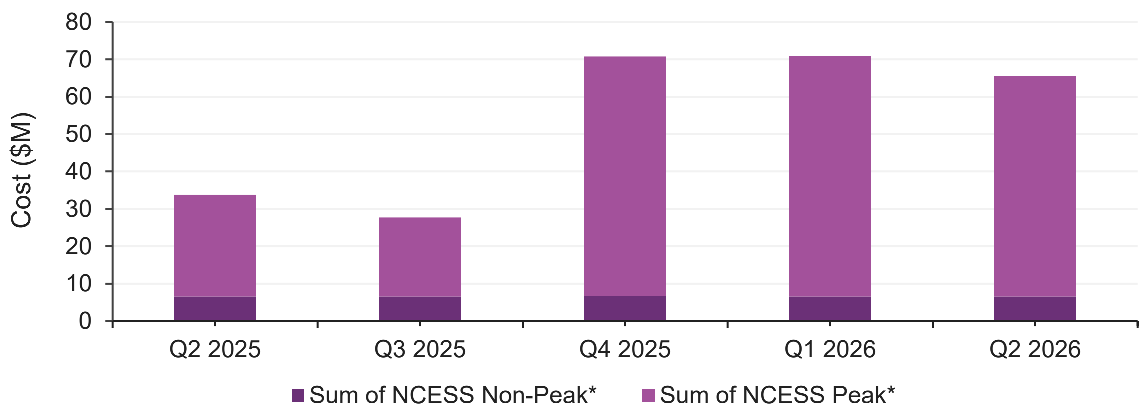
4.5.3 Non-Co-optimised Essential System Services (NCESS)

NCESS costs 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 for reporting purposes.

In Q2 2026, total NCESS costs were $65.5 million[70], an increase of $31.7 million (+94%) compared with Q2 2025 (**Figure 117**). This increase was driven almost entirely by Peak NCESS costs, which increased from $27.2 million in Q2 2025 to $58.9 million in Q2 2026. This was driven by the commencement of eight new Peak NCESS contracts from Q4 2025.

Figure 117 Increased NCESS costs in Q2 2026 compared to Q2 2025 is attributed to higher Peak NCESS costs from Capacity Year 2025-2026

Cost ($M) by NCESS type per quarter



Non-Peak NCESS costs were broadly unchanged in this quarter compared to the previous year, increasing slightly from $6.5 million to $6.6 million (+1%).

Compared with Q1 2026, total NCESS costs decreased from $70.9 million to $65.5 million, mainly due to lower Peak NCESS costs in Q2 2026, as some NCESS service providers entered the reserve capacity mechanism early, from 1 June 2026. Peak

[70] For Trading Days where the Interval Meter Deadline has not yet passed, the data assumes no activations and full contract availability. NCESS data may change up to the statement and invoicing date for the relevant Trading Week.

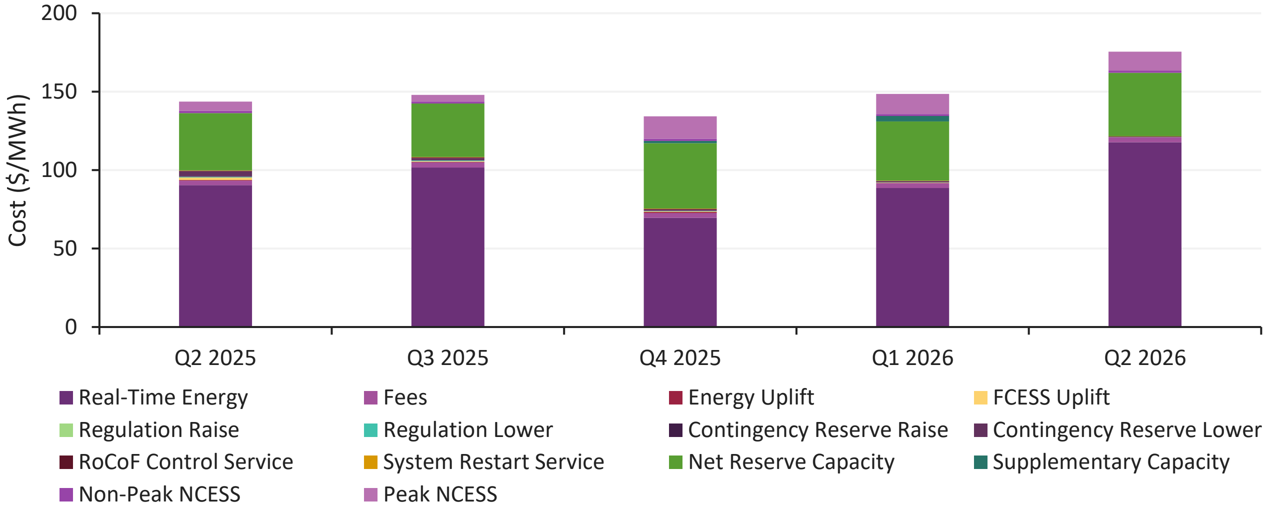
NCESS contract payments are offset by capacity payments, which resulted in some costs being shifted from Peak NCESS contracts to reserve capacity.

4.5.4 Total Wholesale Electricity Market costs

Figure 118 represents WEM costs as a price per MWh normalised by total energy consumed, enabling better comparison of costs between periods with different demand.

