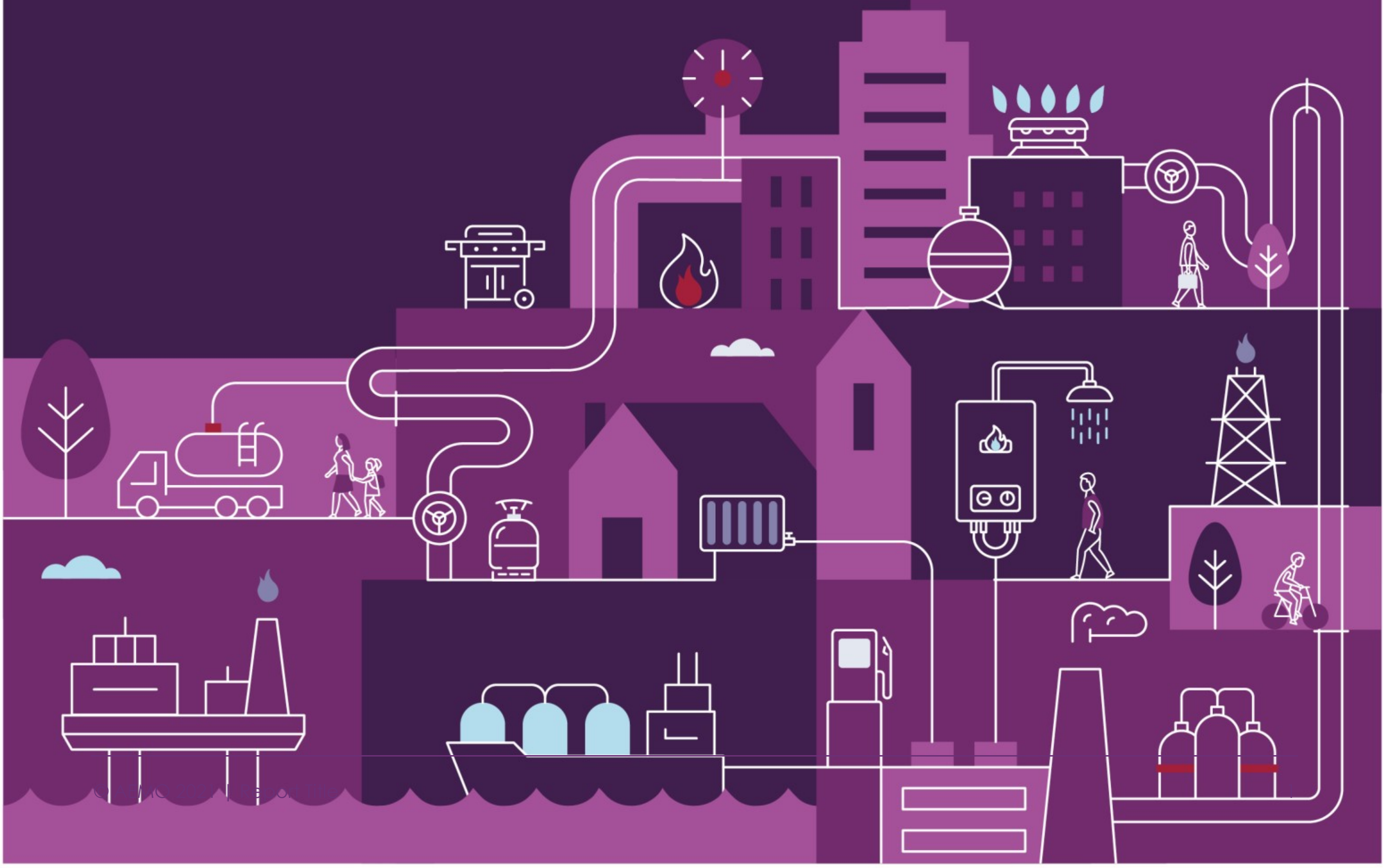
AUSTRALIAN ENERGY MARKET OPERATOR

Quarterly Energy Dynamics Q1 2025

May 2025



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

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

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

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

Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q1 2025 (1 January to 31 March 2025). This quarterly report compares results for the quarter against other recent quarters, focusing on Q1 2024 and Q4 2024. Geographically, the report covers:

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

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Executive summary

East coast electricity and gas highlights

Underlying demand grew to a new Q1 record, offset by record Q1 distributed photovoltaic (PV) output

- Underlying demand across the National Electricity Market (NEM) regions averaged 25,162 megawatts (MW) in Q1 2025, up 340 MW (+1.4%) to a new Q1 record. Victoria and South Australia drove this increase, with hot weather lifting demands. South Australian underlying demand grew 7.6% on Q1 2024 to a new all-time quarterly high, and Victorian underlying demand, up 6.3%, was the highest for a Q1 since 2014.
- With NEM-wide distributed PV output reaching a record Q1 average of 3,782 MW, 512 MW (+16%) above Q1 2024, average NEM operational demand decreased by 172 MW (-0.8%) to 21,380 MW. Mild conditions in New South Wales and Queensland also offset operational demand growth in the southern mainland regions.
- Despite generally lower temperatures in Queensland, which led to year-on-year reductions in average underlying and operational demands, the region recorded a new all-time maximum demand of 11,144 MW in the half-hour ending 1800 hrs on Wednesday 22 January, 139 MW higher than the previous record set last summer.
- Growth in distributed PV output meant that minimum operational demand records were again set this quarter. New South Wales (2,718 MW) and Victoria (1,504 MW) both recorded new all-time minimum demands, and Q1 minimum demand records were set for the NEM (11,680 MW) and South Australia (-58 MW).

Average NEM wholesale prices stabilised in Q1 2025, with varied factors impacting regional price outcomes

- Wholesale spot prices averaged[1] $83 per megawatt hour (MWh) across all NEM regions in Q1 2025, $7/MWh (+9%) above the same quarter last year (Q1 2024), and $5/MWh (-6%) below the preceding quarter (Q4 2024). The NEM-wide year-on-year increase was driven by a very large uplift (+67%) in Tasmanian wholesale prices, with the mainland NEM average reducing from $78/MWh in Q1 2024 to $76/MWh this quarter.
- Upward pressures on wholesale prices included increased operational demand in the southern mainland regions and higher-priced coal and hydro generation offers. Prices set by coal generators when marginal increased from $71/MWh in Q1 2024 to $84/MWh in Q1 2025, and prices set by hydro generators rose from $85/MWh to $123/MWh.
- These upward forces were largely offset by downward price pressures, including fewer extreme price volatility events this quarter than during Q1 2024 and higher variable renewable energy (VRE) availability. Grid-scale solar and wind set prices more often this quarter, up from 10% of intervals in Q1 2024 to 15%, also causing the frequency and impact of negative prices to increase, particularly in the NEM's northern regions.

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

- Given these mixed price drivers, regional price outcomes were varied. Tasmanian wholesale prices were most heavily impacted by the changes in hydro offers, and increased from $67/MWh a year ago to $111/MWh. South Australia's wholesale prices increased by 20%, averaging $66/MWh, and Victoria saw a 15% rise to $59/MWh, with higher operational demand lifting prices throughout most hours of the day. High VRE output and lower operational demand in New South Wales offset higher-priced black coal offers, with prices just 1% higher, at $88/MWh, and reduced volatility in Queensland saw prices decrease by 24% to average $90/MWh.

Steady growth in wind, grid-scale solar and batteries increased renewable market share and reduced emissions

- Grid-scale solar generation achieved a new all-time high, increasing by 10% year-on-year to average 2,386 MW. Wind generation saw an 18% rise to average 3,517 MW, reaching a new Q1 high. Both increases were driven primarily by growth in availability at new and commissioning facilities.
- Battery generation output reached a new all-time high this quarter, increasing to an average of 98 MW (+86%), driven by new capacity entering the market.
- Conversely, average availablity and output from both black and brown coal-fired generators fell to new Q1 quarterly lows. Average black coal-fired generation was at 10,269 MW (-3.2%), while brown coal-fired generation averaged 3,429 MW (-6.7%).
- These changes resulted in renewables providing 43.0% of the NEM supply mix this quarter, up from 39.0% in Q1 2024, and drove quarterly NEM total emissions and emissions intensity to new Q1 lows. Total emissions were 27.4 million tonnes of carbon dioxide equivalent ($MtCO_2$-e) in Q1 2025, down 5.1% from Q1 2024, and emissions intensity averaged 0.59 tonnes of carbon dioxide equivalent (tCO_2-e)/MWh, down 4.4%.

East coast gas prices reached new Q1 high, as reduced supply from Queensland liquified natural gas (LNG) projects was offset by increased domestic production

- East coast wholesale gas prices averaged $13.26 per gigajoule (GJ) for the quarter, a new high for a Q1 and higher than Q1 2024's $11.60/GJ, but lower than Q4 2024, which averaged $13.60/GJ.
- Gas demand decreased by 2% from Q1 2024, with demand for Queensland LNG exports falling slightly (-3 petajoules [PJ]), while still recording its second highest level for a Q1, as well as reduced demand from gas-fired generation (-2 PJ), and lower AEMO markets demand (-1 PJ). Victoria experienced the largest market decrease, led by a significant reduction in industrial demand.
- While projects associated with Queensland LNG exports reduced supply into the domestic market, Victorian production increased, with higher Longford Q1 gas production (+8.7 PJ), as well as the Otway Gas Plant continuing to see an increase in supply in Q1 (+4.4 PJ).

Western Australia electricity and gas highlights

Record average underlying demand outpaced distributed PV growth

- The Wholesale Electricity Market’s (WEM’s) average underlying demand increased to 2,826 MW, up 88.6 MW (+3.2%) in Q1 2025 compared to Q1 2024, which represents an all-time high. This was driven by higher overnight temperatures and an increase of 30.6 MW (+261%) in average battery withdrawal (charging).

Partially offsetting this increase in underlying demand was a 52.2 MW (+9.9%) uplift in distributed PV generation and a 23.7 MW (+740%) increase to embedded system generation, resulting in an overall increase to average operational demand by 12.7 MW (+0.6%).

- High temperatures on 20 January 2025 resulted in a new maximum operational demand record of 4,486 MW and underlying maximum demand record of 5,385 MW. During the operational demand peak, gas was the largest contributor with 2,526 MW (56.3%), with renewables contributing 573 MW (12.9%). Approximately 126 MW of demand side response was activated through various market and contractual mechanisms.

New batteries and hybrid facilities coupled with distributed PV increased average renewable contribution

- Q1 2025 saw the highest average renewable contribution for a Q1 at 41.6% (as a percentage of underlying demand), an increase of 2.5 percentage points (pp) on Q1 last year, the previous highest. This included an increase of 25.6 MW for batteries (+261%) to be 1.3% of the supply mix, and the introduction of the hybrid fuel type, which delivered an average of 22.7 MW to be 0.8% of the fuel mix. Distributed PV comprised 20.5% of the total supply mix, up from 19.3% in Q1 2024.
- There was a reduction in coal output by 36 MW (-4.6%) for Q1, which can be attributed to the semi-retirement of the Muja C Unit 6 facility.
- The increase in renewable contribution and the reduction of coal generation resulted in a Q1 record low emissions intensity of 0.513 tCO_2-e/MWh, which was 5.2% lower than Q1 2024. This resulted in lower overall emissions at 2.46 $MtCO_2$-e, a reduction of 5.7% on Q1 2024.

Energy market clearing prices increased, Frequency-Co-Optimised Essential Systems Service (FCESS) costs decreased

- The average energy price in Q1 2025 was $89.03/MWh, an increase of $10.54/MWh (+11%) from Q1 2024. This was due to a combination of drivers that each caused upwards pressure on price: higher overnight temperatures and decreased overnight wind, increased battery withdrawal, and changes to the FCESS Uplift framework resulting in fewer committed facilities during the middle of the day.
- FCESS costs, including Uplift costs, were $48.4 million, a decrease of $49.5 million (-51%) from Q1 2024. The most significant drivers for the decrease were changes implemented as part of the FCESS Cost Review and downward pressure on FCESS clearing prices as a result of increased competition from batteries in the FCESS markets.
- Energy Uplift costs rose significantly, from $2.4 million in Q1 2024 to $12.9 million in Q1 2025. The majority of these costs were incurred during planned network outages in late March.
- Supplementary Capacity, which was procured by AEMO to address a forecast capacity shortfall for the 2024-25 Hot Season, cost $24.9 million, an increase of 21% on the 2023-24 Hot Season. AEMO procured 25 contracts with a maximum actual contracted service quantity of 198 MW. AEMO activated one or more Supplementary Capacity services on five occasions.

Western Australia domestic gas production up, consumption down in Q1 2025

- Western Australia's domestic gas consumption reduced to 91.7 PJ in Q1 2025 (-5.7% compared to Q1 2024). Conversely, production increased to 101.4 PJ (+1.1% compared to Q1 2024). Storage saw a net withdrawal of 1.8 PJ, an increase on 1.1 PJ in Q1 2024, and extended the number of consecutive net withdrawal quarters to five.
- There was an amber Linepack Capacity Adequacy (LCA) Flag for the Mondarra Storage Facility and Parmelia Gas Pipeline on 26-27 January, and a red LCA Flag for the Parmelia Gas Pipeline on 23 March, indicating likely curtailment of gas flows. These were isolated incidents with no broader gas supply concern.

Contents

Executive summary		3
East coast electricity and gas highlights		3
Western Australia electricity and gas highlights		4
1	Weather	8
2	NEM market dynamics	10
2.1	Electricity demand	10
2.2	Wholesale electricity prices	14
2.3	Electricity generation	24
2.4	Inter-regional transfers	41
2.5	Frequency control ancillary services	46
2.6	Power system management	47
3	Gas market dynamics	49
3.1	Wholesale gas prices	49
3.2	Gas demand	52
3.3	Gas supply	54
3.4	Pipeline flows	57
3.5	Gas Supply Hub (GSH)	59
3.6	Pipeline capacity trading and Day Ahead Auction	60
3.7	Gas – Western Australia	61
4	WEM market dynamics	63
4.1	Electricity demand	63
4.2	Electricity generation	65
4.3	Frequency co-optimised essential system services (FCESS)	68
4.4	WEM price outcomes	69
5	Reforms delivered	76
List of tables and figures		79
Abbreviations		84

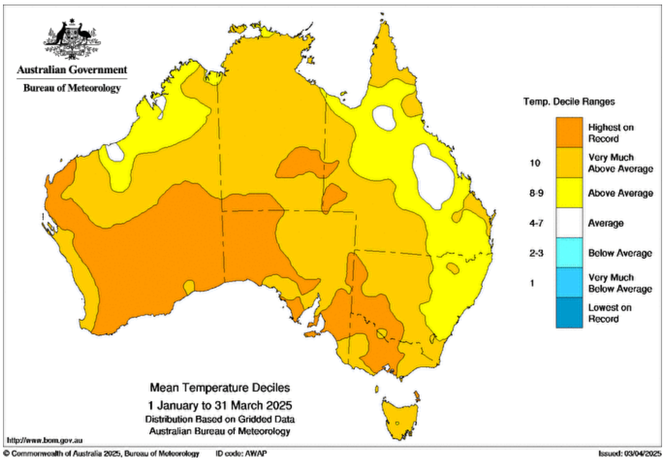
1 Weather

Above average temperatures were recorded across most of Australia in Q1 2025, as shown in Figure 1. On a national area-averaged basis, January was the second warmest, February was the fifth warmest and March was the warmest on record for Australia since 1910. The warm weather was most notable in parts of Western Australia, South Australia and Victoria, with these areas experiencing temperatures very much exceeding long-term averages during the quarter.

Rainfall conditions were mixed, with Tasmania having dry conditions over the quarter, with rainfall totals in both February and March 51% below average. In the north, Severe Tropical Cyclone Alfred contributed to Queensland recording rainfall totals 124% above the average level in March.

Figure 1 Temperatures generally warmer than long-term average throughout Australia

Q1 2025 mean temperature deciles for Australia



Source: Bureau of Meteorology (BOM

Compared to Q1 2024, maximum temperatures were higher across all months in Melbourne and Adelaide (Figure 2), leading to increased cooling requirements as represented by cooling degree days (CDDs)[2] (Figure 3). Melbourne experienced the most pronounced rise, with CDDs up by more than 70% compared to both Q1 2024 and the 10-year average.

Figure 2 Higher maximum temperatures in Melbourne and Adelaide across the quarter

Average monthly maximum temperature variance by capital city – Q1 2025 vs Q1 2024

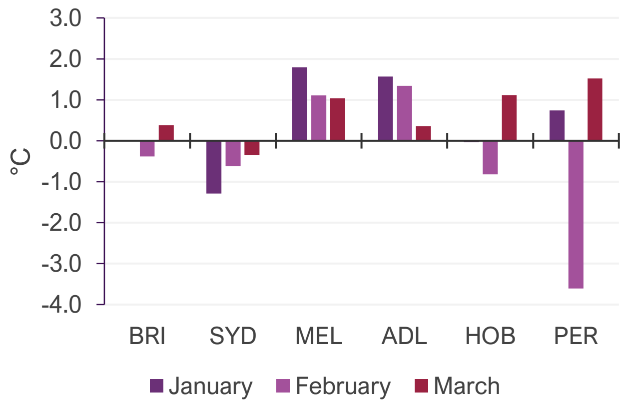
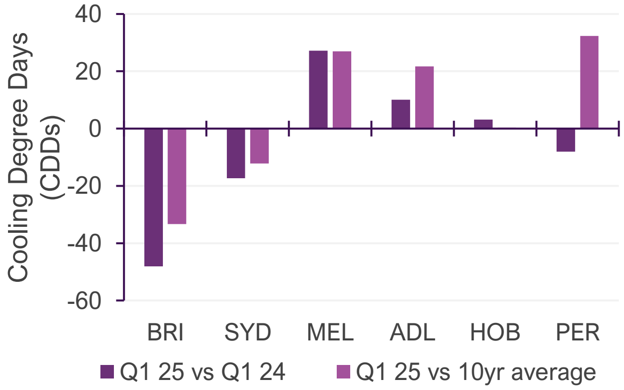


Figure 3 Higher than long-term average cooling requirements in Melbourne, Adelaide and Perth

CDDs variance by capital city



In Hobart, a warm March saw daily maximum temperatures in Hobart increase by 1.1°C to 22.8°C across the quarter, leading to a slight year-on-year increase in cooling requirements.

[2] CDD, which is based on the average daily temperature, is a measurement used as an indicator of outside temperature levels above what is considered a comfortable (base) temperature (24°C). CDD value is calculated as max (0, average temperature – base temperature).

In Perth, cooling requirements were 4% lower than during Q1 2024, but 23% higher than the 10-year average driven by elevated maximum and minimum temperatures in January and March. The primary factor behind the year-on-year decline in CDDs was February, where maximum temperatures were on average 3.6°C below the exceptionally warm February 2024. However, compared to 10-year averages, maximum temperatures in Perth were 0.7°C higher, and minimum temperatures were 0.8°C higher, across Q1 2025.

Conversely, Brisbane and Sydney recorded decreased cooling requirements compared to both Q1 2024 and the 10-year average. Despite similar maximum temperatures, Brisbane's minimum temperatures in Q1 2025 were notably lower than in Q1 2024 when overnight temperatures reached record highs. This resulted in an overall 24% decline in CDDs. Sydney also recorded a reduction in CDDs, down 25% from Q1 2024 as milder conditions led to a 0.8°C drop in maximum temperatures across the quarter.

2 NEM market dynamics

2.1 Electricity demand

In Q1 2025, NEM-wide underlying demand reached 25,162 MW, an increase of 340 MW (+1.4%) from Q1 2024 and a new Q1 record for the NEM (Figure 4). Underlying demand increases were largely driven by growth in Victoria and South Australia, primarily due to higher temperatures, with secondary impacts from population, economic, and electrification trends. Operational demand decreased to an average of 21,380 MW, 172 MW (-0.8%) lower than Q1 2024, as distributed PV output growth outpaced the increase in underlying demand. Average distributed PV output reached 3,782 MW, 512 MW (+16%) higher than Q1 2024 and a new high for a Q1.

Figure 4 Underlying demand reached a new Q1 high, offset by distributed PV output

NEM average underlying and operational demand – Q1s

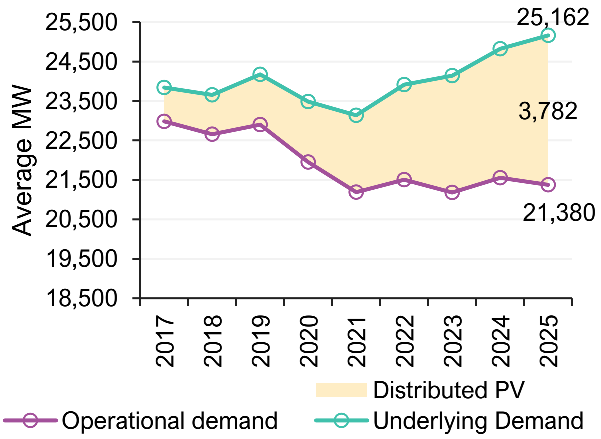
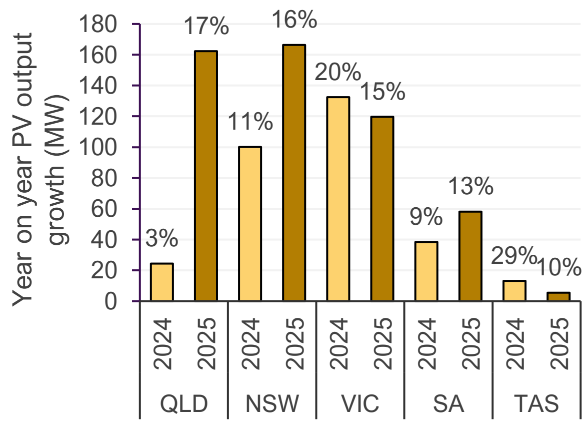


Figure 5 Significant increase in Queensland distributed PV growth

Quarterly distributed PV year-on-year growth (MW and %) by region – Q1s



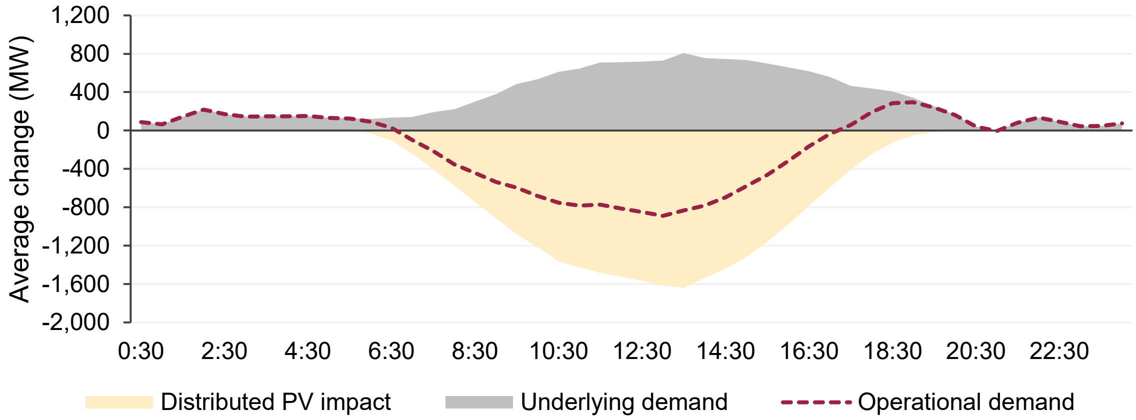
Growth in distributed PV output compared to Q1 2024 accelerated in Queensland, New South Wales and South Australia (Figure 5). Growth in NEM-wide installed distributed PV capacity reached 14% compared to Q1 2024, with every region recording growth of at least 10%. Changes in solar irradiance were more volatile, with Brisbane recording a 9% increase in solar irradiance compared to Q1 2024, and Hobart a 3% decrease.

Distributed PV output growth eased in Victoria and Tasmania, with Tasmania's growth of 6 MW below Q1 2024's 13 MW while Victoria also saw a slowdown (12 MW less than last Q1). All other states saw a pickup in output growth rate, with moderate changes in South Australia (20 MW increase over Q1 2024) and New South Wales (66 MW increase compared to last Q1), while Queensland saw a significant increase on 2024 (138 MW increase from last Q1). Despite these variations, all regions recorded a Q1 high for distributed PV output in Q1 2025.

Operational demand grew over the evening peak and overnight period, with significant distributed PV growth driving operational demand lower from early morning until late afternoon (Figure 6). Underlying demand was higher across all times of day, particularly in daylight hours from mid-morning until early evening, with a relatively flat increase across overnight periods. This increase predominantly reflected demand outcomes in Victoria and South Australia, with both regions seeing strong increases in underlying demand.

Figure 6 Increased underlying demand throughout the day with distributed PV lowering daytime operational demand until late afternoon

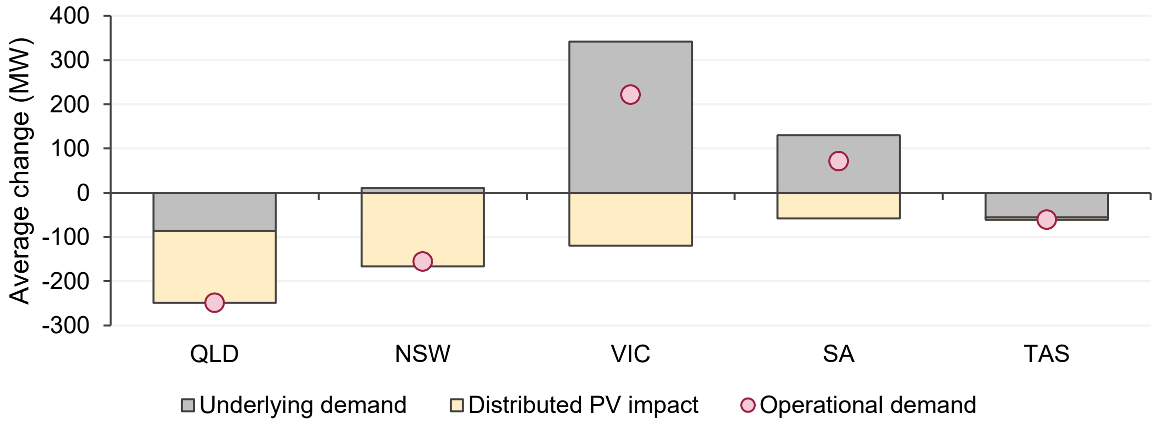
Average changes in NEM operational and underlying demand and distributed PV output – Q1 2025 vs Q1 2024



New South Wales saw minor net changes in underlying demand, which increased in daytime hours but decreased in the evening and overnight (Figure 7). Queensland's daytime underlying demand was consistent with Q1 2024 levels, but evening underlying demand fell significantly. Tasmania was the only region to experience a consistent drop in underlying demand across the entire day.

Figure 7 Weather conditions increased underlying and operational demand in Victoria and South Australia, but operational demand reduced in Queensland, New South Wales and Tasmania

Changes in average underlying and operational demand as well as distributed PV – Q1 2025 vs Q1 2024



Comparing Q1 2025 with Q1 2024:

- **Queensland** experienced an 86 MW (-1.1%) decrease in underlying demand to average 7,761 MW this quarter. This was primarily due to lower cooling requirements resulting from milder temperatures. Distributed PV output rose by 162 MW (+17%) to an average of 1,093 MW, driven by higher solar irradiance and more installed distributed PV capacity. Consequently, operational demand decreased by 249 MW (-3.6%) to average 6,668 MW.
- **New South Wales** underlying demand remained largely steady from Q1 2024, rising by just 11 MW (+0.1%) to average 7,502 MW despite milder weather conditions this quarter. Distributed PV output averaged 1,216 MW,

an increase of 166 MW (+16%), driven by higher solar irradiance and increased installed capacity. As a result, operational demand fell to a new Q1 low, averaging 7,502 MW, a decrease of 155 MW (-2.0%).

- **Victoria** experienced the highest rise in underlying demand, with an average increase of 341 MW (+6.3%) to reach 5,729 MW, the highest Q1 underlying demand since Q1 2014. The increase was mainly due to higher temperatures leading to increased air-conditioning load that was only partially offset by growth in distributed PV output. Distributed PV output rose to an average of 907 MW, up 120 MW (+15%), and operational demand averaged 4,822 MW, an increase of 222 MW (+4.8%).
- Underlying demand in **South Australia** reached a new all-time quarterly high of 1,844 MW, up 130 MW (+7.6%), with warmer weather driving increased cooling load. Distributed PV output also grew, up 58 MW (+13%) to average 503 MW, only partially offseting the increase in underlying demand. Operational demand increased by 71 MW (+5.6%) to average 1,341 MW, with increases evident across most hours of the day, but most pronounced in the evening and overnight.
- **Tasmania** saw the second largest reduction in underlying demand of 56 MW (-4.8%) after Queensland, with underlying demand averaging 1,110 MW. Weather conditions were relatively stable compared to Q1 2024, with the reduction in underlying demand attributed to lower industrial load during the quarter. With a reduction in solar irradiance, distributed PV output grew by just 6 MW (+10%) to average 63 MW and operational demand reduced across all hours of the day to average 1,047 MW, down 61 MW (-5.5%).

Maximum and minimum demands

Queensland was the only NEM region that saw a new maximum demand record for Q1, which was also a new all-time maximum demand record of 11,144 MW (Figure 8). This was set in the half-hour ending 1800 hrs on Wednesday 22 January 2025, replacing the previous record of 11,005 MW set on 22 January 2024.

Most regions saw new minimum demand records for Q1, with the NEM as a whole, New South Wales, Victoria and South Australia all recording new minimum demand levels for Q1 (Figure 9).

Figure 8 Record all-time maximum operational demand in Queensland

Maximum operational demand for mainland regions – Q1s

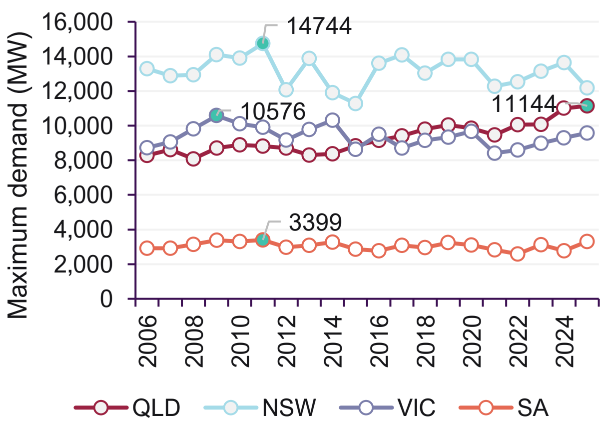
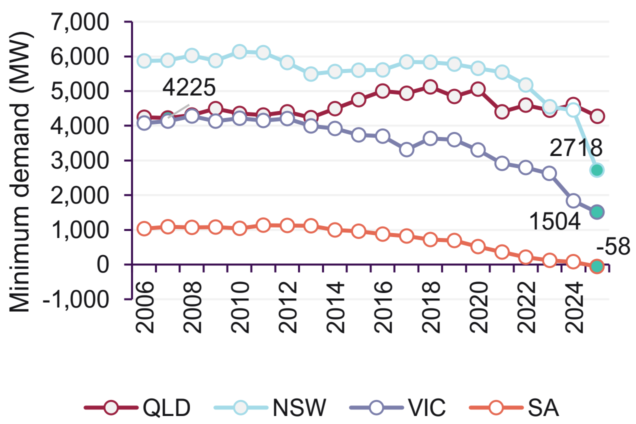


Figure 9 Record all-time low minimum operational demand in New South Wales and Victoria

Minimum operational demand for mainland regions – Q1s



New South Wales set a new minimum all-time operational demand record at 2,718 MW on 16 February 2025 (Table 1). This represented a 40% reduction in minimum operational demand compared to Q1 2024's minimum, and a 13% drop from the previous all-time minimum of 3,121 MW recorded in Q4 2024. It was a Sunday on 16 February, with operational demand impacted by a clear day resulting in high distributed PV output, while a low maximum temperature (23°C) resulted in low air-conditioning load.

Victoria also set a new minimum all-time operational demand record for Q1 of 1,504 MW on Wednesday 1 January 2025. This was an 18% reduction from the previous Q1 minimum set in Q1 2024 and a 7% reduction from the previous all-time minimum operational demand recorded in Q4 2023. There was a public holiday on 1 January which coupled with mild temperatures (22°C maximum) resulted in low underlying demand, with operational demand further reduced by high distributed PV output due to clear sunny conditions.

Table 1 Q1 2025 minimum operational demand records

	New Q1 minimum demand record	New all-time minimum demand record
NEM	11,680 MW (1200 hrs on Sunday 16 February 2025) *Previous record: 13,119 MW at 1200 hrs on Saturday 30 March 2024*	-
Queensland	-	-
New South Wales	2,718 MW (1200 hrs on Sunday 16 February 2025) *Previous record: 4,449 MW at 1200 hrs on Saturday 30 March 2024*	2,718 MW (1200 hrs on Sunday 16 February 2025) *Previous record: 3,121 MW at 1300 hrs on Saturday 26 October 2024*
Victoria	1,504 MW (1200 hrs on Wednesday 1 January 2025) *Previous record: 1,837 MW at 1100 hrs on Monday 01 January 2024*	1,504 MW (1200 hrs on Wednesday 1 January 2025) *Previous record: 1,564 MW at 1300 hrs on Sunday 31 December 2023*
South Australia	-58 MW (1400 hrs on Sunday 16 February 2025) *Previous record: 76 MW at 1300 hrs on Saturday 24 February 2024*	-
Tasmania	-	-

Distributed PV output has a material impact on operational demand extremes. While Queensland was the only state to reach a maximum operational demand record this quarter, South Australia's maximum operational demand of 3,318 MW (reached at 1900 hrs on Wednesday 12 February 2025) was only 81 MW below its historical maximum, recorded on 31 January 2011.

Figure 10 and Figure 11 show the distributed PV output and underlying demand on the days of Queensland and South Australian maximum demand this quarter. Queensland's underlying demand peaked at 12,335 MW at 1600 hrs. Operational demand at this time was 9,565 MW, 2,770 MW (-22%) below underlying demand due to distributed PV generation. Operational demand did not peak in Queensland until two hours later at 1800 hrs, reaching 11,144 MW.

Similarly, South Australia underlying demand peaked at 1730 hrs at 3,594 MW, with operational demand 625 MW (-17%) lower at 2,969 MW. Peak operational demand occurred at 1900 hrs, reaching 3,318 MW once distributed PV generation had ceased.

Figure 10 Queensland maximum demand period peaked in the late afternoon, delayed by distributed PV generation

Queensland underlying demand and distributed PV profile for peak Q1 2025 demand day

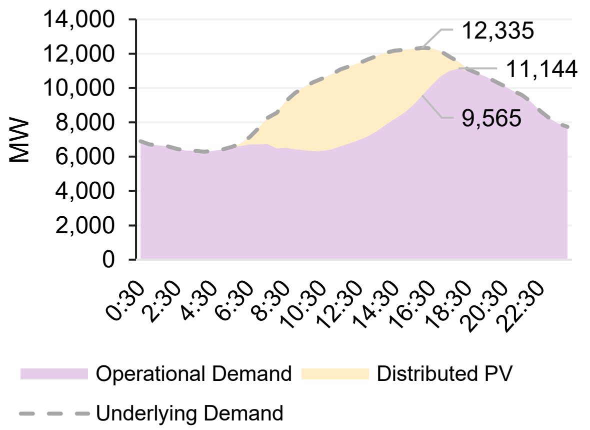
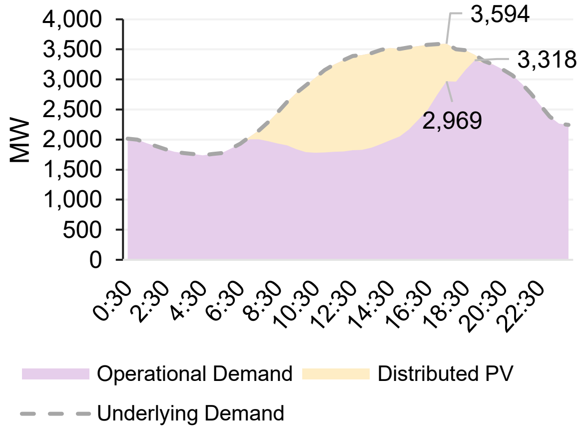


Figure 11 South Australian maximum demand period shifted later into the evening due to distributed PV generation

South Australia underlying demand and distributed PV profile for peak Q1 2025 demand day

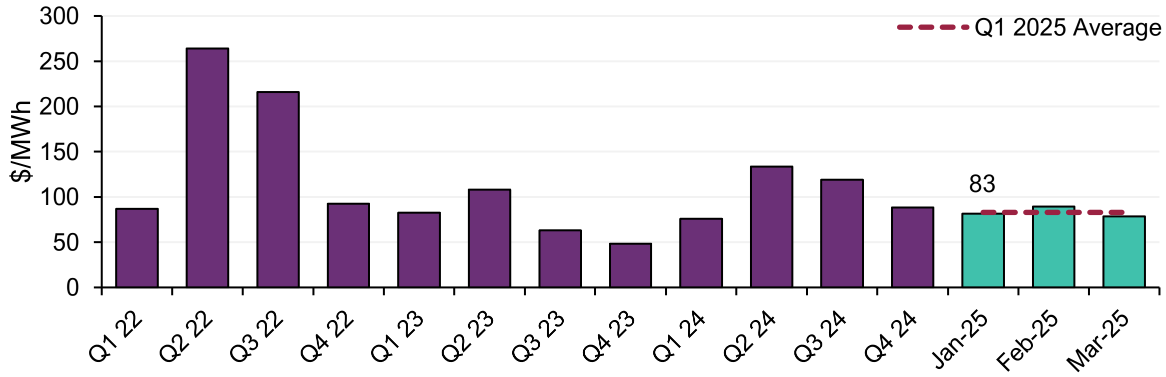


2.2 Wholesale electricity prices

In Q1 2025, wholesale electricity spot prices averaged $83/MWh[3] across the NEM, an increase of $7/MWh (+9%) compared to Q1 2024, but a decrease of $5/MWh (-6%) from Q4 2024 (Figure 12). The NEM-wide year-on-year increase was driven by a 67% lift in Tasmanian wholesale spot prices, with spot prices across the mainland NEM regions averaging $76/MWh, down slightly from Q1 2024's mainland average of $78/MWh.

