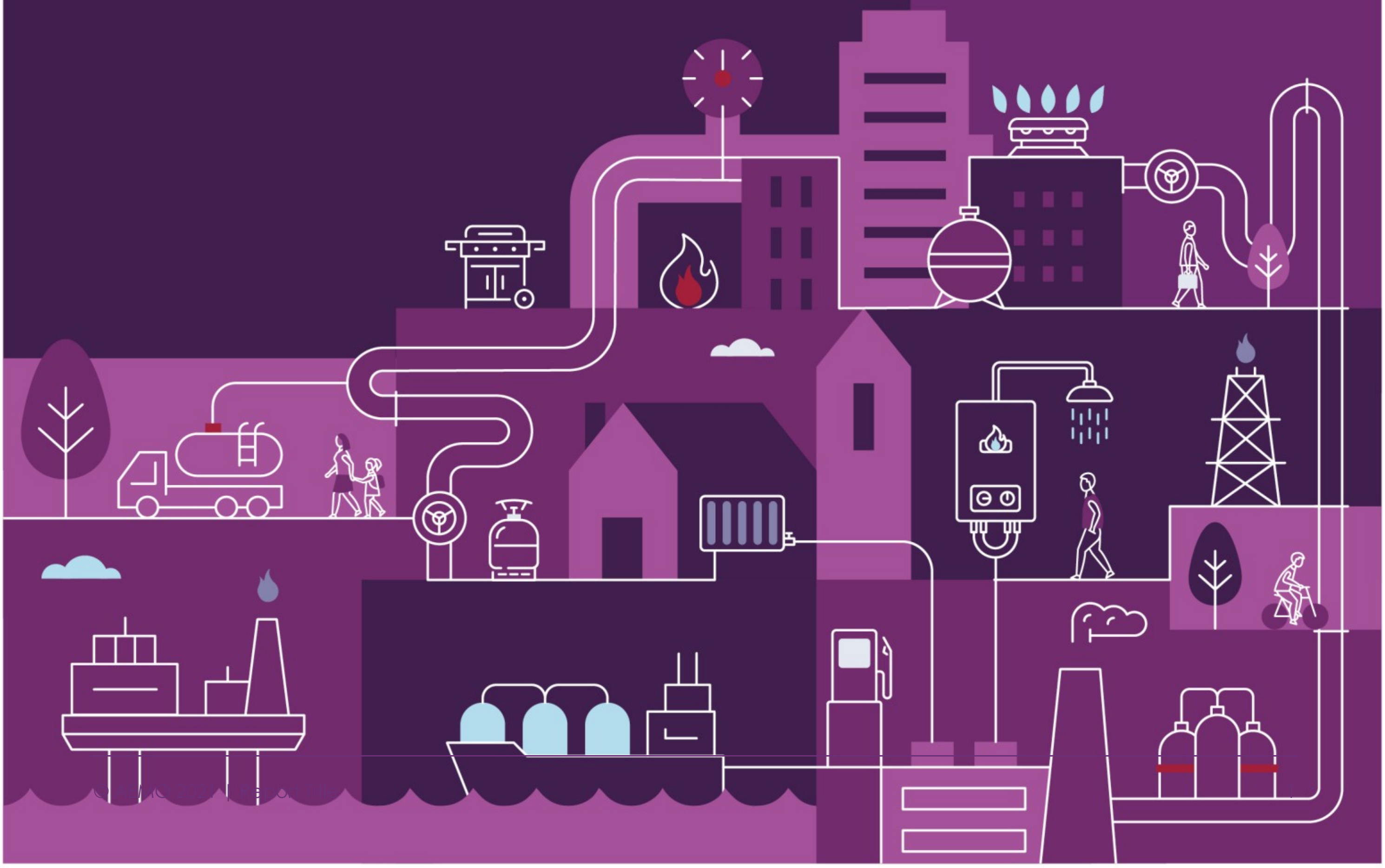
Quarterly Energy Dynamics Q3 2025

October 2025



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

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

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

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

Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q3 2025 (1 July to 30 September 2025). This quarterly report compares results for the quarter against other recent quarters, focusing on Q3 2024 and Q2 2025. Geographically, the report covers:

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

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Executive summary

East coast electricity and gas highlights

National Electricity Market (NEM) operational demand increased, with higher underlying demand outpacing growth in distributed photovoltaic (PV) output

- Operational demand across the NEM regions averaged 22,323 megawatts (MW) in Q3 2025, up 498 MW (+2.3%) from the same period last year. Underlying demand reached a new Q3 high, up 3.2% year-on-year, only partially offset by NEM-wide distributed PV output which increased by 292 MW (+11%), also reaching a new record for Q3.
- The impact of distributed PV growth was evident in minimum demand levels, with the NEM as a whole (10,175 MW), New South Wales (3,265 MW), Queensland (2,790 MW) and South Australia (-14 MW) all recording new lows for Q3 minimum demand.
- Victoria was the only region to observe a new Q3 maximum demand record at 8,623 MW, while New South Wales reached its highest Q3 level since 2008 at 13,204 MW.

Renewable market share increased as growing demand added to supply requirements

- Overall generation supply increased by 3.9% year on year, driven by higher underlying demand and growing battery charging requirements (+143%). Wind generation reached a new all-time high for any quarter, up 16% year on year to average 4,676 MW, and grid-scale solar increased by 16% to average 1,699 MW, a new high for a Q3.
- With 2,936 MW/6,482 megawatt hours (MWh) of new battery capacity entering the NEM since the end of Q3 2024, battery discharge increased by 150% to average 215 MW, principally supporting evening peak demand. Reduced supply requirements from other peaking sources over the evening period contributed to year-on-year reductions in gas-fired generation (down 11%) and hydro output (down 3.5%).
- Coal-fired generation fell by 103 MW (-0.8%), with a 5.0% decrease in brown coal-fired generation offsetting a 0.8% increase in black coal-fired generation.
- These supply changes saw the NEM renewable share increase from 39.3% in Q3 2024 to 42.7%, reaching a new high for a Q3. Total emissions were 28.1 million tonnes of carbon dioxide equivalent ($MtCO_2$-e) in Q2 2025, down 1.2% from Q3 2024, and emissions intensity averaged 0.57 tonnes of carbon dioxide equivalent (tCO_2-e)/MWh, down 4.4% and representing a record low in emissions intensity.
- Renewable contribution also set a record on a half-hourly basis, reaching 77.2% of total NEM generation on 22 September 2025, up from 75.6% in Q4 2024. South Australia reached a renewable share of total regional generation of 98.7% on 10 September 2025, with this new high supported by the minimum synchronous generator requirement for secure operation reducing to one unit, subject to defined system conditions.

Wholesale electricity prices reduced across all NEM regions driven by lower price volatility and renewable energy increases offsetting operational demand growth

- Wholesale spot prices averaged[1] $87 per MWh across all NEM regions in Q3 2025, 27% lower than the same quarter last year (Q3 2024), and 38% below the preceding quarter (Q2 2025).
- Price volatility (spot prices above $300/MWh) fell in all regions, adding just $6/MWh to the NEM quarterly average, down 82% from $31/MWh in Q3 2024. The only notable high-price events driving material regional cap returns were in South Australia, where price volatility on 2 July 2025 contributed $19/MWh to the region's quarterly average price of $104/MWh, 34% down from Q3 2024's quarterly average.
- In New South Wales, wholesale spot prices averaged $90/MWh this quarter, 25% lower than during Q3 2024, and Victorian wholesale spot prices reduced by 26% to average $77/MWh. Tasmania's wholesale spot prices fell by 18% to average $91/MWh for the quarter, despite being impacted by changes in Basslink bidding behaviour which reduced exports from Victoria to Tasmania by 70% and contributed $15/MWh to the region's quarterly average price.
- Queensland recorded the lowest quarterly average spot price across the NEM at $72/MWh, a 28% year-on-year reduction, with a record 25.9% of dispatch intervals at negative or zero prices this quarter.
- The QED now also presents regional volume-weighted average prices (VWAPs), which incorporate the level of demand in each interval to reflect the overall spot market value of energy produced in each region. In this quarter, VWAPs across NEM regions ranged from $80/MWh in Queensland to $124/MWh in South Australia, representing reductions of 22-38% compared to Q3 2024.

East coast Q3 2025 gas prices were slightly higher than Q3 2024 despite lower demand

- East coast wholesale gas prices averaged $12.62 per gigajoule (GJ) for the quarter, marginally higher than Q3 2024 which averaged $12.50/GJ, and Q2 2025 which averaged $12.38/GJ.
- Gas demand decreased by 1% from Q3 2024, driven by lower demand for gas-fired generation (-3 petajoules [PJ]) and lower demand for Queensland liquefied natural gas (LNG) exports which saw a very slight decrease (-0.6 PJ). AEMO markets demand was virtually unchanged (-0.1 PJ), despite colder weather conditions compared to Q3 2024.
- Gas production decreased across all regions at a rate greater than the demand decrease, with projects associated with Queensland LNG exports reducing supply into the domestic market (-2 PJ), along with reduced production at the Moomba gas plant in South Australia (-3.6 PJ) and lower Victorian (-2.1 PJ) production.
- This production decrease led to a greater reliance on Iona Underground Gas Storage (UGS), which saw its highest Q3 utilisation since 2019, and finished the quarter with 11.8 PJ of inventory, its lowest at the end of Q3 since 2021.

[1] Calculated as the time-weighted average, which is the simple average of regional wholesale spot prices over each five-minute dispatch period over the quarter.

Western Australia electricity and gas highlights

Operational demand increases were driven by colder temperatures and battery charging, renewable market share increased

- Cooler temperatures in Q3 2025 compared to Q3 2024, combined with an increase in average battery charging of 77 MW (+493%) and organic demand growth, resulted in an average underlying demand increase of 220 MW (+9.0%) compared with the same quarter last year. This was the primary driver behind a 219 MW (11%) increase in operational demand to 2,228 MW.
- Q3 2025 saw a new Q3 renewable contribution high of 36.4%, an increase of 1.2 percentage points on Q3 2024. In addition, there was a new peak Q3 renewable contribution of 83.2% (+1.3 pp on the previous Q3 record), which occurred on Tuesday 23 September 2025 in the 09:55 interval.
- The increase in operational demand resulted in an uptick in estimated quarterly emissions to 2.55 MtCO2-e in Q3 2025, a 7.5% increase. Mitigating the increase caused by greater operational demand was an improvement in the emissions intensity to 0.52 tCO2-e /MWh, representing a 0.02 tCO2-e /MWh (-3.0%) improvement.

Wholesale Electricity Market (WEM) energy prices increased in line with operational demand, Frequency Co-Optimised Essential Systems Service (FCESS) costs decreased

- Q3 2025 energy prices reached an average of $101.76/MWh, an increase of $21.61/MWh (+27%) on Q3 2024. This reflects the large increase in operational demand across the quarter and changes to the FCESS Uplift framework resulting in fewer committed facilities during the middle of the day. As observed in recent quarters, the daily price profile continues to flatten as more battery capacity seeks to charge during lower priced periods, and discharge in higher priced periods.
- Essential System Services (ESS) costs fell 81% to a total of $22.3 million from $118.9 million in Q3 2024. This can be attributed to rule changes which reduced FCESS Uplift costs by $77.1 million (-97%) compared to Q3 2024. Battery capture of the contingency and regulation markets, which was 77% by volume (+56 pp), contributed to a reduction of $21.9 million (-64%) in direct FCESS enablement costs compared to Q3 2024.
- Overall, normalised WEM costs increased to $149.97/MWh, an increase of $10.88/MWh (+8%) from Q3 2024. The primary drivers of the increase were reserve capacity costs (+$8.14/MWh), and the average energy price (+$21.61/MWh). Primary reducing factors included normalised FCESS enablement costs (-$5.10/MWh) and FCESS Uplift costs (-$17.42/MWh).

Western Australia's domestic gas production increased, consumption decreased

- Western Australia's domestic gas consumption was 98.1 PJ, a decrease of 1.3 PJ (-1.3%) on Q3 2024. Production was 109 PJ, which represented a 2.7 PJ (+2.6%) increase, and the highest quarterly domestic gas production since Q2 2020. Another quarter of storage withdrawals was registered with an increase of 4.1 PJ (+359%) compared to Q3 2024.

Contents

1 Weather

This quarter was characterised by a series of severe weather events across Australia, driven by low-pressure systems and strong cold fronts. In early July, intense rainfall and strong winds impacted coastal and inland areas of New South Wales and Victoria, extending into south-western Western Australia and resulting in above-average rainfall for most of Australia. Mid to late July brought multiple cold fronts across south-east and western regions, causing record low temperatures in parts of New South Wales and Western Australia.

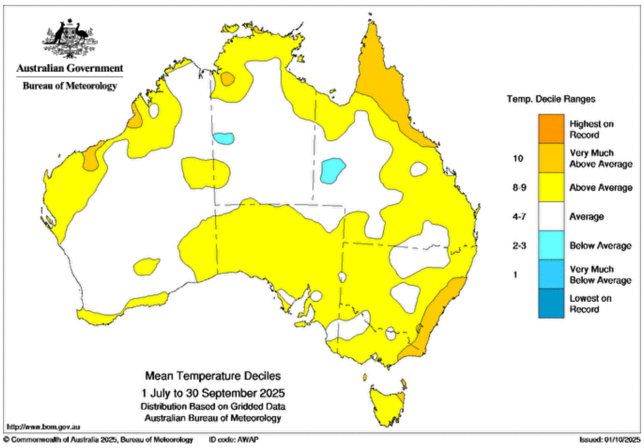
August continued with extreme conditions, including a coastal low that delivered heavy rain, strong winds, and record cold temperatures across New South Wales, Queensland, and the Northern Territory. Western Australia faced further cold fronts and severe storms, alongside isolated early-season heat records. Queensland had its coolest August since 2014 while Perth City observed its lowest daily maximum temperature for any month (11.4°C) since July 1975.

September saw a strong cold front sweep across south-eastern Australia, bringing damaging winds, with Melbourne Airport recording its strongest September gust since 2002. September also brought significantly above-average rainfall to much of Eastern and Western Australia, with many stations in Sydney Metro and other stations in Sydney recording their highest daily rainfall for September. Despite these extremes, average temperatures across most regions stayed above long-term averages (Figure 1), highlighting the variability of this quarter's climate.

On a quarterly average basis, average maximum temperatures were lower across all major mainland cities, with August showing particularly sharp declines (Figure 2). Compared to August 2024, Sydney was 3.0°C cooler, Adelaide 2.4°C, Brisbane and Melbourne both 2.3°C, Perth 0.7°C, and Hobart 0.5°C below the average.

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

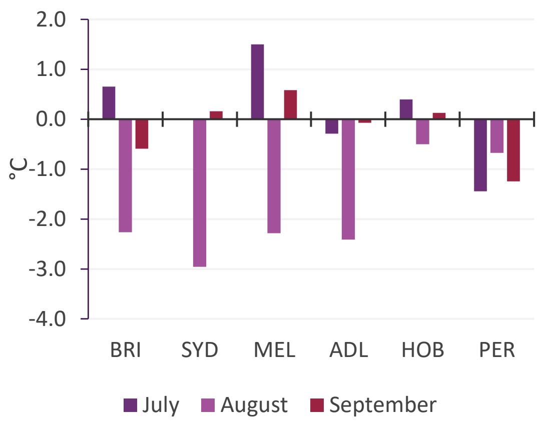
Q3 2025 mean temperature deciles for Australia



Source: Bureau of Meteorology (BOM)

Figure 2 Significantly colder temperatures in all major cities in August

Average monthly maximum temperature variance by capital city – Q3 2025 vs Q3 2024



2 NEM market dynamics

2.1 Electricity demand

In Q3 2025, NEM-wide underlying demand[2] averaged 25,154 MW, up 790 MW (+3.2%) from Q3 2024, marking a new high for a Q3 (Figure 3). This year-on-year growth in underlying demand was driven by increased heating requirements, particularly in August (see Section 1), alongside broader trends in population growth, electrification of heating, rising uptake in electric vehicles and increasing energy demand from data centres[3].

All NEM regions reached new highs for Q3 distributed PV output, with NEM-wide distributed PV output increasing by 292 MW (+11%) to a new Q3 high of 2,831 MW, driven by the ongoing expansion of rooftop solar capacity (Figure 4). Despite this growth in distributed PV output, which partially offset higher underlying demand across daytime hours, operational demand[4] across the NEM increased by 498 MW (+2.3%) from Q3 2024 to average 22,323 MW this quarter.

Figure 3 Underlying demand reached a new Q3 high, which was partially offset by the growth in distributed PV output

NEM average underlying and operational demand – Q3s

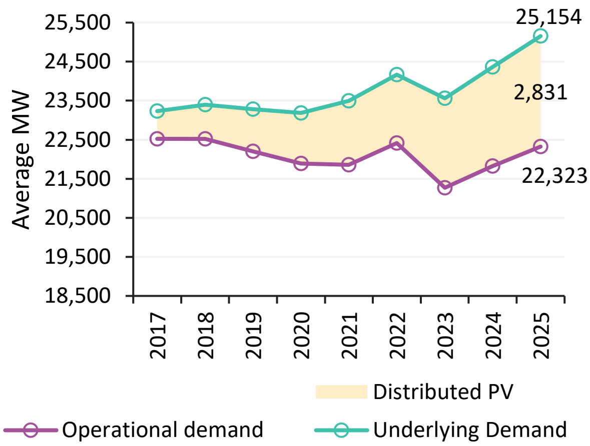
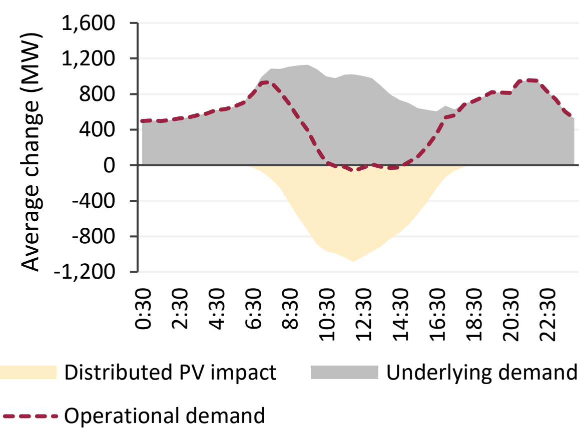


Figure 4 Growth in operational demand outside daytime hours

Average changes in NEM operational and underlying demand and distributed PV output – Q3 2025 vs Q3 2024



Underlying and operational demand rose across all mainland regions but declined in Tasmania (Figure 5). The rise in underlying demand was most pronounced in August and September, while Tasmania's decline was driven by lower industrial consumption.

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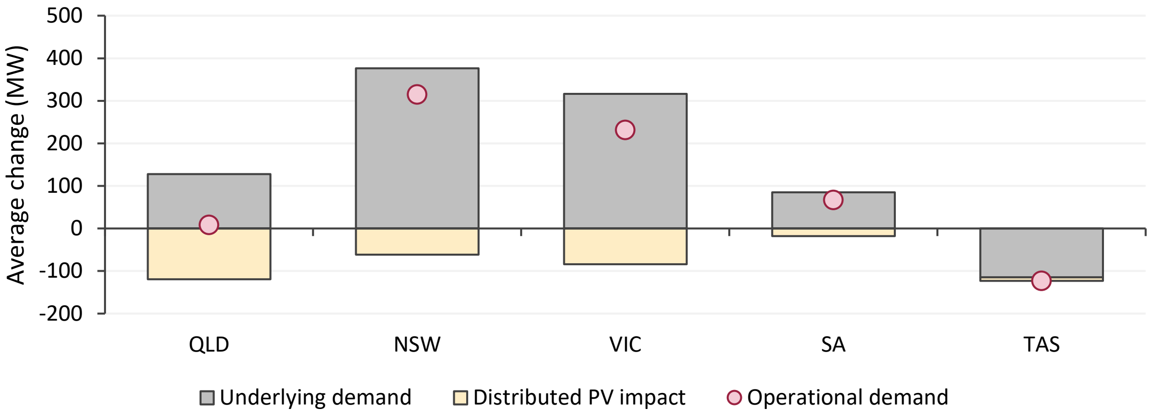
[2] Underlying demand is calculated by adding estimated production from distributed PV to operational demand, to yield an estimate of total electricity generated.

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

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

Figure 5 Operational demand increased year-on-year in all mainland regions

Changes in average underlying and operational demand as well as distributed PV – Q3 2025 vs Q3 2024



Comparing Q3 2025 with Q3 2024:

- **Queensland's** underlying demand increased to a new Q3 high, averaging 6,912 MW this quarter. However, distributed PV output increased by 120 MW (+13%), reaching a Q3 record of 1,026 MW, which led to a marginal increase in operational demand by 8 MW (+0.1%) to 5,886 MW. The increase in the underlying demand was evident across all months, influenced by higher heating requirements as well as other factors like electrification and population growth.
- In **New South Wales**, underlying demand increased by 376 MW (+4.3%) to an average of 9,064 MW, marking the highest Q3 average since 2011. Among other factors such as electrification and population growth, this rise was primarily associated with lower temperatures and increased heating needs, with significant increases noted particularly in August. Distributed PV output reached a new Q3 high, increasing by 62 MW (+7.0%) from Q3 2024 to an average of 935 MW for the quarter. Operational demand rose by 314 MW (+4.0%) to reach an average of 8,129 MW.
- **Victoria** also saw a notable rise in underlying demand, increasing by 316 MW (+5.4%) to average 6,204 MW, recording its highest Q3 average since 2010. As in New South Wales, August saw a pronounced uptick, attributed to lower temperatures that led to greater heating requirements. Distributed PV output grew by 84 MW (+19%) to reach a new Q3 high of 537 MW this quarter, partially offsetting the rise in underlying demand. Consequently, operational demand in Victoria averaged 5,667 MW, 232 MW (+4.3%) higher than the same quarter last year.
- **South Australia**'s underlying demand reached a new Q3 high of 1,764 MW this quarter, with a year-on-year increase of 85 MW (+5.0%). Distributed PV output increased by 18 MW (+6.4%) to 297 MW, a new Q3 high. Operational demand increased by 67 MW (+4.8%) to average 1,467 MW this quarter.
- **Tasmania** recorded the only decline in underlying demand this quarter, down by 115 MW (-8.7%) from the same period last year. Unlike the mainland regions, Tasmania's average maximum temperatures remained largely unchanged (see Section 1), with the reduction in underlying demand mainly driven by lower industrial demand. Distributed PV output reached a new Q3 high of 36 MW, 8 MW (+30%) higher than the same period last year. This further decreased operational demand, which fell by 123 MW (-9.5%) to 1,174 MW, its lowest Q3 average since Tasmania joined the NEM in 2005.

Maximum and minimum demands

In Q3 2025, NEM-wide **maximum operational demand** reached 33,264 MW in the half-hour ending 1830 hrs on 1 July 2025. This was 117 MW (-0.4%) below the Q3 2024 maximum and 1,224 MW (-3.5%) lower than the highest NEM Q3 maximum operational demand recorded in 2008[5].

Victoria set a new Q3 high for maximum operational demand, reaching 8,623 MW in the half-hour ending 1800 hrs on 25 July 2025 (Figure 6). This was 11 MW (+0.1%) above the previous record set in Q3 last year.

New South Wales's maximum demand rose 639 MW (+5.1%) from Q3 2024 to reach its third-highest Q3 level at 13,204 MW, following 14,289 MW in 2008 and 13,871 MW in 2007. South Australia's maximum operational demand also increased by 79 MW (+3.1%) from Q3 2024 to 2,594 MW but Queensland's reduced by 254 MW (-2.9%) and Tasmania's reduced by 175 MW (-10%). All regions' maximums occurred in July.

NEM-wide **minimum operational demand** reached a new Q3 low of 10,175 MW in the half-hour ending at 1300 hrs on 14 September 2025. This was driven by mild and sunny conditions in south-eastern Australia yielding high distributed PV output during a period of low underlying demand. This new Q3 low was 1,218 MW (-11%) below the previous Q3 minimum recorded in 2023. On the same day, South Australia recorded new Q3 minimum operational demand at -14 MW, 35 MW lower than the previous Q3 minimum from 2023. New South Wales set a new Q3 minimum demand record at 3,265 MW in the half-hour ending at 1200 hrs on 21 September 2025, which was 290 MW (-8.0%) below the previous Q3 low set in 2024.

Queensland's minimum operational demand fell to a new record of 2,790 MW in the half-hour ending at 1130 hrs on 31 August 2025, some 301 MW (-9.7%) below the previous mark also set in 2024. Tasmania saw a slight 5 MW (-0.6%) decrease in minimum operational demand compared to Q3 2024, while Victoria's minimum this Q3 was 213 MW (11%) higher than last year's low point (Figure 7).

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

Figure 6 New Q3 maximum operational demand record in Victoria

Maximum operational demand for mainland regions – Q3s

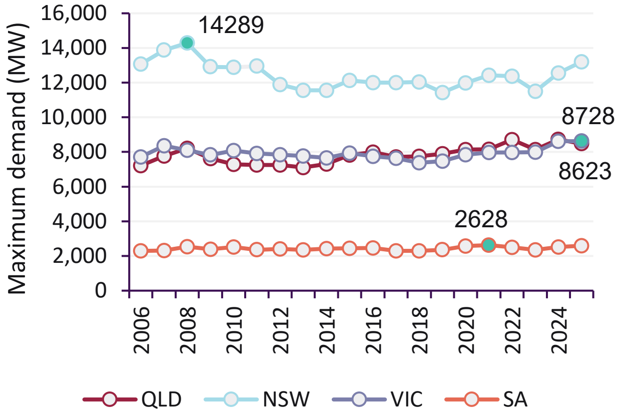
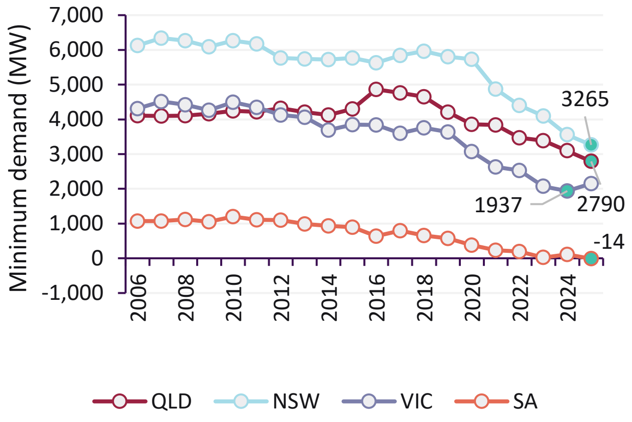


Figure 7 New South Wales, Queensland and South Australia recorded new lows for Q3 minimum operational demand

Minimum operational demand for mainland regions – Q3s

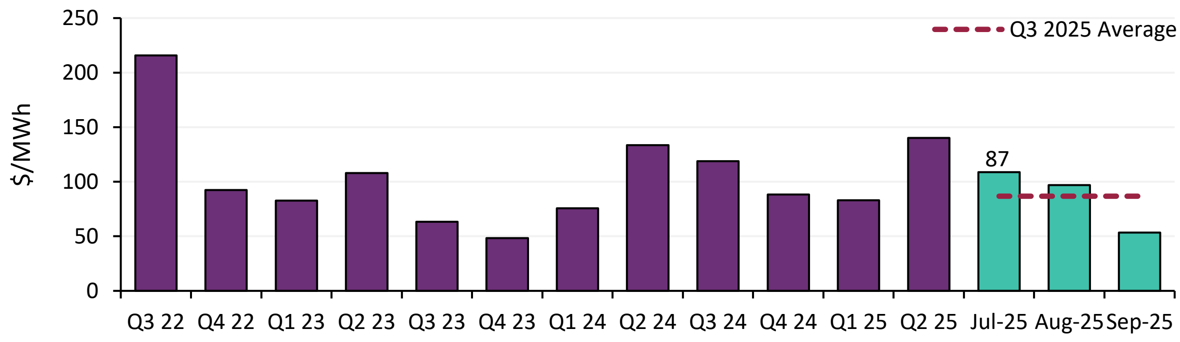


2.2 Wholesale electricity prices

In Q3 2025, wholesale electricity prices across the NEM averaged $87/MWh[6], down 27% from Q3 2024 and 38% from Q2 2025 (Figure 8). Lower price volatility and higher renewable output offset the impact of increased operational demand, resulting in average prices of $109/MWh in July and $97/MWh in August. Seasonally lower demand and warmer sunnier weather conditions pushed September prices further down to $53/MWh.

Figure 8 Significant drop in NEM average wholesale prices

NEM average wholesale electricity spot prices – quarterly since Q3 2022



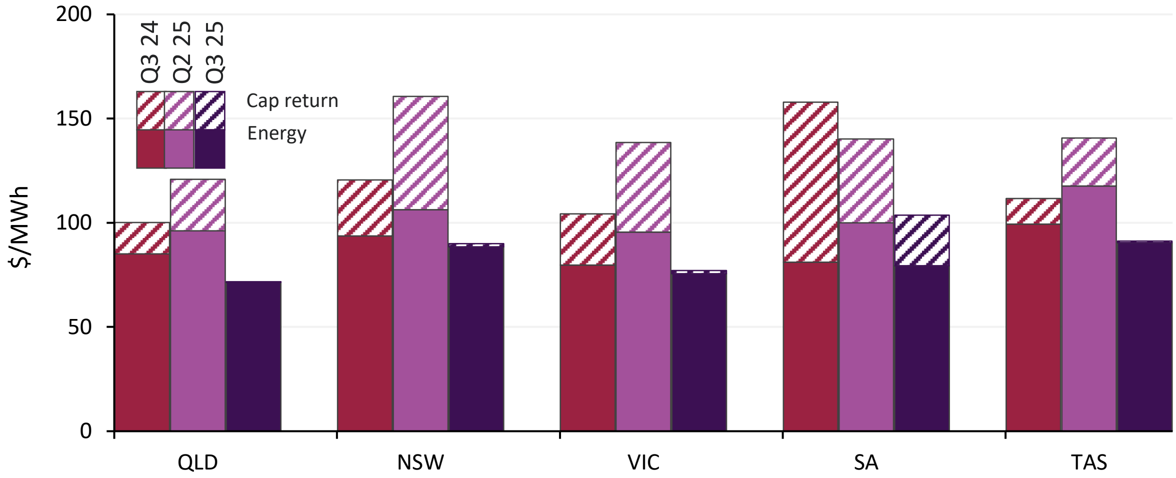
[6] Time-weighted average – simple average of regional wholesale electricity spot prices over each five-minute dispatch period over the quarter.

The energy component[7] of wholesale prices across the NEM dropped from $88/MWh in Q3 2024 to $81/MWh in Q3 2025 (Figure 9). All regions experienced year-on-year decreases in the energy component, with Queensland recording the most notable decline.

Price volatility fell in all regions, with the NEM-wide average cap return down sharply from $31/MWh in Q3 2024 to $6/MWh (-82%) in Q3 2025. The only notable high-price events driving material regional cap returns were in South Australia, where the quarterly cap return component averaged $24/MWh, primarily due to price volatility on 2 July 2025 which contributed $19/MWh to the region's quarterly average price.

Figure 9 Significantly lower price volatility drove Q3 spot prices lower in all regions

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



By region:

- **Queensland** saw the lowest regional average wholesale spot prices across the NEM at $72/MWh, a year-on-year decrease of $28/MWh (-28%) from Q3 2024. Queensland also experienced a notable reduction in the energy component compared to Q3 2024, declining by $14/MWh (-16%) to $71/MWh. The cap return component was negligible, dropping from $15/MWh in Q3 2024, with no significant high-price volatility observed this quarter.
- In **New South Wales**, wholesale spot prices averaged $90/MWh this quarter, down $31/MWh (-25%) from Q3 2024. The energy component of the quarterly average declined from $94/MWh in Q3 2024 to $88/MWh in Q3 2025, while the cap return component dropped sharply from $27/MWh in Q3 2024 to just $2/MWh this quarter.
- **Victoria**'s wholesale prices dropped by $27/MWh (-26%) to an average of $77/MWh. The energy component decreased slightly by $4/MWh (-5%), while cap return fell sharply from $25/MWh in Q3 2024 to just $1/MWh in Q3 2025.
- **South Australia** recorded Q3's highest regional average wholesale spot price across the NEM at $104/MWh, despite a decrease of $54/MWh (-34%) from Q3 2024. This was also the only region to experience material high-priced volatility this quarter, with a cap return contribution of $24/MWh, which was nevertheless a reduction of $52/MWh (-68%) on the

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

same period last year. On 2 July, a high-priced event added $18.5/MWh to the regional average price, with prices in 233 dispatch intervals exceeding $300/MWh on that day. Over the quarter, 775 intervals recorded prices above $300/MWh in South Australia. The region's energy component decreased slightly by $2/MWh (-2%) relative to Q3 2024.

- **Tasmania**'s wholesale spot prices averaged $91/MWh for the quarter, a decrease of $20/MWh (-18%) compared to Q3 2024. Consistent with trends observed in most mainland regions, Tasmania's energy component price experienced a modest decrease of $9/MWh (-9%), resulting in an average of $90/MWh along with reduced operational demand. The cap return component declined significantly from $12/MWh in Q3 2024 to $1/MWh this quarter.

The reduction in NEM wholesale prices was notable during morning and evening peak hours, indicating the influence of reduced price volatility this quarter (see Figure 11 in Section 2.2.2). Throughout most daytime and overnight periods, prices remained largely unchanged from the previous Q3, as increased renewable energy generation offset higher operational demand.

Volume-weighted average price (VWAP)

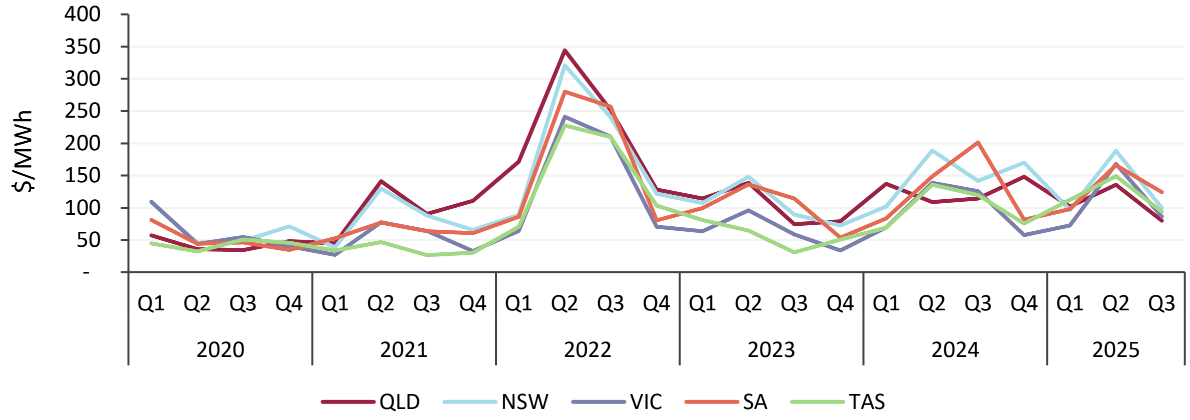
The VWAP[8] reflects the overall spot market value of energy produced in each region, whereas the time-weighted average price (TWAP) (as discussed above) represents the simple average of prices across all intervals, without accounting for the level of demand or generation in each period. VWAP typically exceeds TWAP as prices are correlated with operational demand throughout the day, particularly during evening peaks when demand and prices tend to be higher. Periods of high volatility tend to widen this gap further. In this quarter, with lower volatility compared to Q3 2024, the fall in VWAP was slightly higher than that in TWAP, resulting in both measures converging relative to the previous Q3 across all regions.

