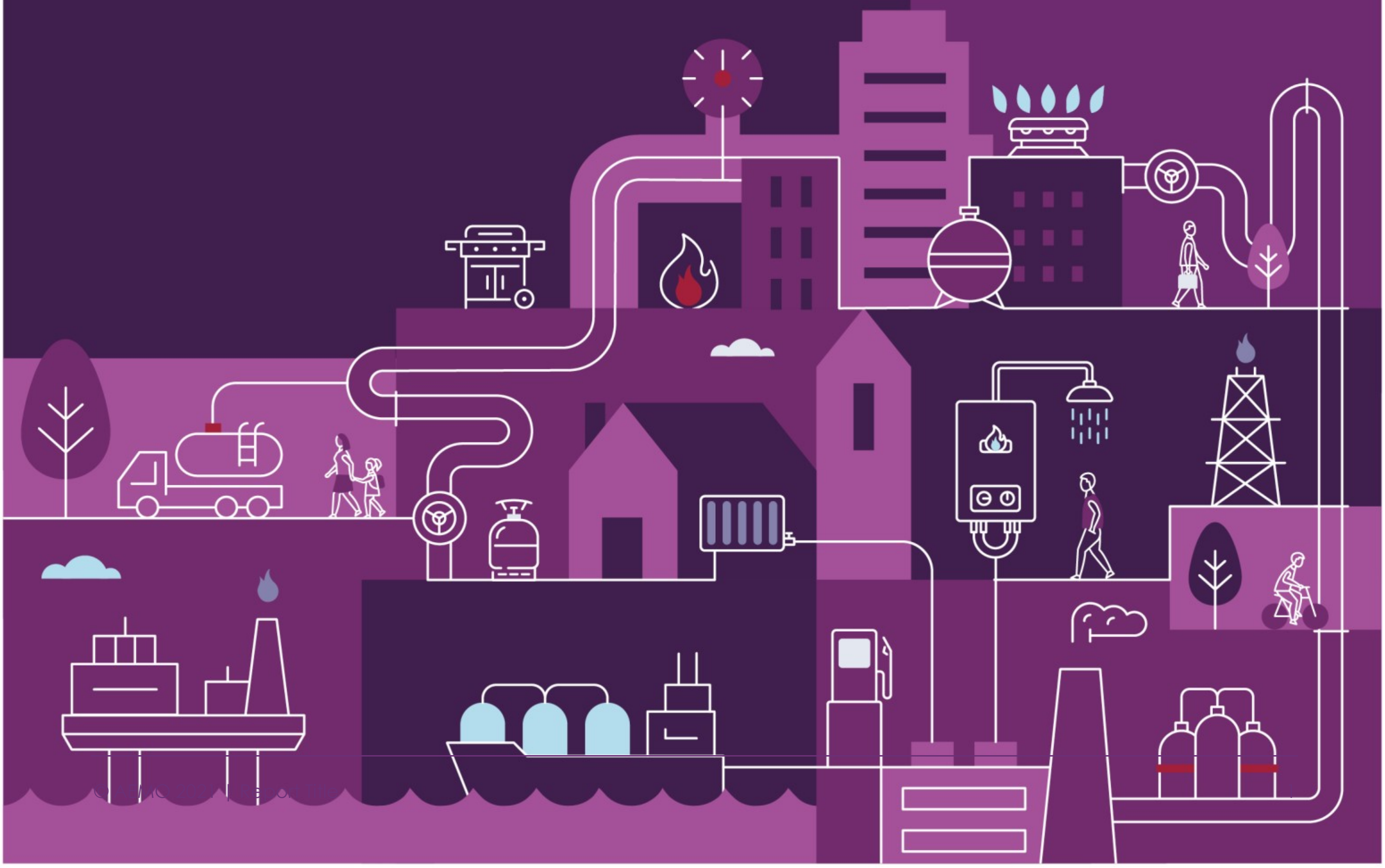
# Quarterly Energy Dynamics Q3 2024

October 2024



**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 2024 (1 July to 30 September 2024). This quarterly report compares results for the quarter against other recent quarters, focusing on Q2 2024 and Q3 2023. Geographically, the report covers:

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

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# Executive summary

## East coast electricity and gas highlights

### Average National Electricity Market (NEM) demand higher with extremes at either end

- A cold start to the quarter increased demand in all NEM regions in Q3 2024. Underlying demand was 3.4% higher than during Q3 2023, and despite a new Q3 high for distributed photovoltaic (PV) output of 2,539 megawatts (MW) (+11%), operational demand averaged 21,825 MW, up 2.6% from Q3 2023.
- The quarter saw extremes for both high and low demands, with new winter maximum demand records in Queensland (8,728 MW) and Victoria (8,612 MW) set during July and all-time minimum demand records set in Queensland (3,096 MW) in August and New South Wales (3,555 MW) in September, along with a new Q3 minimum for Victoria (1,937 MW) in September.

### Elevated demand combined with reduced low-priced hydro volumes and network outages to exert upward pressures on spot prices

- Wholesale spot prices averaged $119 per megawatt hour (MWh) across all NEM regions in Q3 2024, $15/MWh (-11%) lower than in the previous quarter (Q2 2024), but $56/MWh (+88%) higher than this time last year (Q3 2023). These price increases were driven by the winter months, with NEM wholesale prices averaging $163/MWh in July, $145/MWh in August before decreasing to $46/MWh in September.
- Hydro generators offered significantly less volume in lower price bands than in Q3 2023, and the proportion of intervals with average NEM wholesale prices over $100/MWh more than doubled (from 19% in Q3 2023 to 40% this quarter). This was particularly notable in Tasmania, where average hydro generation fell 377 MW (-32%), offset by higher gas generation (+97 MW) and imports from Victoria, yielding average wholesale electricity prices of $112/MWh (+282%) this quarter compared to $29/MWh in Q3 2023.
- Network outages in late July and early August frequently restricted exports from Victoria into South Australia. This played a major role in South Australia recording the highest regional quarterly average spot price in the NEM, at $158/MWh. Price volatility (the impact of spot prices above $300/MWh) contributed close to half of that average at $77/MWh, up from $27/MWh in Q3 2023.
- Multiple instances of high NEM-wide demand drove intervals with simultaneous high prices across NEM regions during morning or evening peaks, particularly in late July and early August. Wholesale electricity prices averaged $121/MWh in New South Wales, $104/MWh in Victoria and $100/MWh in Queensland, with price volatility contributing between $15/MWh and $27/MWh to these averages.

### Increased average and peak renewable contributions

- After low average output for the previous quarter (Q2 2024), wind generation picked up to record a new quarterly high, averaging 4,044 MW, up 21% year-on-year. Despite low hydro generation this quarter, down 22% year-on-year, the overall contribution of renewables to supply reached 39.3%, a new Q3 high.

- A new peak renewable contribution record was set in the half-hour period ending 1200 hrs on Monday, 9 September 2024, when renewable sources supplied 72.2% of total NEM generation. In this interval distributed PV comprised 38.5% of total generation, while grid-scale solar and wind provided 18.3% and 13.4% respectively.
- Renewable potential exceeded 100% this quarter, marking a key milestone in the transition towards operation at times with 100% renewable supply. This measure reached an all-time high of 100.5% in the half-hour ending 1230 hrs on Wednesday 18 September 2024.

### Connections pipeline continued to grow, with more projects reaching milestones

- At the end of Q3 2024, 45.6 gigawatts (GW) of new capacity was progressing through the connection process from application to commissioning, a 36% increase compared to at the end of Q3 2023. This capacity includes 14.6 GW of battery projects, 87% more than this time last year.
- Connections projects reaching milestones during Q3 2024 increased substantially, with 2.6 GW reaching application approval, 3.5 GW registered and connected to the NEM, and 1.3 GW progressing through commissioning to reach full output.

### East coast Q3 2024 gas prices higher than Q3 2023, demand and production higher

- East coast wholesale gas prices averaged $12.50 per gigajoule (GJ) for the quarter, higher than Q3 2023's $10.41/GJ but lower than Q2 2024 which averaged $13.66/GJ.
- Gas demand increased by 3% from Q3 2023, driven by higher demand for gas-fired generation (+7 petajoules (PJ)), while demand for Queensland liquefied natural gas (LNG) exports also increased (+5 PJ), setting a Q3 demand record. AEMO markets demand slightly increased (+0.5 PJ), impacted by significantly warmer than average temperatures in August.
- While domestic gas supply dynamics continued to be influenced by declining Longford gas production and greater reliance on supply from Queensland to southern states, the Otway Gas Plant in Victoria had the largest increase to domestic supply in Q3 (+9.4 PJ), due to commissioning in June of the new Enterprise gas field.
- The East Coast Gas System threat or risk notice that was issued by AEMO on 19 June 2024 was revoked on 23 August 2024 as gas supply and demand trends improved in New South Wales, the Australian Capital Territory, Victoria, South Australia, and Tasmania. The notice was for potential gas supply shortfalls caused by the depletion of southern storage inventories, particularly Iona underground storage (UGS). Iona UGS storage inventories recovered during August from their low point early in the month, assisted by warmer weather and reduced gas-fired generation.

## Western Australia electricity and gas highlights

### Increasing distributed PV and battery introduction continued to shape demand profiles

- An increase in average underlying demand (+88 MW), which included an average increase in battery withdrawal (charging) (+9 MW) compared to Q3 2023, was offset by an increase in distributed PV (+78 MW) and contribution by embedded systems (+19 MW). This resulted in a small drop in average operational demand (-9 MW) compared to Q3 2023.

- During the 12:20 interval on Sunday 22 September 2024, a new minimum unscheduled operational demand record of 538 MW was experienced, driven by 2,005 MW of distributed PV. During this interval, batteries were withdrawing 131 MW, which helped lift operational demand to 680 MW for the interval.

## New Q3 average renewable contribution record observed

- Increases in wind (+90 MW), distributed PV (+78 MW) and batteries (+9 MW) compared to Q3 2023 drove a new Q3 renewable contribution high of 35.2%, surpassing the 29.6% seen in Q3 2022.

## Total real-time market costs reduced slightly as decreases in Essential System Services (ESS) enablement costs were offset by increases in Frequency Co-optimised ESS (FCESS) Uplift costs

- Average energy prices for Q3 2024 were $80.15/MWh, a decrease of $9.03/MWh (-10%) from Q3 2023, however slightly above Q2 2024 by $1.37/MWh (+1.7%).
- In comparison to Q2 2024, there was a reduction in direct enablement costs of Contingency Reserve services (-$7.1 million, -29%) and Regulation services (-$4.9 million, -23%) which were partially offset by an increase in FCESS Uplift costs (+$6.6 million, +9%).
- Total real-time market costs (a normalised price-per-MWh by total energy consumed) was $106.22/MWh in Q3 2024. This was an increase on the $92.87/MWh (+$13.36/MWh) observed in Q3 2023, however was a decrease on the $107.06/MWh (-$0.83/MWh) observed in Q2 2024.

## Domestic gas production increased by 6 PJ, whereas consumption remained unchanged

- Domestic gas production increased to 106.3 PJ (+6%) compared to Q3 2023. A full year of production at Walyering assisted with this increase, coupled with higher production volumes at Karratha Gas Plant and Wheatstone.

# Contents

# 1 NEM market dynamics

## 1.1 Electricity demand

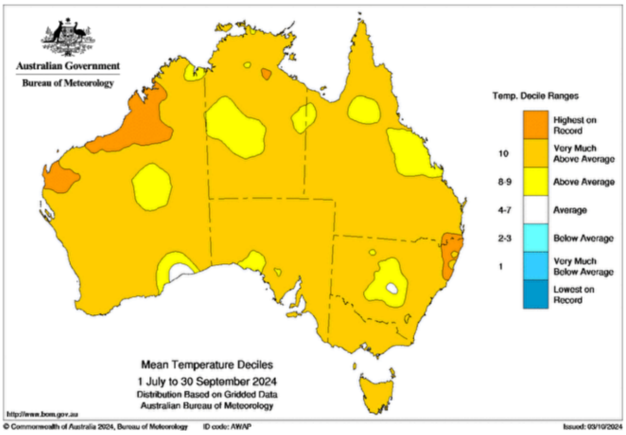
### 1.1.1 Weather

The quarter commenced with a cold southerly airmass bringing morning frost and low temperatures to southern regions of the NEM, with some parts of Tasmania, Victoria and South Australia experiencing their lowest July temperatures on record early in the month. This was followed by an unseasonably warm period across most of Australia in the second half of August, with all NEM regions recording their warmest August on record since national observations began in 1910[1], followed by a warmer and wetter than average September.

While all NEM regions saw temperatures above long-term averages in Q3 2024 (Figure 1), maximum temperatures this year compared to Q3 2023 were lower across all capitals, ranging from marginally lower in Brisbane, to 0.6 °C lower in Melbourne and 1.1 °C lower in Hobart (Figure 2).

**Figure 1 Warmer than long-term averages despite a cold start**

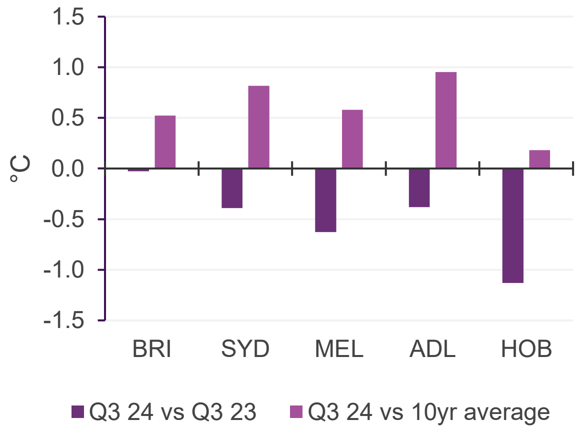
Q3 2024 mean temperature deciles for Australia




Source: Bureau of Meteorology (BoM)

**Figure 2 Colder weather year-on-year**

Average quarterly maximum temperature variance by capital city




### 1.1.2 Demand outcomes

After a particularly warm Q3 last year, where the NEM experienced its lowest Q3 operational demand since Tasmania joined the market in 2005, operational demand rose by 555 MW (+2.6%) to average 21,825 MW this quarter (Figure 3).

NEM quarterly average underlying demand increased by 807 MW (+3.4%) year-on-year to reach 24,364 MW in Q3 2024, and distributed PV output reached 2,539 MW, up by 252 MW (+11%). Despite this being a new Q3 record for distributed PV output, the annual growth rate slowed from 31% a year ago (Q3 2023 vs Q3 2022),

[1] http://www.bom.gov.au/clim_data/IDCKGC1AR0/202408.summary.shtml

reflecting a slowing of installation rates and lower solar irradiance due to higher cloud coverage this quarter (Figure 4).

**Figure 3 Year-on-year increase in underlying and operational demand**

NEM average underlying and operational demand – Q3s

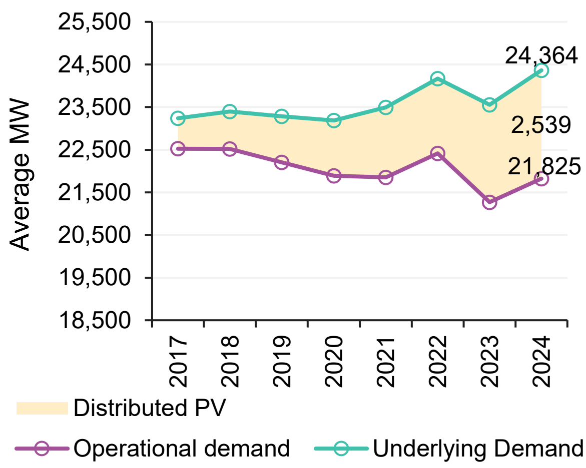
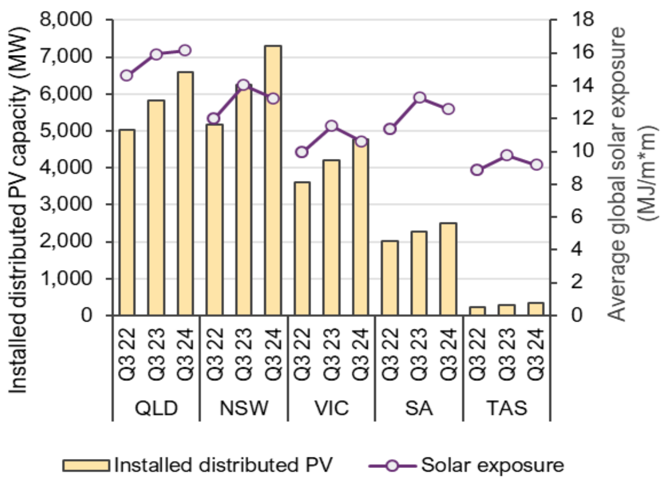



**Figure 4 Lower solar exposure and capacity growth rates for distributed PV**

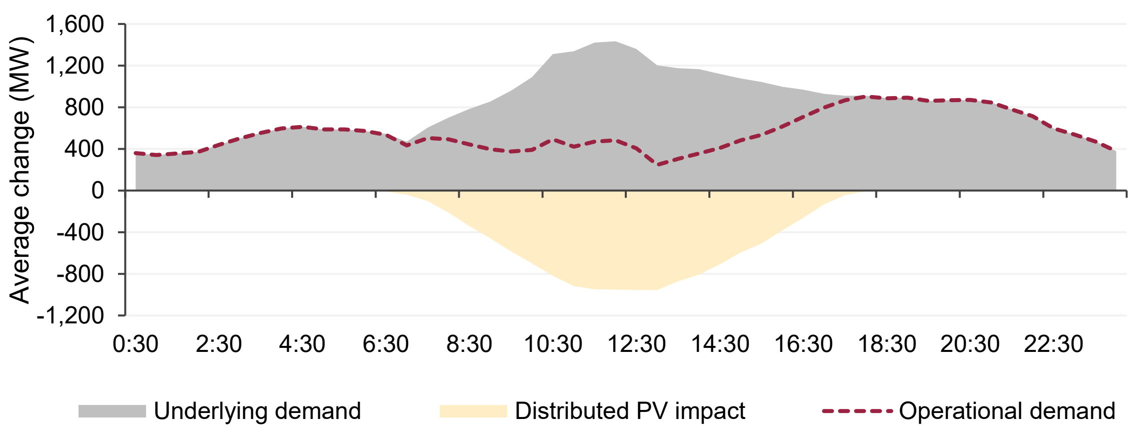
Estimated distributed PV capacity[2] and solar exposure by region – Q3s




The increase in underlying and operational demand was evident at all times of the day, with the increase in distributed PV output not high enough to offset the growth in underlying demand (Figure 5).

**Figure 5 Operational demand increased at all times of the day**

Changes in NEM average operational demand by time of day – Q3 2024 vs Q3 2023




All NEM regions recorded growth in underlying and operational demand for the quarter (Figure 6). Comparing Q3 2024 with Q3 2023:

- **Queensland**'s average underlying demand reached a new Q3 high record of 6,786 MW, up 193 MW (+3%). This increase was driven by higher heating demand in July, followed by warmer temperatures during August causing cooling demand. Although the region saw the largest growth in distributed PV average output for any

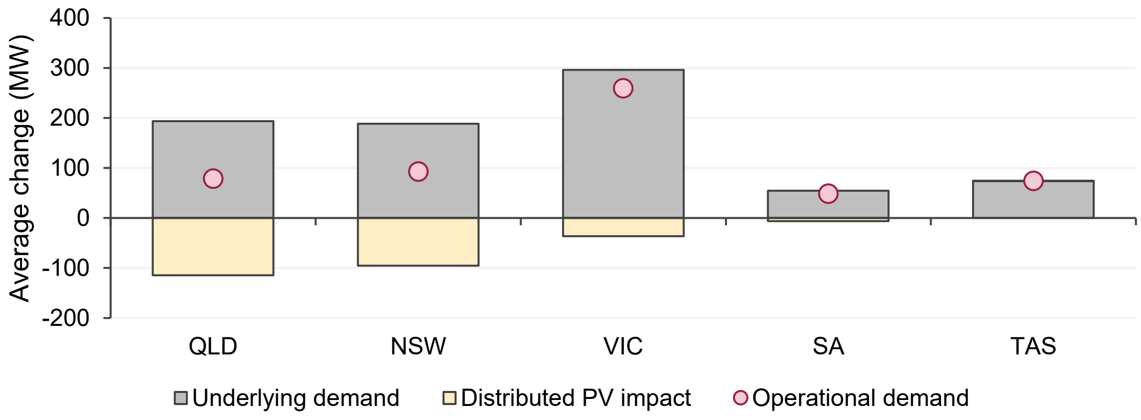
[2] The estimated installed distributed PV capacity is based on postcode data from the Clean Energy Regulator (https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data#postcode-data-files) and an adjustment to reflect the observed accreditation lag.

NEM region, at 115 MW (+14%), this was more than offset by the growth in underlying demand, resulting in a 79 MW (+1%) increase in operational demand to 5,879 MW.

- Underlying demand also increased in **New South Wales**, up 189 MW (+2%) to an average of 8,688 MW. This increase in underlying demand was mainly driven by the colder conditions during July. Distributed PV output grew by 96 MW (+12%), partially offsetting the increase in underlying demand, leading to a 93 MW (1%) uplift in operational demand to average 7,814 MW this quarter.
- **Victoria** experienced the largest growth in average underlying demand among all regions at 296 MW (+5%), reaching 5,888 MW. This increase was driven by a very cold July and a colder than usual September. Distributed PV output grew by 36 MW (9%) to 452 MW this quarter. Operational demand averaged 5,436 MW, up 260 MW (+5%), also the largest increase among NEM regions.
- In **South Australia**, distributed PV output saw a modest rise of 6 MW (+2%), while average underlying demand grew by 55 MW (+3%), reaching 1,678 MW. This increase in demand led to a 49 MW (+4%) rise in operational demand, bringing the average to 1,399 MW.
- **Tasmania** experienced a small drop of 1 MW (-3%) in distributed PV output (due to less solar exposure and slower rate of installed capacity growth), while average underlying demand increased by 74 MW (+6%), reaching 1,324 MW. Operational demand in Tasmania rose 75 MW (+6%) to an average of 1,297 MW.

**Figure 6 Year-on-year increases in operational demand in all regions, led by Victoria**

Changes in average demand components by region – Q3 2024 vs Q3 2023




## Maximum and minimum demands

Maximum NEM-wide operational demand for Q3 2024 was 33,381 MW during the half-hour ending 1830 hrs on 15 July 2024, with widespread cold conditions driving an increase of 2,623 MW (+9%) on Q3 2023's maximum of 30,758 MW.

All NEM regions saw higher maximum operational demands, with New South Wales accounting for the largest year-on-year increase of 1,057 MW (+9%) (Figure 7). In addition to its new Q3 record level of average underlying demand, Queensland also recorded a new Q3 (and winter) high for maximum operational demand at 8,728 MW this quarter, up 591 MW (+7%) from Q3 2023's maximum (Table 1).

Victoria also recorded a new Q3 (and winter) high maximum operational demand at 8,612 MW, a 616 MW (+8%) increase year-on-year. This broke a 17-year winter record for Victorian maximum demand, with the previous maximum of 8,351 MW recorded back on 17 July 2007.

This quarter, NEM minimum operational demand of 11,486 MW occurred during the half-hour ending 13:00 on 22 September 2024, 93 MW (+1%) above the 11,393 MW observed during Q3 2023. All regions except South Australia experienced reductions in minimum operational demand, with New South Wales and Queensland reaching new all-time record[3] minimums at 3,555 MW and 3,096 MW, respectively (Figure 8).

Clear skies and mild temperatures, combined with a public holiday long weekend, contributed to near record minimum demand conditions over 27-28 September in Victoria. The forecast regional demand[4] for Saturday 28 September led to AEMO issuing a Minimum System Load 1[5] (MSL1) market notice for Victoria on 24 September, followed on 25 September by a MSL notice for Friday 27 September.

While Victoria recorded its new Q3 minimum operational demand at 1,937 MW on Saturday 28 September, regional demand did not drop below the intervention threshold of MSL2.

**Table 1 Q3 2024 maximum and minimum operational demand records**

| Region | New Q3 maximum demand record | New Q3 minimum demand record |
|---|---|---|
| Queensland | 8,728 MW (1900 hrs on Wednesday 17 July 2024) | 3,096 MW (1300 hrs on Sunday 18 August 2024) – also all-time record |
| New South Wales | - | 3,555 MW (1300 hrs on Saturday 21 September 2024) – also all-time record |
| Victoria | 8,612 MW (1800 hrs on Monday 15 July 2024) | 1,937 MW (1200 hrs on Saturday 28 September 2024) |

**Figure 7 Maximum operational demand higher in all regions**

Maximum operational demand for mainland regions – Q3s

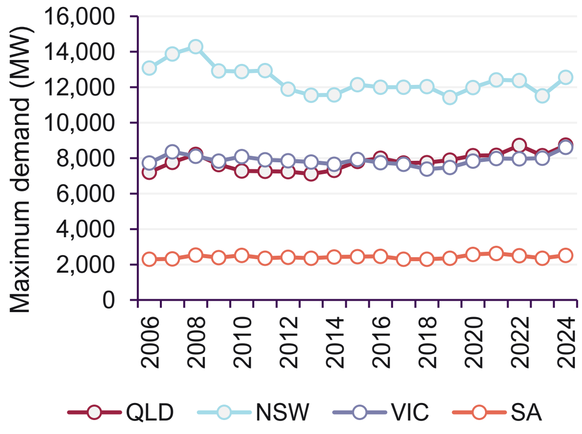
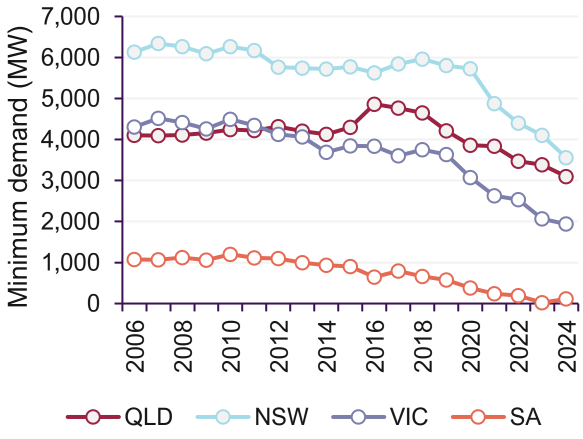



**Figure 8 Mainland minimum operational demands lower, except in South Australia**

Minimum operational demand for mainland regions – Q3s




[3] Multiple new all-time minimum demand records were set after the quarter ended, including a NEM-wide record of 10,305 MW on 20 October, Queensland at 3,091 MW on 5 October, South Australia at -205 MW on 19 October and New South Wales at 3,283 MW on 20 October.

[4] Regional demand refers to the demand used in Pre Dispatch Projected Assessment of System Adequacy (PD PASA) and Short Term (ST) PASA. For more information see Section 2.2.1 of https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/demand-terms-in-emms-data-model.pdf?la=en.

[5] MSL events are forecast when forecast regional demand is less than the relevant MSL threshold. For more information see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation.

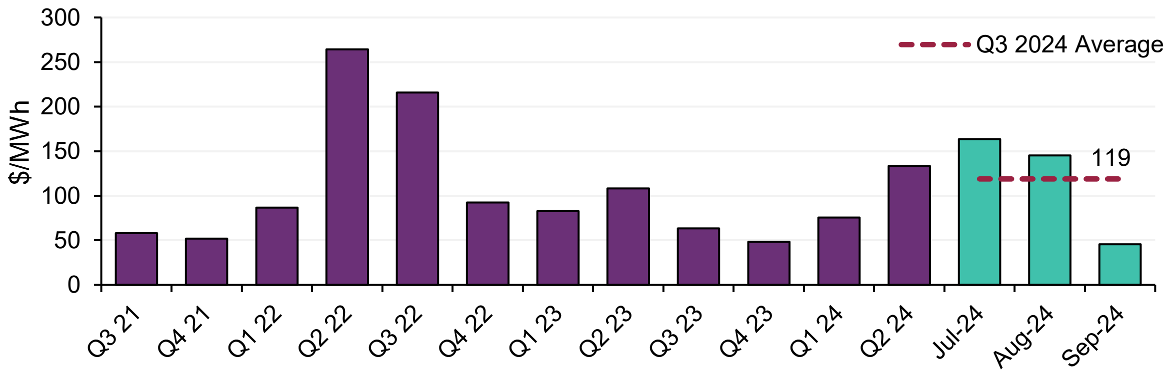
## 1.2 Wholesale electricity prices

In Q3 2024, wholesale electricity spot prices averaged $119/MWh across the NEM, up $56/MWh (+88%) on Q3 2023 where NEM spot prices averaged $63/MWh, but down $15/MWh (-11%) from Q2 2024's $133/MWh (Figure 9). The year-on-year increase was driven by a combination of factors including higher average and peak operational demands, reduced hydro generation, and network outages limiting interconnector flows. Impacts on average prices were concentrated in July and August, with monthly uplifts of 161% (to average $163/MWh) and 71% (to average $145/MWh) year-on-year respectively, compared to 9% (to average $46/MWh) in September.

Volatility increased in all regions, with the cap return component of spot prices averaging $31/MWh, up $24/MWh (+311%) from Q3 2023's $8/MWh. The energy component[6] of spot prices also increased by $32/MWh (+58%) to $88/MWh this quarter.

**Figure 9 Year-on-year increase in NEM average wholesale spot prices**

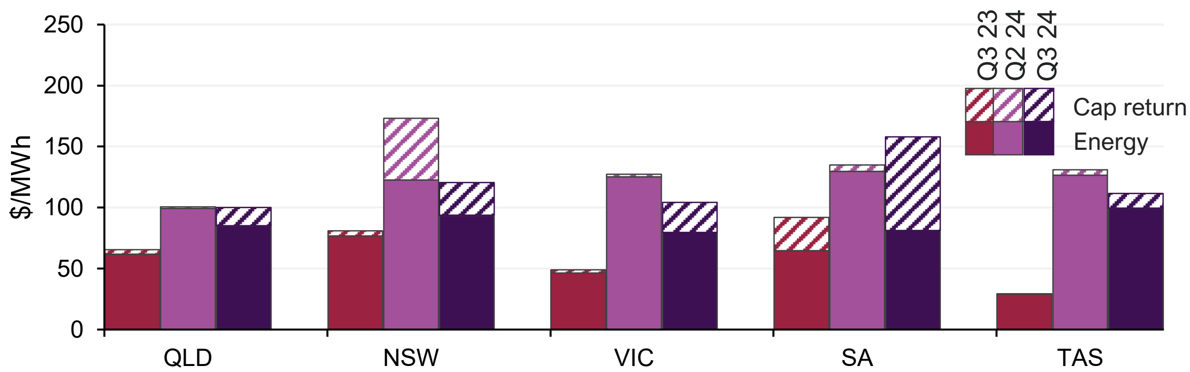
NEM average wholesale electricity spot prices – quarterly since Q3 2021




All regions contributed to the year-on-year increase in quarterly average spot price with higher energy and cap return components, although the size and composition of increases varied widely between regions (Figure 10).

**Figure 10 All regions saw elevated average spot prices year-on-year, with uplifts in both energy and cap return**

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




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

By region:

- **Queensland**'s wholesale spot prices averaged $100/MWh, a $35/MWh (+53%) increase compared to Q3 2023. Both the energy and cap return components rose, by $23/MWh and $12/MWh, respectively. The rise in cap return reflects more frequent price spikes in Queensland during the quarter, primarily driven by higher operational demand. However, compared to Q2 2024, energy prices fell by $14/MWh from $99/MWh, while the cap return component grew by $14/MWh.
- **New South Wales**' quarterly average price rose by $40/MWh (+49%) year-on-year, increasing from $81/MWh in Q3 2023 to $121/MWh this quarter. Both the energy and cap return components contributed to this rise, with energy up by $17/MWh (from $77/MWh to $94/MWh) and cap return up by $23/MWh (from $4/MWh to $27/MWh). However, compared to Q2 2024, both components were lower, leading to a 30% drop in the quarterly average spot price.
- **Victoria**'s quarterly average price reached $104/MWh, an increase of $55/MWh (+113%) relative to $49/MWh last Q3. The energy component of quarterly average price increased by $33/MWh (+72%) and the cap return component saw a notable increase from $3/MWh last year to $25/MWh this quarter. Colder conditions and increase in operational demand throughout the quarter was a key driver of this increase in prices.
- The combination of colder conditions, increased cloud coverage causing reduced distributed PV output, and interconnector outages impacted **South Australia** prices this quarter. Quarterly prices averaged $158/MWh, up $66/MWh (+72%) from $92/MWh last year. This increase was mostly driven by prices above $300/MWh, yielding the largest cap return component for any region at $77/MWh, a $49/MWh (+181%) increase year-on-year.
- Although rainfall in **Tasmania** picked up towards the end of the quarter, low dam levels at the start of the quarter (reflecting a very dry Q2 2024) prompted increases in the pricing of hydro offers to conserve water in storage. This led to higher gas-fired generation and imports from Victoria, and a significantly higher quarterly average price in Tasmania of $112/MWh, up $82/MWh (+282%) from Q3 2023. Higher energy prices, up $70/MWh (+243%) to $99/MWh this quarter, accounted for most of the upward shift, with a cap return component of $12/MWh compared to a negligible level in Q3 2023.

Across the NEM, higher average operational demand at all times of day during Q3 2024, and dispatch of higher cost generation, led to an upward shift in average energy prices relative to Q3 2023 levels (Figure 11).

This quarter saw price separation between South Australia and Victoria during both morning and evening peak hours (Figure 12). This was driven by outage-related limits on the Heywood interconnector in late July and early August, combined with several days of low wind and solar generation in South Australia. These events, which are discussed further in Section 1.2.1, drove South Australia's average spot prices well above other regions at those times of day.