Figure 118 Higher $/MWh in Real-Time Energy is the driver of increased costs for the quarter

$/MWh costs in the WEM by market segment for recent quarters



The sum of all normalised WEM costs was $175.53/MWh in Q2 2026, an increase of $31.87/MWh (+22%) from Q2 2025, largely driven by an increase in energy costs. Key observations and changes include:

- Normalised real-time energy prices were $117.87/MWh, an increase of $27.41/MWh (+30%) from Q2 2025.
- Normalised Energy Uplift costs reduced by $0.29/MWh to $0.04/MWh.
- Normalised FCESS uplift costs decreased by $1.47/MWh to $0.04/MWh.
- Regulation Raise and Regulation Lower costs reduced to $0.04/MWh and $0.01/MWh respectively, while Contingency Reserve Raise and Lower costs reduced to $0.23/MWh and $0.03/MWh respectively.
- Total normalised NCESS costs were $13.43/MWh, increasing by $6.18/MWh (+85%), driven by Peak NCESS increasing by $6.23/MWh to $12.08/MWh, while Non-Peak NCESS was broadly flat at $1.35/MWh.
- Normalised Reserve Capacity costs, net of Reserve Capacity Refunds, were $40.49/MWh, an increase of $3.83/MWh (+9%).
- System Restart Service costs decreased by $0.02/MWh to $0.19/MWh.

4.5.5 Short Term Energy Market (STEM) and Bilateral Trades

The day ahead STEM auction operates as a risk management tool for market participants to provide them an opportunity to trade around their contractual positions and manage variations before physical dispatch in the Real-Time market. In Q2

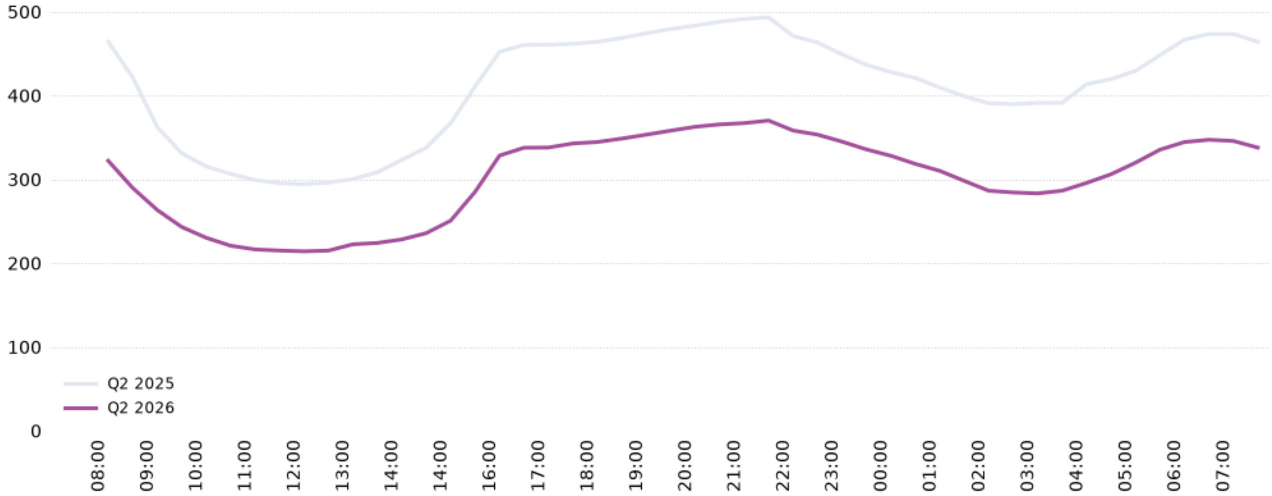
2026, the STEM auction was more liquid when compared to the same quarter last year. Liquidity was noted from an increase in the total traded quantity, higher average clearing price and increased value of transactions.

Bilateral Declared Quantity

Figure 119 shows bilateral energy traded between market participants by trading interval for Q2 2026 and Q2 2025, excluding trades between the same participant. Bilateral traded volumes in Q2 2026 were lower across most trading intervals compared to Q2 2025, with the largest year-on-year reductions observed during peak and evening trading intervals.

Figure 119 Bilateral trades between market participants decreased between Q2 2025 and Q2 2026