In Q3 2025, VWAP across NEM regions ranged from $80/MWh in Queensland to $124/MWh in South Australia, while New South Wales, Victoria, and Tasmania recorded averages of $100/MWh, $86/MWh, and $94/MWh respectively (Figure 10). Regionally, these figures represent reductions of 22-38% compared to Q3 2024, compared to 18-34% year-on-year declines in TWAP.

[8] 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.

Figure 10 Volume-weighted average prices declined significantly in all regions

Volume-weighted average prices by region – quarterly since Q1 2020



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 Q3 2025

Lower price volatility	In Q3 2025, aggregate regional cap returns across the NEM fell sharply from $155/MWh in Q3 2024 to just $28/MWh (Section 2.2.2). The high price volatility in Q3 2024 was driven by frequent periods of peak operational demand (NEM-wide demand > 28 GW), coinciding with low wind output and coal outages, which created tight supply-demand conditions. In South Australia, this was further exacerbated by times when Heywood interconnector exports were constrained to below 100 MW (QED Q3 2024). In contrast, Q3 2025 saw generally higher operational demand than the same quarter last year but experienced far fewer deep wind lulls (see Section 2.3.4). During peak periods the increase in wind generation, supported by higher net coal output, largely offset the rise in operational demand. Across the evening peak (1600–2000 hrs), operational demand increased by 655 MW (+2.5%) (see Figure 4 in Section 2.1), while wind generation recorded a significant year-on-year increase of 552 MW (+14%), helping to meet the demand growth. Battery discharge also rose sharply, increasing by 463 MW (+177%) during the evening peak, reflecting the continued expansion of battery capacity across the NEM. This additional battery output reduced the dispatch level of gas and hydro generation at these peak times on high demand days (Section 2.3). This led to a significant reduction in price volatility compared to Q3 2024. The only major price spike this quarter occurred in South Australia, when high demand coincided with low wind conditions and restricted Heywood flows.
Increased renewable energy output offset the growth in operational demand	In this quarter, average variable renewable energy (VRE) output reached a new quarterly record of 6,374 MW, up 870 MW (+16%) from Q3 2024, supported by continued growth in grid-scale solar and wind capacity. Wind generation contributed an additional 632 MW (+16%), while solar rose by 238 MW (+16%) (Section 2.3.4). The surge in low-cost renewable output more than offset a 498 MW (+2.3%) rise in operational demand (Section 2.1), lifting the renewable share of generation to 42.7%, its highest Q3 level on record (Section 2.3). With more energy supplied by wind and solar, the need for higher-cost thermal generation declined, particularly during peak periods. This VRE growth contributed to reduction in both average spot prices and the frequency of high-priced intervals across all regions. As a result, the energy component of wholesale prices fell from $88/MWh in Q3 2024 to $81/MWh in Q3 2025, with every NEM region contributing to the decline (Section 2.2).

2.2.2 Wholesale electricity price volatility

During Q3 2025, aggregate regional cap returns across the NEM – which reflect contributions from spot prices exceeding $300/MWh – amounted to $28/MWh, a very large decrease of $127/MW (-82%) from Q3 2024 (Figure 12). Virtually all this quarterly cap return arose in South Australia, which averaged $24/MWh, with a high-priced event on 2 July contributing $19/MWh. Notably, the NEM quarterly cap return for Q3 2025 was the lowest recorded since Q4 2023.

All regions contributed to the decrease in cap returns this quarter. South Australia, while experiencing the only significant price volatility this quarter, also recorded the largest year-on-year fall, down by $52/MWh from last Q3's $77/MWh. Other regions had very low cap returns, ranging between $0/MWh and $2/MWh for the quarter.

Figure 11 NEM average prices dropped significantly during the morning and evening peak

NEM average spot price by time of day – Q3 2025 vs Q3 2024

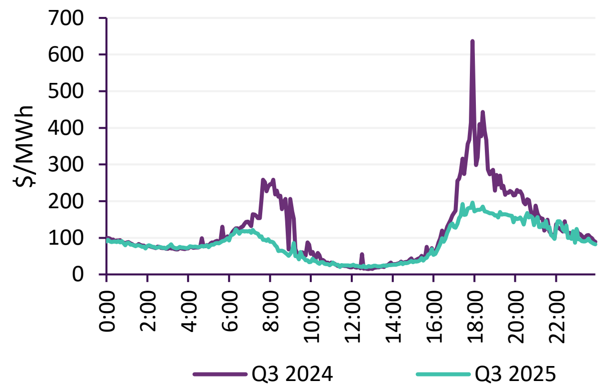
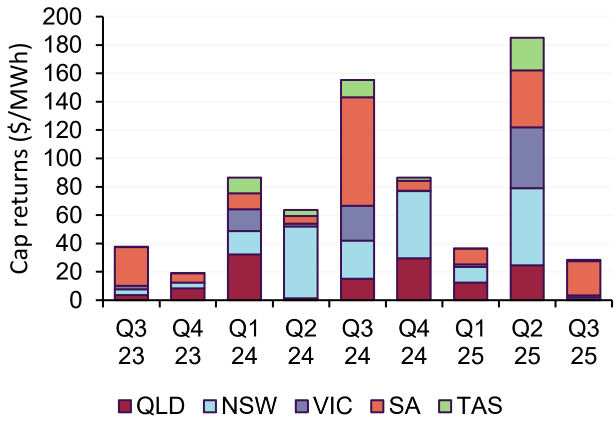


Figure 12 Cap return significantly lower in all regions

Cap returns by region – quarterly

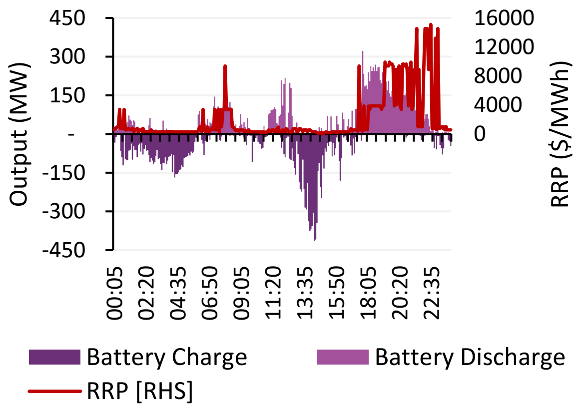


South Australia's price volatility on 2 July

On this day, South Australia experienced elevated electricity prices during both morning and evening peak periods, with 68 intervals exceeding $3,000/MWh including seven intervals above $13,000/MWh.

Figure 13 South Australia's price spike on 2 July

Battery charge, discharge and RRP [RHS] on 2 July – South Australia



Regional demand peaked above 2,300 MW in the evening and 2,100 MW in the morning peak periods. Wind generation was notably low, averaging only 53 MW for the day (2% of maximum capacity). At the same time, imports into South Australia were restricted by transmission limitations on the Heywood interconnector due to a Tailem Bend – South East 275 kV line outage, further tightening the supply conditions. During the day, Heywood flows into South Australia were limited to under 100 MW[9] in 44 intervals, with majority of this occurring during the evening peak.

Outside daylight hours, when solar generation was unavailable, gas and battery output increased to meet demand. However, as battery discharge declined with lower state of charge (SOC), high demand coincided with persistently low wind generation and reduced import capabilities, resulting in tight supply demand balance and sustained high prices throughout peak periods (Figure 13 above). The daily average price reached $1,999/MWh for the region, contributing $19/MWh to the quarterly regional cap return, with 233 out of 288 intervals recording prices above $300/MWh during the day.

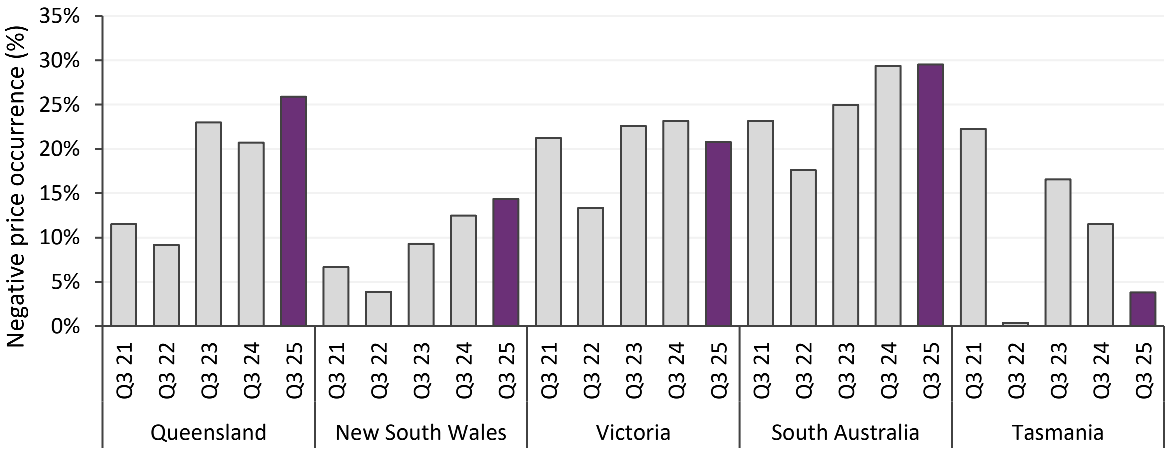
[9] Heywood and the first stage of Project EnergyConnect (PEC-1) have a combined maximum transfer limit of 750 MW from Victoria to South Australia. Refer to Interconnector Capabilities here: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2024/interconnector-capabilities.pdf.

2.2.3 Negative wholesale electricity prices

This quarter, 18.9% of dispatch intervals recorded negative or zero prices, marginally lower – by 0.6 percentage points (pp) – than last Q3. Victoria and Tasmania experienced reductions in the occurrence of negative prices, while other regions saw increases. Queensland's negative price occurrence reached a record high for any quarter at 25.9% this Q3, as did New South Wales at 14.4% (Figure 14).

Figure 14 Record high negative price occurrence in Queensland and New South Wales

Negative price occurrence in NEM regions – Q3s



Negative price occurrence is most frequent in daytime hours when operational demand falls due to distributed PV output, and large-scale variable renewable energy (VRE) generation output is higher (Figure 15). Between 0900 and 1700 hrs, Queensland negative price occurrence reached 66% of intervals (up 13 pp from Q3 2024) and New South Wales 38% (up 5 pp from Q3 2024). South Australia and Victoria also regularly recorded negative prices during overnight hours, reflecting the significant contribution of wind generation in these regions. Between 2200 and 0600 hrs, negative prices occurred 22% and 17% of the time in South Australia and Victoria, compared to 54% and 38% respectively during daytime hours (between 0900 and 1700 hrs).

A larger share of negative spot prices fell within the -$30/MWh to $0/MWh range this quarter, increasing to 90% this Q3 compared to 39% last year (Figure 16). This shift coincided with lower prices for large-scale generation certificates (LGCs), which averaged $13/certificate in Q3 2025 compared with $45/certificate a year earlier. Consequently, the average electricity spot price during negative intervals rose to -$16/MWh, from -$33/MWh in Q3 2024. Together with the slightly lower overall occurrence of negative pricing, this yielded a sharp reduction in the NEM-wide negative price impact[10] – reflecting the combined effect of negative price levels and frequencies on quarterly average price – which declined from $6.4/MWh in Q3 2024 to $3.0/MWh this quarter.

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

Figure 15 Negative prices observed overnight and during daytime in South Australia and Victoria

Negative price occurrence by time of day – Q3 2025

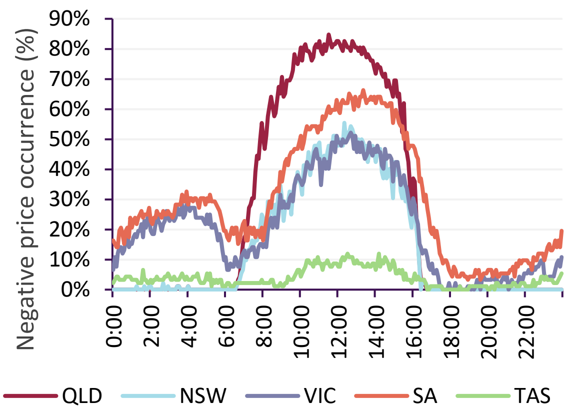
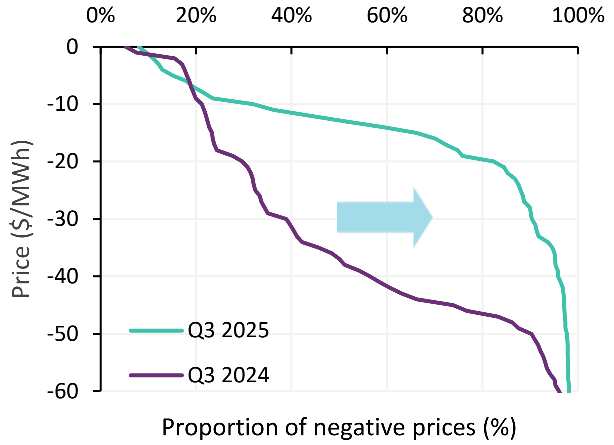


Figure 16 Negative prices were smaller in magnitude in Q3 2025

Cumulative distribution of negative prices – Q3 2025 vs Q3 2024



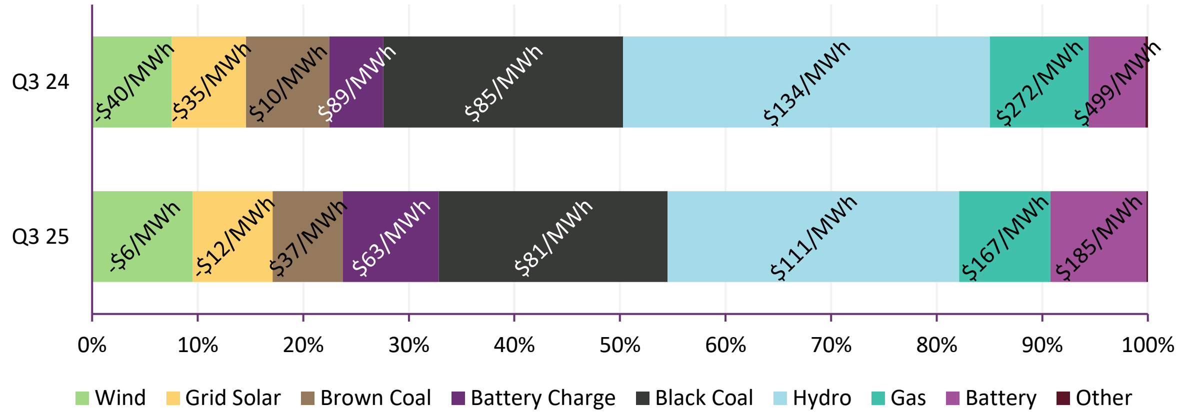
2.2.4 Price-setting dynamics

This quarter found wind, grid-scale solar, battery discharge, and battery charge technologies setting NEM prices more frequently than in Q3 2024, while other energy sources saw a decline. Battery discharge and charge both increased by 4 pp year-on-year, reaching 9% each. Hydro decreased by 7pp but remained the most frequent price setting technology across the NEM at 28%.

Average prices set when marginal declined for most sources, except wind, grid-scale solar, and brown coal, which showed year-on-year increases of $34/MWh, $23/MWh, and $27/MWh, respectively, to averages of $-6/MWh, $-12/MWh, and $37/MWh (Figure 17). Battery discharge recorded the largest decrease, down $314/MWh year-on-year to $185/MWh. Gas also fell from $272/MWh in Q3 2024 to $167/MWh in this quarter. These movements corresponded with reduced price volatility and contributed to the year-on-year decrease in the cap return component of spot prices. These NEM-wide averages for all sources were impacted by the effects of Basslink transfer costs, primarily on Tasmanian spot prices, as explained in the following section.

Figure 17 Wind, grid solar and brown coal saw year-on-year increases in prices set when marginal while other technologies saw reductions

NEM price-setting frequency and average spot price when price-setter by fuel type – Q3 2025 vs Q3 2024



Impact of Basslink on price-setting

Basslink operates as a non-regulated Market Network Service Provider (MNSP), offering transfer capacity between Victoria and Tasmania through market offers. These transfer costs are incorporated into the marginal cost of energy and thus influence price-setting dynamics in both Tasmania and Victoria as well as other regions. In Q3 2025, the pricing of Basslink transfer offers rose sharply, as discussed in Section 2.4 below.

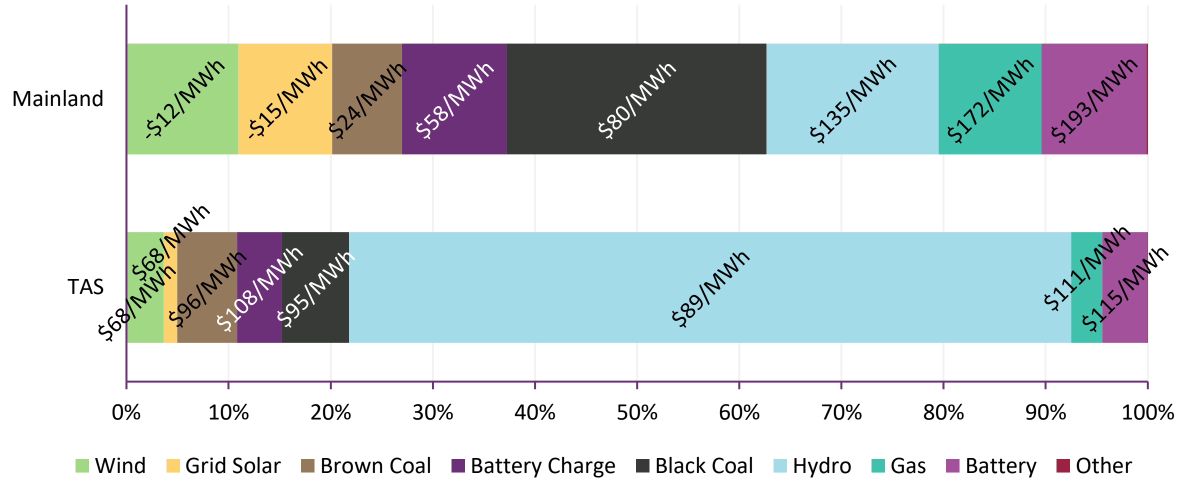
During this quarter, lower-cost fuel sources such as wind and grid-scale solar set marginal prices in Tasmania at significantly higher levels than those observed on the mainland. Specifically, wind and grid-scale solar each set average prices of $68/MWh in Tasmania, compared to $-12/MWh and $-15/MWh respectively in mainland regions (Figure 18). This reflects Basslink transfer costs being incorporated into the marginal cost of energy in Tasmania when the underlying price-setting energy source is on the mainland. In Q3 2025, Basslink imports to Tasmania contributed to price setting in 21% of intervals, with an average transfer price of $73/MWh[11], and contributed $15/MWh to the region's quarterly average spot prices. Black coal, brown coal and battery charge also set higher Tasmanian than mainland price levels when marginal.

Conversely, when higher-cost fuels such as hydro, gas, and battery discharge set prices in Tasmania, the average prices were lower than mainland levels, at $89/MWh, $111/MWh, and $115/MWh respectively. As mainland gas and battery discharge sources typically set prices in Tasmania only when mainland prices are high and Basslink flows northward, for Tasmanian pricing, the marginal cost of Basslink transfers is deducted from the prices being set on the mainland.

[11] This is the average of the marginal "RRN band price" (offer price) for Basslink imports when involved in price-setting.

Figure 18 Wind, grid solar and brown coal set notably higher Tasmanian prices than on mainland

NEM price-setting frequency and average spot price when price-setter by fuel type – Mainland vs Tasmania in Q3 2025

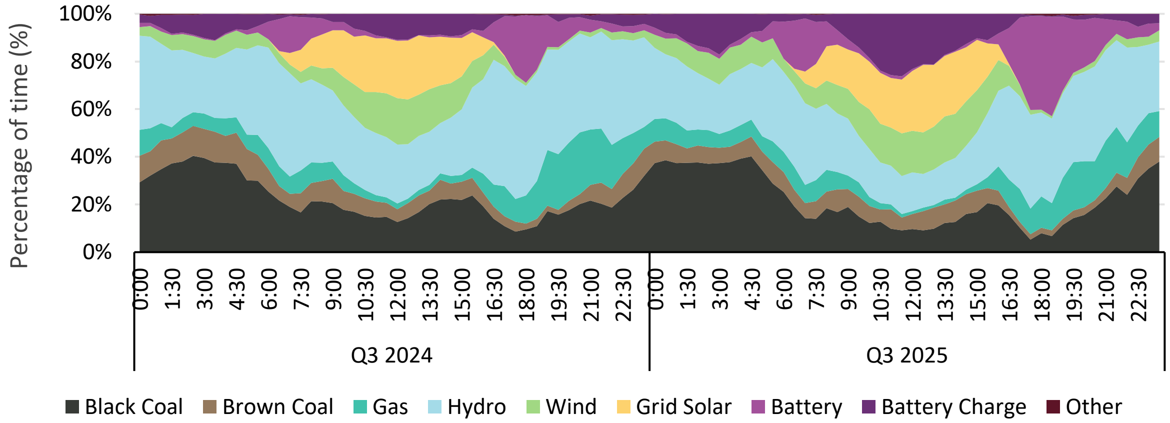


Price-setting by time of day

Hydro generation set prices less frequently across all times of day in Q3 2025, with a particularly pronounced decline during the evening peak. Specifically, the proportion of intervals between 1600 hrs and 2000 hrs where hydro generation set the price fell from an average of 46% in Q3 2024 to 36% in this quarter (Figure 19). In contrast, battery discharge price-setting frequency in those hours rose from 16% to 28%. During the daytime period, battery charging set prices much more frequently, up from 9% to 19%, while black coal price-setting frequency declined from 18% to 13%.

Figure 19 Reduction in hydro price-setting in evening peak offset by an increase in battery discharge price-setting

NEM price-setting frequency by fuel type and time of day – Q3 2024 and Q3 2025

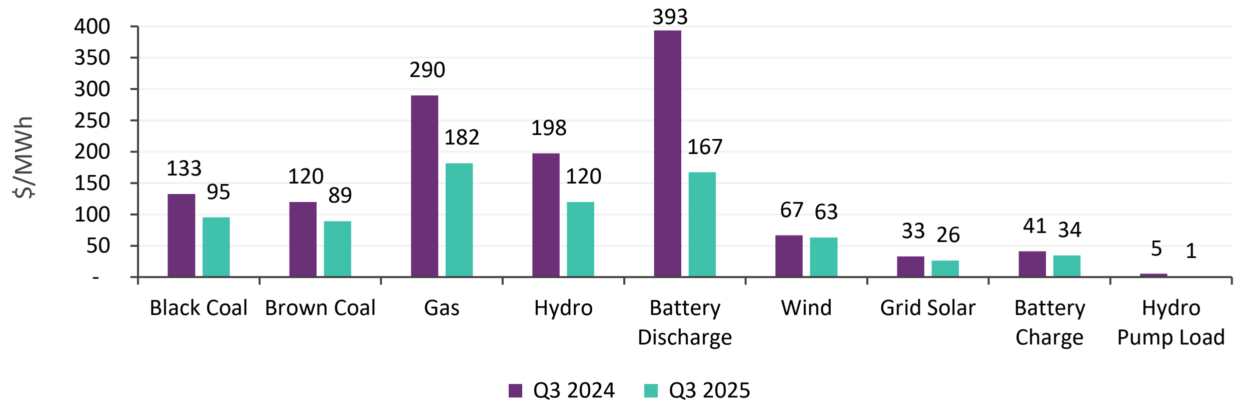


2.2.5 Volume-weighted average prices by fuel type

Figure 20 illustrates the average spot prices earned[12] or incurred by various fuel types across the NEM, determined as VWAP, with that fuel type's generation or load volumes in each dispatch interval used as spot price weights. During this quarter, all fuel types experienced year-on-year reductions in VWAP corresponding to lower spot prices throughout the NEM. Battery discharge and gas recorded significant decreases of 57% and 37%, resulting in VWAPs of $167/MWh and $182/MWh, respectively. This outcome reflects decreased price volatility, with fewer occurrences of prices above $300/MWh. Gas generators earned the highest VWAP among all fuel types in Q3 2025, while grid-scale solar and wind had the lowest averages (except for battery charge and hydro pump), at $26/MWh and $63/MWh respectively. The energy component of spot prices declined across all regions compared to the same period last year; this also resulted in lower average spot prices earned by black coal and brown coal. The VWAP for battery charge and hydro pump load decreased marginally from the previous Q3 to $34/MWh and $1/MWh, respectively.

Figure 20 All fuel types earned or incurred lower average spot prices

Volume weighted average prices by fuel type – Q3 2025 vs Q3 2024



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 21 illustrates Australian Securities Exchange (ASX) daily prices for Q3 2025 base contracts across NEM mainland regions. Final settlement prices for such current quarter contracts are set at quarter end to the time-weighted quarterly average wholesale price for the relevant region, but prior to this "delivery quarter" their traded prices reflect market expectations. During the delivery quarter, traded prices were influenced by both quarter to date wholesale price levels and expectations for the balance of quarter, ultimately converging to the final settlement price.

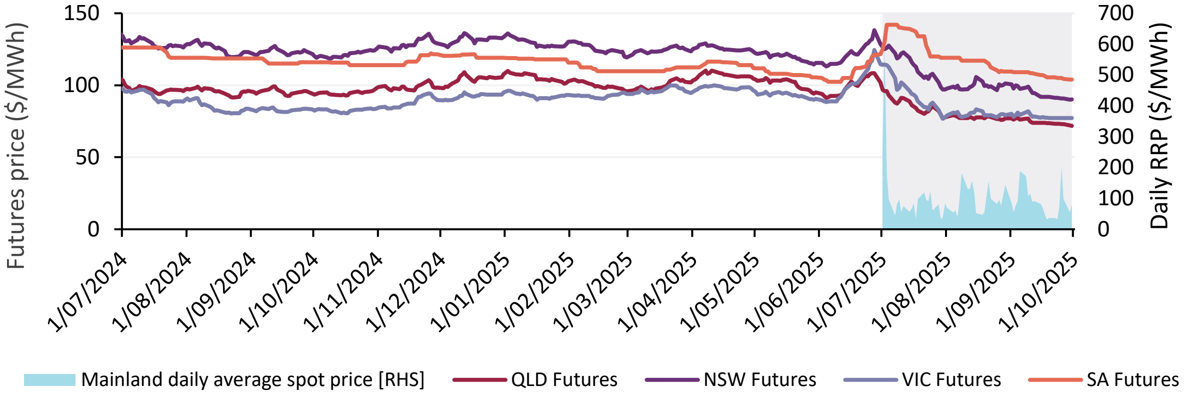
Following the period of high price volatility in South Australia on 1-2 July 2025, ASX contract prices for Q3 2025 rose sharply, increasing from $122/MWh at the end of the previous quarter to $142/MWh on 3 July. Subsequently, Q3 contract prices in South Australia trended lower as market conditions stabilised and volatility eased throughout the remainder of the quarter.

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

Across all other regions, ASX contract prices for Q3 2025 also declined steadily, reflecting the lower-than-expected spot price volatility observed during the period.

Figure 21 Q3 2025 base futures continued to decline throughout the quarter

ASX Energy – Regional daily Q3 2025 base futures prices and daily average spot price for mainland regions

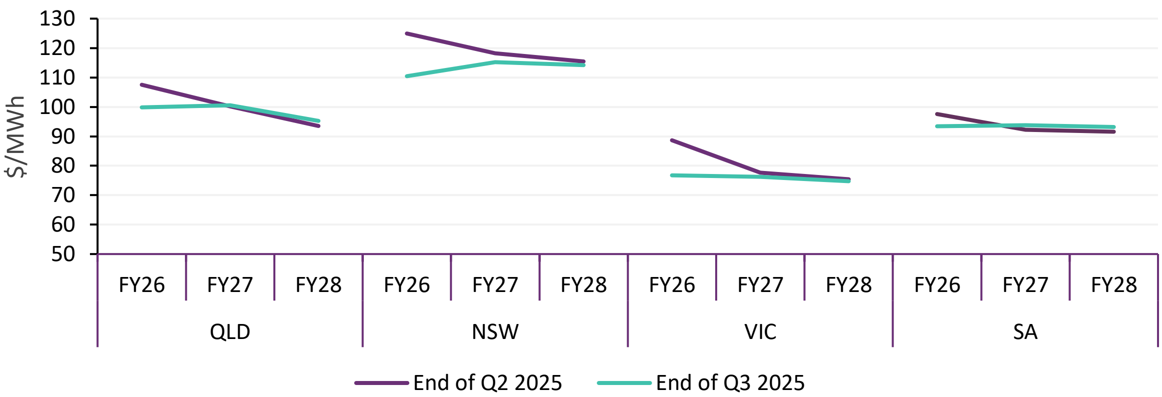


ASX base contract prices for FY26 averaged $98/MWh across mainland regions in Q3 2025, down $3/MWh (-3%) from Q2 and $1/MWh (-1%) year-on-year, driven by lower-than-expected price volatility. Future prices for FY26 eased through most of the quarter and ended the quarter below Q2 levels, with New South Wales at $110/MWh (-12%), Victoria at $77/MWh (-13%), Queensland at $100/MWh (-7%), and South Australia at $93/MWh (-4%).

By the end of Q3, forward futures for Victoria and South Australia flattened into FY27 and FY28, while Queensland continued its downward trend and New South Wales exhibited a long-term increase (Figure 22).

Figure 22 FY26 futures declined over the quarter, with forward contracts flattening across most regions

ASX Energy – Financial year futures contract prices in mainland NEM regions – end of Q2 2025 and end of Q3 2025



Morning and evening peak futures

In Q3 2025, ASX launched Morning and Evening Peak Electricity Futures across NEM regions, with New South Wales commencing on 30 June, followed by Queensland on 7 July, Victoria on 21 July and South Australia on 28 July[13]. These

[13] See ASX Announcement: https://www.asxenergy.com.au/newsroom/industry_news/launching-morning-and-evening.

contracts provide market participants with new hedging options for the morning (0600-0900 Australian Eastern Standard Time [AEST]) and evening (1600-2100 AEST) peak demand periods. Trading activity in these products remained limited during Q3 2025, with minimal liquidity observed through the quarter as the market adjusts to their introduction.

2.3 Electricity generation

Total NEM generation[14] averaged 25,863 MW in Q3 2025, an increase of 981 MW (+3.9%) from Q3 2024. This growth reflects higher underlying demand (+790 MW) and increased supply for battery charging (+154 MW).

The change in average NEM generation by fuel type relative to Q3 2024 is shown in Figure 23 and the changes in supply mix contributions are shown in Table 2. Renewable energy share reached a new Q3 record at 42.7%, up from 39.3% in Q3 2024. Uplifts in wind, distributed PV and grid-scale solar output drove this increase despite a small reduction in hydro generation.

Comparing Q3 2025 with Q3 2024:

- VRE generation, comprising wind and grid-scale solar, reached a new record high of 6,374 MW, supassing the previous record set in Q1 2025 by 471 MW (+8.0%). Wind generation also reached a new quarterly record, increasing by 632 MW (+16%) from the previous record set in Q3 2024 to an average of 4,676 MW. This reflected the growth in new and comissioning wind farms, which was partially offset by increases in economic offloading and curtailment. Distributed PV generation increased to an average 2,831 MW (+11%) and grid-scale solar generation increased by 238 MW (+16%) to average 1,699 MW.
- Battery discharge recorded the highest percentage growth this quarter as new battery systems entered the NEM. Average discharge grew 150% year-on-year to 215 MW, a new quarterly high.
- Overall NEM coal-fired generation decreased by 103 MW (-0.8%), although black coal-fired generation increased by 81 MW to average 9,974 MW. Brown coal-fired generation more than offset this with a decrease of 184 MW to average 3,518 MW in Q3 2025. The share of black coal-fired generation in total generation decreased to 38.6% (-1.2 pp), while brown coal-fired output's share decreased to 13.6% (-1.3 pp), as the share of most renewable sources increased to meet the rise in overall demand. Gas-fired generation also decreased by 159 MW year-on-year to average 1,334 MW this quarter. This resulted in the fossil fuel share of total generation reducing from 60.7% in Q3 2024 to 57.3% in Q3 2025.

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

Figure 23 Net supply rises with higher renewable output

Change in NEM supply by fuel type – Q3 2025 vs Q3 2024

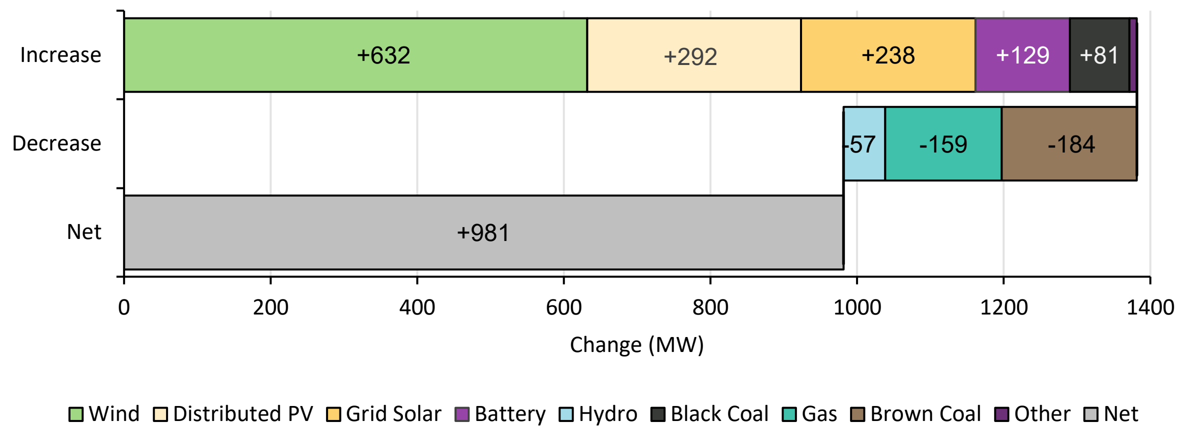


Table 2 NEM supply mix contribution by fuel type

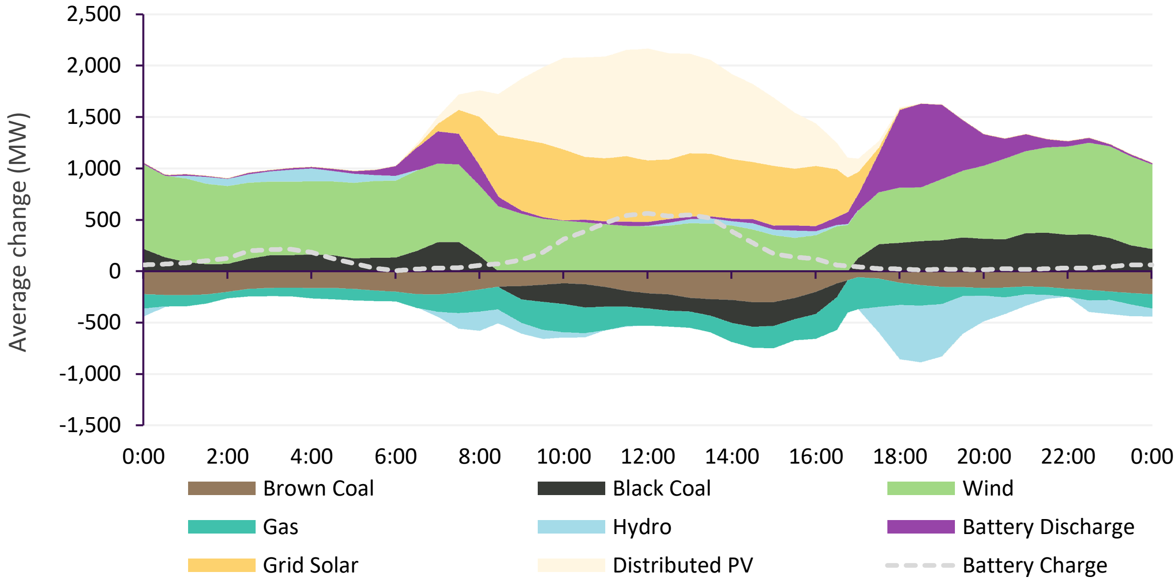
Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Biomass	Battery
Q3 24	39.8%	14.9%	6.0%	0.01%	10.2%	16.3%	5.9%	6.4%	0.23%	0.3%
Q3 25	38.6%	13.6%	5.2%	0.01%	10.9%	18.1%	6.6%	6.0%	0.26%	0.8%
Change	-1.2%	-1.3%	-0.8%	0.00%	0.7%	1.8%	0.7%	-0.5%	0.03%	0.5%

Figure 24 illustrates changes in the NEM supply mix from Q3 2024 to Q3 2025 by time of day. Gas and brown coal-fired generation declined across all hours of the day, while wind output increased across all hours.