**Figure 11 NEM average energy price increased at all times of day**

NEM average energy price by time of day – Q3 2024

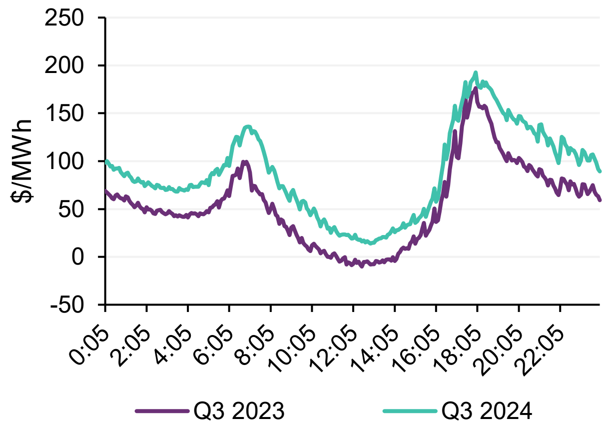
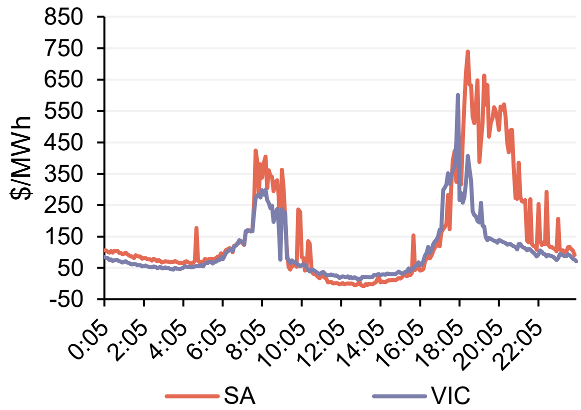



**Figure 12 Significant price gaps between South Australia and Victoria**

Average regional spot price by time of day – Q3 2024




### 1.2.1 Wholesale electricity price drivers

Table 2 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 2 Wholesale electricity price drivers in Q3 2024**

| | |
|---|---|
| **Lower rainfall and higher priced hydro offers** | Although rainfall picked up towards the end of the quarter, dam levels began Q3 at relatively low levels after declining through Q2 2024. Accordingly, as in the previous quarter hydro generators offered less volume to the market in low-priced bands than last Q3 (Figure 13). In Tasmania, this upward repricing of hydro offers combined with a 6% increase in operational demand resulted in a notable uplift in Tasmania wholesale spot prices. This also drove a reversal in transfers between Victoria and Tasmania, shifting from 138 MW northward in Q3 2023 to 189 MW southward in Q3 2024 (see Section 1.4), and contributed to higher NEM average prices. |
| **Higher operational demand** | This quarter saw higher NEM operational demand across all times of the day, with a 2.6% (+555 MW) average increase on Q3 2023. While this was mainly driven by colder year-on-year weather conditions lifting underlying demand (up 3.4%), increased cloud coverage and a slower installation rate of distributed PV capacity limited the offsetting effect of distributed PV output growth. This operational demand shift was another significant contributor to the year-on-year increase in the energy component of spot prices, reflected in higher occurrence of prices over $100/MWh, which increased in frequency from 19% in Q3 2023 to 40% this quarter (Figure 14). |
| **Higher peak demand combined with instances of low variable renewable energy (VRE)** | There was a notable increase in evening peak demand levels relative to previous Q3s. Combined with instances of low VRE output, this resulted in tighter supply conditions at times during this quarter than in Q3 2023. Dispatch of higher priced volumes offered by gas, hydro, and batteries to meet demand peaks led to a significant increase in the cap return component of spot prices. This is discussed further in Section 1.2.2. |
| **Network outages impacting flows on Heywood** | Planned network outages limited the export capacity of the Heywood interconnector from Victoria to South Australia to under 100 MW for 19% of intervals across Q3 2024. This combined with instances of low wind generation in South Australia resulted in multiple price spikes in the region. Heywood export limits under 100 MW were associated with 71% of the intervals in which South Australian spot prices exceeded $1,000/MWh. More information is given in Section 1.2.2. |

**Figure 13 Less volumes offered at all price bands by hydro generators**

NEM hydro bid supply curve – Q3 2024 vs Q3 2023

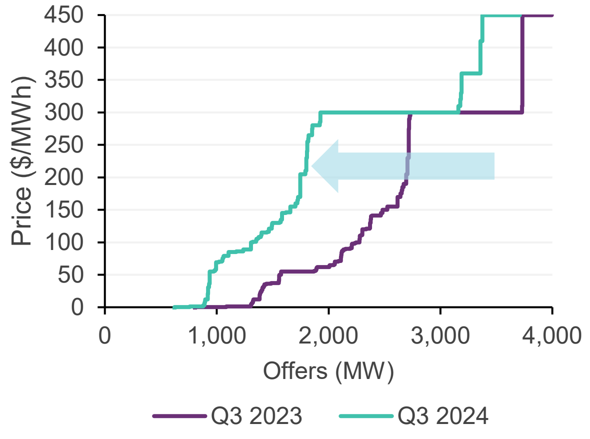
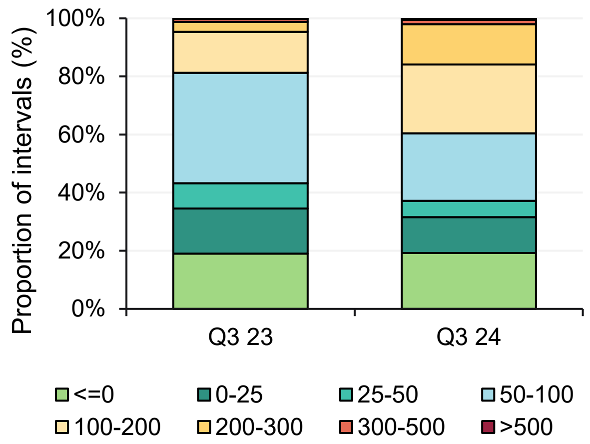



**Figure 14 Increased occurrence of prices between $100/MWh and $300/MWh**

NEM average spot price range – Q3 2024 vs Q3 2023




### 1.2.2 Wholesale electricity price volatility

In Q3 2024, cap returns across the NEM – representing the contribution of spot prices exceeding $300/MWh to the quarterly average – rose by $118/MWh when aggregated across all five regions, increasing from $38/MWh in Q3 2023 to $155/MWh (Figure 15). South Australia accounted for 49% of the total NEM cap return, experiencing multiple price volatility events throughout the quarter, while most of the cap return in the other regions was due to widespread price spikes in the NEM on 5 August 2024 (Figure 16).

**Figure 15 South Australia accounted for almost half of NEM cap returns in Q3 2024**

Cap returns by region – quarterly

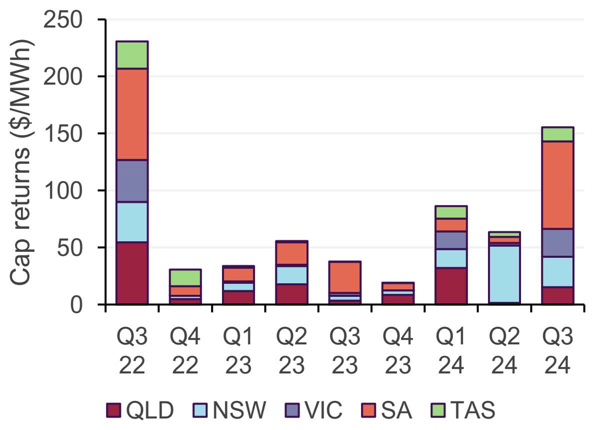
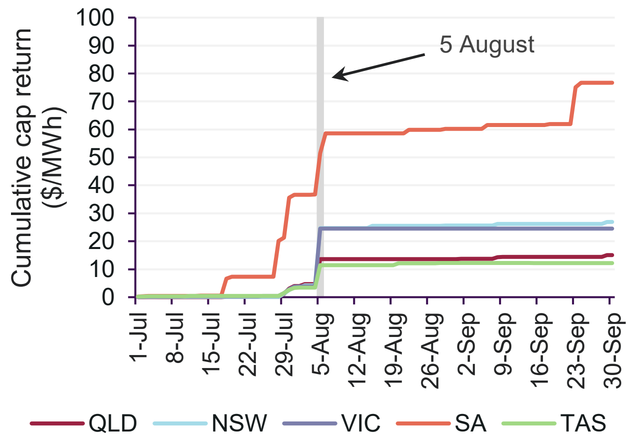



**Figure 16 South Australia saw multiple volatility events throughout the quarter**

Cumulative cap return by region – Q3 2024

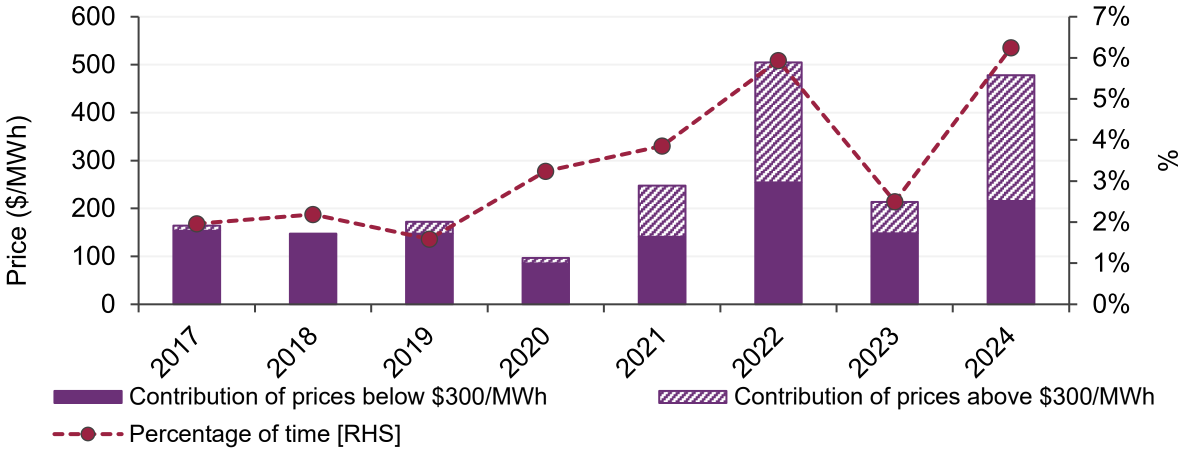



## Increase in peak operational demand levels in Q3 2024

This quarter saw more frequent peak operational demands at relatively high levels compared to previous Q3 periods, which, in conjunction with other factors, led to tighter supply conditions and increased volatility. Figure 17 shows the percentage of time for recent Q3s in which NEM operational demand has exceeded 28,000 MW[7] and the average NEM spot price during these periods.

**Figure 17 Increase in volatility driven by higher instances of peak operational demand**

NEM average price and the percentage of time when NEM operational demand was above 28,000 MW – Q3s




This quarter saw NEM operational demand exceeding 28,000 MW in 6% of dispatch intervals (nearly three times more often than in Q3 2023). The average NEM operational demand during these intervals was 29,548 MW in this quarter, which is the highest such average for Q3 since Tasmania joined the NEM in 2005 and 728 MW (+3%) higher than in Q3 2023.

The average NEM spot price for intervals with operational demand above 28,000 MW was $478/MWh this quarter, $265/MWh (+124%) higher year-on-year. As seen in Figure 17, most of this increase was associated with the contribution of prices in excess of $300/MWh which reached $263/MWh. The combined effect of more frequent instances of high NEM-wide demand and higher average prices at these demand levels was a substantial contribution to the overall year-on-year rise in the quarterly average spot price, particularly its cap return component.

## Widespread price spikes across NEM regions driven by tighter supply and demand balance

Simultaneous price spikes across all NEM regions[8] are relatively rare, having occurred in only 41 five-minute dispatch intervals since 2017, but 18 of these were recorded this quarter during late July and early August.

During these 18 intervals, low temperatures drove high operational demands (averaging 31,467 MW), solar generation was close to zero, wind generation was low (averaging 1,190 MW), and a number of coal units were offline (with an average capacity of 2,654 MW), leading to relatively tight supply-demand conditions.

On 29 July, NEM operational demand reached 32,370 MW during the 18:25 dispatch interval (Figure 18). On that day, prices in all NEM regions rose to above $1,000/MWh from the 17:55 dispatch interval to 18:45 (except the 18:15 and 18:40 dispatch interval). 30 July saw the highest NEM-wide average spot price, reaching $16,419/MWh during the 18:00 dispatch interval, the highest NEM-wide average price for any interval since market start.

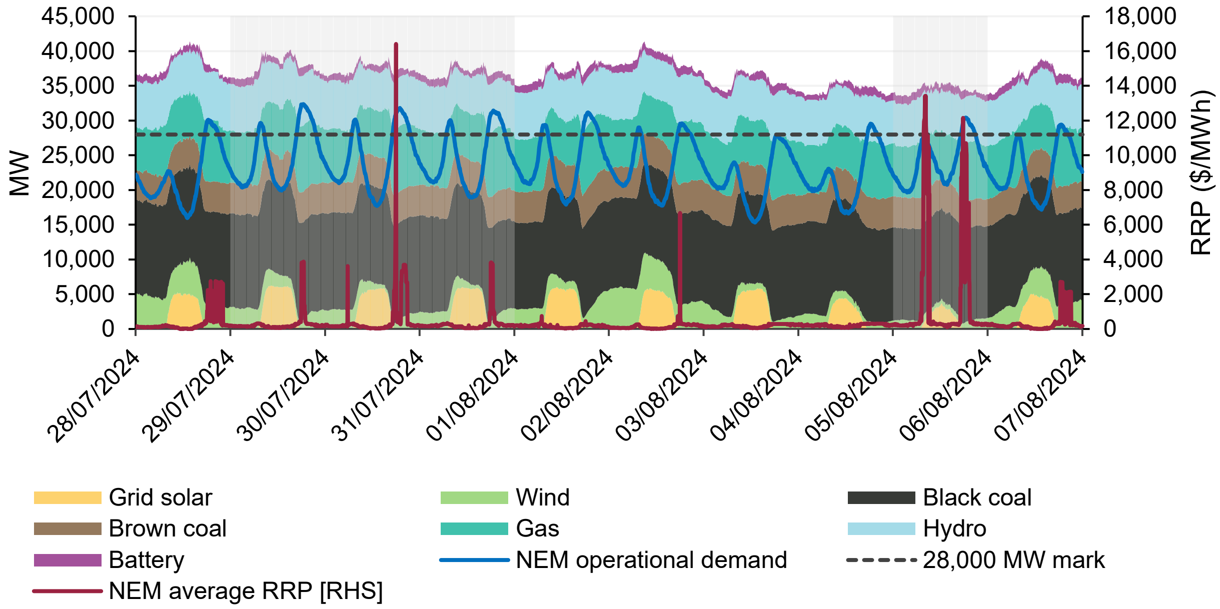
[7] 28,000 MW has been selected as a threshold for comparison of quarterly NEM peak demand levels, since demands only exceed this level in a small percentage of intervals.

[8] Referring to intervals where dispatch prices in all NEM regions exceed $1,000/MWh at the same time.

On 5 August, NEM-wide volatility occurred in the morning peak, with the NEM average spot price reaching $13,427/MWh during the 08:15 dispatch interval, followed by volatility across all mainland NEM regions in the evening, with NEM average spot prices reaching $12,149/MWh during the 17:45 dispatch interval.

**Figure 18 NEM-wide price spikes during late July and early August**

Generation availability per fuel type, NEM total actual demand[9], and NEM average RRP – 28 July to 6 August




## South Australia price spikes in Q3 2024

In addition to the NEM-wide volatility events discussed in the previous section, South Australia experienced more extended periods of price volatility resulting in a regional cap return of $77/MWh, well above other regions and contributing 49% of the total NEM cap return. These events were driven by a combination of factors including cold evenings, low wind conditions, and network outages limiting Heywood interconnector flows or constraining some generators in the region at times.

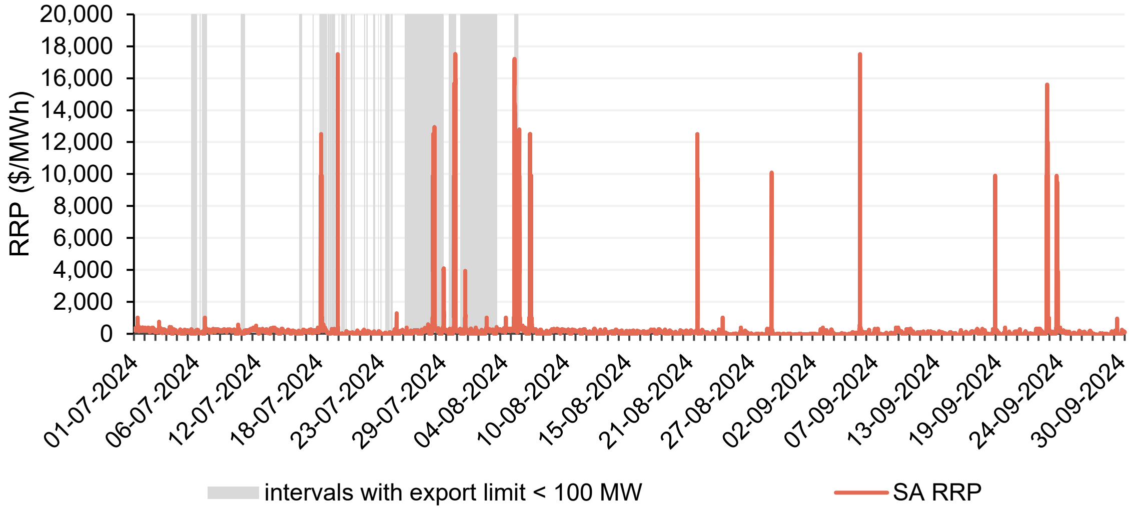
These factors led to multiple instances of tight supply and demand conditions and price volatility, especially on 30 July 2024 where South Australia recorded a $14.4/MWh cap return for the day.

Across Q3 2024, the region saw 218 intervals with prices above $1,000/MWh, in almost 80% of which wind generation was less than 200 MW. Periods when Heywood interconnector exports were limited to less than 100 MW, shaded grey in Figure 19, also coincided with 71% of these high-priced intervals.

[9] Refers to the five-minute total demand, that is met by local scheduled generation and semi-scheduled generation, and by generation imports to the regions, excluding the demand of local scheduled loads, and including wholesale demand response.

**Figure 19 Price volatility in South Australia During the quarter, impacted by interconnector limits**

South Australia spot price and intervals with Heywood interconnector export limited to below 100 MW




In contrast, during price spikes on 23 and 24 September, the Heywood interconnector was at its full capacity, but evening price volatility was driven by a local network outage which significantly constrained the output of several large gas-fired generators while wind availability was simultaneously low.

Table 3 summarises events of significant spot price volatility during Q3 2024.

**Table 3 Significant volatility events in Q3 2024**

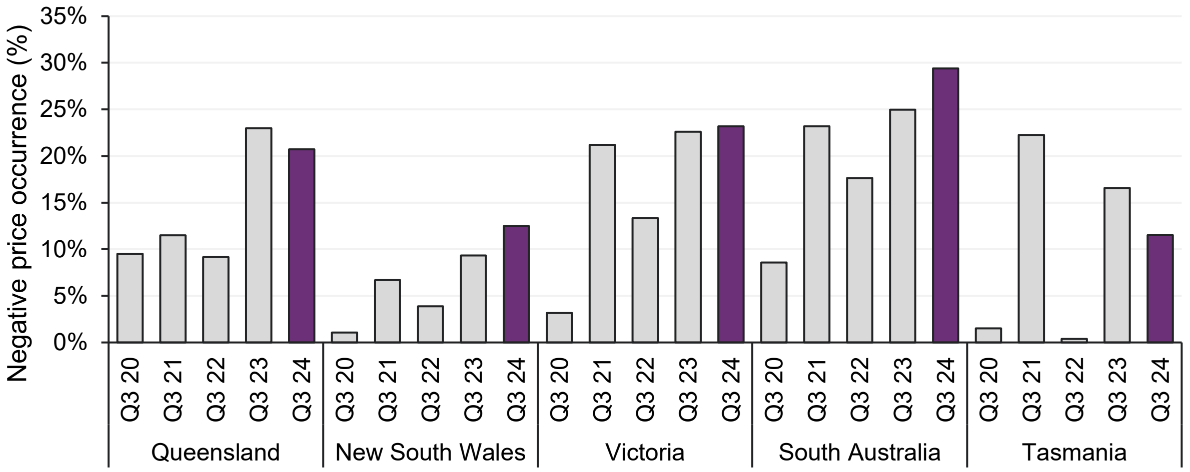
| Date | Region | Contribution to regional cap return ($/MWh) | Drivers |
|---|---|---|---|
| 5 August | Victoria | 20.6 | This day saw price volatilities in both morning and evening peaks. These were driven by tight supply and demand conditions which was caused by low wind and solar output, relatively higher peak demand levels in all regions, and coal outages on the day. Refer to previous sections for more information. |
| | New South Wales | 20.4 | |
| | South Australia | 14.8 | |
| | Queensland | 8.8 | |
| | Tasmania | 8.0 | |
| Multiple dates | South Australia | 14.4 (30 July) | Primarily driven by a combination of factors, including several cold evenings, low wind conditions, and, most notably, network outages that limited Heywood interconnector flows. Refer to previous sections for more information. |
| | | 12.8 (28 July) | |
| | | 7.1 (6 August) | |
| | | 6.1 (18 July) | |
| | | 13.1 (23 September) | Driven by a local network outage constraining output from several gas generators during evening peak, while wind availability was also low. Refer to previous sections for more information. |
| | | 1.6 (24 September) | |

### 1.2.3 Negative wholesale electricity prices

In Q3 2024, 19.5% of dispatch intervals across the NEM experienced negative or zero prices, a 0.2 percentage point (pp) increase from the 19.3% recorded in Q3 2023. Negative price occurrences fell by 5 pp in Tasmania and 2 pp in Queensland, while South Australia, New South Wales, and Victoria experienced increases of 4 pp, 3 pp, and 1 pp respectively, year-on-year (Figure 20). The average spot price during negative price intervals rose from -$36.3/MWh in Q3 2023 to -$33.1/MWh in Q3 2024.

**Figure 20 Slight increase in negative price occurrence in NEM**

Negative price occurrence in NEM regions – Q3s




On a monthly basis, July saw a significant reduction in negative price occurrence driven by notably higher demand, while this pattern changed in August and September where lower demand in the second half of the quarter combined with increased variable renewable energy (VRE) output led to higher occurrence of negative prices (Figure 21).

As seen in Figure 22, Queensland and South Australia experienced higher occurrences of negative prices compared to other NEM regions, primarily during the middle of the day.

**Figure 21 Lower negative price occurrence in July but higher in August and September**

Change in monthly negative price occurrence – Q3s

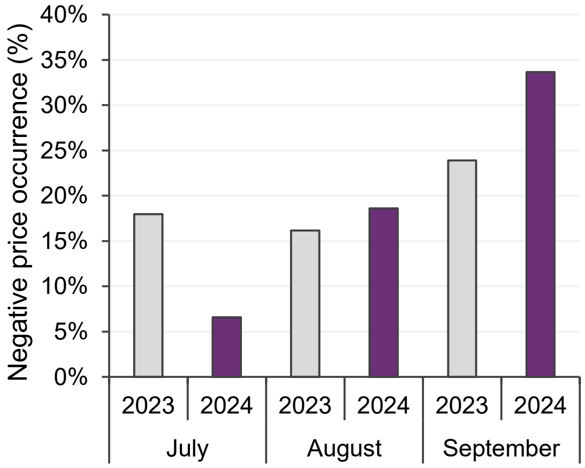
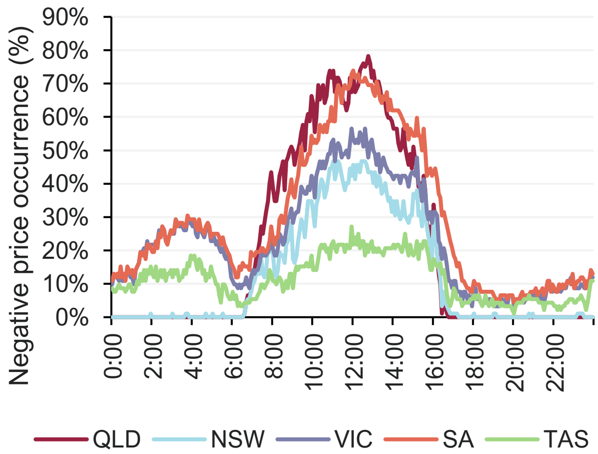



**Figure 22 Queensland and South Australia led negative price occurrence**

Negative price occurrence by time of day – Q3 2024

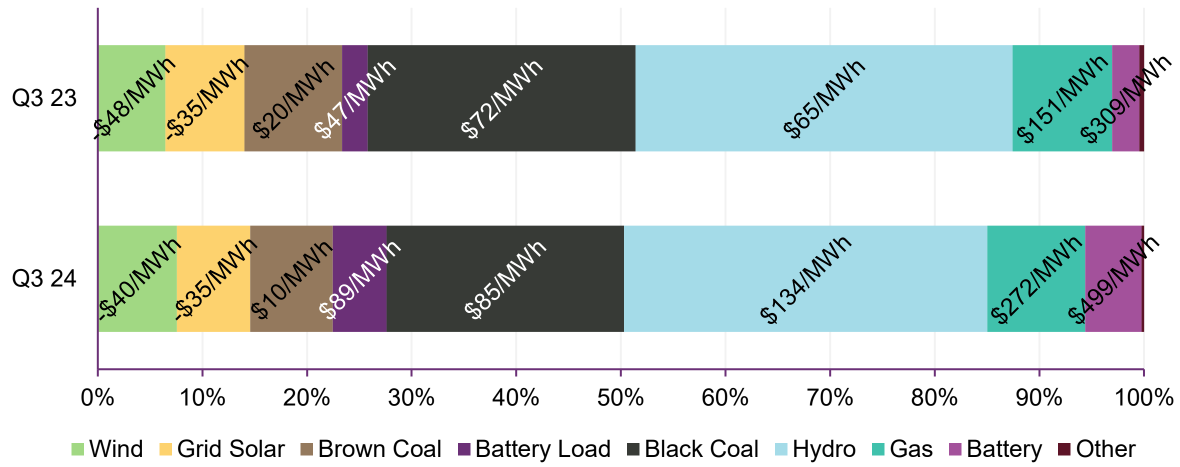


### 1.2.4 Price-setting dynamics

Year-on-year changes in average prices set by each energy source when marginal varied but were generally upwards for most sources (Figure 23). Hydro saw a significant increase, with average price set rising from $65/MWh to $134/MWh, as relatively low dam levels caused generators to shift offer prices upwards to conserve water. With hydro being the source setting prices most often across the NEM (35% of intervals in Q3 2024), this shift contributed significantly to the year-on-year increase in NEM energy prices below $300/MWh. Gas generation also experienced a sharp increase in average price set, from $151/MWh to $272/MWh, while average prices set by battery generation saw a notable surge from $309/MWh to $499/MWh. In the case of these latter two sources, the magnitude of these increases reflected their involvement in price-setting during periods of tighter supply-demand and spot price volatility, which were much more frequent and more volatile this Q3 than last.

**Figure 23 Batteries, gas, and hydro saw largest increases in average prices when marginal**

NEM price-setting frequency and average price when price-setter by fuel type – Q3 2024 vs Q3 2023

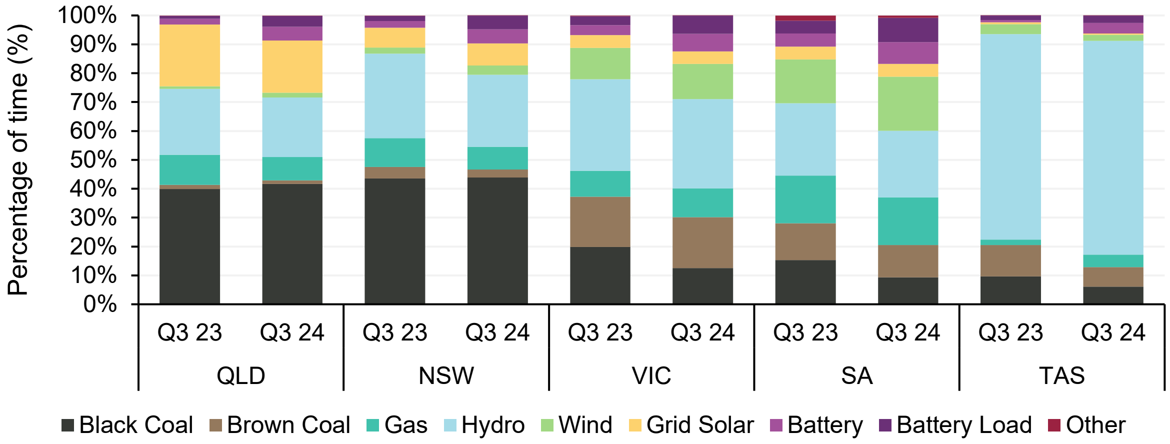



On a regional basis, gas-fired generation set prices more frequently in the southern regions, particularly in Tasmania, where there was a 2 pp increase year-on-year (Figure 24). Hydro set prices less frequently in all regions (ranging from 1 pp less in Victoria to 4 pp less in New South Wales) except Tasmania, which saw a 3 pp increase despite significantly lower generation volumes this Q3.

Batteries saw the largest increases in price-setting frequency across the NEM. The share of intervals where prices were set by battery generation rose to 5% in Q3 2024, up from 3% in Q3 2023, while price-setting frequency for battery loads increased from 2% a year ago to 5% this Q3.

**Figure 24 Batteries and wind set prices more frequently in the NEM while other fuel types saw reductions**

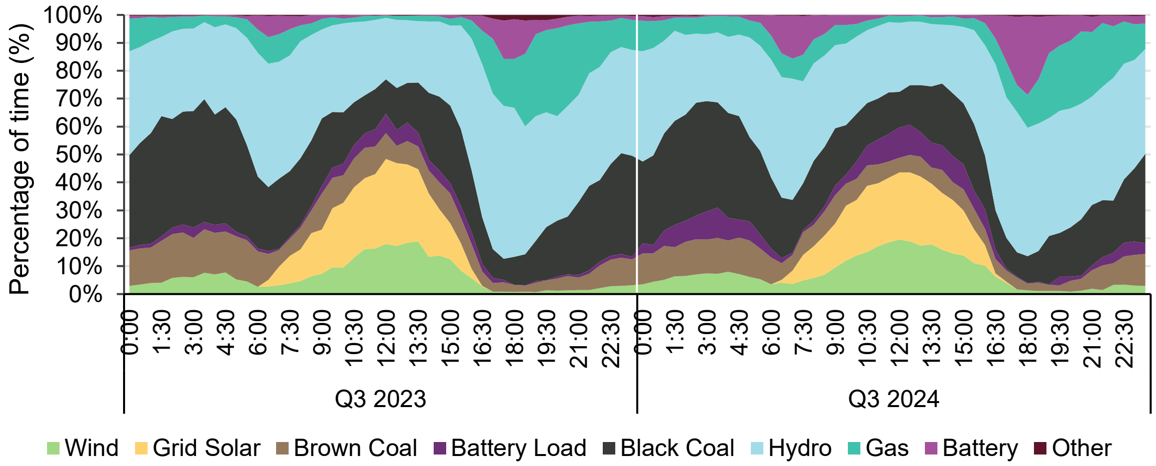
Price-setting frequency by fuel type – Q3 2024 vs Q3 2023




On a time-of-day basis, a reduction in black coal's price-setting frequency was observed across nearly all periods, with the most notable declines occurring toward the end of the day. Black coal's highest price-setting frequency reached 40%, reflecting a 4 pp drop from Q3 2023. In contrast, gas-fired generation saw increases in price-setting frequency throughout most of the day, except during the evening peak hours, where batteries more frequently set prices. The rise in battery price-setting was most prominent during morning and evening peaks for battery generation, and during early morning and middle of day peak solar hours for battery loads (Figure 25).

**Figure 25 Notable increase in price-setting frequency by batteries during peak hours**

NEM price-setting frequency by fuel type and time of day – Q3 2023 and Q3 2024




During some evening dispatch intervals, the average price-setting frequency for batteries in Q3 reached 28%, up from a peak of 14% in Q3 2023. In solar peak intervals (between half-hours ending 1000 and 1330), battery load set prices in 9% of intervals NEM-wide, accounting for a 3 pp year-on-year increase.

### 1.2.5 Electricity futures markets

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

After a notable increase during Q2 2024, ASX daily prices for Q3 2024 base contracts continued increasing during July and August. This increase was mostly evident after the spot price spikes observed in all NEM regions on 5 August, with Victoria and New South Wales recording the largest jumps in quarterly base contract prices by $36/MWh and $32/MWh respectively (Figure 26).

South Australian spot price spikes driven by tight supply and network outages in early August also led to notable jumps in Q3 2024 base contracts, with a $30/MWh increase on 8 August, reaching a maximum of $170/MWh.

During September, and with the increase in VRE share of supply and higher occurence of negative spot prices, Q3 2024 base contract prices started to drop slightly, converging towards quarterly spot price averages.

Price volatility in South Australia led to increases in baseload $300 cap futures for Q3 2024 throughout the quarter. Figure 27 illustrates the daily settled prices for this contract along with movements in minimum cap return[10] in the region over this quarter. After starting the quarter at $20/MWh, the baseload $300 cap price followed the minimum cap return which increased towards the end of July and early August (where the majority of volatility events in South Australia took place) to end the quarter at $77/MWh.

**Figure 26 Increase in Q3 2024 base future prices driven by high spot price volatilities in August**

ASX Energy – Regional daily Q3 2024 base future prices and daily average spot price for mainland regions

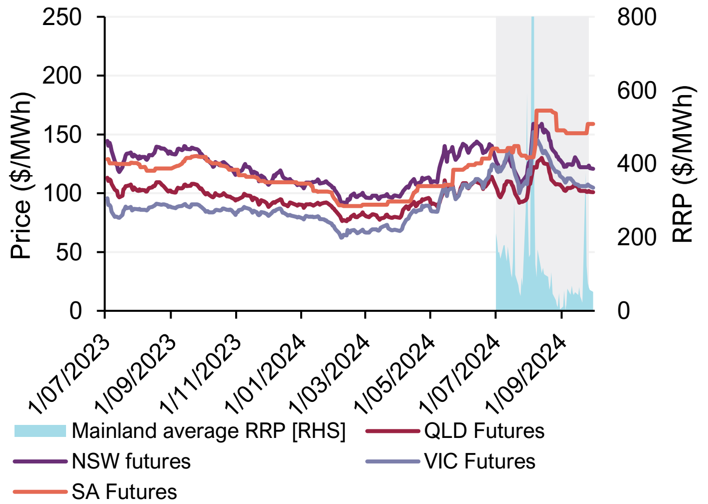



**Figure 27 Increase in South Australia caps driven by volatility events throughout the quarter**

ASX Energy – Daily Q3 2024 base cap price and the change in minimum cap return in South Australia

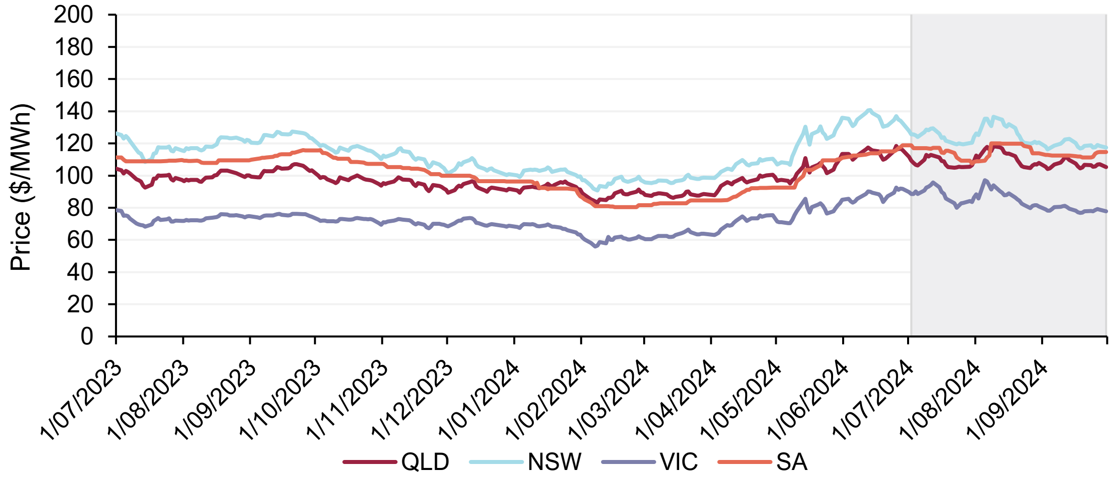

ASX base contract daily prices for the 2024-25 financial year (FY25) averaged $108/MWh over Q3 2024, across mainland NEM regions. This was a 6% increase from their average over Q2 2024 and a 7% increase from Q3 2023 where FY25 contract prices averaged $101/MWh. After a notable increase towards the end of Q2 2024,

[10] The 'minimum cap return' at any point in a quarter represents the cumulative value of spot prices in excess of $300/MWh up to that specific point, when averaged over the entire quarter. It is calculated by dividing the quarter to date sum of these spot price exceedances by the full number of intervals in the quarter.

base contract daily prices reacted through Q3 to trends in spot prices, increasing with spot price volatility in late July early August, but then declining through to the end of the quarter as spot prices moderated. By the end of the quarter, FY25 contract prices for all regions were lower than their start of quarter levels (Figure 28).

**Figure 28 After lifting in early August, FY25 futures prices declined to end the quarter lower**

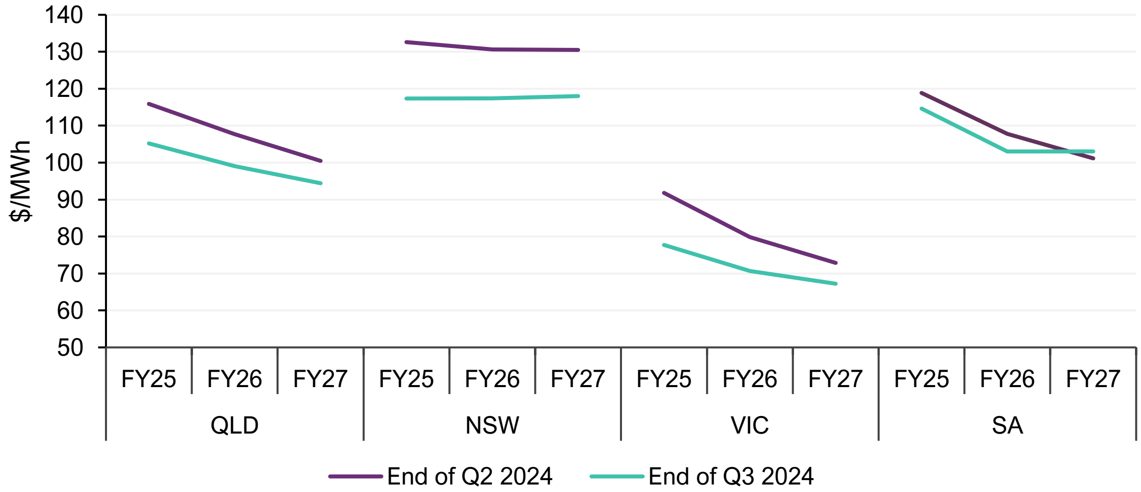
ASX Energy – Daily FY 2024-25 base future by region




At the close of Q3 2024, future financial year contracts saw a notable decline compared to end of Q2 2024 across all regions, except South Australia's FY27 (Figure 29). In New South Wales, FY25 prices fell by $15/MWh (-12%) to $117/MWh, and Queensland's prices dropped by $11/MWh (-9%), settling at $105/MWh. Victoria saw the largest percentage drop with a 15% reduction (-$14/MWh), ending at $78/MWh. South Australia's FY25 prices decreased by $4/MWh (-4%), closing at $115/MWh. Contract prices for FY26 and FY27 generally showed similar downward shifts in all regions.