Average Bilateral Trades Between Participants (MWh) – Q2 2025 vs Q2 2026

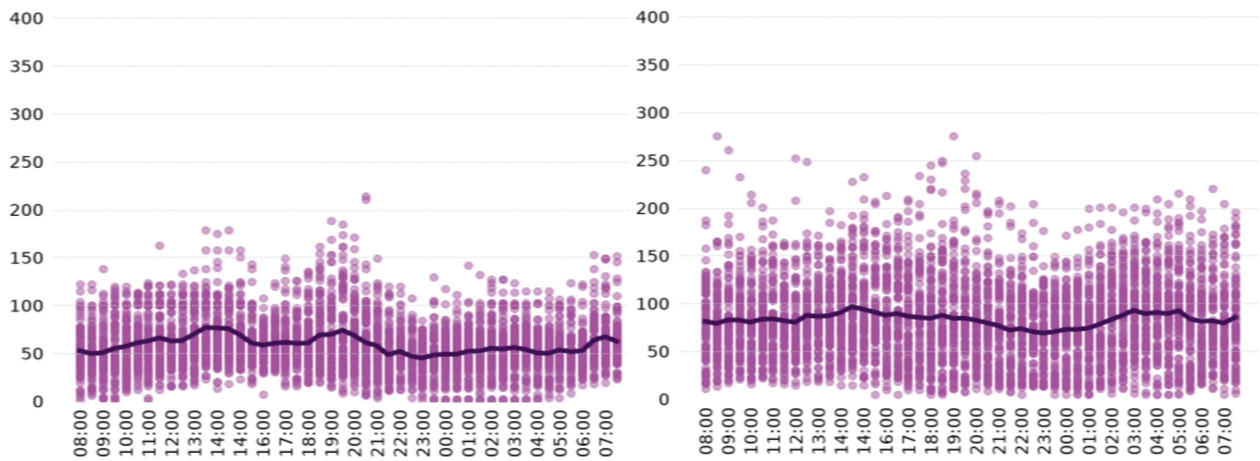


STEM traded quantities

The energy traded between participants in STEM totalled 323 GWh, representing a 55% increase from the Q2 2025 traded volume of 208 GWh, with average traded quantities exceeding 50 MWh across all intervals (dark purple line in **Figure 120**). **Figure 120** shows the distribution of STEM quantities traded by trading interval for Q2 2025 and Q2 2026.

Figure 120 STEM gross traded quantities were materially higher across trading intervals in Q2 2026

Distribution of STEM Gross Trade Quantities by Trading Interval (MWh) – Q2 2025 (LHS) and Q2 2026 (RHS)



In Q2 2025, traded volumes were lower and more tightly clustered, whereas Q2 2026 demonstrated greater dispersion and frequent higher-volume trades exceeding approximately 150-200 MWh for some intervals. This shows market participants trading more actively across the full trading day.

STEM clearing price

The quarterly average STEM clearing price was $123/MWh in Q2 2026, which was an increase of $36/MWh (+42%) from $87/MWh in Q2 2025. **Figure 121** shows the distribution of STEM clearing prices by trading interval for Q2 2025 and Q2 2026, together with the average STEM price profile.

Figure 121 The range and variability of observed STEM prices increased during the evening peak in Q2 2026

Distribution of STEM Clearing Prices by Trading Interval ($/MWh) – Q2 2025 (LHS) and Q2 2026 (RHS)

STEM prices in Q2 2026 were generally higher and more variable compared to Q2 2025 across all trading intervals. Price dispersion was also greater during the evening peak and early morning intervals. There were no negative STEM Clearing prices in this reporting quarter compared to 38 trading intervals with negative prices in the same quarter last year. Synergy set the clearing price for 82% of the trading intervals, followed by Alinta (6%), and NewGen Power (3%).

In Q2 2026, the average price difference between the STEM price and Reference Trading Price was $5.41/MWh higher than in Q2 2025.

Figure 122 shows the average price difference across each Trading Interval. The relationship between the STEM clearing price and the Reference Trading Price varied across trading intervals, with periods where the STEM price was both above and below the Reference Trading Price.

Figure 123 shows the total transaction value of energy traded in the STEM by trading interval for Q2 2026 and Q2 2025, calculated as the product of STEM clearing price and net STEM energy sales.

Figure 122 STEM was on average priced higher than the Energy price in the evening peak and early morning period

Average Daily Variance Between STEM Clearing Price and Energy Reference Trading Price ($/MWh) – Q2 2025 vs Q2 2026