During the morning peak (0600-1000 hrs), wind generation rose by 16% and grid-scale solar by 19%. Battery discharge also surged, increasing by 146 MW (+107%) year-on-year. In the daytime period (1000-1600 hrs), battery charging activity grew significantly, an increase of 388 MW (+166%) as battery capacity increased. During the evening peak (1600-2000 hrs), wind recorded the largest uplift of any fuel type, increasing by 552 MW (+14%). Battery discharge also rose sharply in the evening peak, up 463 MW (+177%), displacing hydro and gas generation, which fell by 304 MW (-10%) and 207 MW (-7%) respectively.

Figure 24 Renewables and battery discharge support demand across the day

NEM change in fuel mix by time of day – Q3 2025 vs Q3 2024



2.3.1 Coal-fired generation

Black coal-fired fleet

Black coal-fired generation averaged 9,974 MW this quarter, an increase of 81 MW (+0.8%) on Q3 2024 (Figure 25). This was supported by a year-on-year rise in availability of 211 MW (+1.7%). Availability increased by 89 MW (+1.3%) in New South Wales and by 122 MW (+2.0%) in Queensland. Increases were largely driven by fewer full outages, with average capacity on full unit outages declining by 487 MW (-16%) as shown in (Figure 26).

Figure 25 Increase in NEM black coal-fired availability and output

Quarterly average black coal-fired generation and availability by region – Q3s

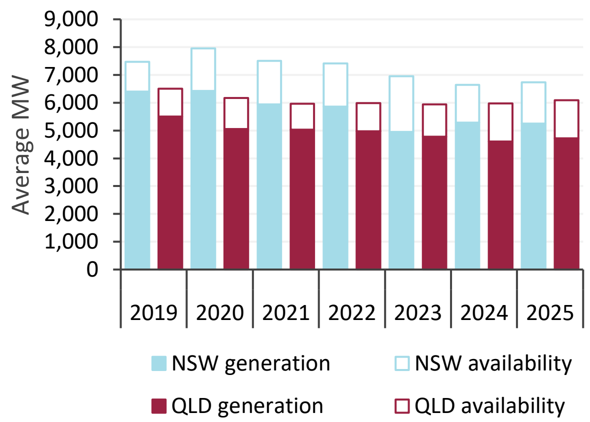
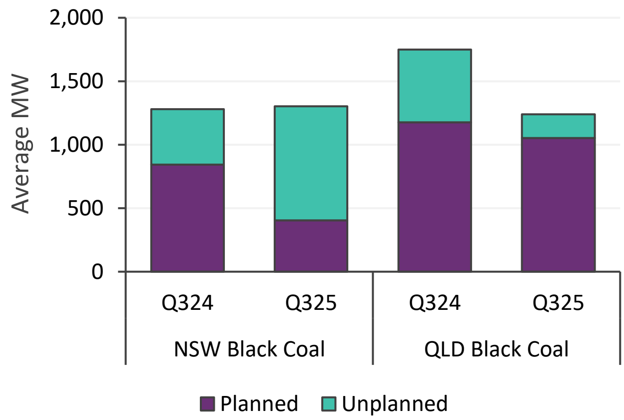


Figure 26 Black coal-fired capacity on full unit outage declined

Average coal-fired capacity on full outage – Q3 2025 vs Q3 2024

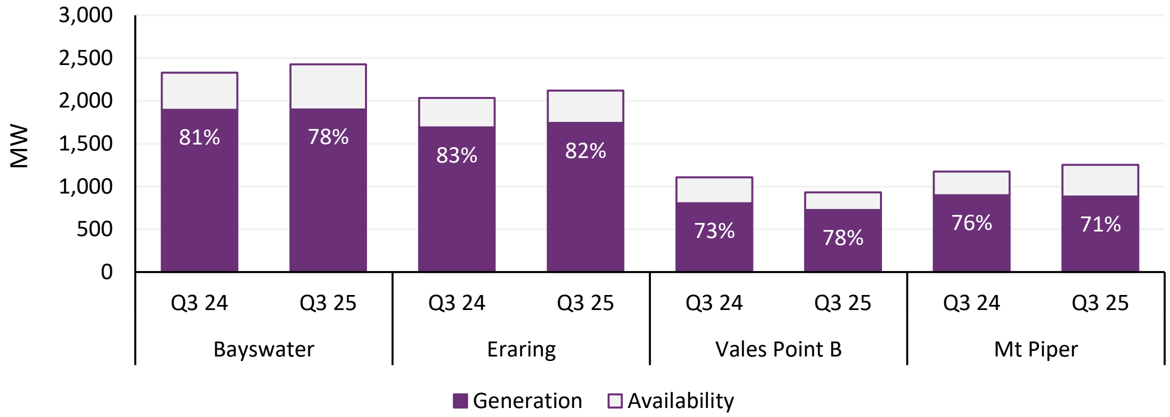


In Q3 2025, black coal-fired generation in New South Wales remained broadly in line with last quarter, averaging 5,249 MW (-0.7%). Total average availability increased to 6,732 MW (+1.3%), while the average capacity on full unit outage increased by 23 MW (+1.8%).

Figure 27 shows the availability, generation and utilisation rates for the New South Wales black coal-fired power stations. Bayswater maintained similar output to Q3 2024, averaging 1,901 MW (+0.3%), supported by a 98 MW increase in availability. The utilisation rate dropped by 3.1 pp to 78% this quarter. Eraring output increased by 53 MW to average 1,741 MW (+3.1%) this quarter, with availability also up by 89 MW. This was driven by a 69 MW reduction in average capacity on outage, while the utilisation rate remained steady year-on-year at 82%. In contrast, Mt Piper saw a slight decline in output, averaging 883 MW (-1.6%), despite a 76 MW (+7%) increase in availability with utilisation dropping by 5.8 pp to 71%. Vales Point B was the only station to record a fall in availability (-175 MW), with average capacity on outage increasing by 245 MW. However, utilisation rose by 5 pp to 78%, so the decline in generation was smaller at 80 MW (-10%) to an average of 724 MW.

Figure 27 Increased availability across New South Wales black coal-fired fleet, excluding Vales Point B

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q3 2025 vs Q3 2024



Queensland black coal-fired generation rose by 118 MW to average 4,724 MW in Q3 2025 (+2.6%), driven by a 2.0% lift in availability. This followed a 510 MW (-29%) reduction in average capacity on full unit outage.

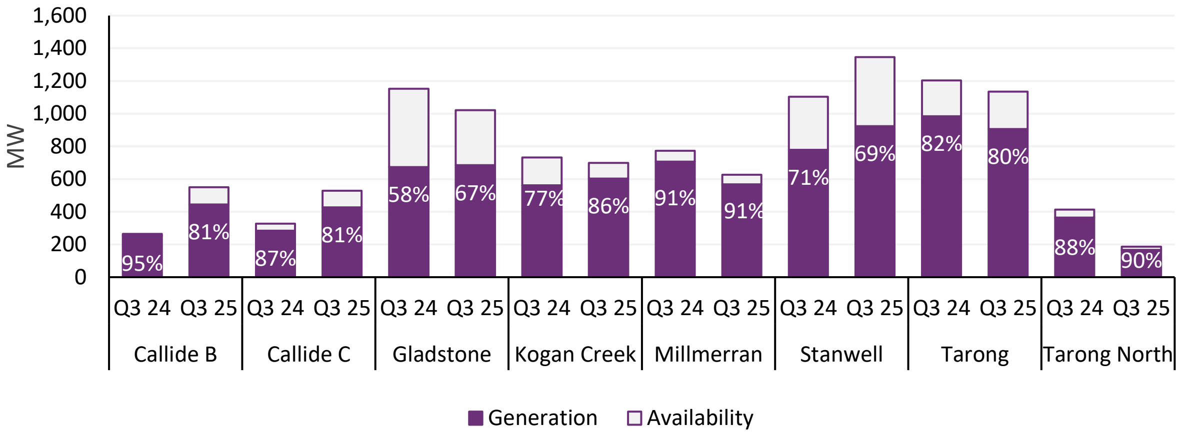
Figure 28 shows the availability, generation and utilisation rates for the Queensland black coal-fired power stations.

This quarter, Callide B and Callide C had the most significant increases in average output, up 192 MW and 143 MW respectively. This was driven by reduced partial and full outages increasing availability at Callide B (+285 MW) and Callide C (+201 MW). However, the utilisation rate declined at both stations, with Callide B down by 14 pp and Callide C down 5.8 pp. Stanwell's average generation increased by 145 MW (+19%) year-on-year. Kogan Creek output rose 7.3% compared to Q3 2024, despite a 4.7% drop in availability, with utilisation up 10 pp to 86%. Average output at Gladstone remained steady (+1.6%) despite lower availability, with utilisation improving by 8 pp to 67%.

In contrast, Tarong North output fell by 198 MW (-54%) alongside a 227 MW (-55%) drop in availability, reflecting full and partial outages. Millmerran's average output declined by 138 MW (-20%), and Tarong's output reduced by 79 MW (-8.0%).

Figure 28 Queensland black coal-fired output rose

Average quarterly availability and generation for Queensland black coal-fired power stations – Q3 2025 vs Q3 2024



Intraday variability in New South Wales increased by 356 MW to reach 3,501 MW in Q3 2025 (Figure 29). Evening peak output (1600-2000 hrs) also rose, up 97 MW to average 6,351 MW. In Queensland, intraday swing increased slightly by 97 MW to 2,101 MW (Figure 30). The minimum generation as a share of average available capacity was 47% in New South Wales, indicating greater flexibility compared to Queensland, where the ratio was 60%.

Figure 29 New South Wales black coal-fired generators had increased swing year-on-year

New South Wales black coal-fired output by time of day (including decommissioned units) – Q3s

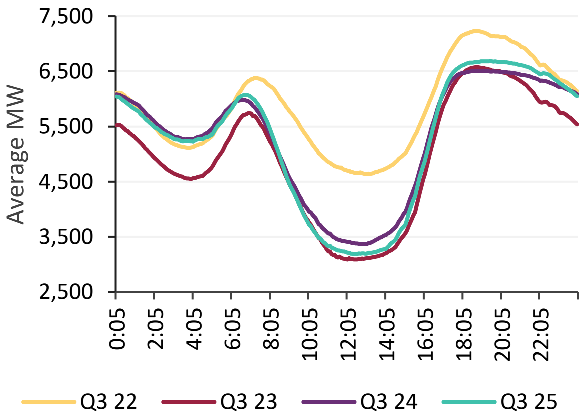
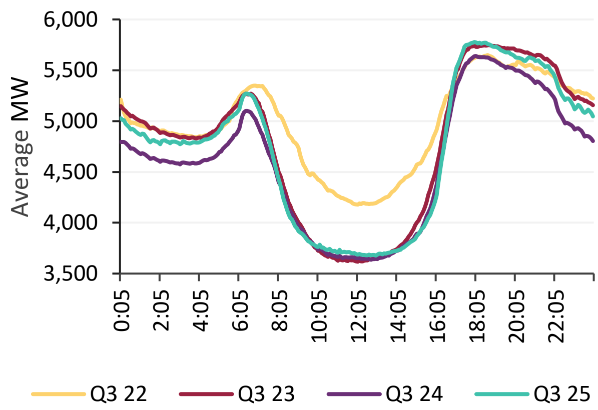


Figure 30 Queensland black coal-fired generation increased across the day

Queensland black coal-fired output by time of day – Q3s



Brown coal-fired fleet

Brown coal-fired generation in Q3 2025 averaged 3,518 MW, down 184 MW (-5.0%) year-on-year (Figure 31), driven by increased outage levels. Average capacity on outage rose to 822 MW, up 318 MW (+63%) from Q3 2024.

The decline in output was led by Yallourn (-158 MW) and Loy Yang B (-87 MW) and, partially offset by a 61 MW increase at Loy Yang A. Loy Yang A recorded reduced outage levels, resulting in higher availability (+17 MW) and a 2 pp lift in utilisation. In contrast, Loy Yang B and Yallourn saw increased full unit outages, with marginal change to utilisation rates year-on-year (Table 3).

Figure 31 Brown coal-fired generation decreased

Quarterly average brown coal-fired generation and availability in Victoria (including decommissioned units) – Q3s

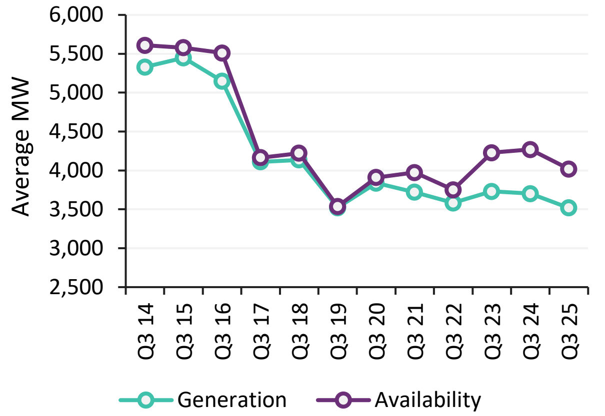
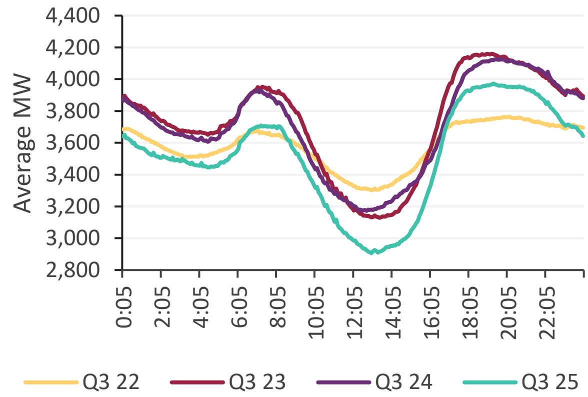


Figure 32 Brown coal-fired output decreased across the day

Brown coal-fired output by time of day – Q3s



Brown coal-fired stations showed a more flexible profile over the day, with the intraday flex increasing from 953 MW in Q3 2024 to 1,067 MW in Q3 2025 (Figure 32). In Victoria, minimum generation represented 72% of average available capacity this quarter. This reflects that while brown coal-fired units have increased swing levels over time, particularly at Loy Yang A compared to last year (Table 3), these units typically display lower daily variation in output than black coal-fired generators.

Table 3 Brown coal availability, output, utilisation, outage, and intraday swing – Q3 2025 vs Q3 2024

Generator	Availability (MW)		Output (MW)		Utilisation		Outage (MW)		Intraday swing (MW)	
	Q3 24	Q3 25	Q3 24	Q3 25	Q3 24	Q3 25	Q3 24	Q3 25	Q3 24	Q3 25
Loy Yang A	1,917	1,934	1,595	1,655	83%	86%	279	241	488	590
Loy Yang B	1,163	1,078	1,028	941	88%	87%	0	76	300	298
Yallourn W	1,190	1,006	1,080	922	91%	92%	225	505	172	191

2.3.2 Gas-fired generation

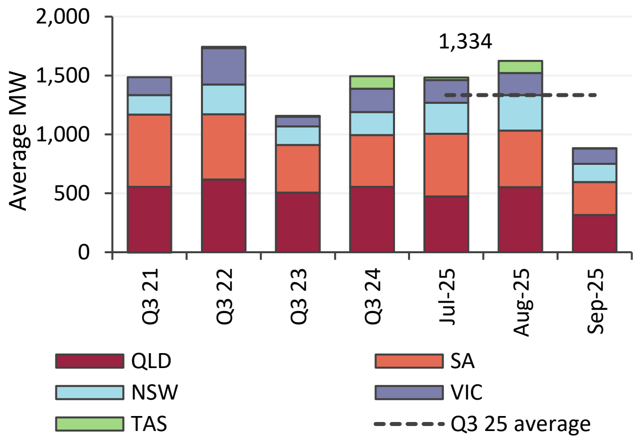
In Q3 2025, gas-fired generation across the NEM averaged 1,334 MW, 159 MW (-11%) lower than Q3 2024 (Figure 33). The decline was driven by significantly lower generation this July than in July 2024 (-594 MW), partly offset by higher output in September than a year ago (+137 MW).

New South Wales was the only state with a year-on-year increase in gas-fired generation, averaging 240 MW, up 44 MW (+23%) due to higher output during morning (0600 - 1000 hrs) and evening peaks (1600 – 2000 hrs). The increase in average output was mainly due to uplifts at Tallawarra A (+26 MW) and Hunter Power Station (+18 MW) as it commenced commissioning this quarter.

Gas-fired generation in Victoria decreased to average 171 MW, down by 27 MW or 14%. South Australia's gas-fired generation remained stable, averaging 432 MW, down just 7 MW (-1.6%) year-on-year. A 42 MW (-33%) reduction at Torrens Island was partially offset by increased output at Osborne (+18 MW), Pelican Point (+15 MW), and other generators in the state.

Figure 33 Gas-fired generation decreased in all NEM regions except New South Wales

Average gas-fired generation by region – Q3s



Queensland recorded the largest decline in gas-fired generation, averaging 449 MW across Q3 2025, a 107 MW or 19% decrease with output lower across all hours of the day. The decline was broadly spread across all generators except Swanbank, which increased by 27 MW (+109%).

Average gas-fired generation in Tasmania was 42 MW in Q3 2025, down 62 MW (60%) from Q3 2024, when output was elevated due to low hydro availability from reduced storage levels. In August this year, average gas generation in Tasmania increased to 103 MW, compared to 20 MW in July and 1 MW in September. This increase was primarily driven by Tamar Valley combined cycle gas power station operating between 11 August and 27 August this quarter.

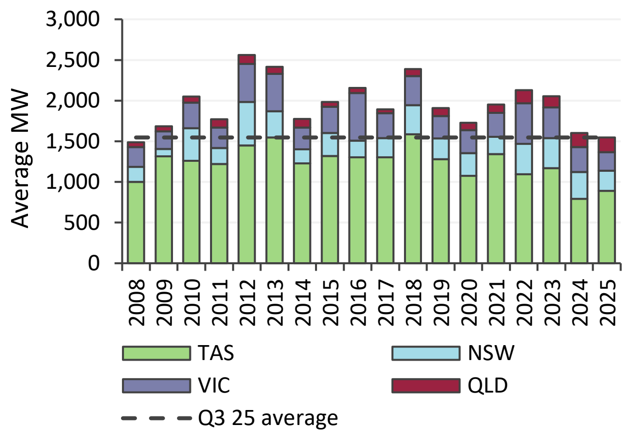
2.3.3 Hydro

In Q3 2025, hydro generation[15] decreased by 57 MW (-3.5%) year-on-year to an average of 1,547 MW, the lowest Q3 level since 2008 (Figure 34).

New South Wales recorded the most substantial decline in average hydro generation over the quarter, with output falling by 83 MW (-25%) to 247 MW. This reduction was primarily driven by a 51 MW (-35%) decrease in generation from Upper Tumut, alongside lower output from other regional generators. Contributing to this trend, Snowy Hydro's Lake Eucumbene storage levels were at 41% capacity at the end of Q3 2025, down from 50% at the same time in the previous year. Victoria also experienced a notable decline, with average hydro generation decreasing to 228 MW (-26%), led by a 90 MW (-39%) reduction at Murray. Queensland's hydro output remained relatively stable, averaging 181 MW, an increase of 6 MW (+3.6%) compared to Q3 2024.

Figure 34 Hydro generation reached lowest Q3 level since 2008

Average hydro-generation by region – Q3s



In contrast, Tasmania recorded a recovery in hydro output, averaging 891 MW with an increase of 100 MW (+13%) from Q3 2024, following low generation last year due to reduced rainfall and hydro storage levels. Tasmanian hydro dam levels increased steadily across the quarter, reaching 48.5% by the end of September, 6 pp higher than at the same time last year.

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

2.3.4 Wind and grid-scale solar

Average VRE generation in the NEM reached a new quarterly record of 6,374 MW, exceeding the previous high of 5,903 MW (Q1 2025) by 471 MW. Compared to Q3 2024, average VRE output rose by 870 MW (+16%), driven by a 632 MW (+16%) increase in wind generation and a 238 MW (+16%) increase in grid-scale solar (Figure 35).

Wind output growth was led by Victoria (+311 MW, +20%) and Queensland (+200 MW, +57%), with additional gains in New South Wales (+96 MW, +10%) and South Australia (+26 MW, +2.8%), while Tasmania remained steady (Figure 36). Grid-scale solar growth was strongest in New South Wales (+140 MW, +23%), followed by Victoria (+71 MW, +51%) and Queensland (+27 MW, +4.4%), whereas South Australia recorded a slight decline (-1.6%).

Figure 35 VRE output growth continued

Average quarterly VRE generation by fuel type – Q3s

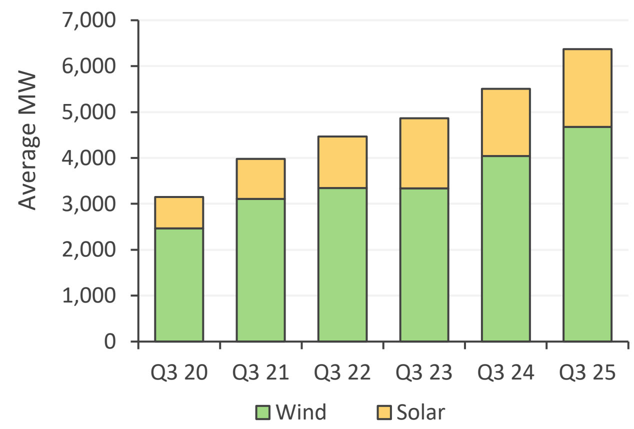
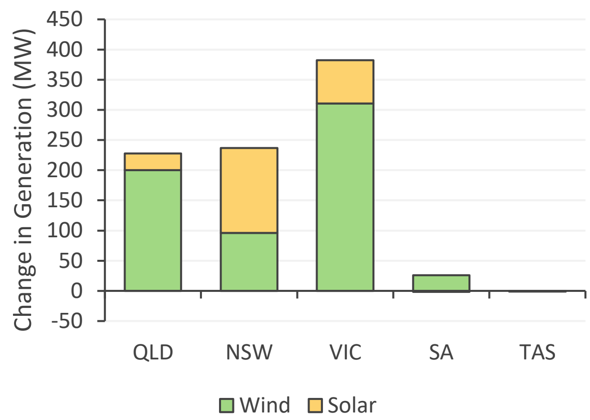


Figure 36 Queensland, New South Wales and Victoria drove renewable increases

Average MW change in output Q3 2025 vs Q3 2024



Grid-scale solar

In Q3 2025, grid-scale solar generation averaged 1,699 MW, increasing by 238 MW from 1,461 MW in the previous year.

Increased VRE availability in the NEM arises from both newly connected facilities and those progressing through their commissioning processes, which can extend over 12 months or longer. These additions contributed to a 314 MW increase in average quarterly solar availability compared to Q3 2024 (Figure 37). Most of this growth occurred in New South Wales, led by Stubbo (+77 MW), Walla Walla (+56 MW) and Wollar (+46 MW). Network curtailment and economic offloading increased year-on-year and reduced potential growth in grid-scale solar output by an additional 94 MW.

NEM-wide quarterly volume-weighted available capacity factors[16] for established[17] grid-scale solar facilities remained broadly consistent with last year. NEM-wide volume-weighted available capacity factor averaged 21.1% this quarter (Figure 38). Queensland recorded the highest average capacity factor at 25.3% (+1.3 pp), while Victoria rose by 2.3 pp to 19.4%. These increases were partially offset by declines in New South Wales (18.0%, -1.5 pp) and South Australia (20.9%, -0.2 pp).

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

[17] Existing (or established) capacity in this section refers to the wind and grid-scale solar facilities that were fully commissioned prior to the start of Q3 2025. These facilities may also appear in the "New Capacity" or "Commissioning" categories in Figure 37 and Figure 39 if they were connected or exhibited ramping activity between Q3 2024 and Q3 2025 respectively.

Figure 37 New capacity led the year-on-year grid-scale solar growth

Changes in grid-scale solar generation – Q3 2025 vs Q3 2024

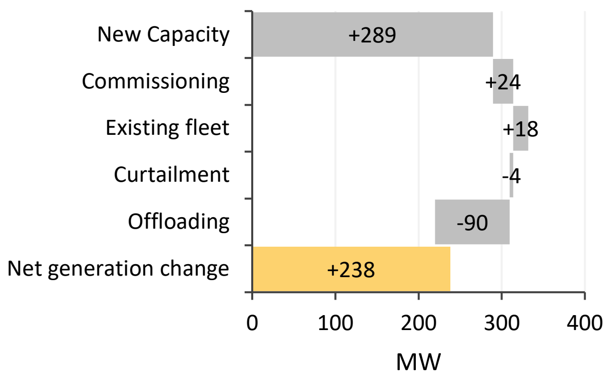
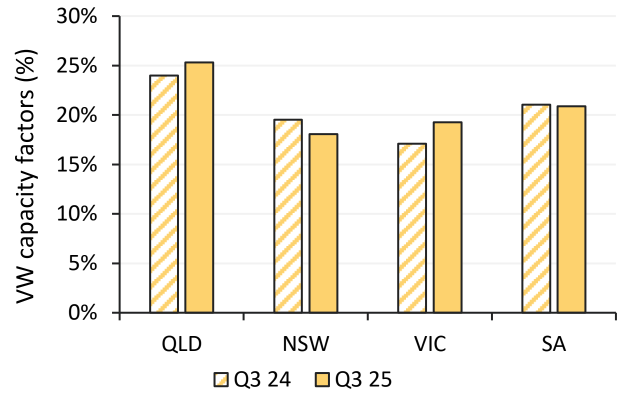


Figure 38 Increased availability in New South Wales and Victoria

Volume-weighted grid-scale solar available capacity factors[18] – Q3s



Wind

NEM-wide wind generation averaged 4,676 MW in Q3 2025, setting a new record and surpassing the previous high of 4,044 MW in Q3 2024 by 632 MW (+16%).

New and commissioning wind farms added 782 MW of availability compared to Q3 2024 (Figure 39). Key contributors included Clarke Creek (+119 MW) and MacIntyre (+103 MW) in Queensland; Golden Plains (+256 MW) and Ryan Corner (+79 MW) in Victoria; and Goyder South (+161 MW) in South Australia. Network curtailment and economic offloading partially offset increased wind availability and reduced potential wind output by an additional 115 MW year-on-year.

Quarterly volume-weighted available capacity factors at established windfarms decreased slightly, with NEM-wide capacity factors averaging 39.4% in Q3 2025, down slightly from 39.5% in Q3 2024 (Figure 40). Tasmania achieved the highest availability capacity factor at 47.2%, up 0.1 pp from previous year. New South Wales had the most notable increase at 37.4%, up 2.5 pp. Victoria also noted a 1.0 pp increase at 41.1% this quarter. These increases were offset by decreases in South Australia (38.5%, -3.6 pp) and Queensland (34.2%, -2.1 pp).

Figure 39 Increased output from new and commissioning wind farms

Changes in wind generation – Q3 2025 vs Q3 2024

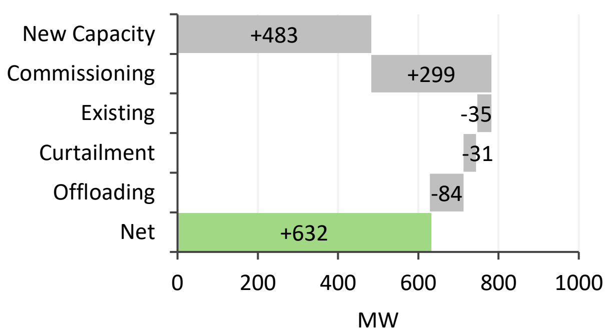


Figure 40 Wind availability up in New South Wales, Victoria and Tasmania

Volume-weighted wind available capacity factors – Q3s

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

Figure 41 shows the number of multi-day wind lull events across NEM regions. During Q3 2025, Tasmania recorded the highest number of consecutive days when the daily wind capacity factor[19] fell below 10%. It was the only region to experience two separate wind lull events lasting three consecutive days each.

While the total number of wind lull days across the NEM remained broadly consistent with Q3 2024, the duration of these events shortened overall. Queensland and Victoria recorded no wind lull conditions longer than a single day, while South Australia and New South Wales experienced brief lulls lasting one to two days.

Figure 41 Fewer multi-day wind lulls in Q3 2025

Count of wind lulls (<10%) by region – Q3s

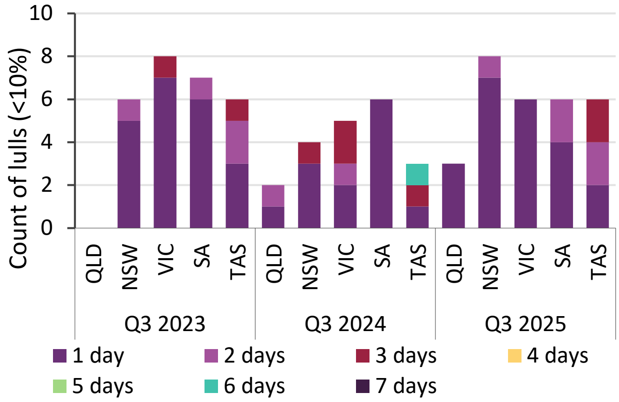
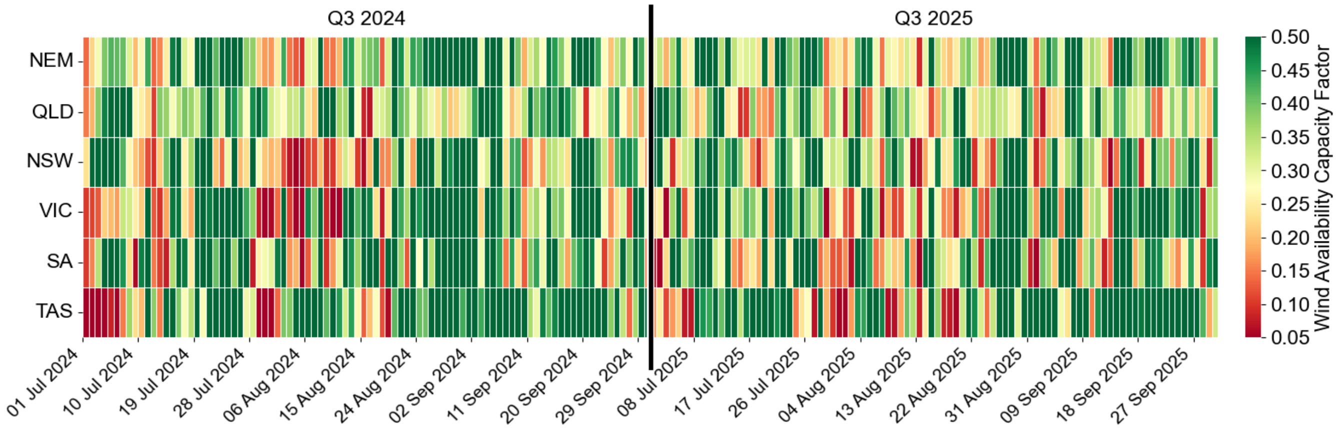


Figure 42 further illustrates daily wind availability capacity factors for Q3 2024 and Q3 2025. In July 2025, the number of days with wind availability capacity factor below 10% declined year-on-year and wind availability improved with no region experiencing a wind lull longer than 2 days. In contrast, Tasmania was the most affected region in July 2024, experiencing two extended low-wind periods lasting six and three days respectively. August in both years showed the greatest variability, marked by alternating highs and lows. In August 2025, wind lulls were shorter, typically lasting 1-2 days across all mainland regions, whereas in August 2024, New South Wales and Victoria both saw three-day lulls. September 2024 and 2025 were both comparatively stable, with moderately high availability and fewer extreme lows. Overall, compared to Q3 2024, this quarter shows less correlation of wind availability patterns across NEM regions, with less frequent shared highs and lows.

Figure 42 Less clustering of highs and lows in wind availability across Q3 2025

Daily wind availability capacity factor – Q3 24 and Q3 25



Economic offloading

During Q3 2025, total economic offloading of wind and grid-scale solar generation averaged 637 MW, up 174 MW (+38%) year-on-year (Figure 43). Grid-scale solar offloading rose from 237 MW in Q3 2024 to 327 MW (+38%), increasing from 14%

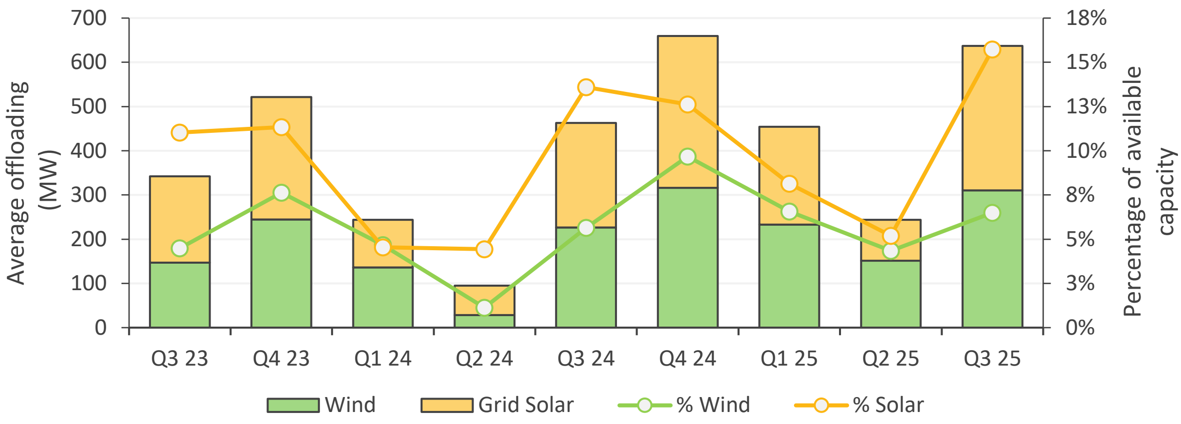
[19] Availability capacity factors are calculated using the available energy divided by the maximum installed capacity. The use of availability instead of generation output removes the impact of economic offloading or curtailment to better capture in-service plant capacity and underlying wind resource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

of average solar availability to 16%. It was most evident in Queensland (+92 MW), reaching more than 25% of available grid-scale solar output in that region as daytime (0900-1700 hrs) negative price occurrence grew by 13 pp to 66%.

For wind generation, economic offloading increased from 227 MW to 311 MW (+84 MW, +37%), rising as a proportion of average wind availability from 5.6% to 6.5%. Higher wind offloading was concentrated in Victoria (+39 MW), South Australia (+39 MW), and Queensland (+15 MW).