Figure 12 NEM average wholesale spot prices up 9% year-on-year, but declined 6% from the preceding quarter

NEM average wholesale electricity spot prices – quarterly since Q1 2022



The cap return[4] component of the NEM average price reduced from $17/MWh in Q1 2024 to $7/MWh in Q1 2025 with fewer high-priced volatility events over the quarter. Energy prices were higher in all regions apart from Queensland, most notably including a year-on-year doubling of energy prices in Tasmania (Figure 13). NEM-wide energy prices averaged $76/MWh, up $17/MWh (+29%) from Q1 2024.

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

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

Figure 13 Year-on-year reduction in cap return offset by increased energy prices in the southern NEM regions

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

By region:

- **Queensland** was the only region to experience a year-on-year fall in wholesale spot prices, averaging $90/MWh across Q1 2025, down $28/MWh (-24%). Compared to Q1 2024, when frequent instances of very high temperatures and demand drove multiple high-price volatility events, milder overall conditions this quarter contributed to a $20/MWh (-61%) reduction in the cap return component. Energy prices reduced by $9/MWh (-10%), with higher distributed PV and grid-scale solar output contributing to lower prices across daytime hours.
- Wholesale spot prices in **New South Wales** remained close to those in Q1 2024, up by $1/MWh (+1%) to average $88/MWh. Less high-priced volatility during the quarter saw the cap return decrease from $17/MWh in Q1 2024 to $11/MWh this quarter. Increased distributed PV and grid-scale solar output contributed to lower prices across daytime hours, but during overnight periods, decreased coal availability and limitations on imports from Victoria due to transmission outages put upward pressure on prices, leading to an overall increase in energy prices from $71/MWh to $77/MWh.
- **Victoria** recorded the lowest quarterly average wholesale spot prices across the NEM at $59/MWh, despite an $8/MWh (+15%) increase from Q1 2024. The cap return component reduced by $14/MWh (-89%) to just $2/MWh after the storm-related volatility events in February 2024 had accounted for almost all of Victoria's cap return in Q1 last year. However, this reduction was offset by a $21/MWh (+58%) increase in energy prices. The increase in energy prices was evident across all hours of the day, driven by higher operational demand, lower brown coal availability and reduced volumes of low-priced hydro generation offers.
- Wholesale spot prices in **South Australia** averaged $66/MWh across the quarter, up $11/MWh (+20%) from those in Q1 2024. As in Victoria, this increase was driven by the energy component, which increased from $44/MWh in Q1 2024 to $55/MWh this quarter, with the increase most evident in the overnight hours. The cap return component remained similar to Q1 2024 at $11/MWh.
- **Tasmania** recorded the most significant increase in wholesale spot prices, increasing by $45/MWh (+67%) to average $111/MWh across Q1 2025. This increase was wholly driven by energy prices, with the cap return component averaging $0.3/MWh, an $11/MWh (-97%) reduction from Q1 2024. Energy prices were higher across all hours of the day despite lower operational demand, with reduced hydro offer volumes at low prices and lower wind generation driving the $55/MWh (+99%) year-on-year increase.

Average NEM wholesale spot prices were higher across most hours of the day, with the most significant rises occurring overnight (Figure 14). These changes align with the observed increase in overnight NEM operational demand.

When comparing time-of-day prices regionally, a price separation between Tasmania and the mainland regions was evident across most hours of the day, with the divergence particularly pronounced during midday hours (Figure 15). The lack of grid-scale solar in Tasmania, combined with imports from Victoria frequently reaching Basslink's import limit during the day, contributed to elevated Tasmanian energy prices. During midday hours (between 1000 and 1600 hrs), Tasmanian energy prices averaged $91/MWh in Q1 2025, $84/MWh higher than those in Victoria. This was a substantial uplift from the $44/MWh price separation between these regions during the same hours of Q1 2024.

Figure 14 NEM average price increased during overnight hours

NEM average spot price by time of day – Q1 2025 vs Q1 2024

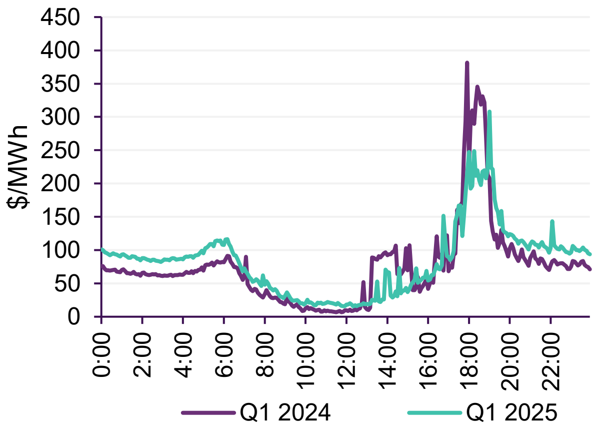
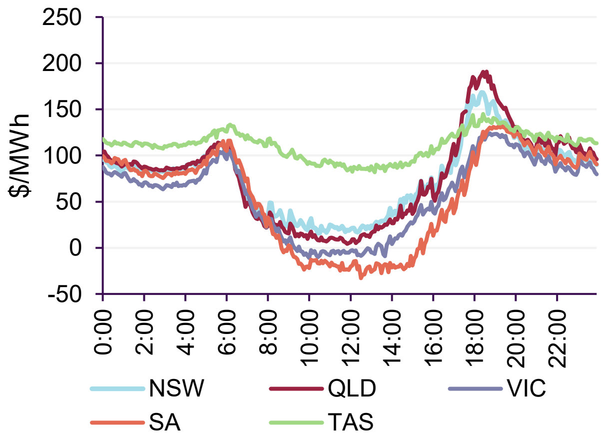


Figure 15 Significant price separation between Tasmania and mainland regions

Average regional energy price by time of day – Q1 2025



In Q1 2025, the energy price separation between the northern regions of Queensland and New South Wales and the southern regions of Victoria and South Australia seen in previous quarters persisted. However, in this quarter the separation between New South Wales and Victoria narrowed, while an emerging separation between Victoria and South Australia was evident. During midday hours (1000 to 1600 hrs) in Q1 2024, New South Wales energy prices averaged $70/MWh and $74/MWh higher than those in Victoria and South Australia, respectively. In the same hours this Q1, the gap between New South Wales and Victoria narrowed to $27/MWh, while the gap to South Australia was $50/MWh, as price separation between Victoria and South Australia grew from $4/MWh to $22/MWh in Q1 2025.

The reduction in the price separation between New South Wales and Victoria was driven by both a lowering of New South Wales prices during daytime hours due to increased distributed PV and grid-scale solar output and an uplift of Victorian prices primarily driven by increasing operational demand, reduced brown coal availability, and reductions in lower-priced hydro generation.

The larger price separation between Victoria and South Australia this Q1 was impacted by the commissioning of Project EnergyConnect Stage 1 (PEC-1), as discussed in Section 2.4.1.

2.2.1 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 Q1 2025

Higher operational demand in Victoria and South Australia lifted energy prices	In Q1 2025, average operational demand increased by 222 MW (+4.8%) in Victoria and 71 MW (+5.6%) in South Australia. These increases were due to a rise in underlying demand (discussed in Section 2.1) and despite significant growth in distributed PV output were observed across nearly all hours of the day. This rise in demand contributed to higher energy prices in Victoria (up 58% year-on-year) and South Australia (up 26% year-on-year).
Higher priced coal offers set prices at higher levels	Black coal generators offered less volume across most price bands with offers under $100/MWh falling by approximately 600 MW compared to Q1 2024 (Figure 16). As a result, the average price set by black coal when marginal increased from $71/MWh to $84/MWh.
Lower offer volumes and higher prices set by hydro	Hydro generators, particularly in Tasmania and New South Wales, offered lower volumes across most price bands in Q1 2025 compared to during Q1 2024 (see Figure 42 in Section 2.3.3). On average hydro generators offered approximately 400 MW less volume at prices less than $100/MWh and as a result the average price set by hydro rose from $85/MWh to $123/MWh. This, along with the higher operational demand in the southern regions and higher-priced coal generation, contributed to the frequency of prices exceeding $100/MWh rising from 15% in Q1 2024 to 41% across the NEM in Q1 2025 (Figure 17).
Increased VRE output set lower and more frequently negative prices when marginal	Grid-scale solar generation achieved a new quarterly high, increasing by 10% year-on-year, and wind generation saw an 18% rise. Both increases were driven primarily by growth in availability at new and commissioning facilities (see Section 2.3.4). This increased availability saw the combined price-setting frequency for these lower cost generation sources rise from 10% in Q1 2024 to 15% in Q1 2025. NEM-wide negative price frequency consequently increased, along with the negative price impact on average prices (see Section 2.2.3).
Fewer high-priced volatility events reduced Q1 2025's cap return price component	Compared to Q1 2024, when there were 1,470 intervals across all five NEM regions where spot prices exceeded $300/MWh, resulting in the aggregate cap return of $86/MW, this quarter experienced only 724 such intervals, and the aggregate cap return decreased to $37/MWh. This reduction was particularly evident in Queensland, where the wholesale spot price reduced year-on-year, with the cap return component dropping from $32/MWh in Q1 2024 to $13/MWh in Q1 2025.

Figure 16 Less volume offered at lower price bands by black coal generators

NEM black coal bid supply curve – Q1 2025 vs Q1 2024

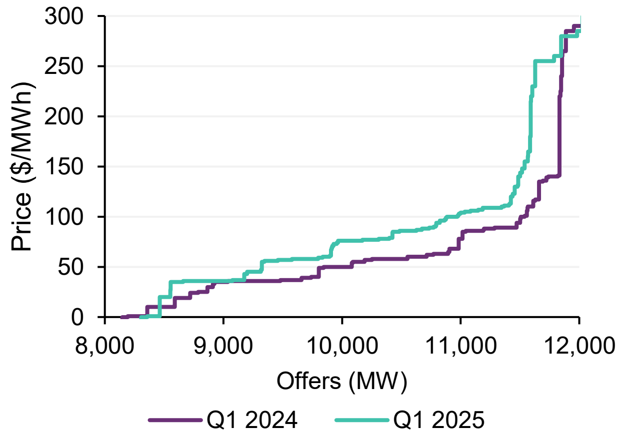
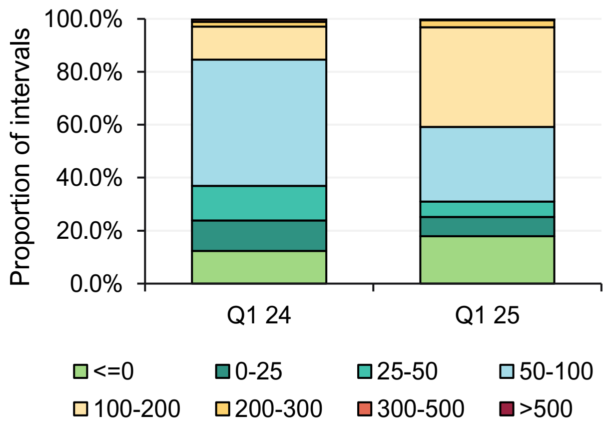


Figure 17 Shift in prices from less than $100/MWh to over $100/MWh

NEM average spot price ranges – Q1 2025 vs Q1 2024



2.2.2 Wholesale electricity price volatility

In Q1 2025, aggregate cap returns across the NEM – representing the contribution of any excess of spot price above $300/MWh – averaged $37/MWh, less than half of Q1 2024's $86/MWh (Figure 18). On a regional basis, cap return was highest in Queensland at $13/MWh, with most of this accruing on 22 February when Queensland recorded a new all-time maximum demand record (Figure 19). South Australia and New South Wales both contributed $11/MWh to the NEM aggregate cap return, with most of South Australia's cap return returning accruing in early February.

Figure 18 Lowest NEM-wide cap return since Q4 2023

Cap returns by region – quarterly

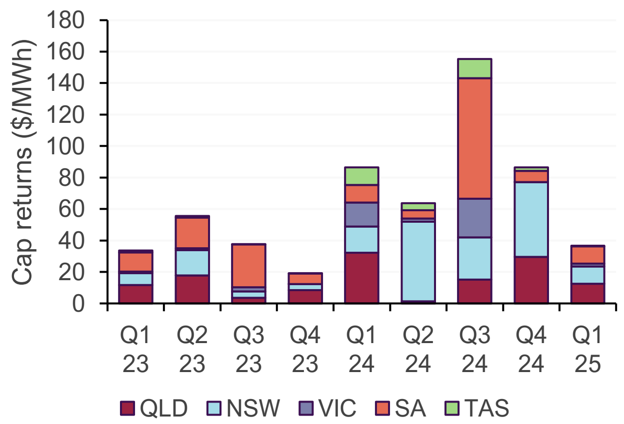


Figure 19 Isolated volatility events across the quarter

Cumulative cap return by region – Q1 2025

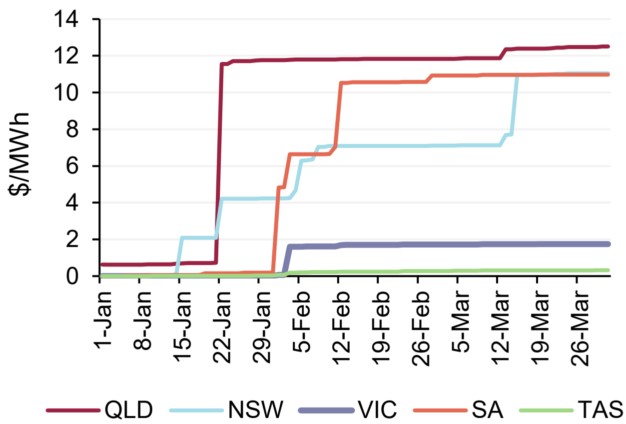


Table 3 summarises events of significant high-priced volatility during Q1 2025.

Table 3 Significant price volatility events in Q1 2025

Date	Region	Contribution to regional cap return ($/MWh)	Drivers
22 January	Queensland	10.8	With parts of Brisbane recording temperatures over 37°C, Queensland recorded a new maximum demand high of 11,144 MW in the half-hour interval ending 18:00. High demands over the evening peak drove tight supply demand conditions and prices exceeded $14,000/MWh in Queensland for 14 dispatch intervals (1 hour 10 minutes). In these intervals, grid-scale solar generation was low due to the time of day, and wind generation was also relatively low, averaging 152 MW, around 40% of the average quarterly generation level.
	New South Wales	2.1	Temperatures in New South Wales were also elevated on this day, with parts of Sydney recording temperatures over 37°C. Prices in New South Wales exceeded $14,000/MWh for two (2) dispatch intervals.
1 February	South Australia	4.7	Prior to the evening peak period, substantial negative inter-regional settlement residue (IRSR) had accumulated on energy flows from Victoria on the Heywood Interconnector (refer to Section 2.4.1). In accordance with AEMO's National Electricity Rules (NER) obligations to mitigate growth in negative IRSR, a constraint limiting flows into South Australia to low levels (under 50 MW) had been triggered, with a minimum activation period. As South Australian demand rapidly ramped up into the evening peak, this flow limitation led to a sudden jump in spot prices during the half hour ending 18:30, before the constraint controlling negative IRSR deactivated. Prices in South Australia exceeded $14,000/MWh for seven (7) consecutive dispatch intervals starting from 17:55.
12 February	South Australia	3.5	A very hot day, with temperatures exceeding 44°C in parts of Adelaide, drove a new underlying half-hourly maximum demand record, and the fourth highest operational demand on record for South Australia, reaching 3,318 MW in the half-hour ending 19:00 (see Figure 11 in Section 2.1). Prices exceeded

Date	Region	Contribution to regional cap return ($/MWh)	Drivers
			$14,000/MWh for five (5) consecutive dispatch intervals starting from 18:45. During these periods, relatively low wind output (at around 40% of the average quarterly level) and low solar output (due to the time of day) contributed to the tight supply-demand conditions.
15 March	New South Wales	3.3	Very hot temperatures drove a maximum operational demand of 12,039 MW in the half-hour ending 17:30, only 144 MW less than New South Wales's maximum demand for the quarter (recorded on the next day). Prices in New South Wales exceeded $14,000/MWh for five (5) dispatch intervals in the evening peak. During these intervals, a network outage on the Collector to Marulan line reduced northward flows on the Victoria – New South Wales Interconnector (VNI) to 0 MW and limited output from generators in the south-west region of New South Wales.

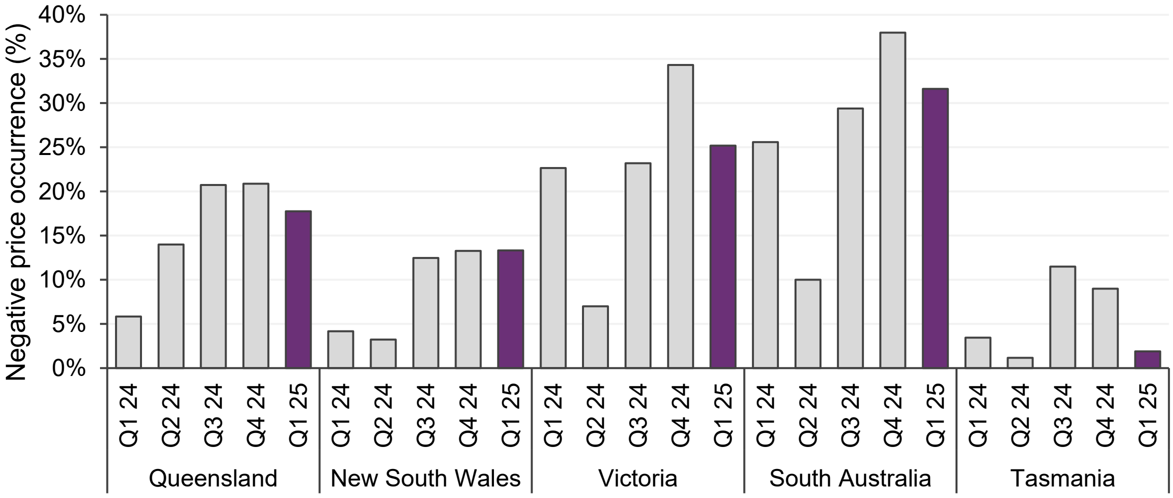
2.2.3 Negative wholesale electricity prices

In Q1 2025, 18.0% of dispatch intervals across the NEM experienced negative or zero prices, a 5.6 pp increase from Q1 2024. The occurrence of negative prices increased in all NEM regions except Tasmania, where their frequency dropped from 3.4% in Q1 2024 to 1.9% this quarter (Figure 20). This increase was most pronounced in the northern NEM regions, driven by significant growth in distributed PV and VRE output and reductions in operational demand (see Section 2.1). In Queensland and New South Wales, the frequency of negative or zero prices more than tripled compared to Q1 2024 levels.

New South Wales recorded negative or zero prices in 13.3% of intervals this quarter, a 9.2 pp increase from Q1 2024 and a new record for the region. South Australia reached 31.6% (up 6.0 pp), Victoria 25.2% (up 2.6 pp), and Queensland 17.8% (up 11.9 pp).

Figure 20 Negative price occurrence increased year-on-year in all NEM mainland regions

Negative price occurrence in NEM regions – Q1s



Negative prices predominantly occurred during daylight hours, with South Australia experiencing a notably higher occurrence during a longer proportion of the daytime periods than other NEM regions (Figure 21).

The proportion of NEM negative prices between -$40/MWh and $0/MWh saw a notable increase this quarter, with only 20% of negative prices settling at levels below -$40/MWh, compared to over 50% in Q1 2024 (Figure 22).

This trend aligned with the decline in large-scale generation certificate (LGC) prices, which averaged $28/certificate this quarter compared to $46/certificate in Q1 2024. Consequently, the average spot price during negative price intervals rose from -$49.2/MWh in Q1 2024 to -$35.4/MWh in Q1 2025, partially offsetting the impact of higher negative price frequencies.

The negative price impact[5] – reflecting the combined effect of negative price levels and frequencies on quarterly average prices – decreased in Tasmania and Victoria. In Tasmania, this was driven by a reduction in the frequency of negative prices, while in Victoria, reductions in negative price levels offset the slight increase in negative price frequency. Conversely, negative price impact rose to reach new Q1 highs in Queensland, New South Wales and South Australia. Overall, the NEM-wide negative price impact increased by 5% to average $6.4/MWh.

Figure 21 South Australia led negative price occurrence

Negative price occurrence by time of day – Q1 2025

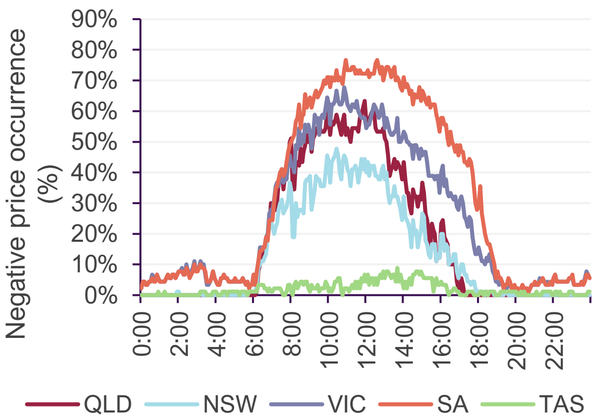
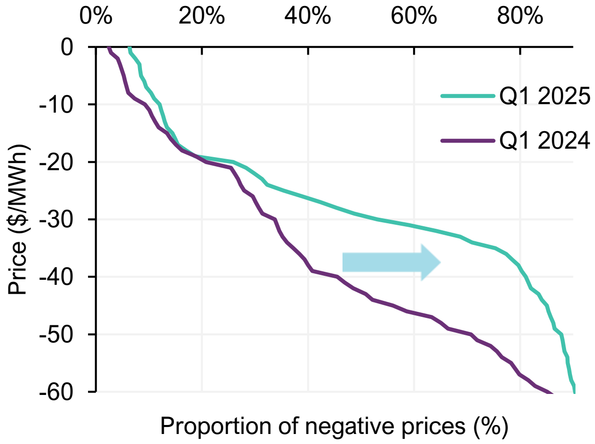


Figure 22 Proportion of negative prices between -$40/MWh and $0/MWh almost doubled

Cumulative distribution of negative prices – Q1 2025 vs Q1 2024



2.2.4 Price-setting dynamics

Consistent with the reduction in hydro offer volumes at low prices (see Section 2.3.3), the decline in black and brown coal availability, and changes in offers by black coal-fired generators (see Section 2.2.1), this quarter saw a notable upward shift in the average prices set when these fuel types were marginal (Figure 23). The impact of this was moderated by a reduction in the frequency of these fuel types setting the price, and an increase in price-setting frequencies for the lower-cost sources of wind, grid-scale solar and battery load.

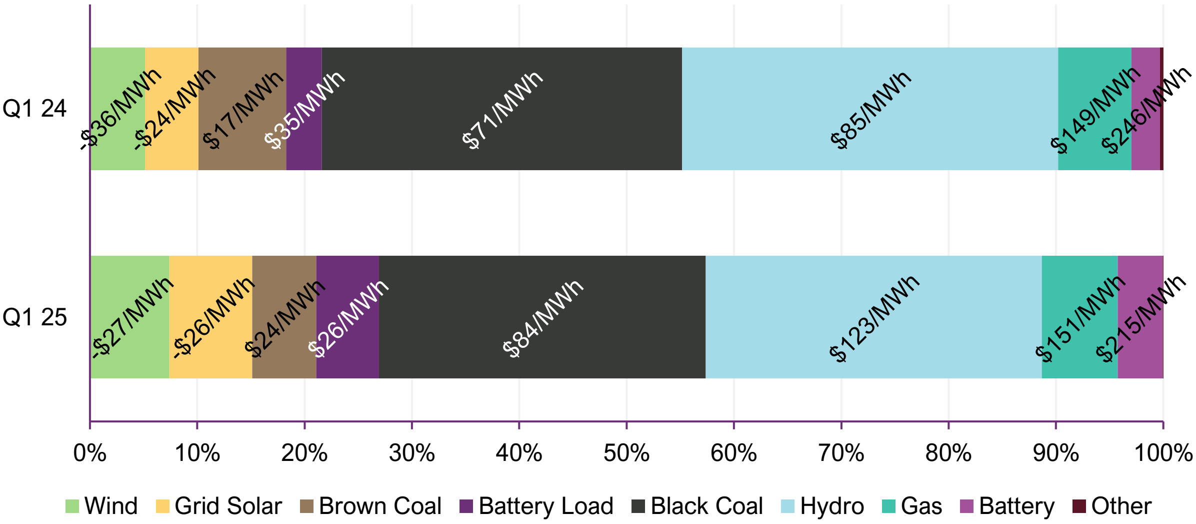
Hydro remained the most frequent price setter this quarter, setting the price in 31% of intervals, a decrease from 35% in Q1 2024. It also experienced the largest increase in prices set when marginal, rising from $85/MWh to $123/MWh.

Black coal was the next most frequent price-setter, at 30% this quarter, down from 34% in Q1 2024, with prices set when marginal increasing from $71/MWh to $84/MWh. Brown coal also saw a decline in price-setting frequency, reducing from 8% to 6%, alongside a rise in average prices set when marginal, from $17/MWh to $24/MWh.

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

Figure 23 Hydro and coal saw largest increases in average prices set when marginal

NEM price-setting frequency and average spot price when price-setter by fuel type – Q1 2025 vs Q1 2024



Grid-scale solar and wind both increased their price-setting frequency, with wind increasing from 5% in Q1 2024 to 7% this quarter and grid-scale solar from 5% to 8%. Prices set by grid-scale solar when marginal decreased slightly, by $2/MWh to -$26/MWh, while prices set by wind when marginal increased by $9/MWh to -$27/MWh.

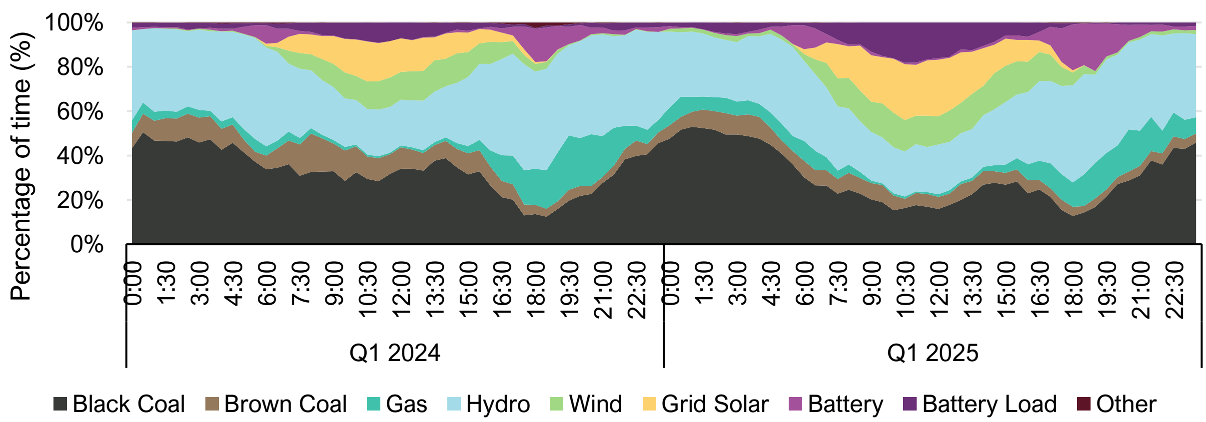
Batteries continued to increase their price-setting frequency – from 3% to 4% for battery generation and 3% to 6% for battery load. However, in a reversal from recent trends, prices set by batteries when marginal decreased this quarter, from $246/MWh to $215/MWh for battery generation and from $35/MWh to $26/MWh for battery load.

Price-setting by time of day

Compared to Q1 2024, increases in price-setting frequency of grid-scale solar and battery load were evident in the middle of the day, with black coal having the most notable decrease during those periods (Figure 24). Between 10:00 to 16:00, the average frequency of price setting by grid-scale solar increased from 13% in Q1 2024 to 20% in Q1 2025, battery load increased from 6% to 13%, and black coal decreased from 33% to 21%.

Figure 24 Notable increases in price-setting frequency by solar and battery load during the day, and by battery generation in the evening peak

NEM price-setting frequency by fuel type and time of day – Q1 2024 and Q1 2025



Battery generation increased its price-setting frequency during the evening peak, while the frequency of hydro and gas price-setting reduced during this period as these sources moved some offer volumes to higher price bands (Sections 2.3.2 and 2.3.3). The average frequency of price-setting by battery generation in the evening peak (between 16:00 to 20:00) increased from 8% in Q1 2024 to 13% in Q1 2025.

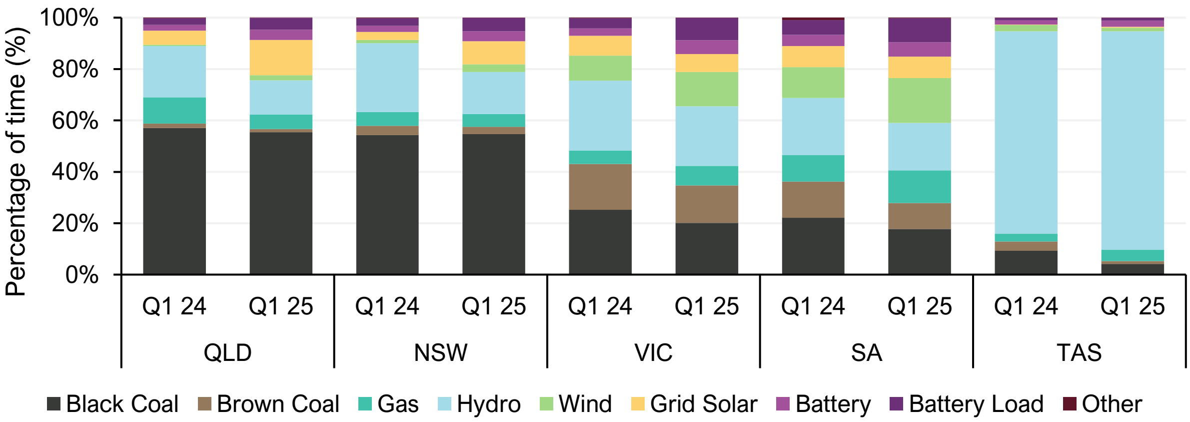
Regional price-setting trends

On a regional basis, the year-on-year reduction in price-setting frequency by black and brown coal was evident across all regions (Figure 25). The increase in price-setting frequency by grid-scale solar was most notable in Queensland and New South Wales, consistent with the growth in grid-scale solar availability in those regions (see Section 2.3.4).

Notably, hydro generation price-setting frequency decreased in all mainland regions but increased in Tasmania, rising from 79% of intervals in Q1 2024 to 85% of intervals in Q1 2025. This increase in price-setting frequency was accompanied by an increase in average prices set when marginal from $55/MWh to $113/MWh, driven by the reduction in lower-priced hydro offers seen in Tasmania this quarter.

Figure 25 Hydro set prices less frequently in all mainland NEM regions but more frequently in Tasmania

Regional price-setting frequency by fuel type – Q1 2025 vs Q1 2024



2.2.5 Electricity futures markets

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

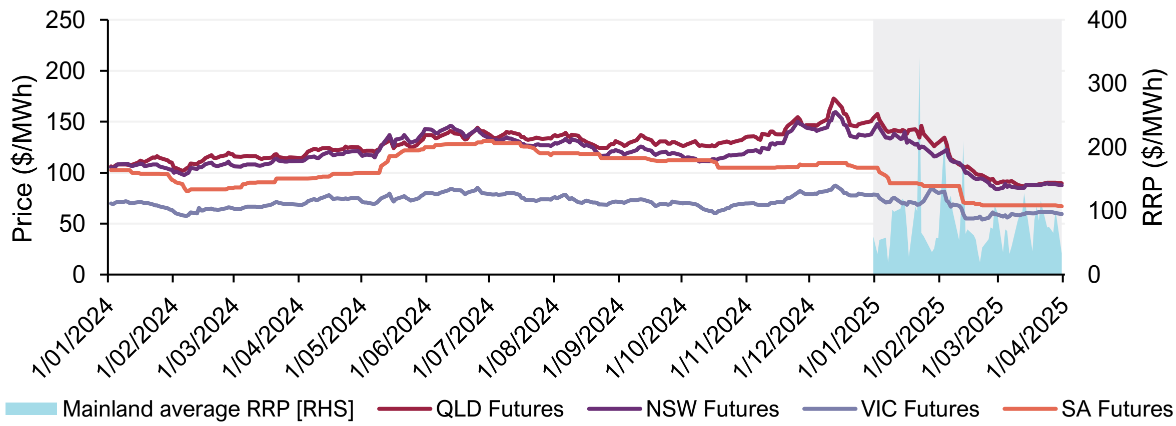
Figure 26 illustrates Australian Securities Exchange (ASX) daily prices for Q1 2025 base contracts across NEM mainland regions. Final settlement prices for such current quarter contracts are set at quarter end to the time-weighted quarterly average wholesale price for the relevant region, but prior to this “delivery quarter” their traded prices reflect market expectations. During the delivery quarter, traded prices were influenced by both quarter-to-date wholesale price levels and expectations for the balance of quarter, ultimately converging to the final settlement price.

In 2024, ASX contract prices for Q1 2025 increased throughout Q2 2024 with low wind and rainfall conditions putting upward pressure on wholesale spot prices. Contract prices stabilised in Q3 2024 before starting to rise, most notably in the northern regions, reflecting high-priced volatility in early November in those regions.

Q1 2025 contract prices for New South Wales and Queensland began to decline from the start of 2025, with high-priced volatility over the quarter lower than previously expected. Victorian Q1 2025 contract prices remained well under the northern regions, with an uptick at the start of February with expectations of hot temperatures driving high demands before stabilising across March.

Figure 26 Reductions in northern region Q1 2025 base futures with lower than expected price volatility

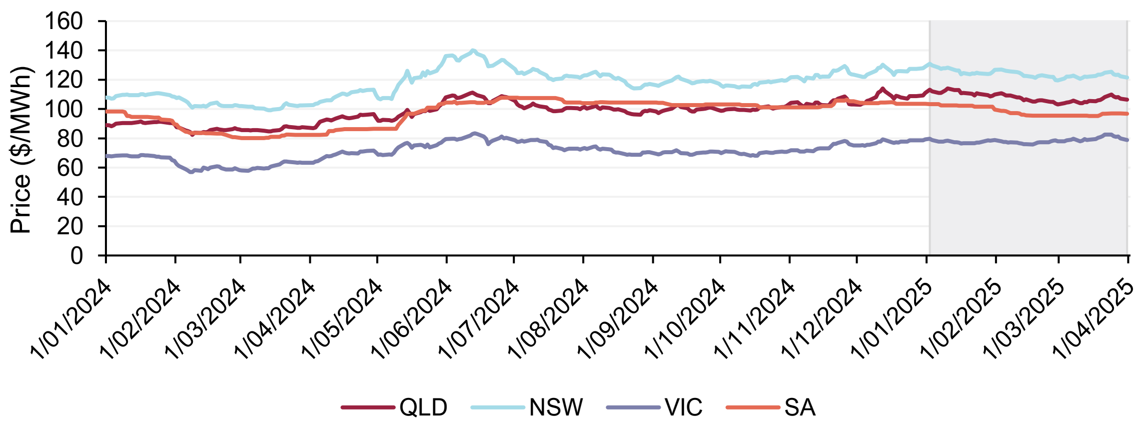
ASX Energy – Regional daily Q1 2025 base future prices and daily average spot price for mainland regions



ASX base contract prices for the 2025-26 financial year (FY26) averaged $102/MWh across all mainland regions in Q1 2025, marginally above Q4 2024's average of $101/MWh and $17/MWh higher than Q1 2024's average of $85/MWh (Figure 27). Despite wholesale average spot prices across mainland regions in Q1 2025 decreasing by $16/MWh (-18%) from Q4 2024 levels, there was a smaller decline in FY26 mainland contract prices across the quarter. These reduced in all regions, with an average fall of $6/MWh (-6%), closing the quarter at an average of $101/MWh after starting the quarter at $107/MWh.

Figure 27 Slight decline in mainland FY26 futures across the quarter

ASX Energy – Daily FY26 base futures by region



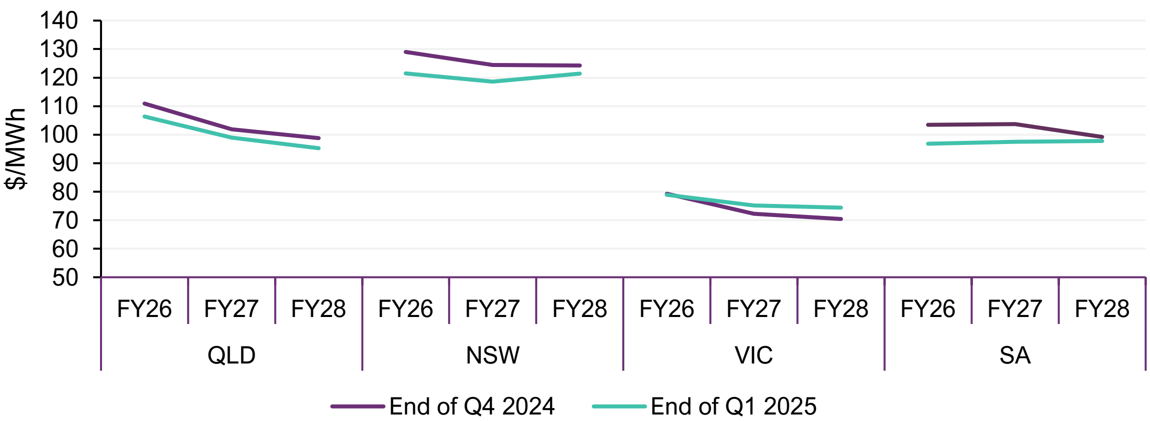
At the end of Q1 2025, forward financial year contracts closed below end Q4 2024 levels in Queensland, New South Wales and South Australia (Figure 28). Victorian forward financial year contracts remained the lowest-priced of the mainland regions, with FY26 contracts steady at $79/MWh at the end of Q4 2024 and Q1 2025.