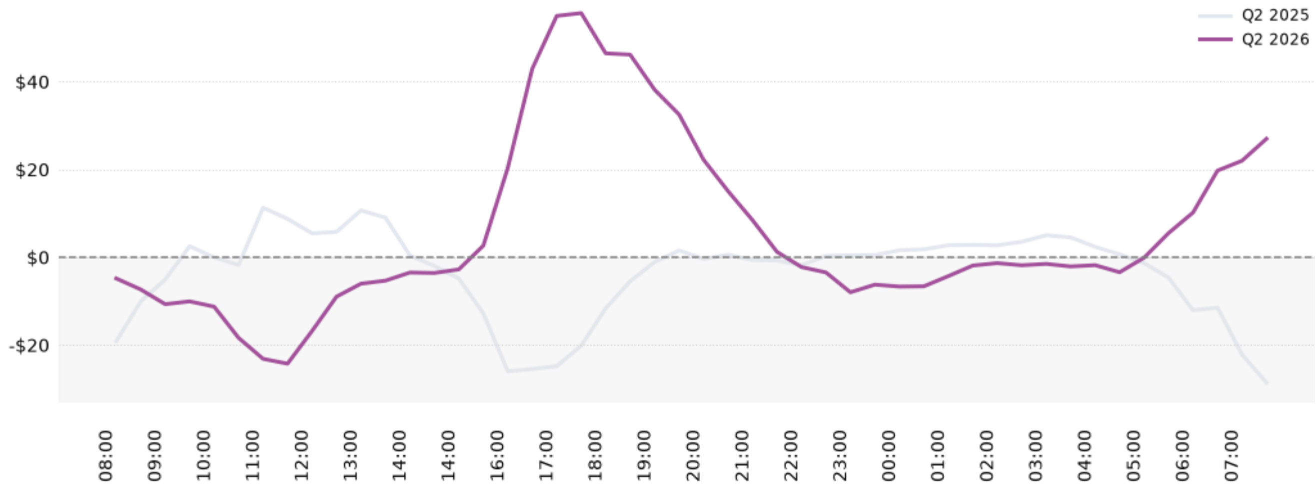
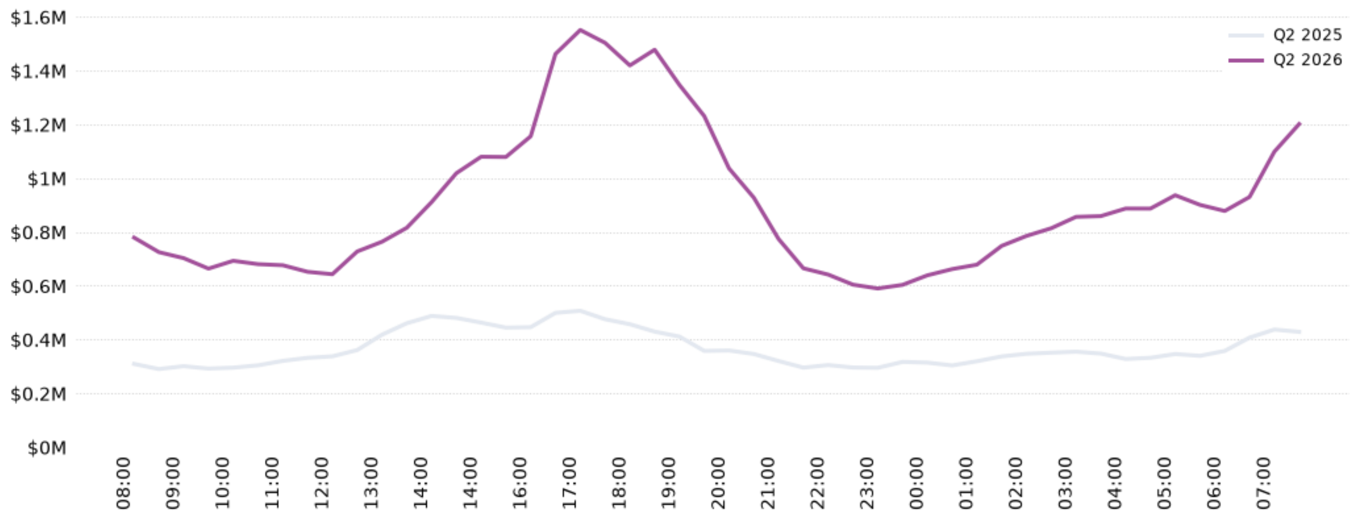


Figure 123 Transaction value of the net STEM traded quantities increased between Q2 2026 vs Q2 2025

Total STEM Transaction Value – Q2 2025 vs Q2 2026



The total transaction value in Q2 2026 was higher than in Q2 2025 across all trading intervals, with a pronounced increase during the evening peak and the overnight to early morning period. Elevated transaction values during the evening and overnight periods coincided with intervals where both STEM traded quantities and prices were higher relative to Q2 2025, as shown above in **Figure 120** and **Figure 121**.

5 Western Australia gas market dynamics

5.1 Gas consumption

A total of 100.3 PJ of gas was consumed across registered pipelines in the Western Australia domestic gas market in Q2 2026, representing a decrease of 9.4 PJ (-8.5%) from the 109.7 PJ consumed in Q2 2025, as shown in **Figure 124**. The decline in gas consumption was primarily driven by lower demand from Other (Non-Large User) category, which largely comprises residential consumers. Consumption in this category fell by 23.4 PJ to 8.7 PJ. Gas consumption in the Industrial, Mineral Processing, and Mining sectors also declined compared with the corresponding quarter in 2025.

Gas consumption in the Dampier zone decreased to 21.6 PJ in Q2 2026, down from 30.58 PJ in Q2 2025, as shown in **Figure 125**. This reduction was largely attributable to lower demand from the Electricity sector. Gas consumption in the other zones remained broadly in line with levels recorded in Q2 2025, with only minor variations observed.

Figure 124 Gas consumption by sector in Western Australia decreased compared to Q2 2025

Quarterly gas consumption by sector (PJ) – Q2 2025 and Q2 2026

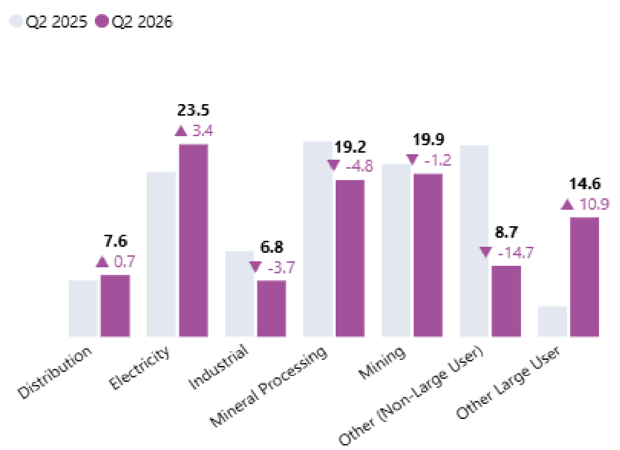
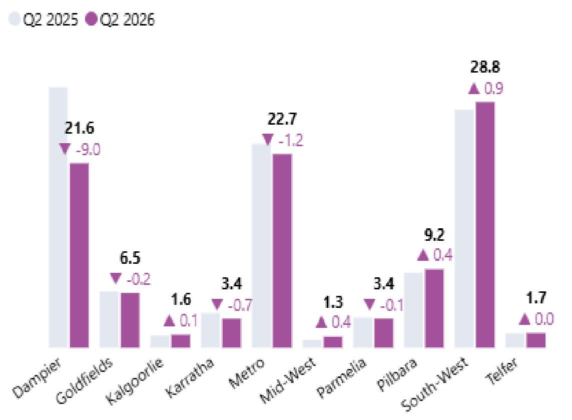