**Figure 29 Future financial year contracts ended the quarter at prices below end of Q2 2024 levels, except South Australia's FY27**

Financial year contract prices in mainland NEM regions – end of Q2 2024 and end of Q3 2024



## 1.3 Electricity generation

Total generation across the NEM[11] averaged 24,881 MW in Q3 2024, up 4.1% (+969 MW) from Q3 2023, reflecting growth in underlying demand (+807 MW) and higher supply for battery charging (+44 MW) and hydro pumping (+84 MW). The change in average NEM generation by fuel type relative to Q3 2023 is shown in Figure 30 and the resultant changes in supply mix contributions are shown in Table 4.

Higher wind generation and distributed PV output offset the reductions in hydro and grid-scale solar generation leading to an increase in the overall contribution of renewables to 39.3% during Q3 2024, up from 38.9% during Q3 2023, and a new Q3 high.

**Figure 30 Underlying demand growth drove increased output from most fuel types**

Change in NEM supply by fuel type – Q3 2024 vs Q3 2023

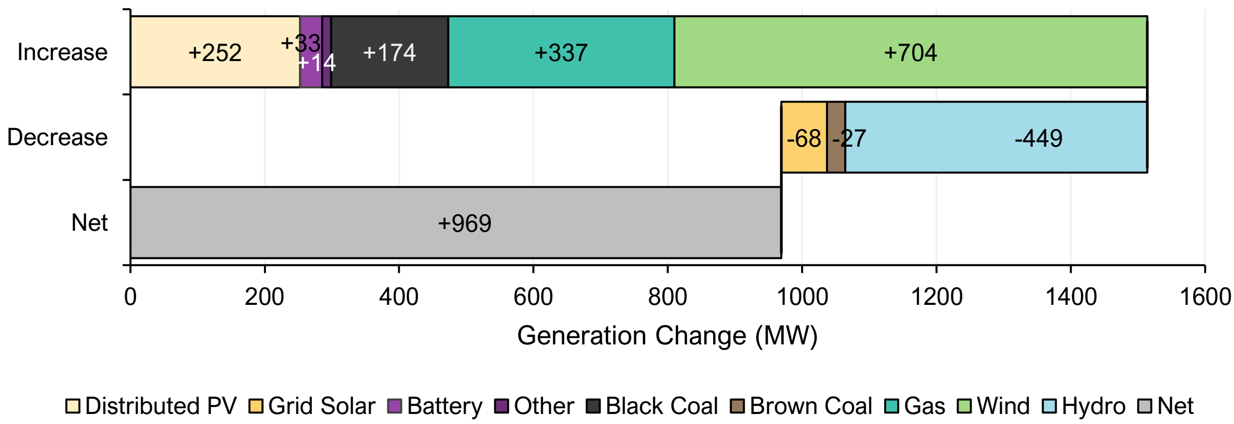



**Table 4 NEM supply mix contribution by fuel type**

| Quarter | Black coal | Brown coal | Gas | Liquid fuel | Distributed PV | Wind | Grid solar | Hydro | Biomass | Battery |
|---|---|---|---|---|---|---|---|---|---|---|
| Q3 2023 | 40.6% | 15.6% | 4.8% | 0.02% | 9.6% | 14.0% | 6.4% | 8.6% | 0.2% | 0.2% |
| Q3 2024 | 39.8% | 14.9% | 6.0% | 0.01% | 10.2% | 16.3% | 5.9% | 6.4% | 0.2% | 0.3% |
| Change | -0.9% | -0.7% | 1.2% | -0.01% | 0.6% | 2.3% | -0.5% | -2.1% | 0.1% | 0.1% |

Comparing Q3 2024 with Q3 2023:

- Distributed PV output increased to average 2,539 MW (+11%) due to growth in installed capacity, but at grid-scale solar facilities, lower solar irradiance and outages for network upgrades combined with more economic offloading saw a 68 MW (-4.5%) reduction in output to average 1,461 MW.
- After starting the quarter with relatively low storage levels, hydro generation averaged 1,603 MW, down 449 MW (-22%), driving a 2.1 pp reduction in volume share to 6.4%.

[11] 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 1.1.2.

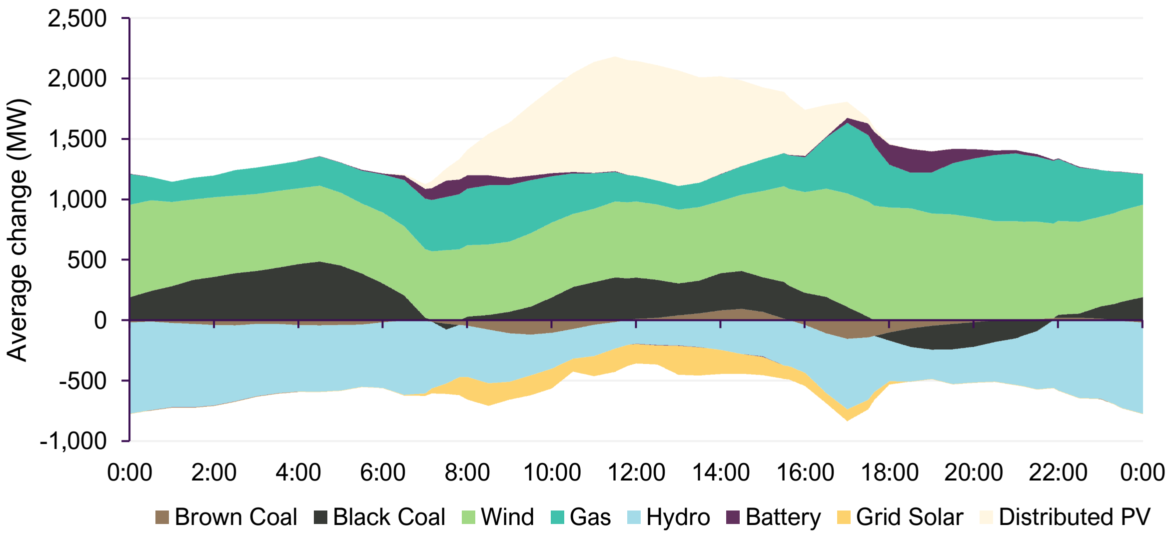
- Increased wind speeds and additional capacity drove wind output to a new quarterly record output of 4,044 MW, up 704 MW (+21%), reflected in a 2.3 pp increase in volume share to 16.3%.
- Gas-fired generation increased to average 1,493 MW, up 337 MW (+29%), despite an increase in east coast gas prices (see Section 2.1). The growth in output was driven by growth in operational demand and high spot prices, and comes after Q3 2023 recorded particularly low gas-fired generation output.
- Black coal-fired and brown coal-fired generation both recorded reductions in volume share, down 0.9 pp and 0.7 pp respectively. Changes in average output were relatively small, with black coal-fired output increasing by 174 MW (+1.8%) to average 9,893 MW, and brown coal-fired output decreasing by 27 MW (-0.7%) to average 3,703 MW.
- Battery generation and biomass recorded the greatest percentage growths in output, with average battery generation increasing to 86 MW (+62%) and biomass to 58 MW (+38%), however the volume shares of these fuel types remain low at 0.3% and 0.2% respectively.

The time of day changes in generation by fuel type are shown in Figure 31. Comparing Q3 2024 with Q3 2023:

- Reductions in hydro generation (-449 MW) and increases in wind (+704 MW) and gas-fired generation (+337 MW) were evident across all hours of the day.
- Focusing on the evening peak (between 1600 hrs and 2000 hrs), wind generation had the largest uplift in output out of all fuel types, increasing by 904 MW (+30%), followed by gas-fired generation, up by 407 MW (+18%). Battery generation had the largest percentage increase, up 72% (+102 MW) to average 244 MW. Output from both brown coal-fired and black coal-fired generation decreased marginally, by 87 MW (-2%) and 9 MW (-0.1%) respectively.
- Wind generation was also the fuel type with the greatest year-on-year increase in output during the morning peak (between 600 hrs and 1000 hrs) increasing by 583 MW (+17%), followed by gas-fired generation up 428 MW (+48%). Battery generation again had the largest percentage uplift in output, up 110% (+69 MW) to average 133 MW.

**Figure 31 Output from wind, gas-fired generators and batteries increased to meet morning and evening peaks**

NEM generation changes by time of day – Q3 2024 vs Q3 2023



### 1.3.1 Coal-fired generation

#### Black coal-fired fleet

In Q3 2024, NEM black coal-fired generation averaged 9,893 MW, increasing 174 MW (+1.8%) from Q3 2023 levels, despite a 272 MW (-2.1%) decrease in availability over the same time period (Figure 32). The decrease in availability was driven by an increase in partial outages limiting the maximum output available at some units, with the capacity on full unit outages down 97 MW (-3%) as shown in Figure 33.

**Figure 32 NEM black coal-fired generation increased despite decrease in availability**

Quarterly average black coal-fired generation and availability by region (including decommissioned units) – Q3s

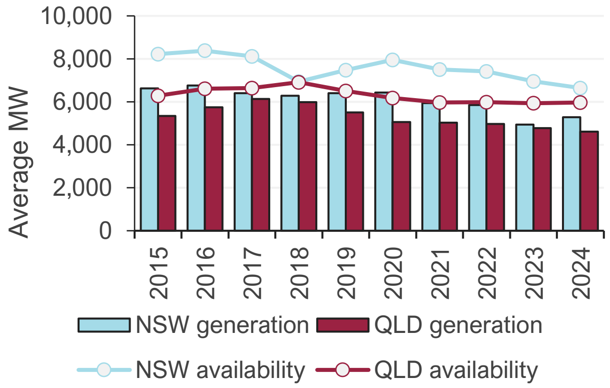
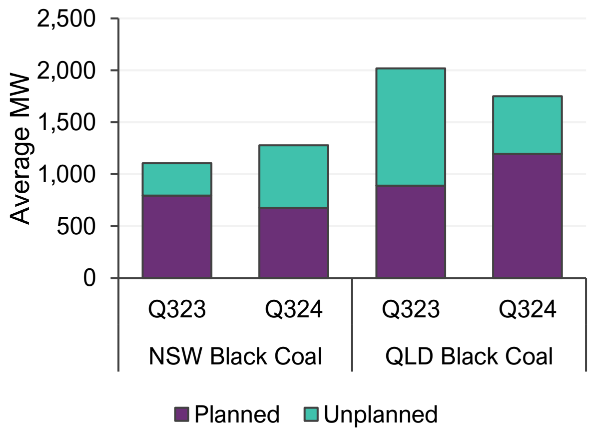



**Figure 33 Capacity on full unit outage decreased**

Average black coal-fired capacity on full outage – Q3 2024 vs Q3 2023




New South Wales black coal-fired generators drove the uplift in output, with a 342 MW (+7%) increase from these units, offseting a 167 MW (-4%) decrease in output from the Queensland black coal-fired generators. These relative changes in output aligned with the year-on-year change in offer volumes with New South Wales fleet offering around 120 MW to 570 MW more volume at prices bands between \$20/MWh to \$100/MWh (Figure 34) and the Queensland fleet offering around 250 MW to 600 MW less volume in the same range (Figure 35).

**Figure 34 Increase in black coal volumes offered at lower prices in New South Wales**

New South Wales black coal bid supply curve – Q3 2024 vs Q3 2023

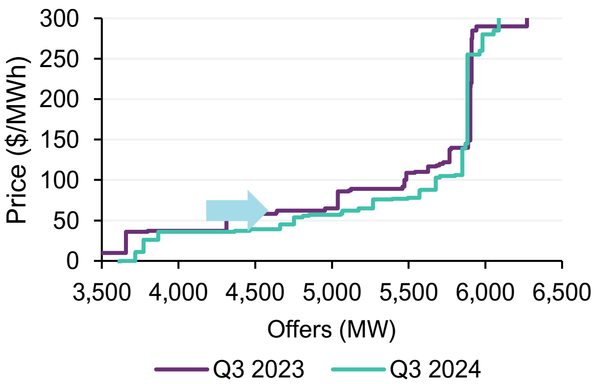



**Figure 35 Decrease in black coal volumes offered in most price bands in Queensland**

Queensland black coal bid supply curve – Q3 2024 vs Q3 2023

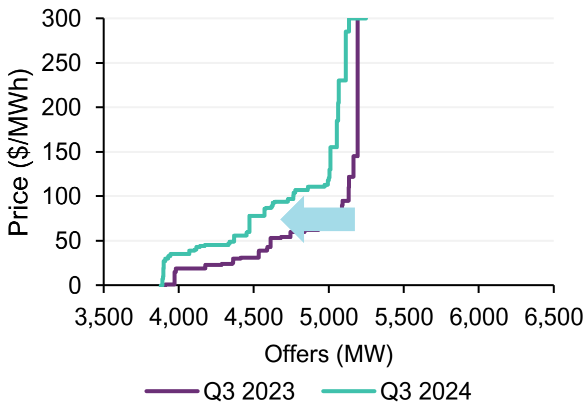


Figure 36 shows availability, generation and utilisation rates for the New South Wales black coal-fired power stations. In Q3 2024, total quarterly average generation across these stations increased to 5,286 MW, despite a 307 MW (-4%) reduction in total quarterly average availability to 6,644 MW. This decrease in availability was driven by a 172 MW (+16%) increase in average capacity on full unit outage across the quarter, combined with increases in partial outages at some units.

Fewer outages at Bayswater over this quarter, with 74 MW less capacity on full-unit outage, drove an increase in availability of 100 MW (+4%) and helped to support an 363 MW (+24%) uplift in output compared to Q3 2023.

Mt Piper had a signifcant 19 pp uplift in utilisation with output increasing by +119 MW (+15%) despite an 176 MW (-13%) decrease in availability driven by an additional 223 MW average capacity on full unit outage (after only having 1 MW average capacity on full unit outage during Q3 2023).

Eraring and Vales Point B both recorded year-on-year decreases in output at 65 MW (-4%) and 75 MW (-9%), respectively, alongside reduced availability. Despite Eraring unit 3 commencing a maintenance outage in late August (scheduled to complete in November 2024), the power station overall had 23 MW less average capacity on full outage over the quarter than during Q3 2023. Availability over the quarter was reduced by 82 MW (-4%) compared to the previous year with a number of units having periods of limited availability throughout the quarter.

Vales Point B also experienced a number of partial outages limiting maximum output over the quarter contributing to availability reducing by 149 MW (-12%), including a 47 MW increase in capacity on full outage compared to Q3 2023.

**Figure 36 Utilisation rates increased at all New South Wales black coal-fired power stations**

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q3 2024 vs Q3 2023

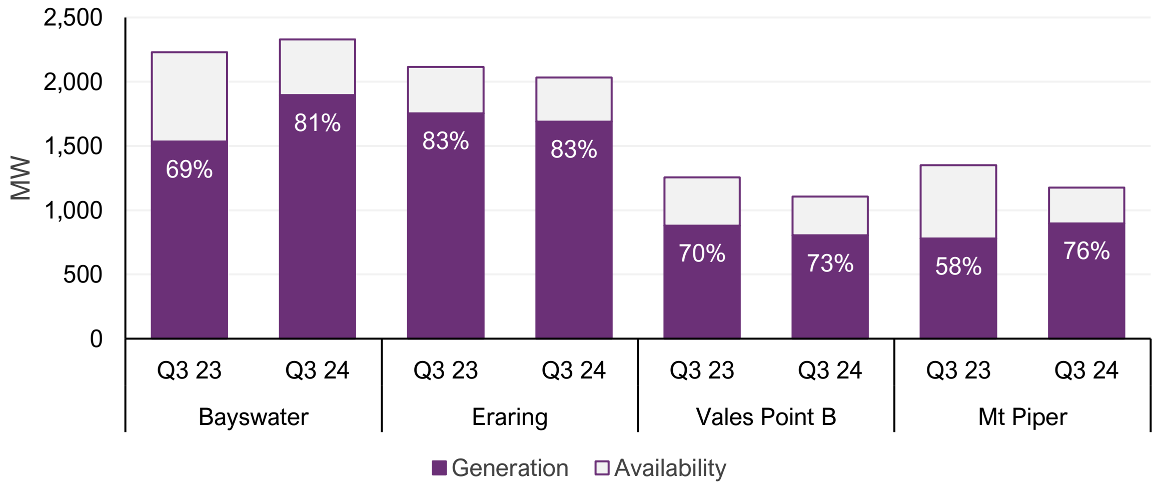


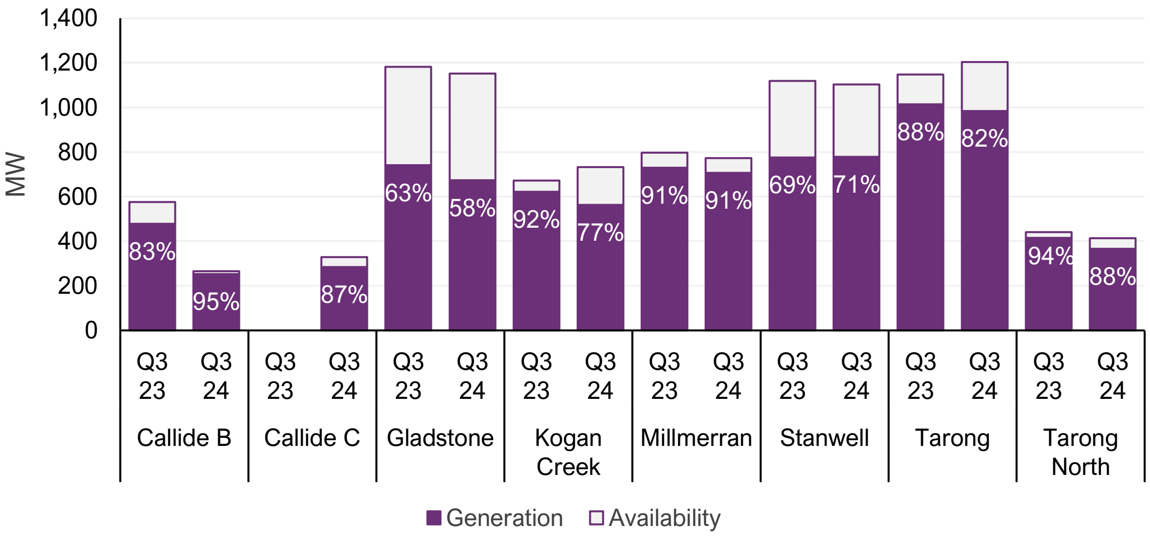

Figure 37 shows availability, generation and utilisation rates for the Queensland black coal-fired power stations. Average quarterly generation across these stations in Q3 2024 decreased to 4,606 MW, despite a small increase in availability to 5,970 MW, up 36 MW (+1%). Full unit outages decreased, with an average of 269 MW (-13%) less capacity on full outage over the quarter, aided by the return of Callide C power station after its extended outage (with unit C3 first returning to service on 1 April 2024 and unit C4 returning to service on 30 August 2024). However, these gains in availaiblity were partially offset by a number of partial outages reducing the maximum availability of some units over the quarter.

Compared to Q3 2023, Callide C had the most significant increase in average output (+284 MW) and availability (+328 MW). Stanwell was the only other Queensland station to record an increase in average generation from Q3 2024, with a small 3 MW (+0.4%) increase in output.

Callide B had the most significant decrease in average output, with a near halving of output to 252 MW (-47%), with a number of partial and full outages reducing availability by more than half to 265 MW (-54%). The most notable decrease in utilisation was at Kogan Creek, with output down by 60 MW (-10%), despite an additional 60 MW (+9%) of availability, leading to utilisation reducing from 92% in Q3 2023 to 77% this quarter.

**Figure 37 Decreased output at Queensland coal-fired power stations except Callide C and Stanwell**

Average quarterly availability and generation for Queensland black coal-fired power stations – Q3 2024 vs Q3 2023




Compared to Q3 2023, intraday swing in New South Wales decreased by 348 MW, to 3,145 MW, with the average output level in the evening peak reaching similar levels, but with a higher middle of the day trough consistent with higher operational demands (Figure 38). Intraday swing in Queensland also reduced, by 128 MW to 2,004 MW this quarter, but with the middle of the day trough at a similar level to during Q3 2023 and the average evening peak output level reduced (Figure 39).

**Figure 38 Increase in New South Wales black coal generation during the middle of the day**

New South Wales black coal-fired output by time of day – Q3s

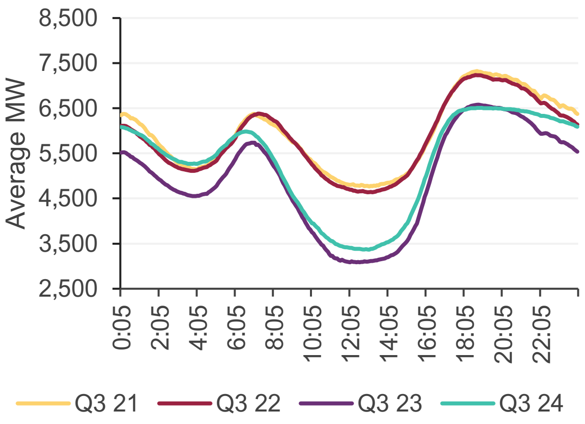
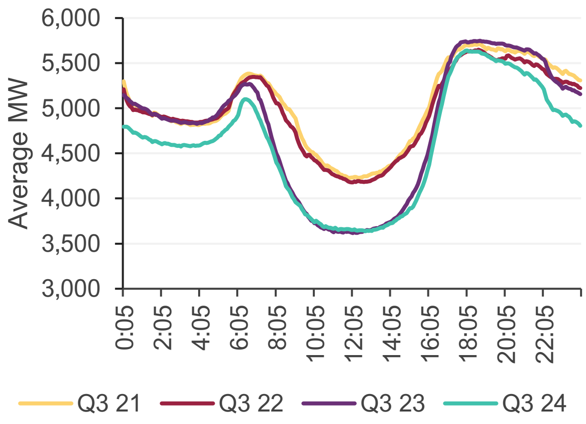



**Figure 39 Decrease in Queensland black coal generation in evening peak and overnight**

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




## Brown coal-fired fleet

In Q3 2024, quarterly average brown coal-fired generation was 3,703 MW, 27 MW (-0.7%) lower than during Q3 2023 (Figure 40), with increases in output at Yallourn W (+162 MW) and Loy Yang B (+42 MW) offset by a reduction in Loy Yang A output (-231 MW). Quarterly average availability increased by 41 MW (+1.0%), with an average of 51 MW (-9%) less capacity on full unit outage.

Intraday swing reduced from 1,031 MW in Q3 2023 to 953 MW in Q3 2024, with average output slightly elevated across the middle of the day, supported by higher operational demand across all hours of the day, and slightly lower in the evening peak (Figure 41).

**Figure 40 Brown coal-fired generation decreased**

Quarterly average black coal-fired generation and availability (including decommissioned units) – Q3s

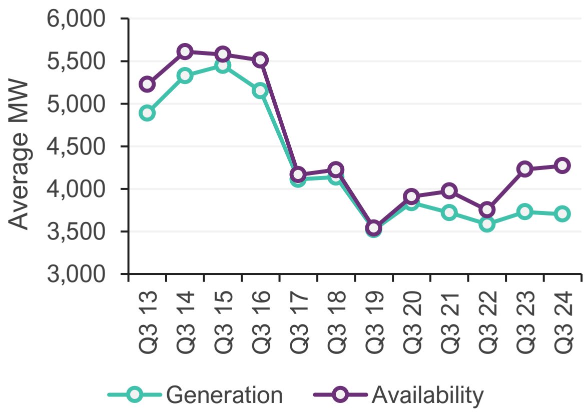
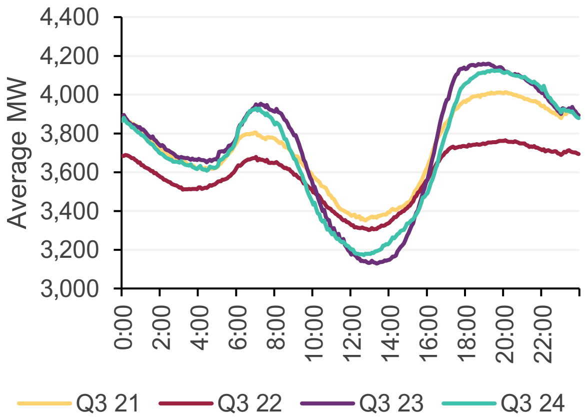



**Figure 41 Brown coal output slightly lower in evening and morning peaks**

Brown coal-fired output by time of day – Q3s




Loy Yang B and Yallourn recorded increases in output and availability this quarter compared to Q3 2023, with reduced capacity on full unit outage (Table 5). In contrast, Loy Yang A had more capacity on full unit outage this quarter leading to lower availability and output. All Victorian brown coal-fired stations experienced reductions in utilisation this quarter.

**Table 5 Brown coal availability, output, utilisation, outage, and intraday swing by generator – Q3 2024 vs Q3 2023**

| Generator | Availability (MW) | | Output (MW) | | Utilisation | | Outage (MW) | | Intraday swing (MW) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Q3 23 | Q3 24 | Q3 23 | Q3 24 | Q3 23 | Q3 24 | Q3 23 | Q3 24 | Q3 23 | Q3 24 |
| Loy Yang A | 2,155 | 1,917 | 1,825 | 1,595 | 85% | 83% | 30 | 279 | 695 | 488 |
| Loy Yang B | 1,092 | 1,163 | 986 | 1,028 | 90% | 88% | 61 | 0 | 219 | 300 |
| Yallourn W | 981 | 1,190 | 919 | 1,080 | 94% | 91% | 464 | 225 | 128 | 172 |

### 1.3.2 Gas-fired generation

During Q3 2024, gas-fired generation across the NEM averaged 1,493 MW, 337 MW (+29%) higher than Q3 2023 when gas-fired generation recorded its lowest Q3 level since 2004 (Figure 42). There was higher gas-fired output across all NEM regions, most significantly in July (up 63% year-on-year) and August (up 21%) reflecting higher operational demands and increased electricity spot prices during these months, before reducing in September (down 10% year-on-year).

- The most significant uplift in gas-fired generation occurred in Tasmania, driven by low hydro generation in response to low hydro storage levels in Tasmania (see Section 1.3.3). Average quarterly generation was 104 MW in Q3 2024, 97 MW higher than during Q3 2023 and the highest quarterly average recorded for a Q3 since 2012. This uplift was concentrated in the winter months, with average monthly generation of 158 MW and 150 MW in July and August, respectively, before reducing to just 2 MW in September.
- With higher operational demand and spot prices, gas-fired generation was also higher in the winter months in Victoria compared to Q3 2023, with quarterly average generation increasing by 117 MW (+143%) to 198 MW. Most of this uplift came from increased output at Mortlake (+48 MW, +109%) and Newport (+45 MW, +321%).
- South Australian gas-fired generation averaged 439 MW this quarter, an increase of 34 MW (+8%) from Q3 2023, with higher output at Torrens Island B (+68 MW, +114%) and Osborne (+30 MW, +95%) offsetting lower output at Pelican Point (-90 MW, -41%).
- All New South Wales gas-fired generators, except Tallawarra A (down 34 MW, -35%), contributed to the 40 MW (+25%) increase in output from Q3 2023 to reach a quarterly average of 196 MW this quarter. The largest uplifts in output were at Shoalhaven Starches (+39 MW) and Tallawarra B (+16 MW) – both newly commissioned since Q3 2023.
- Queensland gas-fired generation averaged 556 MW across Q3 2024, a 49 MW or 10% increase, with average output higher during the morning and evening hours, and slightly lower during solar generation hours compared to Q3 2023.

Consistent with higher operational demands, and higher wholesale prices, NEM gas-fired generators offered more volume at most price bands compared to during Q3 2023. On average over the quarter, they offered around 130 MW to 270 MW more volume at price bands between \$100/MWh to \$300/MWh, increasing to around 230 MW to 470 MW more volume at price bands between \$300/MWh to \$1,000/MWh (Figure 43).

**Figure 42 Gas-fired generation higher than Q3 2023 in all NEM regions**

Average gas-fired generation by region – Q3s

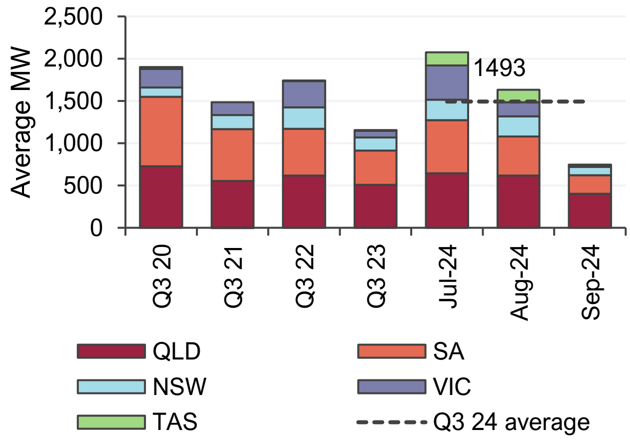
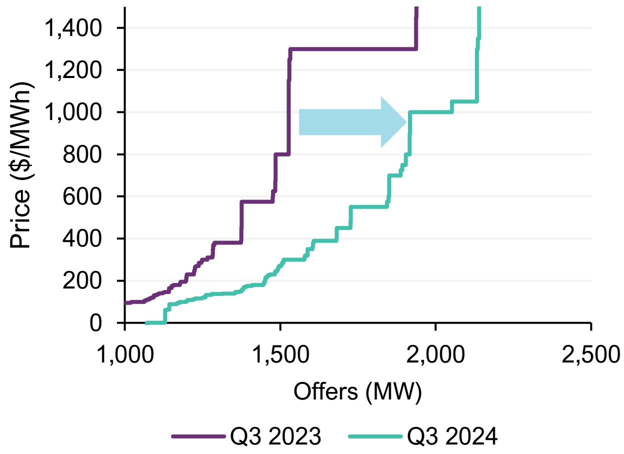



**Figure 43 Gas offer volumes increased**

Gas-fired generation bid supply curve – Q3 2024 vs Q3 2023



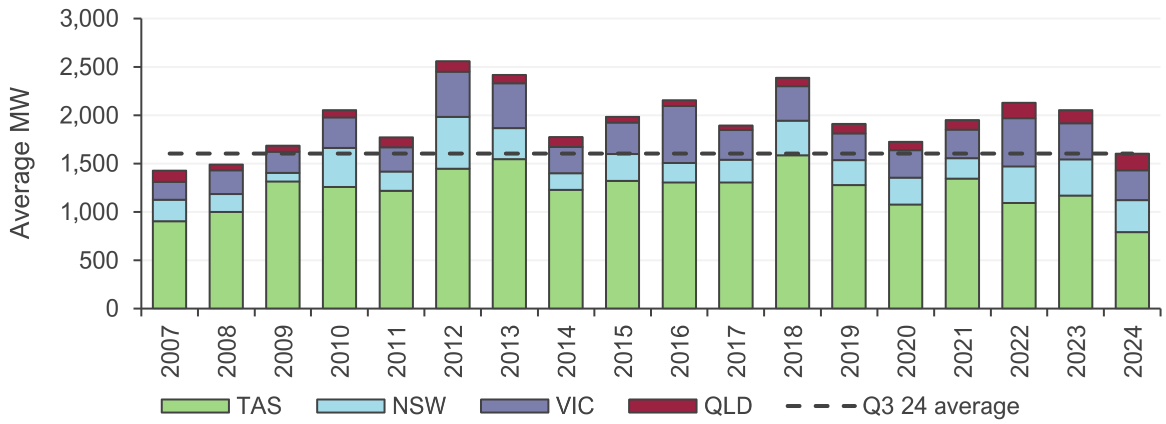

### 1.3.3 Hydro

Hydro generation[12] decreased by 449 MW (-22%) compared to Q3 2023, with quarterly average generation reaching its lowest Q3 level since 2008 at 1,603 MW (Figure 44). This decrease was most notable in the winter months, with average monthly generation reduced year-on-year by 26% in July to 1,699 MW, and by 31% in August to 1,499 MW, before averaging 1,613 MW in September, down only 4% from September 2023.

The reduced generation over Q3 2024 was driven by a reduction in low priced volumes offered by hydro generation, with 640 MW to 1,060 MW less volume offered at price bands between $50/MWh to $300/MWh (see Figure 13 in Section 1.2.1).

**Figure 44 Hydro generation decreased in all regions except Queensland to reach lowest Q3 level since 2008**

Average hydro output by region – Q3s




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

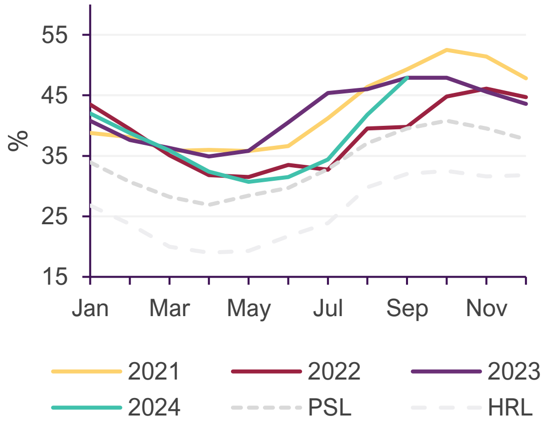
Tasmanian hydro generation averaged 791 MW over the quarter, a 377 MW (-32%) reduction from Q3 2023, representing the lowest Q3 level recorded since Basslink connected Tasmania to the NEM in 2006.

Following on from low rainfall in Tasmania during Q2 2024, average monthly generation levels in July and August were 58% and 52% below longer-term (2006-2023) averages, respectively.

With increasing rainfall levels over August and September[13], hydro generation lifted to 83% of the longer-term September average level, and energy storage levels rose strongly to reach 48% at the end of the quarter (Figure 45).

**Figure 45 Tasmanian energy in storage rose steadily from Q2 lows**

Month-end Tasmania energy storage levels in percentage compared to prudent storage level (PSL) and high reliability level (HRL)[14]




Across the mainland regions, quarterly average hydro generation decreased by 72 MW (-8%) from Q3 2023, with reductions across New South Wales (-42 MW or -11%), and Victoria (-69 MW or -18%), partially offset by an increase in Queensland hydro generation (+39 MW or +29%).

### 1.3.4 Wind and grid-scale solar

In Q3 2024, average NEM VRE generation reached a record quarterly high of 5,504 MW, surpassing the previous record set in Q4 2023 by 336 MW. Compared to Q3 2023 average VRE generation increased by 636 MW (+13%), with a 704 MW (+21%) increase in wind generation more than offsetting a 68 MW (-4.5%) decrease in grid-scale solar generation (Figure 46).

The year-on-year growth in wind output was concentrated in New South Wales (+292 MW), South Australia (+226 MW) and Victoria (+192 MW) with only small changes in wind output in Queensland and Tasmania (Figure 47).

[13] The area-averaged rainfall total for Tasmania was 25.6% and 44.6% above the 1961-1990 average for August and September respectively. See http://www.bom.gov.au/climate/current/month/tas/archive/202408.summary.shtml and http://www.bom.gov.au/climate/current/month/tas/archive/202409.summary.shtml.

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

**Figure 46 Higher wind generation yielded new VRE output record**

Average quarterly VRE generation by fuel type – Q3s

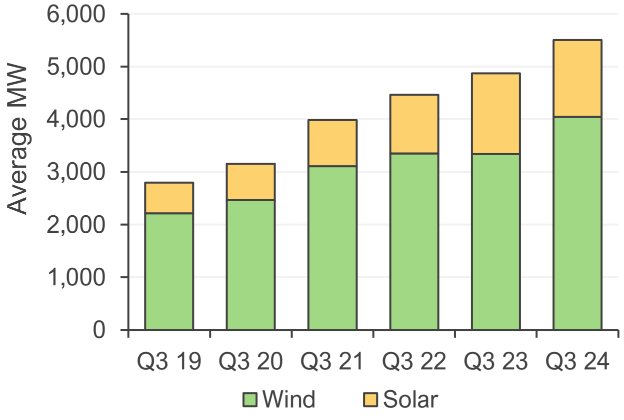
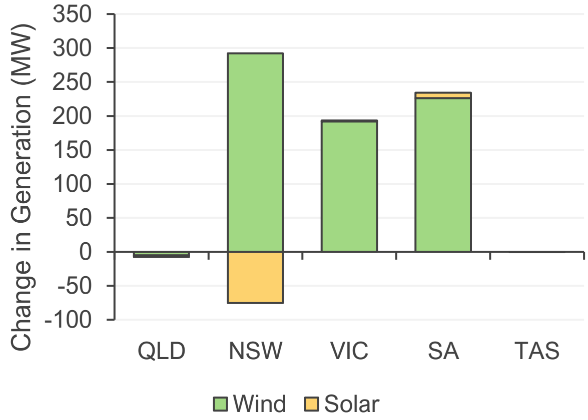



**Figure 47 Renewable growth driven by wind in New South Wales, Victoria and South Australia**

Average change in VRE output by region – Q3 2024 vs Q3 2023




## Grid-scale solar

Grid-scale solar generation averaged 1,461 MW across Q3 2024, rising during the quarter as solar exposure and duration increased. The monthly average grid-scale solar generation was just 1,305 MW in July, before increasing to 1,503 MW in August and 1,578 MW in September.