A reduction in regional wholesale spot prices in Q1 2025, compared to Q4 2024, aligned with a reduction in future price expectations in Queensland and New South Wales, with Queensland FY26 down $5/MWh (-4%) to end at $106/MWh, and New South Wales FY26 down $8/MWh (-6%) to end at $121/MWh. In South Australia, FY26 futures reduced from $103/MWh at the close of Q4 2024 to $97/MWh by the end of Q1 2025. This was despite an increase in wholesale electricity prices during Q1 2025 compared to the previous quarter, although the low liquidity in South Australia's contract markets may have contributed to variations in contract price movements.

Longer-dated contract prices continued to show a declining trend in Queensland and Victoria, but a flat profile across future years in New South Wales and South Australia, where FY26 prices fell by more during Q1 2025 than did FY28 prices. At the end of Q1 2025, FY28 prices were 10% and 6% below FY26 prices in Queensland and Victoria, respectively, whereas FY28 prices in New South Wales and South Australia were very close to those for FY26.

Figure 28 Forward financial year contracts ended the quarter below end of Q4 2024 levels in all mainland NEM regions except Victoria

ASX Energy – Financial year contract prices in mainland NEM regions – end of Q4 2024 and end of Q1 2025



2.3 Electricity generation

Over Q1 2025, total average generation across the NEM[6] increased by 546 MW (+2.2%) from 25,154 MW in Q1 2024 to 25,700 MW this quarter. This increase was driven by growth in underlying demand and increased supply requirements for battery charging (+62 MW) and hydro pumping (+65 MW).

Figure 29 shows changes in average NEM generation by fuel type, and Table 4 presents these changes by supply contribution. Renewables made up 43.0% of the supply mix this quarter, up 4.0 pp from 39.0% in Q1 2024, and a new high for a Q1. Black and brown coal share decreased by 3.5 pp this quarter to 53.3% from 56.8% in Q1 2024.

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

Figure 29 VRE and battery saw increased output compared to all other fuel types

Change in NEM supply by fuel type – Q1 2025 vs Q1 2024

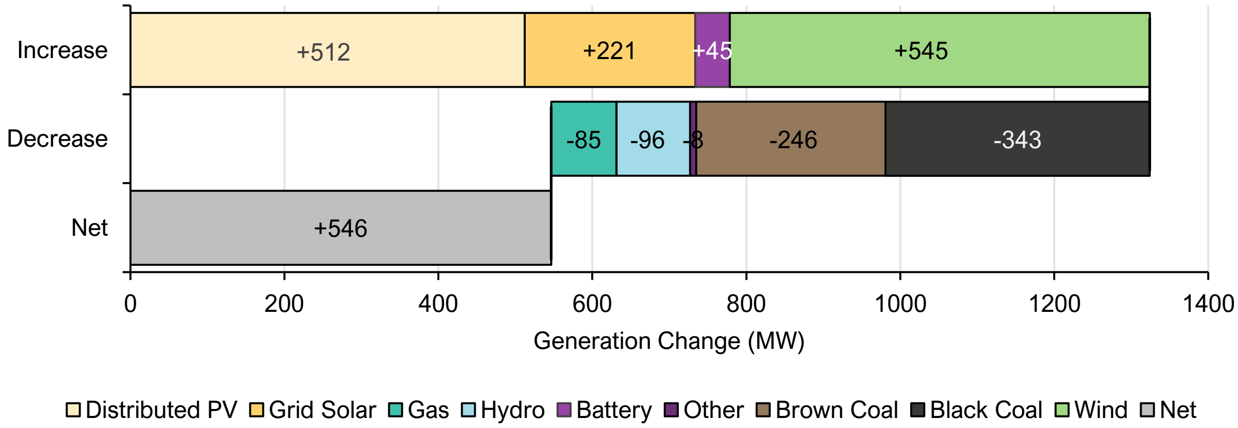


Table 4 NEM supply contribution by fuel type

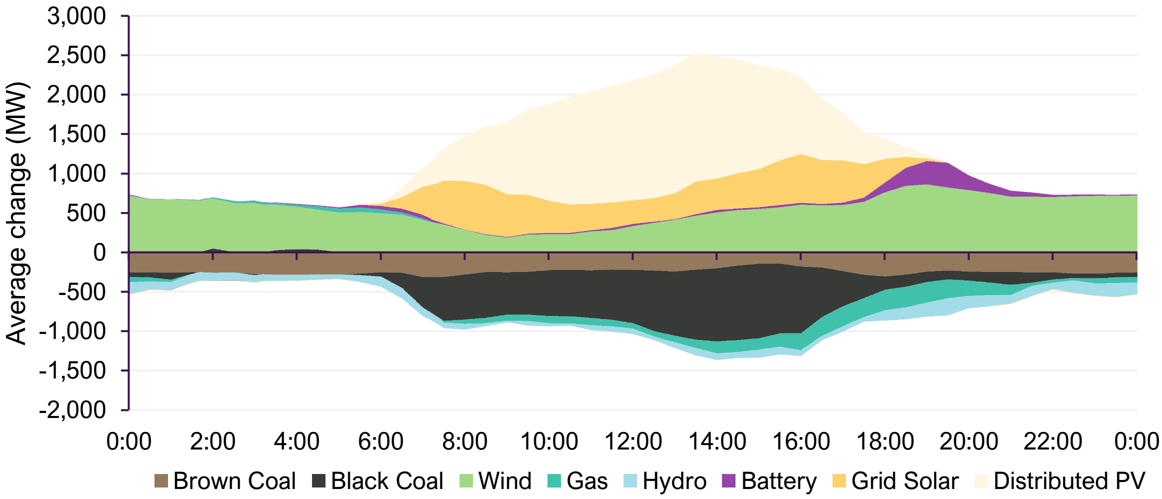
Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Biomass	Battery
Q1 2024	42.2%	14.6%	4.1%	0.1%	13.0%	11.8%	8.6%	5.3%	0.1%	0.2%
Q1 2025	40.0%	13.3%	3.7%	0.0%	14.7%	13.7%	9.3%	4.9%	0.1%	0.4%
Change	-2.2%	-1.3%	-0.4%	0.0%	1.7%	1.9%	0.7%	-0.5%	0.0%	0.2%

In summary, comparing Q1 2025 with Q1 2024:

- Grid-scale solar reached a new all-time high, with a quarterly average output of 2,386 MW (+10%) driven by growth in new and commissioning facilities, partially offset by economic offloading and network curtailment. Distributed PV average output increased to a new Q1 quarterly high of 3,782 MW (+16%) attributed to increases in both solar irradiance and the installed capacity of distributed PV.
- Wind generation increased to average 3,517 MW (+18%), reaching a new Q1 high. Increases in output were recorded across all the regions except Tasmania due to lower wind speeds in the region. Growth in new and commissioning wind farms contributed to the increases in generation which were partially offset by increases in economic offloading.
- Battery generation was at a new all-time high this quarter, with an output increase to 98 MW (+86%) when averaged across all hours but concentrated strongly in the evening peak period (Figure 30).
- Conversely, both black and brown coal-fired average availability and output fell to new Q1 quarterly lows. Average black coal-fired generation was at 10,269 MW (-3.2%), while brown coal-generation averaged 3,429 MW (-6.7%). Across the states, most black coal-fired power stations reported lower levels of both generation and availability, other than Callide C which was out of service in Q1 2024.
- Gas generation decreased to average 941 MW (-8.3%) which was also the lowest Q1 generation level since Q1 2004. These decreases were driven by lower generation in Queensland, which dropped by 110 MW (-19%), particularly during the evening peak due to reductions in underlying demand.
- Hydro generation decreased to average 1,248 MW (-7%), with reduced output levels in all regions except Queensland and Victoria.

Figure 30 VRE output growth dominated throughout the day, pushing down coal, gas and hydro output

NEM generation changes by time of day – Q1 2025 vs Q1 2024



2.3.1 Coal-fired generation

Black coal-fired fleet

Average black coal-fired generation reached a new quarterly low for a Q1 averaging 10,269 MW in Q1 2025, a 343 MW (-3.2%) decrease from Q1 2024 (Figure 31). Similarly, availability also recorded a new quarterly low for a Q1 averaging 13,518 MW in Q1 2025, down 344 MW (-2.5%) from Q1 2024. Although there was a significant reduction in availability, the total capacity on full outage decreased, averaging 1,528 MW in Q1 2025, which was 39 MW (-2.5%) lower than Q1 2024. This decrease was primarily due to a notable reduction in outages in Queensland, where Callide C units were offline for the entirety of Q1 2024 (Figure 32).

Figure 31 Reductions in New South Wales drove NEM black coal-fired output and availability to new Q1 quarterly low

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

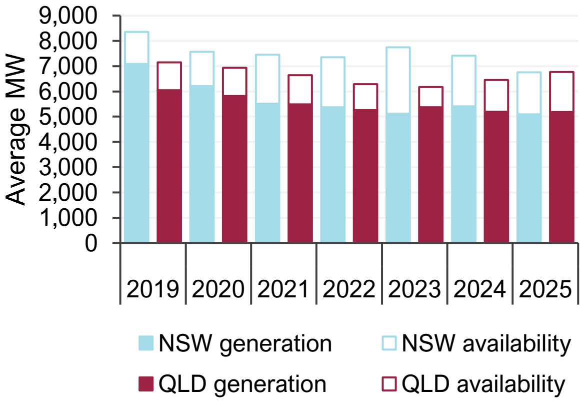
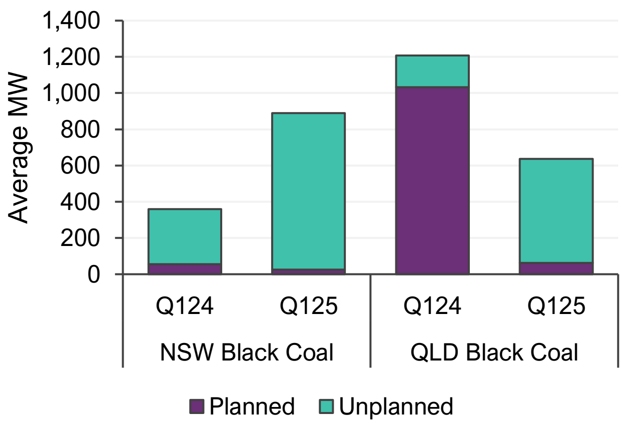


Figure 32 Return of Callide C reduced Queensland black coal-fired capacity on full outage

Average black-coal fired capacity on full outage[7] – Q1 2025 vs Q1 2024

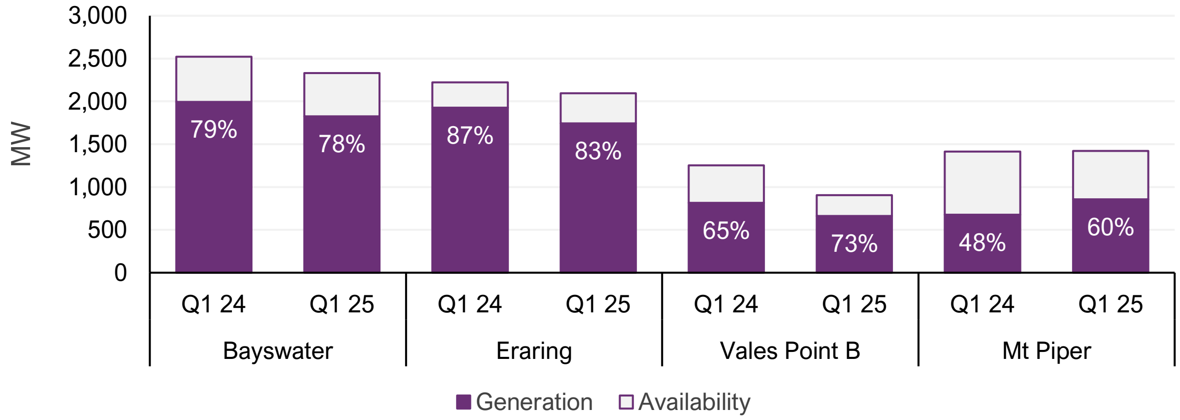


[7] Classification of full unit outages into planned and unplanned in *the Quarterly Energy Dynamics* (QED) is primarily based on Medium Term Projected Assessment of System Adequacy (MT PASA) unit status. For Q1 2024, some outages have been reclassified since the publication of Q1 2024 QED, including a shift of Callide C outages units in Queensland from unplanned to planned (886 MW), and around 200 MW of New South Wales outages from Q1 2024 from planned to unplanned.

New South Wales black coal-fired generation decreased by 326 MW (-6.0%) year-on-year to an average of 5,089 MW this quarter (Figure 33). An increase in full and partial outages reduced availability by 659 MW (-8.9%) to 6,752 MW. All black coal-fired power stations across the state experienced lower generation and availability this quarter, except Mt Piper, which saw generation increasing by 181 MW (+27%) with a slight rise in availability. Vales Point saw significant reductions in generation by 154 MW (-19%) and availability by 345 MW (-28%), with both units limiting availability to less than 250 MW for periods during the quarter.

Figure 33 Lower output from black coal-fired generators in New South Wales, except Mt Piper

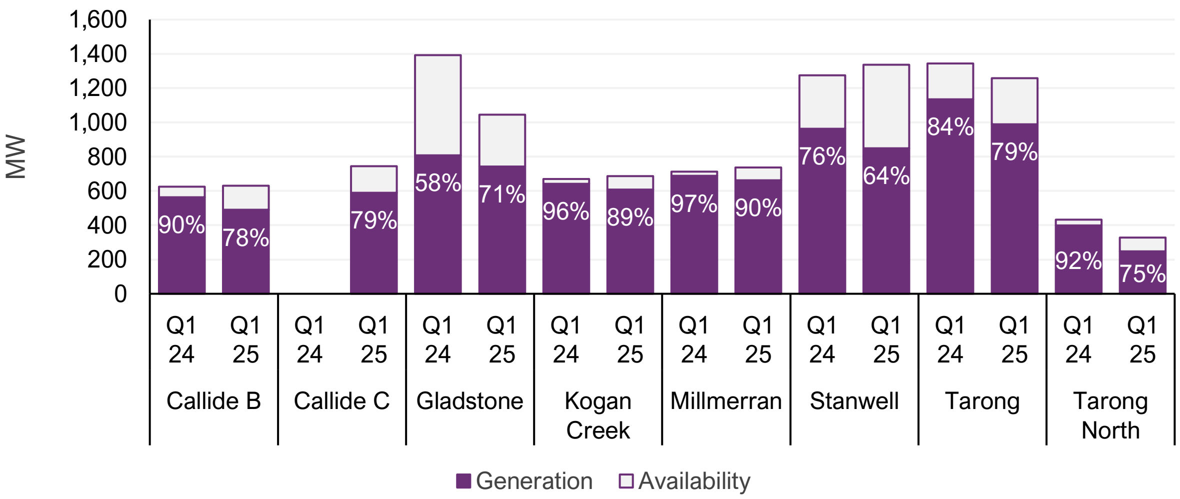
Average quarterly availability and generation for New South Wales black coal-fired power stations – Q1 2025 vs Q1 2024



In Queensland, black coal-fired generators reported lower output this quarter, except for Callide C which generated 589 MW compared to zero output in Q1 2024 due to being fully offline for repairs (Figure 34). Callide C's higher generation, however, was not able to fully offset output reductions across other generators, which led to an overall regional generation decrease this quarter of 17 MW (-0.3%), to average 5,181 MW compared to Q1 2024. The return to service of Callide C also contributed a 745 MW increase in availability, which offset a net decrease across the rest of the Queensland fleet. This resulted in an overall year-on-year availability increase this quarter of 315 MW (+4.9%) to 6,766 MW.

Figure 34 Lower output from black coal-fired generators in Queensland, except Callide C

Average quarterly availability and generation for Queensland black coal-fired power stations – Q1 2025 vs Q1 2024



Gladstone reported the largest drop in availability, decreasing on average by 348 MW (-25%) this quarter, with full outages comprising close to 50% of the loss in availability, and partial outages contributing the balance. This lower availability in turn led to significantly higher utilisation of the capacity available at Gladstone this quarter.

New South Wales black coal-fired generation was on average lower across all hours of the day this quarter, with significant decreases during the daytime and evening peak compared to the same intervals in Q1 2024 (Figure 35). Consistent with the changes in availability and generation levels, all coal-fired power stations except Mt Piper reduced output during the morning and evening peak.

In Queensland, average generation increased this quarter during the evening peak and overnight time periods on a year-on-year basis, assisted by the return of Callide C. However, outside these periods Queensland average generation was lower compared to Q1 2024, leading to a significant increase in intraday swing. Intraday swing increased by 412 MW (+23%), from 1,762 MW in Q1 2024 to 2,174 MW this quarter (Figure 36).

Figure 35 Decrease in New South Wales black coal generation across all hours of the day

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

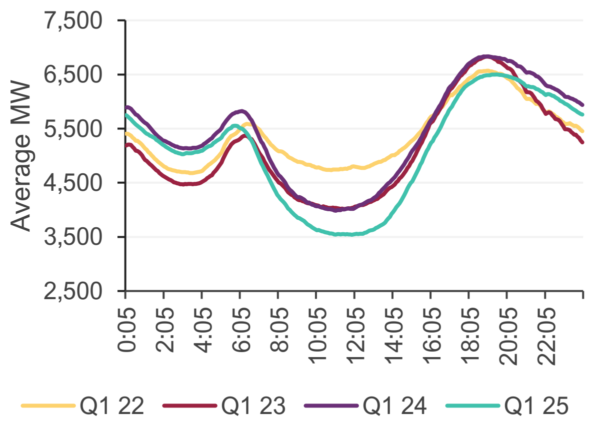
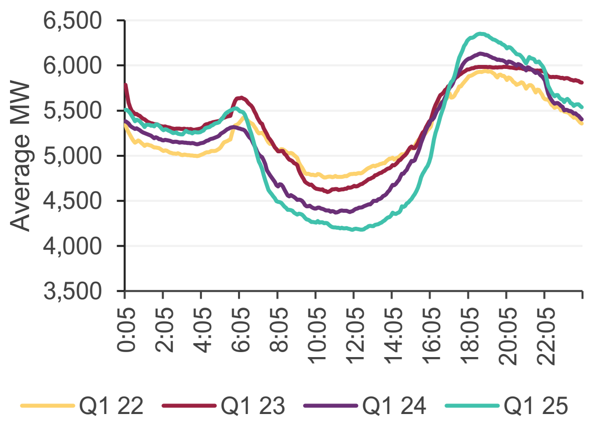


Figure 36 Increase in Queensland black coal generation in evening peak and overnight

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



Brown coal-fired fleet

During Q1 2025, brown coal-fired average generation decreased by 246 MW (-6.7%) year-on-year to a new Q1 low of 3,429 MW. Similarly, availability also recorded a new Q1 quarterly low, decreasing by 205 MW (-4.9%) from Q1 2024 to average 3,998 MW (Figure 37).

Brown coal generation over this quarter was consistently lower throughout the day, with the intraday swing reducing by 44 MW (-3.3%), from 1,331 MW in Q1 2024 to 1,287 MW this quarter (Figure 38).

All brown coal power stations contributed to the year-on-year reduction in availability and output this quarter (Table 5). Notably, output of Loy Yang A reached a new Q1 low and at Yallourn W both output and availability reduced to new Q1 lows.

Figure 37 Brown coal-fired generation and availability recorded new Q1 quarterly lows

Quarterly average brown coal-fired generation and availability (including decommissioned units) – Q1s

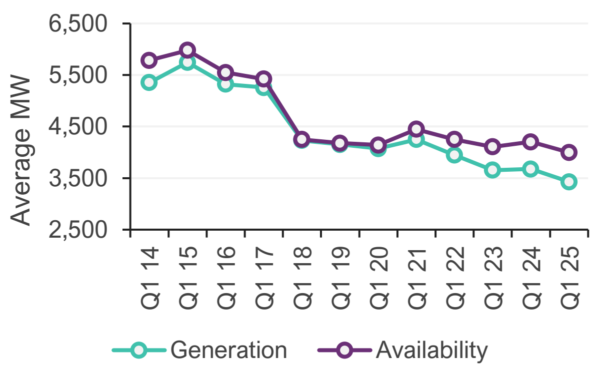


Figure 38 Lower brown coal generation at all times of the day

Brown coal-fired output by time of day – Q1s

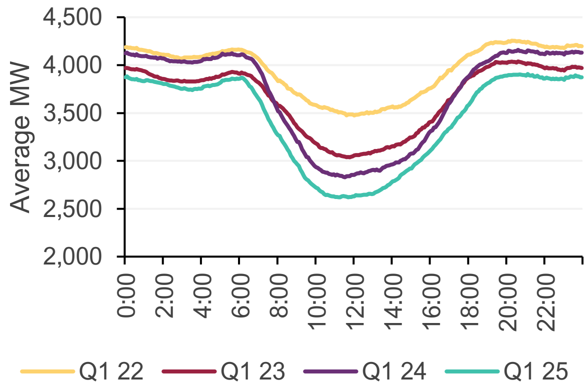


Table 5 Brown coal availability, output, utilisation, full outages, and intraday swing – Q1 2025 vs Q1 2024

Generator	Availability (MW)		Output (MW)		Utilisation		Outage (MW)		Intraday swing (MW)	
	Q1 24	Q1 25	Q1 24	Q1 25	Q1 24	Q1 25	Q1 24	Q1 25	Q1 24	Q1 25
Loy Yang A	2,013	1,850	1,744	1,579	87%	85%	182	320	677	591
Loy Yang B	1,137	1,134	976	955	86%	84%	1	3	408	423
Yallourn W	1,053	1,014	955	896	91%	88%	343	511	253	286

2.3.2 Gas-fired generation

NEM gas-fired generation was down by 85 MW (-8.3%) from Q1 2024, averaging 941 MW in Q1 2025, its lowest Q1 output level since Q1 2004 (Figure 39). This decrease was driven by a reduction in Queensland gas-fired generation of 110 MW (-19%), principally over the evening peak due to lower underlying demand. Most gas-fired generators in Queensland reduced output this Q1 compared to last year. In contrast, gas-fired generation in Victoria and New South Wales increased this quarter by 20 MW (+37%) and 8 MW (+8%) year-on-year respectively. In Q1 2025, gas-fired generators offered the bulk of their capacity above the $300/MWh price band, with less volume offered in price ranges below this level relative to Q1 2024 (Figure 40).

Figure 39 Gas-fired generation reduced to its lowest Q1 level since 2004

Average gas-fired generation by region – Q1s

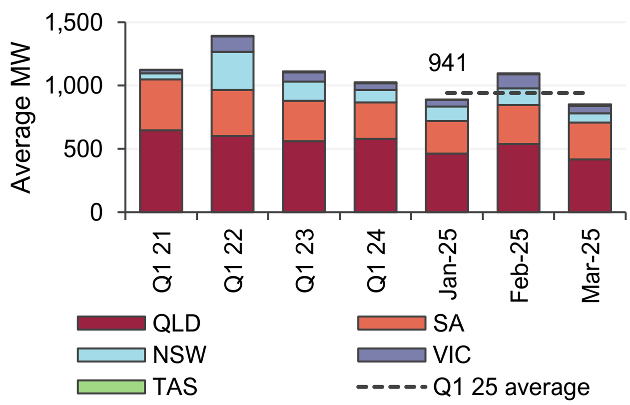
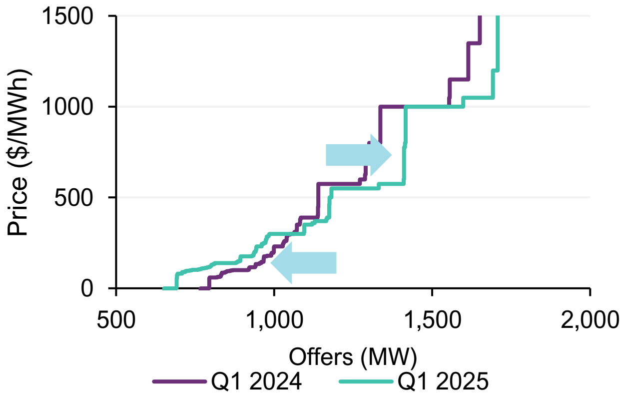


Figure 40 Higher gas volumes offered over $300/MWh

Gas-fired generation bid supply curve – Q1 2025 vs Q1 2024



2.3.3 Hydro

NEM hydro generation[8] in Q1 2025 fell by 96 MW (-7.1%), averaging 1,248 MW, driven by year-on-year decreases of 61 MW (-22%) and 57 MW (-8.8%) respectively in New South Wales and Tasmania (Figure 41), as generators reduced offer volumes in price bands below $300/MWh this quarter (Figure 42). Upper Tumut in New South Wales saw a drop of 82 MW (-54%) this quarter from Q1 last year.

In Queensland, generation increased by 10 MW (+6.9%) from Q1 last year, driven by higher generation at Wivenhoe of 18 MW (+28%). Output in Victoria also increased this quarter by 12 MW (+4.3%), with increases mainly from Dartmouth of 17 MW (+50%) and Eildon 16 MW (+68%), moderated by decreases from Murray of 18 MW (-10%). Hydro generation from Queensland and Victoria contributed mainly to the evening peak demand, which was more than offset by reduced generation from New South Wales and Tasmania during that time.

Figure 41 Lower hydro generation in New South Wales and Tasmania

Average hydro output by region – Q1s

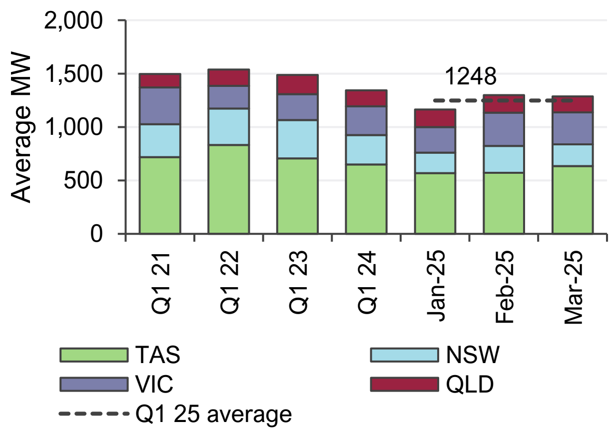
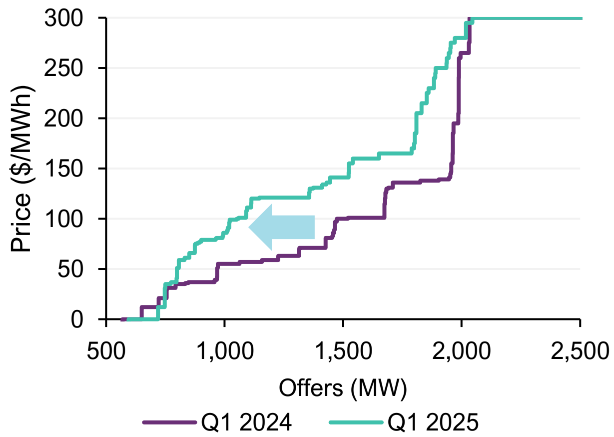


Figure 42 Less volume offered at lower price bands by hydro generators

Hydro generation bid supply curve – Q1 2025 vs Q1 2024



2.3.4 Wind and grid-scale solar

In Q1 2025, grid-scale VRE generation reached an all-time high, averaging 5,903 MW, up 767 MW (+15%) from 5,136 MW in Q1 2024 (Figure 43). Wind generation grew 545 MW (+18%) from Q1 2024 to 3,517 MW, providing 60% of the quarter's VRE output and over 70% of year-on-year output growth. Grid-scale solar generation was up by 221 MW (+10%) from Q1 last year to average 2,386 MW this quarter.

Net VRE output increases were observed in all states except Tasmania. The Q1 2025 VRE increases for Victoria of 351 MW (+27%) and New South Wales of 319 MW (+19%) made up 87% of the overall increase from Q1 2024 (Figure 44). Growth in wind output was most significant in Victoria, up by an average of 275 MW (+26%) while for grid-scale solar, New South Wales recorded the largest increase from Q1 2024, with average growth of 141 MW (+14%).

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

Figure 43 Steady VRE growth continued

Average quarterly VRE generation by fuel type – Q1s

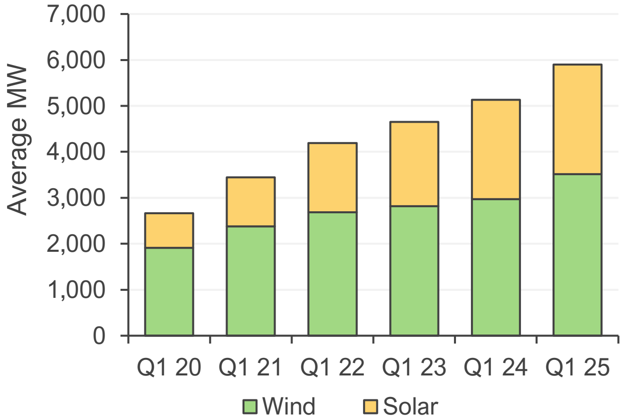
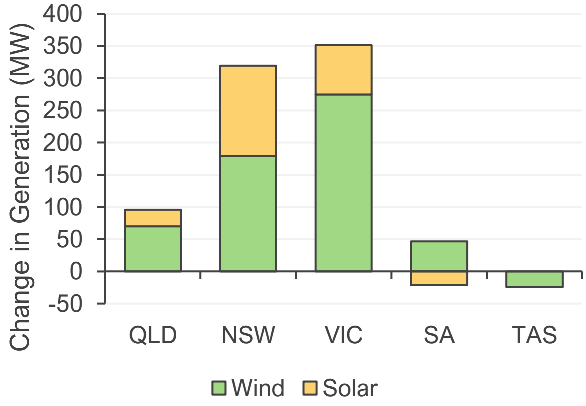


Figure 44 VRE increases led by New South Wales and Victoria

Average change in VRE output by region – Q1 2025 vs Q1 2024



Grid-scale solar

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 yielded an average quarterly increase of 322 MW in grid-scale solar availability compared to Q1 2024 (Figure 45).

New South Wales made up the majority (81%) of availability growth from new capacity, driven by the availability of Wellington North (+121 MW) and Walla Walla (+89 MW). Girgarre (+26 MW) and Wunghnu (+15 MW) in Victoria also contributed to increased availability in the quarter.

In contrast, higher network curtailment and economic offloading in all regions except Victoria collectively lowered average grid-scale solar generation output by 124 MW this quarter compared to Q1 2024, with economic offloading (+112 MW) accounting for most of the change, reflecting the increased incidence of negative prices across the NEM. Queensland recorded the largest increase in economic offloading, up by 50 MW, followed by increases of 49 MW and 31 MW in New South Wales and South Australia respectively. Network curtailment grew most in New South Wales, increasing by 23 MW this quarter. In Victoria, both network curtailment and economic offloading fell, by 14 MW and 18 MW respectively. The effect of PEC-1 in relieving north-west Victorian network constraints (see Section 2.4) contributed to that region's lower solar curtailment.

The output reductions resulting from higher economic offloading and network curtailment more than offset a small increase in available energy from established solar facilities in Q1 2025, yielding an overall net output lift of 221 MW from NEM grid-scale solar, 100 MW less than the availability increase from new and commissioning facilities.

Established[9] grid-scale solar facilities recorded increases in quarterly volume-weighted available capacity factors across all NEM regions, with the NEM-wide capacity factor increasing by 0.7 pp to 30.3% in Q1 2025 (Figure 46). South Australian solar farms recorded the highest available capacity factor at 34.3%, increasing 1.0 pp from Q1

[9] Existing (or established) capacity in this section refers to the grid-scale solar and wind facilities that were fully commissioned prior to the start of Q1 2025. These facilities may also appear in the "New Capacity or "Commissioning" categories in Figure 45 and Figure 47 if they were connected or exhibited ramping capacity between Q1 2024 and Q1 2025 respectively.

2024. The Queensland solar fleet achieved the lowest available capacity factor across the NEM at 27.3%, but recorded the highest year-on-year increase for this measure at 2.2 pp above Q1 2024.

Figure 45 Growth in new and commissioning solar capacity year-on-year

Changes in grid-scale solar generation – Q1 2025 vs Q1 2024

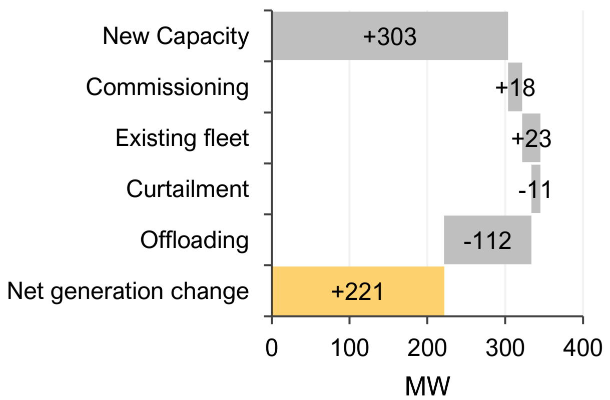
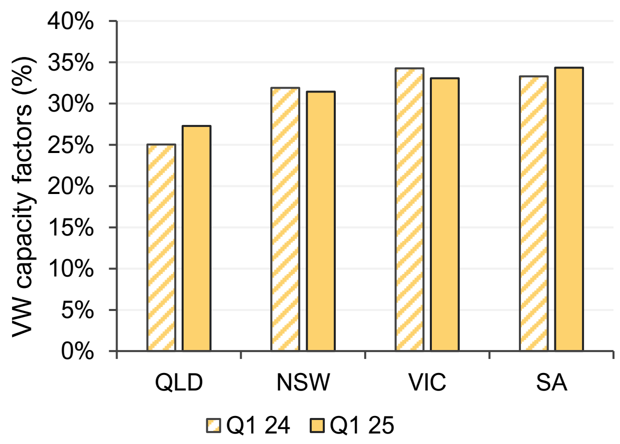


Figure 46 Increases in grid-scale solar availability only in Queensland and South Australia

Volume-weighted grid-scale solar available capacity factors[10] – Q1s



Wind

In Q1 2025, higher output from new and commissioning wind farms contributed a year-on-year increase of 417 MW to the fleet's average availability (Figure 47). These increases were mainly driven by new capacity at Ryan Corner (+69 MW) and Golden Plains (+60 MW) in Victoria and Goyder South (+59 MW) in South Australia. In New South Wales, commissioning wind farms Rye Park Renewable Energy (+68 MW) and Flyers Creek (+43 MW) grew available output over the quarter.

Higher economic offloading lowered average wind output by 93 MW, while network curtailment fell marginally this quarter, contributing to a 2 MW increase in generation compared to Q1 2024. South Australia, where spot prices were negative or zero in 32% of dispatch intervals, recorded the largest change in economic offloading with an increase of 58 MW, followed by a 20 MW increase in Victoria. The largest network curtailment increase was 5 MW in New South Wales which was offset by a decrease of 5 MW in Victoria.

Higher available capacity factors at established wind farms were an additional source of growth, contributing a further 220 MW of available energy in Q1 2025 compared to Q1 2024.

Established wind facilities showed increases in quarterly volume-weighted available capacity factors across all NEM regions except Tasmania, with the NEM-wide capacity factor increasing by 2.4 pp to 32.3% in Q1 2025 (Figure 48). South Australian wind farms recorded the highest available capacity factor at 33.8%, increasing 1.8 pp from Q1 2024, while the highest year-on-year increase of 4.2 pp to 33.5% above Q1 last year was seen in New South Wales. Tasmania experienced a reduction in quarterly volume-weighted available capacity factor by 4.4 pp to 30.4%.

[10] Available capacity factors are calculated using average available energy divided by maximum installed capacity. The use of availability instead of generation output removes the impact of any economic offloading or curtailment and better captures in-service plant capacity and underlying solar or wind resource levels. Available capacity factors for each established facility are weighted by maximum installed capacity to derive a regional weighted average.

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

Changes in wind generation – Q1 2025 vs Q1 2024

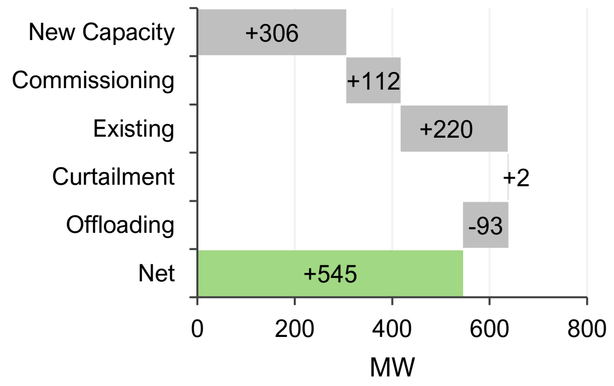
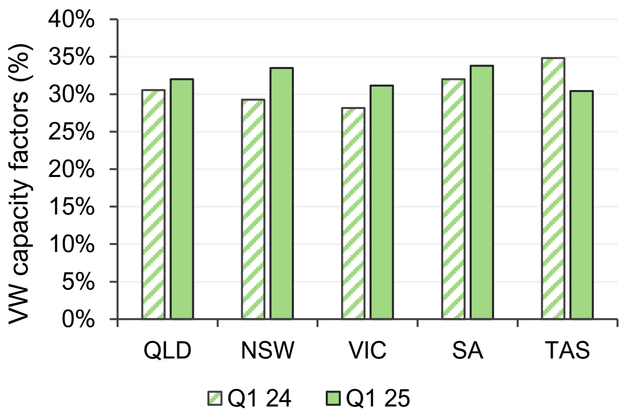


Figure 48 Increases in wind availability across all NEM regions, except Tasmania

Volume-weighted wind available capacity factors – Q1s

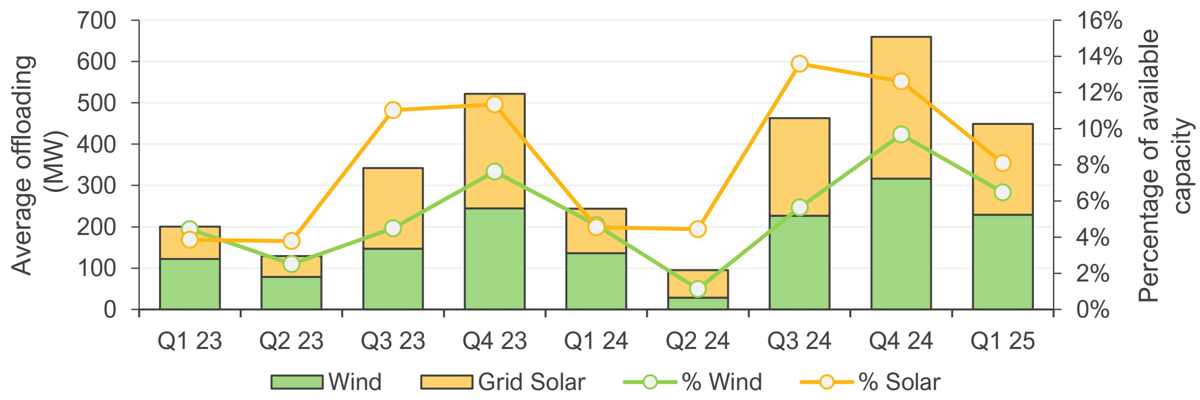


Economic offloading

Compared to Q1 2024, total economic offloading[11] of wind and grid-scale solar generation increased by 205 MW (+84%) to average 449 MW in Q1 2025, reflecting the reduction in daytime operational demand (see Section 2.1) and the increase in negative price occurrence this quarter (see Section 2.2.3). Offloading of wind generation rose from 136 MW to 229 MW, with offloading as a percentage of average availability rising from 4.7% in Q1 2024 to 6.5% in Q1 2025 (Figure 49). Offloading of grid-scale solar generation grew from 108 MW to 220 MW, representing an increase from 4.5% of average availability in Q1 2024 to 8.1% in Q1 2025.