Figure 125 Gas consumption by zone in Western Australia decreased compared to Q2 2025

Quarterly gas consumption by zone (PJ) – Q2 2025 and Q2 2026



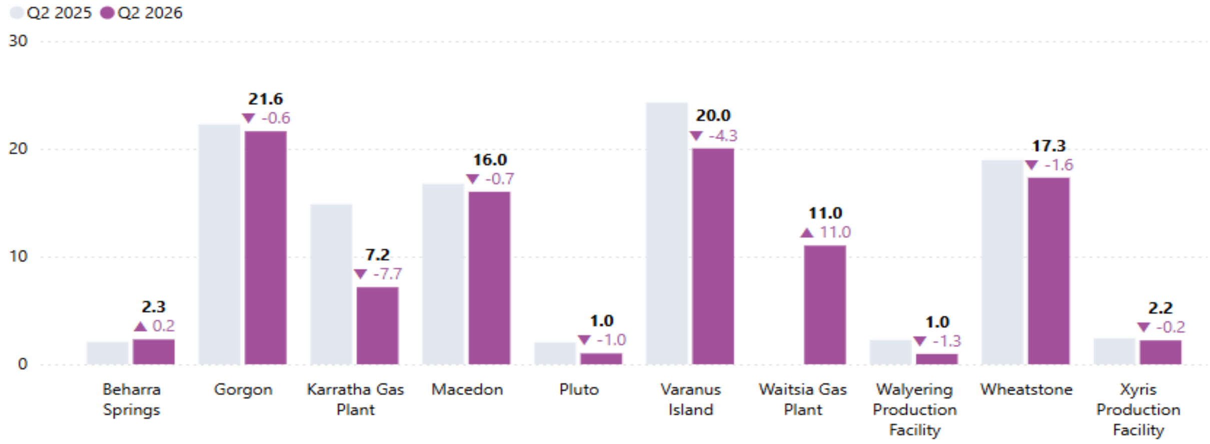
5.2 Gas supply and balance

5.2.1 Gas production

Total gas production decreased to 99.7 PJ in Q2 2026, representing a decline of 6.2 PJ (5.8%) compared to 105.9 PJ in Q2 2025, as shown in **Figure 126**. The overall reduction was primarily driven by lower production across most gas production facilities. Compared with Q2 2025, production from the Karratha Gas Plant decreased by 7.7 PJ, while the Varanus Island facility recorded a decline of 4.3 PJ. The Walyering Production Facility and Wheatstone also contributed to the overall decline in production, with a combined reduction of approximately 3 PJ. Partially offsetting these declines, the Waitsia Gas Plant produced 11 PJ in Q2 2026, whereas it had not yet commenced production in Q2 2025.

Figure 126 Gas production in Western Australian decreased by 6.2 PJ compared to Q2 2025.

Quarterly gas production by facility (PJ) Q2 2025 and Q2 2026



5.2.2 Storage facility

Net withdrawals from storage facilities were recorded in Q2 2026, totalling 2.1 PJ, compared with net withdrawals of 4.9 PJ in Q2 2025, as shown in **Figure 127**.

Mondarra recorded net withdrawals of 1.5 PJ in Q2 2026, compared with 1.8 PJ in Q2 2025, while Tubridgi recorded net withdrawals of 0.6 PJ during the quarter, down from 3.1 PJ in the corresponding quarter of the previous year. In Q2 2026, cumulative gas storage levels were lower than in Q2 2025, as seen in **Figure 128**. This was driven largely by a reduction in storage at Tubridgi.