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 growth sources contributed a 122 MW increase in average quarterly grid-scale solar availability from Q3 2023 (Figure 48). However, this growth was offset by a decrease in availability at existing solar farms due to lower solar irradiance and outages for network upgrades in New South Wales, as well as an increase in economic offloading.

The majority of the increase in availability from new and commissioning solar farms occured in New South Wales, with increases at Wellington North (+53 MW) and Wyalong (+6 MW). Wandoan (+20 MW) in Queensland, Glenrowan (+20 MW) in Victoria and Tailem Bend 2 (+15 MW) in South Australia also contributed to growth in this category.

Established[15] grid-scale solar facilities showed decreases in quarterly volume-weighted available capacity factors[16] across all NEM regions, with a 1.7 pp reduction in the NEM-wide capacity factor to average 21.1% this quarter (Figure 49). Despite the 0.1 pp decrease from Q3 2023, the Queensland fleet still had the NEM's highest available capacity factor at 24.0% this quarter.

[15] 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 2024. These facilities may also appear in the "New Capacity" or "Commissioning" categories in Figure 48 and Figure 50 if they were connected or exhibited ramping activity between Q3 2023 and Q3 2024 respectively.

[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.

**Figure 48 Reduction in availability at existing solar farms and increased economic offloading**

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

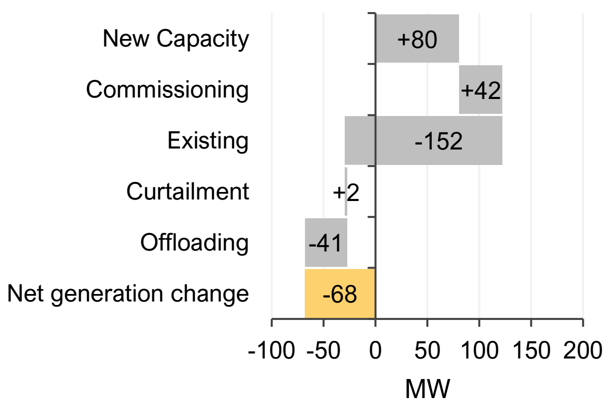
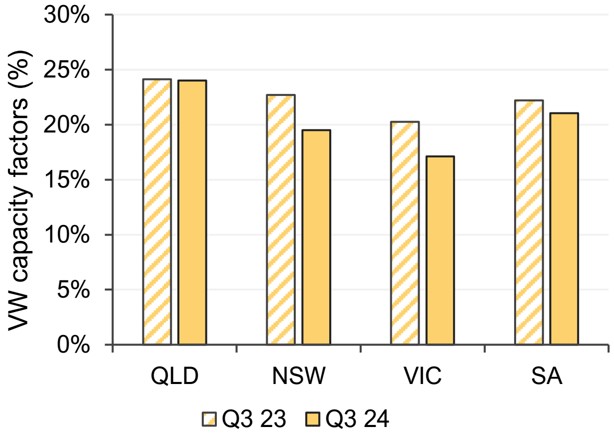



**Figure 49 Reduced availability due to lower solar irradiance and planned network outages**

Volume-weighted grid-scale solar available capacity factors[17] – Q3s




New South Wales had the largest decline in quarterly volume-weighted available capacity factors from Q4 2023, with a 3.2 pp reduction to average 19.5% over Q3 2024. This reduction in availability was a factor of both higher cloud cover over the quarter (see Figure 4 in Section 1.1.2) and planned network outages associated with the commissioning of the Buronga to Red Cliffs line between New South Wales and Victoria (part of Project EnergyConnect) and the Walla Walla substation in New South Wales. These works, undertaken around 20 to 28 September, are estimated to account for approximately 60 MW of the overall 152 MW reduction in availability from existing solar plants shown in Figure 48.

Economic offloading grew causing a 41 MW decrease in output. The increase in solar-generation offloading was largest in New South Wales, with a 36 MW increase from Q3 2023 to average 64 MW in Q3 2024 as negative price occurrence in the region grew from 9% to 12% of dispatch intervals. Across the NEM, economic offloading of solar generation was highest in Queensland at an average of 129 MW, a 4 MW increase from Q3 2023 levels.

## Wind

Average wind speeds recovered after the particularly low wind output experienced during Q2 2024, and NEM-wide quarterly wind generation averaged 4,044 MW in Q3 2024, reaching a new record – 695 MW higher than the previous record set in Q3 2022.

The year-on-year uplift in wind generation increased as the quarter progressed. Average generation across July was just 2% higher than during July 2023, but average generation in August and September was 30% and 36% higher, respectively, than during the same months in the year prior.

Compared to Q3 2023, new and commissioning wind farms added 309 MW to available capacity (Figure 50). Commissioning facilities in New South Wales, including Rye Park (+151 MW) and Flyers Creek (+34 MW), and in Queensland, Dulacca (+27 MW), drove most of this increase. New facilities including Hawkesdale (+33 MW) and Ryan Corner (+15 MW) in Victoria, and Goyder South (+24 MW) in South Australia also contributed.

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

Economic offloading of wind increased by 80 MW to average 227 MW this quarter, with the majority of this occurring in Victoria, averaging 123 MW (+32 MW), and South Australia, averaging 76 MW (+25 MW).

Quarterly volume-weighted available capacity factors at established windfarms increased, with NEM-wide capacity factors averaging 39.5% in Q3 2024, up from just 25.3% in Q2 2024, and 34.4% in Q3 2023 (Figure 51). Despite a small decrease (0.6 pp) across Tasmanian facilities, this region achieved the highest availability capacity factor at 47.1%. South Australia, with a 9.1 pp increase to 42.1% and New South Wales, with a 5.8 pp increase to 34.9% had the most significant year-on-year increases in in quarterly volume-weighted available capacity factors.

**Figure 50 Growth in output from new, commissioning and existing wind farms**

Changes in wind generation – Q3 2024 vs Q3 2023

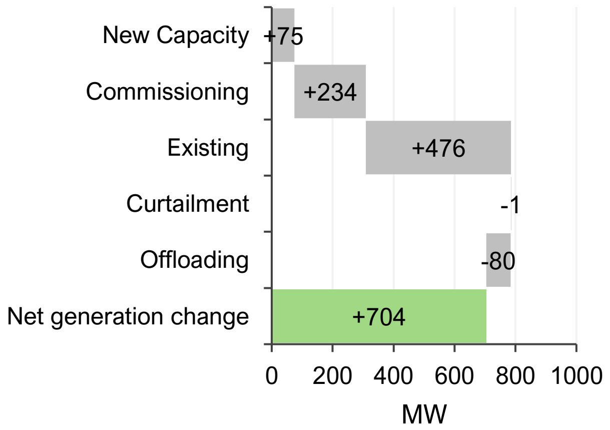



**Figure 51 Wind availability up in New South Wales, Victoria and South Australia**

Volume-weighted wind available capacity factors – Q3s


## Curtailment

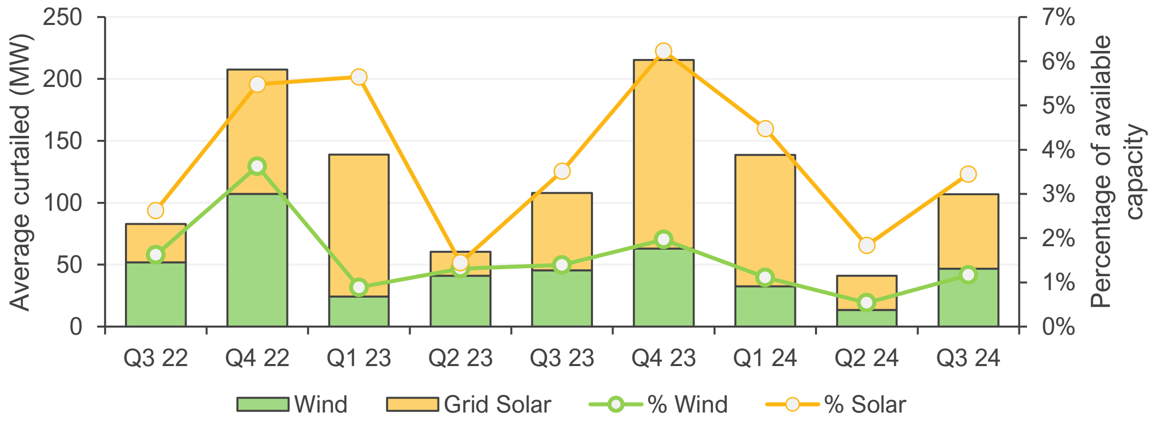
Curtailment[18] remained relatively flat compared to Q3 2023, with an average of 47 MW (+1 MW) of wind capacity curtailed, and 60 MW (-2 MW) of solar capacity curtailed in Q3 2024 (Figure 52). Overall curtailment was most significant in Victoria in Q3 2024, at 47 MW (30 MW wind and 17 MW solar), a 16% increase from Q3 2023 levels. New South Wales had the next highest level of curtailment during Q3 2024 with 43 MW (38 MW solar and 5 MW wind), an increase of 19% from Q3 2023.

Offsetting these increases, curtailment in South Australia more than halved, down from 22 MW in Q3 2023 to an average of 9 MW this quarter.

[18] Curtailment is calculated as '(Availability – Generation) – Economic Offloading'.

**Figure 52 Wind and solar curtailment remained relatively flat year-on-year**

Average MW curtailment and as percentage of availability by fuel type

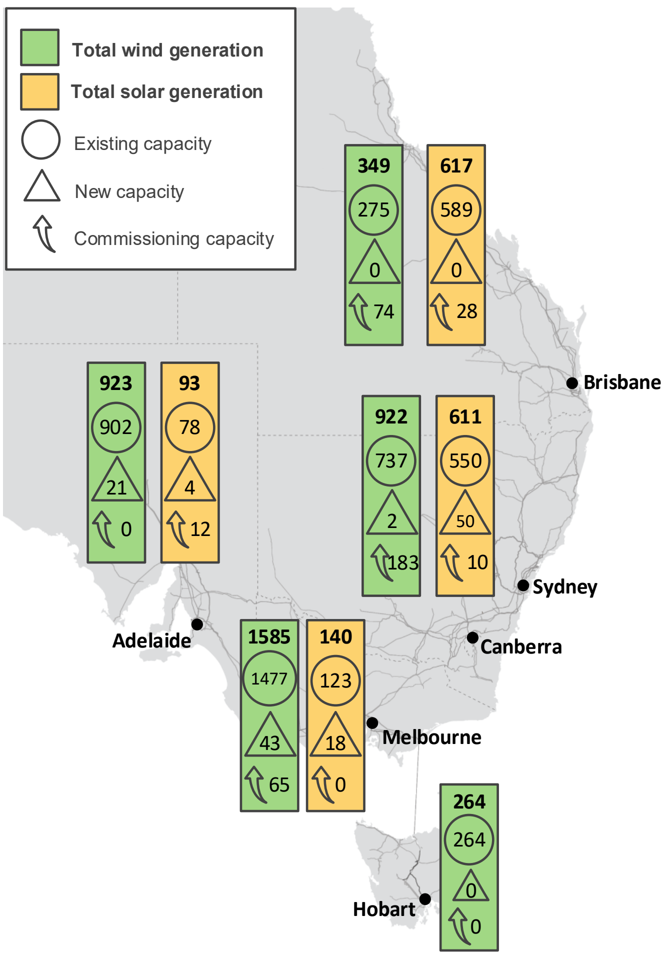



## VRE generation summary

The map in Figure 53 shows a summary representation of VRE output during Q3 2024. Numbers presented in this map are in megawatts and are calculated on a quarterly average basis.

**Figure 53 Regional VRE generation summary during Q3 2024**

Quarterly average generation (MW) by fuel type and region



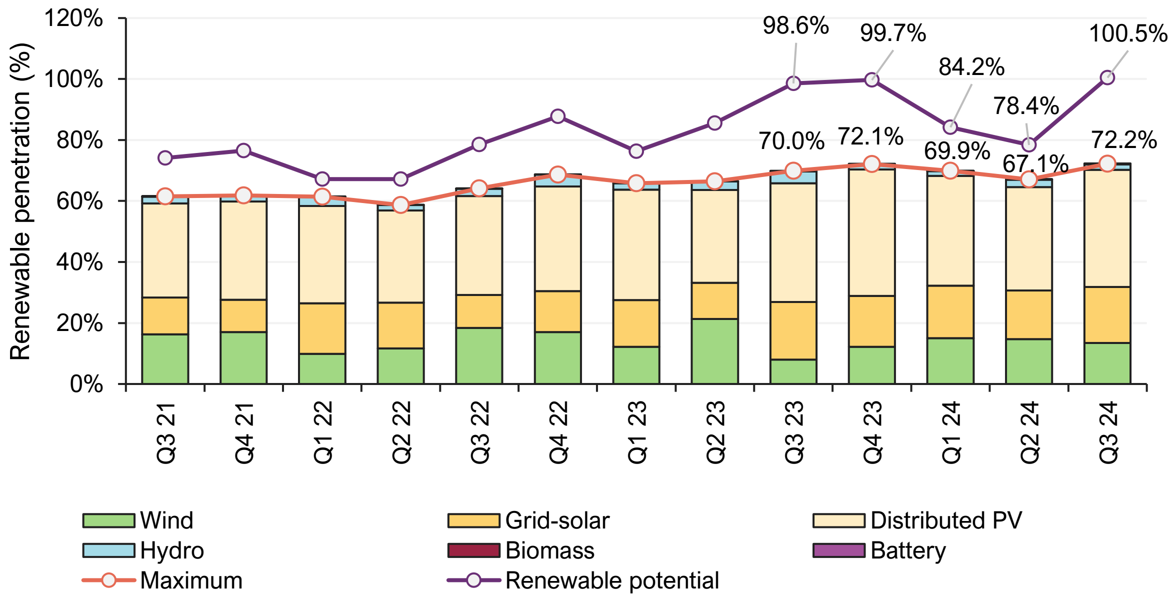
### 1.3.5 Renewables contribution

#### Peak renewable contribution

This quarter saw a new record[19] for peak renewable contribution, reaching 72.2% during the half-hour interval ending at 1200 hrs on Monday, 9 September 2024, slightly higher than the previous record of 72.1% set on 24 October 2023. At the time of the new record, distributed PV contributed 38.5% of total generation, while grid-scale solar and wind provided 18.3% and 13.4% respectively (Figure 54).

**Figure 54 Peak renewable contribution and potential reached all-time highs**

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




Throughout the quarter, renewable contribution exceeded 70% during 79 half-hour intervals.

Figure 55 illustrates the expanding range of minimum and maximum renewable contribution, which reached a 62% swing in Q3 2024, driven by a high of 72.2% and a low of 10.2%. The quarter's minimum renewable contribution occurred during the half-hour ending at 0400 hrs on Friday, 12 July 2024, and was 7.3 pp lower than Q3 2023's 17.5%. This decline was driven primarily by reduced hydro output, which accounted for just 5.5% during this interval, compared to 12.8% during the minimum renewable contribution interval in Q3 2023.

During this quarter, Queensland also set a new record for peak renewable contribution, reaching 67.6% during the half hour interval ending at 1230 hrs on Monday, 30 September 2024 (Figure 56).

[19] A new record for peak renewable contribution was set after the end of quarter. The new record of 74.8% was set at the half-hour ending 1100 hrs on Sunday, 20 October 2024.

**Figure 55 Renewable contribution range widened**

Range of NEM supply share from renewable energy sources – Q3s

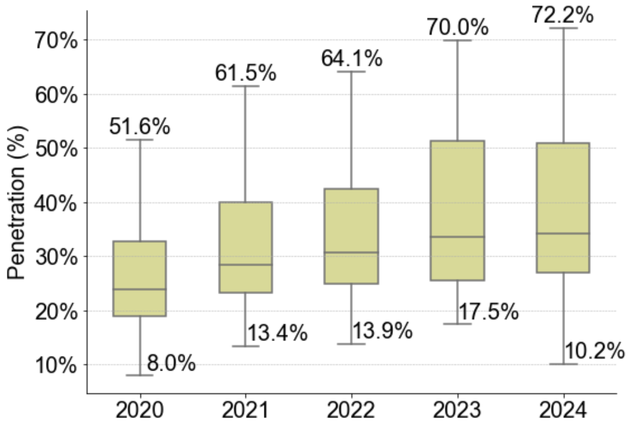
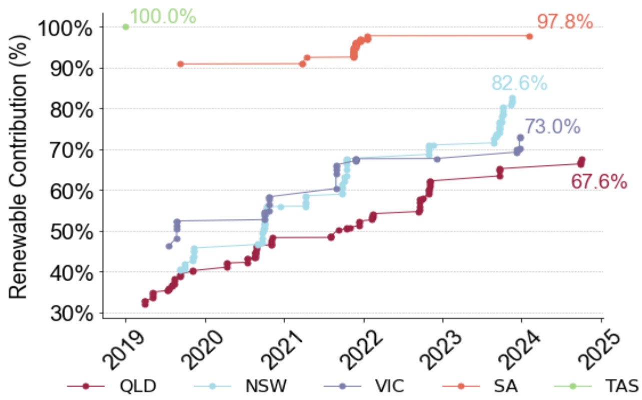



**Figure 56 Record high renewable contribution in Queensland**

Change in peak renewable contribution record by region

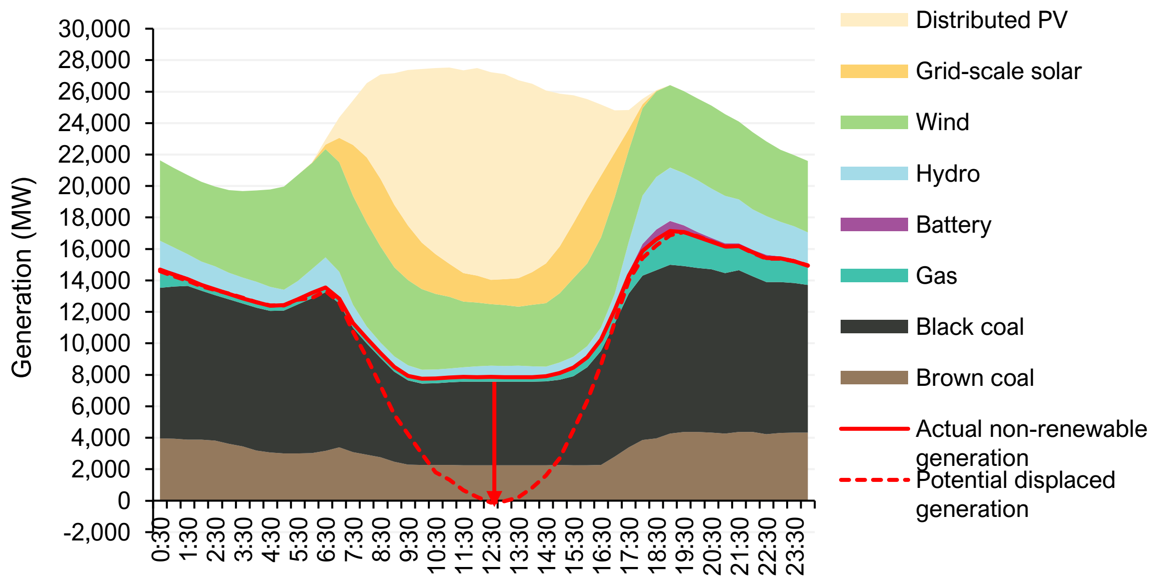



## Peak renewable potential

Renewable potential[20] also set an all-time high of 100.5% during the half-hour ending at 1230 hrs on Wednesday 18 September 2024, 0.8 pp higher than the previous record of 99.7% set on 1 October 2023. At this time, distributed PV share reached a record high of 48.5% of total generation, while the actual renewable contribution was at 71.1%. In this half-hour, out of a total 13,438 MW available, 7,999 MW of wind and grid-scale solar energy sources was not dispatched, mostly due to economic offloading (7,737 MW). If these sources could have been dispatched at maximum availability together with the actual dispatched output from other renewable sources, total renewable output would have surpassed the NEM's total supply requirement by 124 MW (Figure 57).

**Figure 57 Record high peak renewable potential on Wednesday 18 September 2024**

Output by fuel type and potential renewable output – 18 September 2024




[20] 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.

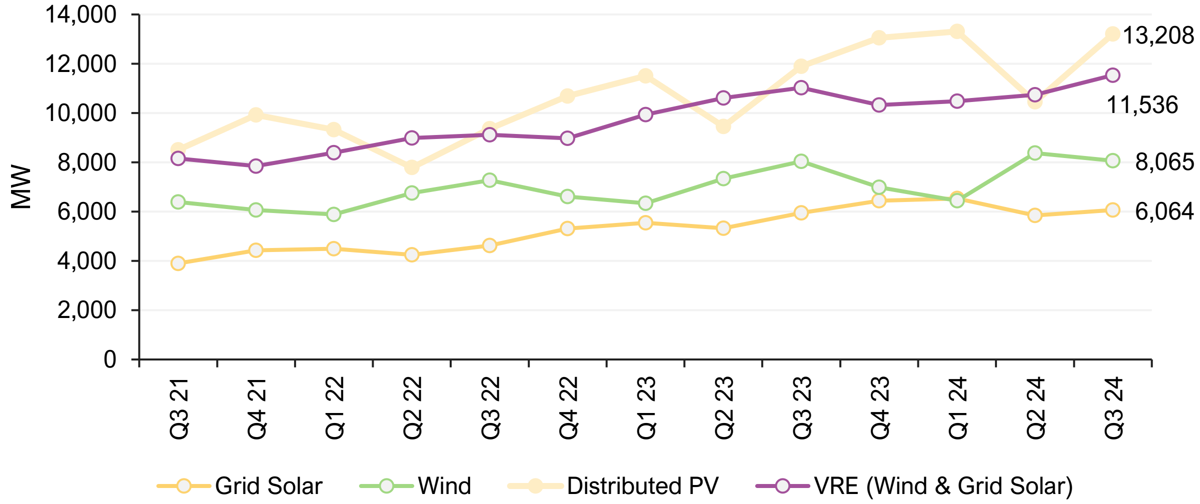
This quarter saw peak renewable potential exceed 100% in two consecutive half-hour periods, marking a key milestone in the transition towards operation at times with 100% renewable supply. Achieving very high levels of actual peak contribution of renewables, at times up to 100%, depends upon market responses to energy prices as well as essential system services needs, alongside the technical readiness to operate a secure and reliable power system without fossil fuels. AEMO's Engineering Roadmap[21] is a body of work that aims to remove barriers to running a secure and reliable power system at times of very high renewable penetration.

## Maximum peak renewable output

Figure 58 shows the maximum grid-scale solar, wind, and distributed PV outputs since Q3 2021. This quarter saw record Q3 outputs for both grid-scale solar and wind, at 6,064 MW and 8,065 MW respectively. Distributed PV reached a new Q3 high of 13,208 MW at 1230 hrs on Wednesday, 18 September, slightly lower (-1%) than the all-time high of 13,311 MW set in Q1 2024. VRE, combining wind and grid-scale solar, achieved a record output of 11,536 MW at 0900 hrs on Saturday, 20 July 2024.

**Figure 58 Record high for peak VRE output, Q3 highs for grid-scale solar, wind and distributed PV**

Maximum quarterly peak generation by fuel type




## Renewable contribution to maximum demand

Figure 59 illustrates the average contribution of large-scale renewable generation to meeting daily maximum NEM operational demand. In Q3 2024, the average renewable contribution rose to a new high of 29.9%, driven largely by wind generation, which supplied 14.7%. Battery generation also saw an uptick, contributing 1.6%, up from 0.9% in Q3 2023.

Since daily maximum demand typically occurs during evening peak periods in Q3, solar's contribution remained minimal, while hydro's share declined to 13.4% from 14.8% the previous year. The highest renewable contribution to meeting daily maximum demand during this quarter was 41.2%, while the minimum was 18.2%.

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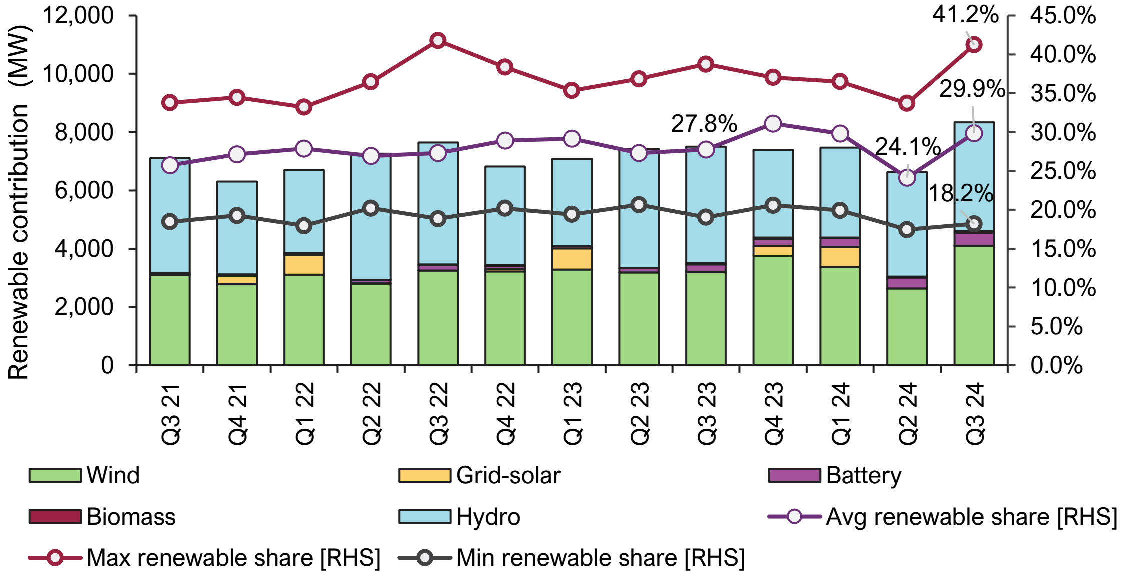
[21] AEMO, *Engineering Roadmap to 100% Renewables*, at https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

**Figure 59 Increased renewable contribution to meet daily maximum demand**

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

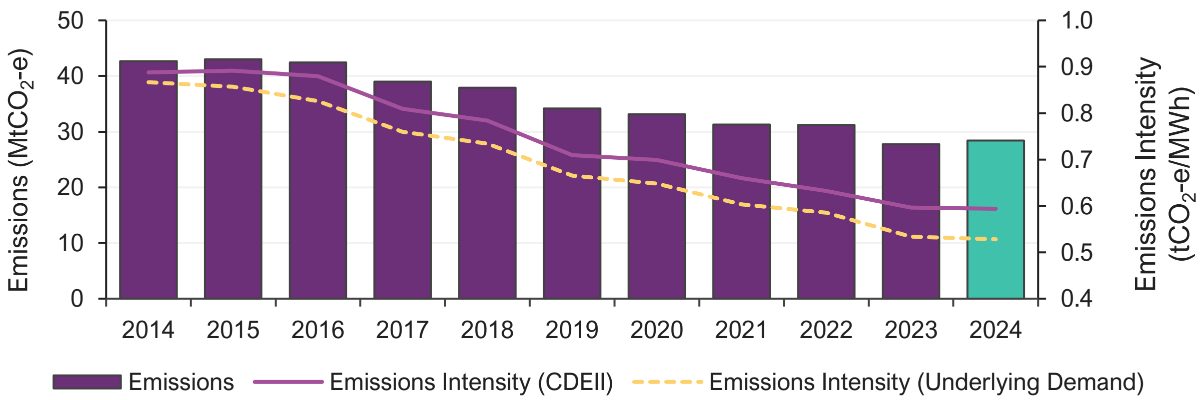



## 1.3.6 NEM emissions

In Q3 2024, total emissions across the NEM amounted to 28.4 million tonnes of carbon dioxide equivalent (MtCO2-e), an increase of 0.7 MtCO2-e (+2%) compared to Q3 2023 levels (Figure 60). The Carbon Dioxide Equivalent Intensity Index (CDEII) emissions intensity is measured by combining sent out metering data with publicly-available generator emissions and efficiency data, to provide a NEM-wide CDEII[22]. This emissions intensity excludes generation from distributed PV, taking into consideration only sent out generation from market generating units. This quarter, CDEII Emissions intensity averaged 0.59 tCO2-e/MWh, slightly lower than Q3 2023's 0.60 tCO2-e/MWh, reflecting the slightly lower volume share of combined coal and gas-fired generation.

**Figure 60 Emissions increased compared to Q3 2023, while emissions intensity decreased**

Quarterly NEM emissions and intensity – Q3s




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

When using underlying demand to calculate emissions intensity, which accounts for the impact of distributed PV, the NEM-wide emissions intensity averaged 0.53 $tCO_2$-e/MWh for Q3 2024, 0.07 lower than the CDEII intensity metric. This highlights the contribution of distributed PV in reducing overall emisisons intensity.

### 1.3.7 Storage

#### Batteries

This quarter, estimated net revenue for NEM grid-scale batteries surged to $76.3 million, growing 135% from the $32.5 million earned in Q3 2023 (Figure 61). Energy arbitrage[23] revenue increased significantly, rising by $46.5 million (+265%) to $64.1 million. This was driven by a $56.1 million (+258%) uplift in energy revenue (including revenue from charging at negative prices), which more than offset the $9.5 million (+230%) increase in energy costs.

In contrast, frequency control ancillary services (FCAS) revenue fell by $2.7 million (-18%) to average $12.2 million this quarter. As a result, the proportion of revenue deriving from the FCAS markets declined to 16%, compared to 46% in the previous year (Figure 62).

**Figure 61 Increase in battery revenue from higher energy arbitrage**

Quarterly revenue from NEM battery systems by revenue stream

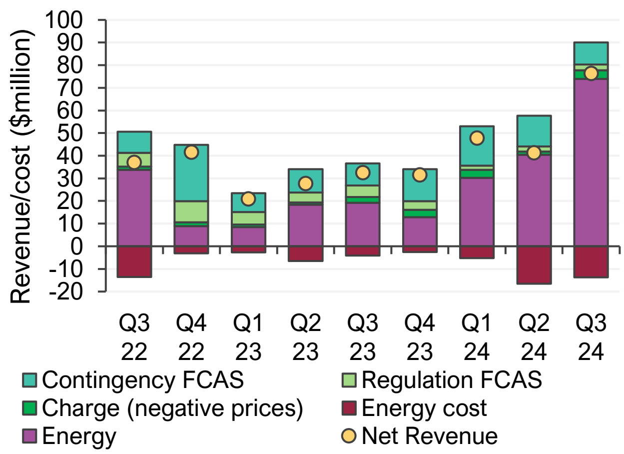
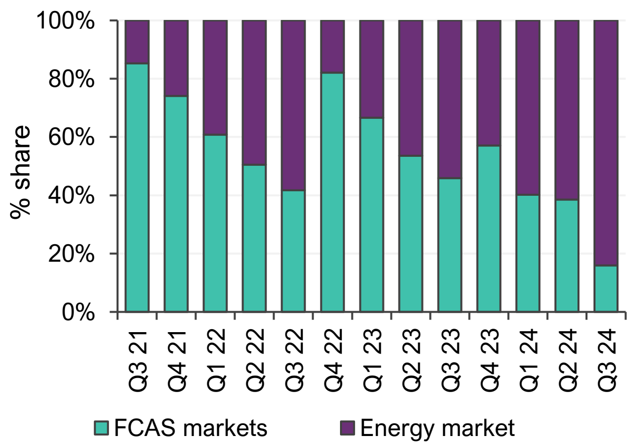



**Figure 62 Significant drop in proportion of battery revenue from FCAS markets**

Percentage share of battery revenue – energy vs FCAS markets




The rise in energy arbitrage revenue across the NEM was driven by increased battery generation and a wider price spread[24] (Figure 63). This quarter, NEM-wide price spread averaged $339/MWh, significantly up from $150/MWh in Q3 2023, reflecting higher price volatility that saw battery operators capture more value during peak prices. Of the $78 million in energy revenue (including revenue from charging at negative prices), approximately 56% ($43 million) was earned by dispatching at prices exceeding $300/MWh.

[23] 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).

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

Battery generation across the NEM averaged 86 MW this quarter, a 33 MW (+62%) increase compared to Q3 2023, driven by expanding battery capacity and availability. NEM-wide average battery availability grew by 58%, from 625 MW in Q3 2023 to 990 MW in Q3 2024 (Figure 64).

**Figure 63 Increase in NEM-wide price spread**

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

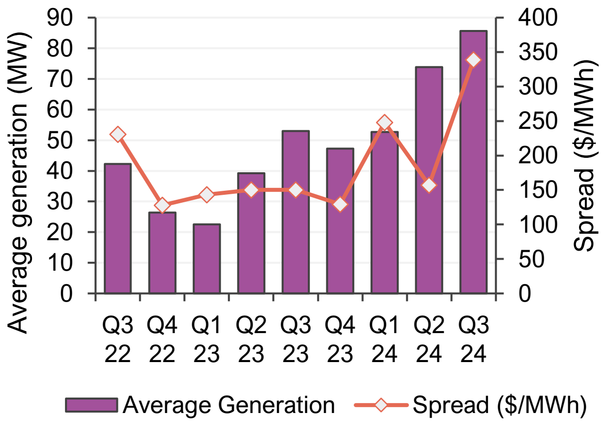
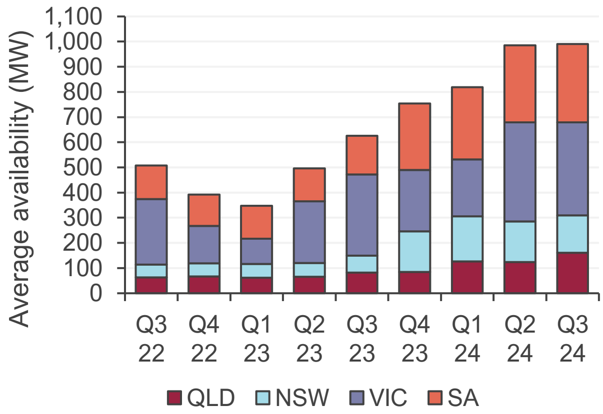



**Figure 64 Year-on-year increase in battery availability in all mainland regions**

Average quarterly battery generation availability




While all regions experienced growth in energy arbitrage revenue, Victoria and South Australia stood out, with energy arbitrage revenue for Victorian batteries increasing by $13.9 million (+175%) and for South Australia by $18.0 million (+319% ). In Victoria availability increased by 47 MW (+14%), while the price spread increased sharply from $137/MWh in Q3 2023 to $292/MWh in Q3 2024. Similarly South Australian batteries captured a $492/MWh price spread in Q3 2024 compared to $190/ MWh in Q3 2023.

New South Wales experienced the largest percentage increase in availability, adding 82 MW (+121%) to average 149 MW this quarter, accompanied by an $8.8 million (+480%) boost in energy arbitrage revenue. Queensland saw energy arbitrage revenue rise by $5.8 million (+271%) with a 79 MW (+97%) increase in availability.

Several major battery systems commenced commissioning activities in Q3 2024, including Waratah (850 MW, 1,680 MWh) in New South Wales, Blyth (200 MW, 400 MWh) in South Australia and Rangebank (200 MW, 400 MWh) in Victoria.

## Pumped hydro

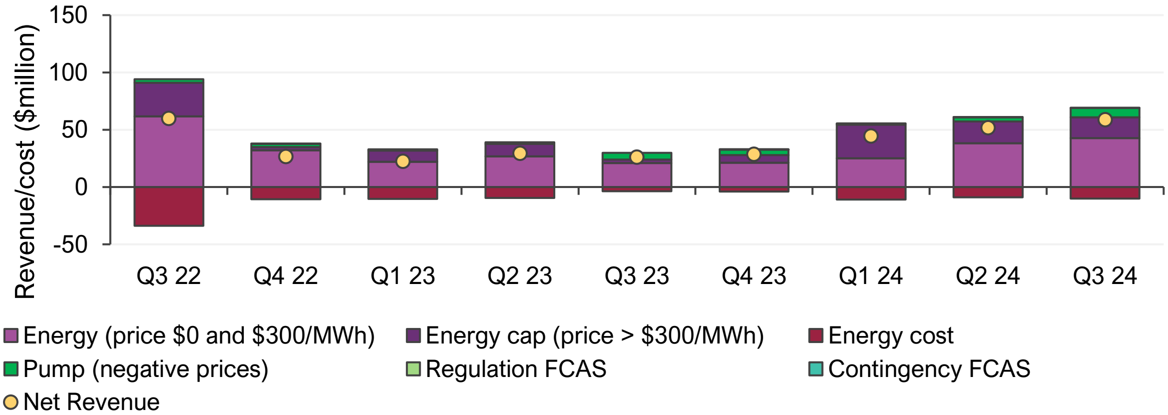
Pumped hydro revenue reached $58.9 million this quarter, a notable increase of $32.6 million (+124%) from Q3 2023 (Figure 65).