Figure 43 Increased economic offloading for wind and grid-scale solar generation

Average MW offloading and as percentage of availability by fuel type

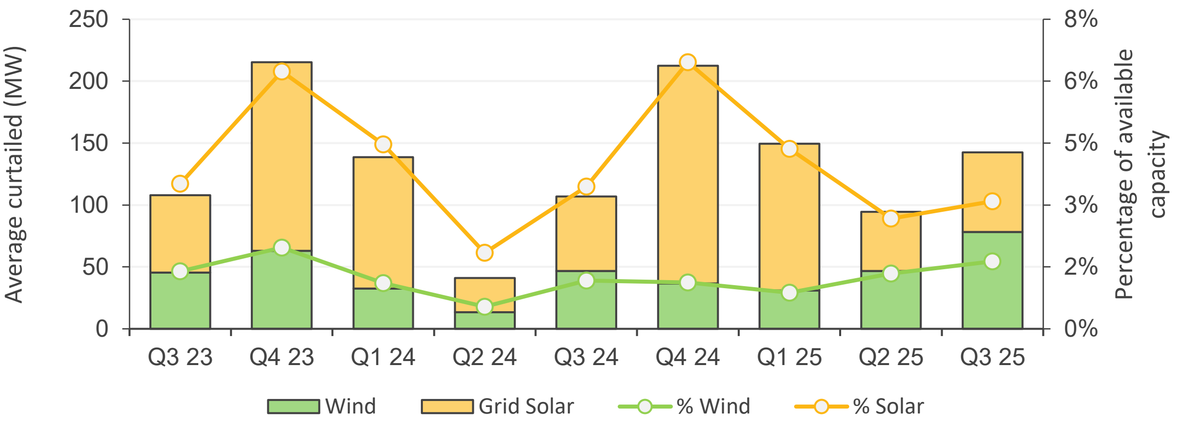


Network curtailment

Average curtailment[20] of wind generation increased from 47 MW in Q3 2024 to 78 MW this Q3 (Figure 44), with most of this 31 MW (+67%) increase in Victoria (+21 MW) and South Australia (+12 MW). Curtailment as a percentage of average wind availability rose to 1.6% from 1.2% in Q3 2024. Grid-scale solar curtailment increased marginally from 60 MW in Q3 2024 to 64 MW in Q3 2025, while as a share of average solar availability it declined by 0.3 pp to 3.1%.

Figure 44 Wind curtailment increased while curtailment at solar farms remained relatively stable

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



[20] 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.

2.3.5 Renewables contribution

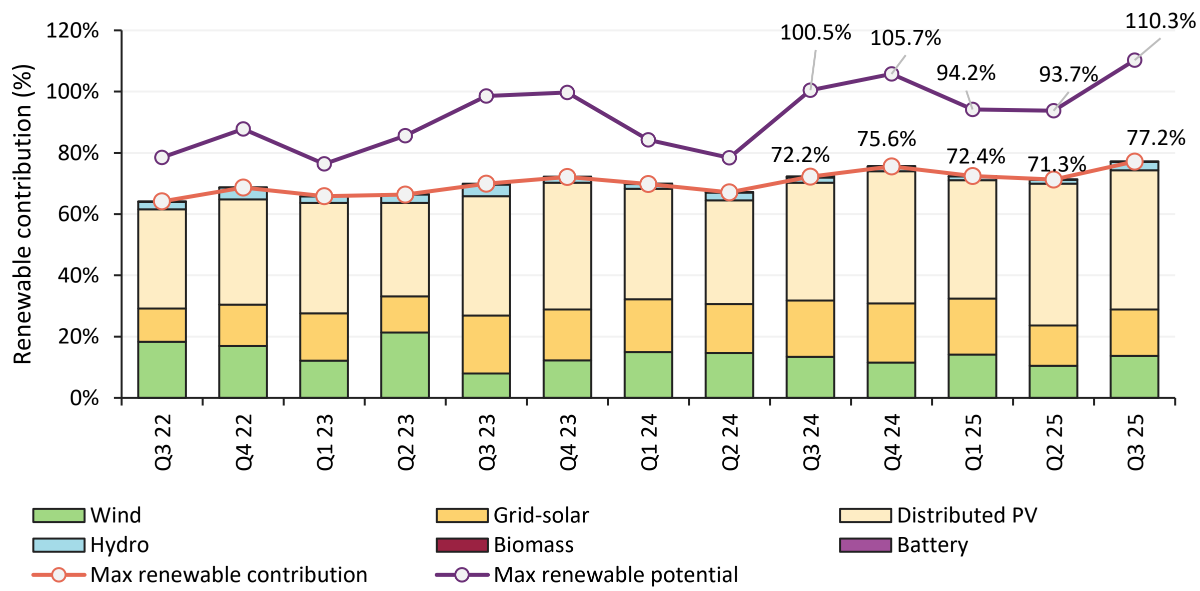
Peak renewable contribution

Peak renewable contribution[21] in the NEM reached a new record of 77.2% during the half-hour interval ending at 1200 hrs on Monday, 22 September 2025, surpassing the previous record of 75.6% set on 6 November 2024. This also represents a 5 pp increase on Q3 2024's high of 72.2%. At the time of the record, distributed PV contributed 45.4% of total generation, while grid-scale solar and wind contributed 15.2% and 13.7% respectively. Maximum renewable potential[22] for this quarter also set a new record reaching 110.3% on 14 September during the half hour ending 1200hrs, surpassing the previous record of 105.7% set in Q4 2024 by 4.5 pp (Figure 45).

Figure 46 illustrates the quarterly range in renewable generation contribution, which recorded a 63.5 pp swing between 77.2% and the quarterly minimum of 13.6%. The minimum contribution occurred during the half-hour ending 2300 hrs on 1-September 2025 and was 3.5 pp higher than Q3 2024's minimum of 10.2%. Both New South Wales and South Australia set new records for renewable generation contribution this quarter, surpassing previous records set in Q2 2025. South Australia reached 98.7% renewable contribution during the half-hour ending at 1400 hrs on 10 September 2025, with the remaining 1.3% of total generation supplied by gas. This outcome was facilitated by a revision to system security requirements, which allowed operation with a minimum of one synchronous generating unit, subject to defined system conditions (see Section 2.6.1). New South Wales achieved a peak contribution of 83.2% during the half-hour ending at 1200 hrs on 30 September (Figure 47).

Figure 45 Peak and potential renewable contribution reached record highs

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



21 Peak renewable 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, biomass, battery discharge and distributed PV. Total generation = large-scale generation + estimated PV output.

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

Figure 46 Higher maximum and minimum renewable contribution

Range of NEM supply share from renewable energy sources - Q3s

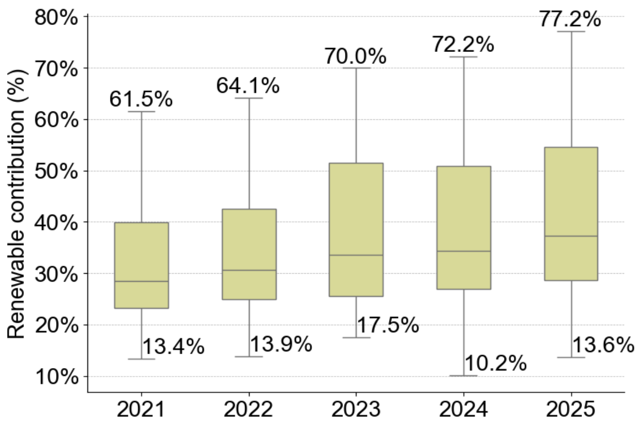
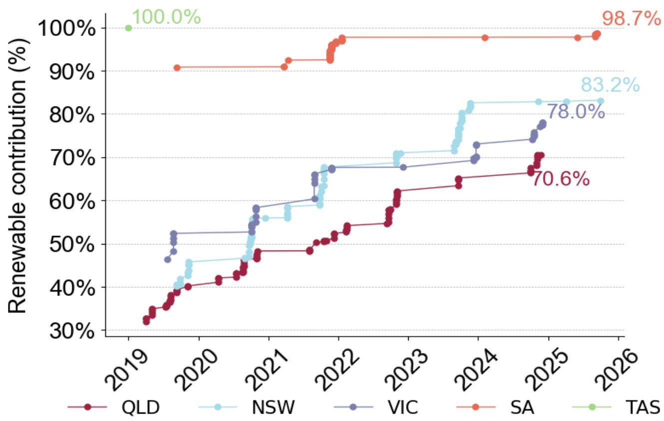


Figure 47 Record high renewable contribution in New South Wales and South Australia

Change in peak renewable contribution record by region

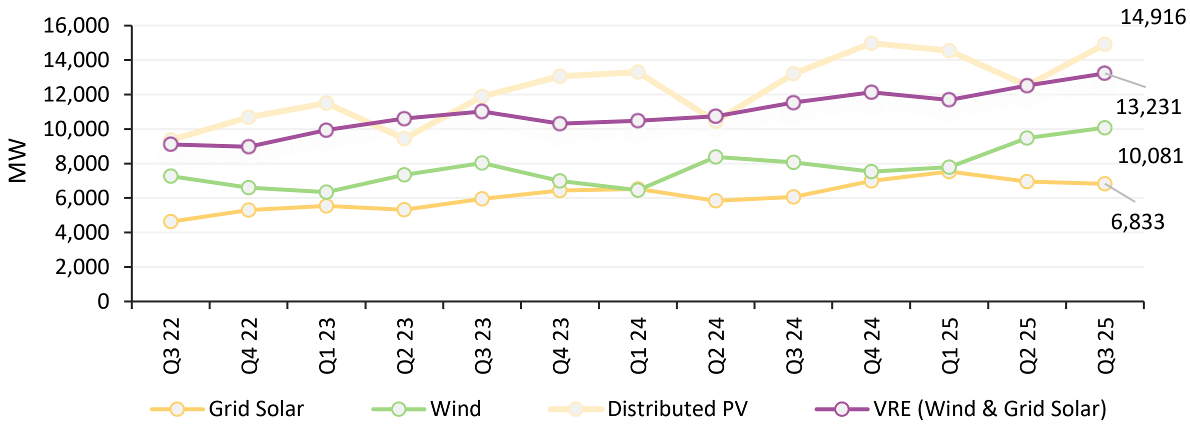


Maximum renewable output

Figure 48 highlights the highest quarterly peak half-hourly generation for grid-scale solar, wind, and distributed PV since Q3 2022. During Q3 2025, wind generation reached a new peak half-hourly output of 10,081 MW in the half hour ending 2130 hrs on Friday, 25 July 2025, surpassing the previous record of 9,472 MW set in Q2 2025 by 6.4%. VRE generation, comprising wind and grid-scale solar, also set a new record of 13,231 MW in the half hour ending 0930 hrs on Monday, 4 August 2025. At this time, VRE supplied 43.3% of total generation and the new record represents a 5.7% increase from the previous record of 12,516 MW in Q2 2025.

Figure 48 Record high for peak VRE and wind generation

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



Renewable contribution to maximum demand

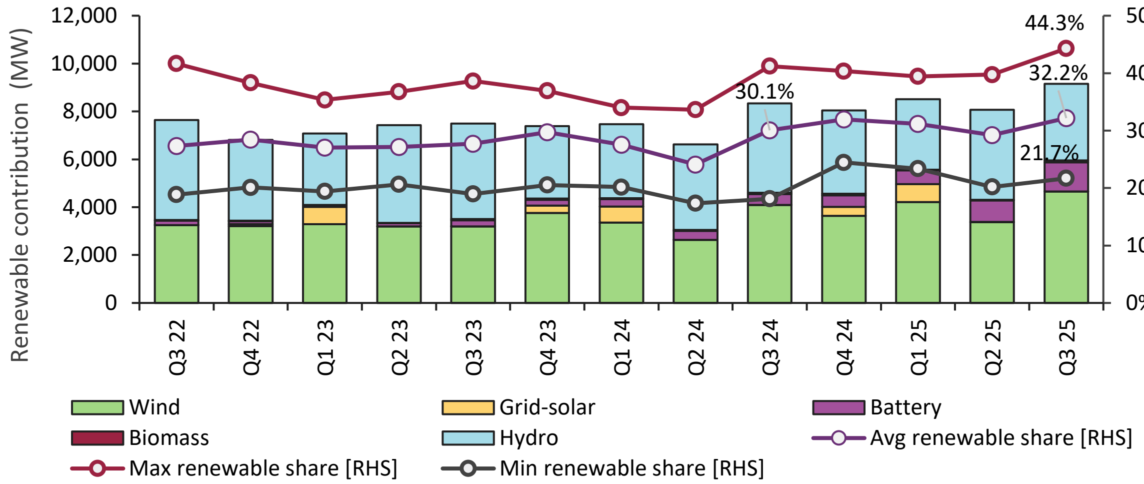
Figure 49 illustrates the average share of large-scale renewable generation in meeting daily maximum NEM operational demand, aggregated across all days in each quarter since Q3 2022[23]. This quarter, the average renewable contribution

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

supplying daily maximum demand rose to 32.2%, up from 30.1% in Q3 2024. The increase was primarily driven by higher wind output, which supplied 16.3% (+1.6 pp) on average, and battery discharge, contributing 4.3% (+2.6 pp). The highest renewable contribution to meeting daily maximum demand during Q3 2025 was 44.3%, while the lowest was 21.7%.

Figure 49 Renewable contribution increased at daily maximum demand

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

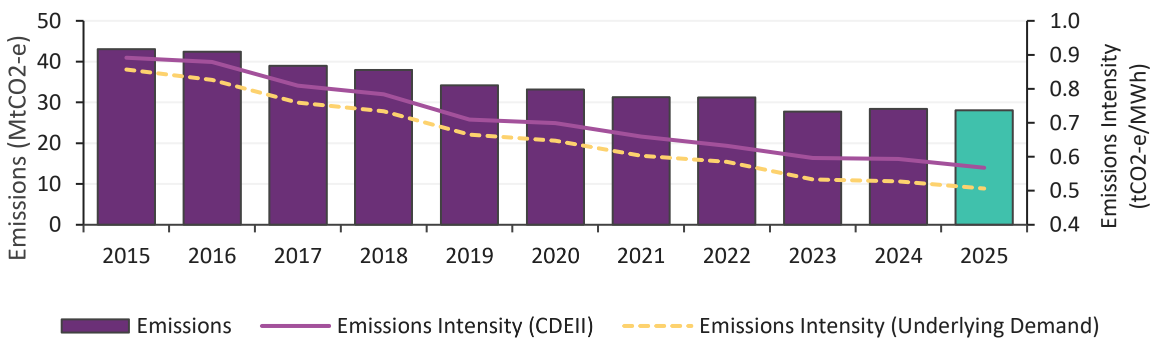


2.3.6 NEM emissions

In Q3 2025, total emissions across the NEM decreased to 28.1 MtCO2-e, down 0.3 MtCO2-e (-1.2%) compared to Q3 2024 (Figure 50).

Figure 50 Emissions and emissions intensity decreased compared to Q3 2024

Quarterly NEM emissions and intensity – Q3s



The Carbon Dioxide Equivalent Intensity Index (CDEII) emissions intensity is measured by combining sent out metering data with publicly available generator emission and efficiency data to provide a NEM-wide CDEII[24]. 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 tCO2-e/MWh, marking the lowest level on record. Compared to Q3 2024, this

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

represents a reduction of 0.03 tCO2-e/MWh (-4.4%), as combined coal and gas-fired generation volume share decreased. Emission intensity associated with underlying demand[25] also declined by 0.02 tCO2-e/MWh year-on-year to 0.51 tCO2-e/MWh, marking a new Q3 low.

2.3.7 Storage

Batteries

In Q3 2025, estimated net revenue for NEM grid-scale batteries increased to $111.9 million, up $35.6 million (47%) from Q3 2024 (Figure 51). However, energy arbitrage[26] revenue decreased by $5.9 million (-9%) to $58.2 million, down from $64.1 million in the previous year. This reflected energy (charging) costs rising by $10.9 million (+79%) to $24.5 million this quarter, only partially offset by a $4.9 million (+6%) uplift in energy revenue (including revenue from charging at negative prices).

In contrast, frequency control ancillary services (FCAS) revenue surged to $53.7 million this quarter, an increase of $41.5 million (+340%), lifting its share of total revenue from 16% in Q3 2024 to 48% in Q3 2025, while the energy market revenue share fell to 52% from 84% a year earlier (Figure 52). South Australian batteries dominated the shift this quarter, contributing 88% of total battery FCAS revenue ($47.4 million), up $40.8 million year-on-year, reflecting high regional FCAS prices during planned outages impacting the Heywood interconnector that required local FCAS enablement (see Section 2.5). Queensland batteries also recorded gains, adding $3.1 million to reach $4.5 million, whereas New South Wales and Victoria experienced declines, with FCAS revenue dropping to $0.5 million (-66%) and $1.3 million (-51%) respectively.

Figure 51 Net battery revenue increased driven by higher FCAS revenue

Quarterly net revenue from NEM battery systems by revenue stream

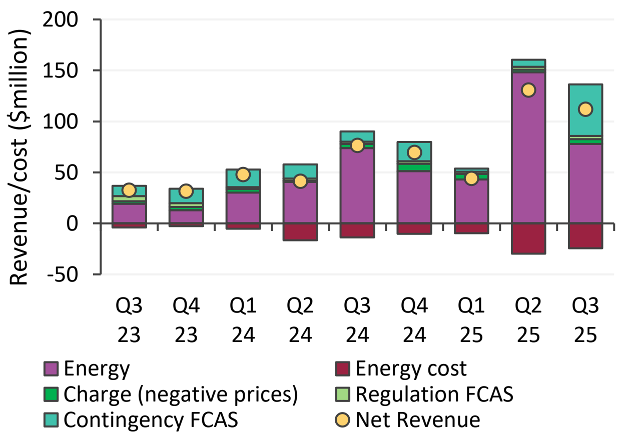
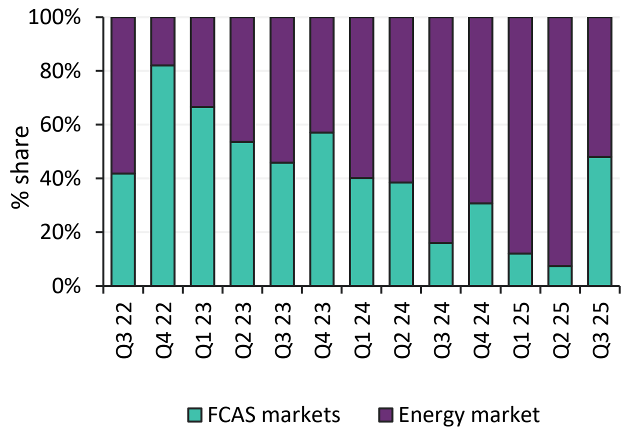


Figure 52 Battery revenue from FCAS markets increased

Percentage share of battery net revenue – energy vs FCAS markets



Between the end of Q3 2024 and the end of Q3 2025[27], the following major battery energy storage systems (BESS) with a combined capacity of 2,936 MW/6,482 MWh have commenced initial commissioning activities into the NEM, with assets now either fully commissioned or continuing their commissioning processes (Table 4).

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

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

[27] In Q3 2025, Limondale Battery Energfy Storage System (BESS, 50 MW/400 MWh) and Liddell BESS (500 MW/1,000 MWh) in New South Wales, along with SuperNode BESS (260 MW/620 MWh) in Queensland, were registered in the NEM but did not commence commissioning by quarter end.

Table 4 New battery systems in the NEM

Battery	Region	First quarter of generation	Capacity
Eraring	New South Wales	Q1 2025	460 MW/1,073 MWh
Smithfield	New South Wales	Q3 2025	65 MW/130 MWh
Brendale	Queensland	Q3 2025	205 MW/410 MWh
Greenbank	Queensland	Q1 2025	200 MW/400 MWh
Tarong	Queensland	Q2 2025	300 MW/600 MWh
Ulinda Park	Queensland	Q2 2025	155 MW/298 MWh
Western Downs – Stage 2	Queensland	Q3 2025	255 MW/510 MWh
Mannum	South Australia	Q2 2025	100 MW/200 MWh
Templers	South Australia	Q2 2025	111 MW/291 MWh
Koorangie	Victoria	Q1 2025	185 MW/370 MWh
Latrobe Valley	Victoria	Q2 2025	100 MW/200 MWh
Melbourne Renewable Energy Hub (Units 1-3)	Victoria	Q3 2025	600 MW/1,600 MWh
Rangebank	Victoria	Q4 2024	200 MW/400 MWh

Reflecting this capacity growth, NEM-wide average quarterly battery discharge availability increased by 1,176 MW (+119%) from 990 MW in Q3 2024 to 2,167 MW in Q3 2025. Average battery discharge in the NEM surged to 215 MW (+150%), up from 86 MW in the previous year. However, with less spot price volatility in Q3 2025, the NEM-wide price spread for batteries decreased by 64% from $339/MWh in Q3 2024 to $123/MWh (Figure 53), reducing total battery earnings from energy arbitrage despite the strong growth in capacity and output.

Batteries set a new peak discharge record this quarter, reaching 1,991 MW on Sunday, 20 July 2025 during the half-hour ending 1800 hrs. This was 235 MW above the previous record of 1,756 MW set earlier this year in Q2 2025. Battery charge also reached a new high of 1,508 MW (+24%) in the half hour ending 1300 hrs on 19 August 2025. Figure 54 illustrates average battery charge, discharge and state of charge this quarter. Battery charge increased through the middle of the day, leading to a higher state of charge by late afternoon. Battery discharge rose sharply in the evening, resulting in a subsequent decline in state of charge. Compared to Q3 2024, battery discharge during the evening peak period 1600-2000 hrs increased by 392 MW, and battery charge during the day 1000-1600 hrs also increased by 325 MW.

Figure 53 Decrease in NEM-wide battery price spread with lower price volatility

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

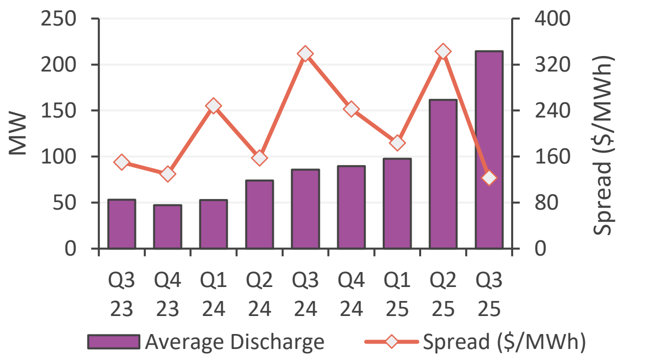
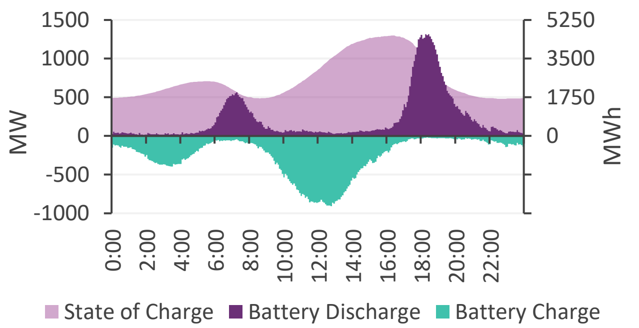


Figure 54 Battery state of charge peaks late afternoon, declines with evening discharge

Average battery charge, discharge (MW) and state of charge (MWh) [RHS] by time of day – Q3 2025

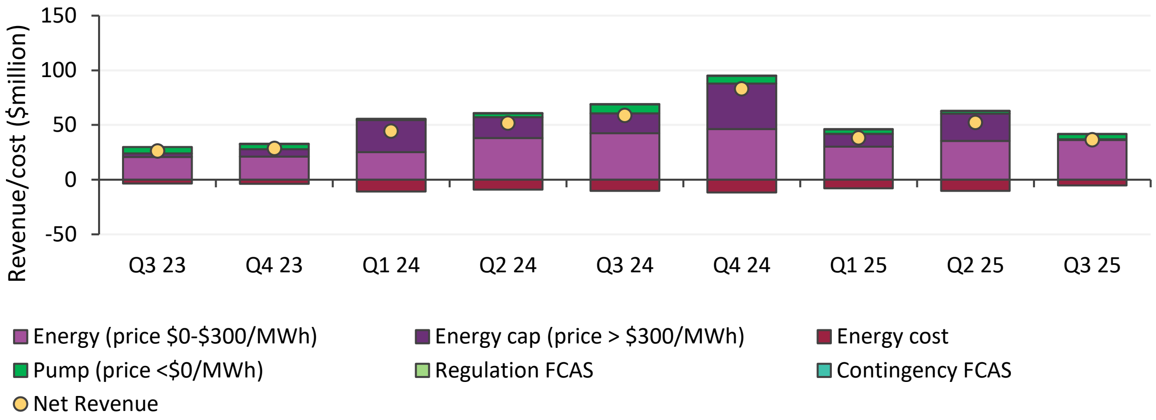


Pumped hydro

Estimated net pumped hydro revenue fell to $36.6 million this quarter, down $22.3 million (-38%) from Q3 2024 (Figure 55). In Queensland, lower spot prices drove Wivenhoe's revenue down $18.5 million (-38%) to $30.6 million. In New South Wales, Shoalhaven's revenue declined $3.8 million (-39%) to $5.9 million as price volatility eased compared to last year. This trend was reflected in energy cap revenues, which dropped sharply year-on-year, down 99% for Wivenhoe and 93% for Shoalhaven.

Figure 55 Pumped hydro revenue decreased year-on-year

Quarterly revenue from NEM pumped hydro by revenue stream

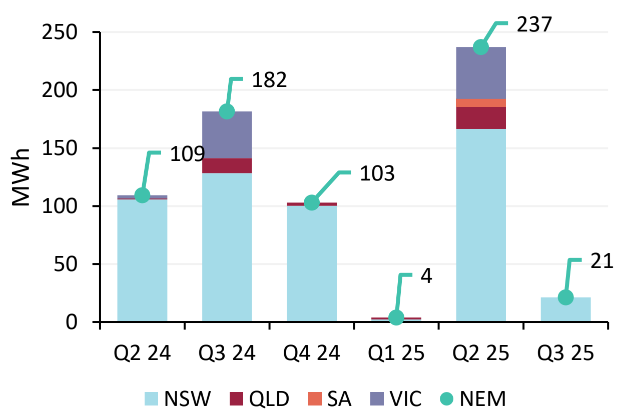


2.3.8 Demand side flexibility

With lower volatility this quarter (see Section 2.2.2), wholesale demand response (WDR) saw a total of 21 MWh of energy dispatched over the quarter, a drop of 160 MWh from 182 MWh in Q3 2024 (Figure 56).

Figure 56 Decrease in WDR dispatched

Total quarterly WDR energy dispatch



During the quarter, WDR was dispatched across seven intervals, a significant reduction from 467 intervals in the same period last year.

WDR dispatch solely occurred in New South Wales:

- On 14 August, one unit was dispatched for a single interval at 4 MW, with the regional reference price averaging $106/MWh.
- On 1 September, one unit was dispatched over six intervals at a combined output of 42 MW, with an average regional reference price of $487/MWh across those intervals.

Demand flexibility continued to play a large role in the FCAS markets, with demand response (DR) supplying 32% of the combined contingency raise services in Q3 2025, up from 24% in Q3 2024.

2.3.9 New grid connections

New grid connections to the NEM follow a process which involves the applicant, network service provider (NSP) and AEMO. Prior to submission of a connection application with AEMO, the applicant completes a pre-feasibility and enquiry phase where the connecting NSP is engaged in the process. The key stages[28] monitored by AEMO to track the progress of projects going through the connections process include application, proponent implementation, registration, commissioning, and model validation.

The increased volume of connection applications approved over the past two financial years are now connecting to the NEM and reaching full operating capacity. This is reflected in both the full output capacity (Figure 57) and the capacity currently in commissioning (Figure 58). During the past year there has been an increase in standalone battery projects. Battery connections made up 74% of applications approved and 83% of plant registered this quarter. They comprise 46% of the capacity of projects in the connections pipeline, with 70% of batteries being grid-forming.

The total capacity of projects in proponent implementation stage, when contracts are finalised and plants are under construction, has increased by 43% compared to the same period last year. This is driven by the increased volume of new applications approved over the past year combined with longer implementation timeframes. Battery projects have taken longer on average to complete proponent implementation than in the prior 12 months, due to changes in ownership, project pauses to await funding certainty and larger battery sizes.

During Q3 2025:

- 1.8 gigawatts (GW) of applications were approved across eight projects.
- 2.2 GW of plant across 10 projects were registered and connected to the NEM.
- 1.6 GW of plant across six projects progressed through commissioning to reach full output: Golden Plains Wind Farm (733 MW), Aldoga Solar Farm (387 MW), Stubbo Solar Farm 1 (202 MW), Ulinda Park BESS (155 MW/ 298 MWh), Mannum BESS (100 MW/ 200 MWh) and Tallawarra A upgrade (29 MW).

Please see the Connections Scorecard[29] for further information.

At the end of Q3 2025, AEMO's snapshot of connection activities in progress shows that:

- 56.6 GW of new capacity was progressing through the end-to-end connection process from application to commissioning, 24% more than at the same time last year when 45.6 GW was in-progress.
- Battery project capacity in the end-to-end connection process increased by 79% over the year, from 14.6 GW to 26.1 GW, comprising 18.2 GW grid-forming, 7.7 GW grid-following, and 0.2 GW compressed air storage.
- While projects with solar generation (19 GW) remained steady compared to the same time last year, the proportion of hybrid solar plus battery projects increased from 25% to 50%, with solar projects contributing 9.6 GW and hybrid solar plus battery projects contributing 9.4 GW. Of these hybrid projects, 55% include grid-forming batteries. Wind (7.5 GW), hydro (2.7 GW) and gas (0.9 GW) remained stable.

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

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

- The total capacity of in-progress applications remained steady and is currently 20.2 GW.
- 23.2 GW of generation and storage projects are finalising contracts and/or under construction (proponent implementation), compared with 16.2 GW in the same period last year (43% increase).
- Registration project capacity has been steady, currently 5.9 GW.
- There was 7.3 GW of new capacity in commissioning, compared to 4.4 GW at the same period last year (66% increase).

Figure 57 Strong quarter for registrations and steady applications and full output

Application approved, registrations and plant commissioned to full output during Q3 2025

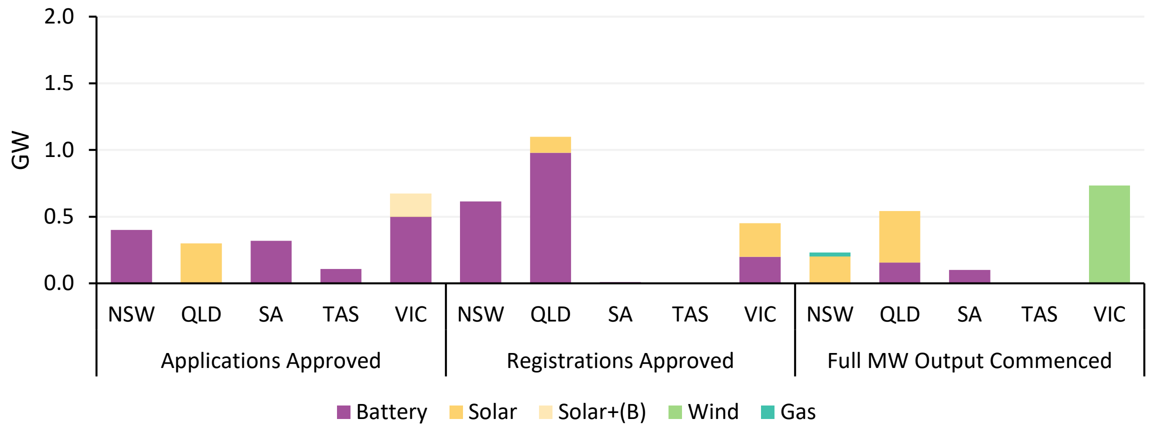
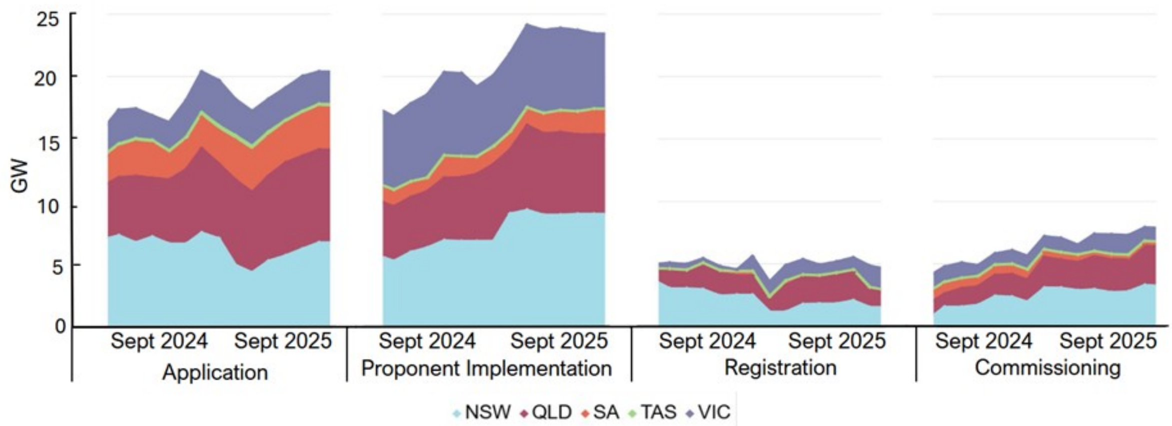


Figure 58 Increased capacity progressing through application, proponent implementation and commissioning stages of the connections pipeline over the year

12-month trend of connection capacity in progress (charts are based on current data, so some variances may exist compared to previously reported capacity in-progress)



2.4 Inter-regional transfers

Total inter-regional transfers were 3,176 gigawatt hours (GWh) in Q3 2025, down 9.1% from 3,494 GWh in Q3 2024 and equivalent to 6.4% of NEM operational demand for the quarter (Figure 59). Driving this decrease was a 64% drop in transfers across Basslink from 338 GWh in Q3 2024 to 120 GWh this quarter caused by a shift in Basslink bidding behaviour (discussed further below). Overall net transfers between Tasmania and Victoria reduced from 189 MW southward in Q3 2024 to 36 MW southward this quarter.

Other significant year-on-year changes were between Queensland and New South Wales, where net flows increased from an average of 283 MW southward to 476 MW southward, and between Victoria and South Australia, where net transfers reversed from 48 MW into Victoria to 4 MW into South Australia.

Figure 59 Decreased flows between Victoria and Tasmania

Quarterly inter-regional transfers

The increase in transfers from Queensland to New South Wales was driven by a change in flows in the overnight hours. This quarter, average flows on Queensland – New South Wales Interconnector (QNI) were southward across all hours of the day, with Queensland wholesale prices typically lower than New South Wales, compared to Q3 2024 where average flow shifted northward overnight.

As discussed in the Q1 2025 QED, the transfer capacity provided by the first stage of Project EnergyConnect (PEC-1) between South Australia and Victoria is represented as an increase in the capacity of the existing Heywood interconnector. Hence transfer on PEC-1 is included in the net flows between Victoria and South Australia shown in Figure 59, and contributed to the increase in net westward flows.

Basslink

Basslink operates as an MNSP and offers its capacity to transfer power between Tasmania and Victoria through market offers, analogous to market supply and demand offers made by scheduled generators and loads. Essentially, the prices offered by Basslink for a particular flow level and direction represent the minimum price difference between importing and exporting regions at which the interconnector will transfer that inter-regional flow. Higher priced MNSP offers mean that larger inter-regional spot price differentials are required before a given level of flow on the link will be scheduled.

Historically Basslink has offered most of its physically available capacity in each direction at very low transfer prices, typically $1/MWh or lower, as represented by Q3 2024 in Figure 61 below. However, from 1 July 2025, the amount of transfer capacity reduced, and the prices for that capacity increased to much higher levels, with very little capacity offered at prices of $1/MWh or lower.