Figure 127 Net withdrawals from storage in Q2 2026

Gas storage facility injections and withdrawals (PJ) – Q2 2025 and Q2 2026

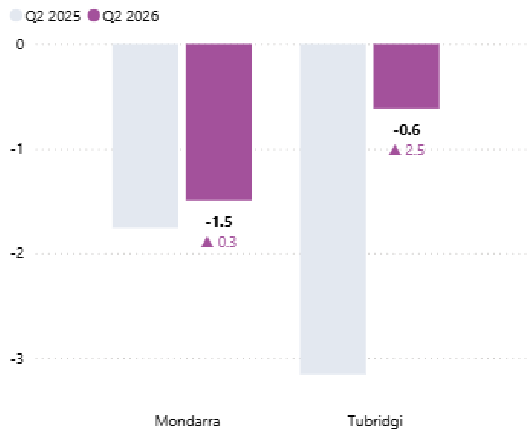
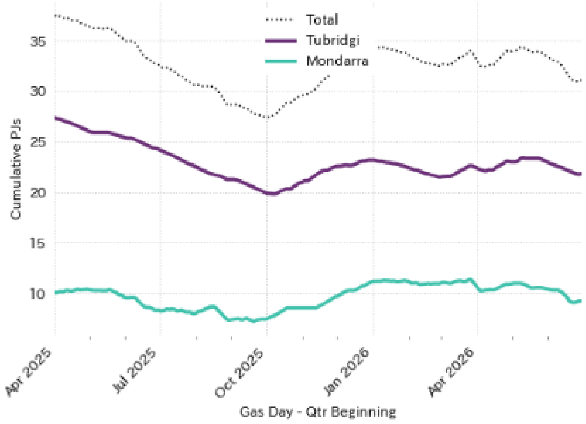


Figure 128 Cumulative storage levels in Q2 2026

Gas storage levels by facility over time



5.2.3 Linepack Capacity Adequacy (LCA)

For Gas Bulletin Board (GBB) pipelines, LCA is an indication of the actual or expected capability of a pipeline to meet relevant delivery nominations based on the pipeline's linepack and capacity. A green flag indicates normal operating conditions, an amber flag indicates likely curtailment of interruptible gas flows, and a red flag indicates likely curtailment of firm gas flows.

For GBB storage facilities, LCA is an indication of the estimated number of days for which natural gas supply can be maintained at maximum operational outlet capacity, allowing for forecast refilling. A green flag indicates more than seven days of supply remaining, an amber flag indicates between three and seven days of supply remaining, and a red flag indicates less than three days of supply remaining.

During the quarter, several gas infrastructure assets experienced operational constraints and maintenance related disruptions:

- From 1 to 4 April, the Dampier to Bunbury Natural Gas Pipeline (DBNGP) operated under Amber conditions across the Dampier, Metro and South West zones, potentially reflecting ongoing recovery from cyclone related impacts.
- The Mondarra Gas Storage Facility was subject to a Red LCA from 4 to 15 May due to zero gas flow during a planned maintenance outage. This was followed by an Amber LCA from 17 to 19 June.
- The DBNGP was also placed under Amber alert from 14 to 16 May because of outages at the Waitsia Gas Project, which remained in its commissioning phase during this period.
- The Parmelia Gas Pipeline (PGP) recorded Red LCAs on 22 May and again from 2 to 12 June due to scheduled maintenance activities.
- Subsequently, from 11 to 21 June, the DBNGP returned to Amber conditions due to concurrent outages across multiple gas production facilities.

6 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 2026

Reform initiative	Market	Description	Reform delivered
Flexible Trading Arrangements (FTA)	NEM	On 15 August 2024, the Australian Energy Market Commission (AEMC) published its final determination on the "Unlocking Consumer Energy Resources (CER) Benefits through Flexible Trading" rule. This rule is designed to enhance the flexibility of how CER are used and traded within the NEM enabling consumers to better manage their energy usage and participate in the market. The rule is optional, and allows: • large customers to engage multiple energy service providers at their premise, • energy service providers for small and large customers to separate and manage 'flexible' CER or active loads (secondary settlement point) from 'passive' loads (connection point), and • minor energy metering flows to be metered to enable the delivery of innovative and essential products and services at lower cost. Further, the final determination introduces new metering types – Type 8 that allows for bespoke requirements to apply for the metering of CER within customers' premises, and Type 9 which is designed to enable the integration of street furniture (such as kerbside electric vehicle chargers, smart street lighting systems) into the NEM metering framework. AEMO is implementing FTA across two releases. • The first release (31 May 2026) gives effect to Type 9 metering arrangements. • A subsequent release in November 2026 will give effect to the remainder of the rule requirements. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/flexible-trading-arrangements.	31 May 2026
Relevant Level Method (RLM)	WEM	In September 2023, the Western Australian Minister for Energy made changes to the RLM detailed in the Electricity System and Market Rules (ESM Rules). The RLM is a key component of the Reserve Capacity Mechanism in the Wholesale Electricity Market. It determines how many Capacity Credits a facility, particularly an intermittent generator like wind and solar, can receive based on its contribution to system reliability. The fundamental change is a move toward Effective Load Carrying Capability (ELCC) based modelling, which is a probabilistic measure of reliability contribution, rather than simple historical averages. The new RLM introduces numerical models that simulate system conditions and better evaluate the contribution of different forms of generation and storage under system stress scenarios. AEMO used the new process to determine Certified Reserve Capacity (CRC) in the 2026 Reserve Capacity Cycle, for intermittent generation and Non-Scheduled Facilities published in June 2026. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/2025/p03427-relevant-level-method-final-ia.pdf.	20 April 2026
Demand Side Programme Participation – Workstream 1	WEM	In September 2023, the Western Australian Minister for Energy made several ESM Rule changes to implement the outcomes of its Reserve Capacity Mechanism Review. One of the initiatives within that review proposed amending Rules to simplify the process for facilities participating as a Demand Side Programme (DSP) within the Reserve Capacity Mechanism but increased the obligations for participation. Commencing from the 2024	19 May 2026

Reform initiative	Market	Description	Reform delivered
		Reserve Capacity Cycle, DSP Facilities can apply for certification without providing locational information. Workstream 1 of this reform focused on the obligation that a Market Participant must provide the network locational information when registering a DSP Facility and associating loads to that DSP Facility. AEMO implemented changes to enable the registration of DSP Facility at the network location referred to as Transmission Node Identifier (TNI) in June 2026. Where a Market Participant did not provide the network location as part of the certification process, it must register DSP Facilities at a TNI, associate loads to the DSP from the same TNI, and distribute Capacity Credits from the certified DSP between one or more registered DSPs by 1 July of the relevant Capacity Year. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/2025/dsp-participation---final-ia.pdf.	