Figure 49 Economic offloading of wind and grid-scale solar generation increased year-on-year

Average MW offloading and as percentage of availability by fuel type



Curtailment

This Q1, average curtailment[12] of grid-scale solar generation increased by 11 MW (+11%) to 118 MW, and solar curtailment as a percentage of quarterly average availability decreased to 4.3% from 4.5% in Q1 2024 (Figure 50).

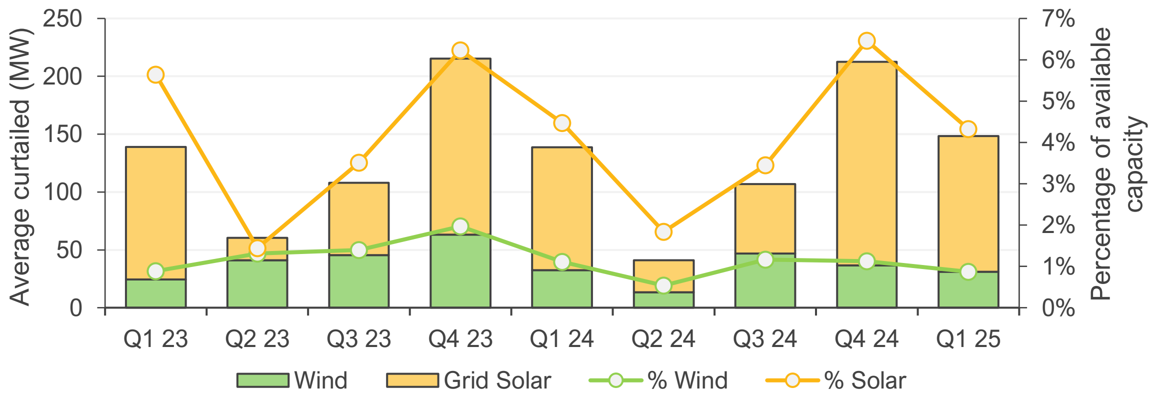
[11] Economic offloading refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price (that is, it was undercut by competitors offering their output at a lower price).

[12] Curtailment refers to energy from a generator not being dispatched, even though it was bid at or below the regional reference price, because of some other limitation (for example a network constraint).

In contrast, curtailment of wind generation decreased by 2 MW (-4.8%) to average 31 MW this Q1, and wind curtailment as a percentage of quarterly average availability at 1% was at a similar level to Q1 last year.

Figure 50 Curtailment of wind generation decreased while curtailment of grid-scale solar generation increased year-on-year

Average MW curtailment and as percentage of availability by fuel type



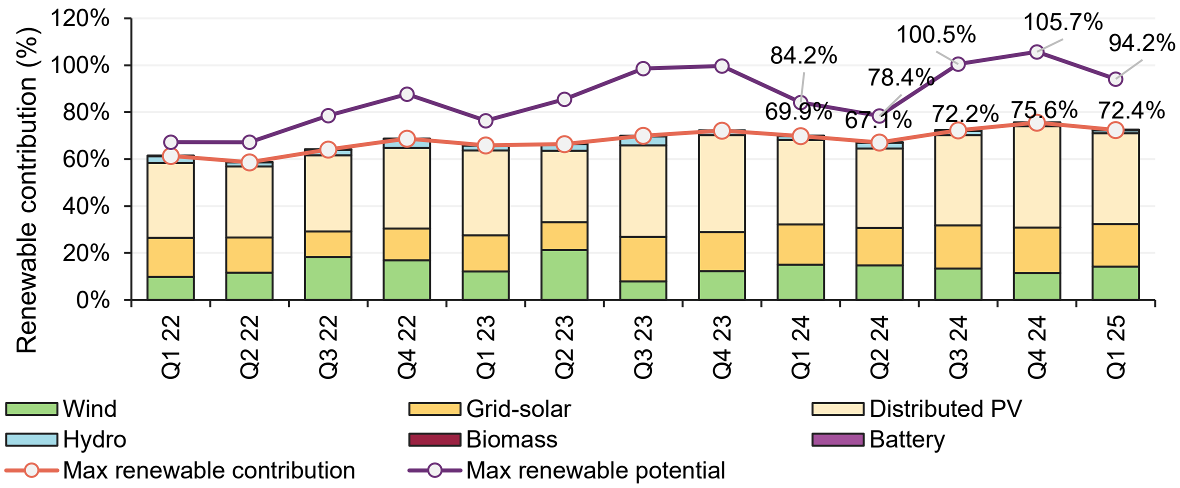
2.3.5 Renewables contribution

Peak renewable contribution

Peak renewable contribution[13] was observed at 72.4% of total generation during the half-hour interval ending at 1300 hrs on Monday, 27 January 2025 (Figure 51). This was 2.5 pp higher than the previous Q1 level observed in 2024, but 3.2 pp below the current record for peak renewable contribution which occurred in Q4 2024 (75.6 %). Renewable potential[14] saw a notable year-on-year increase from 84.2% in Q1 2024 to 94.2% this quarter.

Figure 51 Peak renewable contribution and potential increased year-on-year

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



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

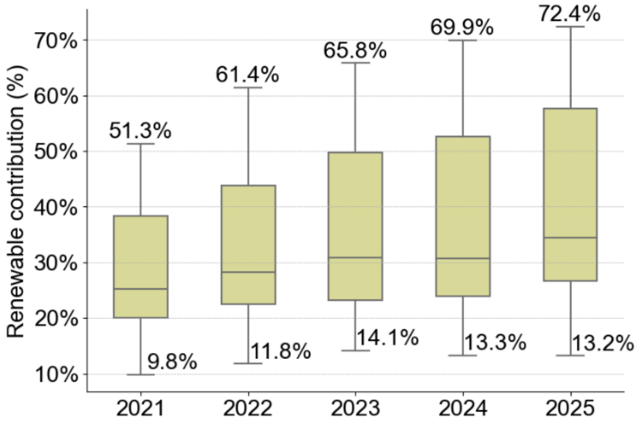
[14] Renewable potential in an operating interval refers to the total available energy from VRE sources, even if not necessarily dispatched, and actual output from dispatchable renewables, expressed as a percentage of the total NEM supply requirement.

Figure 52 shows the expanding width between minimum and maximum renewable contributions, which ranged from a low of 13.2% to a high of 72.4% in Q1 2025.

The quarter's minimum renewable contribution occurred during the half-hour ending at 0300 hrs on Saturday, 22 March 2025, and was 0.1 pp lower than Q1 2024's 13.3%.

Figure 52 Maximum renewable contribution increased

Range of NEM supply share from renewable energy sources – Q1s

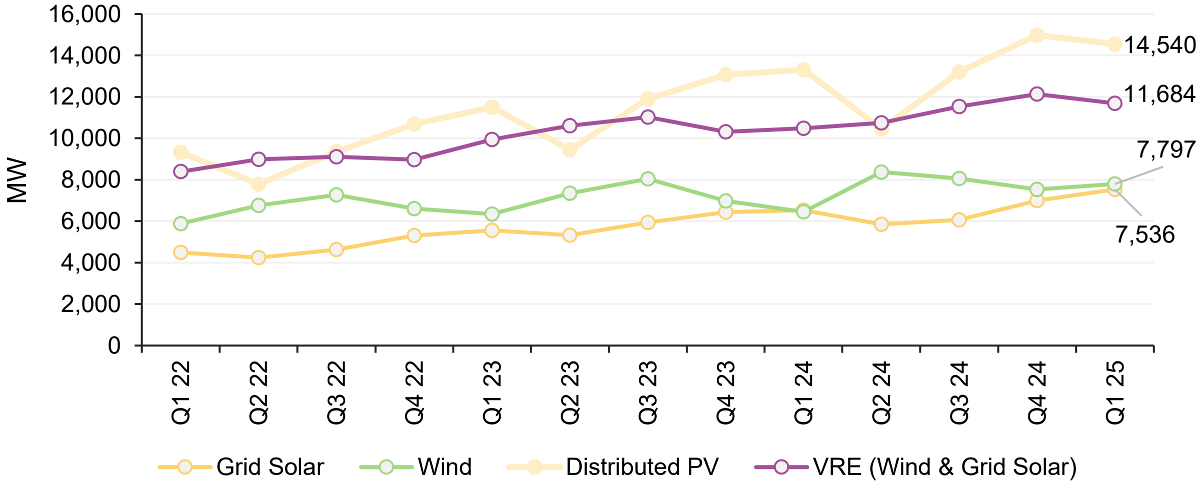


Maximum peak renewable output

Figure 53 highlights the highest quarterly peak half-hourly outputs for grid-scale solar, wind, and distributed PV since Q1 2022. This quarter set a new all-time record for grid-scale solar at 7,536 MW. Peak distributed PV output saw a year-on-year uplift of 1,229 MW (+9%), reaching 14,540 MW, while peak wind output increased by 1,351 MW (+21%) from 6,446 MW in Q1 2024 to 7,797 MW this quarter, but remained below its record of 8,375 MW set in Q2 2024. Additionally, peak VRE output, which combines wind and grid-scale solar, increased from 10,484 MW in Q1 2024 to 11,684 MW this quarter, setting a new Q1 record, but still below its all-time record of 12,133 MW reached during Q4 2024.

Figure 53 Record high for peak grid-scale solar output

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

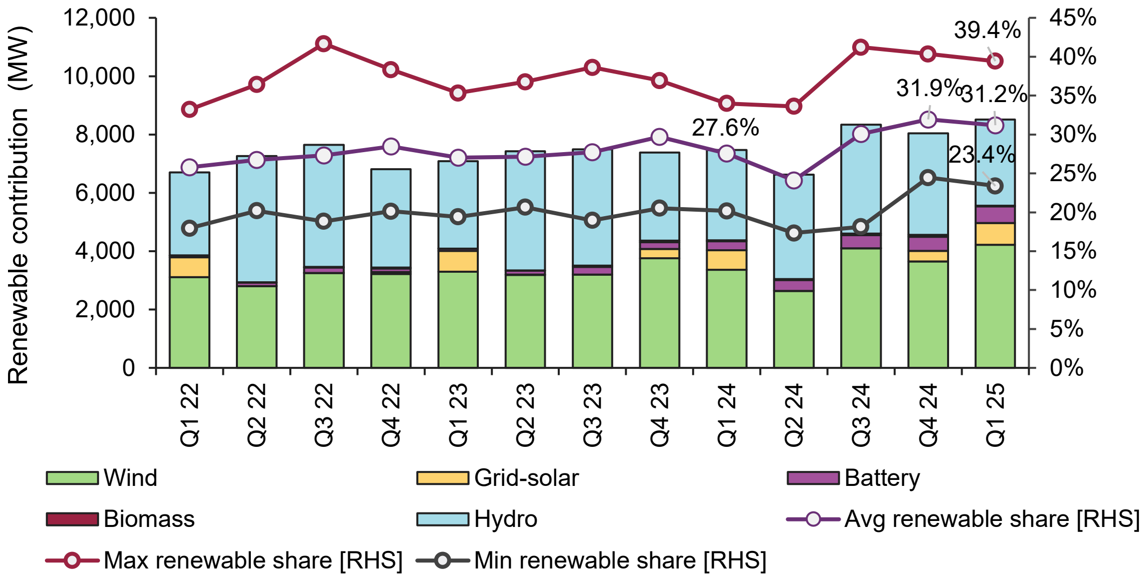


Renewable contribution to maximum demand

Figure 54 illustrates the average contribution of large-scale renewable generation in meeting daily maximum NEM operational demand, computed as an average across all days in each quarter[15]. This measure increased from 27.6% in Q1 2024 to 31.2% this quarter, accounting for a 3.6 pp year-on-year increase.

Figure 54 Increased renewable contribution to meeting daily maximum demand

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



2.3.6 NEM emissions

During Q1 2025, NEM total emissions decreased by 1.5 $MtCO_2$-e (-5.1%) from Q1 2024 levels, reaching a new Q1 quarterly low of 27.4 $MtCO_2$-e (Figure 55). This can be attributed to lower coal-fired and gas-fired generation this quarter (see Section 2.3), along with Q1 2024 having an additional day because it included a leap day.

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[16]. 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 per MWh, down 4.4% from 0.62 tCO2-e per MWh in Q1 2024, also a new Q1 quarterly low. This decline reflects the changing composition of the energy mix, with grid-scale renewables increasing their overall share (with increased wind and grid-scale solar output offsetting a reduction in hydro output), and coal-fired and gas fired generation reducing their volume share (see Table 4 in Section 2.3).

Emissions intensity associated with underlying demand[17] also reduced to a new Q1 low of 0.50 tCO_2-e/MWh, a 0.03 tCO_2-e/MWh (-6.4%) reduction year-on-year, reflecting the impact of increasing penetration of distributed PV.

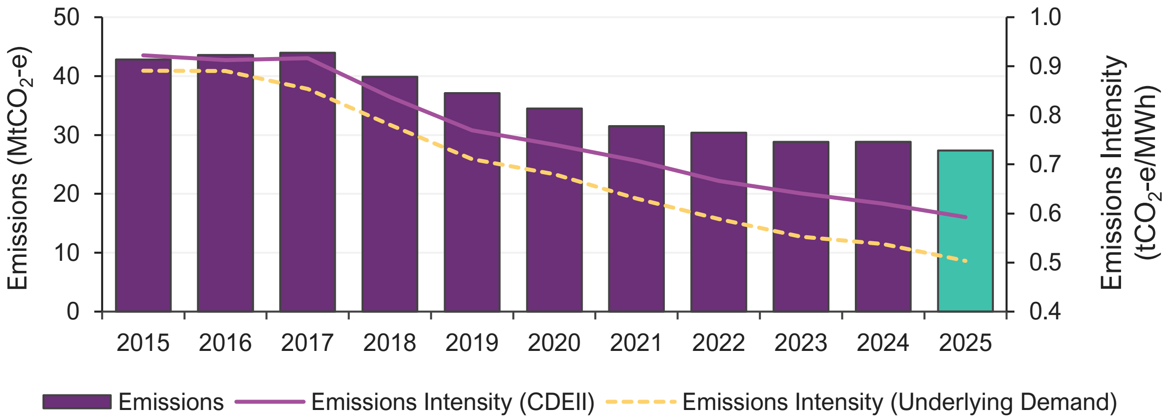
[15] For every day in each quarter, the half-hour of maximum NEM operational demand is found along with large-scale renewable sources' contribution to meeting that demand. These quantities are then averaged over all days in the quarter to compute renewables' average contribution to supplying peak demand.

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

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

Figure 55 Year-on-year reduction in emissions and emissions intensity to all-time lows

Quarterly NEM emissions and intensity – Q1s



2.3.7 Storage

Batteries

This quarter, estimated net revenue for NEM grid-scale batteries, covering both energy and frequency control ancillary services (FCAS) markets, totalled $44.0 million, $3.7 million lower than the estimated revenue for Q1 2024 (Figure 56).

Net revenue from the energy market[18] rose by $14.7 million (+44%) to $48.5 million, accounting for 88% of total estimated net revenue (Figure 57). This growth was primarily driven by a $12.8 million (+42%) increase in revenue from energy generation (discharging). Additionally, charging during negative price periods contributed an extra $1.9 million in revenue, bringing the total to $5.4 million. Meanwhile, energy costs (charging at prices above $0/MWh) increased by $4.5 million (+87%) year-on-year.

Figure 56 Year-on-year fall in battery net revenue driven by reduced FCAS component

Quarterly net revenue from NEM battery systems by revenue stream

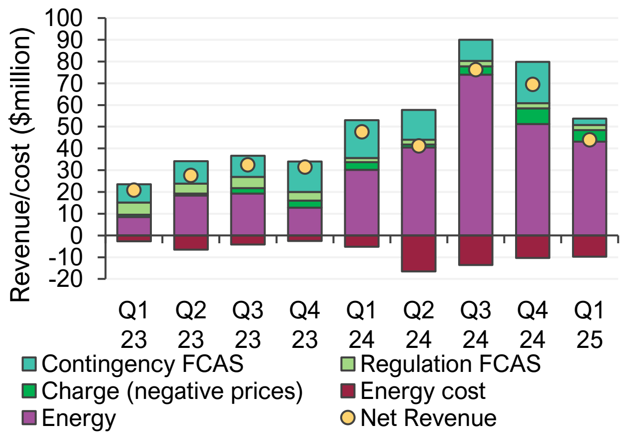
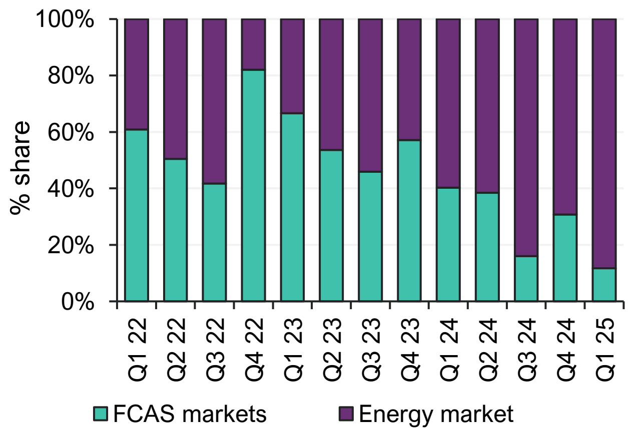


Figure 57 Proportion of battery net revenue from FCAS markets fell

Percentage share of battery net revenue – energy vs FCAS markets



[18] Also known as energy arbitrage revenue for batteries which includes three components: 1) revenue from discharging (selling energy), 2) revenue (or equivalently, negative costs) from recharging during negatively-priced intervals, and 3) cost of recharging at non-negative prices.

While energy market arbitrage net revenue increased year-on-year, revenue from FCAS declined by $13.9 million (-72%), totalling $5.3 million for the quarter. This reduction in revenue from FCAS markets was driven by lower FCAS prices, reflecting greater available supply of FCAS capability particularly from batteries, as well as a limited number of market events during the quarter (see Section 2.5).

The increase in energy arbitrage net revenue across the NEM from Q1 2024 was driven by year-on-year growth in battery capacity, which increased availability and output in the energy market. Average NEM battery availability rose 46% from 819 MW in Q1 2024 to 1,193 MW in Q1 2025 (Figure 58). Battery generation averaged 98 MW this quarter, an increase of 45 MW (+86%) compared to Q1 2024. The NEM-wide price spread[19] for batteries averaged $183/MWh, down from $248/MWh in Q1 2024, reflecting lower price volatility year-on-year (Figure 59).

Figure 58 Year-on-year increase in NEM battery availability

Average quarterly battery generation availability

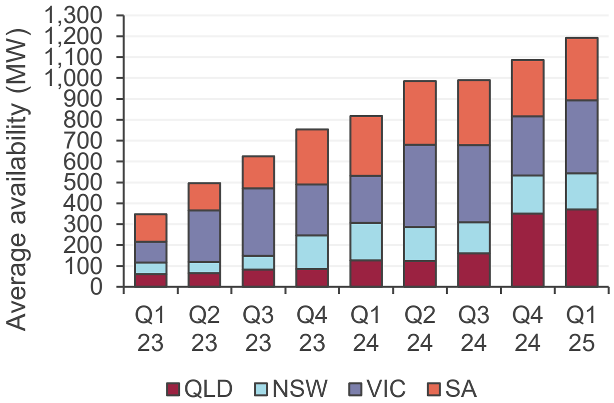
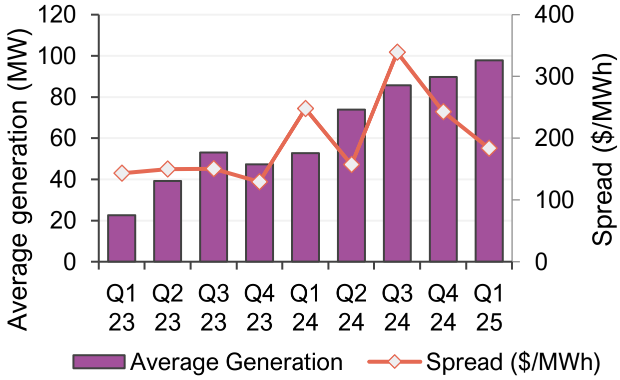


Figure 59 Year-on-year drop in battery price spread partly offset higher output

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



Between the end of Q1 2024 and the start of Q1 2025, several major battery systems entered the NEM and have either reached full operation or are undergoing commissioning. This includes Western Downs (255 MW/510 MWh) in Queensland, 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.

Also during Q1 2025, several new major battery systems registered in the NEM or commenced commissioning, including Greenbank (200 MW/400 MWh) and Tarong (300 MW/600 MWh) in Queensland, Eraring (460 MW/1,073 MWh) in New South Wales, and Koorangie (185 MW/370 MWh) in Victoria.

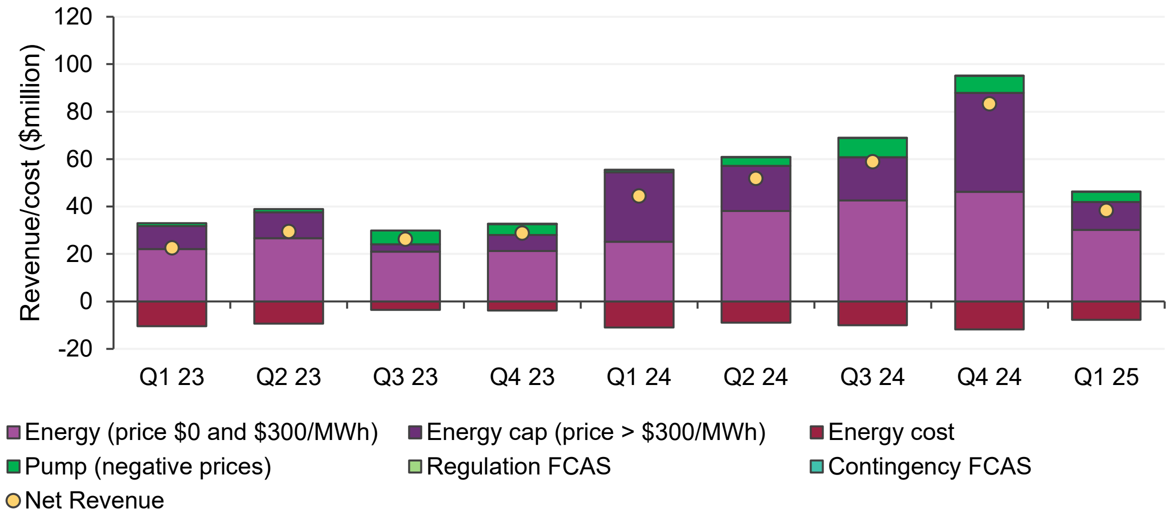
Pumped hydro

Estimated net revenue for pumped hydro facilities this quarter fell to $38.5 million, a $6 million decrease (-14%) compared to Q1 2024 (Figure 60). Lower net revenue at Wivenhoe accounted for most of the decrease, down by $5.0 million year-on-year. The overall decline was primarily driven by reduced price volatility in Queensland and New South Wales (see Figure 13 in Section 2.2). Revenue from prices exceeding $300/MWh dropped significantly by $17.6 million (-60%) to $11.7 million, while revenue from prices below $300/MWh rose by $5.0 million year-on-year to $30.1 million, reflecting higher generation output for Wivenhoe which increased 28% from Q1 2024.

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

Figure 60 Pumped hydro net revenue reduced year-on-year

Quarterly net revenue from NEM pumped hydro by revenue and cost stream

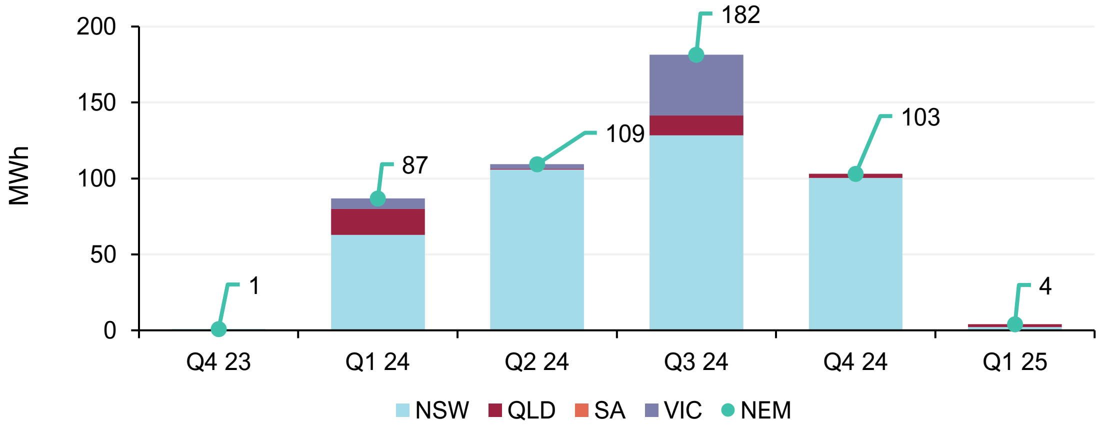


2.3.8 Demand side flexibility

In Q1 2025, wholesale demand response dropped significantly to 4 MWh compared to 87 MWh in Q1 2024 (Figure 61), alongside reduced high-price volatility during the quarter (see Section 2.2.2). Demand response occurred on two days, with 2 MWh dispatched in Queensland on 22 January and 2 MWh in New South Wales on 4 February 2025. Queensland dispatch occurred on the day the region recorded a new maximum demand record and where significant high-priced volatility occurred (see Table 3 in Section 2.2.2). Queensland wholesale spot prices averaged $9,420/MWh over the 21 periods when wholesale demand response (WDR) was dispatched, with a peak output of 1 MW. New South Wales dispatch occurred on a less volatile day, with wholesale spot prices averaging $150/MWh across the three intervals in which dispatch occurred, with a peak output of 9 MW.

Figure 61 Significant drop in wholesale demand response

Total quarterly WDR energy dispatch



The relatively low deployment of wholesale demand response and the slow growth of registered units (20 units, an increase of five from Q1 2024 and nine since Q2 2022) reflects a limited participation in the WDR market in general. This market does not capture the full extent of price-responsive resources that currently exist in the NEM, however, making it difficult to predict and report on their operation. AEMO is currently consulting on the development of Price Responsive Reporting Guidelines[20] required under the 'Integrating price-responsive resources (IPRR) into the NEM' rule change[21]. This rule change establishes a framework for allowing aggregated price-responsive resources, including consumer energy resources (CER), other distributed energy resources (DER) and price-responsive loads to be scheduled and dispatchable within the NEM. Reporting on the impact of unscheduled price-responsive loads is expected to commence in 2026.

Demand flexibility does play a large role in the FCAS markets, with 12 participants registered to provide demand response (DR) ancillary services. In contrast to the WDR market, DR provided 19% of the combined contingency raise services enablement over Q1 2025, at an average enablement level of 330 MW (see Section 2.5).

2.3.9 New grid connections

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

The increased volume of connection applications approved over the past two financial years is now starting to connect to the NEM. This is reflected by the surge in capacity registered in Q1 2025 (Figure 62), with this new capacity now having progressed to commissioning (Figure 63). The elevated rate of application approvals has remained steady for the past five quarters, which should enable the steady flow of projects through to full output if investment conditions continue to remain stable.

During Q1 2025:

- 1.7 gigawatts (GW) of applications were approved across seven projects (Figure 62).
- 2.4 GW of plant across seven projects were registered and connected to the NEM.
- 0.5 GW of plant across five projects progressed through commissioning to reach full output: Blyth Battery Energy Storage System (200 MW), Gangarri Solar Farm (150 MW), Crookwell 3 Wind Farm (56 MW), Mokoan Solar Farm (46 MW) and Kingaroy Solar Farm (40 MW).

The Connections Scorecard[23] contains further information.

At the end of Q1 2025, AEMO's snapshot of connection activities in progress shows that:

- There was 50.5 GW of new capacity progressing through the end-to-end connection process from application to commissioning, 37% more than at the same time last year when 37.1 GW was in progress (Figure 63).
- The capacity of battery projects in the end-to-end connection process increased 86% over the year, from 11.0 GW to 20.5 GW. Solar projects increased 19% from 10.2 GW to 12.1 GW, with 60% of this connecting solar capacity indicating plans to install batteries. Wind increased 11% from 7.5 GW to 8.3 GW. Solar with battery increased 24% from 4.5 GW to 5.6 GW. Gas increased from 0.7 GW to 0.9 GW.

[20] https://aemo.com.au/consultations/current-and-closed-consultations/integrating-price-responsive-resources-guidelines-consultation

[21] https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

[22] 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.

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

- The total capacity of in-progress applications was 19.6 GW. The majority of applications for solar plant now also include batteries in their initial plant design.
- 19.9 GW of new capacity projects are finalising contracts and under construction (proponent implementation), compared with 14.5 GW a year ago (37% increase).
- 4.0 GW of projects are progressing through registration, compared to 4.6 GW at the same time last year (12% decrease).
- There was 7.0 GW of new capacity in commissioning, compared to 1.5 GW at the same time last year (357% increase). This commissioning measure considers all plant in commissioning up to the plant reaching its full output.

Figure 62 Steady progress of application approvals and strong quarter for registrations in Q1 2025

Application approved, registrations and plant commissioned to full output during Q1 2025

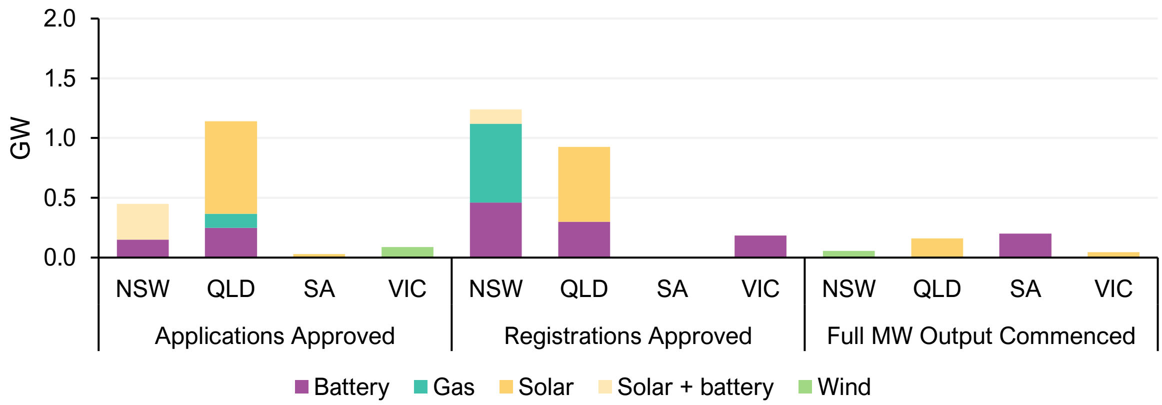
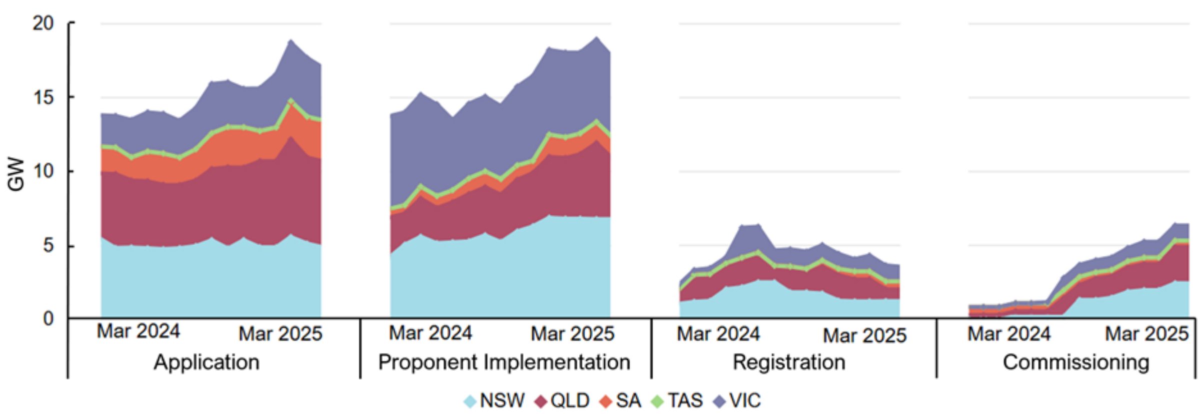


Figure 63 Increase in capacity being progressed through the connections pipeline during the last year

Capacity of connections in progress showing the trend over the past 12 months



2.4 Inter-regional transfers

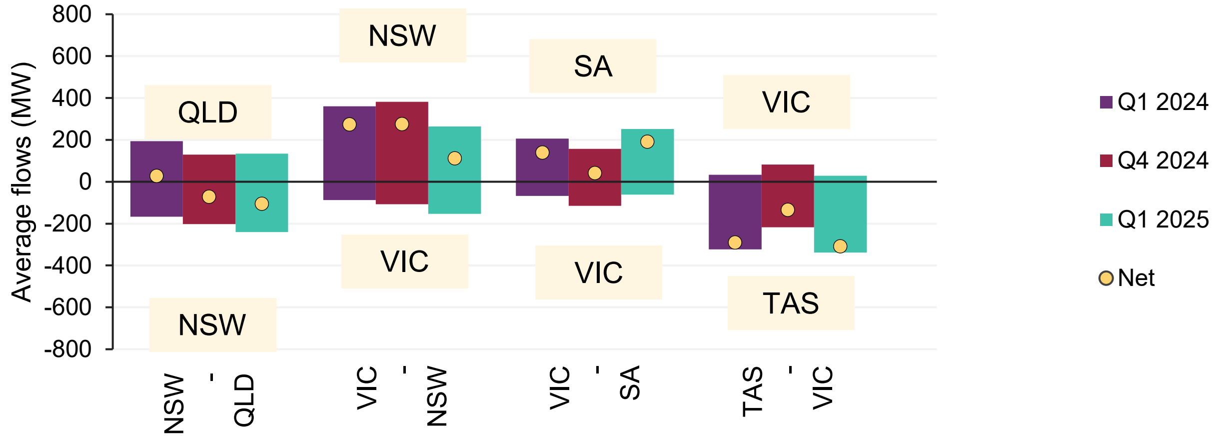
Total inter-regional transfers were 3,179 gigawatt hours (GWh) in Q1 2025, a 1.2% increase on Q1 2024's 3,142 GWh, and equivalent to 6.9% of NEM operational demand for the quarter. The largest year-on-year shifts in net regional transfers were across the Victoria – New South Wales Interconnector (VNI), where net flow fell from an average of 274 MW northward in Q1 2024 to 110 MW this quarter, and between Queensland and New South

Wales, where net transfers of 27 MW northward last Q1 reversed to average 106 MW southward in Q1 2025 (Figure 64).

Net transfers from Victoria to South Australia increased from an average of 138 MW a year ago to 190 MW this quarter, with a significant driver being commissioning of PEC-1 (discussed further below). Tasmania continued to import strongly from Victoria across Basslink with average net flows of 309 MW southward this quarter, compared to 290 MW southward a year ago. Both this and last Q1, exports from Tasmania to Victoria were only around one-tenth the volume of imports, concentrated in evening and morning peak hours when they did occur.

Figure 64 Southward shifts in Queensland – New South Wales – Victoria transfers

Quarterly inter-regional transfers



Changes in regional demand and price relativities contributed to the southward shifts in flows between New South Wales and Queensland, and between Victoria and New South Wales. In Q1 2024, Queensland experienced very high demand levels and recorded an average spot price $30.8/MWh higher than New South Wales, and both of these factors drove net northward energy transfers. Net Q1 transfers between these regions have been northward in only three years since NEM commencement (Figure 65). Significantly lower demands this quarter resulted in Queensland's average spot price being only $2.0/MWh above New South Wales', and energy transfers returned to a more typical net southward pattern. Nevertheless, the volume of northward transfers was the third highest for any Q1 after 2024 and 2022.

Across VNI, net northward transfers were at their lowest level for a Q1 since 2019 (Figure 66). While average New South Wales operational demand fell by 155 MW this Q1 compared to a year ago, Victorian operational demand increased by 222 MW. The gap between the energy component of average prices in New South Wales and Victoria fell by $15.1/MWh from $34.3/MWh in Q1 2024 to $19.2/MWh this Q1. Both factors contributed to lower average northward transfers, and a higher volume of southward flows when Victoria imported from New South Wales.