This growth was driven by increased output and higher spot price volatility, particularly in Queensland, where Wivenhoe's revenue from prices exceeding $300/MWh surged by $13.4 million (+524%) to $16.0 million. Wivenhoe's estimated net revenue for this quarter reached $49.2 million, a significant increase of $25.8 million (+110%) from the previous year. This growth was driven by a 36% year-on-year rise in generation, with Wivenhoe's quarterly output averaging 91 MW this quarter. This marks its all-time highest quarterly output, surpassing the previous record of 80 MW set in Q4 2023 by 11 MW.

Shoalhaven also experienced a strong revenue uplift, with estimated net revenue rising by $6.8 million (+231%). This was largely due to a $7.0 million (+177%) increase in revenue from prices below $300/MWh and an additional $1.7 million (+292%) from prices above $300/MWh.

**Figure 65 Pumped hydro revenue increased year-on-year**

Quarterly revenue from NEM pumped hydro by revenue stream

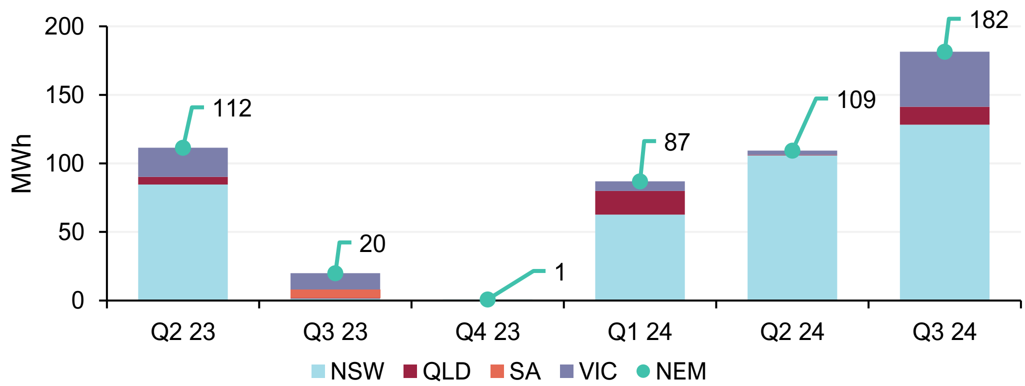



## 1.3.8 Demand side flexibility

Consumer energy resources (CER) continued to be installed at high rates, with distributed PV output reaching a new Q3 record of 2,539 MW this quarter. In Q3 2024, wholesale demand response (WDR) dispatch totalled 182 MWh, a sharp increase of 162 MWh from the 20 MWh in Q3 2023 (Figure 66). This marked the second highest quarterly dispatch volume since the WDR mechanism started in October 2021. During the quarter, WDR was dispatched over 467 intervals, aggregated across all regions. The majority of WDR dispatch over the quarter came from New South Wales, where 128 MWh was dispatched, up from just 2 MWh in Q3 2023. Victoria had the next largest increase, with WDR increasing from 12 MWh in Q3 2023 to 40 MWh this quarter.

**Figure 66 Sharp increase in wholesale demand response dispatched in New South Wales**

Total quarterly WDR energy dispatch

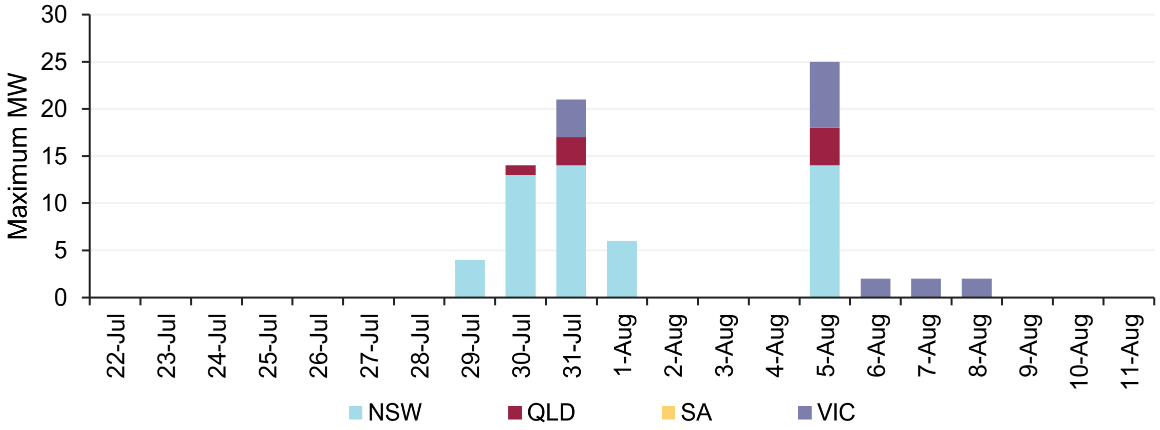



Over 30 July and 31 July, 80 MWh of WDR was dispatched in New South Wales (Figure 67). On 30 July, up to four units were dispatched over 137 intervals, reaching a maximum combined output of 13 MW. Similarly, on 31 July, four units were dispatched across 71 intervals, with a maximum output of 14 MW.

High volatility on 5 August led to 70 MWh of WDR being dispatched across New South Wales, Queensland, and Victoria. In New South Wales, up to four units were dispatched at a peak output of 14 MW for 35 intervals, with the regional wholesale spot price averaging $7,598/MWh over those intervals. In Queensland, one unit was dispatched at a peak of 4 MW for 34 intervals with an average regional wholesale spot price of $6,868/MWh. In Victoria, up to four units were dispatched at a peak of 7 MW for 34 intervals, with the regional wholesale spot price averaging $6,956/MWh over those intervals.

**Figure 67 Active WDR participation dispatch in late-July to early-August**

Maximum daily WDR dispatch




### 1.3.9 New grid connections

New grid connections to the NEM follow a process which involves the applicant, network service provider (NSP) and AEMO. Prior to submission of a connection application with AEMO, the applicant completes a pre-feasibility and enquiry phase where the connecting NSP is engaged in the process. The key stages[25] monitored by AEMO to track the progress of projects going through the connections process include application, proponent implementation, registration, commissioning, and model validation. At the end of Q3 2024, AEMO's snapshot of connection activities in progress shows that:

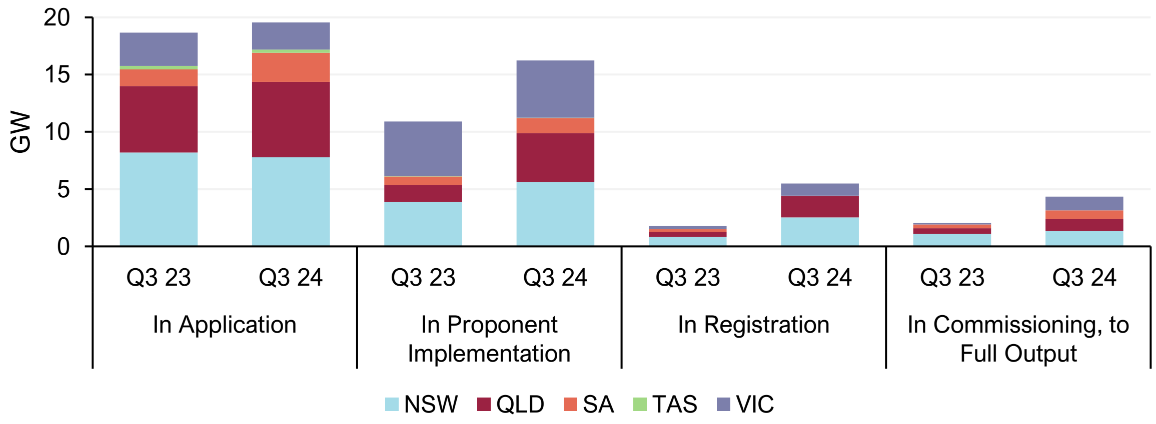
- There was 45.6 GW of new capacity progressing through the end-to-end connection process from application to commissioning, which is a 36% increase in capacity compared to 33.4 GW at the end of Q3 2023 (Figure 68). Around 38% of this capacity is in New South Wales, 30% in Queensland, 21% in Victoria and 10% in South Australia.
- The capacity of battery projects in the end-to-end connection process was 14.6 GW at the end of Q3 2024, an 87% increase compared to 7.8 GW at the end of Q3 2023. All technology types except gas increased, but battery projects increased the most.
- The majority (79%) of projects are in early stages of development, in either Application or Proponent Implementation stages. Connection projects in these early stages are 45% solar, 31% battery, 15% wind, 7% hydro and 2% gas.

[25] 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.

- The total capacity of in-progress applications was 19.6 GW, compared with 18.7 GW at the same time last year. 40% of the current capacity in application stage are New South Wales projects, 34% Queensland, 13% South Australia, 12% Victoria and 1% Tasmania.
- An additional 16.2 GW of new capacity projects are finalising contracts and under construction (proponent implementation), with 35% of this capacity in New South Wales, 31% in Victoria, 26% in Queensland and 8% in South Australia. This compares to 10.9 GW at the end of Q3 2023.
- There were 30 projects, totalling 5.5 GW, progressing through registration, compared with 1.8 GW at the end of Q3 2023 (205% increase). Some 46% of the 5.5 GW capacity is in New South Wales, 34% in Queensland and 20% in Victoria.
- There was 4.4 GW of new capacity in commissioning to full output, compared to 2.1 GW at the end of Q3 2023. This commissioning measure considers all plant in commissioning up to the plant reaching its full output.

**Figure 68 Increased capacity in proponent implementation, registration and commissioning stages**

Connections snapshot as at end Q3 for 2023 and 2024




During Q3 2024:

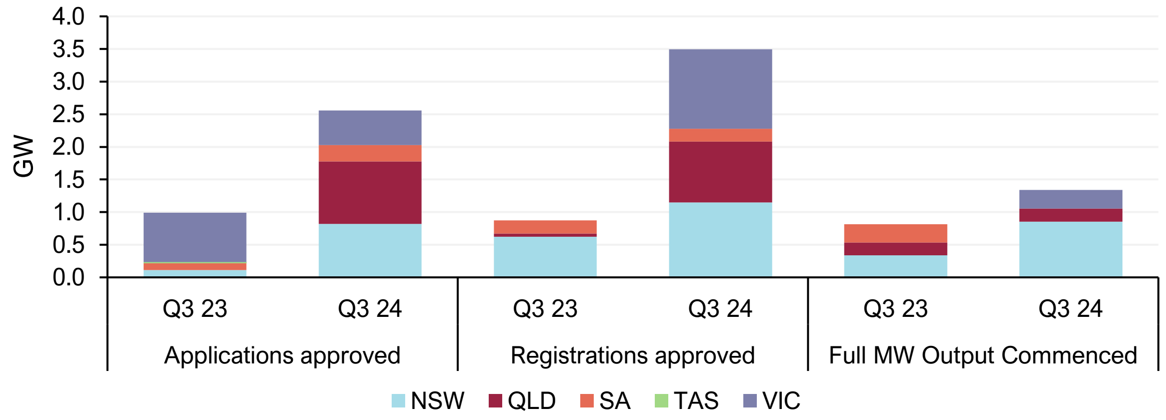
- 2.6 GW of applications were approved across 15 projects (Figure 69) compared with 1.0 GW across 10 projects during Q3 2023.
- 3.5 GW of plant across 10 projects were registered and connected to the NEM, in comparison to 0.9 GW across five projects during Q3 2023.
- 1.3 GW of plant across seven projects progressed through commissioning to reach full output, compared with 0.8 GW across eight projects in Q3 2023.

The Connections Scorecard contains further information[26].

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

**Figure 69 Substantial increase in application approvals, registrations and commissioning in Q3 2024 compared with Q3 2023**

Comparison of applications approved, registrations and commissioning in Q3 for 2023 and 2024




## 1.4 Inter-regional transfers

Gross inter-regional transfers during Q3 2024 totalled 3,494 gigawatt hours (GWh), a 458 GWh (-12%) decrease from 3,952 GWh in Q3 2023. A significant southward shift occurred in energy transfers between Victoria and Tasmania, primarily to support Tasmania's lower hydro generation (Section 1.3.3). Average net flows across Basslink reversed from 138 MW northward in Q3 2023 to 189 MW southward in Q3 2024 (Figure 70), contributing to higher spot prices in Victoria, particularly during daylight hours.

Average net transfers between Victoria and South Australia also changed direction, with several network outages across the quarter lowering the export limit into South Australia on the Heywood interconnector. Net transfers shifted from an average of 164 MW towards South Australia in Q3 2023 to 48 MW towards Victoria in Q3 2024.

Transfers into New South Wales declined from both Queensland and Victoria. Average net flows from Queensland to New South Wales fell from 492 MW to 283 MW, while net flows from Victoria to New South Wales fell from 517 MW to 351 MW.

**Figure 70 Net flows decreased into New South Wales, increased toward Victoria and Tasmania**

Quarterly inter-regional transfers

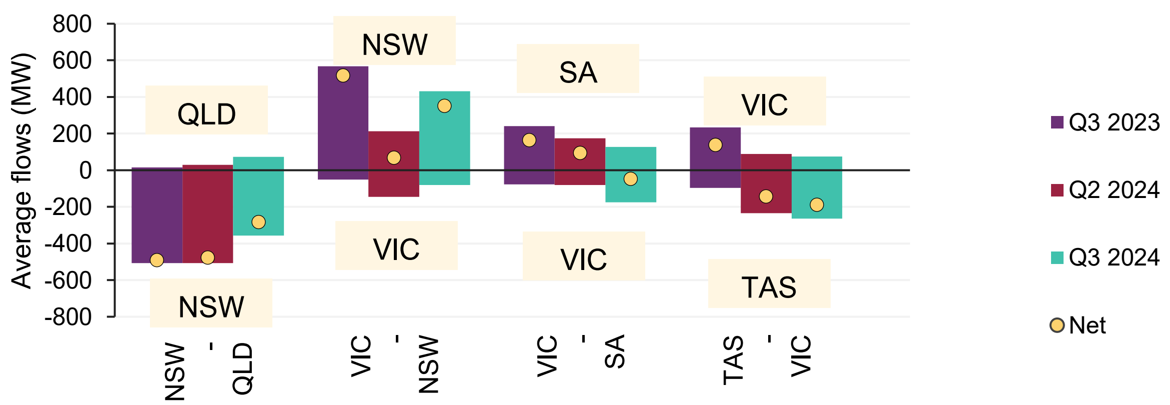


Figure 71 shows the average flows between Victoria and Tasmania on the Basslink interconnector by time of day, which saw a notable shift, with flows moving towards Tasmania across almost all hours. As a result, Basslink reached its import limit into Tasmania during 59% of the dispatch intervals this quarter, almost doubling the 31% in Q3 2023 (Figure 72).

**Figure 71 Basslink flows shifted strongly southwards**

Average Basslink flow by time of day

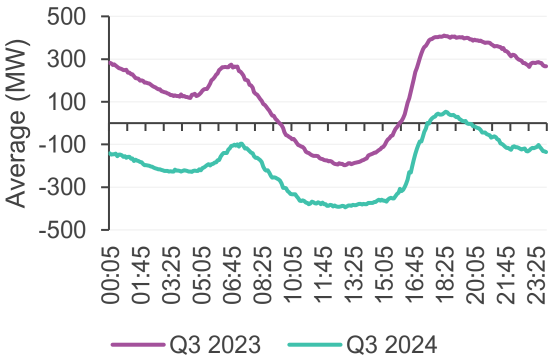
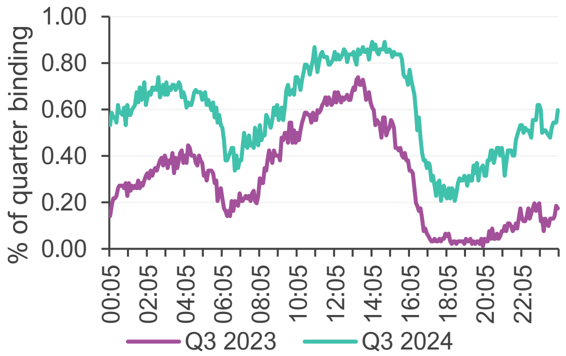



**Figure 72 Basslink southward limit bound more often**

Proportion of intervals with binding Basslink import limit by time of day




Heywood interconnector also shifted its net flow direction, averaging 59 MW towards Victoria this quarter, compared to 132 MW flowing towards South Australia in Q3 2023 (Figure 73). This reversal was particularly notable during daytime, when average energy prices in Victoria were above South Australia due to increased flows towards Tasmania. Between 0600 hrs and 1800 hrs this Q3, Victoria's average energy prices (capped at $300/MWh) were $14/MWh higher than South Australia, a sharp contrast to Q3 2023 when Victoria's prices were $9/MWh lower. Consequently, Heywood reached its import binding limit (from South Australia to Victoria) in 22% of dispatch intervals, up from 11% in Q3 2023.

**Figure 73 Heywood flows shifted towards Victoria**

Average Heywood flow by time of day (MW)

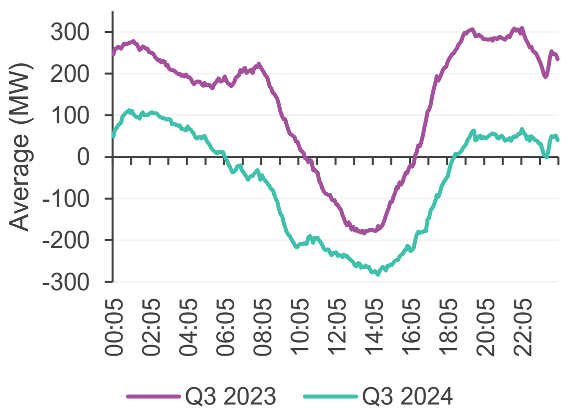
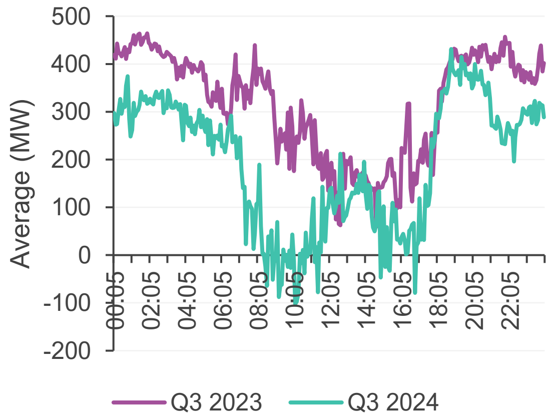



**Figure 74 Heywood export limit drops significantly**

Average Heywood export limit (when binding) by time of day




Additionally, Heywood's export limit (when binding) saw a notable reduction during overnight and morning hours, on the back of several network outages including Heywood–South East 275 kilovolts (kV) No. 2 line, Tailem Bend–Tungkillo 275 kV No. 2 line and Hazelwood–South Morang 500 kV No. 2 line. During the quarter, Heywood's export limit into South Australia reduced to 50 MW[27] or below during 4,480 intervals, or 17% of total dispatch intervals, resulting in a drop in flows towards South Australia across all hours. Throughout the quarter, Heywood's export limit (when binding) averaged 194 MW compared to 317 MW in Q3 2023 (Figure 74).

On the Victoria – New South Wales Interconnector (VNI), average net northward flows decreased across most times of day, principally outside daytime hours, reflecting a shift in Victorian exports towards Tasmania (Figure 75). Additionally, VNI's export limits (when binding) into New South Wales were lower outside daytime hours, also affecting the level of net flows.

The Queensland – New South Wales Interconnector (QNI) experienced a notable reduction in net southward flows, dropping from 442 MW in Q3 2023 to 282 MW in Q3 2024. This reduction was most notable during overnight hours (Figure 76), particularly between 0200 hrs and 0600 hrs, when flows reversed towards Queensland. During the corresponding time, average New South Wales prices were $7/MWh lower than Queensland's, compared to $3/MWh higher during the same period last year.

**Figure 75 Average VNI flows dropped outside daytime**

Average VNI flow by time of day

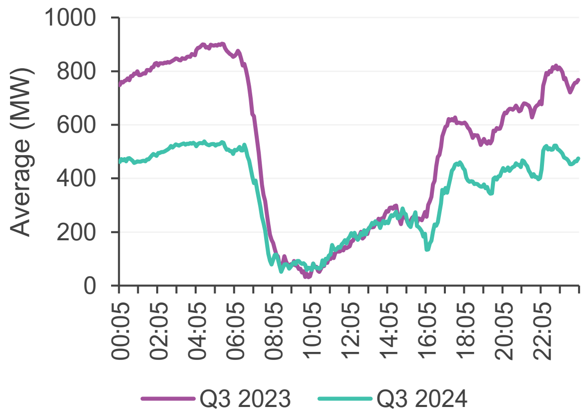
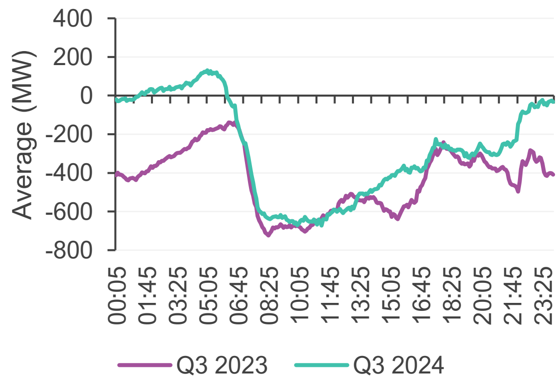



**Figure 76 Queensland to New South Wales flows decreased outside daylight hours**

Average QNI flow by time of day




### 1.4.1 Inter-regional settlement residue

Positive inter-regional settlement residue (IRSR) totalled $160 million in Q3 2024, an increase of $52 million (+47%) from Q3 2023 (Figure 77). The majority of these residues, $93 million or 58% of the total, were generated from flows into New South Wales. Notably, $50 million came from Queensland, where lower prices compared to New South Wales drove the accumulation. Nearly two-thirds of this ($29 million) was linked to the price volatility event in New South Wales on 5 August 2024, when the QNI transferred energy southward from the relatively low-priced Queensland region (Figure 77).

Meanwhile, negative IRSR remained largely unchanged, totalling -$3.8 million in Q3 2024 (Figure 78). Counter price flows into New South Wales accounted for -$1.7 million of the total, with the majority (-$1.2 million) arising from flows out of Victoria. Counter price flows into Victoria totalled -$2.0 million this quarter.

[27] From 9 October 2024, AEMO changed constraints used during planned transmission outages that create a credible risk of South Australia islanding to increase the maximum allowable flow on the Heywood interconnector from 50 MW to 250 MW in the Victora to South Australia direction. See https://aemo.com.au/market-notices?marketNoticeQuery=118672&marketNoticeFacets=.

**Figure 77 Increased positive settlement residues into New South Wales**

Quarterly positive IRSR values

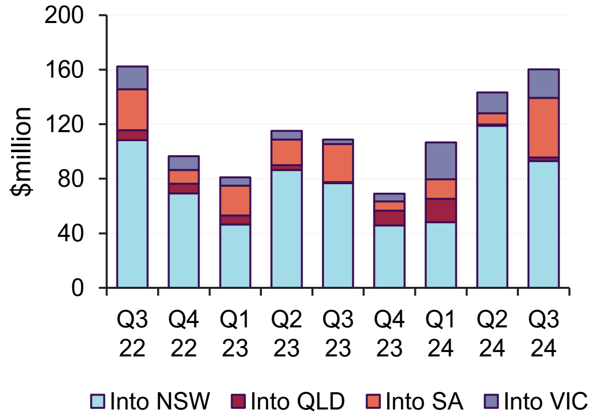
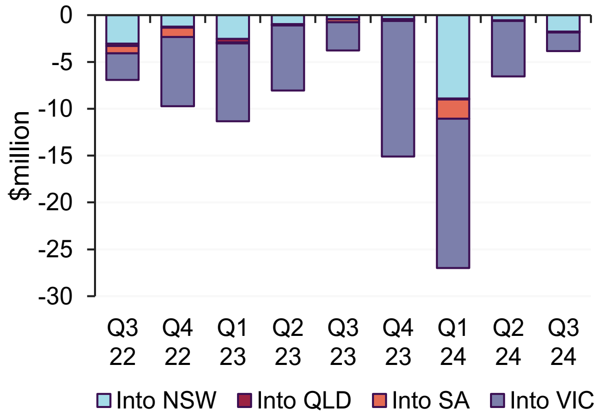



**Figure 78 Negative settlement residues increased into New South Wales, reduced into Victoria**

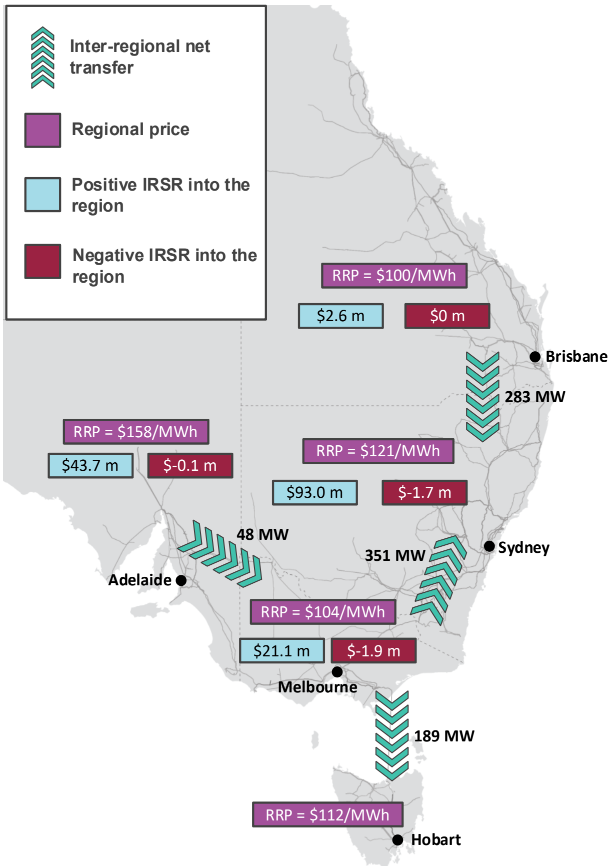
Quarterly negative IRSR values




The map in Figure 79 shows a summary representation of inter-regional exchanges during Q3 2024. Regional reference prices and the inter-regional net transfers are shown on a quarterly average basis. The positive and negative IRSR numbers refer to the total IRSR into the region from its neighbouring regions.

**Figure 79 Inter-regional transfers, wholesale spot price, and settlement residues in Q3 2024**

Quarterly average net inter-regional transfer, quarterly average wholesale spot price, and quarterly total IRSRs per region



## 1.5 Frequency control ancillary services

Total FCAS costs saw a sharp decline of $13 milion from $40 million in Q3 2023 to $27 million in Q3 2024 (Figure 80). All regions experienced a reduction in FCAS costs relative to Q3 2023, except for South Australia, which saw an increase of $3 million, driven by high FCAS prices during the volatility event on 5 August. On this day, NEM-wide FCAS costs totaled $8.8 million, contributing 33% of the quarterly NEM-wide total, with South Australian costs on this day being $2.9 million.

**Figure 80 FCAS costs reduced across all regions except South Australia**

Quarterly FCAS costs by region

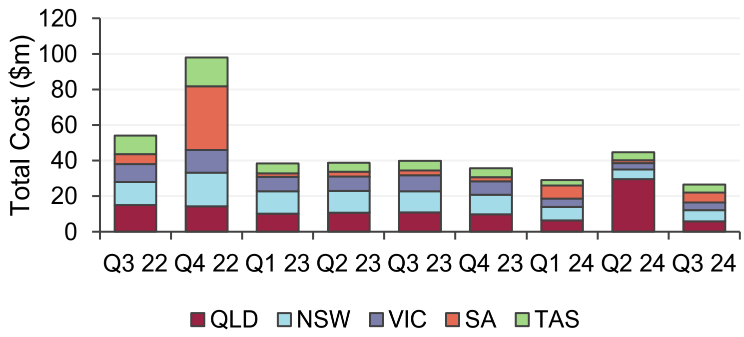
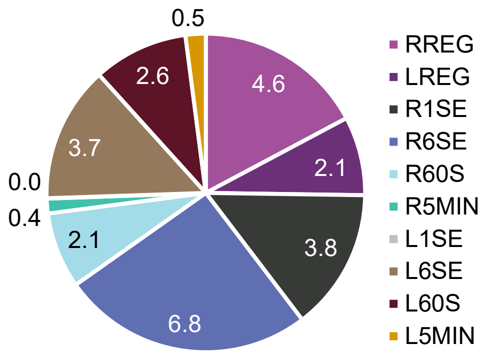



**Figure 81 High share of raise 6-sec costs**

NEM quarterly FCAS cost by market – Q3 2024 ($m)




In this quarter, all services, except for contingency lower 6-second (L6SE), saw lower FCAS costs compared to Q3 2023, primarily due to reduced average FCAS prices. Contingency raise 1-second (R1SE) recorded its lowest quarterly cost at $3.8 million since the commencement of very fast FCAS markets in Q4 2023. R6SE accounted for $6.8 million, or 26% of the total FCAS costs, with nearly $4.8 million accumulating on 5 August (Figure 81).

**Figure 82 Batteries dominated FCAS market share**

FCAS volume market share by technology – Q3 2024

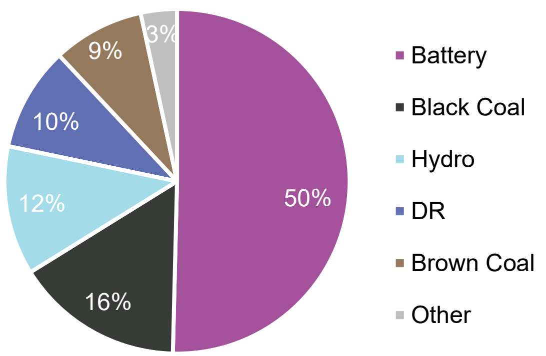
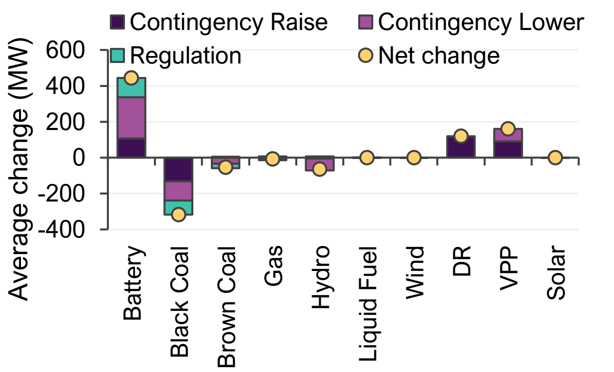



**Figure 83 Higher enablement for batteries, demand response and VPP**

Change in FCAS enablement by technology – Q3 2024 vs Q3 2023




Battery enablement continued to be the dominant source technology in providing FCAS, with 50% of share this quarter (Figure 82). This was an increase from the 40% share in Q3 2023 but slightly lower than the 52% observed in Q2 2024. The average enablement of batteries rose by 444 MW compared to Q3 2023 (Figure 83). This increase was driven in part by the commencement of new 1-second markets in Q4 2023, with batteries accounting for 58% of combined enablement for R1SE and L1SE services. Further year-on-year enablement growth across all regions came from new battery installations, including Hazelwood (+150 MW), Riverina (+125 MW), and Torrens Island (+55 MW).

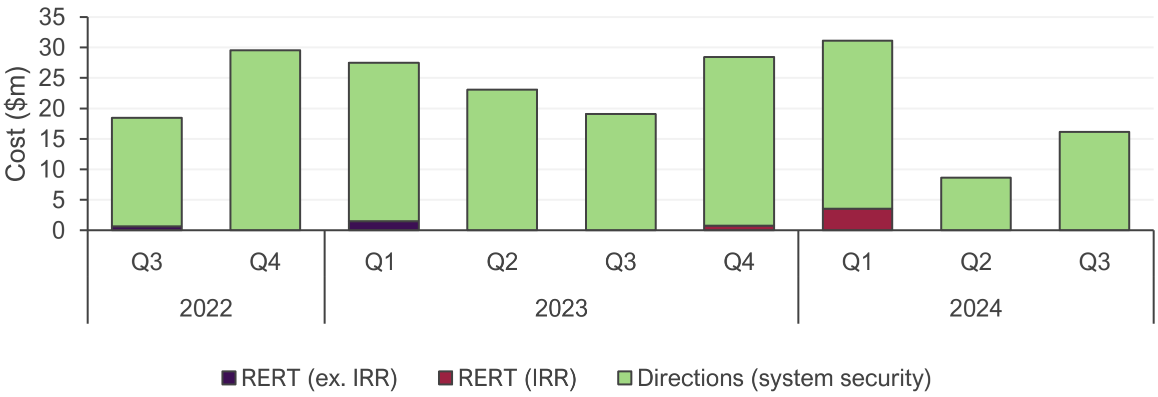
In addition to batteries, increased average enablement levels since Q3 2023 were also seen for demand response, and virtual power plants (VPP), with gains of 120 MW and 160 MW respectively. Most of the growth in demand response was attributed to the R1SE service with a 67 MW increase in enablement, while VPP enablement saw a 59 MW increase across both the R1SE and L1SE services.

## 1.6 Power system management

Estimated power system management costs[28] were $16 million in Q3 2024, up $8 million (87%) from Q2 2024, but down $3 million (-15%) from Q3 2023, with costs all attributable to system security directions in these three quarters (Figure 84).

**Figure 84 System security costs up from previous quarter but down year-on-year**

Estimated quarterly system security costs by category




### 1.6.1 South Australian system security directions

Directions to maintain minimum synchronous generation levels to ensure system security were in place for 53% of dispatch intervals in South Australia this quarter, increasing from 22% in Q2 2024 and 39% in Q3 2023 (Figure 85). A driver for the increase in directions was the increase in wind generation, with average output up 55% from Q2 2024 and 32% from Q3 2023. The increase was particularly noticeable in September, with nearly 80% of dispatch intervals requiring directions, as gas-fired generators more frequently opted to decommit as South Australia's wholesale spot prices decreased relative to July and August prices.

Over the quarter, an average of 39 MW of gas-fired generation in South Australia was directed, representing 9% of total gas-fired generation output (Figure 86). Overall direction costs decreased, despite the year-on-year increase in directed quantity (from 26 MW and 6% of output in Q3 2023), with the quarterly direction compensation price[29] reducing from $237/MWh to $218/MWh in Q3 2024.

[28] 'Power system management costs' are those associated with Reliability and Reserve Trader (RERT) and compensation for system security directions only.

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

**Figure 85 Decrease in South Australian direction costs year-on-year despite increase in frequency**

South Australia system security directions – time and estimated costs

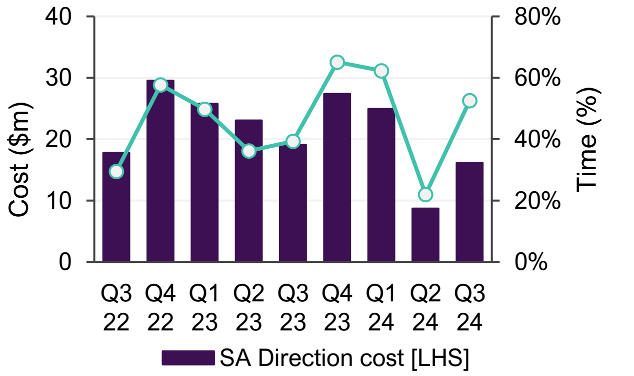
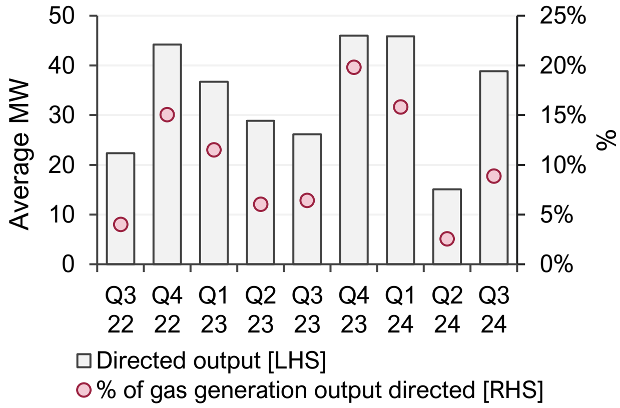



**Figure 86 Increase in South Australian gas volumes directed**

South Australian gas-fired generation directed – volume and share



# 2 Gas market dynamics

## 2.1 Wholesale gas prices

Quarterly average wholesale gas prices increased compared to Q3 2023 but were 8% lower than Q2 2024. The average price across all AEMO markets was $12.50/GJ compared to $10.41/GJ in Q3 2023 (Table 6).