In addition to these reforms, work continues to progress on the next wave of initiatives set for release in 2026. **Table 11** below provides a brief description of initiatives to be delivered in Q3 and Q4 2026.

Table 11 Upcoming implementation of reforms Q3 2026 – Q4 2026

Reform initiative	Market	Description	Reform to be delivered
Demand Side Programme Participation – Workstream 2	WEM	In September 2023, the Western Australian Minister for Energy made several ESM Rule changes to implement the outcomes of its Reserve Capacity Mechanism Review. One of the initiatives within that review proposed amending Rules to simplify the process for facilities participating as a DSP within the Reserve Capacity Mechanism but increased the obligations for participation. Commencing from 1 October 2026, DSP Facilities will be subject to more stringent refunds for failure to provide the obligated capacity when dispatched to subject to a reserve capacity test. Workstream 2 of this reform focuses on the dispatch, reserve capacity testing, and settlement obligations of DSP Facilities. AEMO will implement changes to enable: • DSP aggregators to identify in their DSP Profile Submissions where the facility will provide injection or withdrawal, • simplification of AEMOs dispatch process for DSPs to effectively dispatch large numbers of DSP Facilities within the obligations of the ESM Rules, • both summer and winter testing of DSP facilities where they have not already proven their ability to provide their Capacity Credits, • a new dynamic baseline methodology (Relevant Demand) to measure the performance of the DSP following a dispatch or reserve capacity test, and • revised settlement calculations for failure to deliver the expected capacity in line with the Reserve Capacity obligations. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/2025/dsp-participation---final-ia.pdf.	Q3 2026
Metering Services Review – Package 2	NEM	The Accelerating Smart Meter Deployment (ASMD) rule seeks to achieve universal smart meter deployment in the NEM by 2030. To facilitate the accelerated deployment, the AEMC final determination introduces new obligations for industry coordination between Distribution Network Service Providers (DNSPs), Financially Responsible Market Participants (FRMPs), and Metering Coordinators (MCs) for sites with shared points of isolation. This includes a requirement for MCs to provide DNSPs with a basic power quality data (PQD) service and for AEMO to determine the specifications, formats, and delivery mechanism for this service. The second and final release enables better access to PQD for DNSPs. AEMO remains focused on delivering Basic Power Quality Data (BPQD) as soon as possible (initially scheduled for 1 July 2026) and continue to progress the activities required to establish a revised go-live date.	Q3 2026

Reform initiative	Market	Description	Reform to be delivered
		More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/metering-services-review---accelerating-smart-meter-deployment.	
Improving Security Frameworks	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 was initially implemented across multiple milestones, scheduled between 30 June 2024 and 2 December 2025, providing for: • alignment of existing inertia and system strength frameworks, • removal of the exclusion to procuring inertia network services and system strength in the NSCAS framework, • creation of a new transitional non-market ancillary services (NMAS) framework for AEMO to procure security services necessary for the energy transition, • a requirement for AEMO to enable (or 'schedule') security services across the whole NEM for a variety of service types, and • changing the directions reporting framework. Subsequent releases scheduled for June 2026 and November 2026 will deliver automated enablement functionality and other non-core components of the solution. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/improving-security-frameworks-for-the-energy-transition.	Q3 2026
Shortening the settlement cycle	NEM	On 12 December 2024, the AEMC published its final determination on the "Shortening the settlement cycle" rule change. The final rule shortens the NEM settlement cycle to nine (9) business days following the end of a billing period and introduces a new revision 20 business days following the end of the billing period. The final rule has three major implementation components: • establishing metering and settlement processes that support a new, shorter settlement cycle, • adapting the credit limit procedures (CLP) and supporting process to reflect the shorter settlement cycle, and • transitioning metering, settlement and prudential processes from the current settlement cycle to the shorter settlement cycle. The final rule will commence on 9 August 2026. AEMO will have from 9 August 2026 to 17 October 2026 to complete this transition from a 20-business day to nine-business day settlement period. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/shortening-the-settlement-cycle.	Q3 2026
Project EnergyConnect (PEC) – Market Integration	NEM	When implemented, PEC (Stage 2) will provide approximately 800 MW of transmission capacity between New South Wales and South Australia. This will create a parallel transmission configuration between three adjacent regions which presents new challenges for the NEM, especially for the way negative inter-regional settlement residue is managed. AEMO undertook stakeholder consultation on PEC Market Integration (PEC-MI), with the final recommendations published on 9 February 2024. On 25 September 2025, the AEMC made a final determination and more preferable final rule that will net off inter-regional settlements residue (IRSR) in transmission loops. The final rule commenced on 2 October 2025, noting that the new IRSR arrangements for transmission loops will not take effect until a transmission loop is in operation in the NEM dispatch engine and changes to AEMO's settlement systems have been implemented. The final rule requires project go-live to occur no earlier than 1 October 2026 and no later than 2 November 2026. Integration of PEC Stage 2 into AEMO's systems is designed in two phases: • Release 1 August 2026: Integrate a transmission loop into AEMO dispatch systems (price scaling and negative residue management), and	Q3 2026