Figure 65 New South Wales – Queensland transfers shifted south

New South Wales to Queensland transfers – Q1s

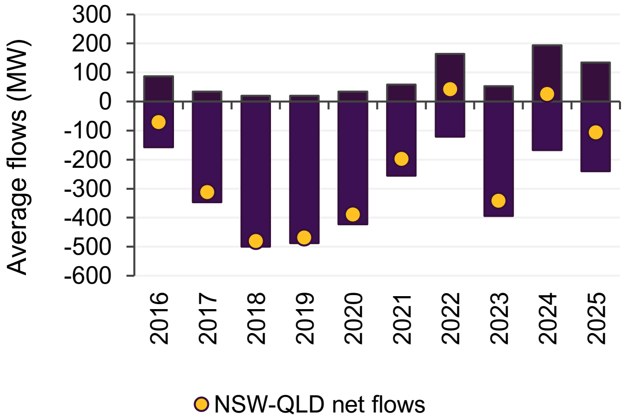
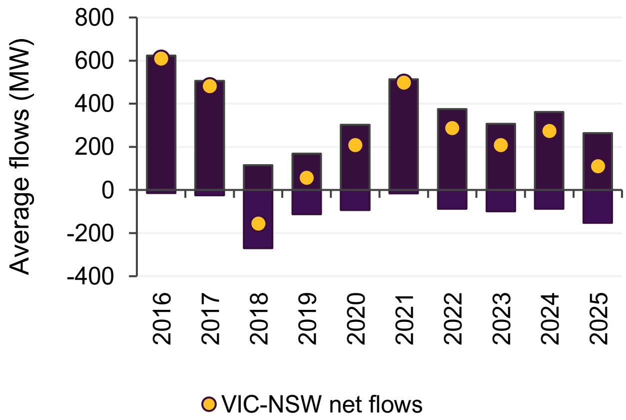


Figure 66 Victorian net exports to New South Wales fell again

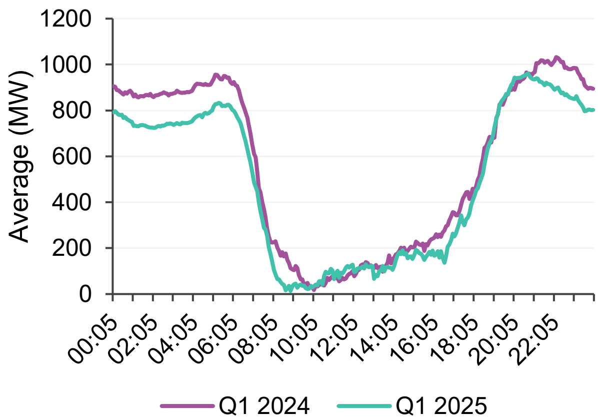
Victoria to New South Wales transfers – Q1s



Transmission constraints within New South Wales continued to limit maximum northward transfers on VNI, particularly at times of high solar generation in the south of the state and north-west Victoria (Figure 67). Constraints related to transmission outages also played a more prominent role this Q1, accounting for over 40% of all export-limited intervals on VNI, compared to only around 10% in Q1 2024. Outage constraints particularly affected overnight northward limits in Q1 2025, limiting average VNI flows when binding to 719 MW between 2200 hrs and 0600 hrs, compared to 876 MW for outage constraints in Q1 2024.

Figure 67 Northward limits on VNI impacted by daytime solar output and outage constraints overnight

Average VNI export limit. by time of day



Conversely, a change to the Yass to Wagga control scheme in late February allowed the removal of a set of system normal constraints which in January and February had set VNI export limits in 36% of all intervals in which export limits were binding – on average these constraints had forced export limits to negative levels (requiring flows from New South Wales into Victoria).

PEC-1 commissioning

Project EnergyConnect (PEC) is a new interconnection under construction between South Australia and New South Wales. The first stage of the project (PEC-1) comprises a new transmission line between Bundey in South Australia and Buronga in south-west New South Wales, with a spur connection to Victoria at Red Cliffs. In its initial operation, the transfer capability provided by PEC-1 to and from South Australia is being represented as in increase in the capacity of the existing Heywood alternating current (AC) interconnection with Victoria, by up to

150 MW. PEC-1 underwent inter-network testing and progressive release of capacity over Q1 2025[24], with the full capacity released shortly after the end of the quarter on 11 April 2025.

Another impact of PEC-1 is the new connection's role in relieving constraints on generation in north-west Victoria and south-west New South Wales by carrying additional energy into South Australia. Scheduling of these relieving flows requires a westward shift in overall transfers and transfer limits on the combined AC interconnection.

In Q1 2025, this was evident in a reduction or reversal of daytime energy imports into Victoria from South Australia, the typical flow direction in Q1 2024 between 0830 hrs and 1700 hrs (Figure 68). In Q1 2024, average flows in this period were 152 MW into Victoria, but in Q1 2025 flows in the same hours averaged only 11 MW net into Victoria. The incidence of constraints affecting these flows, despite the lower volume of imports, is also evident in the increased proportion of daytime hours in which import limits into Victoria were binding (Figure 69).

Figure 68 Daytime Victorian imports fell on Heywood and PEC-1 interconnection

Average Victoria to South Australia flows on Heywood and PEC-1, by time of day

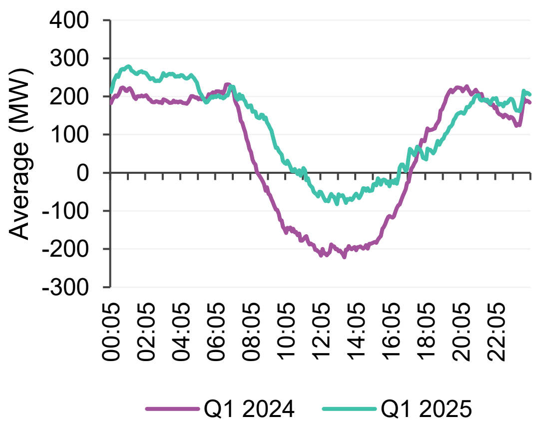
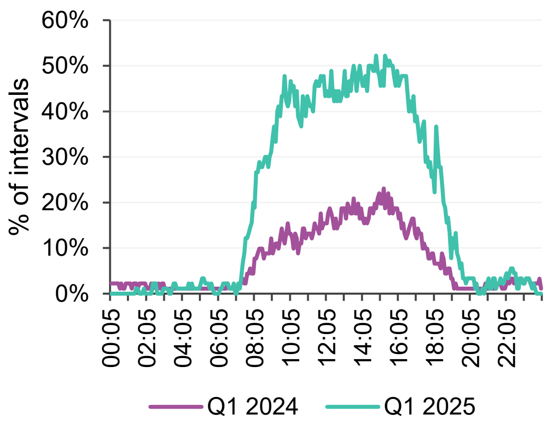


Figure 69 Constraints drove Victoria – South Australia daytime flow changes

Average binding incidence of import constraints on Heywood and PEC-1, by time of day



2.4.1 Inter-regional settlement residue (IRSR)

Positive IRSR totalled $84.4 million in Q1 2025, down $22.2 million (-21%) from last Q1 (Figure 70). The major driver of this fall was on flows into Victoria, where positive residue of $27.0 million in the prior Q1 was elevated by extreme spot price volatility following transmission system storm damage sustained in February 2024. This Q1 positive IRSR on flows into Victoria totalled $10.9 million.

After Q4 2024's record level of -$38.7 million negative IRSR, Q1 2025 saw a significantly lower result of -$22.1 million, also smaller than Q1 2024's -$27.0 million (Figure 71). Negative residues on flows into New South Wales fell from -$8.9 million a year ago to just -$0.9 million, having been driven last Q1 by non-recurring factors including the Victorian transmission system event and transmission constraints coinciding with high Queensland spot prices. Negative IRSR on flows into Victoria, the largest contributor both this and last Q1, was relatively stable at -$15.1 million in Q1 2025, compared to -$16.0 million a year ago. As noted above,

[24] AEMO, Project EnergyConnect Stage 1 and Heywood Interconnector Test Program for Inter-Network Tests, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/project-energyconnect-stage-1-and-hic-capacity-release/pec-stage-1-and-hic---final-test-program.pdf?la=en.

outage-related constraints on VNI were more prominent this Q1 and accounted for well over half of the negative IRSR into Victoria, as against less than 5% of the total for Q1 2024.

Figure 70 Reduction in positive IRSR

Quarterly positive IRSR by region

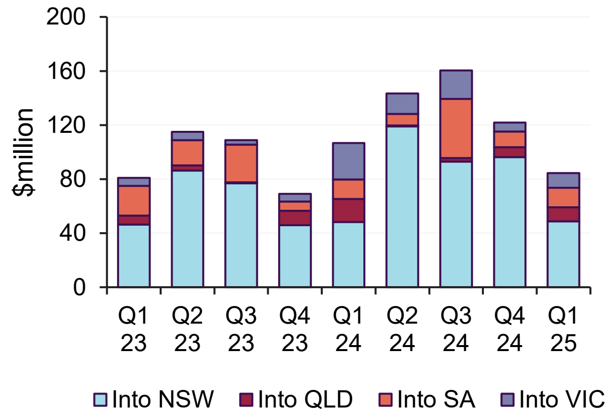
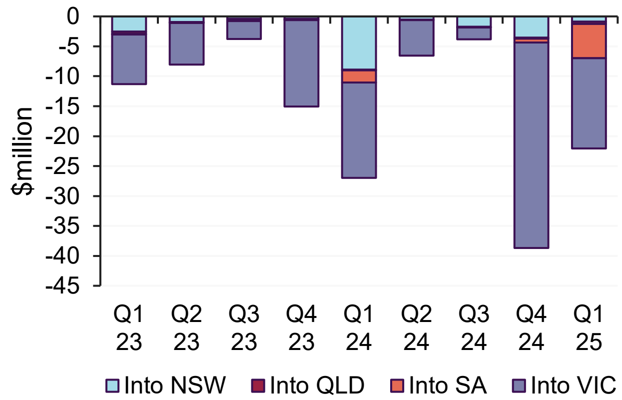


Figure 71 Negative IRSR fell except on Victoria – South Australia

Quarterly negative IRSR by region



Conversely, on flows into South Australia, negative IRSR grew from -$2.1 million in Q1 2024 (partly due to the February 2024 Victorian transmission system event) to -$5.8 million this Q1. The driver of the counterprice flows creating these larger negative residues was the role of PEC-1 in relieving constraints on generators in north-west Victoria and south-west New South Wales, as outlined in the previous section. This frequently resulted in constraint-driven transfer limits scheduling westward flows on the combined Heywood and PEC-1 interconnection at times when South Australian spot prices were below those in Victoria. These effects are evident in both the higher incidence of counterprice flows on this link in Q1 2025 (Figure 72), and the emergence of significant daytime price separation between South Australia and Victoria (Figure 73). In Q1 2024, the energy components of these spot prices differed on average by only $0.8/MWh between 0700 hrs and 1800 hrs, but in Q1 2025, this gap grew to $16.6/MWh, despite flows shifting towards South Australia (Figure 68 above).

Figure 72 Increased counterprice flow west on Heywood and PEC-1 interconnection

Average proportion of westward counterprice flows on Heywood and PEC-1, by time of day

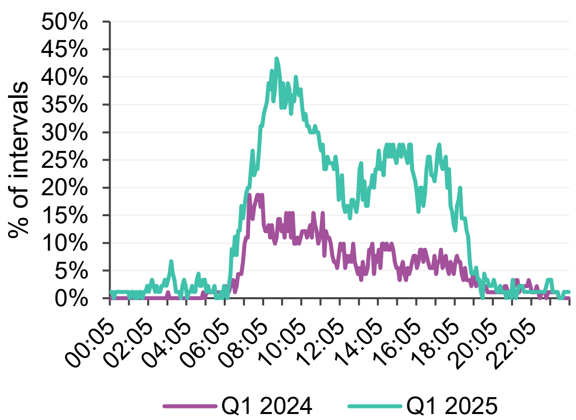
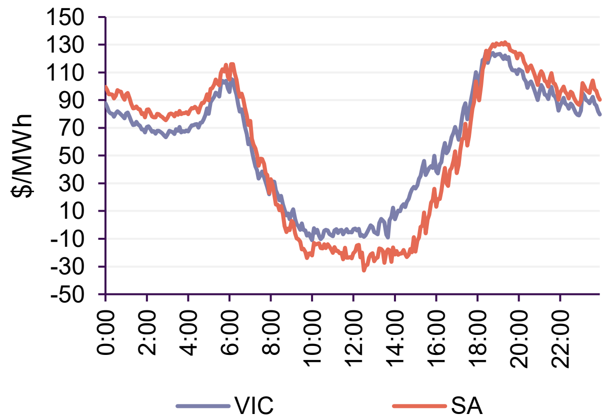


Figure 73 Daytime South Australian prices fell below Victoria's

Average energy price components by time of day – South Australia and Victoria



2.5 Frequency control ancillary services

Total FCAS costs reached $13 million in Q1 2025, representing approximately 0.3% of the total cost of consumed energy[25] for the quarter. This marks a $16 million decrease compared to the same period last year, with cost reductions observed across all regions except Tasmania. This reduction was mainly driven by lower FCAS prices and a smaller number of volatility events during the quarter, relative to last year. South Australia and New South Wales recorded the largest year-on-year declines, down by $6.8 million and $5.1 million respectively (Figure 74).

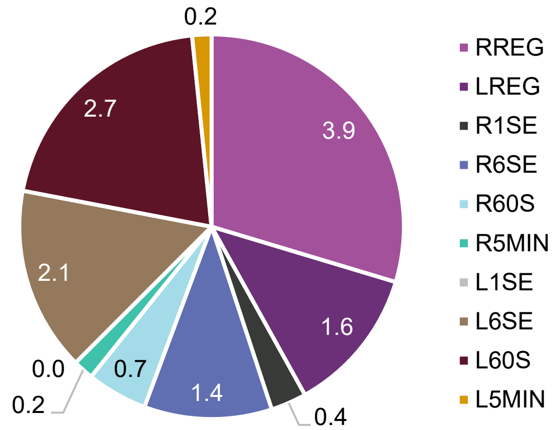
The raise regulation (RREG) service contributed the highest share of FCAS costs this quarter at 30%, and also recorded the largest year-on-year increase, rising by $1.0 million to $3.9 million (Figure 75). Despite a reduction from last year, the contingency lower 60-second (L60S) service incurred the second highest cost at $2.7 million. All other services, with the exception of RREG and contingency raise 60-second (R60S), experienced year-on-year cost declines.

Figure 74 Notable reduction in FCAS costs

Quarterly FCAS costs by region

Figure 75 High share for regulation FCAS costs

NEM quarterly FCAS cost per service – Q1 2025 ($m)



Batteries remained the dominant source of FCAS provision in Q1 2025, accounting for 59% of total enablement volume (Figure 76). This came alongside a modest 7 MW increase in average battery enablement compared to Q1 2024. Virtual power plants (VPPs) recorded a significant year-on-year increase of 113 MW, while hydro saw the largest decline in enablement, particularly for contingency raise services (Figure 77).

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

Figure 76 Batteries dominated FCAS market share

FCAS volume market share by technology – Q1 2025

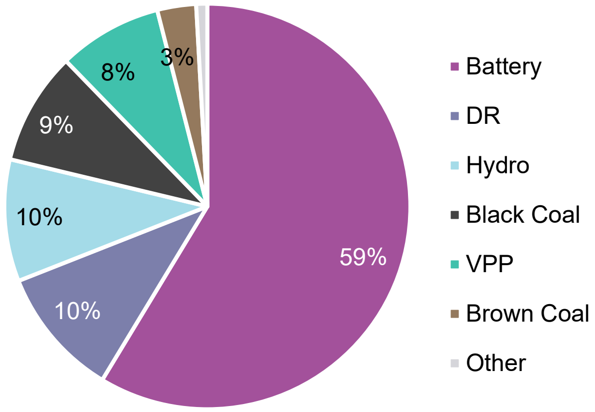
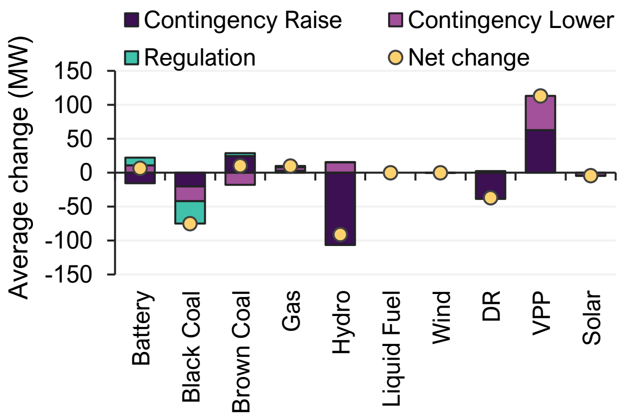


Figure 77 Reduction in hydro enablement while VPP enablement surged in FCAS

Change in FCAS enablement by technology – Q1 2025 vs Q1 2024

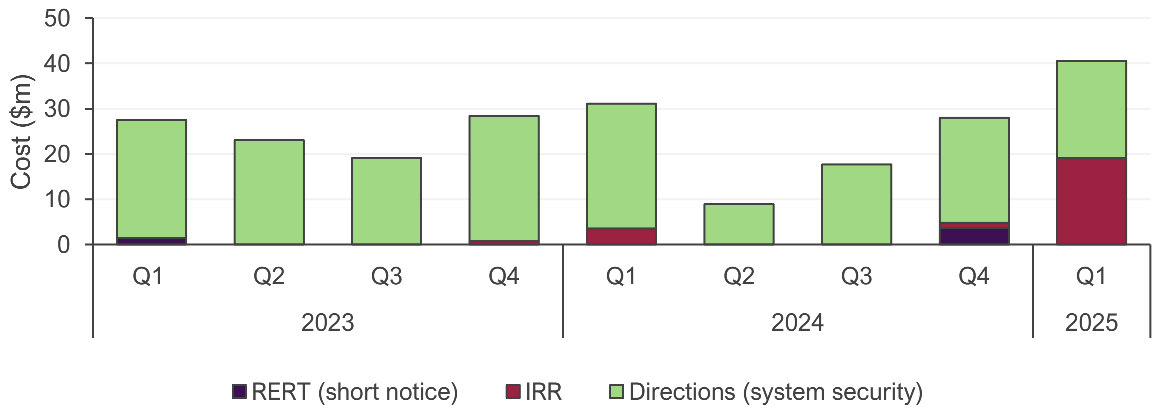


2.6 Power system management

Estimated power system management costs[26] totalled $40.6 million in Q1 2025, representing approximately 1.0% of the total cost for consumed energy during the quarter. This marks a $9.4 million increase compared to Q1 2024 and a $12.6 million increase from Q4 2024 (Figure 78).

Figure 78 System security direction costs down year-on-year while IRR costs increased

Estimated quarterly system security costs by category



Reliability and Emergency Reserve Trader (RERT) is a mechanism used by AEMO to ensure reliability of supply by securing the availability of reserves using reserve contracts. AEMO entered into interim reliability reserve (IRR) agreements with four providers for the New South Wales region for the period from 1 December 2024 to 31 March 2025, and four providers in South Australia commencing across January 2025[27]. The combined payments to these providers in Q1 2025 were $19.1 million.

[26] 'Power system management costs' are those associated with Reliability and Reserve Trader (RERT) and compensation for system security directions for energy services only and excludes compensation costs for reliability directions (including those to maintain a state of charge) and system security directions for other services (that is, operating as synchronous condenser).

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

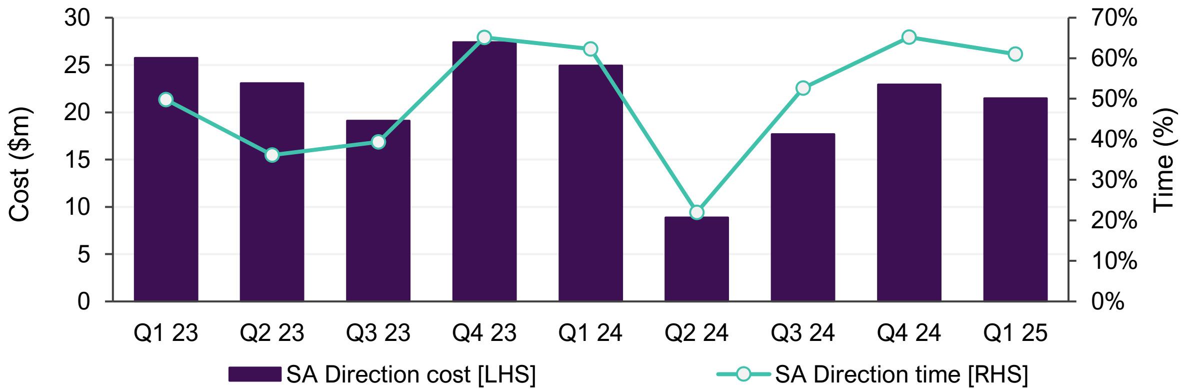
Power system management costs also included an estimated $21.5 million in compensation payments to generating systems that were directed to provide energy services to maintain system security in South Australia during the quarter.

2.6.1 System security energy directions

System security directions were in place in South Australia for 61% of dispatch intervals in Q1 2025, slightly less than the 62% of intervals in Q1 2024 (Figure 79). The average amount of gas-fired generation directed in South Australia also decreased slightly from Q1 2024, reducing by 1 MW to an average of 45 MW this quarter, with the share of total South Australian gas-fired output directed remaining constant at 16%.

Figure 79 Direction frequency of South Australian generators remained almost constant year-on-year

Time and cost of energy only system security directions – South Australia and Victoria Q1 2023 to Q1 2025



The initial estimated cost for the Q1 2025 system security directions in South Australia is $21.5 million, which is lower than the finalised total of $24.9 million for Q1 2024 directions compensation. However, any additional compensation claims for generators directed during Q1 2025 have not yet been finalised, so the estimated costs are subject to change[28].

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

3 Gas market dynamics

3.1 Wholesale gas prices

Quarterly wholesale gas prices increased from Q1 2024 but were 2.5% lower than Q4 2024. The average price across all AEMO markets was $13.26/GJ compared to $11.60/GJ in Q1 2024 (Table 6). This is the highest average Q1 price on record, surpassing the previous record of $11.86/GJ set in 2023. Key factors influencing the movement of prices throughout Q1 2025 are summarised in Table 7, with further analysis and discussion referred to relevant sections elsewhere in this report.

Table 6 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q1 2025	Q4 2024	Q1 2024	Change from Q1 2024
Victorian Declared Wholesale Gas Market (DWGM)	12.18	12.25	11.19	9%
Adelaide	13.51	13.55	11.65	16%
Brisbane	13.64	14.71	11.80	16%
Sydney	13.33	13.66	11.71	14%
Gas Supply Hub (GSH)	13.63	13.85	11.62	17%

Table 7 Wholesale gas price levels: Q1 2025 drivers

Large reduction in net domestic supply from LNG participants	Compared to Q1 2024, supply into the domestic market associated with the LNG projects fell 8 PJ. This led to greater reliance on Victorian supply to meet demand, with significantly higher flows into Queensland from southern markets. As a result, much of this supply was offered into markets at prices higher than Q1 2024. This also led to the continuation of Brisbane being the highest priced market, as observed in Q4 2024.
Increase in volume of gas required to refill Iona gas storage	Iona gas storage began 2025 5.6 PJ lower than at the start of 2024. Much attention is paid to Iona storage levels, with a desire to have Iona full before the start of winter, when this storage is traditionally used to help meet southern markets demand. Withdrawals to refill Iona storage were 8.1 PJ higher than Q1 2024, creating a large increase in overall supply requirements in Victoria, despite overall market demand being lower.

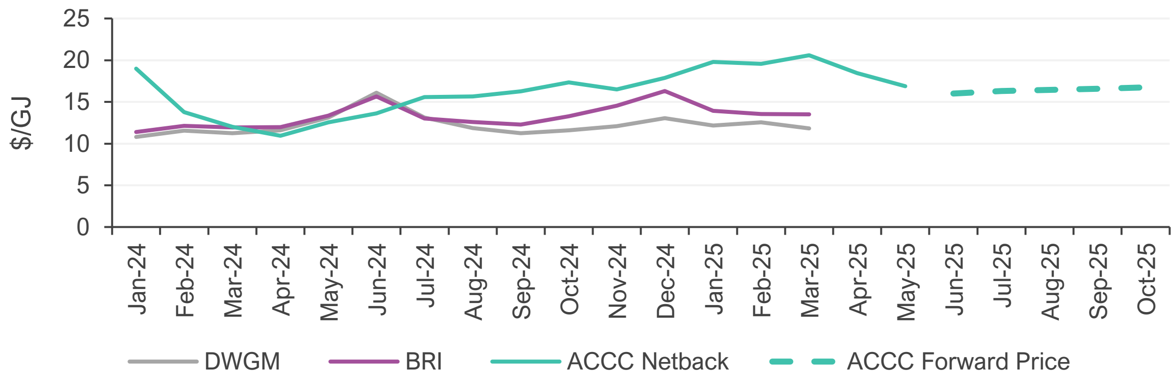
International prices continued the trend observed in Q4 2024 and increased during the quarter. This increase was reflected in upward movements in the Australian Competition and Consumer Commission (ACCC) netback price to March 2025, with corresponding forward prices then slightly lower at between $16.30/GJ and $16.74/GJ over the next six months (Figure 80). Drivers for international prices are discussed in Section 3.1.1.

Prices in Q1 2025 were at record Q1 levels in all markets, with prices in the Adelaide, Brisbane and Sydney Short Term Trading Markets (STTMs) ranging between $13/GJ-$15/GJ on most days, while the Victorian Declared Wholesale Gas Market (DWGM) price ranged between $11/GJ-$13/GJ on most days. Prices dropped across all markets for a short period in late February and early March due to Tropical Cyclone Alfred impacting Australia Pacific LNG (APLNG) and Gladstone LNG (GLNG) production and Brisbane demand, as well as a simultaneous Queensland Curtis LNG (QCLNG) train outage.

The price disparity between Brisbane and the southern states, first observed in Q4 2024, persisted into 2025. On 17 March, Brisbane's gas price peaked at $15.15/GJ, surpassing the DWGM peak of $13.51/GJ on the same day. This ongoing regional price variation is primarily driven by the necessity of transporting gas from southern states to support Queensland's near-record LNG production, alongside a decline in net domestic supply from LNG participants. Additionally, Iona's demand for storage replenishment ahead of winter surged by 8.1 PJ compared to Q1 2024, increasing gas demand in Victoria.

Figure 80 Domestic prices at record Q1 levels but eased slightly from Q4 2024

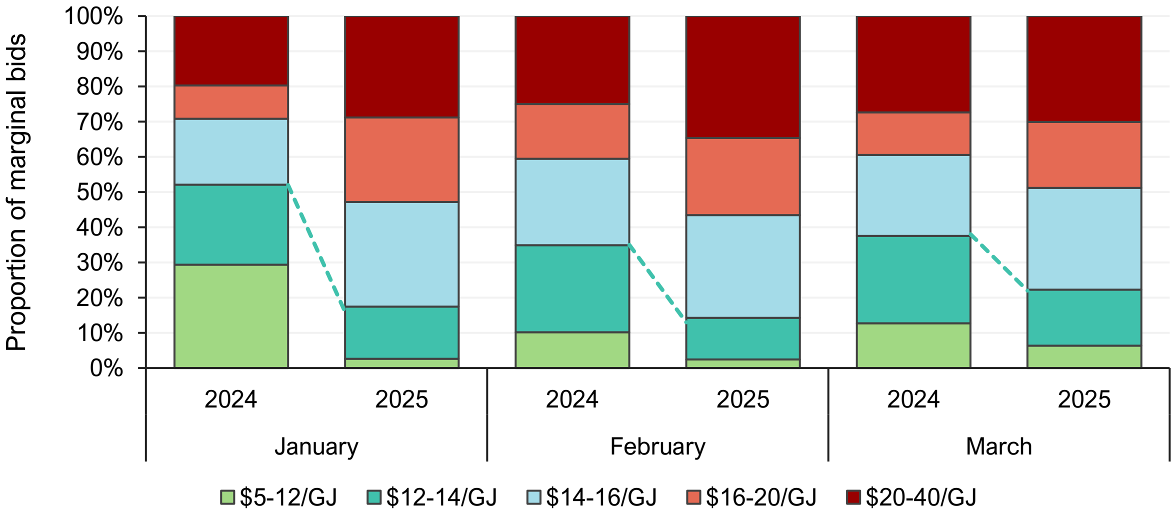
ACCC netback and forward prices[29], DWGM and STTM Brisbane average gas prices by month



Compared to Q1 2024, there was a significant increase in the proportion of DWGM bid volumes above $14/GJ, particularly across January and February (Figure 81). Factors contributing to this include increased exports from Victoria, particularly to New South Wales which saw a large increase in northerly flows to Queensland, as well as a large increase in filling Iona storage in preparation for winter.

Figure 81 Reduced proportion of DWGM bids at lower prices compared to 2024

DWGM – proportion of marginal bids by price band – Q1 2025 vs Q1 2024 by month



3.1.1 International energy prices

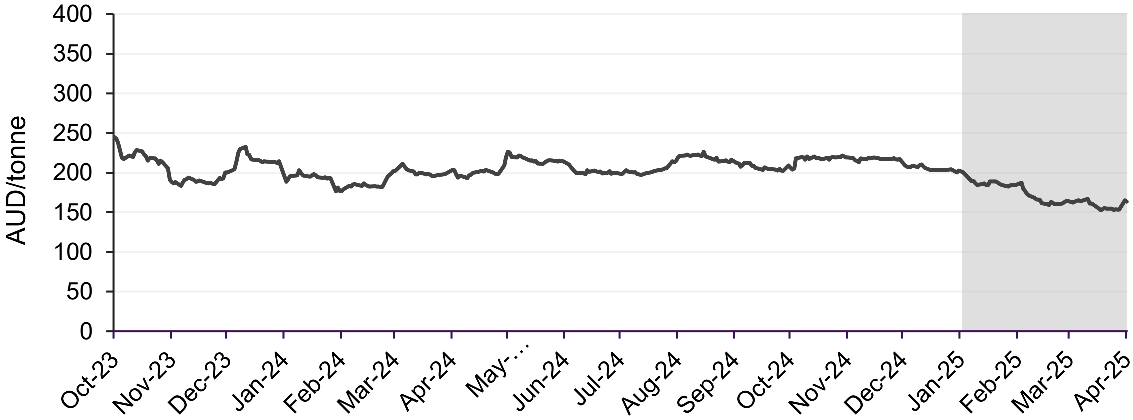
Newcastle export coal prices averaged $171/tonne this quarter, a reduction from $213/tonne in Q4 2024, and $193/tonne in Q1 2024 (Figure 82). High inventories in Asia, built to address energy security concerns and

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

expected seasonal peaks, pushed prices down to the lowest level recorded in almost four years amid mild winter demand in the Northern Hemisphere[30].

Figure 82 Traded thermal coal prices reduced across the quarter

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

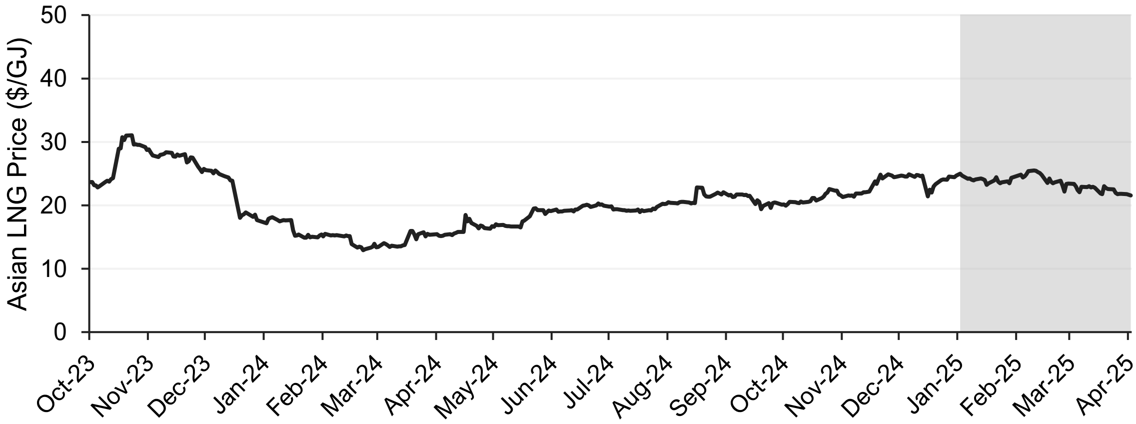


Source: Bloomberg ICE data

Asian spot LNG prices fell during the quarter, ending Q1 at A$21.80/GJ, the lowest level since early October 2024 (Figure 83). The primary driver behind the price decline was weaker than expected demand from Chinese and Japanese LNG buyers in the spot market[31], stemming from a milder than expected winter and reduced industrial manufacturing demand. This, combined with increased domestic production and pipeline imports from Russia, added downward pressure on spot prices in north Asia. Some of the price activity could have also been attributed to ongoing trade disputes between the United States and China, as Chinese LNG buyers halted importing any United States LNG[32].

Figure 83 Asian spot LNG prices fell during the quarter

Asian LNG price in A$/GJ daily



Source: Bloomberg ICE data.

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

[31] Reuters, March 2025: https://www.reuters.com/markets/commodities/asian-spot-lng-prices-nearly-6-month-low-muted-chinese-demand-2025-03-28/

[32] Yahoo Finance, April 2025: https://finance.yahoo.com/news/china-halts-us-lng-imports-061447892.html

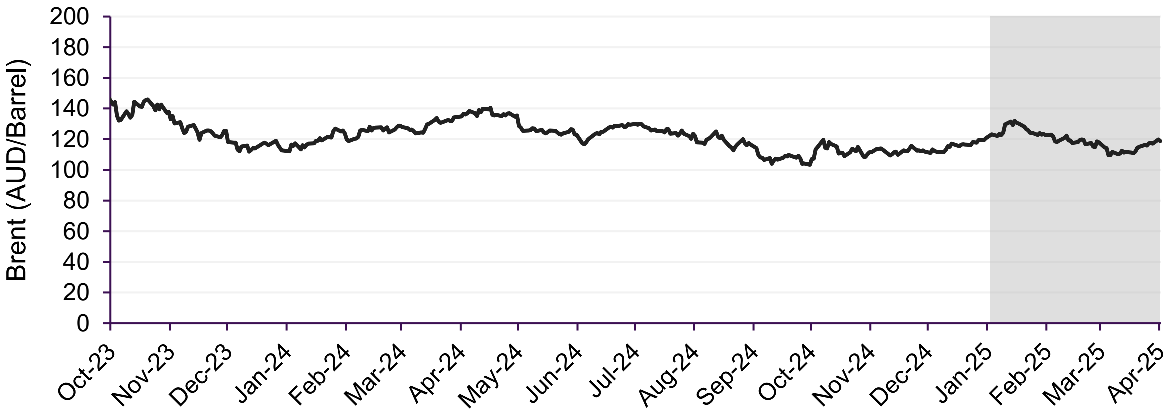
European Union gas storage levels ended Q1 2025 at 33.8%, lower than the five-year average of 45% at this time of year. Currently European Union member nations are required to refill their gas storage facilities to 90% by 1 November, which may see global LNG prices stay elevated, however there are ongoing discussions between member states to allow for more flexibility around the 90% target, including consideration for "unfavourable" market conditions[33].

Brent Crude oil prices averaged A$119/barrel, which was a A$6/barrel increase from last quarter, and coincidentally ended Q1 2025 at the same price as the average for the quarter (Figure 84). The price increase early in the quarter was attributed to potential supply disruptions from Russia and the Middle East, however this sentiment changed quickly as the prospects of United States tariffs became more apparent in the middle of the quarter[34].

The International Energy Agency (IEA) reported that the macroeconomic conditions that underpin its oil demand projections have deteriorated over the quarter with escalating retaliatory tariffs being implemented against the United States. The IEA also noted these disruptions to global trade, along with OPEC+ confirming it will be unwinding production cuts, led to prices reaching as low as A$109/barrel before recovering at the end of the quarter[35].

Figure 84 Brent Crude oil prices averaged A$119/barrel

Brent Crude Oil in A$/Barrel daily



Source: Bloomberg ICE data.

3.2 Gas demand

Total east coast gas demand decreased by 2% compared to Q1 2024 (Figure 85 and Table 8). Queensland LNG production saw the largest decrease (-3 PJ), followed by a decrease in gas-fired generation (-2 PJ).

AEMO markets saw a small fall in overall demand (-1 PJ), with the largest decrease of 2 PJ in Victoria's DWGM due to lower commercial and industrial demand. This decline is discussed further in Section 3.2.1. Sydney STTM demand was 0.7 PJ higher, due to a large user having an outage during Q1 2024.