**Table 6 Average east coast gas prices – quarterly comparison**

| Price ($/GJ) | Q3 2024 | Q2 2024 | Q3 2023 | Change from Q3 2023 |
|---|---|---|---|---|
| **Victoria Declared Wholesale Gas Market (DWGM)** | 12.08 | 13.60 | 10.27 | +18% |
| **Adelaide** | 12.78 | 13.86 | 10.80 | +18% |
| **Brisbane** | 12.63 | 13.66 | 10.34 | +22% |
| **Sydney** | 12.57 | 13.94 | 10.36 | +21% |
| **Gas Supply Hub (GSH)** | 12.48 | 13.21 | 10.34 | +21% |

Key factors influencing the movement of prices throughout Q3 2024 are summarised in Table 7, with further analysis and discussion referred to relevant sections elsewhere in this report.

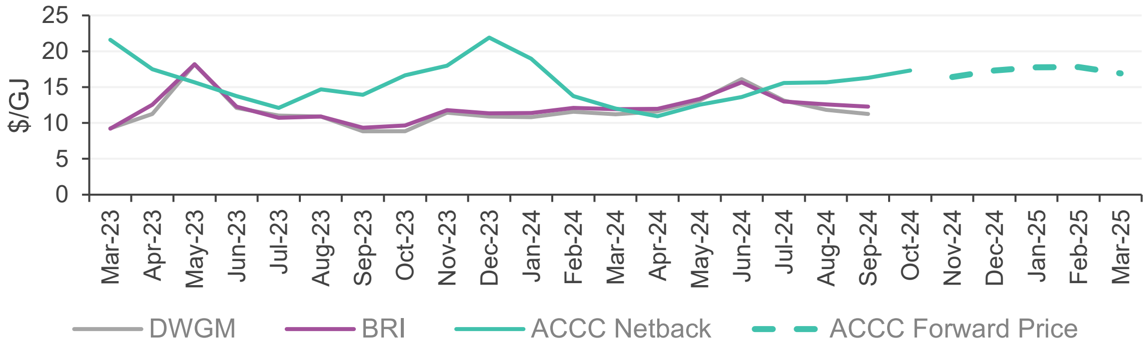
**Table 7 Wholesale gas price levels: Q3 2024 drivers**

| | |
|---|---|
| **High demand and rapid depletion of Iona UGS in June leading to higher offer prices in DWGM and Short Term Trading Market (STTM) to start Q3** | Compared to 2023, June 2024 saw significantly higher gas-fired generation, colder weather, rapid emptying of Iona storage inventory and record gas flows from Queensland to southern markets, with higher prices as a result. This led to a very different landscape starting Q3 2024 compared to 2023, with Iona storage inventory 8 PJ lower, and AEMO having issued an East Coast Gas System Risk or Threat Notice in June due to the potential for gas supply shortfalls caused by the high rate of depletion of southern storage inventories.<br>This had the effect of July 2024 offers being higher than for the same period in 2023, which continued throughout the quarter. |
| **Higher gas-fired generation demand in July and August** | Demand from gas-fired generation increased most notably in the first half of Q3 2023 due to higher NEM demand, reduced hydro generation, and colder weather. This put upward pressure on spot prices across all AEMO markets. The second half of Q3 2024 saw warmer weather and an increase in wind generation, leading to lower gas-fired generation demand, particularly in September. Gas-fired generation demand is discussed in more detail in Section 2.2.1. |

International prices continued the trend observed in Q2 2024 and increased during the quarter, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, with corresponding forward prices ranging from $16/GJ to $18/GJ over the next six months (Figure 87). Drivers for international prices are discussed in Section 2.1.1.

**Figure 87 Domestic prices decreased from Q2 2024 but were higher than Q3 2023**

ACCC netback and forward prices[30], DWGM and STTM Brisbane average gas prices by month



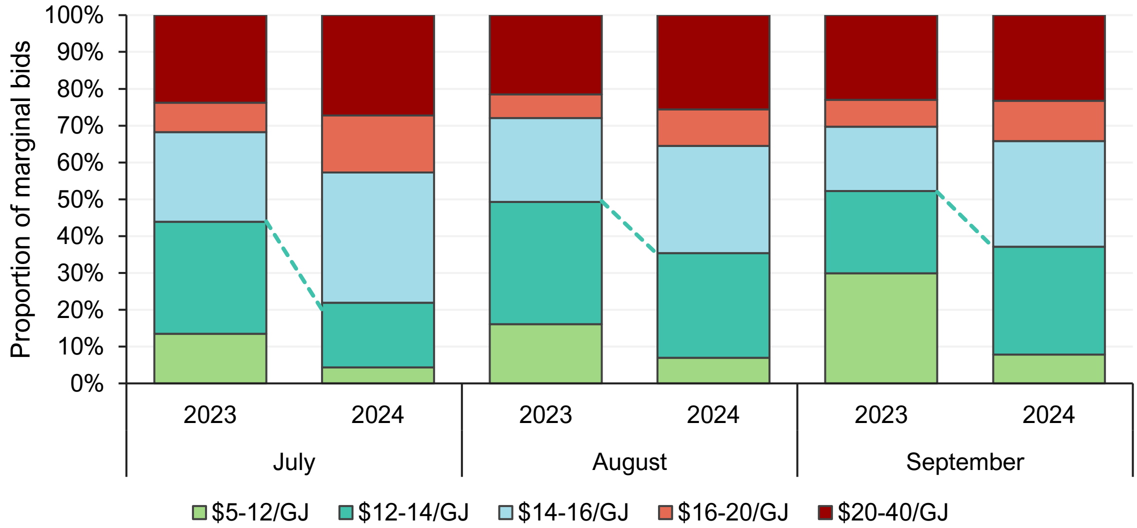

Prices in Q3 2023 were subdued due to warm weather, and low gas-fired generation demand combined with an increase in supply from Queensland to the southern markets, which led to reduced reliance on Iona storage to supply the markets. This contrasts with Q3 2024, which was coming off higher gas-fired generation demand and colder weather in June and started Q3 with a much lower storage inventory at Iona.

In the Declared Wholesale Gas Market (DWGM), higher demand from gas -fired generation as well as colder weather in July led to a continuation of market participants increasing bid volumes priced between $14/GJ and $20/GJ (Figure 88). This also led to a reduction in bid volumes priced between $12/GJ and $14/GJ in DWGM, reflecting significantly lower storage inventory at Iona compared to 2023.

Prices eased slightly in August and September, reflecting above average temperatures across the east coast, reduced gas-fired generation, and less reliance on Iona to supply the market.

**Figure 88 Reduced DWGM bids at lower prices throughout Q3 2024 compared to Q3 2023**

DWGM – proportion of marginal bids[31] by price band – Q3 2024 vs Q3 2023 by month




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

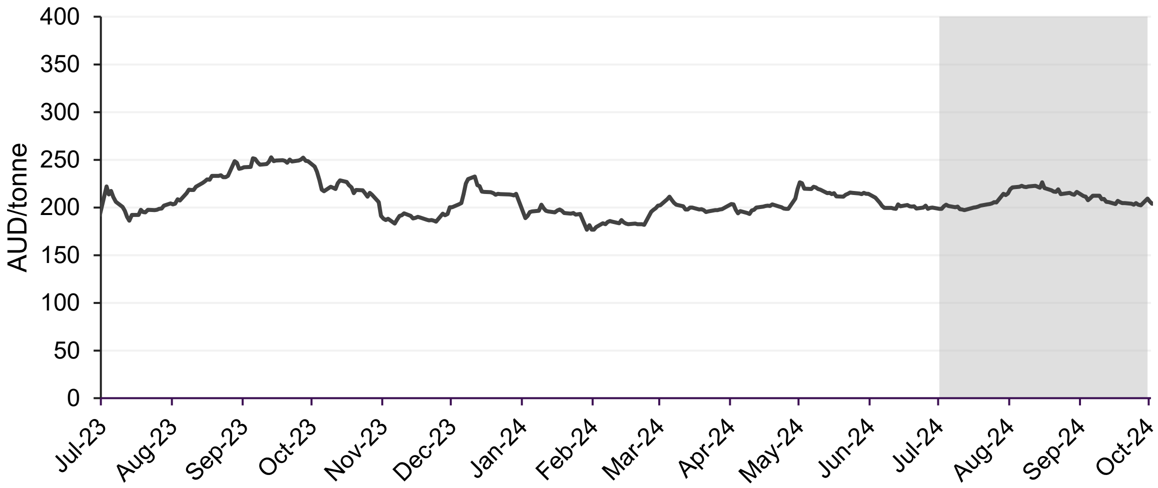
[31] Bids between $5/GJ and $40/GJ.

### 2.1.1 International energy prices

Newcastle export coal prices averaged $209/tonne, up slightly from $207/tonne in Q2 2024, and down from $225/tonne in Q3 2023 (Figure 89). Over the quarter, upward drivers of thermal coal prices included the exclusion of Russian coal from some markets, record summer heat across Asia boosting demand, and supply disruptions in South Africa and Colombia. These factors were somewhat balanced by downward pressures arising from improved hydropower generation in China and India due to the rainy season, increased output from renewables and nuclear power reducing coal demand, and record high coal inventories in China[32].

**Figure 89 Traded thermal coal prices remained steady**

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




Source: Bloomberg ICE data

Asian spot LNG prices stayed relatively stable throughout the quarter (Figure 90). There was a small increase in spot prices in the middle of August due to warmer temperatures in Northeast Asia boosting the need for power demand for cooling purposes. South Korea was the most affected by the warm weather as the nation reached a new record peak power demand on 13 August[33]. This price spike was short lived as spot cargo demand dried up quickly with EU LNG storage levels ending the quarter at over 94%[34], while Asian LNG storage levels are understood to be relatively full in advance of the coming winter, reducing the level of re-stocking demand required[35].

This quarter, Brent Crude prices averaged A$117/barrel, marking an A$13/barrel decrease from last quarter, ending the quarter at A$103/barrel (Figure 91). The price slide was a result of weaker Asian demand coupled with uncertainty on whether OPEC would unwind their extra voluntary production cuts[36]. Similarly, the United States has reported that global oil demand outweighed declines in oil inventories, pushing prices lower. The Energy

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

[33] S&P Global, August 2024: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/lng/081424-south-koreas-power-demand-increases-to-new-record-high-amid-heat-wave.

[34] ENTSOG Gas Storage Dashboard, September 2024: https://gasdashboard.entsog.eu/#map-storage.

[35] Reuters, August 2024: https://www.xm.com/au/research/markets/allNews/reuters/asian-spot-lng-price-little-changed-on-muted-demand-53930056.

[36] IEA Oil Market Report, September 2024: https://www.iea.org/reports/oil-market-report-september-2024

Information Administration (EIA) believes that once OPEC increases their production it may outpace oil demand growth, resulting in lower prices[37].

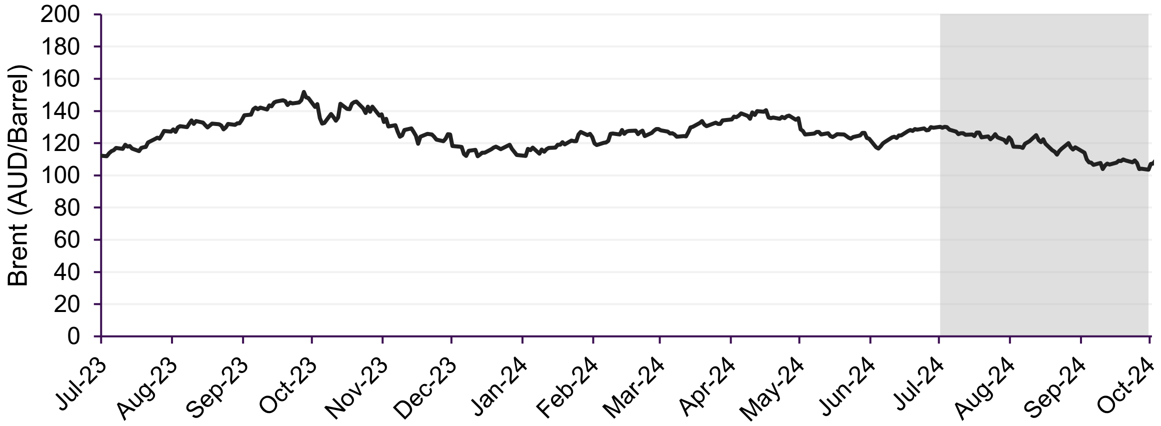
**Figure 90 Asian LNG stable throughout the quarter**

Asian LNG price in A$/GJ daily


Source: Bloomberg ICE data

**Figure 91 Brent crude oil prices slide due to weaker demand**

Brent Crude Oil in A$/Barrel daily




Source: Bloomberg ICE data

## 2.2 Gas demand

Total east coast gas demand increased by 3% compared to Q3 2023 (Figure 92 and Table 8). There were increases in gas-fired generation (+7 PJ), demand for Queensland LNG production (+5 PJ), and a small increase in AEMO markets (+0.5 PJ). Victoria's Declared Wholesale Gas Market (DWGM) recorded an increase of 0.5 PJ, primarily due to a significantly colder July 2024 compared to July 2023. August 2024 temperatures however were amongst the warmest on record across the east coast markets, resulting in lower demand and leading to only a

[37] EIA Short- Term Energy Outlook, October 2024: https://www.eiaEE.gov/outlooks/steo/pdf/steo_full.pdf.

modest overall quarterly increase. The increase in DWGM demand was solely due to an increase in heating requirements from residential customers due to the colder July, with commercial and industrial demand decreasing, a trend also observed in Q1 and Q2 2024. Reflecting a downward trend in DWGM demand, this was the second year in a row that combined residential and commercial and industrial demand did not exceed 1,000 TJ in a day at least once during winter since the DWGM began in 1999.

**Figure 92 Large increases for gas generation and LNG exports with a small increase for AEMO market demand**

Components of east coast gas demand change – Q3 2024 to Q3 2023

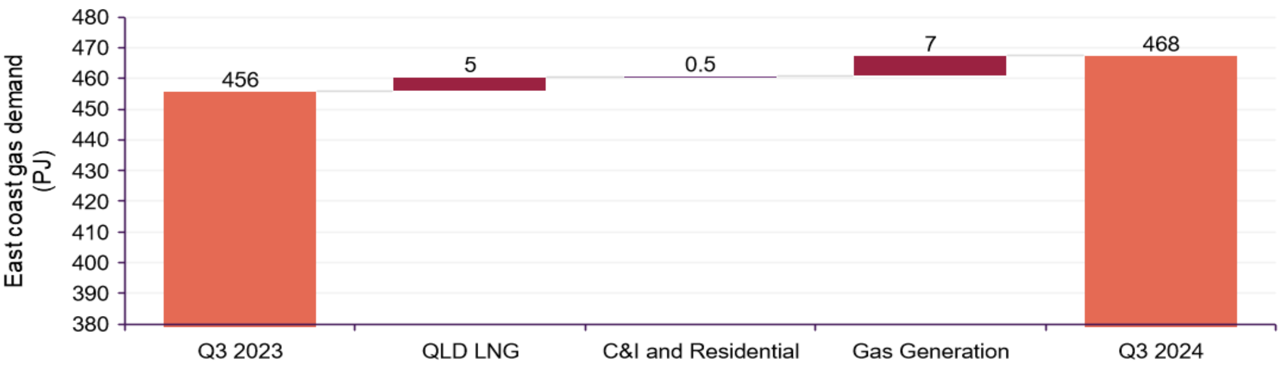



**Table 8 Gas demand – quarterly comparison**

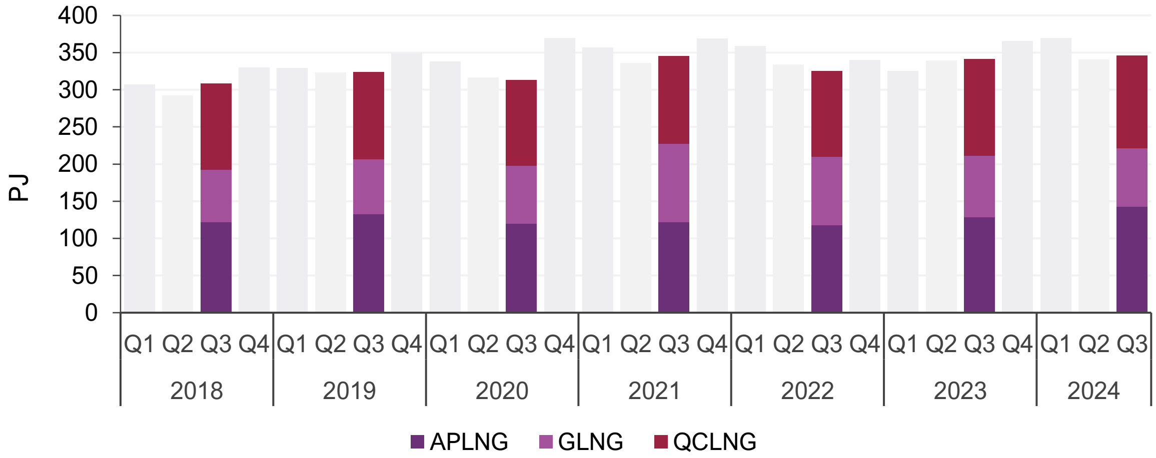
| Demand (PJ) | Q3 2024 | Q2 2024 | Q3 2023 | Change from Q3 2023 |
|---|---|---|---|---|
| AEMO markets * | 91.9 | 84.3 | 91.4 | +0.5 (1%) |
| Gas-fired generation ** | 29.6 | 34.0 | 23.0 | +7 (29%) |
| Queensland LNG | 346.0 | 341.0 | 341.5 | +5 (1%) |
| Total | 467.5 | 459.3 | 455.9 | +12 (3%) |

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

Queensland LNG export demand increased compared to Q3 2023, solely due to a large increase in APLNG demand, while QCLNG and GLNG experienced planned and unplanned outages during the quarter resulting in decreases. The combined total demand of 346 PJ is a new record for Q3 LNG export demand (Figure 93).

**Figure 93 Highest Q3 on record for Queensland LNG production**

Total quarterly pipeline flows to Curtis Island



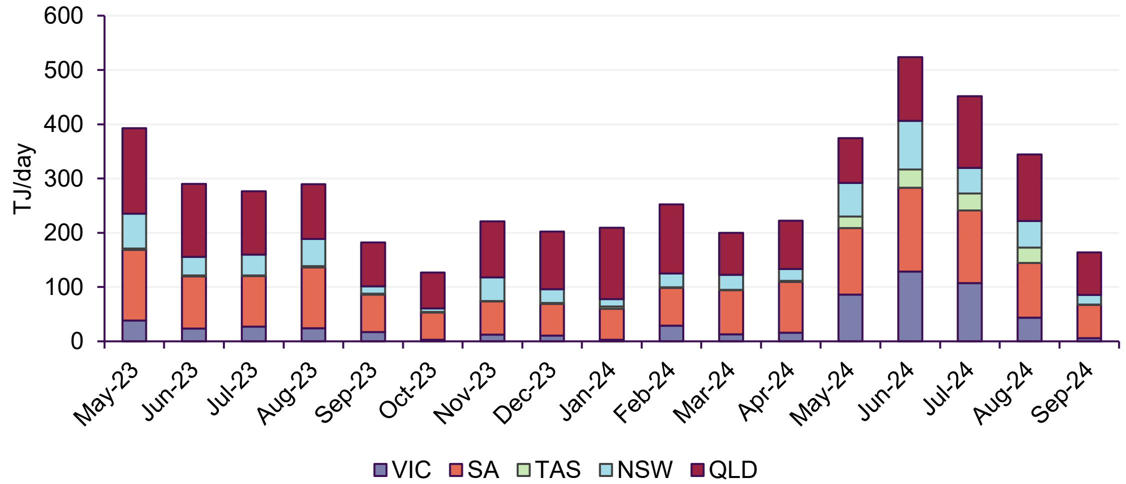

By participant, in comparison to Q3 2023, APLNG demand increased by 14.3 PJ, while QCLNG decreased by 5.7 PJ, and GLNG by 4.2 PJ. There were 87 cargoes exported during the quarter, up from 86 in Q3 2023.

### 2.2.1 Gas-fired generation

Demand from gas-fired generation increased in July and August but was lower in September (Figure 94). Demand increases for the entire quarter were observed in all states. Victoria's demand increased by 131%, Queensland by 12%, South Australia's by 8%, New South Wales' by 11%, and Tasmania's by 998%. Section 1.3 discusses drivers of this higher generation demand.

**Figure 94 Increase in gas-fired generation in July and August contributed to increased market prices**

Average daily gas-fired generation demand by state




## 2.3 Gas supply

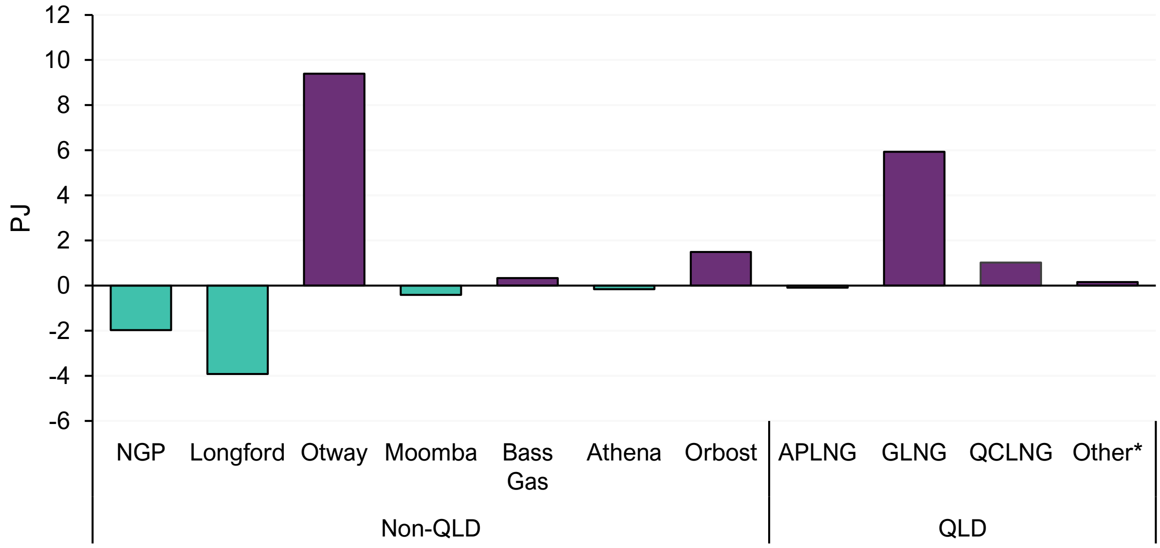
### 2.3.1 Gas production

East coast gas production increased by 13.7 PJ compared to Q3 2023 (+3%, Figure 95). Key changes included:

- Increased Victorian production (+7.1 PJ), mainly driven by increased production at the Otway Gas Plant (+9.4 PJ) due to production from the Enterprise gas field commencing in June[38]. Orbost production also increased (+1.5 PJ), more than offsetting the continued decline in production at Longford (-3.9 PJ).
- Increased Queensland production (+7.0 PJ), with the majority of that due to assets operated by GLNG increasing by 5.9 PJ and QCLNG assets by 1.0 PJ, while APLNG operated assets marginally decreased by 0.1 PJ. Gas demand for Queensland LNG exports increased by 4.6 PJ, meaning that an additional 2.4 PJ of supply associated with Queensland LNG projects went into the domestic market compared to Q3 2023 (Figure 96).
- Decreased Northern Gas Pipeline (NGP) supply (-2.0 PJ), with continuing upstream supply issues in the Northern Territory that began in February 2024. This meant that like Q2 there was no supply from the Northern Territory to Queensland for the entire quarter.

**Figure 95 Large production increase from Otway Gas Plant offsets continued fall in Longford output**

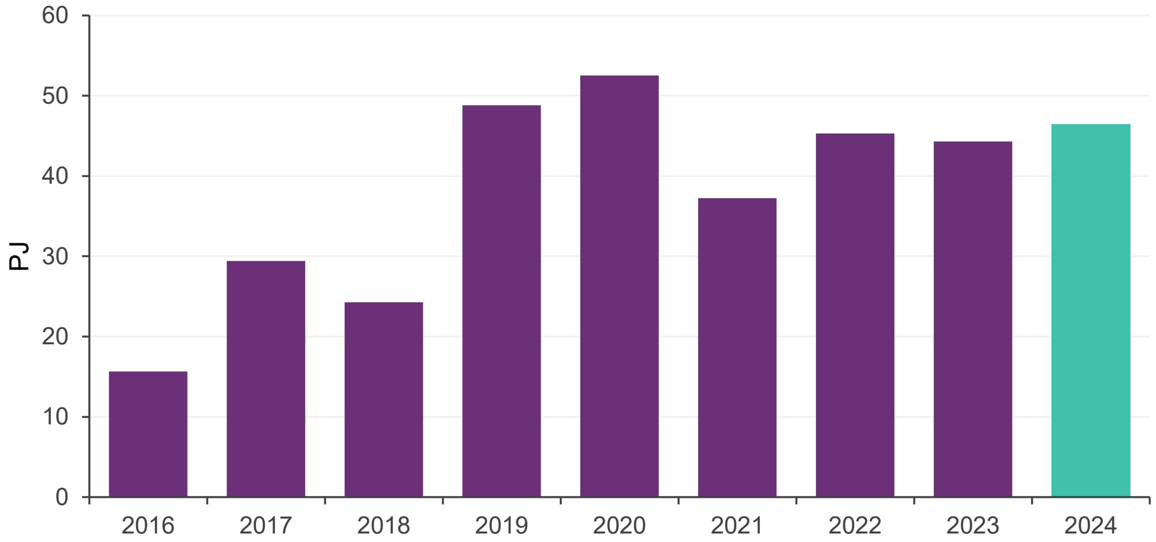
Change in east coast gas supply – Q3 2024 vs Q3 2023




38 See https://beachenergy.com.au/enterprise-project/.

**Figure 96 Queensland Q3 2024 net domestic supply marginally increases compared to Q3 2023**

Queensland net domestic supply during Q3



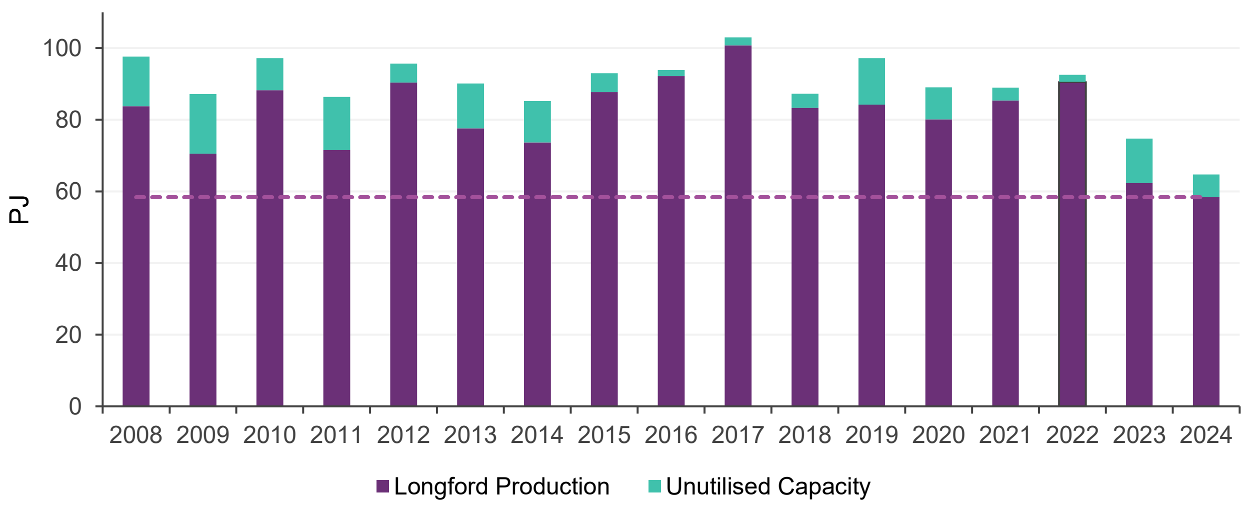

## 2.3.2 Longford production and capacity

This quarter saw the continued decline in Longford production that has been observed since the start of 2023. Longford's production of 58 PJ was the lowest for any Q3 since data collection commenced on the Gas Bulletin Board (GBB) on 1 July 2008 (Figure 97), and the available production capacity of 65 PJ was also the lowest recorded since this time.

Longford Gas Plant 1, operational since April 1969, is expected to be retired during October. This will leave only gas plants 2 and 3 in operation, limiting Longford production to approximately 700 TJ/day going forward.

**Figure 97 Lowest Longford Q3 production and lowest available capacity since data reporting began**

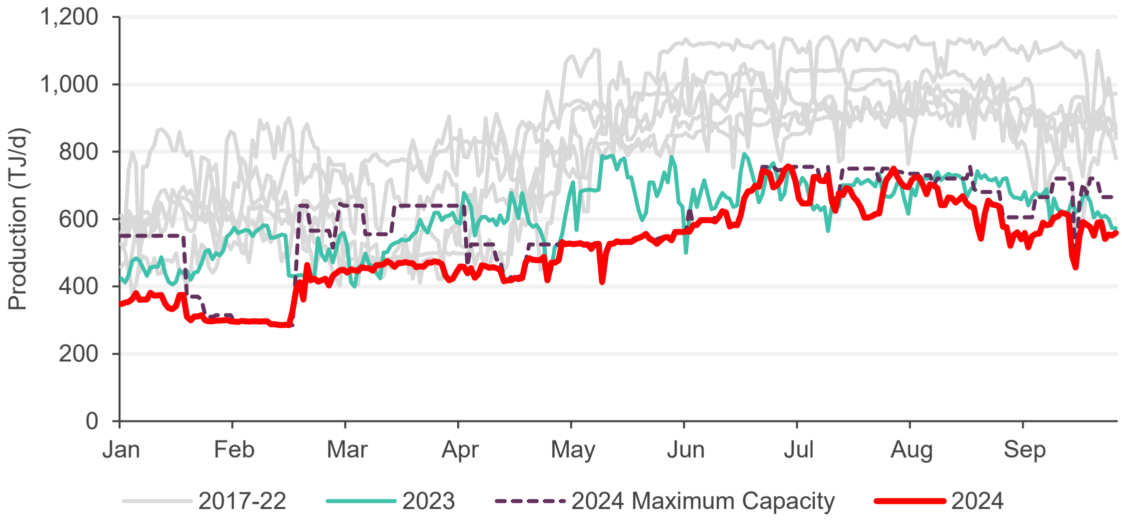
Longford Q3 production and unutilised capacity




Notwithstanding Longford's overall capacity decrease, daily production through much of Q3 was below available capacity (Figure 98), with Longford's capacity factor at 90%. While some of this gap was driven by milder weather in August and September combined with reduced gas-fired generation demand, the increase in unutilised capacity was also driven by an increase in Longford supply offer pricing to above the daily DWGM and Sydney STTM price outcomes.

**Figure 98 Daily Longford production declined but still below maximum capacity for much of the quarter**

Daily Longford production 2017-2024, maximum capacity profile 2024



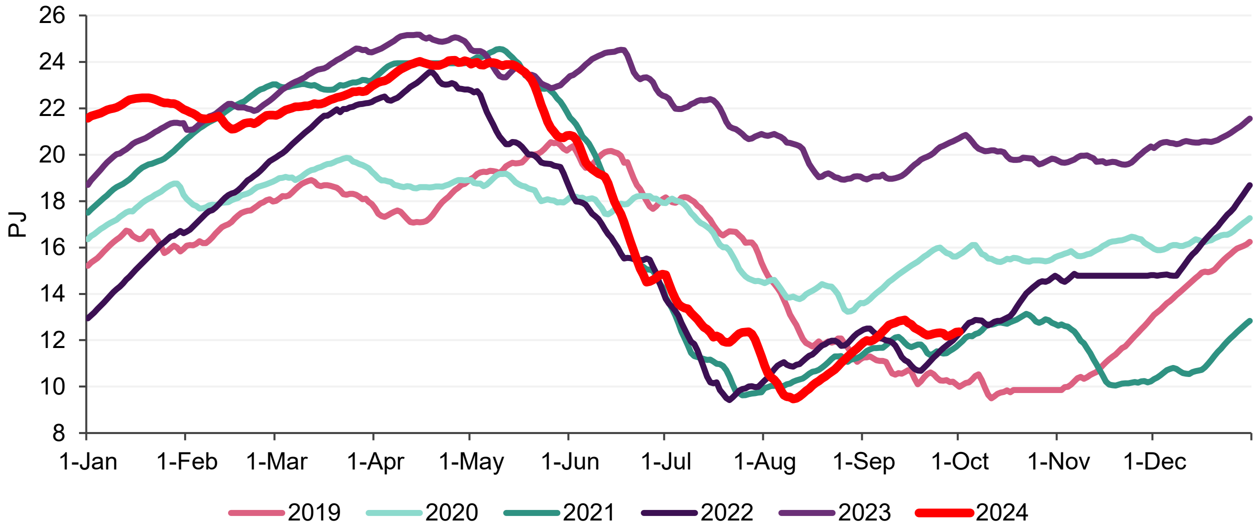

### 2.3.3 Gas storage

The Iona storage facility finished the quarter with an inventory of 12.4 PJ, 8.3 PJ lower than at the end of Q3 2023 (Figure 99) but marginally higher than at the end of Q3 2022 (12.1 PJ) and Q3 2021 (11.7 PJ).

Iona storage levels dropped to a low of 9.5 PJ on 10 August before recovering throughout the rest of the month, peaking at 12.9 PJ on 12 September, due to milder weather, reduced gas-fired generation demand, continuing strong southerly flows on the South West Queensland Pipeline, and increased supply from the Otway Gas Plant. Storage levels then trended slightly lower for the rest of September, driven by Longford offer prices higher than market outcomes and early spring gas demand.

**Figure 99 Iona storage levels recovered in second half of Q3 2024**

Iona storage levels




### 2.3.4 East Coast Gas System Risk or Threat Notice

The East Coast Gas System Risk or Threat Notice[39] issued by AEMO on 19 June 2024 due to the potential for gas supply shortfalls caused by the high rate of depletion of southern storage inventories, particularly Iona UGS, was revoked on 23 August 2024[40]. The revocation notice was issued after AEMO determined that the potential risk or threat to gas supply had end and demand trends in New South Wales, the Australian Capital Territory, Victoria, South Australia, and Tasmania had improved. There were no directions issued or trading functions invoked during the period of the notice.

## 2.4 Pipeline flows

Compared to Q3 2023, there was a 0.9 PJ decrease in net transfers south to Moomba from the South West Queensland Pipeline (SWQP, Figure 100) predominantly in August. The decreased flows coincided with an increase in net Victorian exports to New South Wales, South Australia and Tasmania of 3.3 PJ and an increase in pipeline flows to Curtis Island of 4.6 PJ from Q3 2023.

The increase in Victorian gas exports to other states (Figure 101) was driven by a 9.4 PJ increase in Otway production, alongside the use of Iona storage. The key changes include:

- A 0.8 PJ increase in net flows north via Culcairn.
- A 0.2 PJ increase in net flows north via the Eastern Gas Pipeline (EGP).

[39] See https://www.nemweb.com.au/Reports/CURRENT/ECGS/ECGS_Notices/Attachments/20240619180058%20-%20EAST%20COAST%20GAS%20SYSTEM%20RISK%20OR%20THREAT%20NOTICE%2019%20JUNE%202024.PDF.

[40] See https://nemweb.com.au/Reports/Current/ECGS/ECGS_Notices/Attachments/20240823135740%20-%20REVOCATION%20OF%20EAST%20COAST%20GAS%20SYSTEM%20RISK%20OR%20THREAT%20NOTICE%2023%20AUG%202024.PDF.

- Increased net flows south on the Tasmanian Gas Pipeline (1.7 PJ) and west on the SEA Gas pipeline (0.5 PJ) which was consistent with increased gas-fired generation demand in Tasmania and South Australia.