In Q3 2025, the average transfer capacity reduced to around 440 MW in both directions, compared to around 570 MW to Victoria and 470 MW to Tasmania offered in prior quarters. On average across the quarter, 27% of Basslink's transfer capacity to Tasmania was offered at prices between $75-150/MWh, and 65% at $35-$75/MWh, with the capacity in this lower price band increasing as the quarter progressed. Capacity to Victoria was typically spread across a wider price range, averaging 18% at $15-$35/MWh, 33% at $35-75/MWh and 37% at $75-$150/MWh across the quarter, with the capacity offered at higher prices (from $75-$150/MWh) increasing as the quarter progressed.

Figure 60 shows the average time of day flows on Basslink this quarter, compared to the same time last year. Transfers from Victoria to Tasmania reduced by 70% and transfers from Tasmania to Victoria reduced by 44%. Additionally, Basslink spent 39% of dispatch intervals at 0 MW flow compared to just 1% in Q3 2024.

Figure 60 Average southward flows on Basslink reduced across all hours of the day

Average Basslink flow by time of day

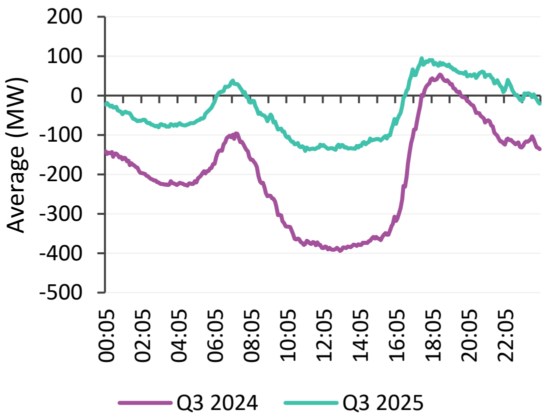
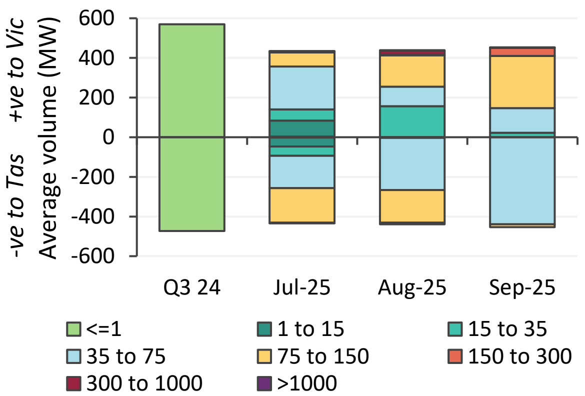


Figure 61 Basslink capacity offered at higher prices than during previous quarters

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



2.4.1 Inter-regional settlement residue (IRSR)

Positive IRSR totalled $94 million in Q3 2025, down 41% from $160 million in Q3 2024 (Figure 62). Compared to Q3 2024, when isolated events caused region-specific price volatility, this quarter experienced overall reduced high-price volatility (see Section 2.2.2), leading to lower positive IRSR into all regions. The largest year-on-year reductions were into South Australia, down $27 million to $17 million and into New South Wales, down $26 million to $67 million.

Negative IRSR totalled -$4.2 million this quarter, compared to -$3.8 million in Q3 2024 (Figure 63). Reduction of negative IRSR into Victoria (down from -$2.0 to -$1.2 million) and into New South Wales (-$1.7 to -$1.6 million) were offset by an increase into South Australia (up from -$0.1 to -$1.4 million).

Figure 62 Decreased positive settlement residues into all regions

Quarterly positive IRSR by region

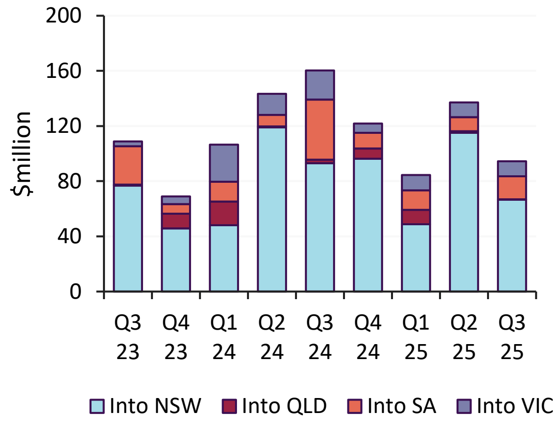
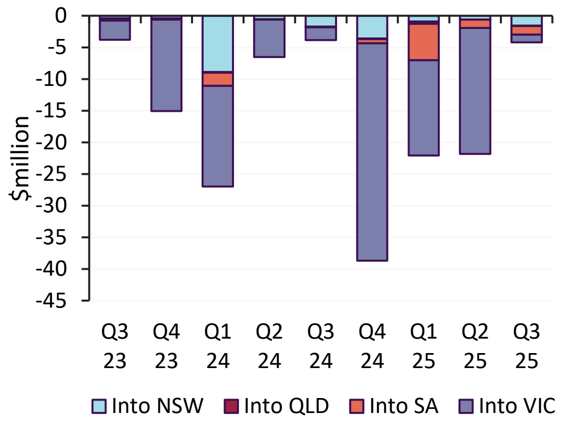


Figure 63 Increased negative settlement residues into South Australia

Quarterly negative IRSR by region



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

Total FCAS costs reached $73 million in Q3 2025, representing approximately 1.7% of the total cost of consumed energy for the quarter. This represented an increase of $47 million from Q3 2024, with the majority of the increase arising in South Australia (Figure 64). The costs for contingency and regulation services remained in line with the same period last year, with the notable exception of the contingency lower 1-second (L1SE) service which increased from less than $1 million in Q3 2024 to $47 million this quarter (Figure 65).

Figure 64 Large increase in FCAS costs in South Australia

Quarterly FCAS costs by region

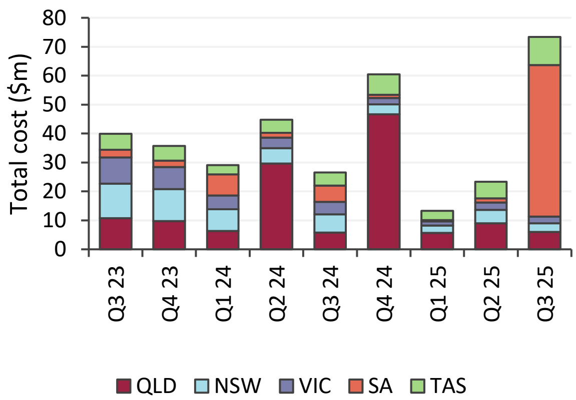
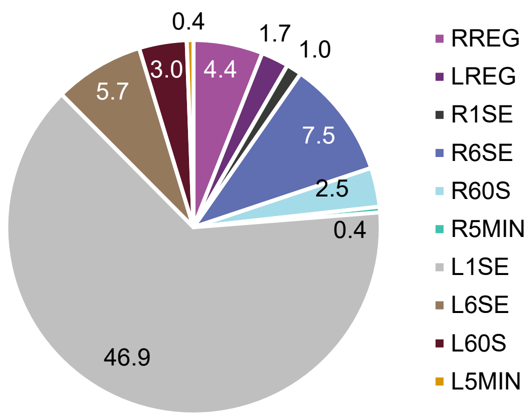


Figure 65 Increased cost for the L1SE service

NEM quarterly FCAS costs per service – Q3 2025 ($m)



Battery enablement continued to be the dominant source providing FCAS, with 56% share this quarter (Figure 66). Batteries and DR increased their average enablement with increases of 353 MW and 191 MW respectively (Figure 67). Virtual power plant (VPP) enablement decreased by 209 MW, due to a reduction in availability, including a 76% year-on-year reduction in Energy Locals' VPP availability across both sets of contingency markets.

Figure 66 Batteries dominated FCAS market share

FCAS volume market share by technology – Q3 2025

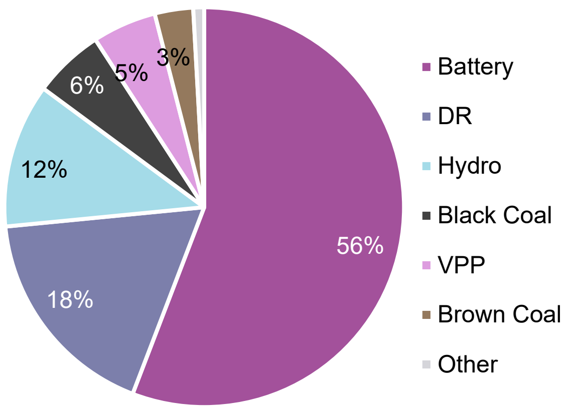
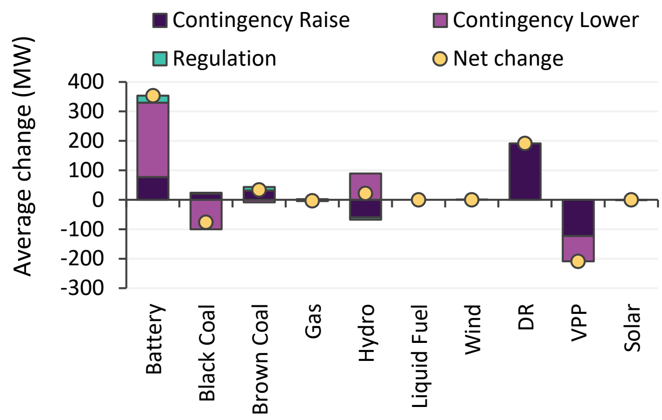


Figure 67 Increased enablement for batteries and demand response

Change in FCAS enablement by technology – Q3 2025 vs Q3 2024



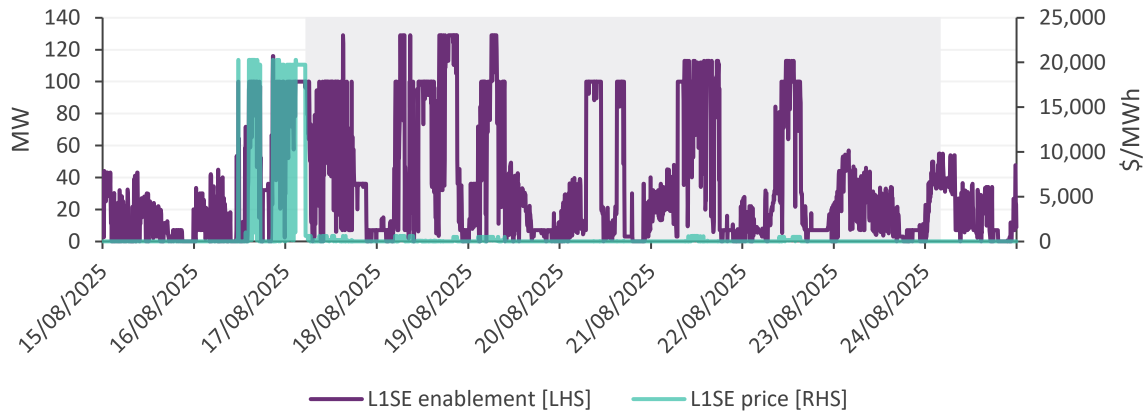
Contingency FCAS

Contingency FCAS correct the supply/demand balance in response to major frequency disturbances causing frequency to move outside the normal operating frequency band, which can occur after contingency events such as the loss of a generating unit or a major load. In Q3 2025, costs for contingency raise services were $11 million, lower than $13 million in the same period last year. However, costs for contingency lower services increased from $7 million in Q3 2025 to $56 million this quarter. This increase in cost was driven by planned outages impacting the Heywood interconnector during July and August requiring local FCAS enablement in South Australia due to the risk of islanding in the event of a credible contingency.

Over 16 and 17 August, during a planned outage of the Tailem Bend–Tungkillo No.1 275 kV line, high wind generation in South Australia increased exports to Victoria on Heywood and subsequently increased L1SE requirements (Figure 68).

Figure 68 South Australia L1SE price spikes leading to administered price period

South Australia L1SE enablement and price – 15 August to 24 August 2025



Participants able to provide local L1SE were restricted to those within South Australia located north-west of the network outage, causing tight supply-demand conditions and extreme prices in the region's L1SE market. Consequently, cumulative prices for the L1SE service in South Australia breached the Cumulative Price Threshold (CPT) of $1,823,600 and AEMO declared an administered price period to apply from 0520 hrs on 17 August. The administered price period lasted to 0400 hrs on 24 August. During this period the Administered Price Cap (APC) of $600/MWh was applied to all market ancillary service prices in South Australia.

Contingency FCAS costs also increased in Tasmania, rising from $2 million in Q3 2024 to $8 million this quarter. The contingency lower 6-second (L6SE) and contingency raise 6-second (R6SE) service costs grew from under $1 million each to $3 million and $4 million, respectively. This increase was primarily driven by a higher number of intervals during which Basslink was unable to transfer FCAS[30], including more intervals where Basslink's flow was within its 'No-Go' zone of between approximately -50 MW and 50 MW. These 'No-Go' zone intervals rose sharply from 2% in Q3 2024 to 42% in Q3 2025.

Regulation FCAS and frequency performance payments (FPPs)

Regulation FCAS provide frequency correction in response to minor deviations in the demand/supply balance. The FPP incentive arrangements introduced in Q2 2025 are intended to provide economic signals to participants about the value of good frequency performance and the cost of poor performance. FPPs are not an ancillary service, but a separate function inter-related with the regulation FCAS requirements.

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

Since the introduction of FPP, used and unused regulation FCAS costs are recovered separately. The costs for regulation services used in a trading interval are allocated based on negative CFs determined for the trading interval. In contrast, the costs for regulation services not used in a trading interval are allocated based on default contribution factors, which are intended to reflect the longer-term historical performance of a facility[31]. FCAS payments continue to be based on the enablement quantity for each unit and the market clearing price for the relevant service in each region.

In Q3 2025, costs for regulation FCAS were $6.1 million, slightly down from $6.7 million in Q3 2024, and a total of $7.6 million in FPP incentive payments were credited (and debited). Figure 69 shows the FPP credits and debits, and regulation FCAS payments and cost recovery by fuel type in Q3 2025.

For batteries, hydro, black coal-fired and brown coal-fired units, combined FPP credits and regulation FCAS payments offset combined FPP debits and regulation FCAS recovery costs. Batteries received $3.6 million, hydro generators received $1.7 million, black coal-fired generators received $1.4 million, and brown coal-fired generators received $0.8 million in net FPP and regulation FCAS settlements.

The residual category, which includes sites without appropriate metering to calculate individual contribution factors, such as small consumers and distributed resources, incurred the largest share of charges, with $3.0 million in total net FPP and

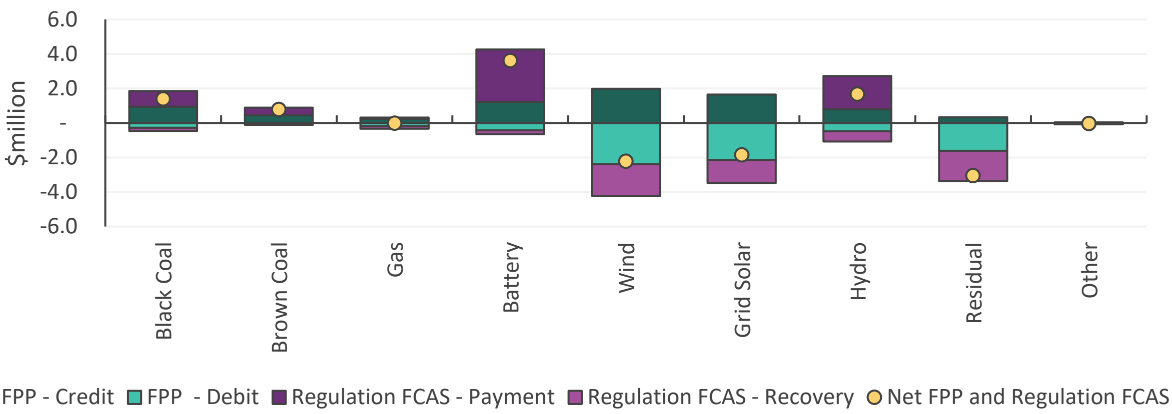
[30] AEMO, Constraint Formulation Guideline. June 2023: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2023/constraint-formulation-guidelines-v12---final_1.pdf?rev=e3d6e8636273414c9d6bbf6d8f5b59ed&sc_lang=en.

[31] For more detailed information on FPP and regulation FCAS cost recovery refer to AEMO's Settlement guide: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/ancillary-services-data/ancillary-services-payments-and-recovery.

regulation FCAS settlements. Wind and grid-scale solar units followed with total net FPP and regulation FCAS settlements of $2.2 million and $1.8 million respectively.

Figure 69 Batteries received highest share of FPP and FCAS net settlements

Sum of Frequency Performance Payments (FPP) and regulation FCAS recovery and payments by fuel type – Q3 2025

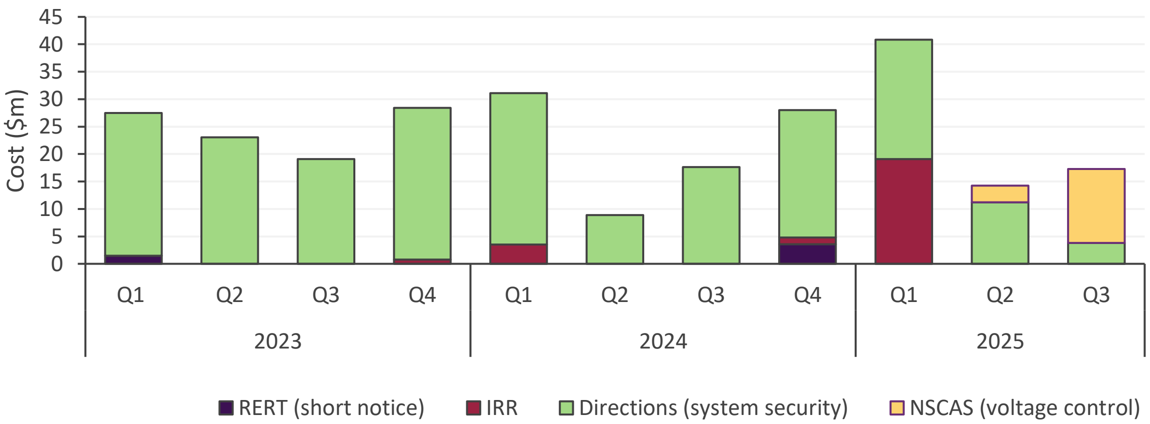


2.6 Power system management

Estimated power system management costs[32] were $17 million in Q3 2025 (Figure 70), representing approximately 0.4% of the total cost of consumed energy for the quarter, and slightly lower than $18 million in Q3 2024. The cost for system security energy directions dropped from $18 million to $4 million, with the commencement of two network support and control ancillary services (NSCAS) agreements for voltage control in South Australia (discussed in more detail below). The estimated costs for the enablement of these contracts across the quarter was $13 million.

Figure 70 Power system management costs remained steady year-on-year

Estimated quarterly system security costs by category



[32] 'Power system management costs' are those associated with Reliability and Reserve Trader (RERT) and compensation for system security directions for energy services and costs associated with network support and control and ancillary services (NCSAS) for voltage control. 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 here: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports.

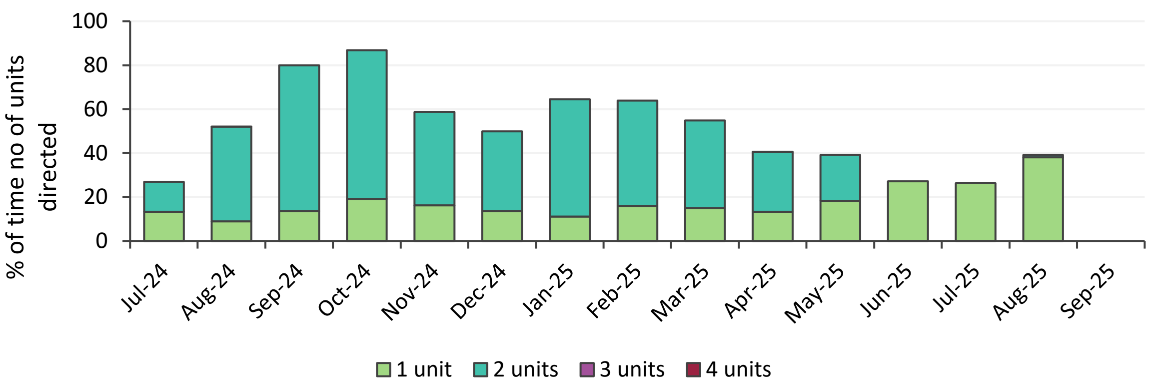
2.6.1 System security directions

In December 2023, AEMO declared a NSCAS gap for voltage control in the South Australian region[33], and in July 2024, AEMO published a notice that the NSCAS gap remained in place, with a permanent solution expected to be in place progressively across 2025-26[34]. AEMO completed the expression of interest and tender processes for the procurement of services to meet this gap in June 2025[35]. The first of two services procured became active from 21 May 2025, and the second on 1 September 2025.

Also, from 3 September 2025, AEMO confirmed, through its updated transfer limit advice for South Australia[36], that the minimum synchronous generator combinations required for secure operation in South Australia could be reduced to one unit, subject to defined system conditions[37]. The impact of these two factors can be seen in the sharp reduction in system security directions in South Australia in Figure 71. In Q3 2025, system security directions were issued in South Australia during 22% of intervals, down from 53% intervals in Q3 2024, and the volume of gas-fired generation also decreased, down from 39 MW to 9 MW.

Figure 71 Significant decrease in South Australian system security energy directions

Number of South Australian gas-fired units simultaneously directed – proportion of month



On 28 August 2025, a direction was issued in the New South Wales region for a generating unit to operate as a synchronous condenser to provide system strength services[38]. Prior to the event there were eight major coal units online before an additional major coal unit required an unplanned outage starting from 1110 hrs, creating a system strength gap[39]. The direction was in place from 1110 hrs and was cancelled at 1200 hrs after one of the units on outage returned to service.

[33] AEMO, 2023 Network Support and Control Ancillary Services (NSCAS) Report. December 2023: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-nscas-report.pdf.

[34] AEMO, Notice that the NSCAS gap remains in South Australia. July 2024: https://www.aemo.com.au/-/media/files/stakeholder_consultation/tenders/2024/notice-that-nscas-gap-remains-in-sa-july-2024.pdf?rev=69b3071e93ce421ca3e7d4df186811d3&sc_lang=en.

[35] See https://aemo.com.au/consultations/tenders/nscas-procurement.

[36] AEMO, Transfer Limit Advice – Minimum Generator combinations in SA, September 2025: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf.

[37] AEMO, Reduction of Minimum Synchronous Generators in South Australia. August 2025: 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.

[38] AEMO, Market Notice 128743: https://www.aemo.com.au/market-notices.

[39] Transgrid, New South Wales Synchronous Generation, September 2025: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2024/transfer-limit-advice---system-strength-nsw.pdf.

3 Gas market dynamics

3.1 Wholesale gas prices

Quarterly wholesale gas prices saw a slight increase from Q3 2024 (except Adelaide) and were also 2% higher than Q2 2025. The average price across all AEMO markets was $12.62/GJ compared to $12.50/GJ in Q3 2024 (Table 5).

Table 5 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q3 2025	Q2 2025	Q3 2024	Change from Q3 2024
Victoria Declared Wholesale Gas Market (DWGM)	12.11	11.60	12.08	0%
Adelaide	12.76	12.90	12.78	0%
Brisbane	12.79	12.40	12.63	1%
Sydney	12.75	12.59	12.57	1%
Gas Supply Hub (GSH)	12.71	12.31	12.48	2%

Key factors influencing the movement of prices throughout Q3 2025 are summarised in Table 6, with further analysis and discussion in relevant sections elsewhere in this report.

Table 6 Wholesale gas price levels: Q3 2025 drivers

Higher offer prices into DWGM and Short Term Trading Market (STTM) in August and September	Average prices in August and September 2025 were 4% and 1% higher respectively compared to the same months in 2024. This increase was primarily driven by a shift in the supply mix toward higher-priced gas from Iona Underground Gas Storage (UGS), which reduced the proportion of offers priced below $14/GJ and lifted the overall quarterly average price (Figure 73). The change in offer patterns reflected reduced supply from Queensland into southern markets and a greater dependence on Iona UGS, even though demand in AEMO markets and for gas-fired generation was lower than in August and September 2024.
Decrease in domestic supply in across all regions leading to greater reliance on Iona UGS	While domestic market demand was 3.1 PJ lower than Q3 2024, supply from Queensland, Northern Territory and southern production facilities to the domestic market was 6.5 PJ lower than Q3 2024, with Iona UGS utilised more to supply the market. This supply decrease was observed in all major supply regions, with Moomba lower by 3.6 PJ, Victorian supply lower by 2.1 PJ, and net domestic Queensland supply by 2 PJ. The only region to increase supply was Northern Territory, which was 1.2 PJ higher, but that only occurred for 1 month.

International prices remained relatively steady in Q3 2025, with decreases observed in September and October 2025 compared to 2024. This decrease was reflected in downward movements in the Australian Competition and Consumer Commission (ACCC) netback price to September 2025, with corresponding forward prices trending downwards over the next six months (Figure 72).

Prices in July 2025 were slightly lower than July 2024, which had experienced higher prices due to higher gas-fired generation demand combined with colder weather during July 2024[40], leading to market participants increasing bid volumes priced between $12/GJ and $14/GJ (Figure 73).

[40] Winter 2025 was colder overall than winter 2025 with August 2025 being much colder than 2024, which was a record mild month.

In contrast, prices increased in August and September 2025 due to a decrease in supply from Queensland to southern states, combined with a reduction in Moomba and Longford supply, with increased withdrawals from Iona UGS used to meet demand. This change in supply led participants to increase bid volumes priced between $14/GJ and $20/GJ.

Figure 72 Domestic prices up slightly year-on-year due to higher levels in August and September 2025

ACCC netback and forward prices[41], DWGM and STTM Brisbane average gas prices by month

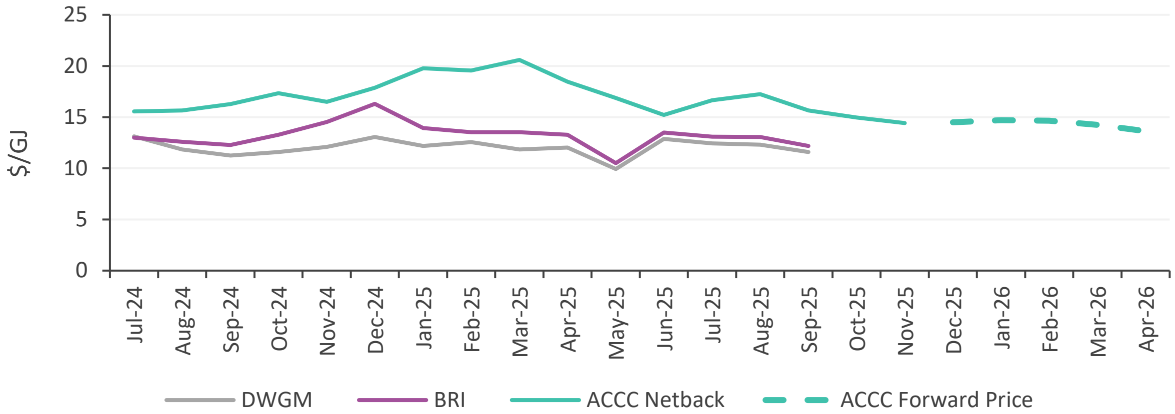
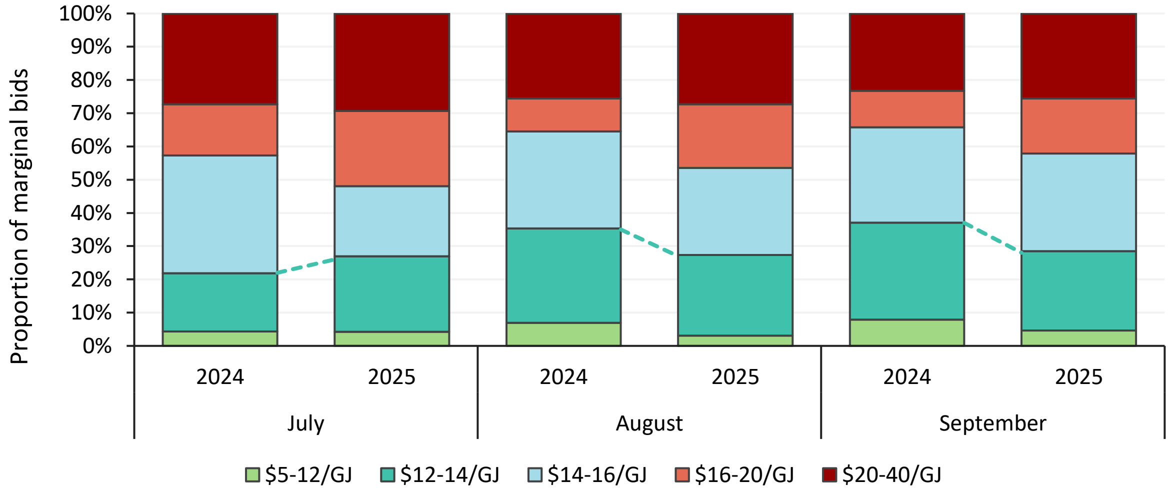


Figure 73 Increased proportion of DWGM bids in August and September at higher prices compared to 2024

DWGM – proportion of marginal bids by price band – Q3 2025 vs Q3 2024 by month



3.1.1 International energy prices

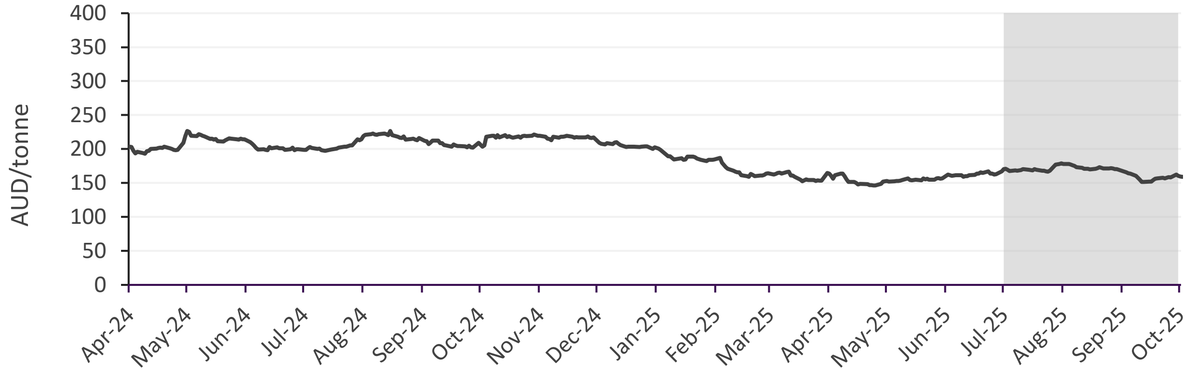
Newcastle export thermal coal prices averaged $167/tonne this quarter, an increase from $157/tonne in Q2 2025, but lower than $209/tonne in Q3 2024 (Figure 74). After reaching their lowest average since Q2 2021 in Q2 2025, Newcastle export thermal coal prices rebounded in Q3 2025 due to due to higher summer demand in the Northern Hemisphere and a

[41] ACCC, LNG netback price series published on 16 October 2025: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

vessel backlog at Newcastle port that restricted supply. This backlog started with May flooding in New South Wales and was compounded by ongoing ship loader replacement work expected to continue through November[42].

Figure 74 Thermal coal prices rebounded from the lows of Q2 2025

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

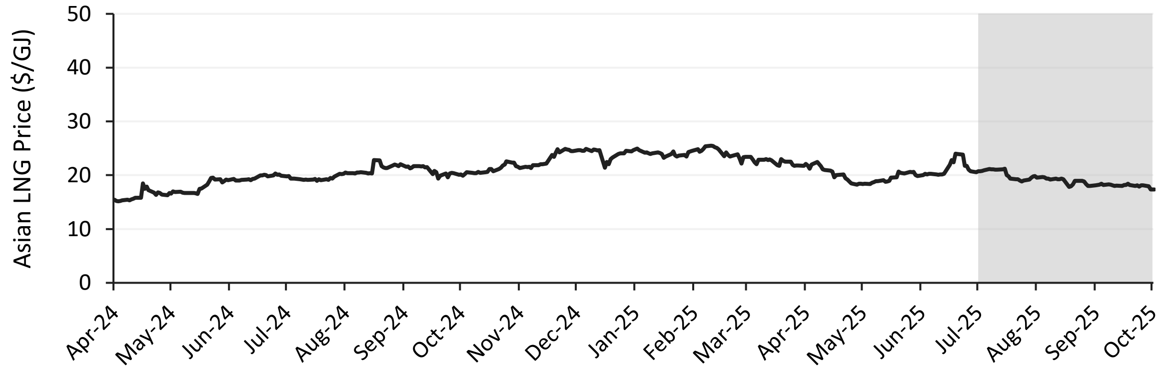


Source: Bloomberg ICE data

In contrast to Q2 2025, Asian LNG prices saw a steady decline ending Q3 at A$17.40/GJ, down A$3.30/GJ from the start of the quarter (Figure 75). This was primarily due to increased domestic natural gas production in China and increased flows of piped gas from Russia reducing the need to import LNG from the spot market[43]. The Japan Organisation for Metals and Energy Security (JOGMEC) reported that heatwaves temporarily increased demand for spot LNG cargoes in September, but this was a short-lived event. As the region enters a shoulder season, reports of low demand and high inventory levels are adding downward pressure on Asian LNG prices[44].

Figure 75 Asian LNG prices soften as LNG buyers procured gas from alternative sources

Asian LNG price in A$/GJ daily



Source: Bloomberg ICE data

[42] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly September 2025: https://www.industry.gov.au/publications/resources-and-energy-quarterly-september-2025.

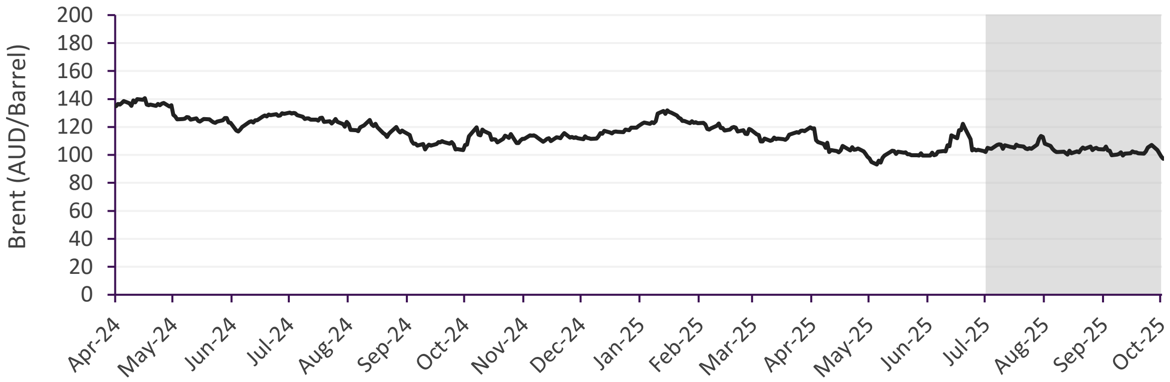
[43] IEA Gas Market Report Q3, 2025: https://www.iea.org/reports/gas-market-report-q3-2025.

[44] JOGMEC, September 2025: https://oilgas-info.jogmec.go.jp/nglng_en/1007907/1010612.html.

The Brent crude oil market experienced a relatively stable period with prices fluctuating within a narrow range averaging A$104/barrel for the quarter (Figure 76). This period of stability was a result of OPEC+ countries easing production cuts sooner than anticipated, however this increase in supply was offset by continuing geopolitical tensions globally[45]. Market sentiment remained relatively cautious leading to limited price volatility over the quarter.