[33] Reuters, April 2025: https://www.reuters.com/business/energy/eu-countries-consider-changing-2025-gas-storage-targets-sources-say-2025-04-03/

[34] IEA Oil Market Report – February 2025: https://www.iea.org/reports/oil-market-report-february-2025

[35] IEA Oil Market Report – March 2025: https://www.iea.org/reports/oil-market-report-march-2025

Figure 85 Slightly lower gas demand across all sectors

Components of east coast gas demand change – Q1 2025 to Q1 2024

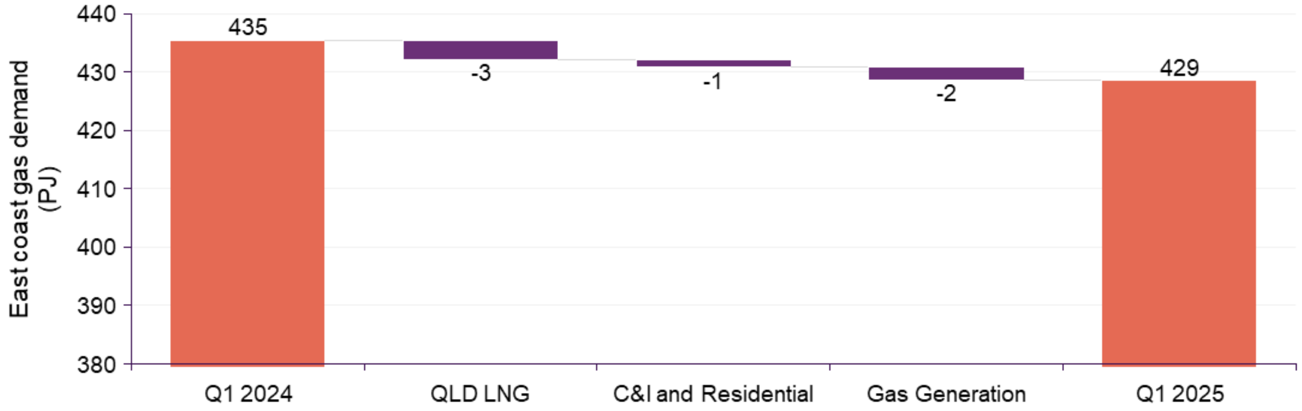


Table 8 Gas demand – quarterly comparison

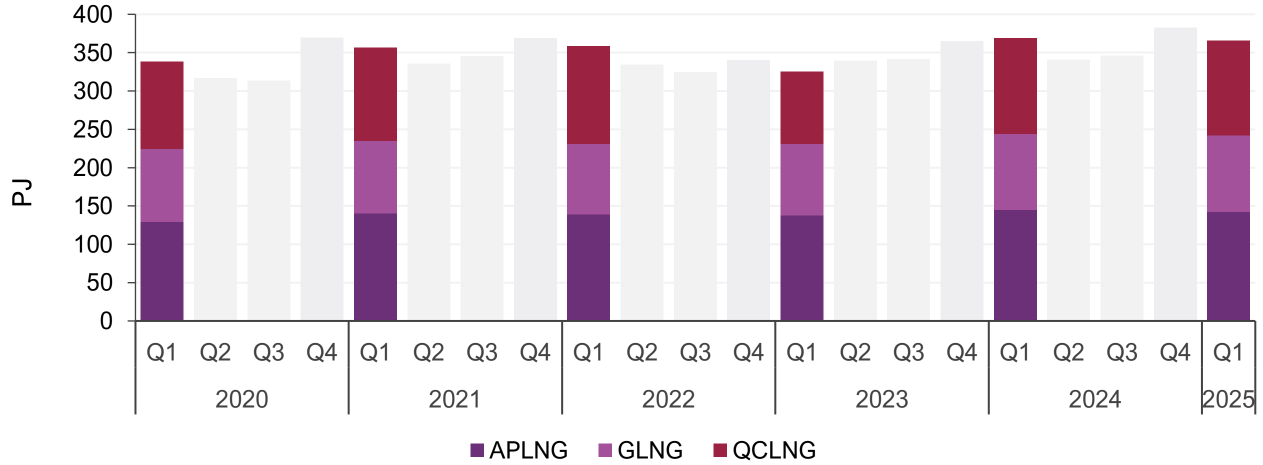
Demand (PJ)	Q1 2025	Q4 2024	Q1 2024	Change from Q1 2024
AEMO markets *	44.8	54.4	46.2	-1 (-3%)
Gas-fired generation **	17.8	20.8	20.0	-2 (-11%)
Queensland LNG	366.0	382.6	369.3	-3 (-1%)
Total	**428.6**	**457.9**	**435.5**	**-7 (-2%)**

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

Queensland LNG export demand slightly decreased compared to Q1 2024, due to decreases in APLNG and QCLNG demand, offset by a small increase in GLNG demand. The combined total demand of 366 PJ is the second-highest LNG export demand for Q1, with the record set in Q1 2024 (Figure 86).

Figure 86 Slightly lower Queensland LNG production but still second highest Q1 on record

Total quarterly pipeline flows to Curtis Island



The decline in LNG production during Q1 2025 was primarily driven by events surrounding Tropical Cyclone Alfred's late February landfall in Queensland. During this period, LNG producers were impacted by shipping delays leading to high inventory levels in their LNG tanks at Curtis Island, which forced some producers to manage their productions levels. Coincidentally, QCLNG experienced a complete train outage during this period. A heatwave in the Gladstone region in mid-January, combined with the aftermath of ex-Tropical Cyclone Alfred, resulted in further temporary decreases in LNG production.

By participant, in comparison to Q1 2024, APLNG demand decreased by 2.6 PJ and QCLNG by 1.5 PJ, while GLNG increased by 0.8 PJ. There were 91 cargoes exported during this Q1, the same total exported in Q1 2024.

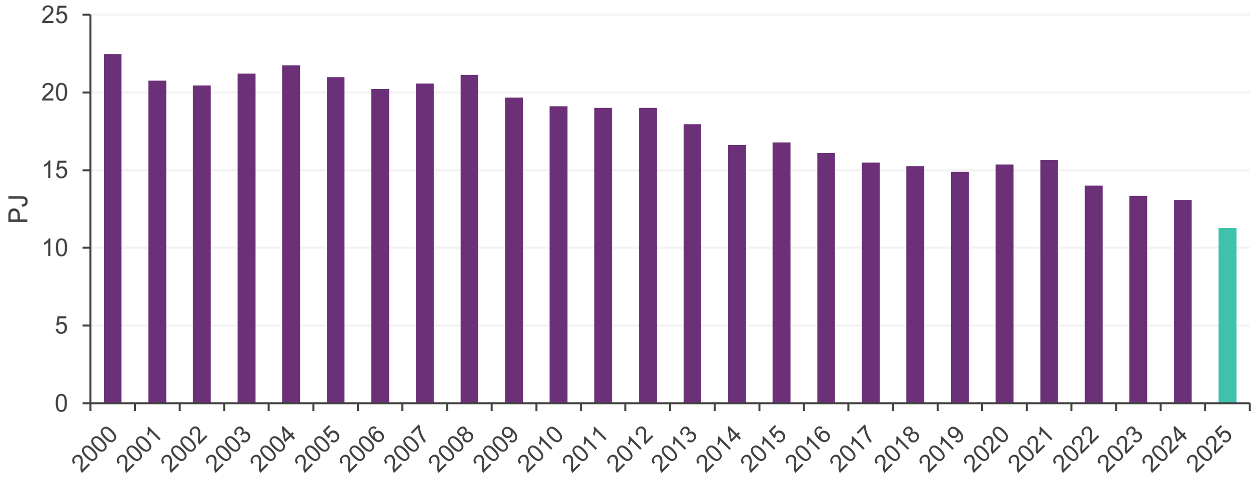
3.2.1 Victorian industrial demand

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

Q1 2025 saw the largest decrease in Tariff D demand for any Q1 since the DWGM began in March 1999, with demand decreasing 14% from 13.1 PJ in Q1 2024 to 11.3 PJ in Q1 2025 (Figure 87).

Figure 87 Victorian industrial demand at its lowest Q1 level since at least the DWGM began

Q1 DWGM Tariff D demand



As noted in AEMO's 2025 *Victorian Gas Planning Report* (VGPR)[36], Victoria has seen significant declines in manufacturing from 2021 to 2024, including closures in large heavy industries such as Qenos and its Altona refinery, as well as dairy, food manufacturing and paper industries.

Further, in March 2025, Oceania Glass, one of the top five Tariff D consumers in 2024, shut down[37]. In 2024, Oceania Glass accounted for 3% of total annual Tariff D demand.

3.3 Gas supply

3.3.1 Gas production

East coast gas production increased by 2.0 PJ (+1%) compared to Q1 2024 (Figure 88). Key changes included:

[36] 2025 VGPR, Section 1.1, at https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

[37] https://www.linkedin.com/posts/corn%C3%A9-k-b3a96b22_on-monday-3-march-2025-australia-lost-another-activity-7305060496091586561-CaRZ

- Increased Victorian production (+14.4 PJ), mainly driven by higher production at Longford (+8.7 PJ) and the Otway Gas Plant (+4.4 PJ) and BassGas (+0.9 PJ). The Longford increase is due to less maintenance than during Q1 2024, and the Otway increase is due to the Enterprise gas field commencing production in June 2024[38] and Thylacine West 1 and 2 development wells in October 2024[39].
- Decreased Queensland production (-11.4 PJ), with QCLNG-operated assets decreasing by 8.1 PJ and APLNG-operated assets decreasing by 6.0 PJ. Gas demand for Queensland LNG exports decreased by 3.3 PJ, meaning supply associated with Queensland LNG projects into the domestic market was 11.8 PJ lower than in Q1 2024. This represents the lowest domestic market supply for Q1 since 2017 (Figure 89).

Figure 88 Victorian supply increased mainly due to higher Otway and Longford production

Change in east coast gas supply – Q1 2025 vs Q1 2024

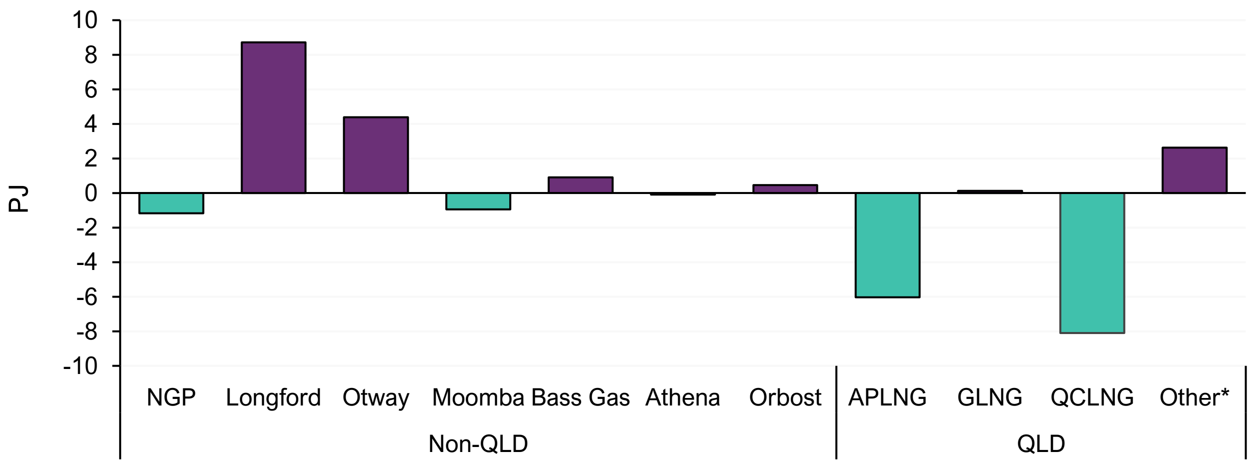
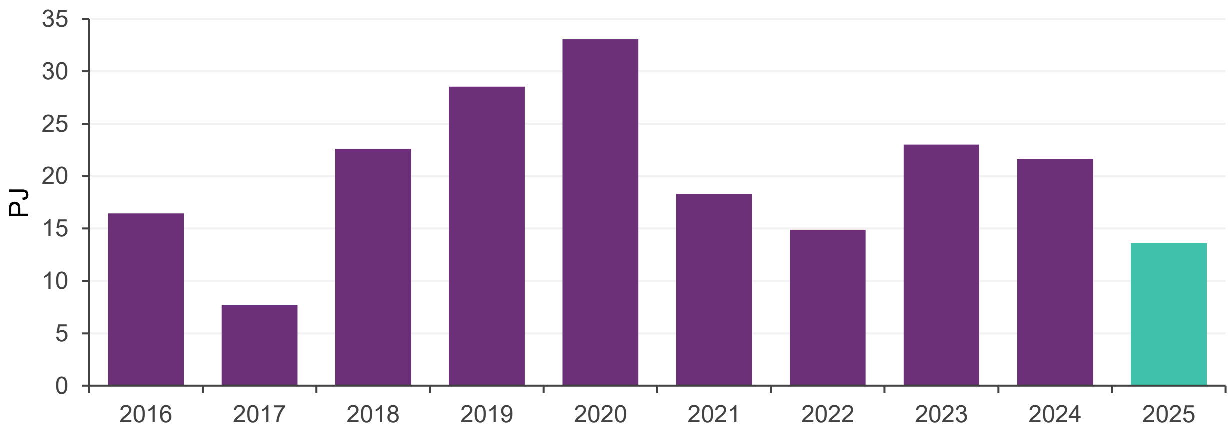


Figure 89 Queensland Q1 2025 net domestic supply decreased to lowest level since 2017

Queensland net domestic supply during Q1



3.3.2 Longford production and capacity

This quarter saw an increase in Q1 Longford production compared to 2024, reaching 43 PJ, but was close to 2023 (Figure 90). Production in 2024 was impacted by an extended period of very low capacity due to maintenance,

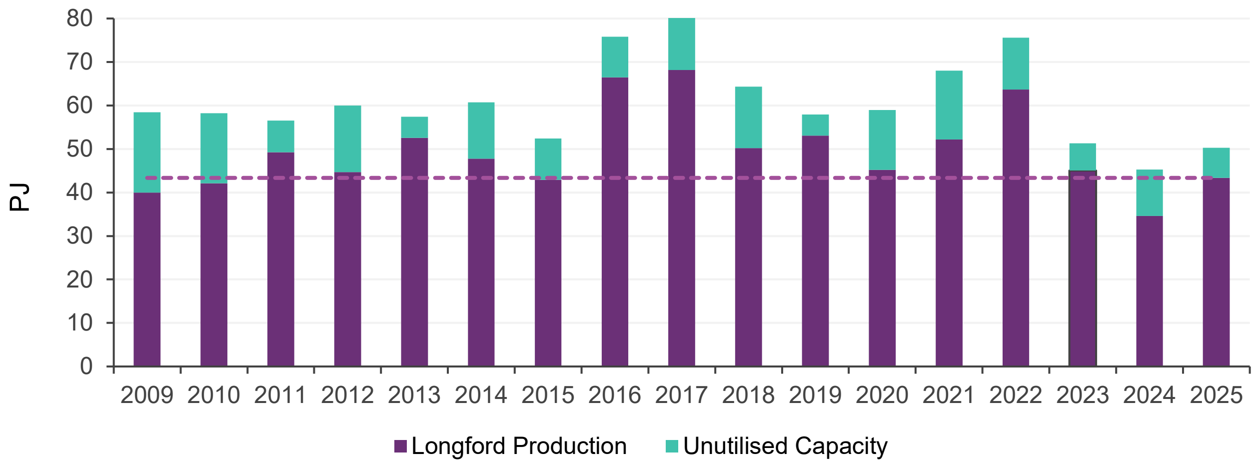
38 https://beachenergy.com.au/enterprise-project/

39 https://beachenergy.com.au/wp-content/uploads/Media-release-Thylacine-West-First-Gas-24102024.pdf

and Longford's available production capacity of 50 PJ this Q1 was higher than in Q1 2024, reflecting less maintenance impacting capacity.

Figure 90 Higher Longford Q1 production after maintenance impacted 2024

Longford Q1 production and unutilised capacity

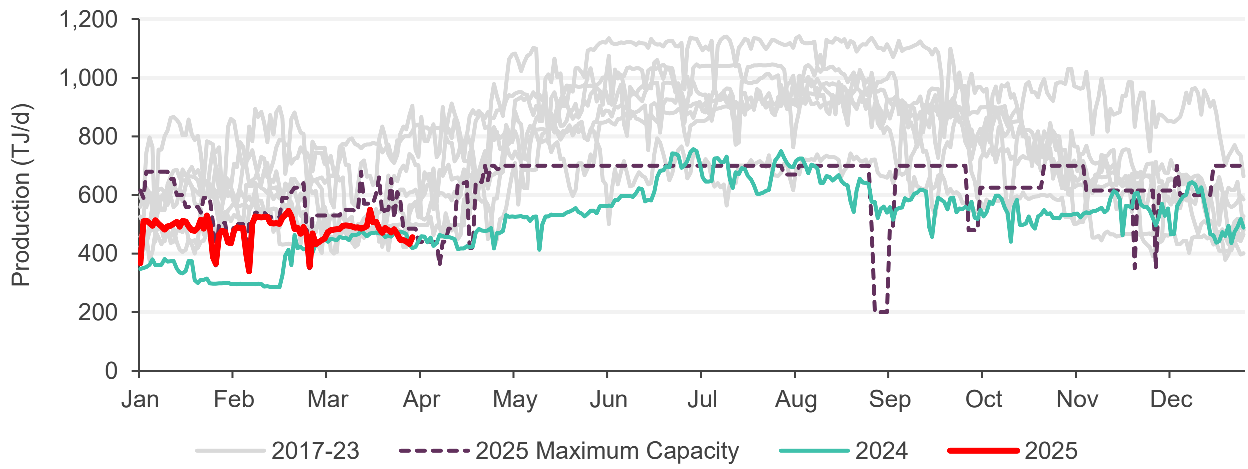


As observed in Q3 and Q4 2024, daily production through much of Q1 was below available capacity, particularly in January and March (Figure 91), with Longford's capacity factor at 86%. This gap continued to be driven by Longford supply offer prices being above the daily DWGM and Sydney STTM price outcomes. This narrowed in February when Longford capacity decreased due to planned maintenance.

As previously reported, Longford capacity is limited to 700 terajoules per day (TJ/d) going forward due to gas plant 1 being retired in October 2024.

Figure 91 Longford daily production higher than Q1 2024 due to higher available capacity

Daily Longford production 2017-2025, maximum capacity profile 2025



3.3.3 Gas storage

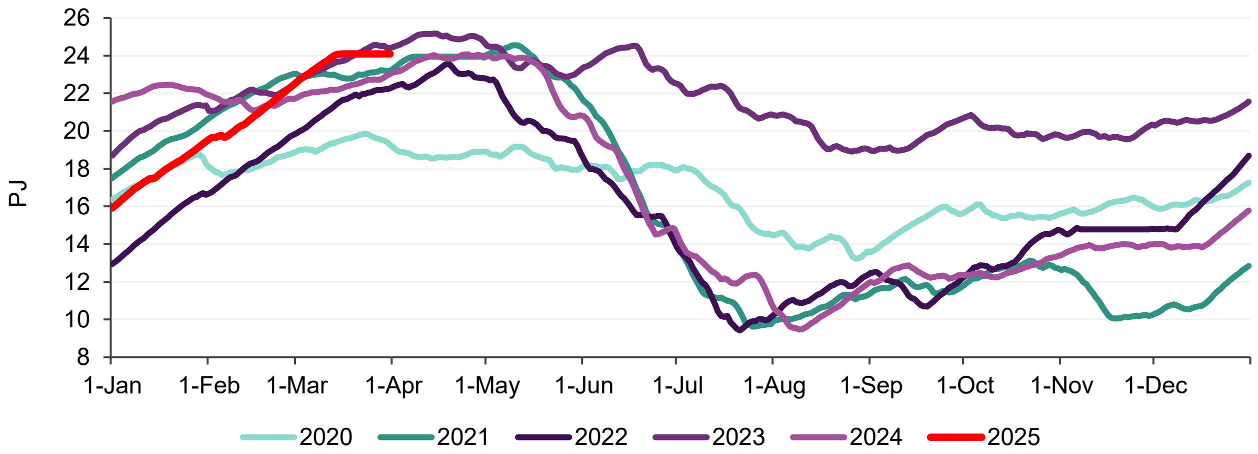
After starting Q1 at the lowest level since 2022, the Iona underground gas storage (UGS) facility recovered to finish the quarter with an inventory of 24.1 PJ, the second highest level since reporting began in 2017 (Figure 92).

Storage inventory consistently filled on most days during the quarter, aided by increased Victorian supply, low gas-fired generation, and reduced industrial demand in the DWGM, as discussed in previous sections.

Iona commenced a planned maintenance outage on 16 March and remained offline for the rest of the month.

Figure 92 Iona storage ended the quarter at its second highest level since reporting began in 2017

Iona storage levels

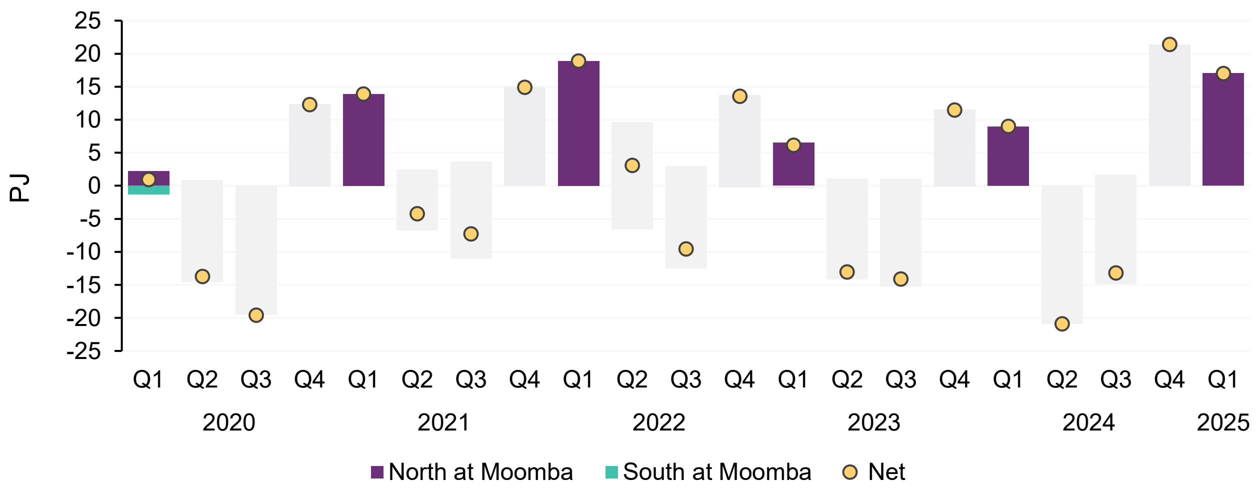


3.4 Pipeline flows

Compared to Q1 2024, there was an 8.1 PJ increase in net transfers north at Moomba on the South West Queensland Pipeline (SWQP, Figure 93) which represented the highest Q1 flow north from Moomba since Q1 2022. January recorded the highest northward flows from Moomba this quarter, coincident with increased Victorian production at the Longford and Otway gas plants.

Figure 93 Net Q1 flows north on SWQP increased to highest level since Q1 2022

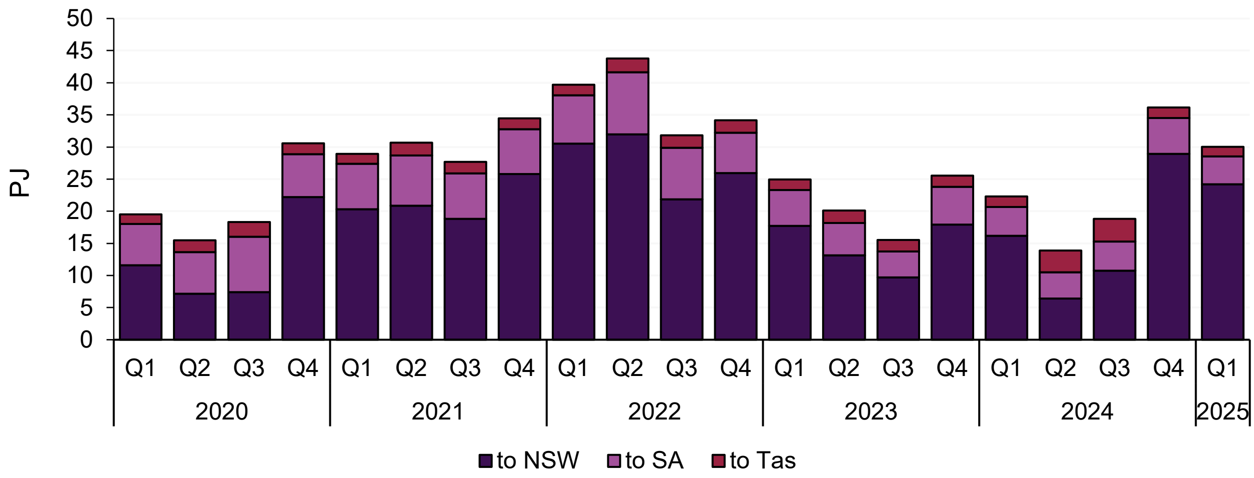
Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states increased by 4.6 PJ from Q1 2024 levels (Figure 94), solely due to an increase in flows to New South Wales via Culcairn. Victoria exported a net 9.6 PJ via Culcairn, compared to 1.5 PJ in Q1 2024. Exports to New South Wales via the Eastern Gas Pipeline (EGP) decreased by 0.2 PJ in comparison to Q1 2024.

Figure 94 Highest Victorian Q1 exports to New South Wales since 2022

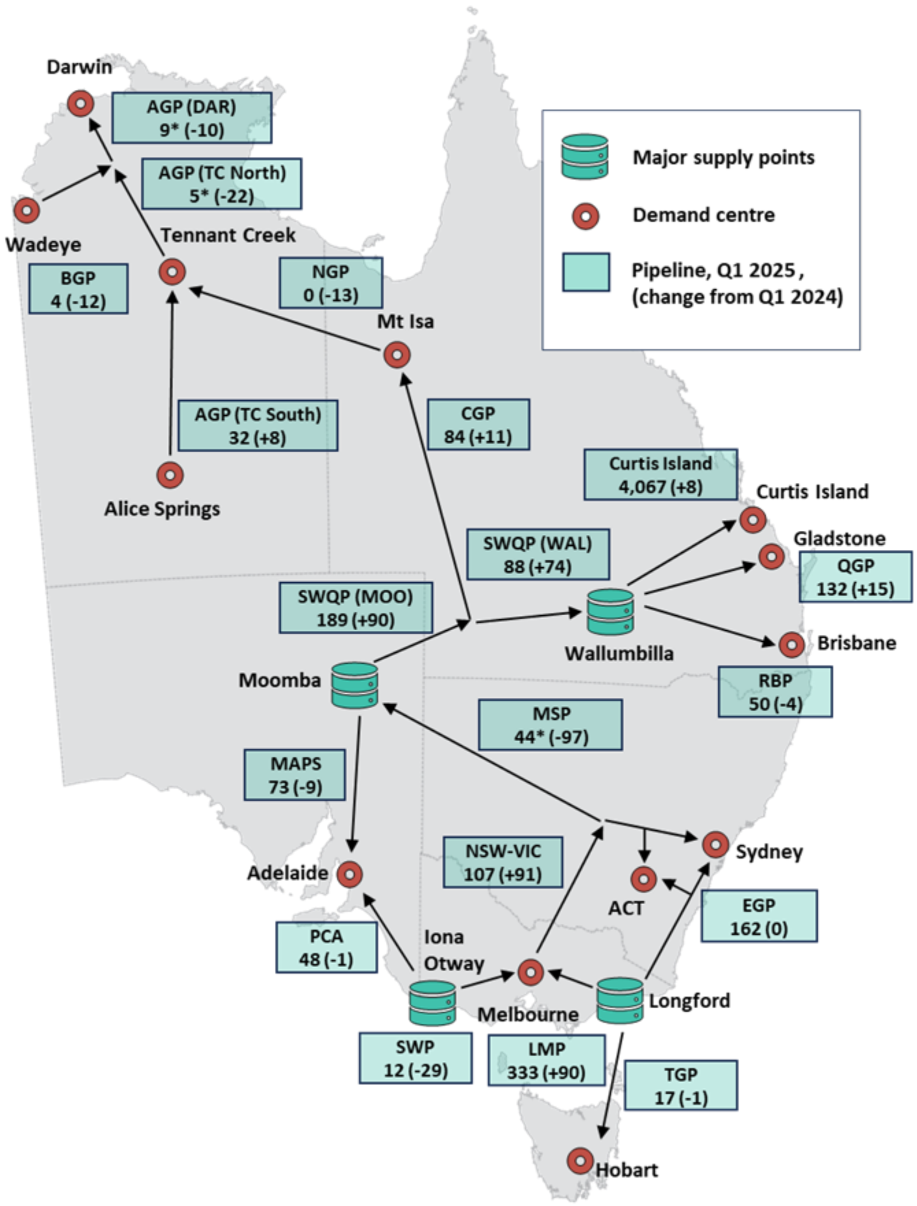
Victorian net gas transfers to other regions



Average daily pipeline flows in Q1 2025 were significantly higher on key northbound routes, particularly on the SWQP and the New South Wales – Victoria Interconnect (Figure 95 below), reflecting greater production at the Longford and Otway gas plants to supply New South Wales. Curtis Island flows reached 4,067 TJ/d in Q1 2025, up 8 TJ/d from Q1 2024, despite a decline in Queensland production. In Queensland, Mt Isa demand continued to be solely supplied from Queensland, reflecting the upstream supply issues experienced in the Northern Territory.

Figure 95 Increased average daily pipeline flows north

Average daily pipeline flows Q1 2025 vs Q1 2024

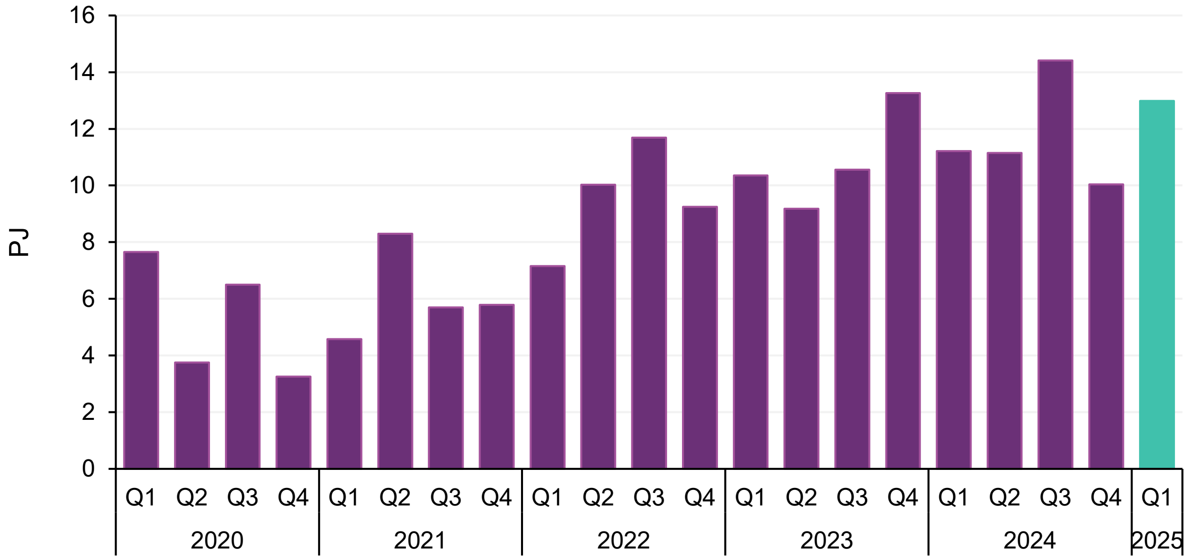


3.5 Gas Supply Hub (GSH)

In Q1 2025, traded volumes on the GSH increased by 1.8 PJ in comparison to the previous Q1 record set in 2024, setting a new Q1 record (Figure 96). The traded volume this quarter was 13.0 PJ, and represented the third highest volume since market start. February 2025 was the highest monthly traded volume for the quarter at 5.8 PJ, traded predominantly for delivery in the same month (3.2 PJ) and for delivery in March 2025 (2.6 PJ).

Figure 96 Highest Q1 traded volumes on record

Gas Supply Hub – quarterly traded volume

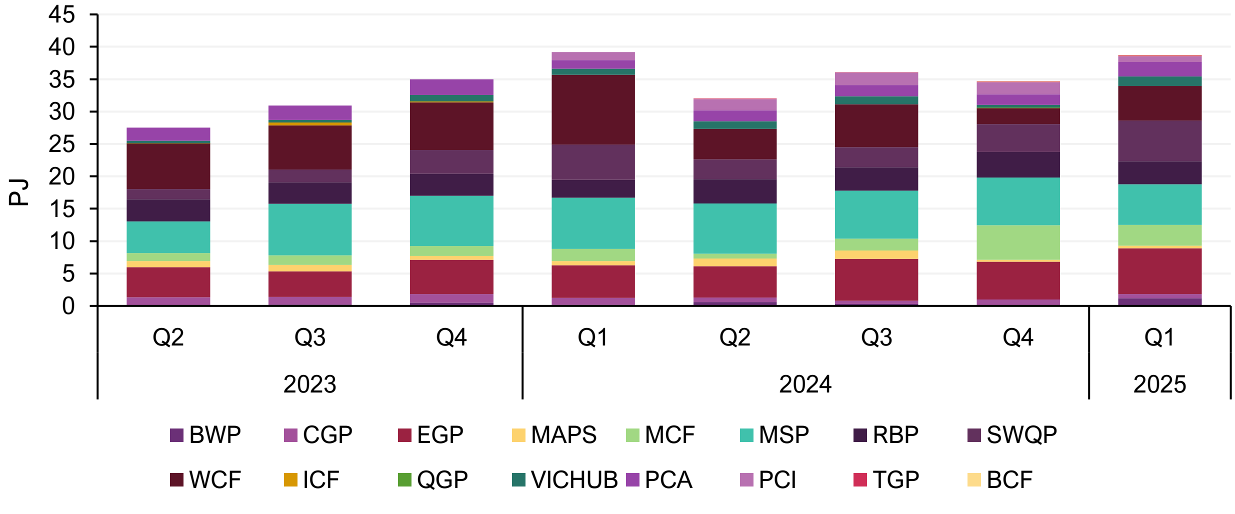


3.6 Pipeline capacity trading and Day Ahead Auction

Day Ahead Auction (DAA) volumes decreased slightly by 0.5 PJ in comparison to the Q1 record of 39.2 PJ set last year (Figure 97). Compared to Q1 2024, there was a notable decrease in auction volumes on the Wallumbilla Compression Facility (WCF, -5.4 PJ) and an increase in auction volumes on the EGP (+2.0 PJ).

Figure 97 Slight decrease in DAA volumes traded

Day Ahead Auction volumes by quarter



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

- the Carpentaria Gas Pipeline (CGP) which averaged $0.56/GJ
- the EGP which averaged $0.39/GJ
- the Ballera Compression Facility (BCF) which averaged $0.23/GJ

- the SWQP which averaged $0.19/GJ, and
- the Roma to Brisbane Pipeline (RBP) which averaged $0.17/GJ.

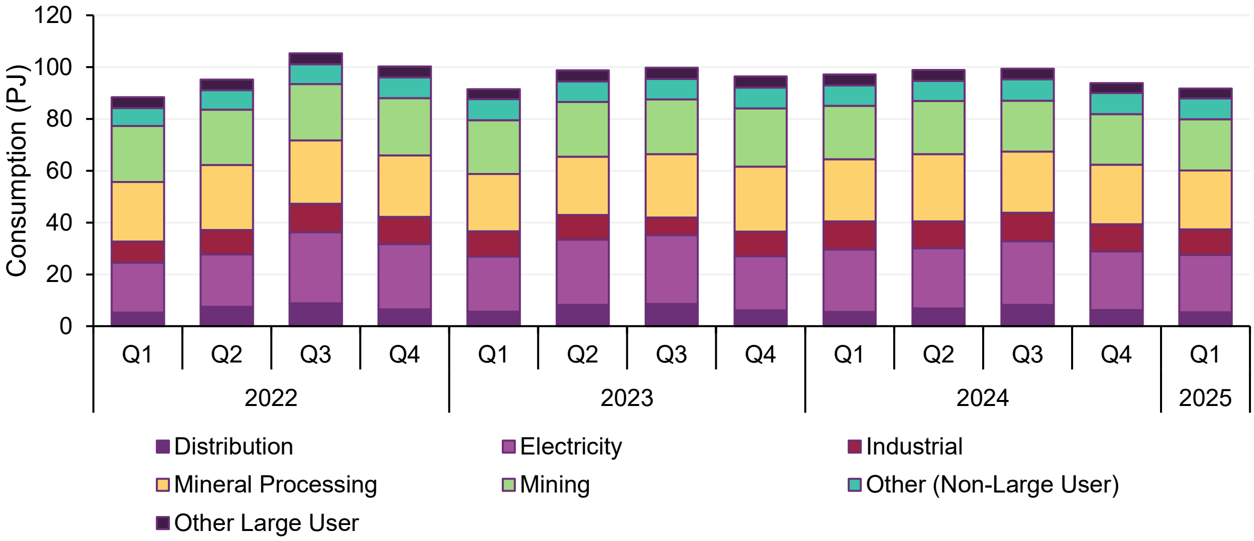
3.7 Gas – Western Australia

3.7.1 Gas consumption

A total of 91.7 PJ was consumed from registered pipelines in the Western Australian domestic gas market in Q1 2025 (Figure 98). This was a decrease of 5.5 PJ (-5.7%) compared to Q1 last year, and a slight decrease of 2.1 PJ (-2.2%) from Q4 2024. The largest difference compared to Q4 2024 was observed in the industrial sector, which was down by 0.7 PJ (-6.4%). All other sectors saw slight reductions this quarter. There were also changes in consumption when reviewing geographic zones with Q4 2024; Parmelia zone decreased consumption by 0.6 PJ (-13.4%), and the Telfer zone increased consumption by 0.4 PJ (+29.6%).

Figure 98 Gas consumption in Western Australia dropped slightly compared to Q4 2024

Western Australia quarterly gas consumption by sector Q1 2022 to Q1 2025



3.7.2 Gas production

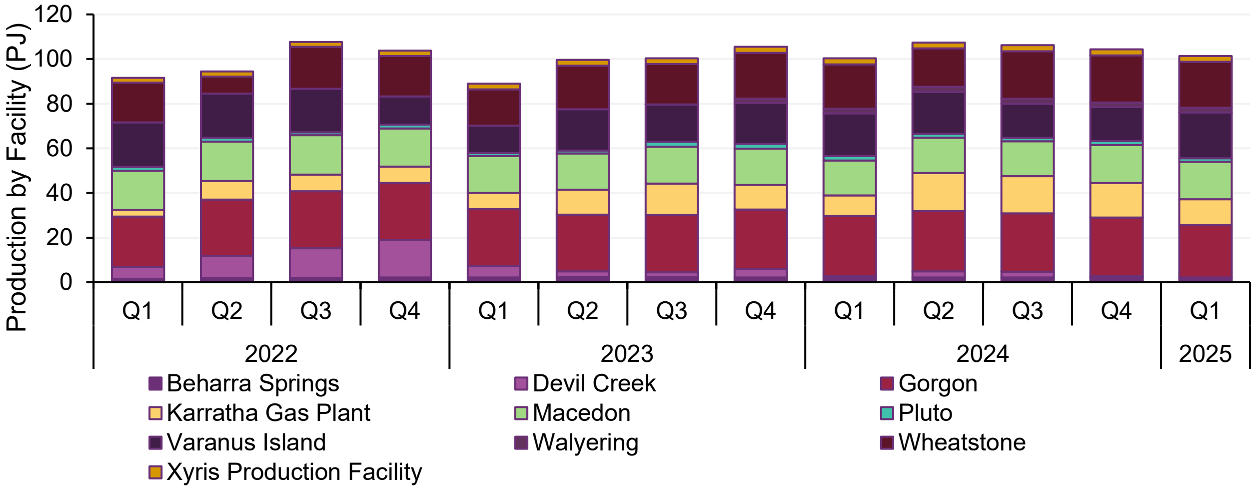
Gas production in Western Australia was 101.4 PJ, an increase of 1.1 PJ (+1.1%) compared to Q1 2024 and a reduction of 3 PJ (-2.9%) compared to last quarter (Figure 99)[40].