Reform initiative	Market	Description	Reform to be delivered
		• Release 2 November 2026: Integrate PEC into AEMO settlement systems (IRSR, Settlement Residue Auction [SRA]). More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/project-energyconnect-market-integration-project.	
Flexible Trading Arrangements (FTA)	NEM	As outlined in **Table 10** above, AEMO is implementing FTA across two releases: • The first release giving effect to Type 9 metering arrangements went live on 31 May 2026. • A subsequent release in November 2026 will give effect to the remainder of the rule requirements. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/flexible-trading-arrangements.	Q4 2026
Cash Security	NEM	On 26 June 2025, the AEMC published the final determination and rule 'Allowing AEMO to accept cash as credit support', to amend the credit support arrangements to increase flexibility for participants that provide credit support in the NEM. The rule expands the range of eligible credit support instruments by enabling AEMO to accept cash deposits as an approved form of prudential collateral up to a limit of $20 million per market participant. Participants are now able to meet part or all of their credit support obligations through cash security held by AEMO, alongside existing instruments such as bank guarantees. This provides participants with greater flexibility in managing prudential requirements while maintaining the integrity of AEMO's risk management framework. Consultation on Cash Security Guidelines is underway with final guidelines to be published before 1 August 2026 as per the rule. The final rule is to commence from 1 November 2026. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/cash-as-credit-support.	Q4 2026

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
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
ASEFS	Australian Solar Energy Forecasting System
ASMD	Accelerating Smart Meter Deployment
ASX	Australian Securities Exchange
BESS	battery energy storage system
BPQD	basic power quality data
BOM	Bureau of Meteorology
CDEII	Carbon Dioxide Equivalent Intensity Index
CER	consumer energy resources
CGP	Carpentaria Gas Pipeline
CLP	credit limit procedures
CRC	Certified Reserve Capacity
DAA	Day Ahead Auction
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DNSP	distribution network service provider
DR	demand response
DSP	Demand Side Programme
DTS	Declared Transmission System
DUID	Dispatchable Unit Identifier
DWGM	Declared Wholesale Gas Market
ECGS	east coast gas system
EDD	effective degree day
EGP	Eastern Gas Pipeline
ELCC	Effective Load Carrying Capability
ESM Rules	Electricity System and Market (previously WEM Rules)
ESR	electric storage resource
ESS	essential system services
FCAS	frequency control ancillary services
FCESS	frequency co-optimised essential system services
FPP	Frequency Performance Payment
FRMP	Financially Responsible Market Participant
FTA	flexible trading arrangements
GBB	Gas Bulletin Board

Abbreviation	Expanded term
GJ	gigajoule/s
GW	gigawatt/s
GWh	gigawatt hour/s
GLNG	Gladstone LNG
GSH	Gas Supply Hub
HDD	heating degree day
IEA	International Energy Agency
IRSR	inter-regional settlement residue
kV	kilovolt/s
kVa	kilovolt ampere/s
kW	kilowatt/s
LCA	Linepack Capacity Adequacy
LGC	large-scale generation certificate
LNG	liquefied natural gas
LOR	Lack of Reserve
MAPS	Moomba to Adelaide Pipeline
MC	Metering Coordinator
MFP	Market Floor Price
MNSP	market network service provider
MoU	Memorandum of Understanding
MSP	Moomba Sydney Pipeline
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
NMI	National Metering Identifier
NSCAS	network support and control and ancillary services
NGP	Northern Gas Pipeline
NSP	network service provider
OECD	Organisation for Economic Co-operation and Development
OEM	original equipment manufacturer
PD PASA	Pre Dispatch Projected Assessment of System Adequacy
PEC	Project EnergyConnect
PEC-1	Project EnergyConnect Stage 1
PEC-MI	Project EnergyConnect – Market Integration
PGP	Parmelia Gas Pipeline
pp	percentage points
PJ	petajoule/s

Abbreviation	Expanded term
PQD	power quality data
PV	photovoltaic
QED	*Quarterly Energy Dynamics*
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
R6SE	raise 6-second (FCAS)
RBP	Roma to Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
RHS	right hand side
RLM	Relevant Level Method
RoCoF	Rate of Change of Frequency
RREG	raise regulation (FCAS)
RRP	regional reference price
SOC	state of charge
SRA	Settlement Residue Auction
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	terajoule/s
TNI	Transmission Node Identifier
TNSP	transmission network service provider
TWAP	time-weighted average price
UGS	Underground Storage Facility
VEEC	Victorian Energy Efficiency Certificate
VWAP	volume-weighted average price
VPP	virtual power plant
VRE	variable renewable energy
VNI	Victorian Northern Interconnection
WARBS	Western Australian Residential Battery Scheme
WEM	Wholesale Electricity Market
WDR	wholesale demand response
WORM	Western Outer Ring Main
WPP	Wickham Point Pipeline