Figure 76 Brent Crude oil price remained relatively stable over the quarter

Brent Crude Oil in A$/Barrel daily



Source: Bloomberg ICE data

3.2 Gas demand

Total east coast gas demand decreased by 1% compared to Q3 2024 (Figure 77 and Table 7). Gas-fired generation saw the largest fall in overall demand (-3 PJ), while AEMO markets and Queensland LNG production were relatively stable. The main reasons for reduced gas-fired generation were higher renewables output in the NEM and fewer multi-day wind lulls (see Figure 39 in Section 2.3.4). As AEMO's 2025 *Gas Statement of Opportunities* (GSOO)[46] highlighted, gas-fired generation plays a critical function in supporting the reliability and secure operation of the power system, however the need for high levels of gas-fired generation was lower during Q3 2025 than in Q3 2024 or Q2 2025.

[45] US Energy Information Administration (EIA) Q3 2025 publication: https://www.eia.gov/todayinenergy/detail.php?id=66264.

[46] At https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf.

Figure 77 Gas-fired generation demand largest decrease compared to 2024

Components of east coast gas demand change – Q3 2025 vs Q3 2024

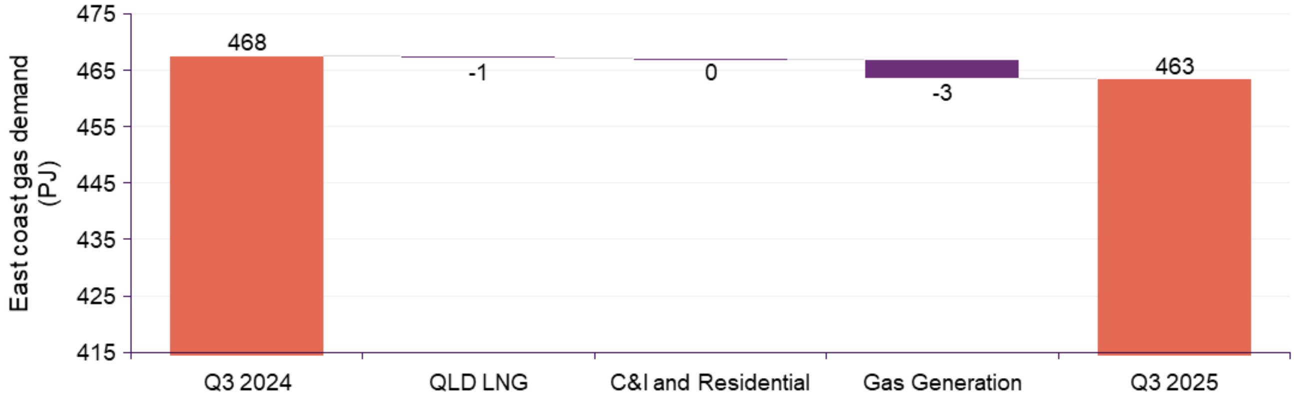


Table 7 Gas demand – quarterly comparison

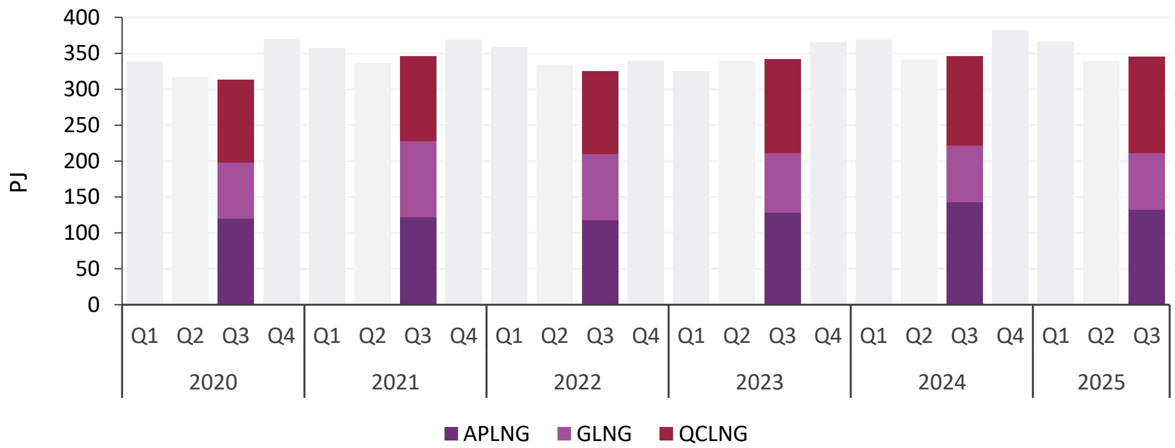
Demand (PJ)	Q3 2025	Q2 2025	Q3 2024	Change from Q3 2024
AEMO markets *	91.8	77.0	91.9	0 (0%)
Gas-fired generation **	26.1	30.5	29.6	-3 (-12%)
Queensland LNG	345.5	338.91	346.1	-1 (0%)
Total	463.4	446.4	467.6	-4 (-1%)

* 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 was slightly lower than in Q3 2024, by just under 1 PJ (Figure 78). The 10 PJ decrease in APLNG production (driven by a variety of planned maintenance events over the quarter) was offset by a 9 PJ increase for QCLNG, while GLNG saw a modest increase in LNG production of just under 1 PJ. Overall, this led to the second-highest Q3 LNG production on record (with the record set last year). There were 85 cargoes exported during the quarter, down from 87 during Q3 2024.

Figure 78 Queensland LNG production saw a slight decrease driven by APLNG which was offset by increases to QCLNG and GLNG

Total quarterly pipeline flows to Curtis Island



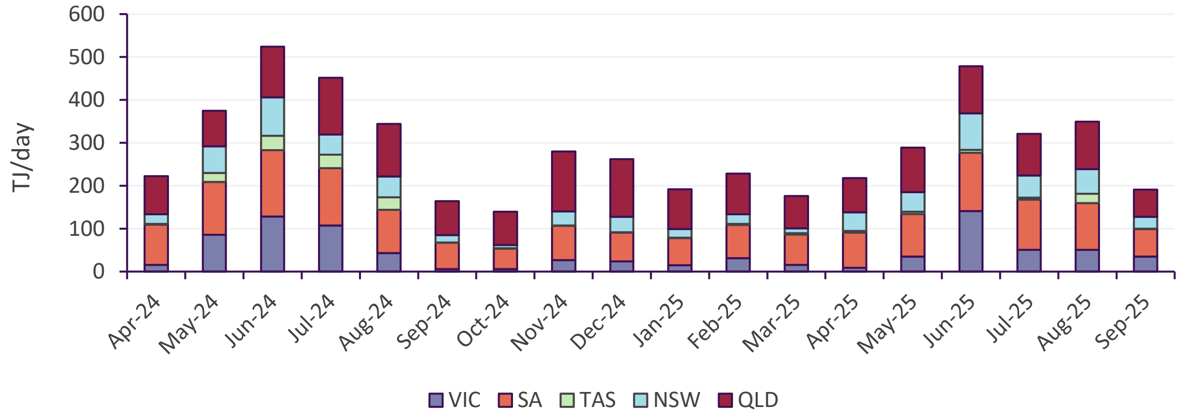
3.2.1 Gas-fired generation

Gas fired generation decreased 12% compared to Q3 2024 (Figure 79). The lower demand for gas-fired generation was due to fewer wind lulls and a surge in battery discharge during morning and evening peak periods (see Figure 24 in Section 2.3).

There were some localised increases to gas-fired generation during the quarter as Hunter Power Station began commissioning from the second half of July, leading to a 20% increase to New South Wales gas-fired generation demand. Tasmania also saw increased gas-fired generation with the Tamar Valley Combined Cycle facility operating from 11 to 27 August, which coincided with outages at a few hydro generators, including at Poatina.

Figure 79 Decrease in gas-fired generation demand due to reduced wind lulls

Average daily gas-fired generation demand by state



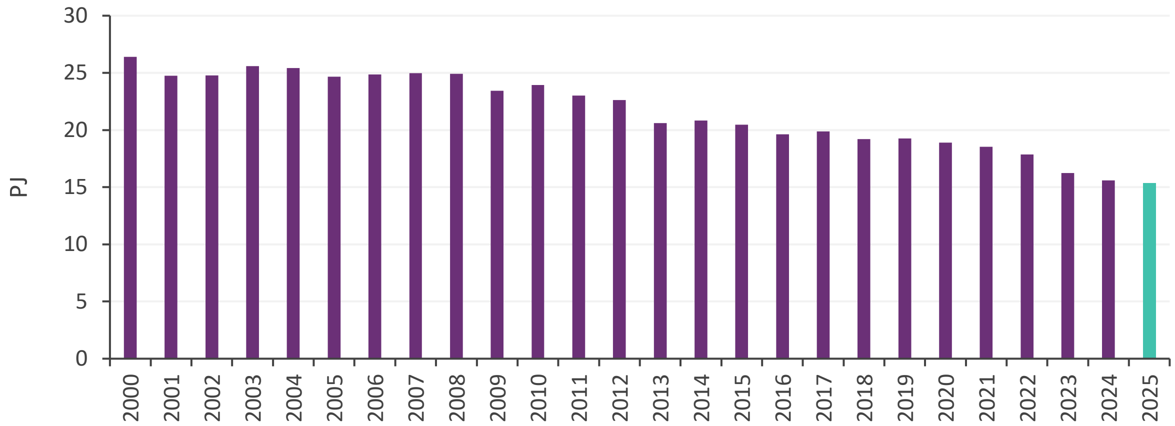
3.2.2 Victorian Declared Wholesale Gas Market (DWGM) demand

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

Continuing the trend observed in Q1 and Q2 2025, Q3 2025 saw another decrease in Tariff D demand, with demand decreasing from 15.6 PJ in Q3 2024 to 15.3 PJ in Q3 2025, a 2% decrease (Figure 80). This represents the lowest Q3 Tariff D demand since the DWGM began in 1999, and an 11 PJ or 42% decrease from the peak in 2000.

Figure 80 Victorian industrial and large commercial demand at lowest level since the DWGM began

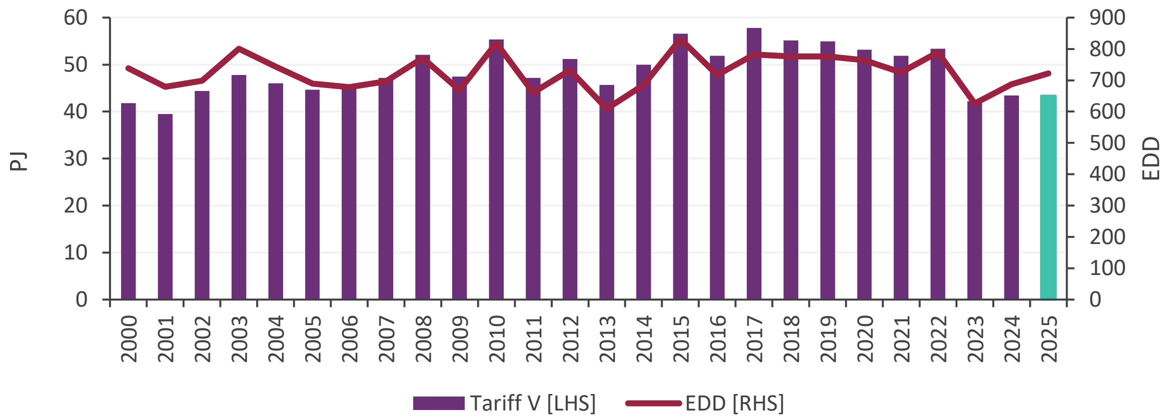
Q3 DWGM Tariff D demand



While Tariff V demand was similar to Q3 2024 and higher than Q3 2023, much of Tariff V demand is typically used for heating, so varies from year to year depending on weather conditions. To capture the impact of weather on demand, AEMO uses a measure known as the Effective Degree Day (EDD), which considers the temperature profile, average wind speed, sunshine hours, and the season for the gas day. The higher the EDD, the higher the likely gas use. The cumulative EDD in Q3 2025 was 722, significantly above Q3 2023 and 2024. The closest recent level to Q3 2025 occurred in Q3 2021 with aggregate EDD of 725. That quarter recorded a Tariff V demand of 51.9 PJ, 8.5 PJ higher than this Q3. This represents a 16% drop in Tariff V demand since 2021 (Figure 81).

Figure 81 Tariff V Q3 demand similar to 2024 despite colder weather

Q3 DWGM Tariff V demand and EDD



3.3 Gas supply

3.3.1 Gas production

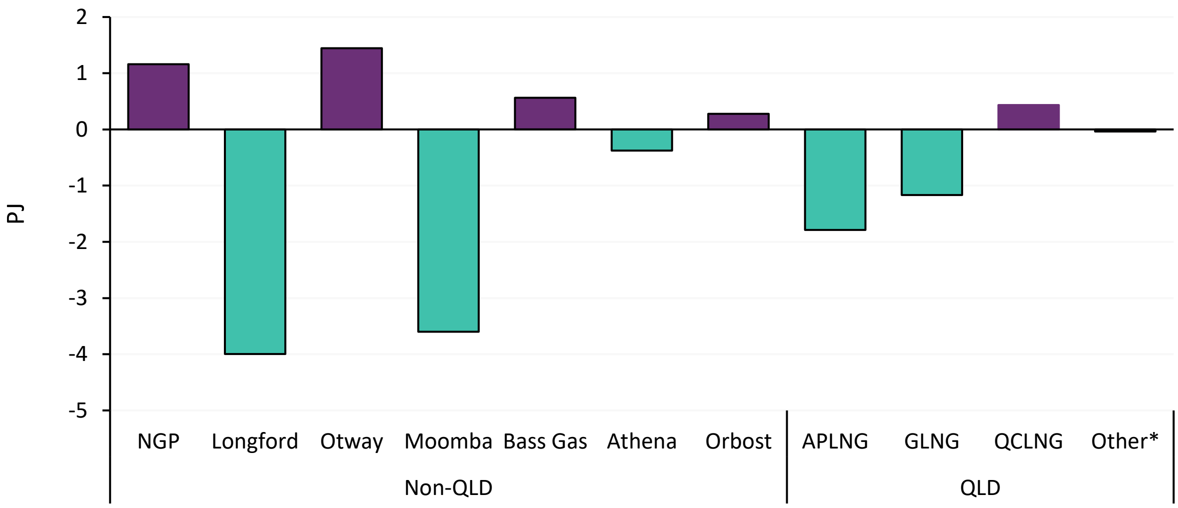
East coast gas production decreased by 8.3 PJ (-2%) compared to Q3 2024 (Figure 82). Key changes included:

- Queensland production decreased by 2.6 PJ, with assets operated by APLNG decreasing by 1.8 PJ, GLNG operated assets decreasing by 1.2 PJ, and QCLNG operated assets increasing slightly by 0.4 PJ. Gas demand for Queensland LNG exports decreased by 0.6 PJ, resulting in 2 PJ less net supply associated with Queensland LNG projects entering the domestic market compared to Q3 2024, marking the lowest Q3 domestic supply since Q3 2023 (Figure 83).

- Victorian production decreased by 2.1 PJ, mainly driven by the decrease in Longford production (-4.0 PJ). Most other Victorian production facilities saw increases, with Otway the largest (+1.4 PJ), followed by smaller increases at Bass Gas (+0.6 PJ) and Orbost (+0.3 PJ).
- Production fell by 3.6 PJ at Moomba, which continued to be impacted by widespread flooding in far northern South Australia which occurred in mid-April. Average daily output dropped from 255 TJ/day in Q3 2024 to 216 TJ/day in Q3 2025. On 16 October, Santos reported that Cooper Basin production continues to recover from flooding earlier in the year, with 50 wells and an upstream compressor since returned to service and production continuing to increase[47].
- Northern Gas Pipeline (NGP) supply increased by 1.2 PJ. As reported in the Q2 2025 QED, new production issues emerged on 24 June 2025, causing flows to Queensland to cease after they had resumed in May. These were temporarily resolved, allowing NGP to flow again for one month from 19 July to 19 August, before planned maintenance ceased flows again for the rest of the quarter. This is discussed in more detail in Section 3.3.3.

Figure 82 Production fell mostly due to lower Longford, Moomba and Queensland output

Change in east coast gas supply – Q3 2025 vs Q3 2024

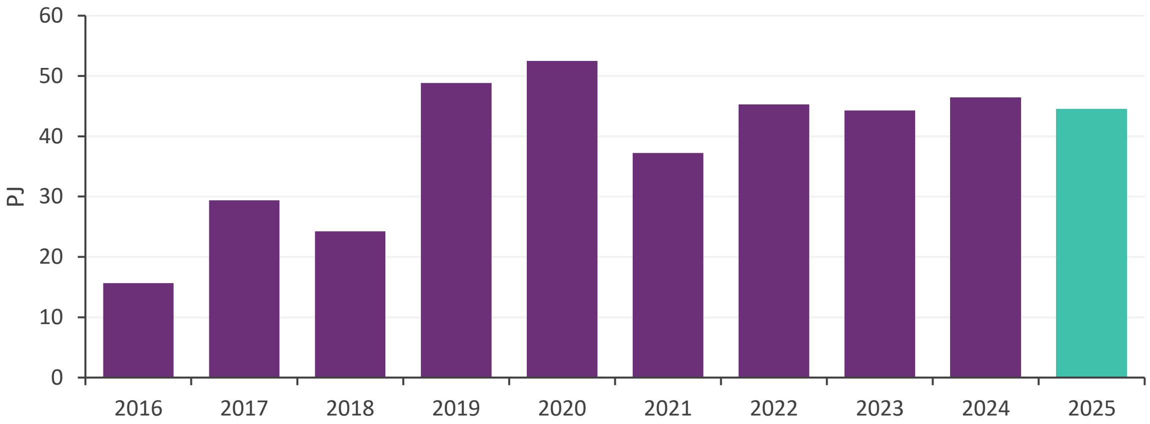


*Other Queensland supply is calculated by total Queensland production minus production associated with Queensland LNG export projects

[47] Santos, Third Quarter Report for period ending 30 September 2025, October 2025: https://www.santos.com/wp-content/uploads/2025/10/2025-Santos-Third-Quarter-Report.pdf.

~~Figure 83~~ Queensland net domestic supply similar to 2023 and slightly lower than 2024

Queensland net domestic supply during Q3

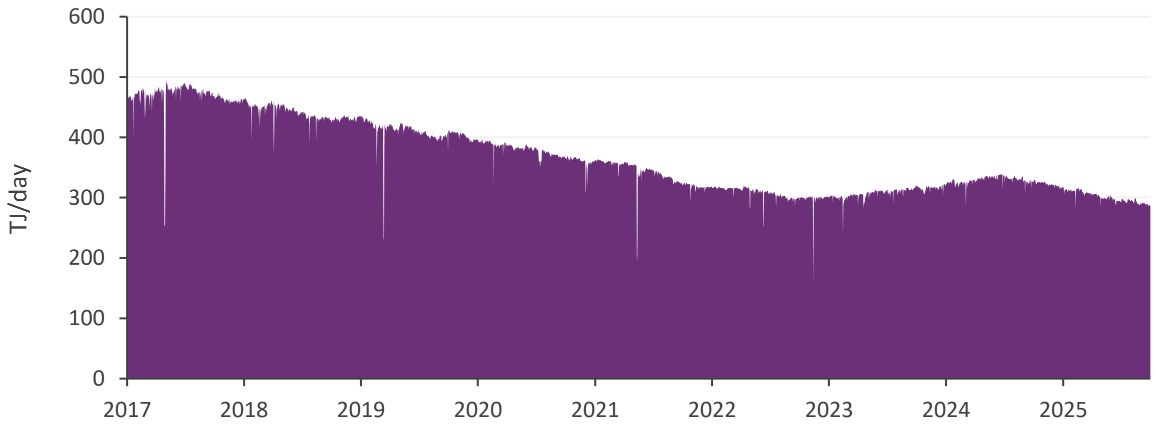


3.3.2 GLNG Fairview production

Fairview gas field in Queensland is part of the GLNG portfolio of coal seam gas production assets, and has been the largest component of GLNG's production portfolio since LNG exports began in 2015. Since its peak production in May 2017, Fairview production declined year-on-year from 2017 to 2023 before seeing a small increase in 2024, but the decline resumed in 2025. Daily production peaked at 495 TJ on 5 May 2017, and was down to 286 TJ on 30 September 2025, a 42% decrease (Figure 84).

Figure 84 GLNG's Fairview production down 42% from its peak in 2017

Fairview daily production 2017-2025



3.3.3 Northern Territory supply

As reported in the Q2 2025 QED, AEMO was notified on 24 June 2025 that the Northern Territory was unable to be supplied from the Ichthys LNG plant until mid-July due to planned pipeline maintenance. Northern Territory demand was being supported by supply from the Yelcherr Gas Plant (processing gas from the Blacktip gas field), as well as gas plants in southern Northern Territory. This, in turn, caused the NGP to cease flows from 28 June due to insufficient gas flow to meet minimum flow requirements.

Flows recommenced on 19 July but were halted again on 20 August when Ichthys LNG started a major planned maintenance outage on 16 August, which was planned to run through to 8 October. During this period of decreased Northern Territory supply availability, there was insufficient supply in the Northern Territory to supply Mt Isa via the NGP.

During the outage, all demand on the Carpentaria Gas Pipeline (CGP) had to be met by supply from the South West Queensland Pipeline (SWQP).

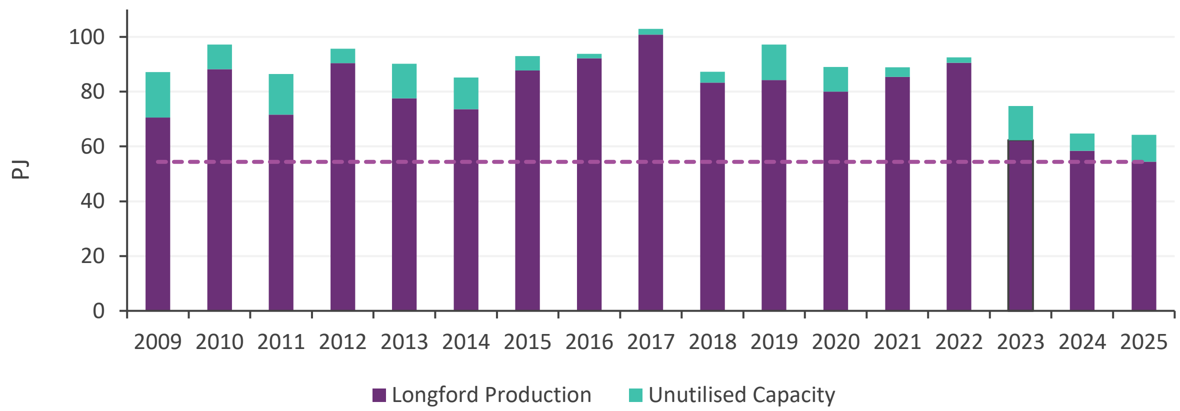
AEMO continued to monitor Northern Territory supply due to the planned outage of the Ichthys LNG facility, which supplies gas to Darwin. This limited Northern Territory gas supply sources to Blacktip, Palm Valley and Mereenie, with the Darwin LNG facility offline until processing of gas from the Barossa gas field commences. The NGP does have the capability to reverse flow from Queensland into the Northern Territory if there is insufficient supply in the Northern Territory, but this requires a lead time to configure this reverse flow capability. A reverse flow test of 5 TJ was conducted during September, but no additional flows from Queensland to the Northern Territory were required during the Ichthys outage.

3.3.4 Longford production and capacity

Longford's gas production in Q3 2025 was 4 PJ lower compared to the same period in 2024, reaching 54.4 PJ compared to 58.4 PJ in Q3 2024. Although available production capacity was similar, with Q3 2025 capacity at 64.2 PJ, compared to 64.7 PJ in Q3 2024, daily Longford capacity was higher in Q3 2024 peaking at 750 TJ/day, compared to 720 TJ/day in Q3 2025, though Q3 2025 had fewer capacity reductions, noting Longford Gas Plant 1 was retired in Q4 2024 (Figure 85).

Figure 85 Longford production lower compared to Q3 2024 after Gas Plant 1 retired in Q4 2024

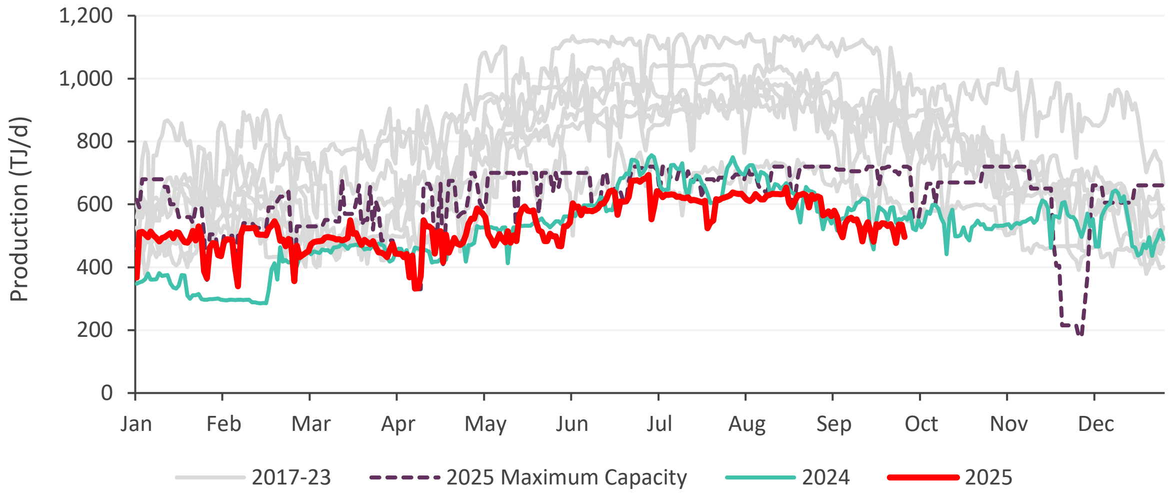
Longford Q3 production and unutilised capacity



Consistent with trends observed throughout 2025, daily production through much of Q3 remained below available capacity, with Longford operating at a capacity factor of 85% (Figure 86). This remains largely due to a proportion of Longford supply offers from the Longford producers, Esso and Woodside, continuing to exceed daily price outcomes in the DWGM and Sydney Short Term Trading Market (STTM).

Figure 86 Daily Longford production lower than 2024 levels

Daily Longford production 2017-2025, maximum capacity profile 2025



3.3.5 Gas storage

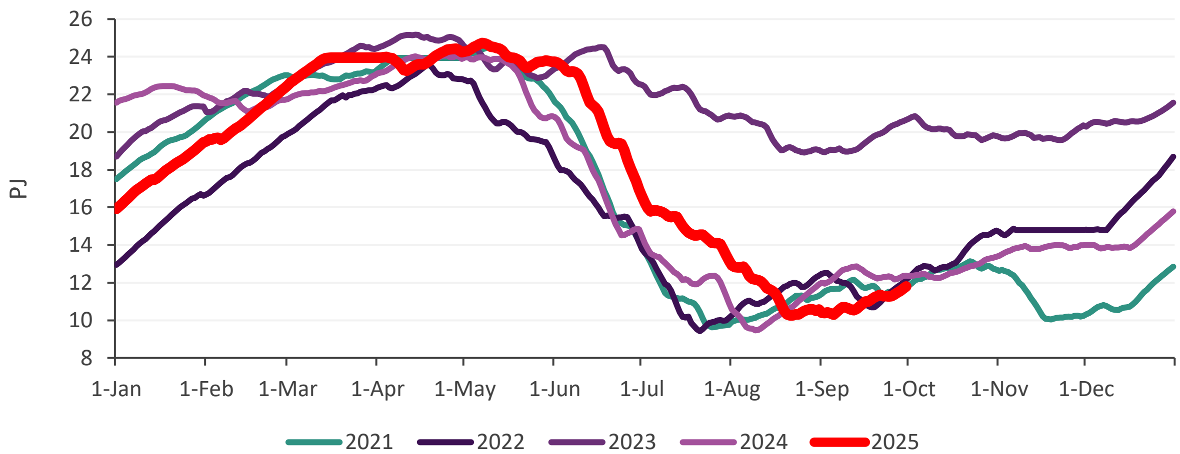
The Iona UGS facility began July at 16.6 PJ (67% full), its highest start to a Q3 since 2020, however it finished the quarter with 11.8 PJ (48% full) in storage, 0.6 PJ lower than at the end of Q3 2024 (Figure 87) and the lowest end to a Q3 since 2021, when it finished the quarter with 11.7 PJ.

The drawdown of 4.8 PJ from start to end of Q3 was the largest for any Q3 since 2019 when Iona storage levels decreased by 8.1 PJ. The main contributing factors were a decrease in supply to southern markets from Queensland, and lower production at Moomba and Longford gas plants.

Iona storage levels dropped to a low of 10.26 PJ on 21 August before slowly recovering throughout the rest of the quarter. Aside from 2023, where Iona was not heavily utilised because of above average temperatures resulting in lower demand, this is the first time in a Q3 since 2020 that Iona storage levels did not drop below 10 PJ.

Figure 87 Iona storage finished Q3 at its lowest level since 2021

Iona storage levels



3.4 Pipeline flows

Compared to Q3 2024, there was a 3.4 PJ increase in net transfers south to Moomba from the South West Queensland Pipeline (SWQP, Figure 88). The increase was coincident with lower production in Victoria that was mainly driven by the decrease in Longford production, and reduced production at Moomba while demand across southern markets remained relatively steady.

The increase in Victorian gas exports to New South Wales and South Australia (Figure 89) was supported by the higher utilisation of Iona UGS and higher Otway production, offsetting reduced Longford production.

Figure 88 Net Q3 flows south on South West Queensland Pipeline in Q3 2025

Flows on the South West Queensland Pipeline at Moomba

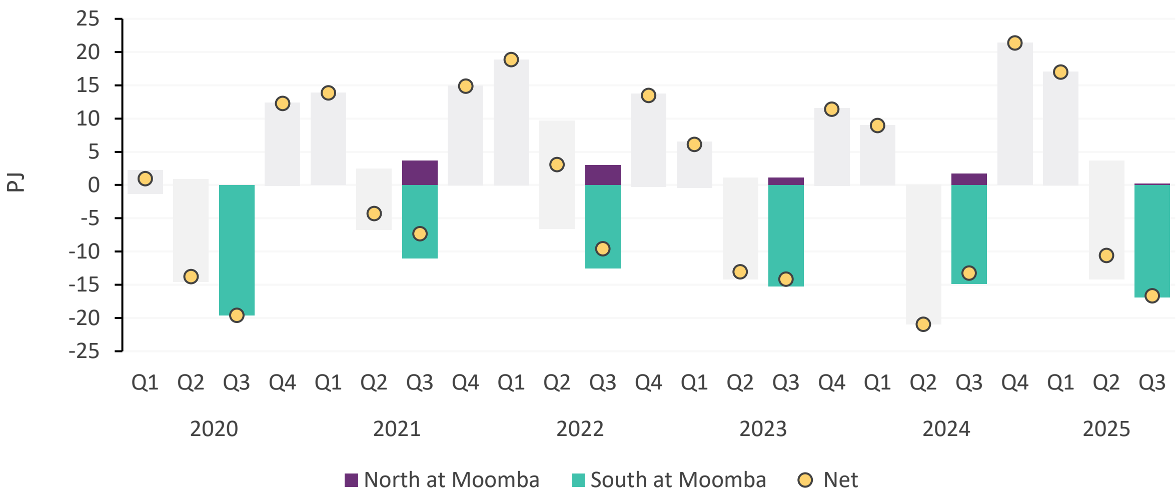


Figure 89 Increase in Victorian Q3 exports to New South Wales and South Australia

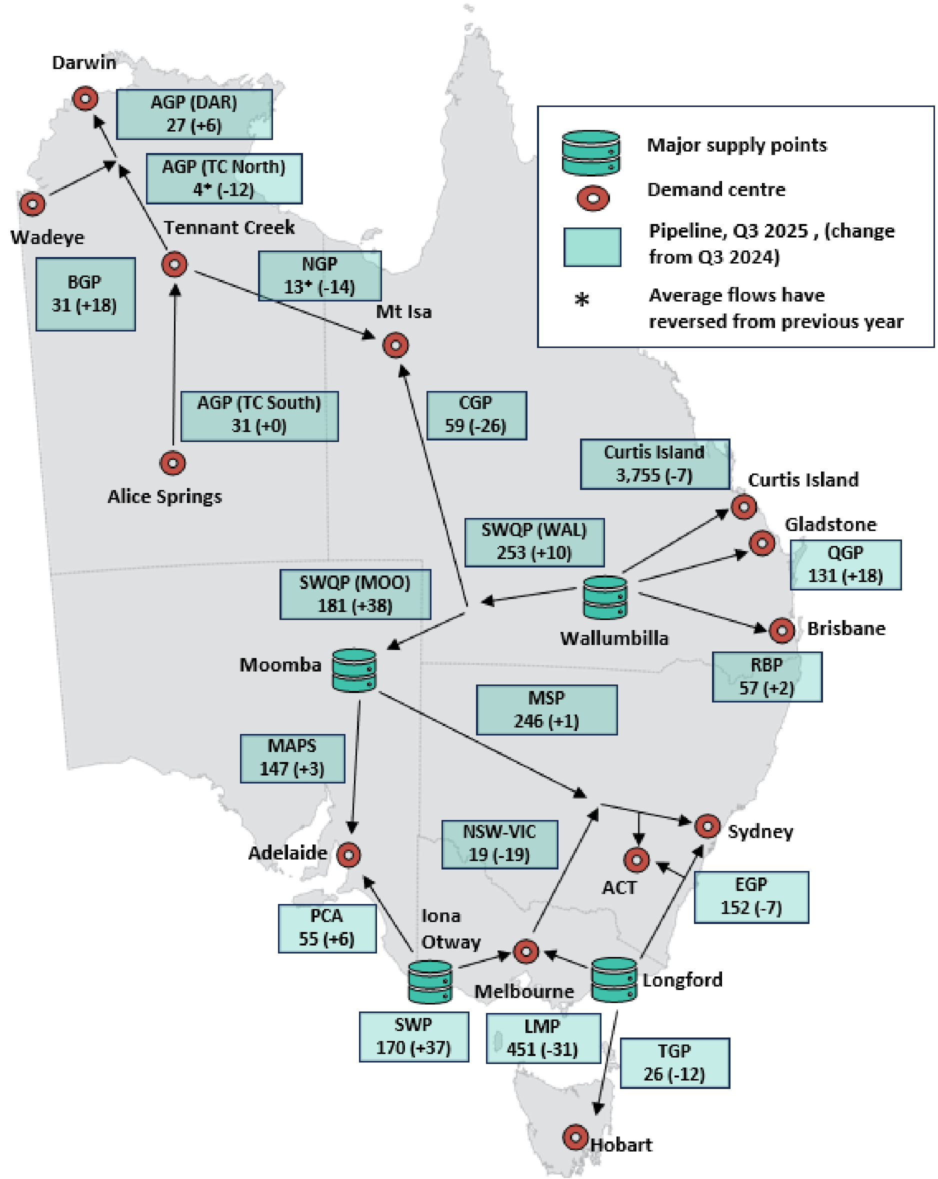
Victorian net gas transfers to other regions

In Victoria, average daily pipeline flows in Q3 2025 were significantly higher on the South West Pipeline (SWP), reflecting a greater utilisation of Iona UGS and the Otway Gas Plant to supply the DWGM, while flows to South Australia via the SEA Gas Pipeline were also higher (Figure 90). The corresponding decrease in flows on the Longford to Melbourne Pipeline (LMP) reflected lower overall supply from the Longford Gas Plant. Supply from Queensland to the southern markets also increased for the quarter.