The decrease in production from Q4 2024 can be mainly attributed to a broad reduction for most production facilities, partially offset by a 5.3 PJ (+35%) increase at Varanus Island.

[40] 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 99 Q1 2025 saw a decrease in gas production of 3.0 PJ from Q4 2024

Western Australia quarterly gas production by facility Q1 2022 to Q1 2025

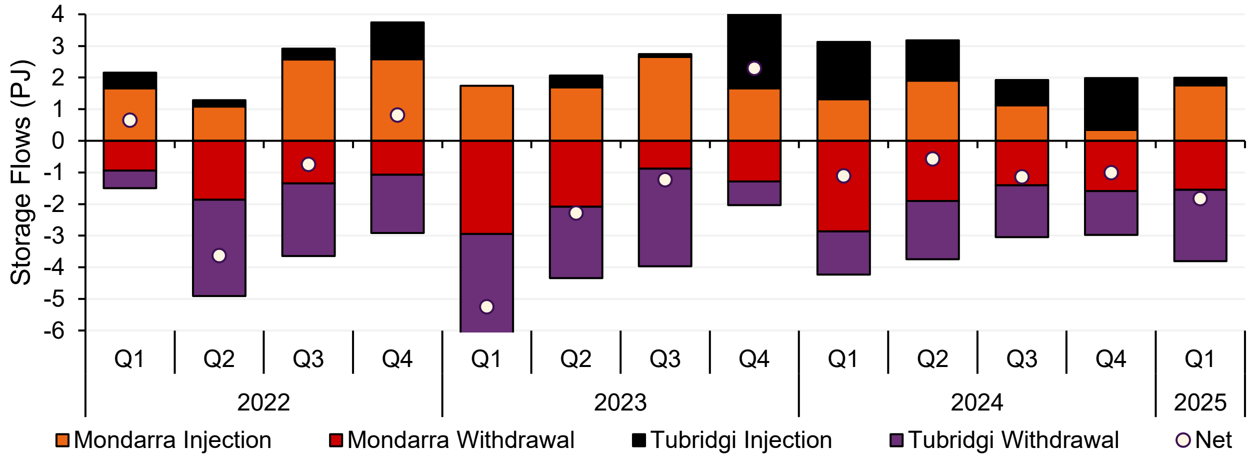


3.7.3 Storage facility behaviour

In Q1 2025, there was net withdrawal from storage facilities of 1.8 PJ (Figure 100). This is the fifth consecutive quarter of net withdrawals. Withdrawal from storage in Q1 2025 increased by 0.7 PJ (+72%) compared to the Q1 2024, when there was a net withdrawal of 1.1 PJ. Compared to Q4 2024, withdrawals increased 0.8 PJ (82%).

Figure 100 Net withdrawals from storage continued in Q1 2025

Western Australia gas storage facility injections and withdrawals – Q1 2022 to Q1 2025



3.7.4 Linepack Capacity Adequacy

LCA is an indication of the actual or expected capability of a pipeline to meet relevant delivery nominations, and, for a storage facility, an indication of the number of days for which supply of natural gas can be maintained at the maximum operational outlet capacity. During Q1 2025, there was an amber LCA flag for the Mondarra Storage Facility and by connection, the Parmelia Gas Pipeline (26-27 January), indicating the Storage Facility's inability to inject at its maximum capacity; and a red LCA Flag for the Parmelia Gas Pipeline (23 March), reflecting an issue at a single connection point, but not affecting the remainder of the pipeline. These were isolated incidents, so there was no broader gas supply concern as a result.

4 WEM market dynamics

4.1 Electricity demand

Average operational demand[41] increased by 12.7 MW (+0.6%) in Q1 2025 compared to Q1 2024. This was driven by an increase in average underlying demand of 88.6 MW to 2,826 MW (+3.2%), which represents an all-time record. In addition to growth from increasing population and economic activity, increased underlying demand was due to:

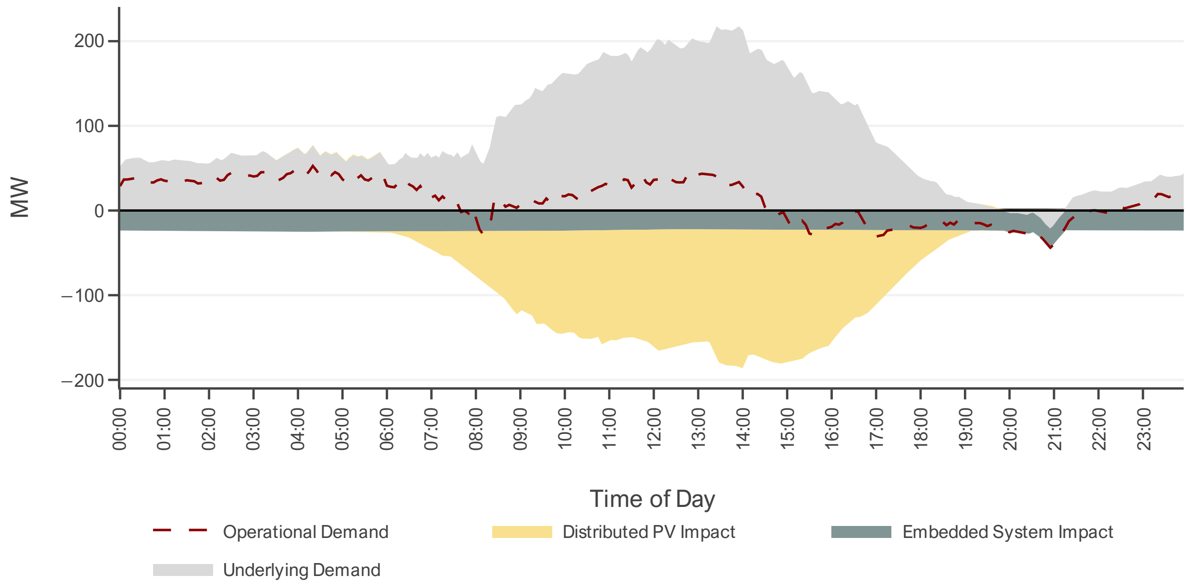
- higher overnight temperatures as noted in Section 1, as average minimum temperatures increased by 0.4°C on Q1 2024, resulting in higher overnight underlying demand (Figure 101), and
- an increase in average battery withdrawal (charging) of 30.6 MW (+261%) in Q1 2025. This was pronounced overnight, and during late morning to early afternoon, as evident in Figure 102.

Components that reduce operational demand combined to partially offset increases to average underlying demand by 75.9 MW:

- average distributed PV[42] generation increases of 52.2 MW (+9.9%) as installed capacity increased, and
- increases in average embedded system generation[43] by 23.7 MW (+740%), due to a reduction in local load that the embedded systems serve.

Figure 101 Higher operational demand as increases to underlying demand outpaced distributed PV growth

Change in WEM average operational demand components by time of day – Q1 2024 vs Q1 2025



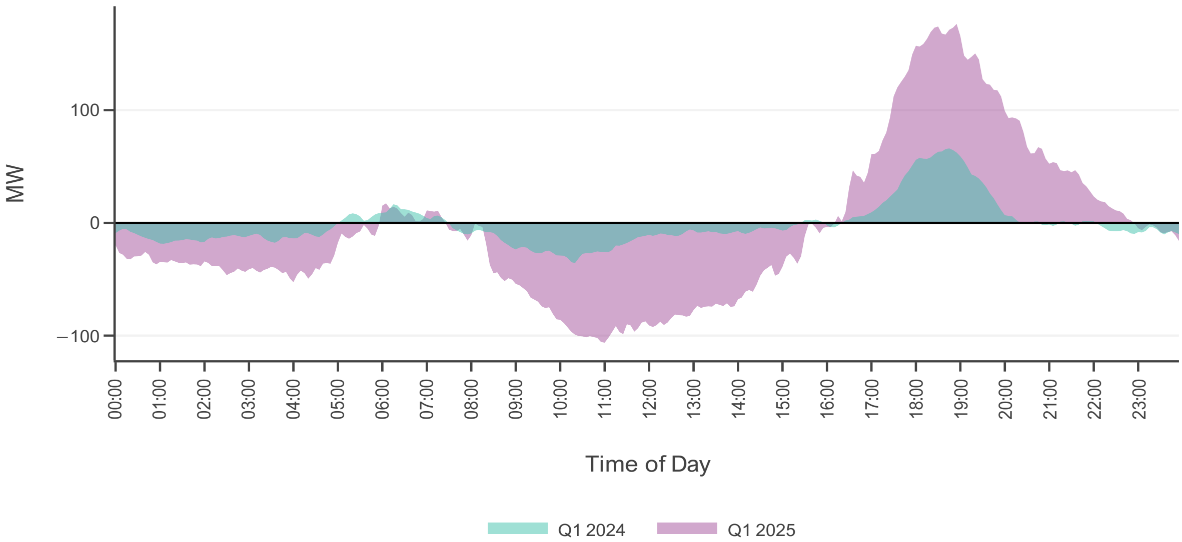
[41] Operational demand considers the total injection, in megawatts, from all scheduled facilities, semi-scheduled facilities and non-scheduled facilities that are injecting at the end of the dispatch interval. As such, it includes scheduled demand driven by electric storage resources dispatched for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

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

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

Figure 102 Battery withdrawal and injection grew

Batteries average energy generation/withdrawal, time of day – Q1 2024 and Q1 2025

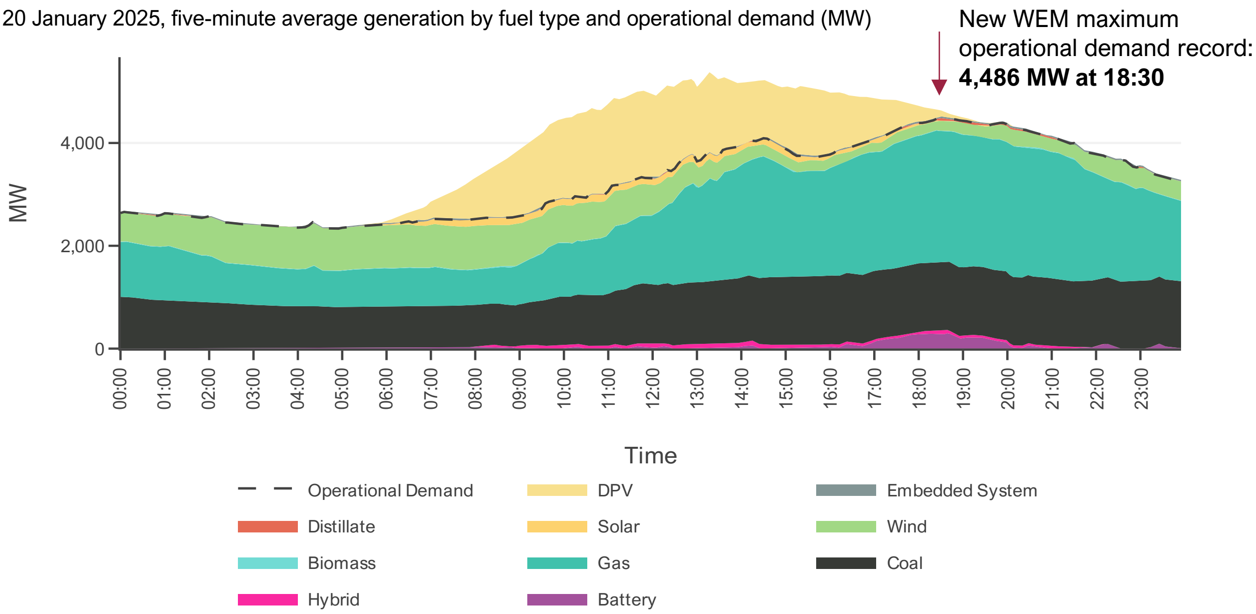


4.1.1 New underlying and operational demand records

A new maximum operational demand record of 4,486 MW occurred on Monday 20 January 2025 during the 18:30 interval (Figure 103), surpassing the prior record of 4,233 MW from Q1 2024. In addition, at 13:15 on the same day, the all-time underlying demand record was set at 5,385 MW, surpassing the record of 5,262 MW set in December 2024.

Figure 103 New operational demand record set 20 January 2025

20 January 2025, five-minute average generation by fuel type and operational demand (MW)



This was due to high temperatures, with a daily maximum of 43.6°C[44]. During the peak operational demand interval:

[44] http://www.bom.gov.au/climate/current/month/wa/archive/202501.summary.shtml

- Renewable contribution was measured at 12.9% of operational demand at the peak. The primary renewable contributors were batteries, providing 296 MW (6.6%), and wind, providing 188 MW (4.2%).
- The largest contributing fuel type was gas, at 2,526 MW, which was 56.3% of operational demand.
- Approximately 126 MW of demand side response was activated[45], which helped reduce operational demand over the peak period. This comprised:
  - 20 MW of Demand Side Participation,
  - 11.5 MW of Supplementary Capacity, and
  - 94.5 MW of Non-Co-Optimised Essential System Services.

Higher-than-usual operational demand was also observed throughout the middle of the day due to cloudy conditions driven by Tropical Cyclone Sean, which suppressed distributed PV output.

4.2 Electricity generation

Figure 104 shows the change in average WEM generation by fuel type relative to Q1 2024, and Table 9 shows the resultant changes in supply mix contributions:

- As noted in Section 4.1, distributed PV continued its upwards trend, increasing average generation by 52.2 MW (+9.9%). This can be attributed to increased installed capacity.
- Average battery injection increased by 25.6 MW (+261%), including an increase in injection of 124 MW during the daily operational peak for Q1 2025 compared to Q1 2024. Notably, there has also been an increase in duration over which batteries injected over compared to Q1 2024 (see Figure 102). This is attributable to an increase in battery generation capacity comprised of:
  - COLLIE_ESR1, with a capacity of 200 MW/800 MWh, which commissioned since Q1 2024 and prior to Q1 2025, and
  - KWINANA_ESR2, with a capacity of 225 MW/900 MWh, which completed commissioning during Q1 2025.
- The WEM's first hybrid fuel type facility completed commissioning during the quarter, resulting in an average generation of 22.7 MW (from 0 MW in Q1 2024). The Cunderdin Hybrid Facility is a combined solar and battery facility with a maximum sent out capacity of 100 MW. Figure 105, which shows change in fuel mix on average by time of day, shows the hybrid facility injection profile.
- Average coal generation decreased by 36 MW (-4.6%), driven by lower availability from coal facilities, which can be partially attributed to semi-retirement of the Muja C Unit 6 power station[46] (capacity 196 MW). As shown in Figure 105, the reduction in coal occurred during the day and through the evening peak; it was replaced primarily by the battery and hybrid fuel types.

[45] Activated demand reduction is not equivalent to delivered, or actual, demand reduction. Actual demand reduction is measured on a trading interval (30-minute) basis and as such has not been estimated for the peak dispatch interval (5-minute).

[46] Muja C Unit 6 entered 'reserve outage mode' on 1 October 2024, meaning it was restricted in use and no longer actively participating in the market, but was available to AEMO during peak demand periods until 1 April 2025, when it was fully retired.

Figure 104 Underlying demand increases met by distributed PV, battery and hybrid generation

Change in quarterly average generation – Q1 2024 vs Q1 2025

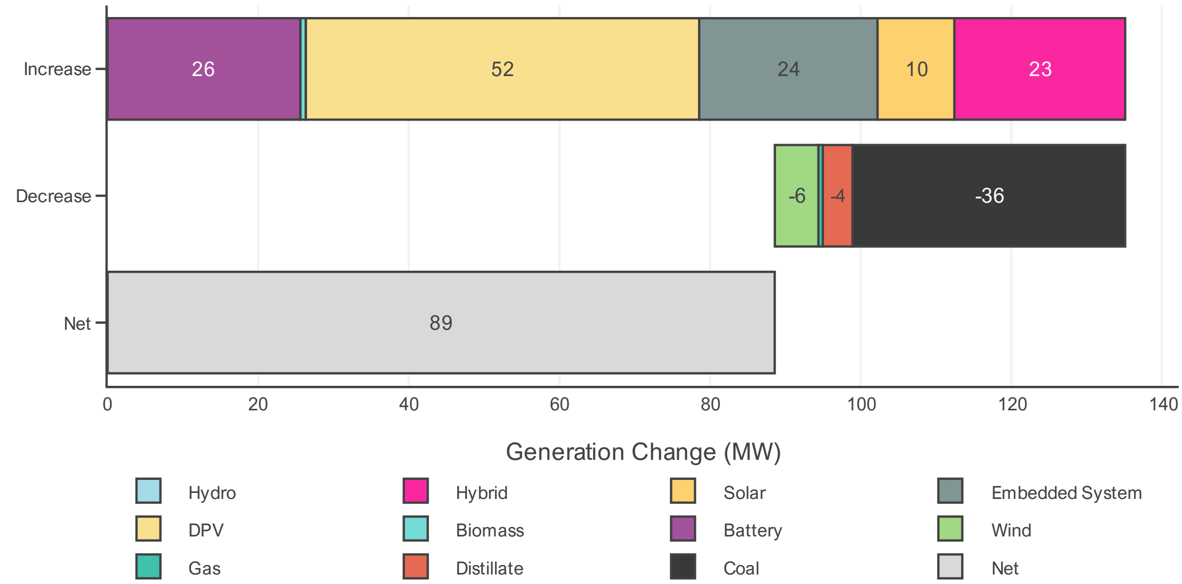


Figure 105 Q1 2025 saw reductions in coal being replaced by battery and hybrid facilities

Average WEM change in fuel mix by time of day – Q1 2024 vs Q1 2025

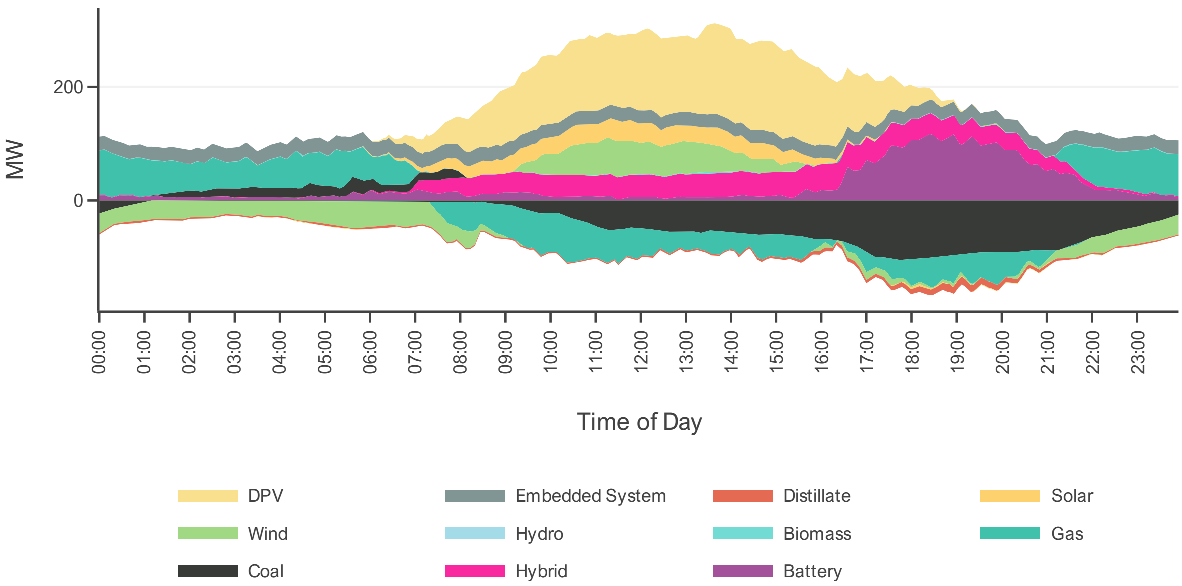


Table 9 WEM supply contibution by fuel type

Quarter	Coal	Gas	Distillate	Grid solar	Wind	Biomass	Battery	Hybrid	Hydro	Distributed PV	Embedded systems
Q1 2024	30.2%	30.4%	0.2%	1.6%	17.5%	0.3%	0.4%	0%	-	19.3%	0.1%
Q1 2025	27.9%	29.4%	0.1%	1.9%	16.8%	0.3%	1.3%	0.8%	<0.1%	20.5%	1%
Change	-2.3%	-1.0%	-0.1%	0.3%	-0.7%	-	0.9%	0.8%	<0.1%	1.2%	0.9%

4.2.1 Renewable contribution

Average renewable contribution rose to its highest ever Q1 level in Q1 2025, at 41.6% of underlying demand (+2.5 pp). This was driven by distributed PV recording a 1.2 pp increase on Q1 2024 to 20.5% in Q1 2025, a 0.9 pp increase to the battery share to 1.3%, and a 0.8 pp increase from hybrid to 0.8% (Figure 106).

The WEM also experienced its highest Q1 peak renewable contribution (and seventh of all time) of 83.4% during the 11:10 interval on Sunday 23 February 2025. In this interval, strong distributed PV of 65.4% combined with wind generation of 10.3%, grid-scale solar generation 5%, and hybrid 1.7% (Figure 107).

Figure 106 Q1 2025 saw the highest ever Q1 average renewable contribution

Renewable contribution components – Q1s

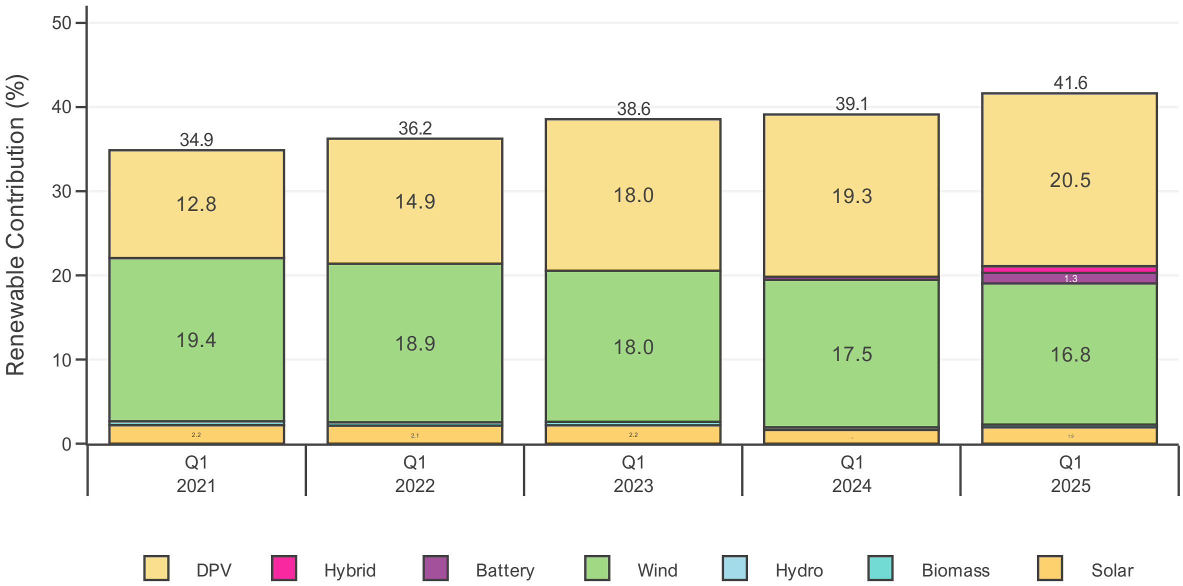
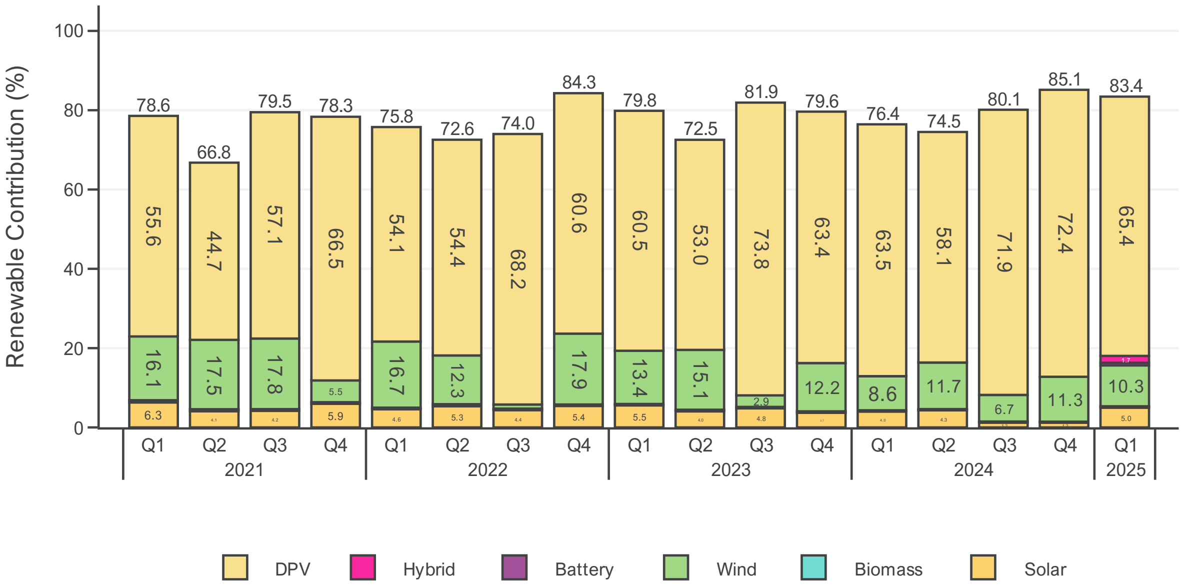


Figure 107 New highest Q1 peak 5-minute renewable contribution in 2025

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

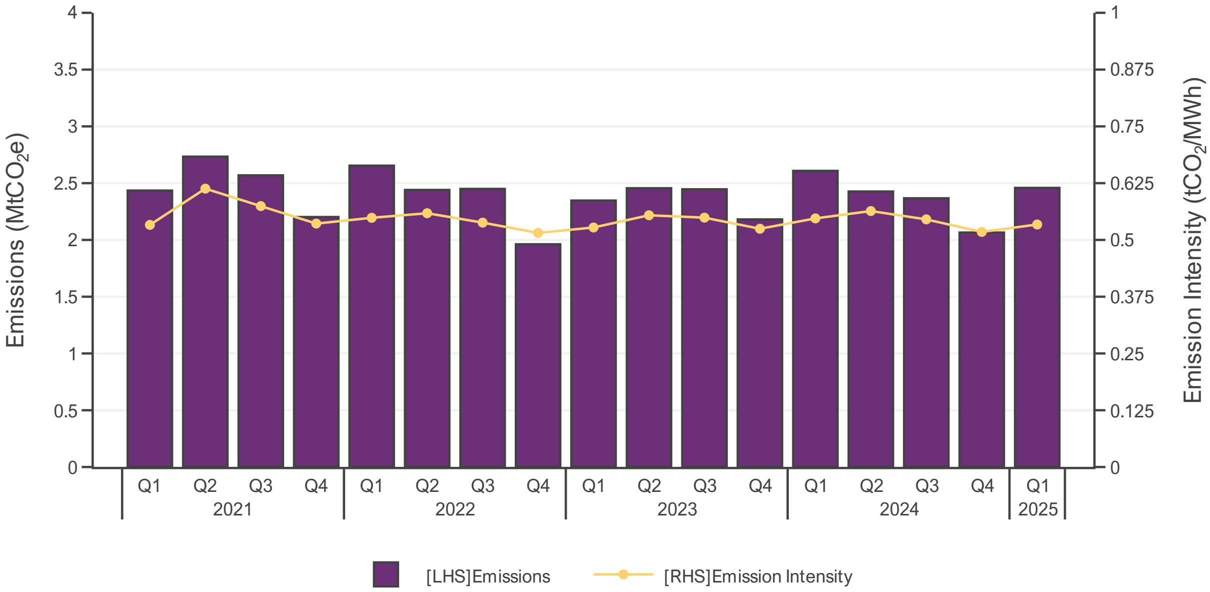


4.2.2 Carbon emissions

Total estimated WEM emissions[47] were 2.46 $MtCO_2$-e, a decrease of 0.15 $MtCO_2$-e (-5.7%) on Q1 2024 (Figure 108). This can be attributed to a reduction in the emissions intensity from 0.541 tCO_2-e /MWh to 0.513 tCO_2-e /MWh (-5.2%), which represents a record low emissions intensity for a Q1; this was due to the increase in renewables and reduction in coal in the fuel mix. There was also one fewer trading day during the period in 2025, due to Q1 2024 including a leap day.

Figure 108 Reduction in emissions intensity driven by lower coal

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



4.3 Frequency co-optimised essential system services (FCESS)

FCESS markets experienced significant changes in fuel mix as batteries participated in FCESS markets for the first time in a Q1 (Figure 109). Key observations include:

- Two batteries became accredited to provide FCESS since Q1 2024, capturing 39% of the overall FCESS market this quarter (Figure 110):
  - There was a 55.8 MW increase in average battery contribution to contingency raise. This can be attributed to the ability of batteries to provide a faster response than other fuel types, making them more effective in the contingency raise market.
  - There was a 48 MW increase in regulation lower (57% of market share) and 18.8 MW of contingency lower (49% of market share).
- Gas facilities retained the largest overall FCESS market share, with 40% of the overall market in Q1 2025, despite a reduction from 78% FCESS market share in Q1 2024, largely driven by market displacement by batteries in all FCESS markets.

[47] 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.

- Coal facilities experienced a reduction in contingency reserve lower market share, driven by a combination of displacement by batteries and a reduction in overall requirements.

Figure 109 Batteries displaced gas in the FCESS markets

Change in FCESS enablement by fuel type – Q1 2024 vs Q1 2025

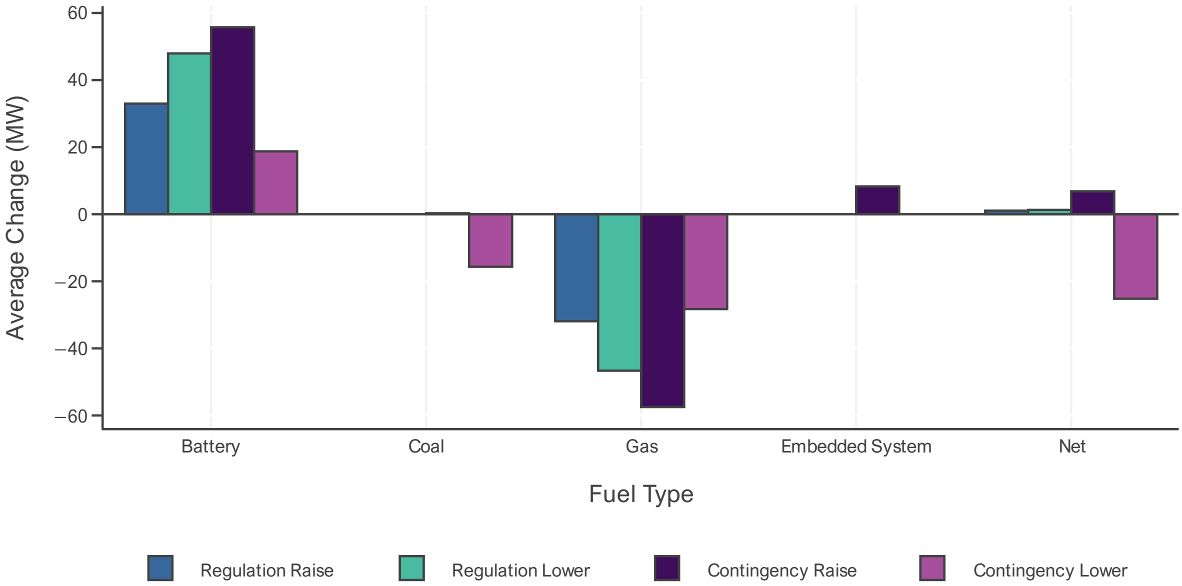
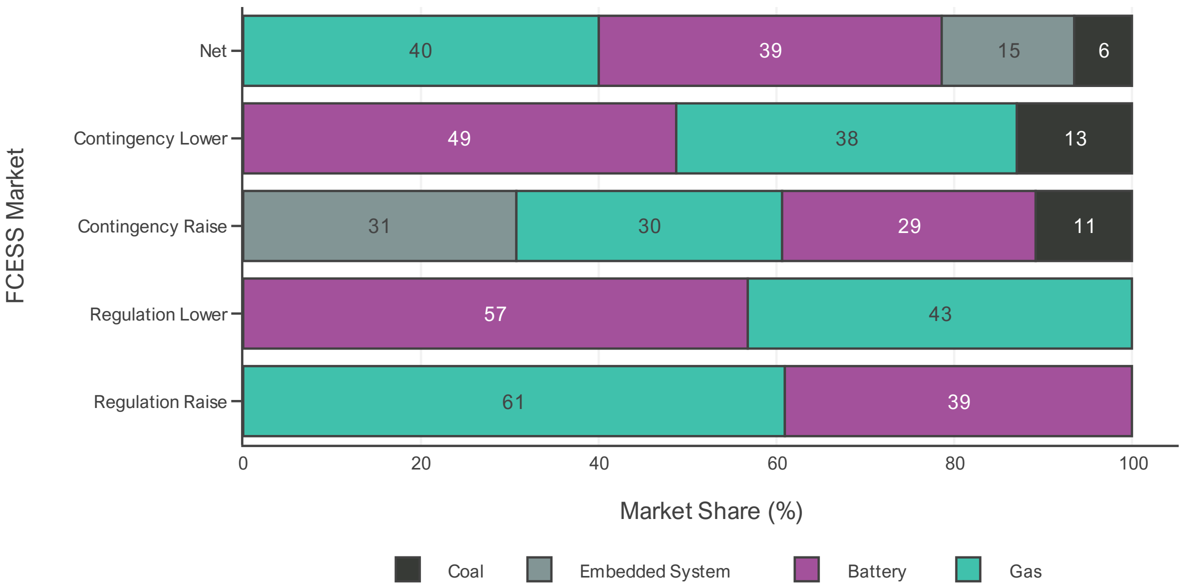


Figure 110 Batteries captured 39% FCESS market share

FCESS volume market share by market and fuel type – Q1 2025



4.4 WEM price outcomes

4.4.1 Real-Time Market price dynamics

The average energy price in Q1 2025 was $89.03/MWh, an increase of $10.54/MWh (+11%) from Q1 2024, and an increase of $9.11/MWh (+11%) from Q4 2024 (Figure 111). This resulted from an increase in average energy prices overnight and during the middle of the day, offset slightly by average price decreases during the evening peak, shown in Figure 112. This was driven by a variety of factors:

- Increased withdrawal and injection by batteries during the middle of the day and the evening peak respectively (Section 4.1), leading to higher average operational demand and energy prices during the middle of the day, and downward pressure on energy prices during the evening peak.
- Lower overnight wind availability (see Figure 105 in Section 4.2) resulting in more expensive gas being dispatched.
- Changes to the FCESS Uplift payment framework, which led to fewer committed facilities through the middle of the day, resulting in lower FCESS Uplift costs, but also upward pressure on energy clearing prices during the middle of the day.
- Higher overnight temperatures (Section 4.1) that put upward pressure on energy prices overnight.