**Figure 100 Net Q3 flows south on SWQP decreased**

Flows on the South West Queensland Pipeline at Moomba

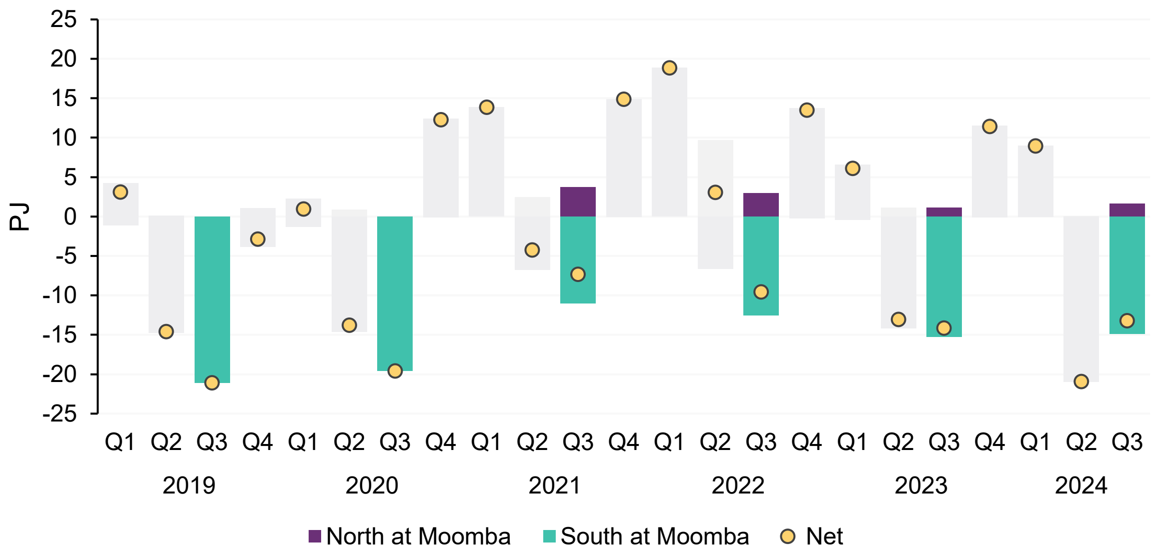
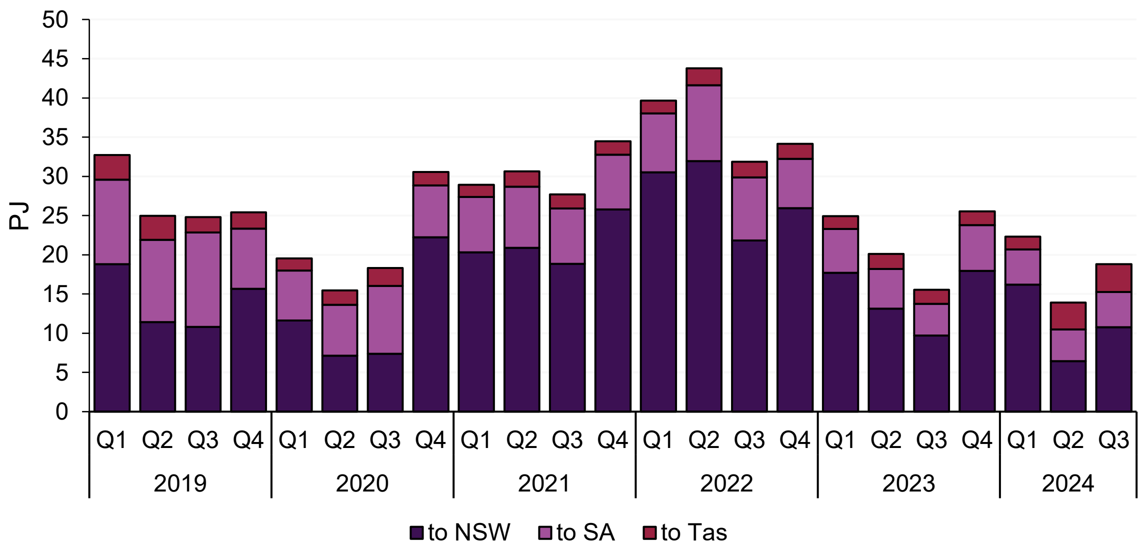



**Figure 101 Victorian Q3 transfers increased coinciding with increase in Otway production**

Victorian net gas transfers to other regions

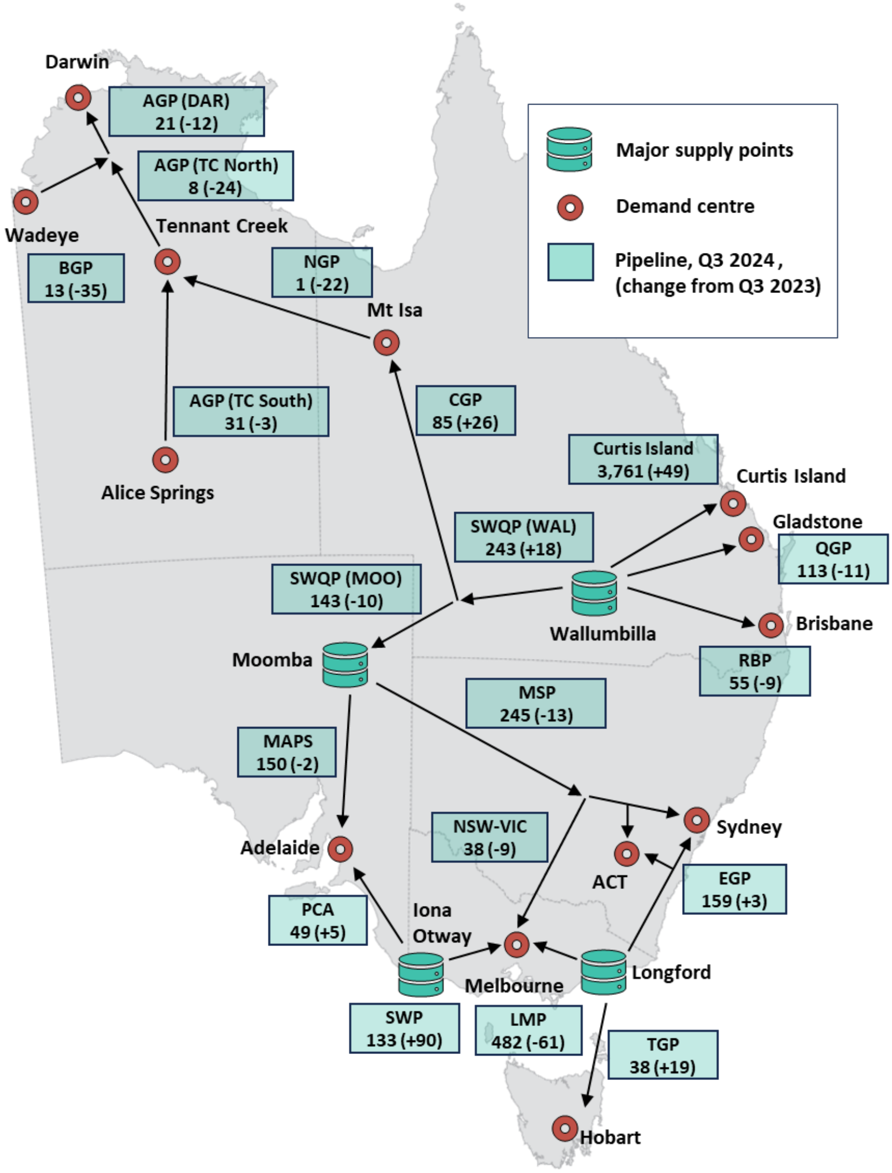



Average daily pipeline flows in Q3 2024 were significantly higher on the South West Pipeline (SWP), reflecting a greater utilisation of the Iona UGS inventory and Otway gas plant to supply the DWGM and South Australia, with a corresponding decrease in Longford to Melbourne (LMP) flows reflecting the reduction in supply from the Longford facility. Supply from Queensland to the southern markets was also marginally lower.

In Queensland, Mt Isa demand was solely supplied from Queensland compared to Q3 2023, reflecting the upstream supply issues experienced in the Northern Territory. On 7 August 2024 the Northern Gas Pipeline (NGP) became bi-directional, allowing gas to flow back into the Northern Territory. This occurred on several days in August peaking at 20 TJ on 10 August, creating a small average daily flow towards NT (Figure 102). These flows were part of a commissioning and testing phase, which is expected to be completed by 31 October 2024.

**Figure 102 Increase in Iona and Otway supply and NGP became bi-directional in August**

Average daily pipeline flows Q3 2024 vs Q3 2023

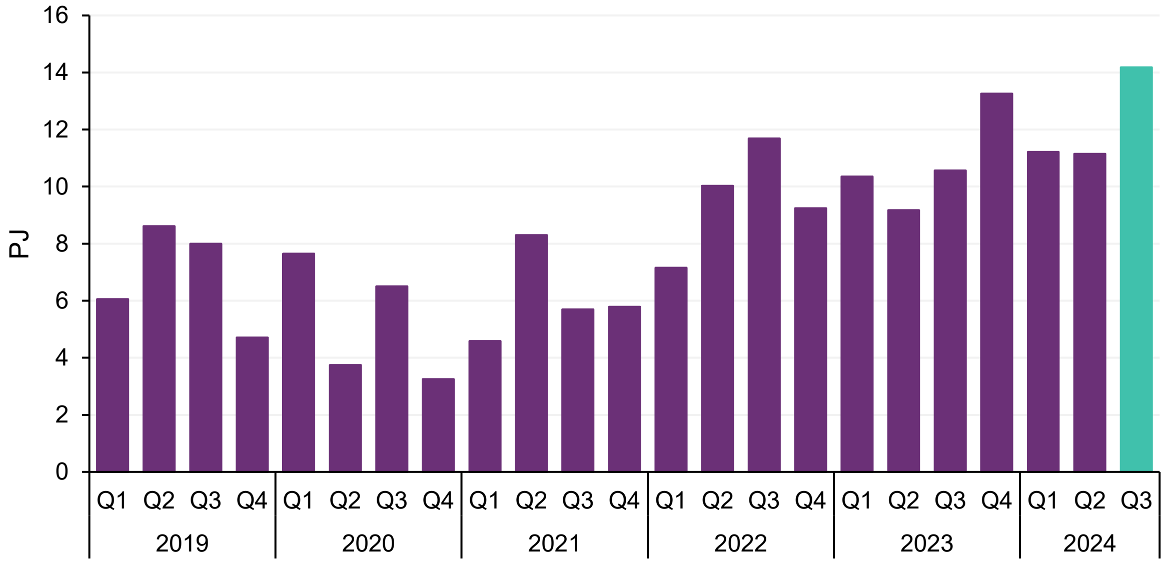



## 2.5 Gas Supply Hub (GSH)

In Q3 2024, traded volumes on the GSH increased by 3.6 PJ in comparison to Q3 2023 (Figure 103). The traded volume this quarter was 14.2 PJ and represented the highest quarter GSH traded volume since market start. August was the highest monthly traded volume for the quarter at 5.6 PJ predominantly for delivery in the same month.

**Figure 103 Highest quarter GSH traded volume since market start**

Gas Supply Hub – quarterly traded volume

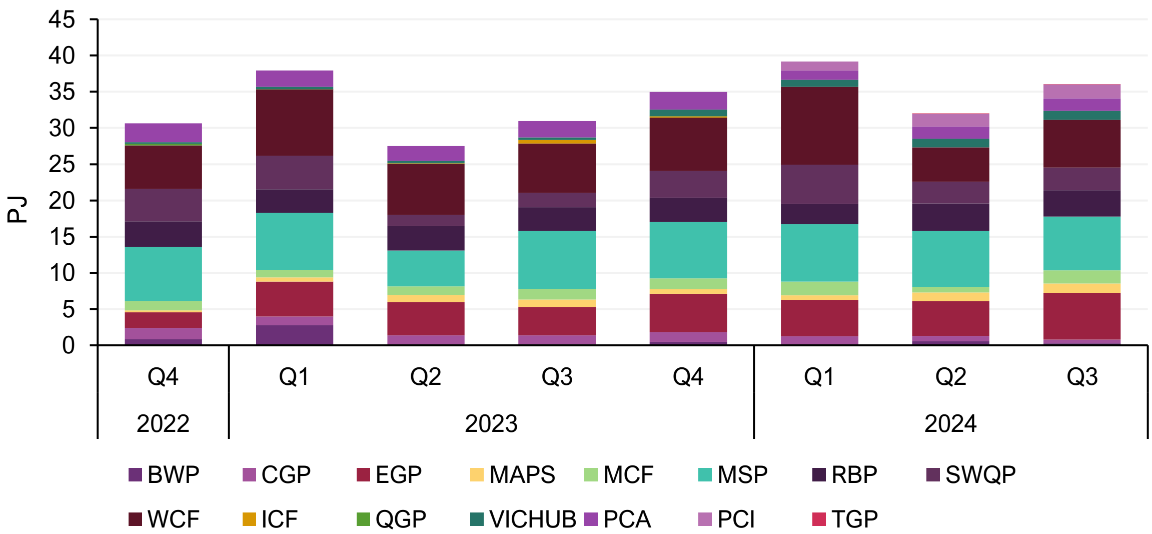



## 2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes set a new Q3 record of 36.1 PJ, 5.1 PJ higher than the previous Q3 record set in 2023 (Figure 104). Compared to Q3 2023, the largest increase occurred on the Eastern Gas Pipeline (EGP) (+2.5 PJ) with approximately 85% of gas volumes won being northern haul.

**Figure 104 Highest Q3 Day Ahead Auction utilisation since market start**

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 SWQP which averaged $0.42/GJ.
- The Carpentaria Gas Pipeline (CGP) which averaged $0.50/GJ.

- The Roma to Brisbane Pipeline (RBP) which averaged $0.08/GJ.
- The EGP which averaged $0.05/GJ.
- The Moomba to Adelaide Pipeline (MAPS) which averaged $0.01/GJ.
- The Moomba to Sydney Pipeline (MSP) which averaged $0.01/GJ.

## 2.7 Gas – Western Australia

### 2.7.1 Gas consumption

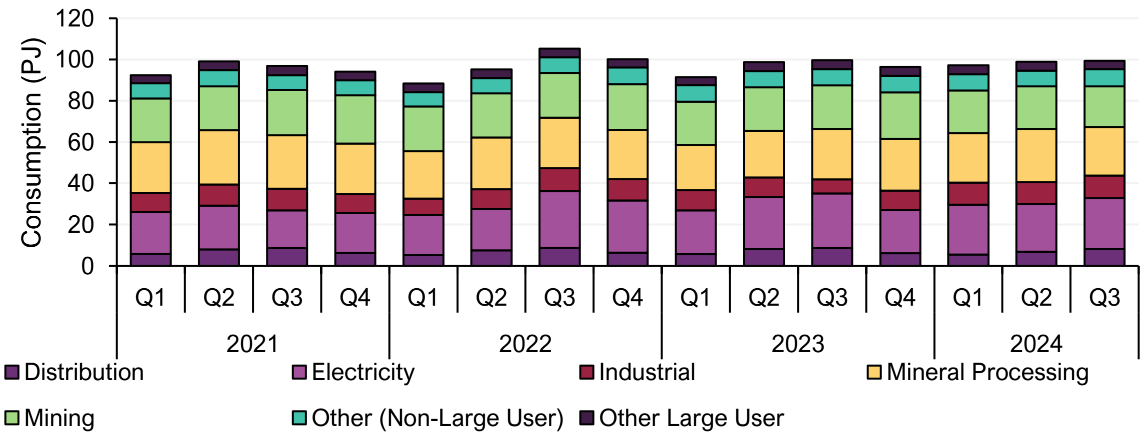
A total of 99.4 PJ was consumed from registered pipelines in the Western Australian domestic gas market in Q3 2024 (Figure 105). This was similar (-0.3 PJ) to Q3 last year and a slight increase (+0.5 PJ) from Q2 2024. The largest difference compared to Q3 2023 was observed in the industrial sector, up by 4.2 PJ (+62%). This was driven by the Yara Pilbara Liquid Ammonia Plant doubling its consumption since last year, bringing it more in line with previous Q3s.

The other main difference to Q3 2023 was observed in gas usage for electricity, down by 2 PJ (-7%) as gas fired generation was displaced by other electricity generation sources such as distributed PV, wind and coal (see Section 3.2.1). Reductions were recorded across almost all gas fired power stations with only Alinta Wagerup Power Station the exception; gas consumption rebounded after a comparatively low level of consumption in 2023.

There are also changes in consumption when reviewing geographic zones with Q3 2023; Perth Metro region reduced its consumption by 5.3 PJ (-16%) compared to the same period last year, whereas the Dampier region increased its consumption by 2.7 PJ (+22%).

**Figure 105 Gas consumption in WA remained stable compared to Q3 2023**

WA quarterly gas consumption by sector – Q1 2021 to Q3 2024

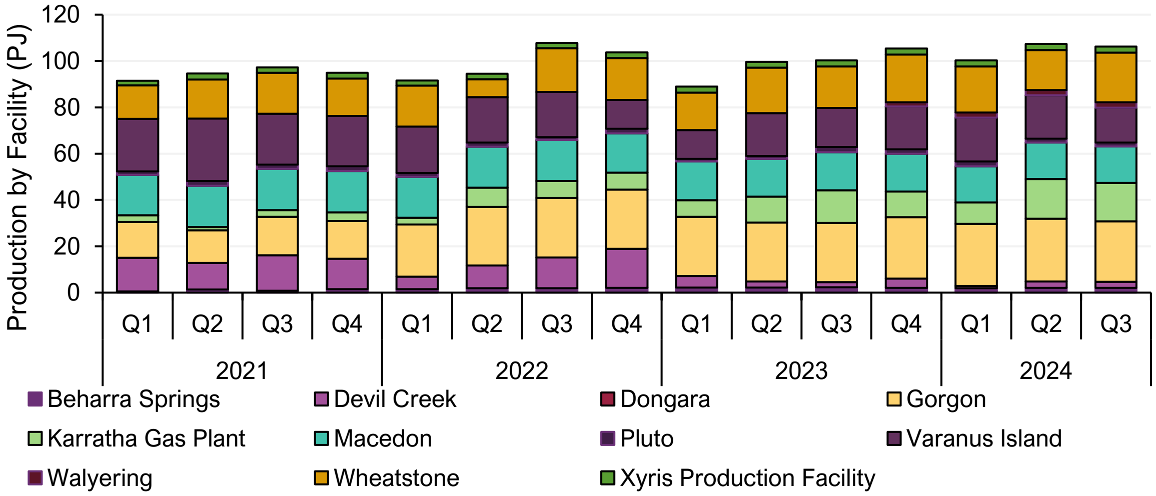


### 2.7.2 Gas production

Gas production in Western Australia was 106.3 PJ, an increase of 6 PJ (+6%) compared to Q3 2023 and a reduction of 1.1 PJ (-1%) compared to last quarter (Figure 106)[41].

**Figure 106 Q3 2024 saw an increase in gas production of 6 PJ**

WA quarterly gas production by facility – Q1 2021 to Q3 2024




The increase in production from Q3 2023 can be mainly attributed to higher output levels at Karratha Gas Plant, up by 2.5 PJ (+18%), and Wheatstone, up by 3.3 PJ (+18%). Wheatstone produced a total of 21.3 PJ this quarter, its highest production level since 2020. Another driver for the increase in production volumes was seen at the Walyering Production Facility; Walyering started production in Q3 2023 and currently operates at steady production levels.

Varanus Island reduced production by 1.7 PJ (-10%) compared to Q3 2023 and by 3.6 PJ (-19%) compared to the previous quarter. These reduced production volumes were most notably observed over July and September, where the Facility reported well and processing constraints.

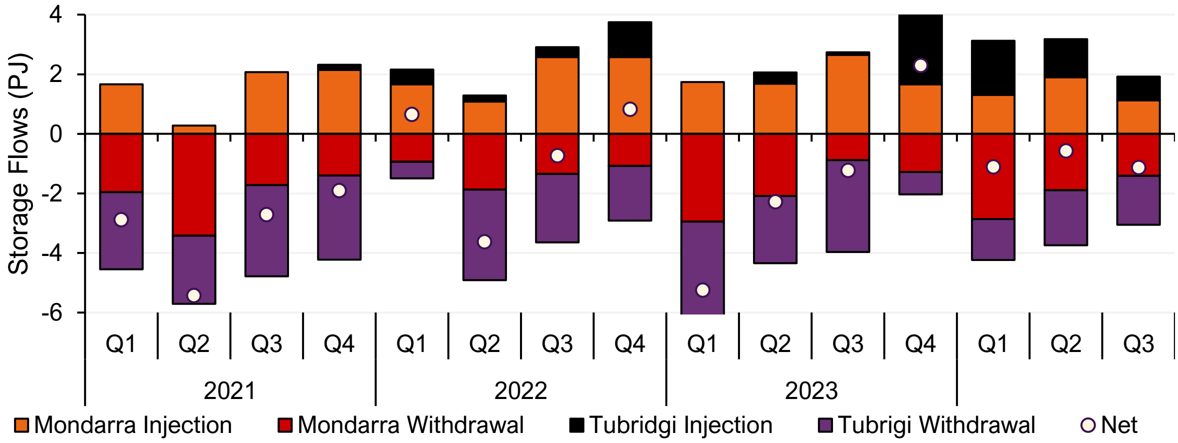
### 2.7.3 Storage facility behaviour

In Q3 2024 there was net withdrawal from storage facilities of 1.1 PJ (Figure 107). Net withdrawals have been observed in the last four Q3s. Withdrawal from storage in Q3 2024 was slightly lower compared to the same quarter last year, when net withdrawal was 1.2 PJ. Compared to Q2 2024, net withdrawals increased by 0.6 PJ (+98%).

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

**Figure 107 Net withdrawals from storage continue in Q3 2024.**

WA gas storage facility injections and withdrawals – Q1 2021 to Q3 2024



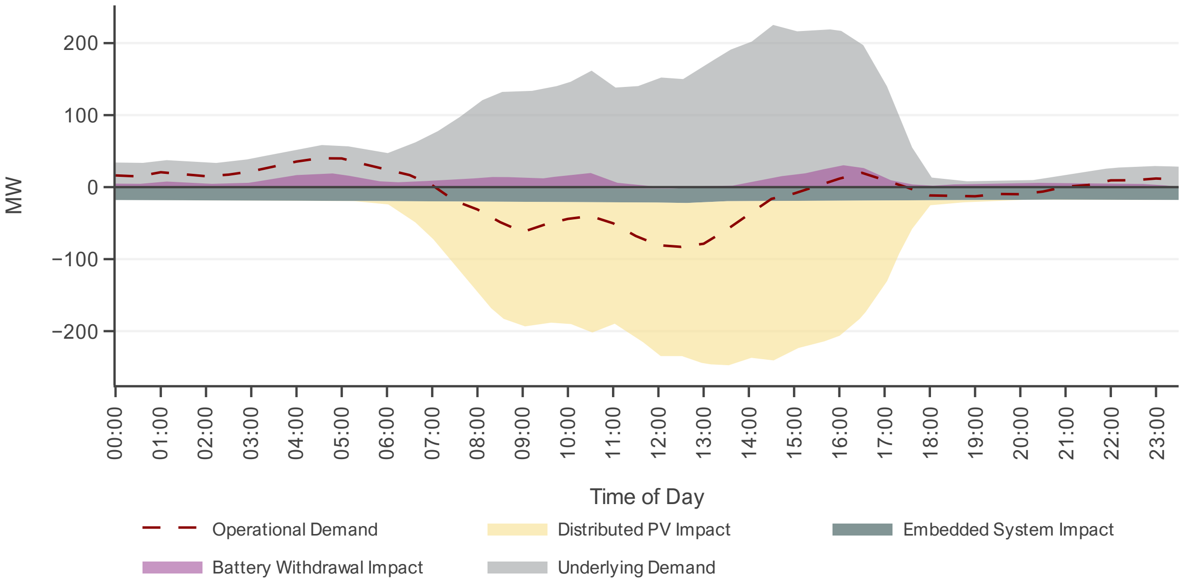
# 3 WEM market dynamics

## 3.1 Electricity demand and weather observations

Operational demand was steady in Q3 2024, with an average decrease of 9 MW compared to Q3 2023 to 1,991 MW (Figure 108). An average increase in underlying demand (+88 MW) was offset by an increase in estimated distributed PV generation[42] (+78 MW). Battery withdrawal increased operational demand slightly with an average 9 MW increase, while embedded systems[43] contributed an average of 19 MW to lowering operational demand compared to Q3 2023.

**Figure 108 An increase in underlying demand was largely offset by increased distributed PV**

Change in WEM average operational demand components by time of day – Q3 2023 vs Q3 2024



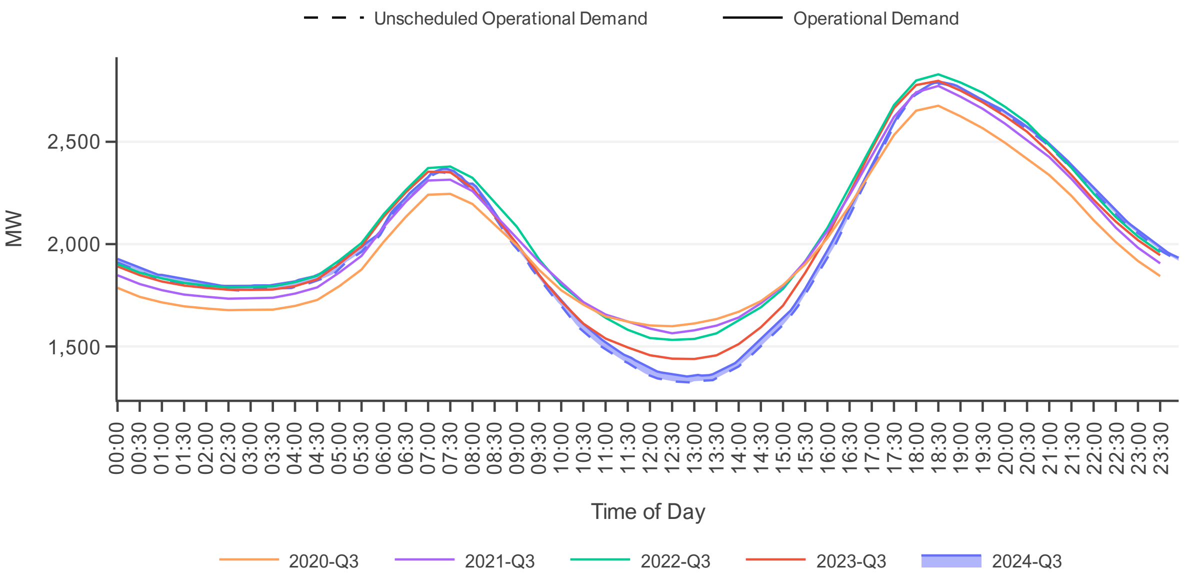

The increase in distributed PV and its erosion of operational demand during daylight hours is also evident when assessing quarterly demand profiles across Q3 of the last four years (Figure 109). Over this period, Q3 2024 had the lowest average operational demand despite also having the highest battery withdrawal recorded during the midday trough.

[42] Estimated distributed PV is an extrapolation based on solar irradiance data and installed distributed PV capacity data available to AEMO. For QED Q3 2024, AEMO has used a new data source in estimating DPV generation, and as such may contribute to the generation differences when comparing to prior quarters.

[43] An embedded system is a network connected to the 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.

**Figure 109 Average operational demand in Q3 continues to decrease despite support from scheduled battery withdrawal**

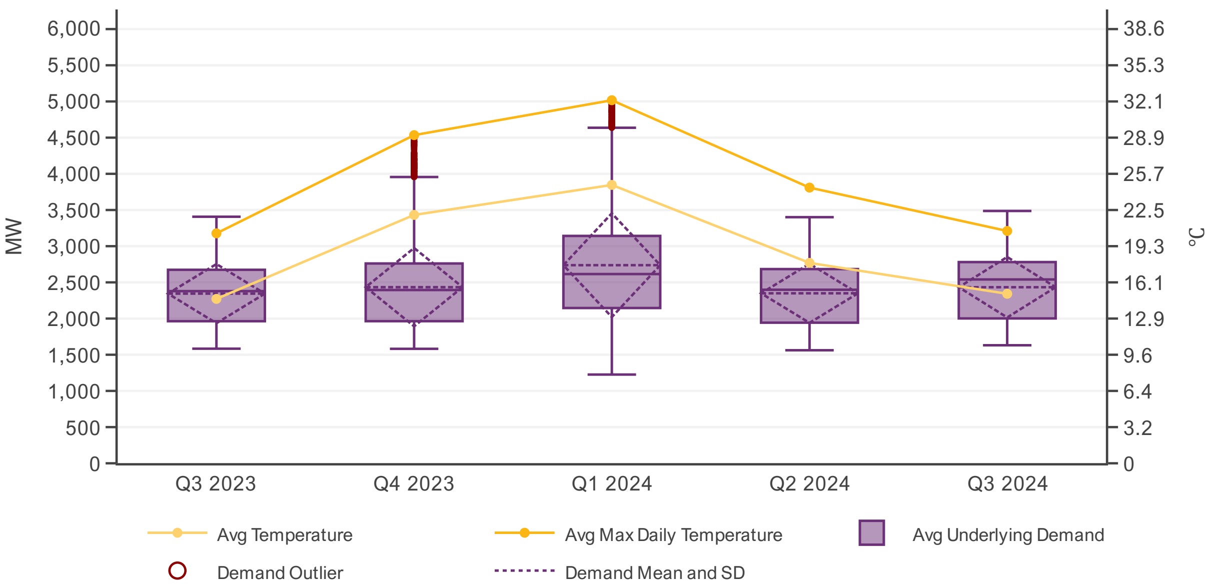
Average operational demand and average unscheduled operational demand – Q3s




Temperatures for Q3 2024 were relatively consistent with historical Q3 temperatures; average temperature slightly increased to 15.1°C (+0.5°C) and average maximum temperature to 20.6°C (+0.2°C). Temperature contributions to increases in underlying demand therefore are likely negligible. In addition, the spread of average underlying demand was consistent with the prior Q3, with a mean of 2,433 MW and standard deviation of 418 MW for Q3 2024, and 2,344 MW mean and 409 MW standard deviation for Q3 2023.

**Figure 110 Typical Q3 temperatures resulted in low variation of underlying demand through the quarter**

Average temperature and average maximum daily temperature, with average operational demand – Q3 2023 to Q3 2024

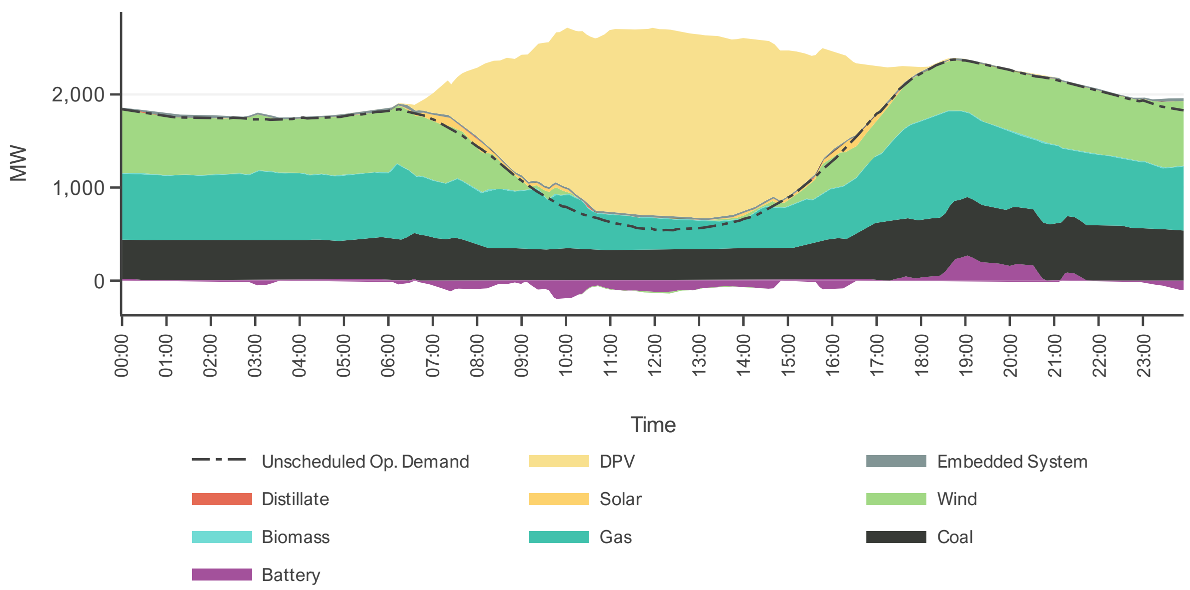


### 3.1.1 Minimum Unscheduled Operational Demand record on Sunday 22 September 2024

On Sunday 22 September 2024, the WEM experienced a record minimum average unscheduled operational demand[44] record of 538 MW during the 12:20 interval (Figure 111). This occurred during a long weekend and was driven by clear, sunny conditions and mild temperatures enabling high distributed PV contribution (estimated 2,005 MW during the record interval). Withdrawal from batteries of 131 MW assisted in increasing average operational demand for the interval to 680 MW, with a minimum average operational demand for the day of 659 MW observed during 12:40 interval.

**Figure 111 Average unscheduled operational demand record observed on 22 September 2024**

22 September 2024, five-minute average generation by fuel type and unscheduled operational demand (MW)




## 3.2 Electricity generation

### 3.2.1 Change in fuel mix

The total generation output over Q3 2024 was, on average, 88 MW higher than Q3 2023 due to the increase in underlying demand. The majority of the increase was met by higher wind, distributed PV and coal contributions which displaced gas generation (Figure 112).

Changes in generation by fuel type and time of day, compared to Q3 2023 (Figure 113 and Table 9) were:

- An increase in wind resource availability and the introduction of the Flat Rocks Wind Farm (76 MW maximum capacity) resulted in a 90 MW uplift in wind contribution, with increases observed during all intervals.
- Distributed PV increased 78 MW, as discussed in Section 3.1.
- Coal increased by 30 MW due to coal facility availability increasing from 75% in Q3 2023 to 86% in Q3 2024. The increased contribution occurred outside the midday trough, where it was displaced by distributed PV.

[44] Unscheduled operational demand represents the total injection from registered facilities that does not relate to scheduled withdrawal (withdrawal from energy storage systems).

- An increase in battery contribution of 9 MW can be linked to the introduction of the Collie Battery, the second battery in the WEM, which was undergoing commissioning tests during the quarter. In addition, Kwinana Battery Energy Storage System (Kwinana BESS) was continuing to undergo commissioning tests during Q3 2023. Injection from batteries increased the most during the morning and evening peaks.
- Embedded Systems provided 19 MW more than Q3 2023, with a consistent spread across all intervals.
- Gas generation was down at all times of the day (-128 MW) due to displacement by distributed PV and lower cost dispatchable generation.