Although net supply from Queensland producers to the domestic market was lower, the requirement for Queensland gas to flow north on the CGP was also lower overall for the quarter. Mt Isa demand was supplied by both Queensland and the Northern Territory, consistent with the increase in average flows south on the NGP compared to Q3 2024[48]. The quarter began with no flows on the NGP due to ongoing upstream supply issues in the Northern Territory, as discussed in Section 3.3.3. Limited flows south to Mt Isa resumed from 19 July for a month, before ceasing again.

Figure 90 Increase in Iona and Otway supply

Average daily pipeline flows Q3 2025 vs Q3 2024



48 The change in average daily pipeline flows on the NGP reflects a reversal in direction compared to Q3 2024.

3.5 Gas Supply Hub (GSH)

In Q3 2025, traded volumes on the GSH decreased by 5.9 PJ in comparison to Q3 2024 (Figure 91). The traded volume this quarter was 8.6 PJ and represented the lowest Q3 traded volume since 2021. July was the highest monthly traded volume for the quarter with volumes predominantly for delivery in the same month.

Figure 91 Lowest Q3 traded volume since 2021

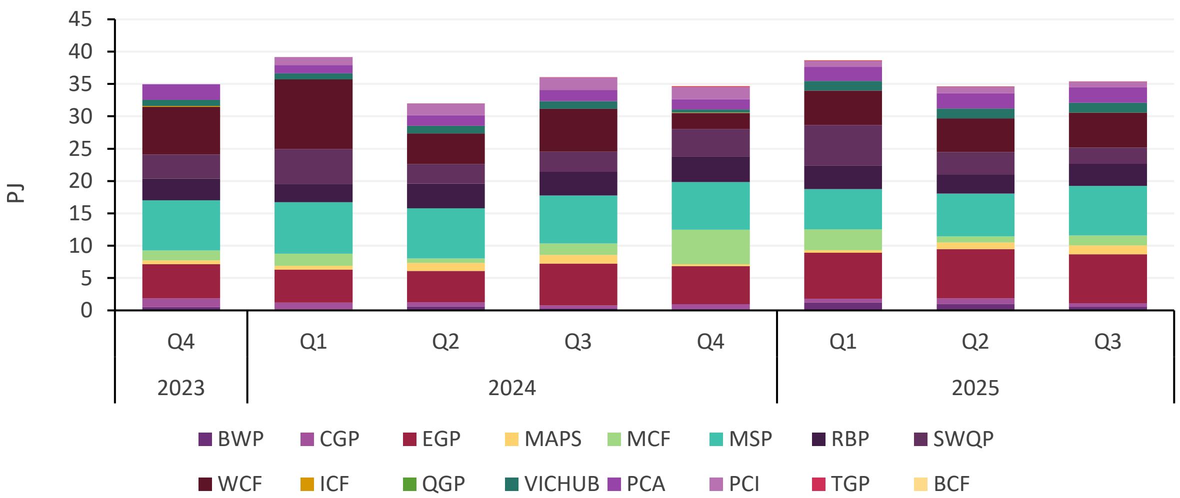
Gas Supply Hub – quarterly traded volume

3.6 Pipeline capacity trading and Day Ahead Auction

Day Ahead Auction (DAA) volumes decreased by 0.6 PJ to 35.4 PJ in comparison to Q3 2024 (Figure 92). The largest decreases occurred on the Wallumbilla Compression Facility (WCF, -1.2 PJ) and on the Port Campbell to Iona Pipeline (PCI, -1.1 PJ). The largest increase occurred on the Eastern Gas Pipeline (EGP, +1.1 PJ) with approximately 83% of gas volumes won being northern haul.

Figure 92 Decrease in DAA volumes traded in Q3 2025

Day Ahead Auction volumes by quarter



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

- the Carpentaria Gas Pipeline which averaged $0.48/GJ,
- the EGP which averaged $0.20/GJ,
- the SWQP which averaged $0.20/GJ, and
- the Roma – Brisbane Pipeline (RBP), which averaged $0.12/GJ.

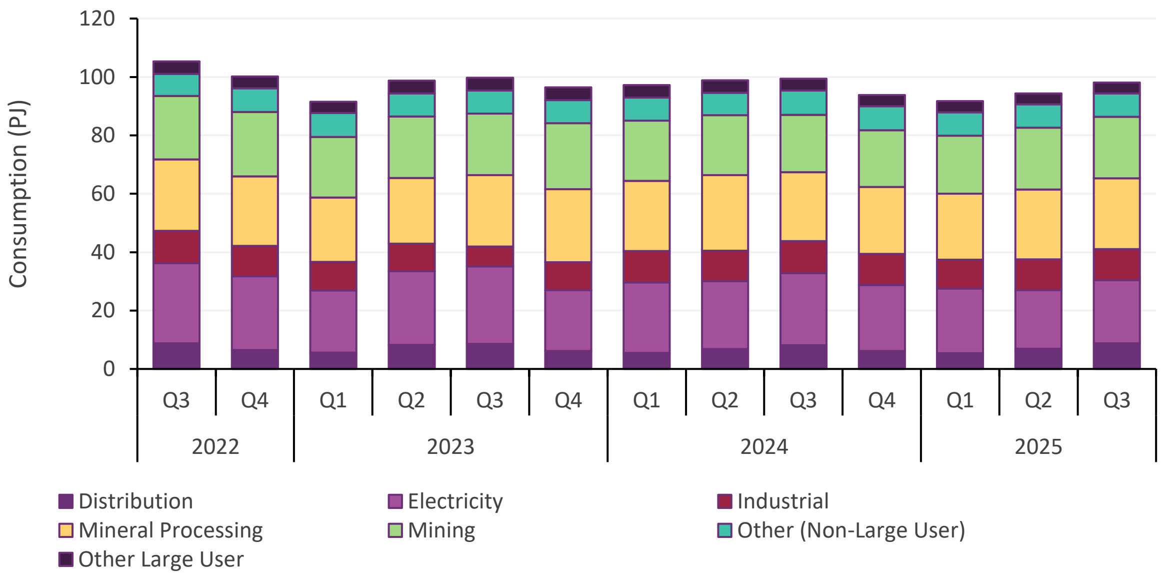
3.7 Gas – Western Australia

3.7.1 Gas consumption

A total of 98.1 PJ was consumed from registered pipelines in the Western Australian domestic gas market in Q3 2025 (Figure 93). This was a decrease of 1.3 PJ (-1.3%) compared to Q3 last year, and a slight increase of 3.8 PJ (+4%) from Q2 2025. The largest difference compared to Q2 2025 was observed in the distribution category, which increased by 1.9 PJ (+28%). There were also changes in consumption when reviewing geographic zones with Q2 2025; the largest increase was 3.3 PJ (+13.8%) in the Metro Zone, and the Karratha zone decreased consumption by 0.6 PJ (+15.2%).

Figure 93 Gas consumption in Western Australia increased slightly compared to the Q2 2025

Western Australia quarterly gas consumption by sector Q3 2022 to Q3 2025

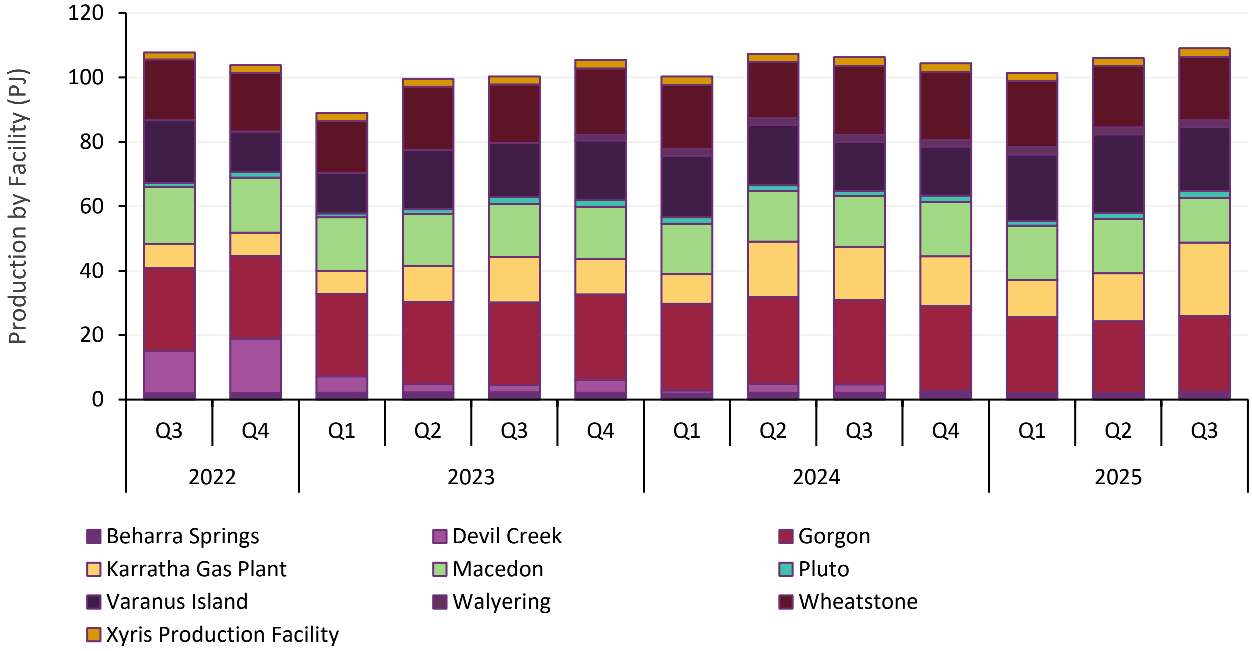


3.7.2 Gas production

Gas production in Western Australia was 109 PJ, an increase of 2.7 PJ (+2.6%) compared to Q3 2024, and an increase of 3.1 PJ (+2.9%) compared to last quarter (Figure 94). It was also the highest quarter of domestic gas production since Q2 2020. The increase in production from Q2 2025 can be mainly attributed to increases at the Karratha Gas Plant (7.8 PJ, +52.7%).

Figure 94 Q3 2025 saw an increase in gas production of 3.1 PJ from Q2 2025

Western Australia quarterly gas production by facility Q3 2022 to Q3 2025

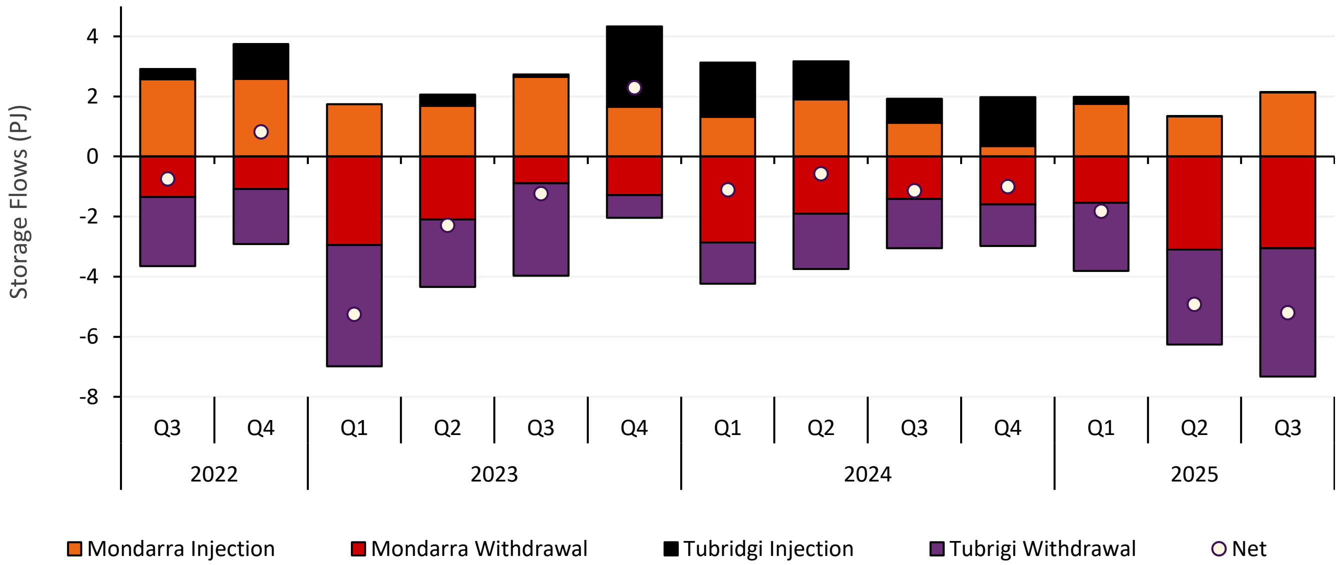


3.7.3 Storage facility behaviour

In Q3 2025, there was net withdrawal from storage facilities of 5.2 PJ (Figure 95). This was the seventh consecutive quarter of net withdrawals. Net withdrawal from storage in Q3 2025 increased by 4.1 PJ (+359%) compared to Q3 2024. Compared to Q2 2025, withdrawals increased by 0.3 PJ (+5.6%).

Figure 95 Net withdrawals from storage continued in Q3 2025

Western Australia gas storage facility injections and withdrawals – Q3 2022 to Q3 2025



3.7.4 Linepack Capacity Adequacy (LCA)

LCA is an indication of the actual or expected capability of a pipeline to meet relevant delivery nominations, and, for a storage facility, an indication of the number of days for which supply of natural gas can be maintained at the maximum operational outlet capacity.

During Q3 2025, there was a red LCA flag for the Mondarra Storage Facility on 1 July due to planned maintenance activities. In addition, the Dampier to Bunbury Natural Gas Pipeline (DBNGP) flagged an Amber LCA on 22-25 August, 27-28 August, and 19-20 September.

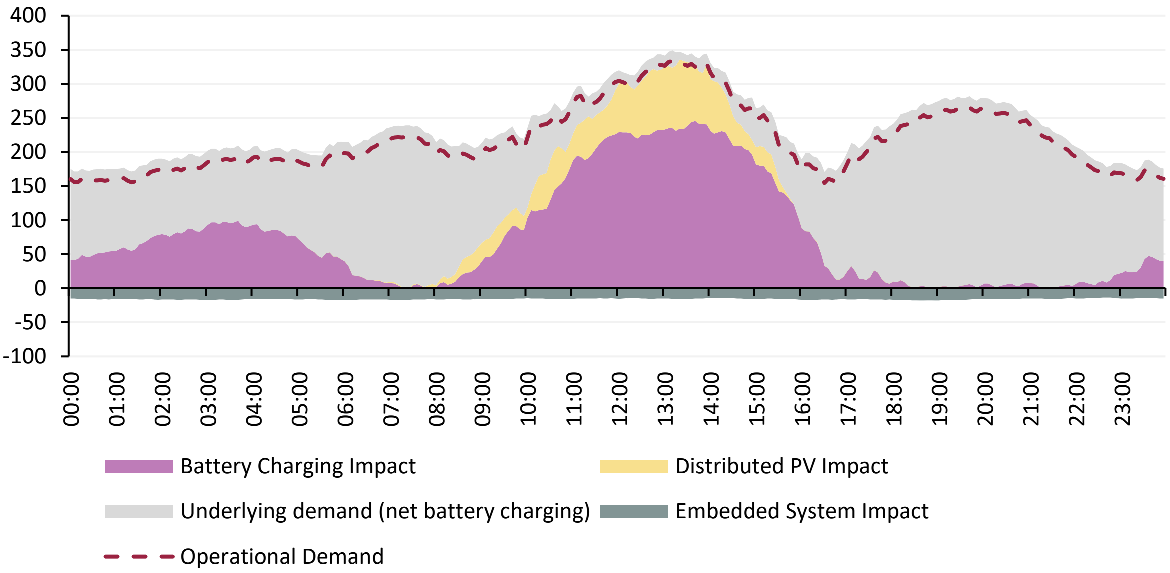
4 WEM market dynamics

4.1 Electricity demand

Average operational demand[49] was 2,228 MW in Q3 2025, an increase of 219 MW (+10.9%) on Q3 2024. This increase was comprised of an increase in average underlying demand of 220 MW (+9.0%) and a decrease in average distributed PV[50] generation of 15 MW (-3.7%), marginally offset by an increased average embedded system[51] impact of 16 MW (+85.4%).

Figure 96 Significant increases in average operational demand at all times of day

Change in WEM average operational demand components by time of day – Q3 2024 vs Q3 2025



In addition to growth caused by a larger population and increased economic activity, the increase in average underlying demand can be attributed to the following:

- Significantly cooler average temperatures, with the average minimum temperature 2.1°C lower than Q3 2024 (see Figure 2 in Section 1). The effect of this is evident in Figure 96, with morning and evening increases in operational demand driven by underlying demand increases independent of battery charging. See Section 1 for more details on weather.
- An increase in average battery charging of 77 MW (+492%) compared to Q3 2024. The increase in battery charging primarily occurred during the early morning hours and the middle of the day (see Figure 99 in Section 4.2). This can be attributed to the increase in battery capacity commissioned since Q3 2024 (Section 4.2).

[49] 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. As such, it includes scheduled demand driven by charging of electric storage resources (batteries).

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

[51] 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.

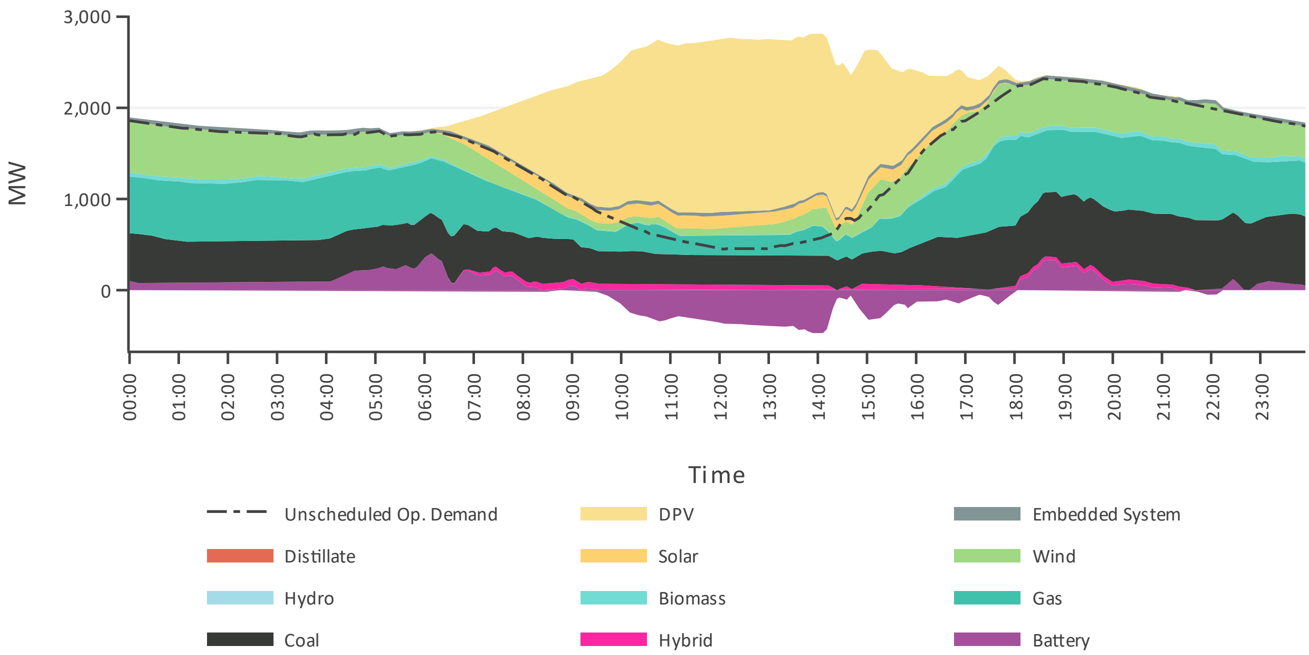
There was also a 14.9 MW decrease in average estimated distributed PV generation in Q3 2025 compared to Q3 2024. Notably, distributed PV generation models have been updated since Q3 2024, resulting in comparatively lower estimates when comparing similar-day data. This may have contributed to lower average distributed PV estimates in Q3 2025.

4.1.1 Minimum Unscheduled Operational Demand record on Saturday 27 September 2025

On Saturday 27 September 2025, the WEM experienced a record minimum unscheduled operational demand of 449 MW during the 12:05 interval (Figure 97). This occurred during a long weekend and was driven by the clear, sunny conditions and mild temperatures that facilitated a high distributed PV contribution and a low underlying demand. Charging from batteries supplied an average of 384 MW of demand in this interval, bringing average operational demand to 833 MW. The minimum operational demand for the day was 819 MW, during the 11:40 interval.

Figure 97 New unscheduled operational demand record observed on 27 September 2025

27 September 2025, five-minute average generation by fuel type and unscheduled operational demand (MW)



4.2 Electricity generation

Gas and coal remain the largest contributors to the fuel mix in the WEM, supplying 32.6% and 29.7% of underlying demand in Q3 2025, respectively. Increases in coal generation and battery discharge satisfied most of the increase in underlying demand (Figure 98). All Q3 2025 contributions can be seen in Table 8, with the following key changes since Q3 2024:

- Average coal generation increased by 92.1 MW (+13.3%). This increase was primarily driven by the need to meet increased underlying demand.
- Average battery discharge increased by 67.6 MW (+501%). Batteries primarily discharged in the morning and evening peaks (Figure 99). The increased discharge is attributable to new battery capacity since Q3 2024, composed of:
  - COLLIE_ESR1, with a capacity of 200 MW/800 MWh, which was commissioned during Q4 2024,
  - KWINANA_ESR2, with a capacity of 225 MW/900 MWh, which was commissioned during Q1 2025, and

– COLLIE_BESS2, with a capacity of 300 MW/1200 MWh, which was commissioned during Q2 2025.

- Average biomass generation increased 23.9 MW (+321%). This can be attributed to the commissioning of facility PHOENIX_KWINANA_WTE_G1, with a capacity of 46.1 MW, registered in Q1 2025.
- Average gas generation saw a marginal increase of 5.1 MW (+0.6%). Increased underlying demand drove increased gas generation in the early morning and early afternoon, which was offset by battery discharge replacing gas generation during the evening peak.
- Average wind generation increased by 5.8 MW (+1.4%). This increase was composed of increased generation in the middle of the day offset by decreased generation in the evening.
- The hybrid fuel type increased its average generation by 17.9 MW. This was an increase from 0 MW in Q3 2024 after the WEM's first hybrid type facility (the Cunderdin Hybrid Facility, a 100 MW solar/battery hybrid) completed commissioning during Q1 2025.

Figure 98 Battery discharge increased, along with biomass, hybrid and coal generation

Change in quarterly average generation – Q3 2024 vs Q3 2025

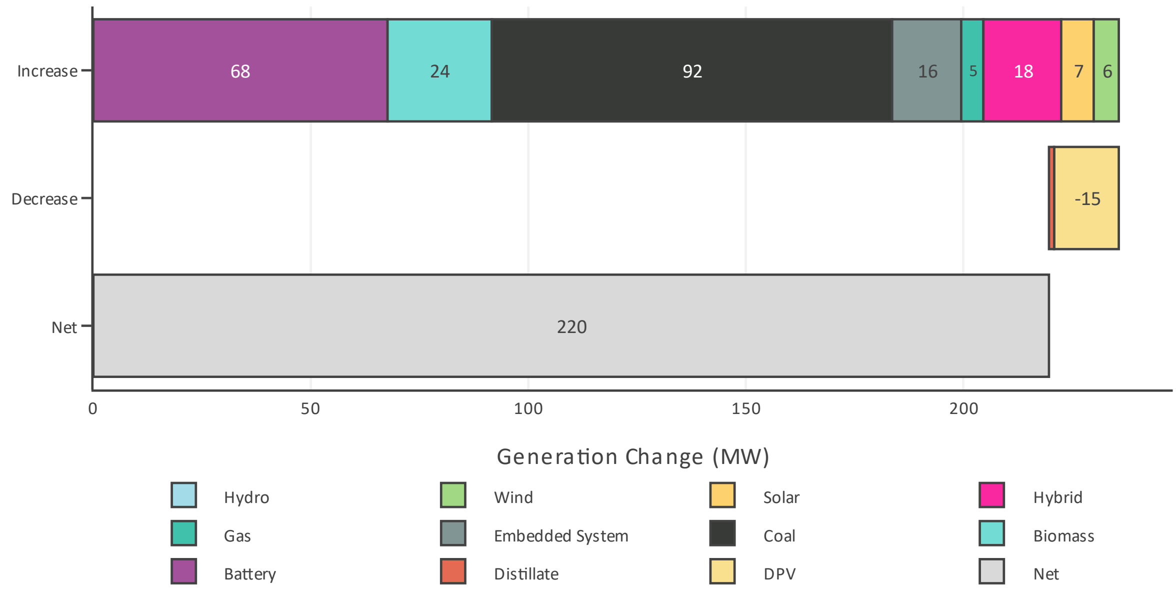
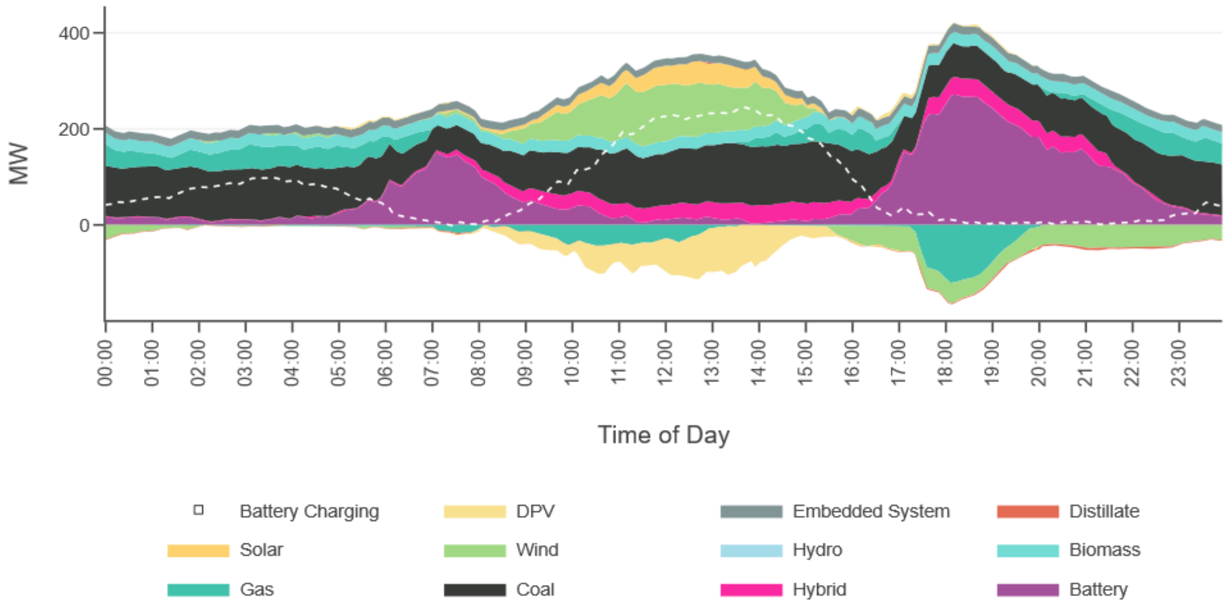


Table 8 WEM supply contributions by fuel type

Quarter	Coal	Gas	Distillate	Grid solar	Wind	Biomass	Battery	Hybrid	Hydro	Distributed PV	Embedded systems
Q3 2024	28.5%	35.4%	0.1%	1.0%	16.7%	0.3%	0.6%	0	<0.1%	16.7%	0.8%
Q3 2025	29.7%	32.6%	<0.1%	1.2%	15.5%	1.2%	3.1%	0.7%	<0.1%	14.7%	1.3%
Change	1.1%	-2.7%	<0.1%	0.2%	-1.1%	0.9%	2.5%	0.7%	-	-1.9%	0.5%

Figure 99 Gas generation replaced by batteries at the evening peak, batteries increased charging overnight and during the day

Average WEM change in fuel mix by time of day – Q3 2024 vs Q3 2025



4.2.1 Renewable contribution

The average renewable contribution in Q3 2025 increased to 36.4% of underlying demand (Figure 100), a Q3 record high, exceeding Q3 2024 by 1.2 pp despite the large increase in underlying demand noted in Section 4.1. This was driven by:

- an increased battery contribution of 2.5 pp (noting that battery charging also increases underlying demand), and
- higher contributions from hybrids (+0.7 pp) and biomass (+0.9 pp), which can be attributed to the commissioning of new facilities, as noted in Section 4.2.

A marginal increase in average wind generation (+5.8 MW) limited the decrease in wind contribution to 0.4 pp. Q3 2025 saw a new record wind generation output of 1,022 MW, which occurred during the 15:55 interval on Sunday 20 July 2025.

Q3 2025 also experienced the highest Q3 peak renewable contribution of 83.2% (+1.3 pp on the previous Q3 record), occurring on Tuesday 23 September 2025 in the 9:55 interval (Figure 101). The primary contributors were distributed PV (56.1%) and wind (18.2%).

Figure 100 Record high Q3 average renewable contribution

Renewable contribution components – Q3s

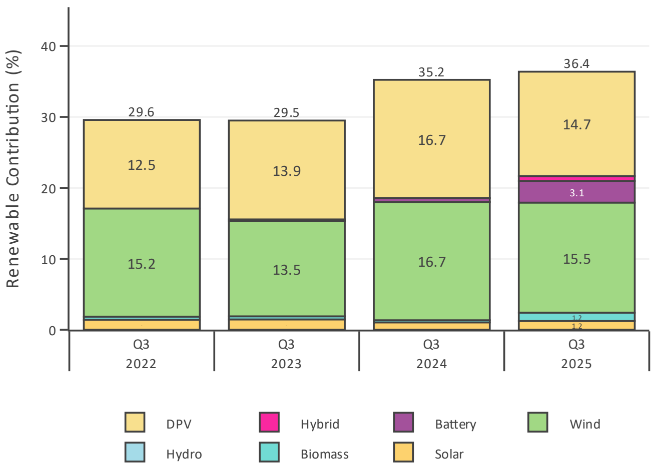
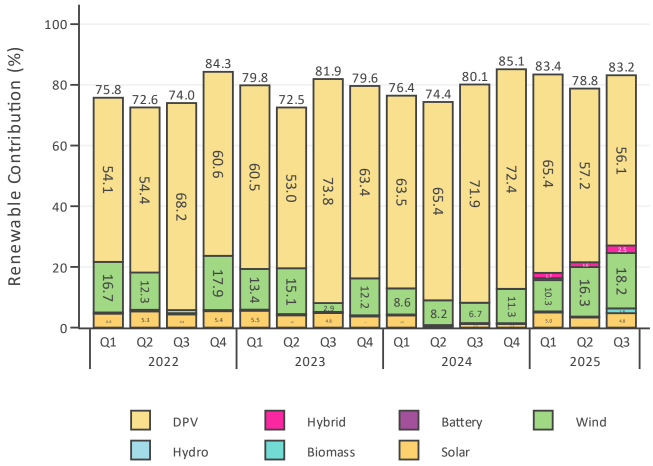


Figure 101 New highest renewable contribution peak for Q3s of 83.2%

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

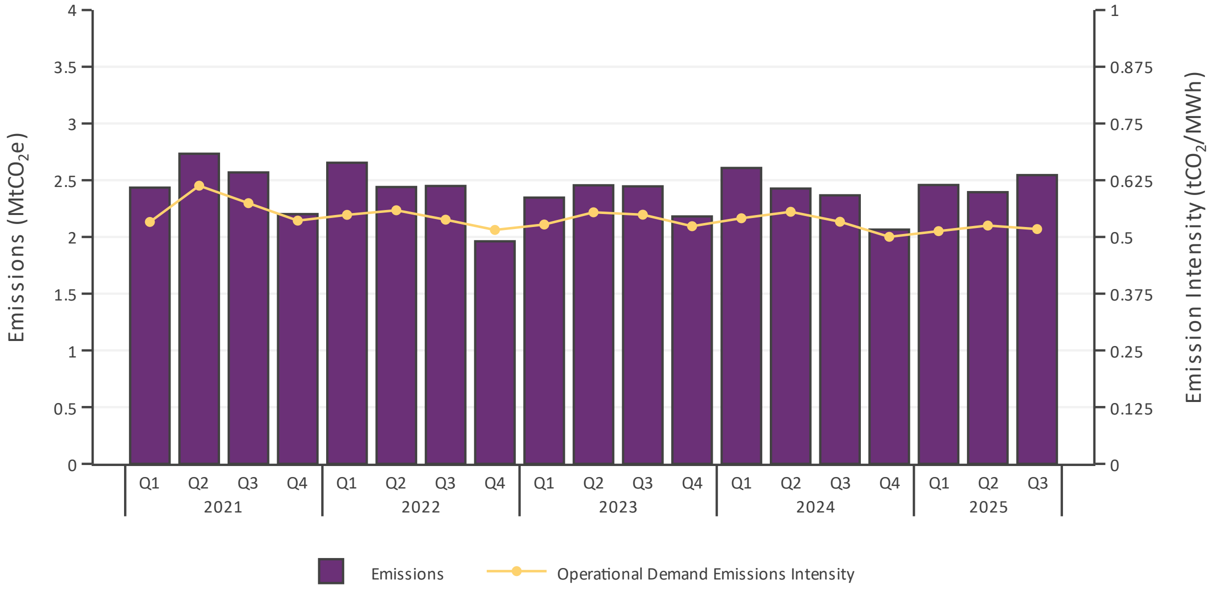


4.3 Carbon emissions

Total WEM emissions increased by 0.18 MtCO2-e (+7.5%) to 2.55 MtCO2-e (Figure 102) which was driven by the increase to operational demand (+10.9%) as noted in Section 4.1. Mitigating this increase was a reduction in emissions intensity by 0.02 tCO2-e /MWh to 0.52 tCO2-e /MWh (-3.0%), which can be attributed to an improvement in the renewable contribution as noted in Section 4.2.1.

Figure 102 Emissions increased on Q3 2024 as operational demand increased

Quarterly WEM emissions and emission intensity – Q1 2021 to Q3 2025



4.4 Frequency co-optimised essential system services (FCESS)

Q3 2025 saw batteries increase their market share across the contingency and regulation markets to 77% of total volume, an increase of 56 pp on Q3 2024 and 10 pp on Q2 2025 (Figure 103). This can be attributed to the introduction of two further batteries becoming accredited in FCESS markets since the end of Q3 2024 (COLLIE_ESR1 and KWINANA_ESR2). The increase in contingency lower of 71.9 MW (+105%) can also be attributed to the increase in battery sizes (see Section 4.4) resulting in larger credible load contingencies (Figure 104). In the Rate of Change of Frequency (RoCoF) Control Service market, gas covered 63.1% of the market, with coal the remaining 36.9%.