Figure 111 Average energy prices increased relative to previous quarters in 2024

Quarterly average energy prices – Q1 2024 to Q1 2025

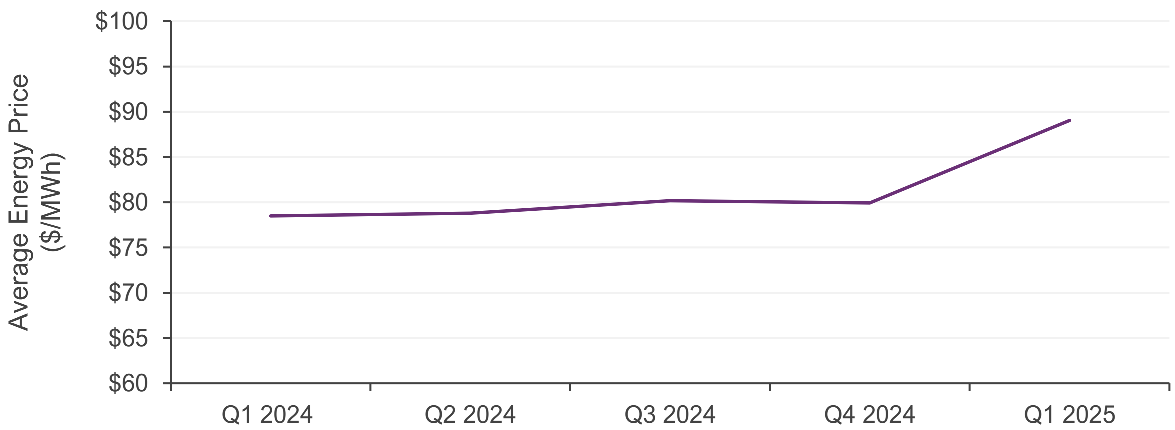
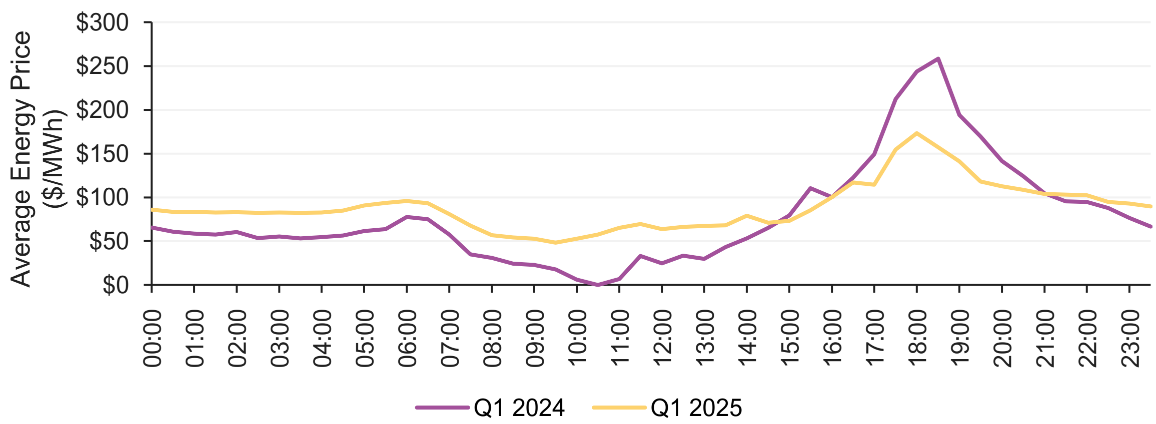


Figure 112 Batteries and high overnight temperatures drove changes to daily energy price profiles

Average energy prices by Trading Interval – Q1 2024 and Q1 2025



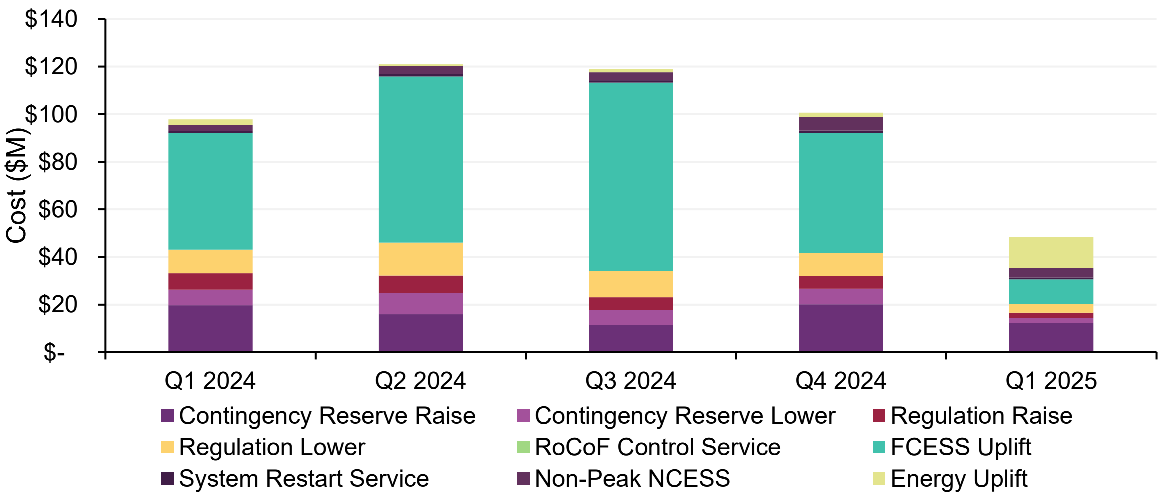
4.4.2 Essential system services (ESS) costs

Total ESS and Uplift costs in Q1 2025 were $48.4 million, a decrease of $49.5 million (-51%) from Q1 2024, and $52.3 million (-52%) from Q4 2024 (Figure 113):

- The most significant drivers for this decrease were changes implemented as part of the FCESS Cost Review and downward pressure on FCESS clearing prices as a result of increased competition in the FCESS markets.
- FCESS enablement costs[48] were $20.2 million, a decrease of $22.9 million (-53%) from Q1 2024. The most significant change in costs was observed in the contingency reserve raise market, which decreased $7.4 million (-38%), while the cost of other market services fell by between $4.5 million and $6.3 million (representing relative changes between 63% and 68%). This was largely driven by increased competition from the accreditation of two new batteries to provide FCESS (see Section 4.3).
- FCESS Uplift costs decreased by $38.6 million (-79%) from Q1 2024, driven primarily by changes to the FCESS Uplift payment framework implemented as part of the FCESS Cost Review in November 2024. Higher energy prices also put downward pressure on FCESS Uplift costs.
- Provisional Non-Peak Non-Co-Optimised Essential System Services (NCESS) costs increased by $1.6 million, primarily driven by the commencement of one new Non-Peak NCESS contract in Q4 2024 (see Section 4.4.4). NCESS costs are only available up to 8 March 2025 due to a lag in payment calculations.
- Energy Uplift costs rose significantly from $2.4 million in Q1 2024 to $12.9 million in Q1 2025, a 443% increase. The majority of these costs were incurred during planned network outages in late March. There was also a comparatively smaller increase driven by changes implemented as part of the FCESS Cost Review, which introduced Energy Uplift payments for Facilities constrained on to provide Rate of Change of Frequency (RoCoF) Control Service under certain circumstances.

Figure 113 Total ESS costs decreased by $49.5 million compared to Q4 2024

Total Cost of ESS and Uplift (excluding Non-Peak NCESS costs after 8 March 2025)



48 Total FCESS enablement costs comprise the sum of the quarterly costs for Contingency Reserve Raise, Contingency Reserve Lower, Regulation Raise, Regulation Lower, and ROCOF Control Service. This does not include uplift costs.

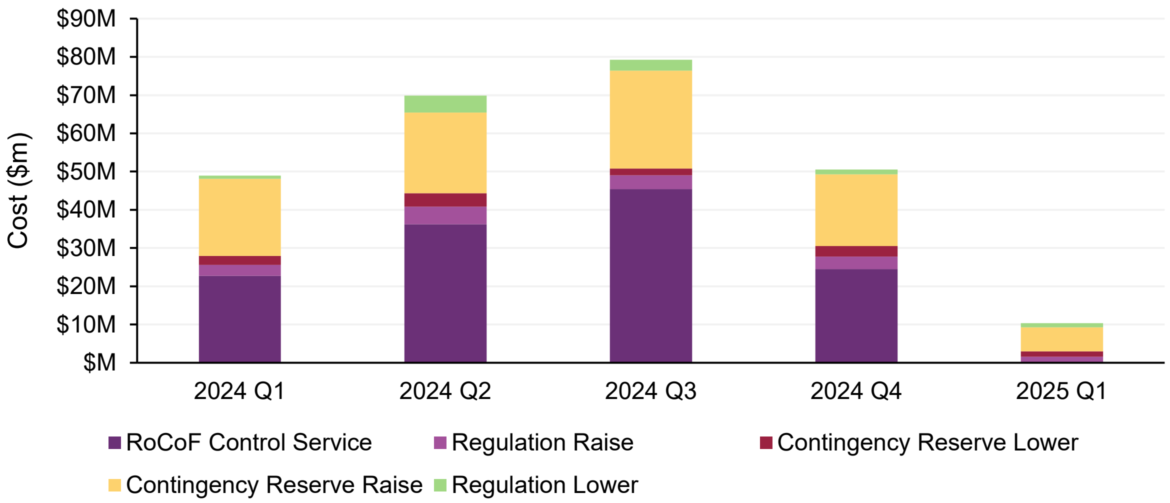
4.4.3 FCESS Uplift share costs

When a facility receives FCESS Uplift payments in a dispatch interval, those costs are assigned to, and recovered through, normal cost distribution processes for FCESS market services. FCESS Uplift costs stopped being recovered through RoCoF Control Service charges on 20 November 2024.

Figure 114 provides a breakdown of the total FCESS Uplift costs assigned to each FCESS market service. This data can be combined with FCESS enablement costs to understand the total costs (enablement plus uplift) recovered in respect of each FCESS market service. Most significantly, the FCESS Uplift costs recovered through contingency reserve raise charges decreased by $13.8 million (69%).

Figure 114 FCESS Uplift costs decreased by $38.6 million (-79%) from Q1 2024

Distribution of FCESS uplift costs to FCESS market services – Q1 2024 to Q1 2025



4.4.4 Non-Co-optimised Essential System Services

Since 7 October 2024, NCESS costs are divided into two categories, with different cost-recovery mechanisms, based on the nature of the NCESS service. AEMO refers to these as “Peak NCESS” and “Non-Peak NCESS” costs, and groups these with Capacity and ESS costs respectively for reporting purposes.

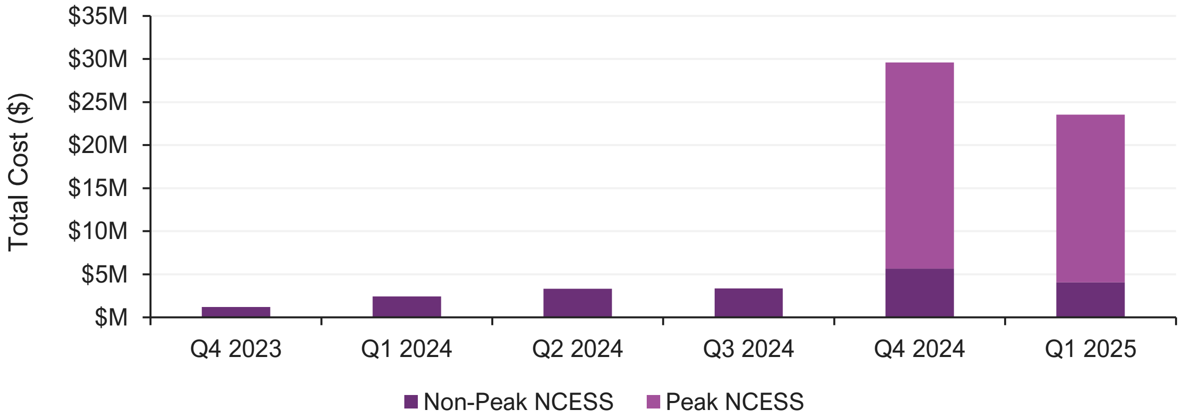
Prior to 7 October 2024, all NCESS costs were recovered in the same manner as Non-Peak NCESS costs, and were treated as ESS costs for reporting purposes.

Total NCESS costs in Q1 2025 were $23.6 million, an increase of $21.1 million from Q1 2024, driven by the commencement of seven new NCESS contracts in Q4 2024, and one in Q1 2025 (Figure 115). Of these costs, $19.5 million were Peak NCESS costs and $4.1 million were Non-Peak NCESS costs.

NCESS costs for Q1 2025 are only available up to 8 March 2025 due to a lag in payment calculations.

Figure 115 NCESS costs increased as new contracts commenced

NCESS costs by cost recovery mechanism (excluding NCESS costs after to 8 March 2025) – Q4 2023 to Q1 2025



4.4.5 Supplementary Capacity

In 2024, AEMO identified a potential capacity shortfall for the 2024-25 Hot Season (defined as the period 1 December 2024 to 31 March 2025). To address this, AEMO initiated the procurement of Supplementary Capacity with the aim of procuring up to 285 MW of additional capacity.

AEMO entered a total of 25 contracts with a maximum potential contracted service quantity of 217.7 MW. The actual contracted service quantity was reduced to 198 MW as a result of verification testing undertaken by AEMO.

During the 2024-25 Hot Season, AEMO activated one or more Supplementary Capacity services on five occasions. The total cost of Supplementary Capacity contracts was $24.9 million, a $4.4 million (+21%) increase from the 2023-24 Hot Season. This cost was comprised of $20.8 million in availability payments and $3.9 million dollars in activation payments.

4.4.6 Total Wholesale Electricity Market costs

Figure 116 presents WEM costs as a price per MWh normalised by total energy consumed, enabling better comparison of costs between periods with different demand. Note that this cost includes capacity costs, which have not been included in previous *Quarterly Energy Dynamics* (QED) reporting.

The sum of all normalised costs in the WEM was $146.83/MWh in Q1 2025, an increase of $16.13/MWh (+12%) from Q1 2024. Key observations and changes include:

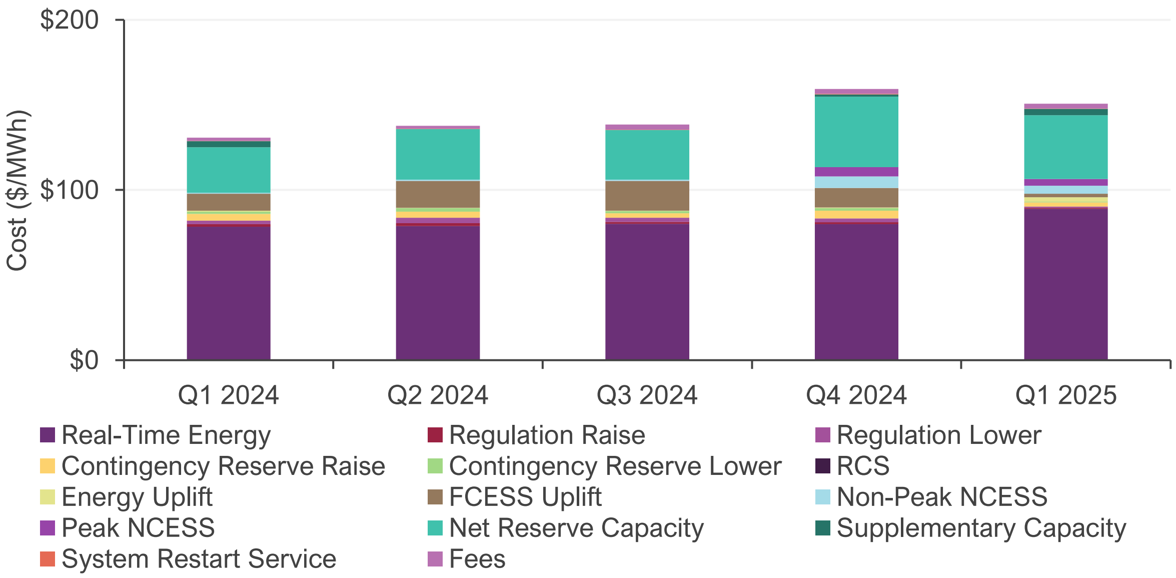
- average energy prices were $89.03/MWh, an increase of $10.54/MWh (see Section 4.4.1)
- normalised reserve capacity costs, net of reserve capacity refunds, were $37.31 per MWh, an increase of $10.62 per MWh, mainly driven by an increase[49] in the reserve capacity price for Capacity Year 2024-25
- normalised energy uplift costs rose by $2.12 per MWh to $2.61 per MWh as a result of unusually high energy uplift costs in Q1 2025 (see Section 4.4.2)
- total normalised NCESS costs were $4.77 per MWh, increasing $4.26 per MWh due to the commencement of eight new NCESS contracts (see Section 4.4.3), and

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

- normalised FCESS enablement costs (including FCESS Uplift) fell by $4.76 per MWh, while normalised FCESS uplift costs decreased by $7.96 per MWh in FCESS Uplift (see Section 4.4.2).

Figure 116 Wholesale Electricity Market costs increased compared to Q1 2024

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

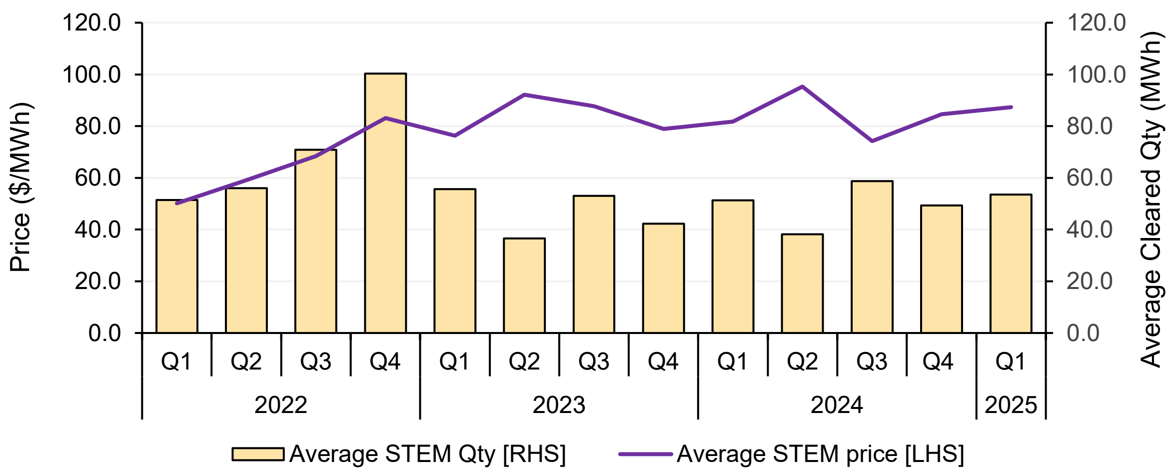


4.4.7 Short Term Energy Market (STEM)

The average STEM price[50] for Q1 2025 was $87.40/MWh, an increase of $2.79/MWh (+3%) from the previous quarter and an increase of $5.66/MWh (+7%) compared to Q1 last year (Figure 117). The quarterly average quantity of energy cleared in the STEM per interval was 54 MWh, an increase of 4 MWh (+9%) from Q4 2024. When compared to the Q1 2024, quantities cleared increased by 2 MWh (+4%).

Figure 117 The average STEM price increased by 3% in Q1 2025

WEM average STEM price and quantity cleared in STEM – Q1 2022 to Q1 2025

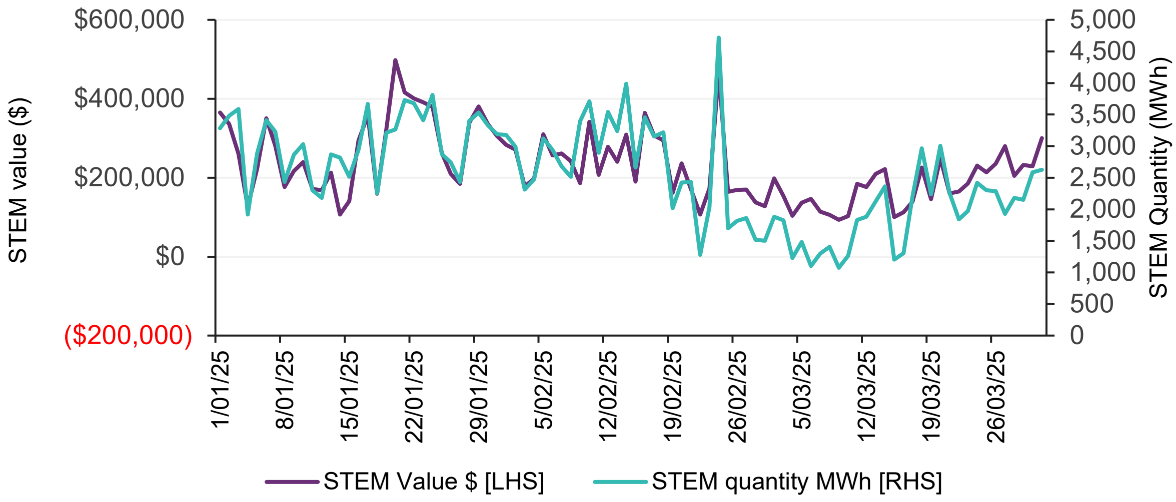


[50] AEMO has changed this reporting metric from 'weighted average STEM price' to 'average STEM price' for better alignment with other metrics in this report such as the average reference trading price.

The daily traded value in STEM ranged from $93,341 to $497,967 in Q1 2025, whereas the daily quantities traded in megawatt hours varied between 1,074 MWh and 4,719 MWh (Figure 118). The change in minimum daily traded value from last quarter (-$175,433) is mostly driven by the reduction in intervals clearing at a negative price. A total of 74 intervals cleared at a negative price this quarter, compared with 176 in Q4 2024.

Figure 118 Daily STEM values fluctuated between $93, 341 and $497,967

Daily quantities (MWh) and value ($) traded in STEM – Q1 2025



5 Reforms delivered

AEMO, with government and industry, continues to deliver energy market reforms across the WEM, NEM and east coast gas markets. These reforms provide for changes to key elements of Australia's electricity and gas market design to facilitate a transition towards a modern energy system, capable of meeting the evolving wants and needs of consumers, as well as enabling the continued provision of the full range of services necessary to deliver a secure, reliable and lower emissions system at least cost. Table 10 provides a brief description of the reforms implemented over the last quarter.

Table 10 Reforms delivered Q1 2025

Reform initiative	Market	Description	Reform delivered
Implementation of renewable gas in AEMO's facilitated gas markets	Gas	On 3 March 2025, AEMO implemented the final renewable gas reforms required for AEMO's facilitated gas markets. The renewable gas project was initially implemented in August 2021 when Energy Ministers agreed that the national gas regulatory framework be reviewed and extended to accommodate hydrogen, biomethane and other renewable gases. In October 2022, Energy Ministers agreed to amendments to extend the National Gas Law (NGL) and National Energy Retail Law (NERL) to hydrogen and other renewable gases. These changes were implemented in the National Gas Amendment (Other Gases) rule changes which commenced on 12 March 2024 and were gazetted on 21 March 2024 with the publication of the South Australian Government Gazette. AEMO implemented Procedure changes and IT system changes to facilitate renewable gases for the AEMO-facilitated gas markets as part of the following Procedure consultations undertaken over the past two years: • Amendments to STTM and Retail Market Procedures (Queensland, New South Wales/Australian Capital Territory and South Australia) for renewable gas and other minor changes – effective 3 March 2025 release (https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-sttm-and-retail-market-procedures). • Amendments to Gas Bulletin Board (GBB) Procedures for renewable gas – effective 3 March 2025 (https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-gbb-procedures-for-renewable-gas). • Amendments to Gas Statement of Opportunities (GSOO) Procedures for renewable gas – effective 31 July 2024 (https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-gsoo-procedures). • Amendments to Victorian Declared Wholesale Gas Market and Retail Market – effective 1 May 2024 (https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-victorian-declared-wholesale-gas-market-and-retail-market-1-may-2024-release). These reforms allow AEMO's facilitated gas markets to inject and settle renewable gases as part of the covered gas supply.	March 2025
RCM Review (2025 Capacity Cycle Certification)	WEM	AEMO has implemented system and process changes to enable the certification of new capacity in the 2025 Reserve Capacity Cycle: • Flexible Capacity is a new incentive for providers to invest in capacity that can start, stop and ramp quickly. Facilities that can meet the minimum requirements will be able to apply for Flexible Capacity in addition to their Peak Capacity Credits from the 2025 Reserve Capacity Cycle onwards. • Demand Side Programmes can now be certified to provide capacity when exporting to the grid, allowing demand side resources to participate in the RCM through this facility class. More information: https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism	March 2025

In addition to these reforms, work continues to progress on the next wave of initiatives set for release later in 2025. Table 11 below provides a brief description of initiatives to be delivered in Q2 and Q3 2025.

Table 11 Upcoming implementation of reforms Q2 – Q3 2025

Reform initiative	Market	Description	Reform to be delivered
RCM Review (2025 Capacity Cycle Certification)	WEM	AEMO has scheduled further changes to its systems and processes, to go live in Q3, to enable the assignment of Flexible Capacity and the determination of the Reserve Capacity Prices for the 2025 Reserve Capacity Cycle. The Peak Reserve Capacity Price and the Flexible Reserve Capacity Price curves have changed to reduce volatility in the price and incentivise investment. Additionally, Flexible Capacity Providers will also have the option of applying for a 10-year price guarantee aligned with their year of entry. More information: https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism	July 2025
Metering Services Review - Accelerating Smart Meter Deployment (Package 1)	NEM	The Accelerating Smart Meter Deployment Rule seeks to implement the recommendations of the Australian Energy Market Commission's (AEMC's) review of the metering framework in 2023 of accelerating the deployment of smart meters in the NEM. AEMO has broken the rule change into three work packages. AEMO published its final determination on Package 1 on 2 April 2025 which accounted for Legacy Meter Replacement Plan, Defects management, Shared isolation as well as other matters including Issue/Change Forms, Retailer of Last Resort (RoLR) and Embedded Network Settlement Anomalies. Package 2 (testing, inspection and malfunctions) and 3 (basic Power Quality Data) are to go live from December 2025 and July 2026 respectively. More information: https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/metering-services-review---accelerating-smart-meter-deployment	April 2025 December 2025 July 2026
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. More information: https://aemo.com.au/initiatives/major-programs/nem-reformprogram/nem-reformprogram-initiatives/scada-lite	June 2025
Frequency Performance Payment (Financial Operation)	NEM	In accordance with the NEM Primary Frequency Response Incentive Arrangement rule change, financial operation of the new Frequency Performance Payment (FPP) system is scheduled to go live in June 2025. This follows an extended period of non-financial operation from December 2024 of the new FPP system to allow market participants to familiarise themselves with its operation. The FPP system and associated procedures and guidelines (including Frequency Contribution Factor Procedures) provide incentives for all facilities to operate in a way that helps maintain power system frequency within the normal operating band, at the lowest cost to consumers. More information: https://aemo.com.au/initiatives/majorprograms/frequencyperformance-paymentsproject	June 2025

Reform initiative	Market	Description	Reform to be delivered
Enhancing Reserve Information (ERI)	NEM	In accordance with the Enhancing Reserve Information (ERI) rule change, AEMO will implement incremental improvements that support the current market and allow for AEMO to observe the energy availability of participants allowing for better forecasting decisions. Specifically, from 1 July 2025 AEMO will publish: the previous trading days' energy availability for batteries, by Dispatchable Unit Identifier (DUID) and for each five-minute dispatch interval, at the end of the trading day (note that within the ERI rules, a 'battery' is a scheduled bidirectional unit, excluding pumped hydro), and the daily energy limits (total availability) of scheduled generators (including pumped hydro), aggregated by region, at the start of the trading day. A third measure requiring AEMO to publish energy availability of batteries (state of charge in megawatt hours), aggregated by region, each Dispatch Interval, was set to go live from 1 July 2027. AEMO intends to voluntarily commence publishing this information from 1 July 2025 for all regions except Tasmania. AEMO will only commence publication of such data in Tasmania once at least three independently operated grid-scale batteries are present, or on 1 July 2027. More information: https://aemo.com.au/initiatives/major-programs/nem-reform-program/enhancing-reserve-information-project	July 2025
Short Term Projected Assessment of System Adequacy (ST PASA) Procedure and Recall Period	NEM	The Updating ST PASA rule change introduced a principles-based approach for AEMO to administer ST PASA. This included an obligation to publish a ST PASA Procedure, and made changes to ST PASA publication timetable, the definition of 'energy constraint' and PASA availability. The resulting system and procedural changes are to go live from 31 July 2025 and provide flexibility to participants to communicate to the market on their unit availability and outage conditions as well as support AEMO's ability to assess reliability and security conditions in the NEM as the market develops. More information: https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/st-pasa	July 2025

List of tables and figures

Tables

Table 1	Q1 2025 minimum operational demand records	13
Table 2	Wholesale electricity price drivers in Q1 2025	17
Table 3	Significant price volatility events in Q1 2025	18
Table 4	NEM supply contribution by fuel type	25
Table 5	Brown coal availability, output, utilisation, full outages, and intraday swing – Q1 2025 vs Q1 2024	29
Table 6	Average east coast gas prices – quarterly comparison	49
Table 7	Wholesale gas price levels: Q1 2025 drivers	49
Table 8	Gas demand – quarterly comparison	53
Table 9	WEM supply contibution by fuel type	66
Table 10	Reforms delivered Q1 2025	76
Table 11	Upcoming implementation of reforms Q2 – Q3 2025	77

Figures

Figure 1	Temperatures generally warmer than long-term average throughout Australia	8
Figure 2	Higher maximum temperatures in Melbourne and Adelaide across the quarter	8
Figure 3	Higher than long-term average cooling requirements in Melbourne, Adelaide and Perth	8
Figure 4	Underlying demand reached a new Q1 high, offset by distributed PV output	10
Figure 5	Significant increase in Queensland distributed PV growth	10
Figure 6	Increased underlying demand throughout the day with distributed PV lowering daytime operational demand until late afternoon	11
Figure 7	Weather conditions increased underlying and operational demand in Victoria and South Australia, but operational demand reduced in Queensland, New South Wales and Tasmania	11
Figure 8	Record all-time maximum operational demand in Queensland	12
Figure 9	Record all-time low minimum operational demand in New South Wales and Victoria	12
Figure 10	Queensland maximum demand period peaked in the late afternoon, delayed by distributed PV generation	14
Figure 11	South Australian maximum demand period shifted later into the evening due to distributed PV generation	14
Figure 12	NEM average wholesale spot prices up 9% year-on-year, but declined 6% from the preceding quarter	14

Figure 13	Year-on-year reduction in cap return offset by increased energy prices in the southern NEM regions	15
Figure 14	NEM average price increased during overnight hours	16
Figure 15	Significant price separation between Tasmania and mainland regions	16
Figure 16	Less volume offered at lower price bands by black coal generators	17
Figure 17	Shift in prices from less than $100/MWh to over $100/MWh	17
Figure 18	Lowest NEM-wide cap return since Q4 2023	18
Figure 19	Isolated volatility events across the quarter	18
Figure 20	Negative price occurrence increased year-on-year in all NEM mainland regions	19
Figure 21	South Australia led negative price occurrence	20
Figure 22	Proportion of negative prices between x -$40/MWh and $0/MWh almost doubled	20
Figure 23	Hydro and coal saw largest increases in average prices set when marginal	21
Figure 24	Notable increases in price-setting frequency by solar and battery load during the day, and by battery generation in the evening peak	21
Figure 25	Hydro set prices less frequently in all mainland NEM regions but more frequently in Tasmania	22
Figure 26	Reductions in northern region Q1 2025 base futures with lower than expected price volatility	23
Figure 27	Slight decline in mainland FY26 futures across the quarter	23
Figure 28	Forward financial year contracts ended the quarter below end of Q4 2024 levels in all mainland NEM regions except Victoria	24
Figure 29	VRE and battery saw increased output compared to all other fuel types	25
Figure 30	VRE output growth dominated throughout the day, pushing down coal, gas and hydro output	26
Figure 31	Reductions in New South Wales drove NEM black coal-fired output and availability to new Q1 quarterly low	26
Figure 32	Return of Callide C reduced Queensland black coal-fired capacity on full outage	26
Figure 33	Lower output from black coal-fired generators in New South Wales, except Mt Piper	27
Figure 34	Lower output from black coal-fired generators in Queensland, except Callide C	27
Figure 35	Decrease in New South Wales black coal generation across all hours of the day	28
Figure 36	Increase in Queensland black coal generation in evening peak and overnight	28
Figure 37	Brown coal-fired generation and availability recorded new Q1 quarterly lows	29
Figure 38	Lower brown coal generation at all times of the day	29
Figure 39	Gas-fired generation reduced to its lowest Q1 level since 2004	29
Figure 40	Higher gas volumes offered over $300/MWh	29
Figure 41	Lower hydro generation in New South Wales and Tasmania	30
Figure 42	Less volume offered at lower price bands by hydro generators	30
Figure 43	Steady VRE growth continued	31
Figure 44	VRE increases led by New South Wales and Victoria	31

Figure 45	Growth in new and commissioning solar capacity year-on-year	32
Figure 46	Increases in grid-scale solar availability only in Queensland and South Australia	32
Figure 47	Growth in new and commissioning wind capacity year-on-year	33
Figure 48	Increases in wind availability across all NEM regions, except Tasmania	33
Figure 49	Economic offloading of wind and grid-scale solar generation increased year-on-year	33
Figure 50	Curtailment of wind generation decreased while curtailment of grid-scale solar generation increased year-on-year	34
Figure 51	Peak renewable contribution and potential increased year-on-year	34
Figure 52	Maximum renewable contribution increased	35
Figure 53	Record high for peak grid-scale solar output	35
Figure 54	Increased renewable contribution to meeting daily maximum demand	36
Figure 55	Year-on-year reduction in emissions and emissions intensity to all-time lows	37
Figure 56	Year-on-year fall in battery net revenue driven by reduced FCAS component	37
Figure 57	Proportion of battery net revenue from FCAS markets fell	37
Figure 58	Year-on-year increase in NEM battery availability	38
Figure 59	Year-on-year drop in battery price spread partly offset higher output	38
Figure 60	Pumped hydro net revenue reduced year-on-year	39
Figure 61	Significant drop in wholesale demand response	39
Figure 62	Steady progress of application approvals and strong quarter for registrations in Q1 2025	41
Figure 63	Increase in capacity being progressed through the connections pipeline during the last year	41
Figure 64	Southward shifts in Queensland – New South Wales – Victoria transfers	42
Figure 65	New South Wales – Queensland transfers shifted south	43
Figure 66	Victorian net exports to New South Wales fell again	43
Figure 67	Northward limits on VNI impacted by daytime solar output and outage constraints overnight	43
Figure 68	Daytime Victorian imports fell on Heywood and PEC-1 interconnection	44
Figure 69	Constraints drove Victoria – South Australia daytime flow changes	44
Figure 70	Reduction in positive IRSR	45
Figure 71	Negative IRSR fell except on Victoria – South Australia	45
Figure 72	Increased counterprice flow west on Heywood and PEC-1 interconnection	45
Figure 73	Daytime South Australian prices fell below Victoria's	45
Figure 74	Notable reduction in FCAS costs	46
Figure 75	High share for regulation FCAS costs	46
Figure 76	Batteries dominated FCAS market share	47
Figure 77	Reduction in hydro enablement while VPP enablement surged in FCAS	47
Figure 78	System security direction costs down year-on-year while IRR costs increased	47

Figure 79	Direction frequency of South Australian generators remained almost constant year-on-year	48
Figure 80	Domestic prices at record Q1 levels but eased slightly from Q4 2024	50
Figure 81	Reduced proportion of DWGM bids at lower prices compared to 2024	50
Figure 82	Traded thermal coal prices reduced across the quarter	51
Figure 83	Asian spot LNG prices fell during the quarter	51
Figure 84	Brent Crude oil prices averaged A$119/barrel	52
Figure 85	Slightly lower gas demand across all sectors	53
Figure 86	Slightly lower Queensland LNG production but still second highest Q1 on record	53
Figure 87	Victorian industrial demand at its lowest Q1 level since at least the DWGM began	54
Figure 88	Victorian supply increased mainly due to higher Otway and Longford production	55
Figure 89	Queensland Q1 2025 net domestic supply decreased to lowest level since 2017	55
Figure 90	Higher Longford Q1 production after maintenance impacted 2024	56
Figure 91	Longford daily production higher than Q1 2024 due to higher available capacity	56
Figure 92	Iona storage ended the quarter at its second highest level since reporting began in 2017	57
Figure 93	Net Q1 flows north on SWQP increased to highest level since Q1 2022	57
Figure 94	Highest Victorian Q1 exports to New South Wales since 2022	58
Figure 95	Increased average daily pipeline flows north	59
Figure 96	Highest Q1 traded volumes on record	60
Figure 97	Slight decrease in DAA volumes traded	60
Figure 98	Gas consumption in Western Australia dropped slightly compared to Q4 2024	61
Figure 99	Q1 2025 saw a decrease in gas production of 3.0 PJ from Q4 2024	62
Figure 100	Net withdrawals from storage continued in Q1 2025	62
Figure 101	Higher operational demand as increases to underlying demand outpaced distributed PV growth	63
Figure 102	Battery withdrawal and injection grew	64
Figure 103	New operational demand record set 20 January 2025	64
Figure 104	Underlying demand increases met by distributed PV, battery and hybrid generation	66
Figure 105	Q1 2025 saw reductions in coal being replaced by battery and hybrid facilities	66
Figure 106	Q1 2025 saw the highest ever Q1 average renewable contribution	67
Figure 107	New highest Q1 peak 5-minute renewable contribution in 2025	67
Figure 108	Reduction in emissions intensity driven by lower coal	68
Figure 109	Batteries displaced gas in the FCESS markets	69
Figure 110	Batteries captured 39% FCESS market share	69
Figure 111	Average energy prices increased relative to previous quarters in 2024	70
Figure 112	Batteries and high overnight temperatures drove changes to daily energy price profiles	70
Figure 113	Total ESS costs decreased by $49.5 million compared to Q4 2024	71
Figure 114	FCESS Uplift costs decreased by $38.6 million (-79%) from Q1 2024	72

Figure 115	NCESS costs increased as new contracts commenced	73
Figure 116	Wholesale Electricity Market costs increased compared to Q1 2024	74
Figure 117	The average STEM price increased by 3% in Q1 2025	74
Figure 118	Daily STEM values fluctuated between $93, 341 and $497,967	75

Abbreviations

Abbreviation	Expanded term
5MS	Five-Minute Settlement
AC	alternating current
ACCC	Australian Competition and Consumer Commission
ACE	Adjusted Consumed Energy
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APLNG	Australia Pacific LNG
ASX	Australian Securities Exchange
BCF	Ballera Compression Facility
CDD	cooling degree day
CDEII	Carbon Dioxide Equivalent Intensity Index
CGP	Carpentaria Gas Pipeline
DAA	Day Ahead Auction
DER	distributed energy resources
DR	demand response
DUID	Dispatchable Unit Identifier
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
ERI	Enhancing Reserve Information
ESS	essential system services
FCAS	frequency control ancillary services
FCESS	frequency co-optimised essential system services
FPP	Frequency Performance Payment
GAB	Gas Advisory Board
GBB	Gas Bulletin Board
GJ	gigajoule/s
GJ/h	gigajoules per hour
GW	gigawatt/s
GWh	gigawatt hour/s
GLNG	Gladstone LNG
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
IEA	International Energy Agency
IPRR	integrating price-responsive resources
IRR	interim reliability reserve
IRSR	inter-regional settlement residue
L60S	lower 60-second (FCAS)
LCA	Linepack Capacity Adequacy

Abbreviation	Expanded term
LGC	large-scale generation certificate
LNG	liquefied natural gas
MT PASA	Medium Term Projected Assessment of System Adequacy
$MtCO_2$-e	million tonnes of carbon dioxide equivalents
MW	megawatt/s
MWh	megawatt hour/s
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NCESS	non-co-optimised essential system service
NGL	National Gas Law
NSP	network service provider
PEC	Project EnergyConnect
PEC-1	Project EnergyConnect Stage 1
pp	percentage points
PJ	petajoule/s
PV	photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG
R60S	raise 60-second (FCAS)
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
RoCoF	Rate of Change of Frequency
RoLR	Retailer of Last Resort
RREG	raise regulation
ST PASA	Short Term Projected Assessment of System Adequacy
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
tCO2-e	tonnes of carbon dioxide equivalent
TJ/d	terajoules per day
TJ/y	terajoules per year
UGS	Underground Storage Facility
VGPR	*Victorian Gas Planning Report*
VPP	virtual power plant
VRE	variable renewable energy
VNI	Victoria – New South Wales Interconnector
WCF	Wallumbilla Compression Facility
WEM	Wholesale Electricity Market
WDR	wholesale demand response