**Figure 112 Gas-fired generation was displaced by an increase in wind, distributed PV and coal**

Change in quarterly average generation – Q3 2023 vs Q3 2024

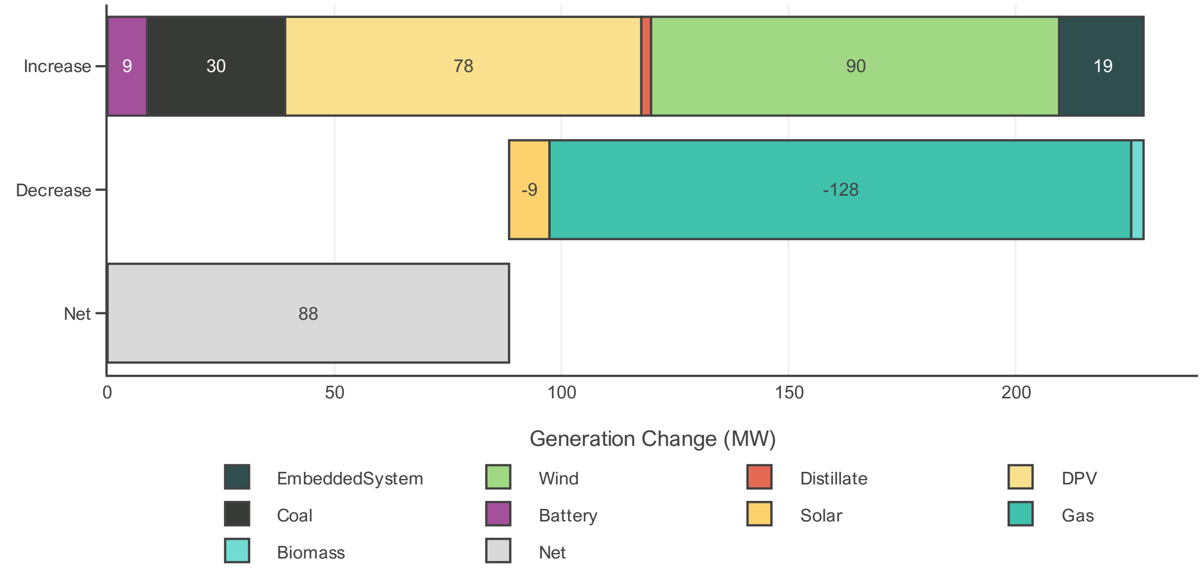



**Figure 113 Wind and coal displaced gas-fired generation at all times of the day**

Average WEM change in fuel mix by time of day – Q3 2023 vs Q4 2024

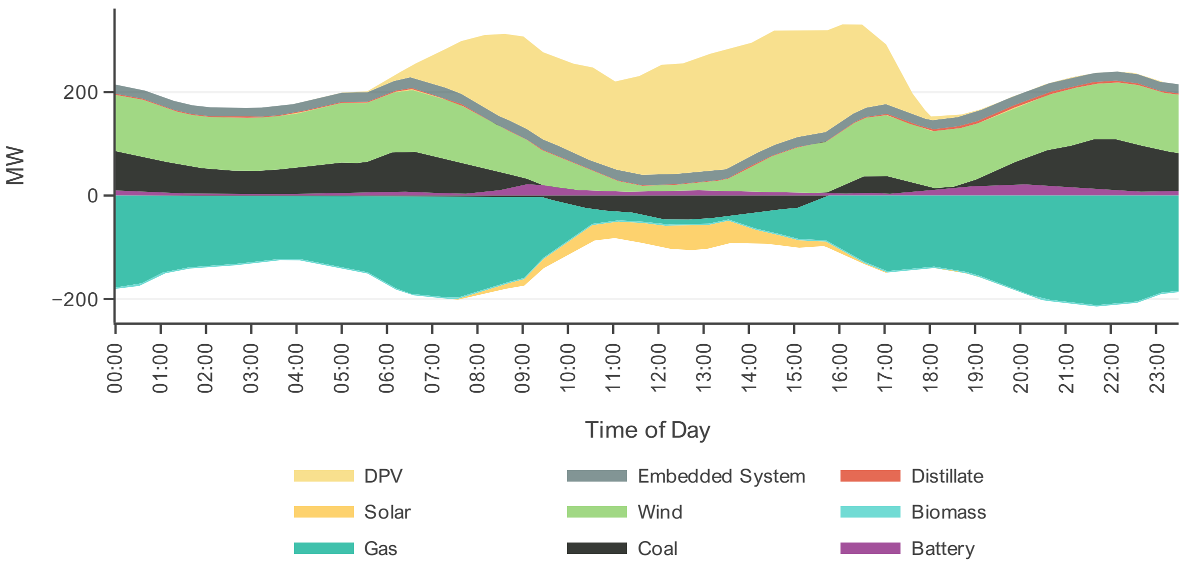


**Table 9 WEM fuel mix Q3 2023 and Q3 2024**

| Quarter | Coal | Gas | Distillate | Grid Solar | Wind | Biomass | Battery | Distributed PV |
|---|---|---|---|---|---|---|---|---|
| Q3 2023 | 28.3% | 42.2% | 0.0% | 1.5% | 13.5% | 0.4% | 0.2% | 13.9% |
| Q3 2024 | 28.6% | 35.4% | 0.1% | 1.0% | 16.7% | 0.3% | 0.6% | 16.7% |
| Change | 0.3% | -6.8% | 0.1% | -0.5% | 3.2% | -0.1% | 0.4% | 2.8% |

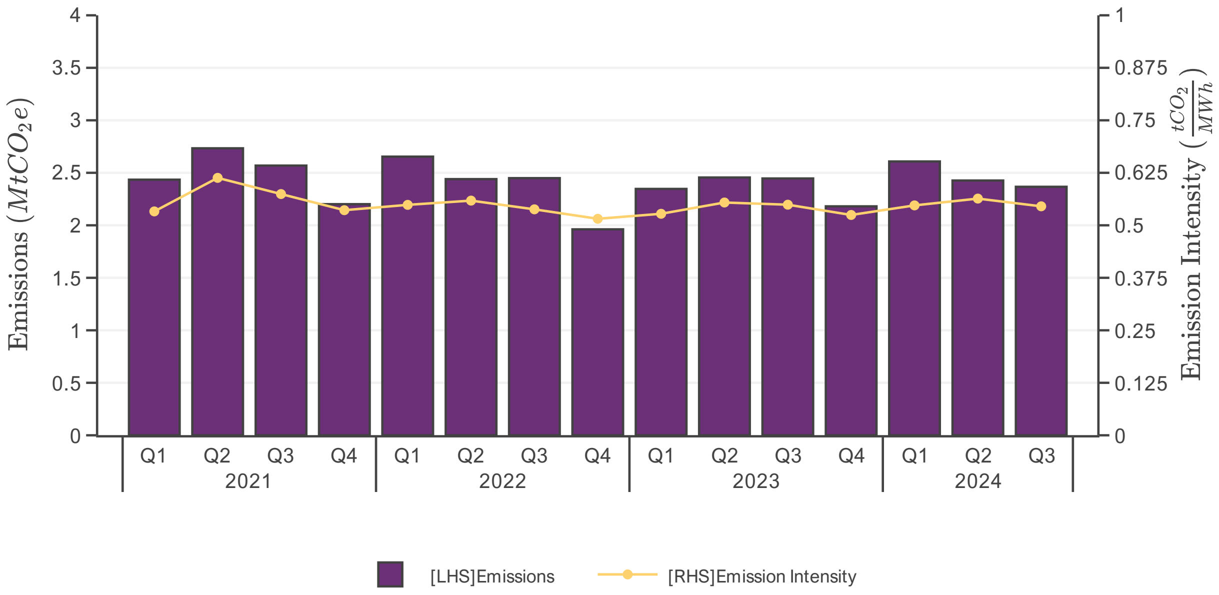
### 3.2.1 Carbon emissions

Total WEM emissions[45] in Q3 2024 were 2.37 $MtCO_2e$, a decrease of 0.08 $MtCO_2e$ (-3.2%) on Q3 2023. This can be attributed to:

- A reduction in average emissions intensity from 0.549 $tCO_2e/MWh$ to 0.545 $tCO_2e/MWh$ (-0.7%). This occurred due to an increase in contribution from renewable energy facilities (primarily wind), which was partially offset by an increase in coal generation.
- A reduction in average operational demand (see Section 3.1).

**Figure 114 WEM emissions reduced 3.2% compared to Q3 2023**

Quarterly WEM emissions and emission intensity – Q1 2024




### 3.2.2 Renewable contribution

Renewable contribution increased to 35.2% of the overall generation (Figure 115), a 5.7 pp increase compared to Q3 2023, and a new Q3 record, driven by increases in wind, battery and solar. The highest five-minute average renewable contribution was 80.1%, observed on 23 September 2024 during the 13:25 interval.

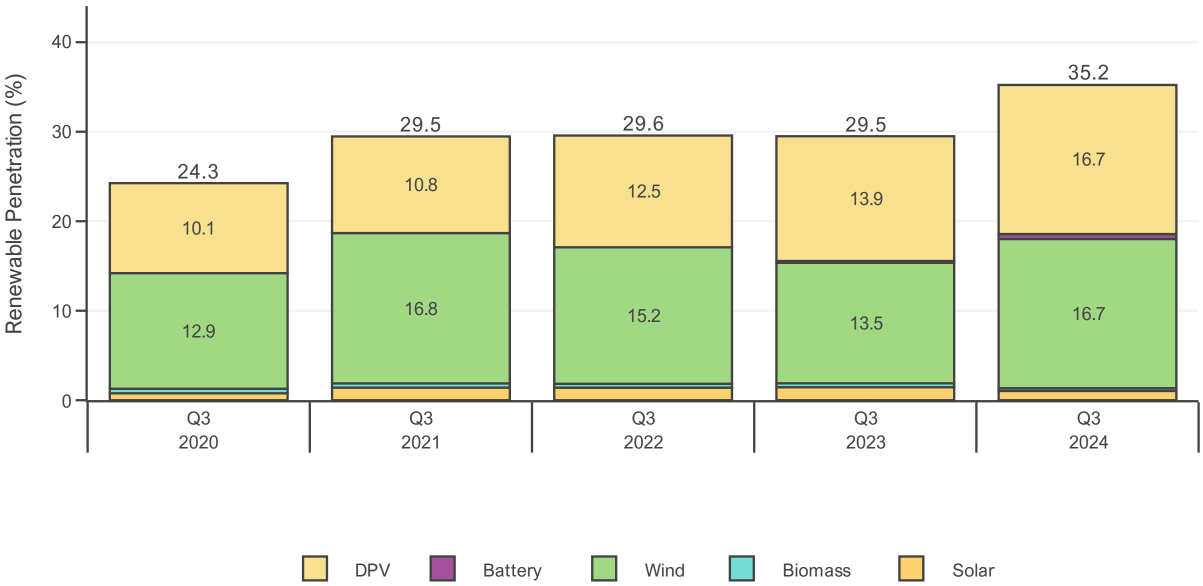
The key drivers of the new quarterly renewable contribution record were:

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

- Increased in wind generation from 13.5% to 16.7%, driven by the introduction of Flat Rocks Wind Farm, as well as higher wind resource availability compared to Q3 2023 for wind farms already operating. A maximum wind generation record was also observed with 1,005 MW recorded on 6 July 2024 during the 15:40 interval.
- An increase in distributed PV resulting in 16.7% contribution, a record for the quarter compared to previous years, surpassing the record from Q3 2023. This was driven by an estimated increase in installed capacity of 280 MW compared to Q3 2023.
- An increase in the output of Kwinana BESS and introduction of the Collie Battery increasing battery contribution to 0.6%. A record high battery injection of 292 MW was observed on 27 September 2024 during the 18:25 interval.

**Figure 115 Average renewable contribution over Q3 2024 reached 35.2%, a new Q3 record**

Renewable contribution components – Q3s




## 3.3 Short Term Energy Market

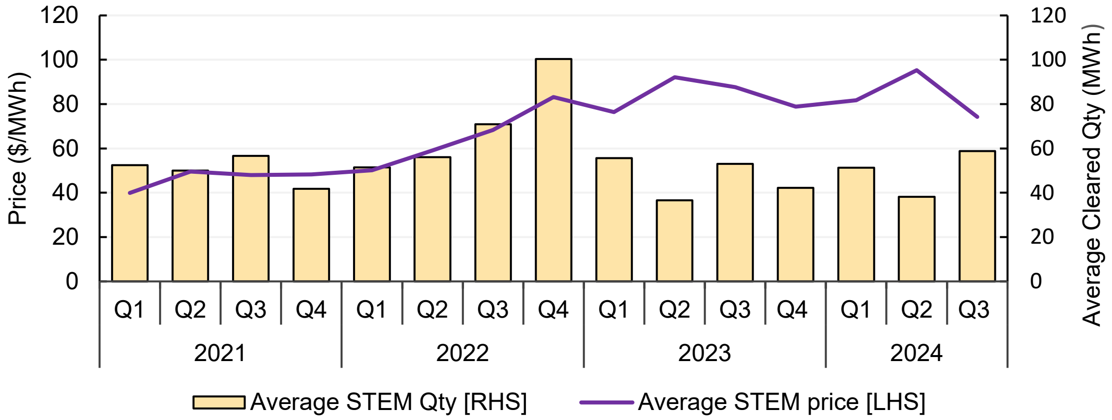
The average Short-Term Electricity Market (STEM) price[46] for Q3 2024 was $74.25/MWh, a decrease of $21.03 /MWh (-22%) from the previous quarter and a decrease of $13.46/MWh (-15%) compared to Q3 last year (Figure 116). This decrease in average STEM price was mostly driven by the STEM price clearing near the price floor of -$1,000 for several intervals on eight trading days in September 2024. This resulted in an average STEM price of $40.43/MWh in September.

The quarterly average quantity of energy cleared in the STEM per interval was 59 MWh, an increase of 21 MWh (+54%) from Q2 2024. When compared to the same quarter last year, quantities cleared increased by 6 MWh (+11%).

[46] AEMO has changed this reporting metric from 'weighted average STEM price' to 'average STEM price' for better alignment with other metrics in this report such as the average reference trading price.

**Figure 116 The average STEM price dropped by 22% in Q3 2024**

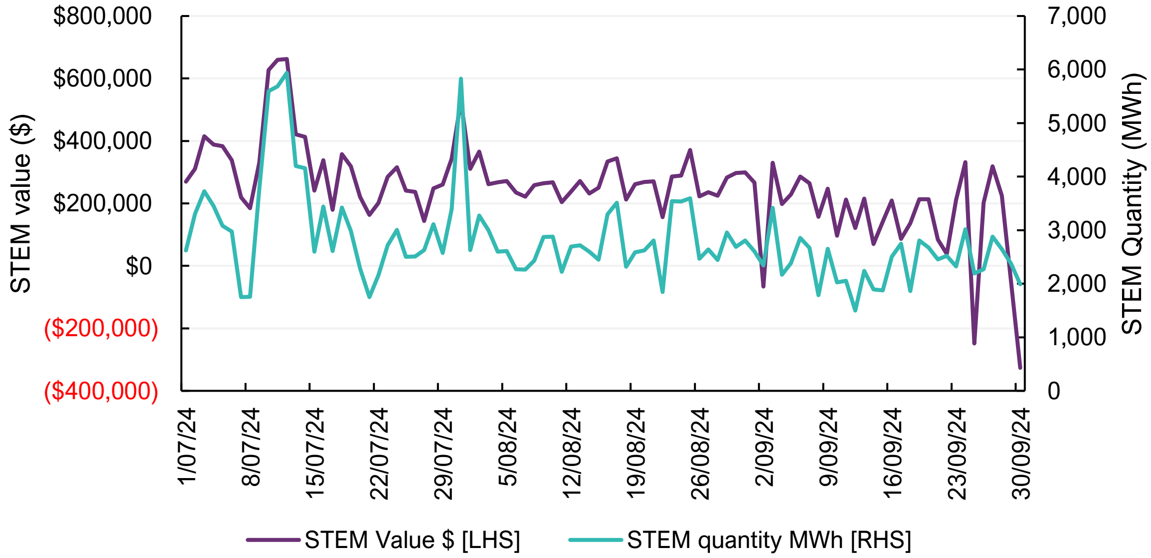
WEM average STEM Price and quantity cleared in STEM – Q1 2021 to Q3 2024




The daily traded value in STEM ranged from -$326,341 to $662,315 in Q3 2024, whereas the daily quantities traded in MWh varied between 1,499 MWh and 5,939 MWh (Figure 117). The negative STEM daily values are a result of the STEM price reaching the floor price of $-1,000 on three intervals in July and clearing below $-980 on 30 intervals in September 2024.

**Figure 117 Negative daily STEM values as a result of negative prices in STEM**

Daily quantities (MWh) and value ($) traded in STEM – Q3 2024



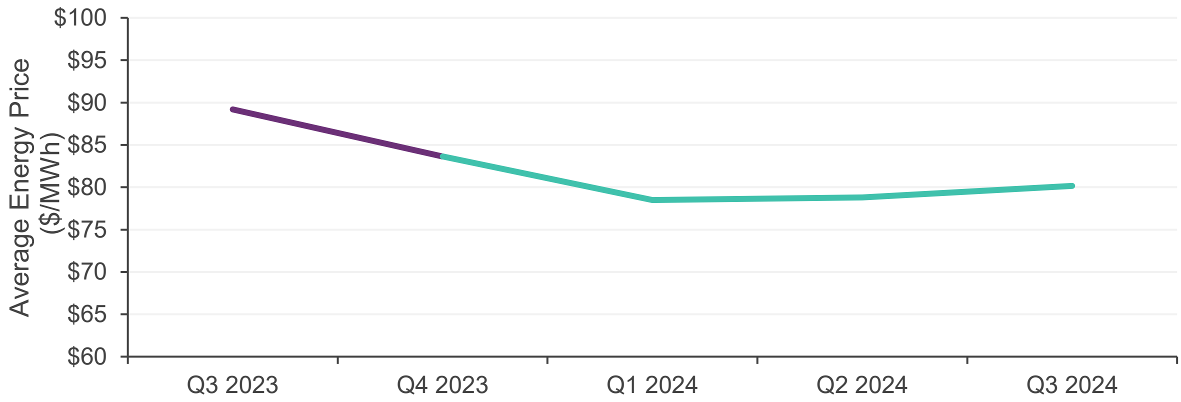
## 3.4 WEM Real-Time Market prices

### 3.4.1 Real-Time Market price dynamics

The average energy price[47] in Q3 2024 was $80.15/MWh. This was a decrease of -$9.03/MWh (-10%) from Q3 2023 where there was lower than average facility availability combining with elevated operational demand that resulted in higher energy prices for that quarter[48] (Figure 118). The average energy price in Q3 2024 was marginally (+$1.37/MWh) higher than Q2 2024.

**Figure 118 Average Energy prices remained relatively unchanged from Q2 2024**

Quarterly Average Energy Prices – Q3 2023 to Q3 2024

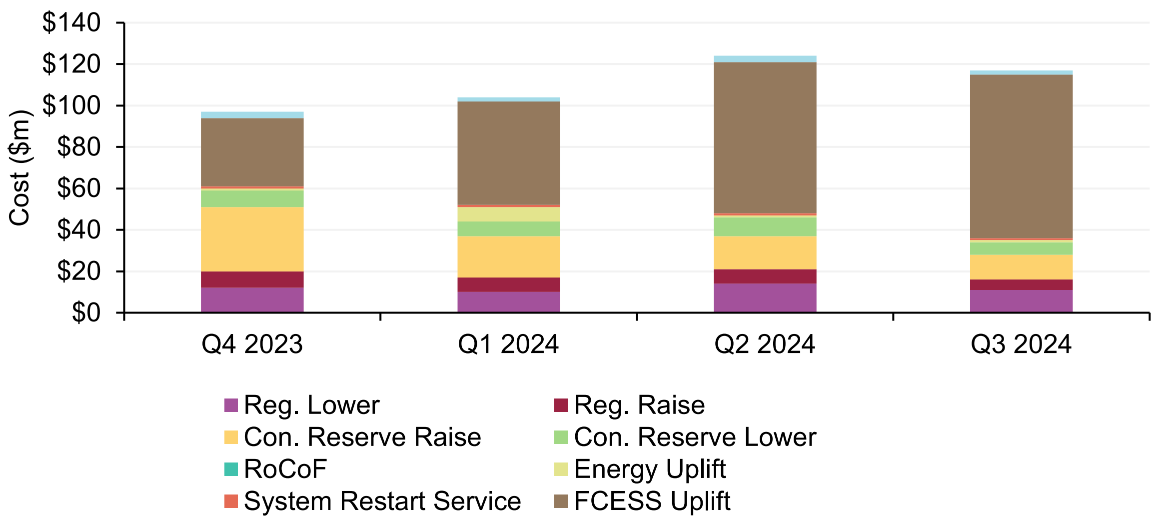



### 3.4.2 Essential System Services (ESS) costs

The total cost of ESS and Uplift in Q3 2024 decreased by -$6.2 million (-5%) compared to Q2 2024 (Figure 119).

**Figure 119 Total Essential System Services costs decreased $6.23M compared to Q2 2024**

Total Costs ESS and Uplift Q4 2023 to Q3 2024




[47] Energy Prices refer to Final Reference Trading Prices from the commencement of the new market (Q4 2023) onwards and Balancing Prices in prior quarters.

[48] See Quarterly Energy Dynamics – Q2 2023 at https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

This was driven by decreases across all FCESS market services, most significantly Contingency Reserve Raise (-$4.4 million, -28%), partially offset by an increase in FCESS Uplift costs of $6.6 million (+9%).

- Contingency Reserve Raise and Contingency Reserve Lower together cost $17.7 million over the quarter, down from $24.8 million in Q2 2024. The cost of Regulation Raise and Lower fell from $21.3 million in Q2 2024 to $16.3 million, decreasing by $2.1 million (-29%) and $2.8 million (-20%) respectively. In all cases the reduction was to a significant extent driven by the new WEM Rules introduced on 22 May 2024, just over halfway through Q2 2024, which implemented a price cap of $500/MW/hr on these Market Services.
- There were no enablement costs from Rate of Change of Frequency (RoCoF) Control service this quarter.
- Energy Uplift payments totalled $1.2 million this quarter, 21% higher than the cost in Q2 2024.
- FCESS Uplift costs totalled $79.3 million, an increase of $6.6 million (+9%) compared to Q2 2024, accounting for 56% of total FCESS costs this quarter. See Section 3.4.3 for further details.

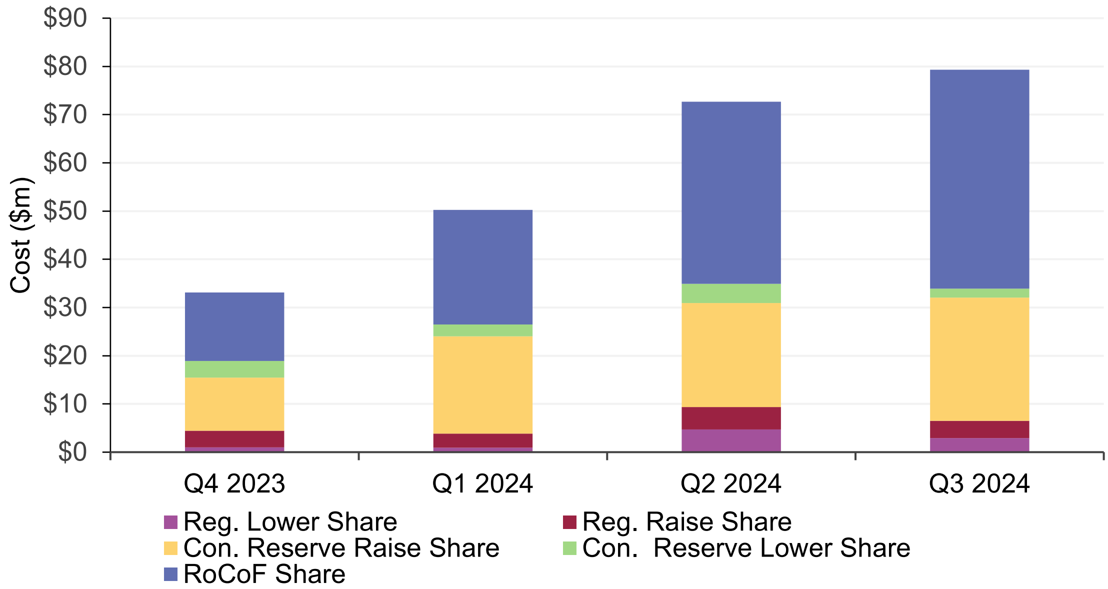
### 3.4.3 FCESS Uplift share costs

When a Facility receives FCESS Uplift[49] payments in a Dispatch Interval, those costs are assigned equally through all FCESS Market Services the Facility was enabled for in that Dispatch Interval, and recovered via normal cost distribution processes for that Market Service[50].

The total cost of FCESS Uplift in Q3 2024 was $79.3 million. Figure 120 provides a breakdown of the total FCESS Uplift costs assigned to each of the five FCESS market services.

**Figure 120 FCESS Uplift costs increased by $6.6 million (9%) compared to Q2 2024**

Total costs of FCESS Uplift Q4 2023 to Q3 2024




[49] A payment made to a Market Participant as compensation for Enablement Losses incurred by a Registered Facility providing one or more Frequency Co-optimised Essential System Services.

[50] Note that on a high level, Regulation Raise and Lower costs are paid by consumers, semi-scheduled facilities and non-scheduled facilities; Contingency Reserve Lower costs are paid by consumers; Contingency Reserve Raise costs are paid by generating facilities; and RoCoF control service costs are paid by generating facilities, network operators, and consumers. Refer to the WEM Rules for full details including exceptions.

In summary:

- The majority (57%) of this cost was recovered through RoCoF control service charges, a slightly higher percentage to previous quarters. This occurs because it is rare for a facility to be enabled for a Regulation or Contingency Reserve market service without also being enabled for RoCoF market service: as a result, whenever a facility receives FCESS Uplift payments for a Regulation or Contingency Reserve market service, part of that cost is recovered from RoCoF market service.
- 32% was recovered from Contingency Reserve Raise, while Contingency Reserve Lower, Regulation Raise, and Regulation Lower accounted for 2%-5% each.

### 3.4.4 Real-Time Market costs

Figure 121 presents energy and ESS costs (including Uplift costs) as a price-per-MWh normalised by total energy consumed, enabling some comparison of costs between new and previous markets[51] and periods with different demand.

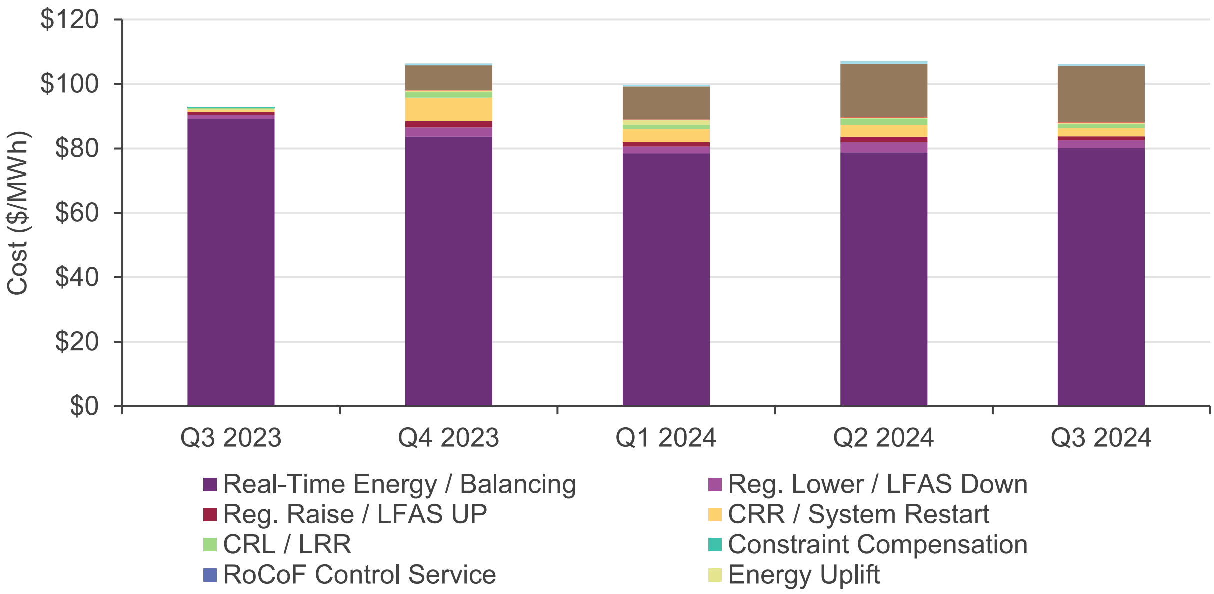
The total cost of the Real-Time Market (Energy and ESS) rose from $92.87/MWh in Q3 2023, to $106.22/MWh in Q3 2024, an increase of 14%. The average cost of energy decreased by $9.03/MWh, however the cost of ESS (excluding FCESS Uplift) rose $5.05/MWh compared to ancillary services (AS), while the cost of FCESS Uplift and Energy Uplift was $17.35/MWh higher than Constrained Compensation, resulting in a net increase.

Compared to Q2 2024, total costs decreased by $0.83/MWh, driven by lower enablement costs for all FCESS Market Services, offset by higher Real-Time Energy (+$1.37/MWh) and FCESS Uplift (+$0.88/MWh) costs.

Note that these costs do not include Reserve Capacity or Supplementary Reserve Capacity (SRC).

**Figure 121 Real-Time Market costs decreased $0.83/MWh compared to Q2 2024**

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




[51] The Real-time Market commenced on 1 October 2023 meaning data from Q3 2023 relates to the Balancing Market.

# 4 Reforms delivered

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

Table 10 provides a brief description on the implementation of reforms delivered across the WEM, NEM and east coast gas markets over the last quarter.

**Table 10 Reforms delivered Q3 2024**

| Reform initiative | Market | Description | Reform delivered |
|---|---|---|---|
| **WA Distributed Energy Resources (DER) Dashboard Uplift (DER Roadmap)** | WEM | As part of the WA DER Program, AEMO uplifted the visuals and data displayed, reflecting changes made to the WA DER Register to produce a specific WEM DER Register dashboard[52], ensuring compliance with AEMO's reporting obligations outlined in AEMO's WEM DER Register Information Procedure. | July 2024 |
| **ASX Wallumbilla Futures** | East Coast Gas | The ASX Wallumbilla Natural Gas Futures contract commenced trading on 19 August 2024. This product replaces a previously cash settled product with a product that is physically deliverable on the AEMO GSH (Gas Supply Hub) at Wallumbilla.<br>Changes to the ASX product have been industry led and jointly developed by the ASX and AEMO. The first month of delivery was October 2024 after the product both traded on the ASX and was taken to physical delivery on the AEMO GSH.<br>The product is designed to support Australia's east coast gas market by providing a transparent forward price curve out to 3 years. The contract will also help to improve liquidity in the GSH and provide an additional hedging tool that allows gas market participants to efficiently manage their risk exposure.<br>Live prices can be found at https://www.asxenergy.com.au/futures_gas. | August 2024 |
| **Retail Market Improvements (Net System Load Profile)** | NEM | AEMO successfully implemented an adjustment to the way basic meters are settled in the wholesale market. The introduction of a preferred longer-term Net System Load Profile (NSLP) Methodology provides for a more indicative NSLP shape supporting critical market settlements eliminating energy volume spikes in profile reads. | September 2024 |
| **Capacity Assignment of 2024 Reserve Capacity Cycle (RCM Review)** | WEM | System and process enhancements have been delivered to enable AEMO to assign Capacity Credits for the 2024 Reserve Capacity Cycle in the WEM. These changes implement new functionality introduced in the RCM Review gazette including:<br>• Implement Capability Classes in Appendix 3 rules relating to Network Access Quantity (NAQ);<br>• Assignment of capacity to Separately Certified Components of a Facility; and<br>• Publish NAQ inputs and outputs to the public data website.<br>Additionally new functionality is introduced to enable Reserve Capacity Testing using Facility Sub-Metering for Capacity Credits effective from 1 October 2024. | September 2024 |

[52] See https://www.aemo.com.au/energy-systems/electricity/der-register/data-der/data-dashboard-wa.

In addition to these reforms, work continues to progress on the next wave of initiatives set for release later in 2024 and in early 2025. Table 11 below provides a brief description of those initiatives to be delivered in Q4 2024 and Q1 2025.

**Table 11 Upcoming reforms Q4 2024 – Q1 2025**

| Reform initiative | Market | Description | Reform to be delivered |
|---|---|---|---|
| **FCESS Uplift Review** | WEM | Energy Policy WA is proposing to introduce changes to the FCESS markets in the WEM to reduce the costs associated with the provisioning of FCESS relative to comparable historical Ancillary Service costs in the Balancing Market.<br>The proposed changes will introduce:<br>• A new FCESS Tie-Break methodology;<br>• Changes to FCESS Uplift Payments; and<br>• Additional Facility commitment obligations on Market Participants.<br>The technical changes will be implemented in the WEM Dispatch Engine and WEM Settlement system to align with the proposed rule changes which are expected to commence from 20 November 2024. Reference:<br>https://www.wa.gov.au/government/announcements/energy-policy-wa-has-released-the-exposure-draft-of-the-fcess-cost-review-amending-rules-consultation | November 2024 |
| **Retail Market Improvements (Metering Substitutions)** | NEM | As part of the ongoing suite of Retail Market Improvement initiatives, work continues to progress on the implementation of various Substitution Type and Reason code changes associated with small market interval metering providing for greater insights, improved customer communication and support and more efficient processes including introduction of seven new substitution types; the obsoletion of substitution type 16; and the addition of 10 new Reason Codes. Reference: https://aemo.com.au/consultations/current-and-closedconsultations/july-2023-retail-electricity-market-procedures-consultation | November 2024 |
| **Outage Intention Plans (WEM Reform)** | WEM | Modifications to the WEM Outage Management system will implement new obligations in the WEM Rules taking effect from 1 March 2025, Outage Intention Plans (OIP). The OIP report will significantly improve the Outage coordination process between AEMO and Market Participants. It will provide all Market Participants with early visibility of the reserve requirements for the next calendar year, as well as planned high impact Network Outages, to then outlay their intended Outages for the upcoming year. (i.e. routine maintenance, any major overhauls etc. | December 2024 |
| **Improving Security Frameworks for the Energy Transition** | NEM | In accordance with the Improving Security Frameworks for the Energy Transition, AEMO and participants continue to work towards the following December 2024 milestone:<br>• Commencement of the new inertia framework in the NEM with AEMO to publish updated inertia requirements, methodology and system security reports.<br>• Publication of the Transitional Services Guideline providing AEMO with the ability to procure transitional services.<br>• Publication of the first transition plan report for system security in the NEM.<br>Reference: https://aemo.com.au/initiatives/major-programs/improvingsecurity-frameworks-for-the-energy-transition | December 2024 |
| **Frequency Performance Payments – Non-financial operation** | NEM | In accordance with the NEM Primary Frequency Response Incentive Arrangement rule change, work continues to progress with the establishment of a new Frequency Performance Payments system and associated procedures and guidelines (including Frequency Contribution Factor Procedures) that provide incentives for all facilities to operate in a way that helps maintain power system frequency within the normal operating band, at the lowest cost to consumers.<br>Implementation of new FPP system includes an extended period of non-financial operation from December 2024 of the new FPP system to allow market participants to familiarise themselves with its operation ahead of go-live in June 2025. Reference: https://aemo.com.au/initiatives/major-programs/frequencyperformance-payments-project | December 2024 |

| Reform initiative | Market | Description | Reform to be delivered |
|---|---|---|---|
| **SCADA Lite** | NEM | SCADA Lite (an AEMO foundational and strategic initiative under the NEM Reform Program) will enable NEM non-NSP participants to establish a bi-directional connection to exchange operational information (telemetry and control) with AEMO. Specifically, those requirements defined in both the Wholesale Demand Response Guidelines (Version 1.0, Effective Date: 24 June 2021) and Power System Data Communication Standard (Version 3.0, Effective Date: 3 April 2023). AEMO continues to progress with implementation in conjunction with its pilot test partner. Reference: https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/scada-lite | January 2025 |

# List of tables and figures

## Tables



## Figures

# Abbreviations

| Abbreviation | Expanded term |
|---|---|
| ACCC | Australian Competition and Consumer Commission |
| AEMO | Australian Energy Market Operator |
| APLNG | Australia Pacific LNG |
| ASX | Australian Securities Exchange |
| BESS | Battery energy storage system |
| CGP | Carpentaria Gas Pipeline |
| DAA | Day Ahead Auction |
| DWGM | Declared Wholesale Gas Market |
| EGP | Eastern Gas Pipeline |
| FCAS | Frequency control ancillary services |
| FCESS | Frequency Co-Optimised Essential System Services |
| GJ | Gigajoule/s |
| GWh | Gigawatt hour/s |
| GLNG | Gladstone LNG |
| GSH | Gas Supply Hub |
| IRSR | Inter-regional settlement residue |
| L1SE | Contingency lower 1-second FCAS |
| L6SE | Contingency lower 6-second FCAS |
| LNG | Liquefied natural gas |
| MPC | Market price cap |
| MSP | Moomba to Sydney Pipeline |
| $MtCO_2$-e | Million tonnes of carbon dioxide equivalents |
| MW | Megawatt/s |
| MWh | Megawatt hour/s |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NCESS | Non-Co-optimised Essential System Service |
| NGP | Northern Gas Pipeline |
| pp | Percentage points |
| PJ | Petajoule/s |
| PV | Photovoltaic |
| QED | Quarterly Energy Dynamics |
| QCLNG | Queensland Curtis LNG |
| QNI | Queensland – New South Wales Interconnector |
| R1SE | Contingency raise 1-second FCAS |
| RBP | Roma Brisbane Pipeline |
| RERT | Reliability and Emergency Reserve Trader |
| RTM | Real Time Market |

| Abbreviation | Expanded term |
|---|---|
| **SCED** | Security Constrained Economic Dispatch |
| **STEM** | Short-Term Energy Market |
| **STTM** | Short Term Trading Market |
| **SWQP** | South West Queensland Pipeline |
| **TJ** | Terajoule/s |
| **UGS** | Underground Storage Facility |
| **VRE** | Variable renewable energy |
| **VNI** | Victoria – New South Wales Interconnector |
| **WEM** | Wholesale Electricity Market |
| **WDR** | Wholesale demand response |