Figure 103 Batteries took 77% of the contingency and regulation market volume in Q3 2025

FCESS volume market share by market and fuel type, excluding RoCoF control service – Q3 2025

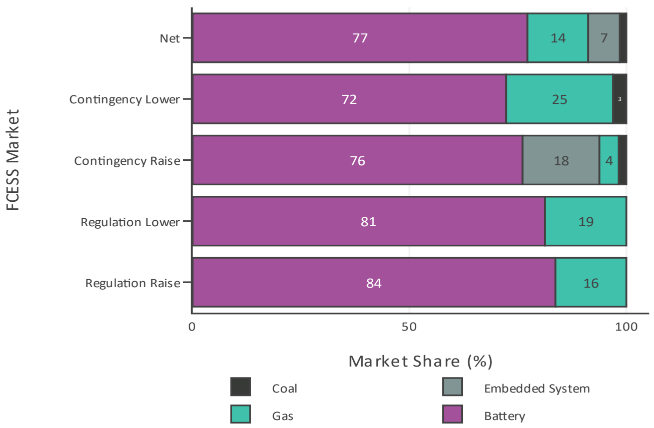
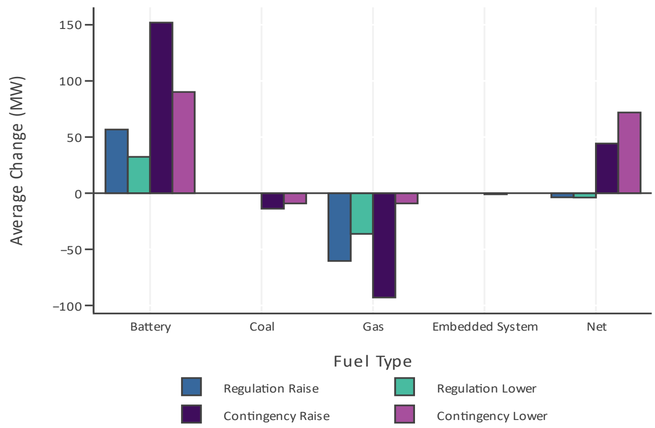


Figure 104 Batteries increased market share, and contributed to higher contingency lower requirements

Change in FCESS (regulation and contingency markets) enablement by fuel type – Q3 2024 vs Q3 2025



4.5 WEM price outcomes

4.5.1 Real-Time Market price dynamics

The average energy price rose by 27% in Q3 2025 to $101.76/MWh compared to $80.15/MWh in Q3 2024 (Figure 105). This represents the highest quarterly average energy price since the commencement of the new WEM market on 1 October 2023, driven by several factors:

- Increasing charge by batteries (and therefore operational demand) during the middle of the day has contributed to increased prices during this time. Conversely, increased discharge by batteries during the morning and evening peak has put downward pressure on prices during these intervals. This has resulted in a flattening of the daily energy price profile (Figure 106 and Figure 107).

- Adjustments to the FCESS Uplift payment framework[52] resulted in fewer committed facilities during the middle of the day, contributing to lower FCESS Uplift costs. This placed additional upward pressure on energy clearing prices during daytime periods.
- On 25 August 2025, Perth recorded its coldest winter day (Section 1), significantly increasing energy demand. Coupled with lower-than-expected battery charge levels, this triggered a series of operational interventions coinciding with higher-than-average energy prices.

Figure 105 Highest quarterly average energy price since WEM reform in Q3 2025

Quarterly average energy prices – Q2 2024 to Q3 2025

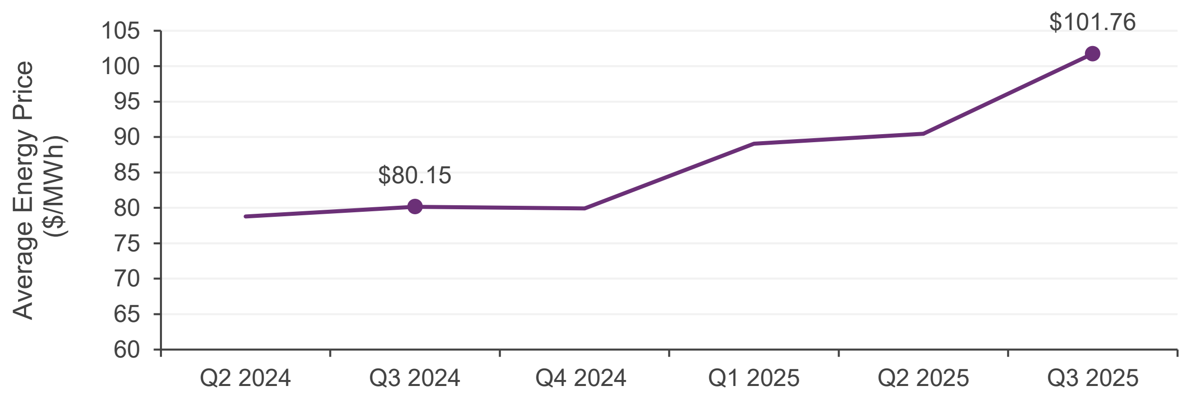


Figure 106 Flattening of the daily price profile

Average energy price by time of day – Q3 2024 vs Q3 2025

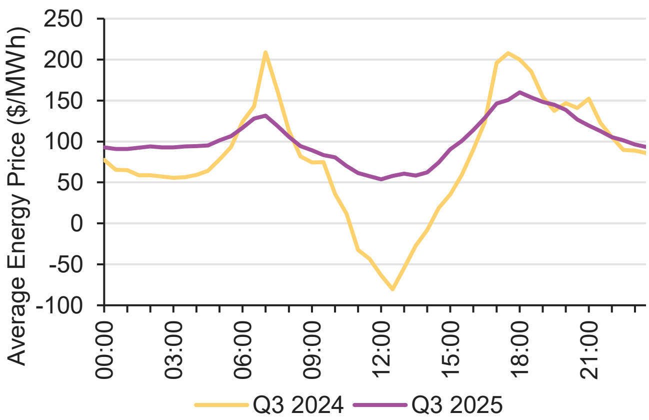
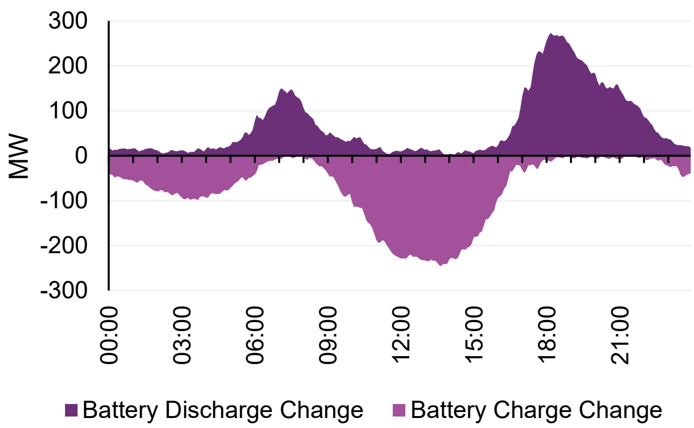


Figure 107 Batteries a driver of flatter price profile

Average change in battery charge and discharge – Q3 2024 vs Q3 2025



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

4.5.2 Essential system services (ESS) costs

Total ESS including Uplift costs fell to $22.3 million in Q3 2025, down $96.6 million (-81%) from Q3 2024, primarily driven by the FCESS Cost Review in November 2024 (Figure 108). Key observations include:

- FCESS Uplift costs decreased to $2.1 million in Q3 2025, a significant reduction of $77.1 million (-97%) from $79.3 million in Q3 2024, driven primarily by the FCESS Cost Review. Higher energy prices also placed downward pressure on FCESS Uplift costs. Figure 109 illustrates how FCESS Uplift Costs were assigned to the five FCESS Market Services[53].
- FCESS enablement costs decreased to $12.2 million in Q3 2025, a reduction of $21.9 million (-64%) compared to Q3 2024. This was largely driven by the accreditation of three new batteries in FCESS markets since Q3 2024.
- KWINANA_ESR2's participation, commencing on 6 June 2025, contributed to a $7.9 million reduction in FCESS enablement costs in Q3 2025 compared to Q2 2025. The facility's role in placing downward pressure on FCESS costs was further highlighted during its outages from 29 August to 4 September and 15 to 19 September 2025, which coincided with an increase in FCESS enablement costs across the market (Figure 110).
  - The largest decrease occurred in the regulation lower market, decreasing down to $1.3 million (-88%) from $11.0 million in Q3 2024.
  - The regulation raise market also saw a significant decrease of $3.6 million (68%).
  - The contingency reserve raise market remained the largest contributor to total FCESS enablement costs, accounting for $5.7 million (47%) of Q3 2025 FCESS enablement cost total.
- Provisional Non-Peak NCESS cost increased to $4.8 million in Q3 2025, an increase of 43% since Q3 2025, driven by the commencement of two Non-Peak contracts since Q3 2024. Note that NCESS costs data in this report are only available up to 6 September 2025 due to timing discrepancies in payment reconciliation at the time of reporting.
- Energy Uplift costs totalled $2.3 million in Q3 2025, an increase of $1.1 million (+88%) compared to Q3 2024.

[53] Note that since November 2024, no FCESS Uplift costs are assigned to the RoCoF Control Service Market Service.

Figure 108 Total ESS and Uplift cost decrease driven by FCESS Cost review and battery participation

Total ESS and Uplift cost per quarter since Q1 2024

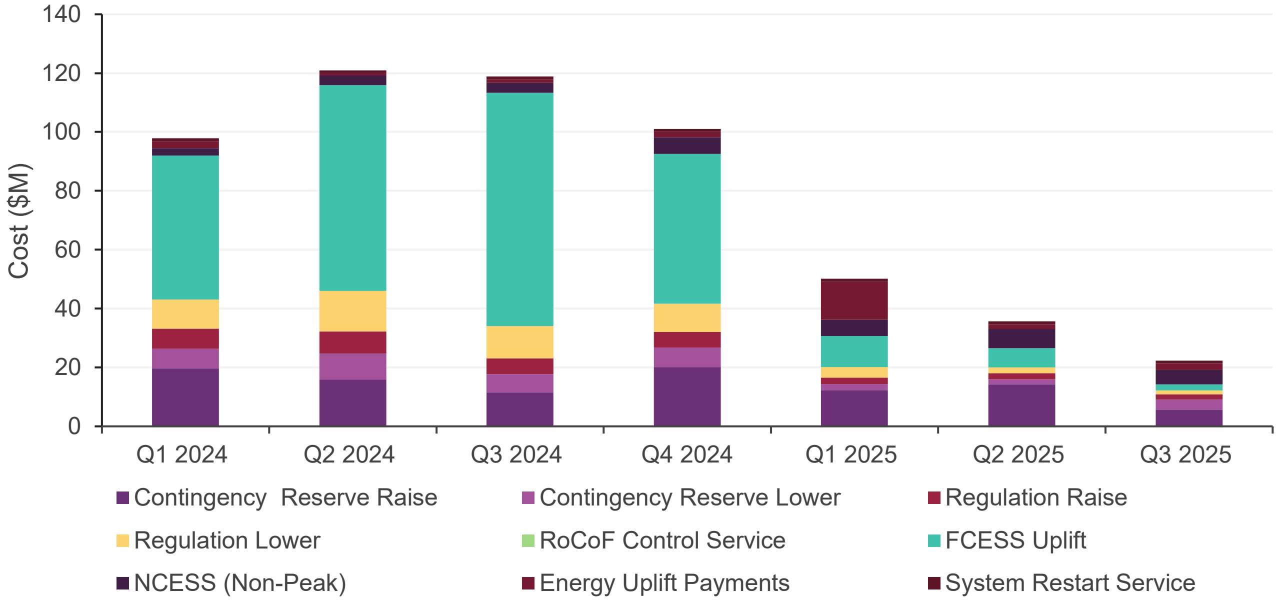


Figure 109 Total FCESS Uplift Share Costs decreased by $77.1 million (-97%) in Q3 2025 compared to Q3 2024

Distribution of FCESS Uplift costs across market services per quarter – Q2 2024 to Q3 2025

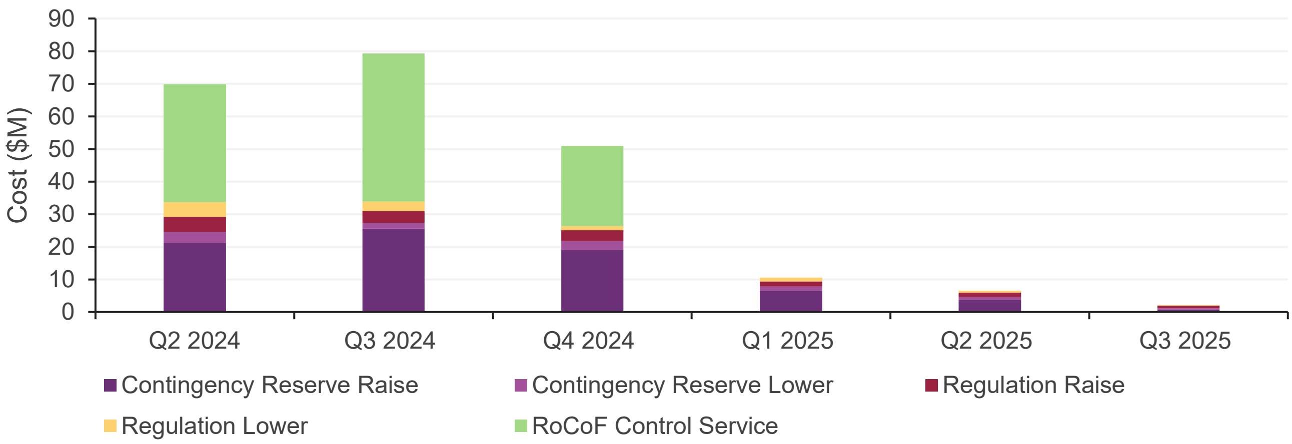
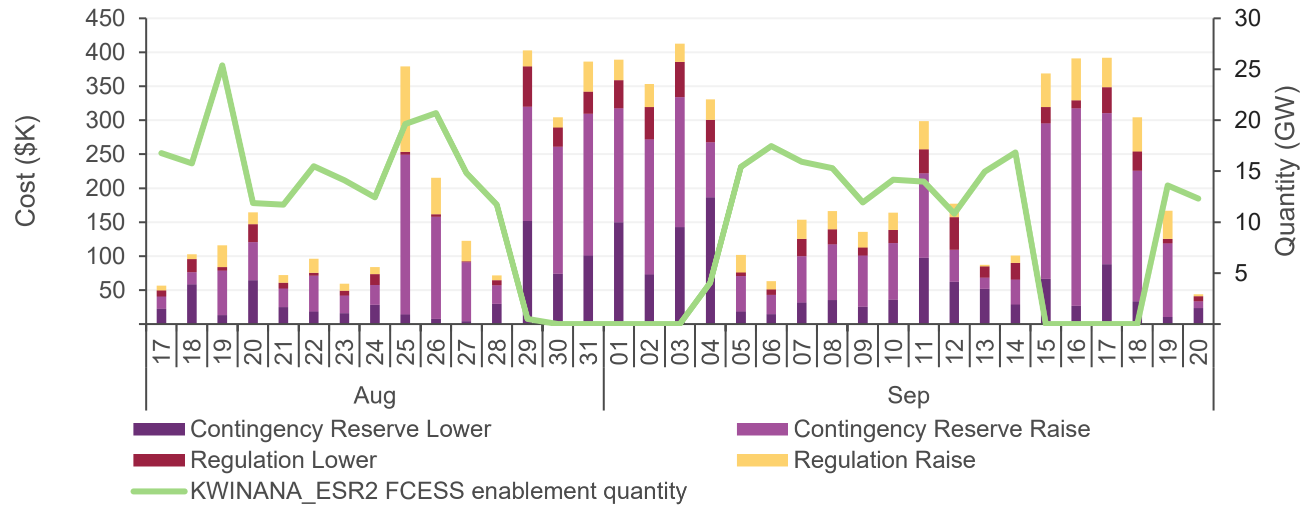


Figure 110 KWINANA_ESR2 reduced availability coincided with increased FCESS enablement costs

KWINANA_ESR2's FCESS enablement quantity versus total WEM FCESS enablement cost from 17 August to 20 September 2025



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

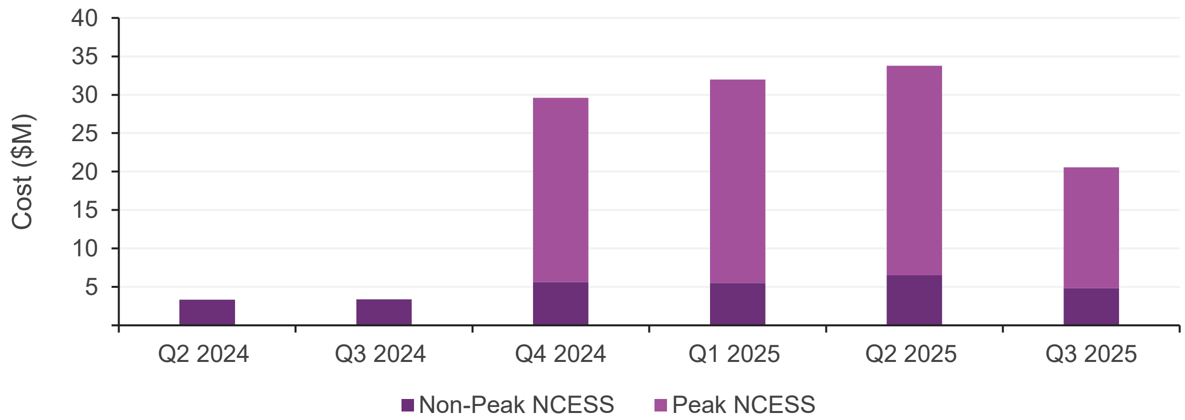
Since 7 October 2024, NCESS costs are divided into two categories, with different cost-recovery mechanisms, based on the nature of the NCESS service. AEMO refers to these as "Peak NCESS" and "Non-Peak NCESS" costs, and groups these with Capacity and ESS costs respectively for reporting purposes. Prior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

Note that NCESS costs data in this report are only available up to 6 September 2025 due to timing discrepancies in payment reconciliation at the time of reporting.

In Q3 2025, total NCESS costs reached $20.6 million, a $17.2 million increased compared to Q3 2024 (Figure 111). This increase was driven by the commencement of 10 new Peak NCESS contracts since Q3 2024. Of the total NCESS cost, $15.7 million were Peak NCESS costs, while $4.8 million were Non-Peak NCESS costs. Total Non-Peak NCESS costs increased by $1.5 million (43%) compared to Q3 2024.

Figure 111 NCESS costs increased, 10 new Peak NCESS contracts since Q3 2024

NCESS costs by cost recovery mechanism (excluding NCESS costs after to 6 September 2025) – Q2 2024 to Q3 2025



4.5.4 Total Wholesale Electricity Market costs

Figure 112 represents the WEM costs as a price per MWh, normalised by total energy consumed to enable better comparison of costs between periods with different demand.

In Q3 2025, the sum of all normalised costs in the WEM totalled $149.97/MWh, an increase of $10.88/MWh (+8%) from Q3 2024. Changes are outlined below and are discussed further in referenced sections:

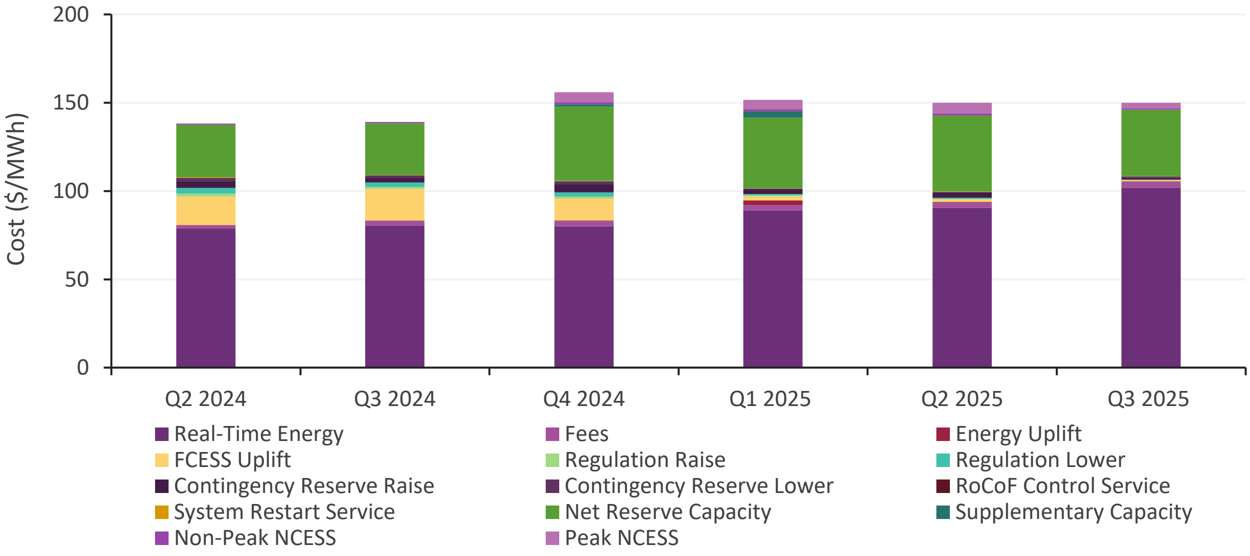
- The total WEM cost increase was largely attributed to a rise in the average energy price, which rose to $101.76/MWh in Q3 2025, an increase of $21.61/MWh (+27%) compared to Q3 2024 (Section 4.5.1).
- Normalised reserve capacity costs, net of reserve capacity refunds, increased to $37.49/MWh in Q3 2025, an $8.14/MWh (+28%) increase, primarily due to a higher Reserve Capacity Price[54] set for the 2024-25 Capacity Year.
- Normalised energy uplift costs increased to $0.54/MWh, up $0.27/MWh driven largely by changes relating to the FCESS Cost Review (Section 4.5.2).
- Normalised NCESS costs were $3.96/MWh, an increase of $3.21/MWh driven by commencement of 10 new Peak NCESS contracts since Q3 2024 (Section 4.5.3).

Conversely, several cost components saw decreases:

- Normalised FCESS enablement costs (excluding Uplift) fell to $2.46/MWh in Q3 2025, a reduction of $5.10/MWh (-68%) from Q3 2024 (Section 4.5.2).
- Normalised FCESS Uplift costs fell to $0.44/MWh in Q3 2025, representing a $17.42/MWh (-98%) decrease compared to Q3 2024 (Section 4.5.2).

Figure 112 Wholesale Electricity Market costs increased compared to Q3 2024

Normalised Energy, ESS and Capacity costs per MWh consumed in the WEM since Q2 2024



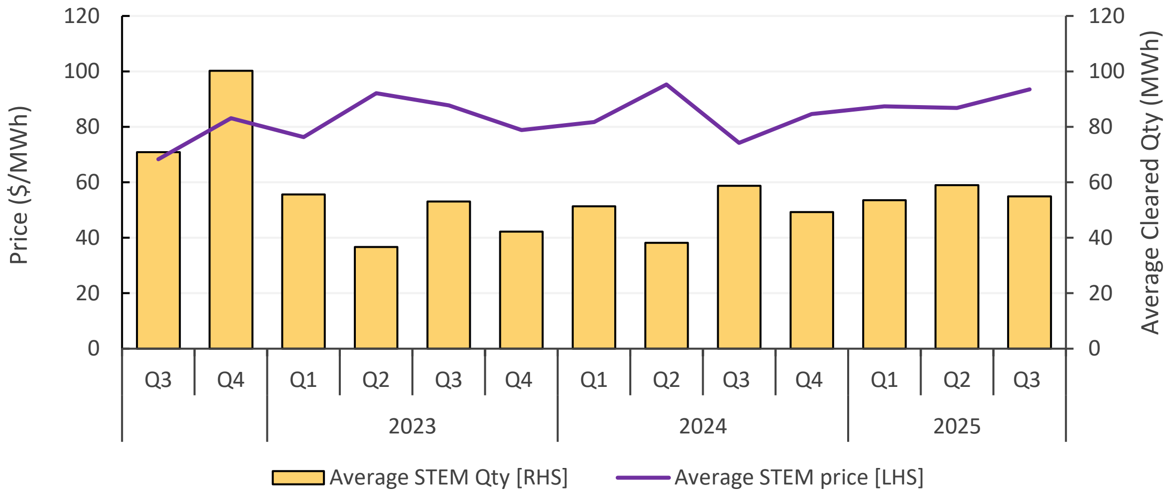
[54] The reserve capacity price for transitional facilities, which is applicable to the majority of facilities, increased from $118,599.19/MW/yr in capacity year 2023-24 to $150,745.81/MW/yr in capacity year 2024-25, while the reserve capacity price increased from $105,949.27/MW/yr to $194,783.54/MW/yr.

4.5.5 Short Term Energy Market (STEM)

The average STEM price for Q3 2025 was $93.55/MWh, an increase of $6.67/MWh (+9%) from the previous quarter and an increase of $19.28/MWh (+26%) compared to Q3 last year (Figure 113). The quarterly average quantity of energy cleared in the STEM per interval was 55 MWh, a decrease of 4 MWh (-7%) from Q2 2025. Compared to Q3 2024, quantities cleared also decreased by 3.8 MWh (-6%).

Figure 113 The average STEM price increased by 9% in Q3 2025

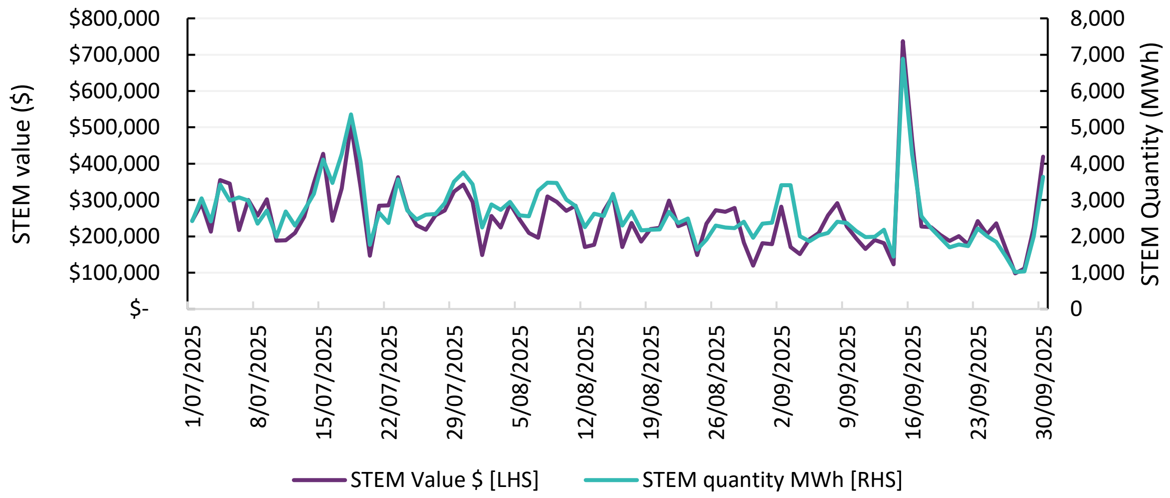
WEM average STEM price and quantity cleared in STEM – Q3 2022 to Q3 2025



The daily traded value in STEM ranged from $98,125 to $737,091 in Q3 2025, whereas the daily quantities traded varied between 1,018 MWh and 6,889 MWh (Figure 114). The maximum traded value of $737,091 occurred on 15 September.

Figure 114 Daily STEM values fluctuated between $98,125 and $737,091 in Q3 2025

Daily Quantities (MWh) and value ($) traded in STEM – Q3 2025



5 Reforms delivered

AEMO, with government and industry, continues to deliver energy market reforms across the WEM, NEM and east coast gas markets. These reforms provide for changes to key elements of Australia's electricity and gas market design to facilitate a transition towards a modern energy system, capable of meeting the evolving wants and needs of consumers, as well as enabling the continued provision of the full range of services necessary to deliver a secure, reliable and lower emissions system at least cost. Table 9 provides a brief description of the reforms implemented over the last quarter.

Table 9 Reforms delivered Q3 2025

Reform initiative	Market	Description	Reform delivered
Enhancing Reserve Information	NEM	In accordance with the Enhancing Reserve Information (ERI) rule change, the ERI reform improves the transparency of energy availability across the NEM. This will allow participants to make more informed decisions about their own behaviour, including when periods of tighter supply-demand balance are anticipated. As of Tuesday 1 July, the ERI rule commenced and AEMO now publishes: • Energy availability for batteries (by Dispatchable Unit Identifier (DUID) and for each 5-minute trading interval) at the end of the trading day for the previous trading day; • Daily energy limits (total availability) of scheduled generators and scheduled bidirectional units that are not batteries, aggregated by region; and • Energy availability of batteries (that is, state of charge), aggregated by region, for each trading interval. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/enhancing-reserve-information-project.	July 2025
Short Term Projected Assessment of System Adequacy (ST PASA) Procedure and Recall Period	NEM	The Updating ST PASA rule change introduced a principles-based approach for AEMO to administer ST PASA. This included an obligation to publish a ST PASA Procedure, and made changes to ST PASA publication timetable, the definition of 'energy constraint' and PASA availability. The resulting system and procedural changes went live from 31 July 2025 and provide flexibility to participants to communicate to the market on their unit availability and outage conditions as well as support AEMO's ability to assess reliability and security conditions in the NEM as the market develops. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/st-pasa.	July 2025
Improving Security Frameworks (ISF)	NEM	The Improving Security Frameworks for the Energy Transition Rule builds on existing tools and frameworks within the power system to enhance system security procurement frameworks, providing increased transparency on system security needs and understanding of how AEMO plans to manage system security as we transition to a secure net zero emissions power system. The rule sets forth multiple milestones, scheduled between 30 June 2024 and 2 December 2025. In August 2025, AEMO published a complete Security Enablement Procedure inclusive of methodology for enablement of system security services. Full enablement obligations on AEMO commence in December 2025 (refer to Table 10 below) More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/improving-security-frameworks-for-the-energy-transition.	August 2025

In addition to these reforms, work continues to progress on the next wave of initiatives set for release later in 2025 and in early 2026. Table 10 below provides a brief description of initiatives to be delivered in Q4 2025 and Q1 2026.

Table 10 Upcoming implementation of reforms Q4 2025 – Q1 2026

Reform initiative	Market	Description	Reform to be delivered
Contingency Reserve Lower Procurement and Recovery (Cost Allocation Review)	WEM	The Western Australian Government has introduced changes, commencing 30 October 2025 in the Electricity System and Market Rules (ESM Rules), to the methodology used to procure and settle Contingency Reserve Lower in the WEM. AEMO will deliver changes to its dispatch systems to enable the co-optimised procurement of the Largest Credible Load Contingency within the dispatch algorithm. A complementary change to the settlement recovery methodology will introduce a modified runway method to allocate costs based on the causer pays principle. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/p3109--first--final-ia202501.pdf?rev=b716f0d3dcea44daa4fbbdd896bd5aa0&sc_lang=en.	Q4 2025
Contingency Reserve Raise and RoCoF cost recovery (Cost Allocation Review)	WEM	Changes to the recovery of Contingency Reserve Raise and RoCoF essential system services in the WEM will commence 26 February 2025. To enable these changes AEMO will implement changes to its settlement system and supporting applications of the dispatch engine to effect the requirements of the ESM Rules. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/p3109--first--final-ia202501.pdf?rev=b716f0d3dcea44daa4fbbdd896bd5aa0&sc_lang=en.	Q1 2026
East coast gas system (ECGS) notice of closure rule change	Gas	On 11 September 2025, the AEMC completed its consultation on the ECGS notice of closure rule change request. AEMO is amending the GSOO Procedures in response to the Rule change. The notice of closure Rule change applies to a reportable closure decision, which is the decision of a facility to permanently cease supply of covered gas services. This reform strengthens transparency and supports more effective planning across the ECGS. More information: https://www.aemc.gov.au/rule-changes/ecgs-notice-closure-gas-infrastructure.	Q1 2026
Metering Services Review – Package 1	NEM	The Accelerating Smart Meter Deployment (ASMD) seeks to achieve universal smart meter deployment in the NEM by 2030. There are four key changes for 2025 as part of this Rule change: • Legacy Meter Replacement Plan: a plan developed by the distribution network srvice provider (DNSP) that provides for the replacement of all legacy (Type 5 & 6) meters at connection points on its distribution network. The program starts on 1 December 2025 to 30 November 2030. • Defect Management: Metering Coordinators are required to notify the retailer of a defect when attempting to exchange a meter as well a record the defect in Market Settlements and Transfer Solution (MSATS), including the nature of the defect. • One in All in: a new procedure for managing the replacement of meters with shared fusing. • Testing and inspection: AEMO has proposed a new Procedure for testing and inspection for all metering installations and changes to the malfunction and exemption process. A second release package (Package 2) enabling better access to power quality data (PQD) for DNSPs is to go live in July 2026. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/metering-services-review---accelerating-smart-meter-deployment.	December 2025

Reform initiative	Market	Description	Reform to be delivered
Improving Security Frameworks (ISF)	NEM	The Improving Security Frameworks for the Energy Transition Rule builds on existing tools and frameworks within the power system to enhance system security procurement frameworks, providing increased transparency on system security needs and understanding of how AEMO plans to manage system security as we transition to a secure net zero emissions power system. The rule sets forth multiple milestones, scheduled between 30 June 2024 and 2 December 2025. AEMO is implementing ISF system security enablement functions across two releases. • The first release delivers enablement functions focusing on external-facing components and reporting from 2 December 2025. • A subsequent release in mid-2026 (August) 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.	December 2025

List of tables and figures

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Abbreviations

Abbreviation	Expanded term
5MS	Five-Minute Settlement
ACCC	Australian Competition and Consumer Commission
ACE	Adjusted Consumed Energy
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APC	Administered Price Cap
AEST	Australian Eastern Standard Time
APLNG	Australia Pacific LNG
ASX	Australian Securities Exchange
BCF	Ballera Compression Facility
BESS	battery energy storage system
CDEII	Carbon Dioxide Equivalent Intensity Index
CF	contribution factor
CGP	Carpentaria Gas Pipeline
CPT	Cumulative Price Threshold
CRL	contingency reserve lower
DAA	Day Ahead Auction
DR	demand response
DUID	Dispatchable Unit Identifier
DWGM	Declared Wholesale Gas Market
ECGS	east coast gas system
EDD	effective degree day
EGP	Eastern Gas Pipeline
ERI	Enhancing Reserve Information
ESM	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
GAB	Gas Advisory Board
GBB	Gas Bulletin Board
GJ	gigajoule/s
GJ/h	gigajoules per hour
GSOO	Gas Statement of Opportunities
GW	gigawatt/s
GWh	gigawatt hour/s
GLNG	Gladstone LNG

Abbreviation	Expanded term
GSH	Gas Supply Hub
IEA	International Energy Agency
IRR	interim reliability reserve
IRSR	inter-regional settlement residue
L1SE	lower 1-second (FCAS)
L6SE	lower 6-second (FCAS)
LCA	Linepack Capacity Adequacy
LCLC	Largest Credible Load Contingency
LGC	large-scale generation certificate
LNG	liquefied natural gas
MTPA	million tonnes per annum
MT PASA	Medium Term Projected Assessment of System Adequacy
$MtCO_2$-e	million tonnes of carbon dioxide equivalents
MW	megawatt/s
MWh	megawatt hour/s
NEM	National Electricity Market
NCESS	non-co-optimised essential system service
NSCAS	network support and control and ancillary services
NGP	Northern Gas Pipeline
NO	Network Operator
NSP	network service provider
NT	Northern Territory
pp	percentage points
PJ	petajoule/s
PV	photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
R6SE	raise 6-second (FCAS)
RBP	Roma – Brisbane Pipeline
RCM	Reserve Capacity Mechanism
RCR	requirement for corrective response
RERT	Reliability and Emergency Reserve Trader
RoCoF	Rate of Change of Frequency
RREG	raise regulation
RRP	regional reference price
ST PASA	Short Term Projected Assessment of System Adequacy
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System

Abbreviation	Expanded term
SWQP	South West Queensland Pipeline
tCO2-e	tonnes of carbon dioxide equivalent
TJ/d	terajoules per day
TJ/y	terajoules per year
TWAP	time-weighted average price
UGS	Underground Storage Facility
VGPR	*Victorian Gas Planning Report*
VWAP	volume-weighted average price
VPP	virtual power plant
VRE	variable renewable energy
VNI	Victoria – New South Wales Interconnector
WCF	Wallumbilla Compression Facility
WEM	Wholesale Electricity Market
WEMDE	WEM dispatch engine
WDR	wholesale demand response