Quarterly Energy Dynamics Q4 2023

January 2024

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 Q4 2023 (1 October to 31 December 2023). This quarterly report compares results for the quarter against other recent quarters, focusing on Q3 2023 and Q4 2022. Geographically, the report covers:

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

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Version control

Version	Release date	Changes
1	25/01/2024	

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Executive summary

East coast electricity and gas highlights

North – south divide evident in National Electricity Market (NEM) demand and price outcomes

- Higher underlying demand driven by warmer than average temperatures led to the first year-on-year Q4 increase in average operational NEM demand since 2015. NEM average operational demand this quarter was 19,745 megawatts (MW), a 1.6% increase from Q4 2022. This outcome was despite an all-time record for average distributed photovoltaic (PV) output of 3,433 MW, 505 MW higher than the same time last year.
- The northern regions of the NEM drove the increased demand, with both Queensland and New South Wales experiencing increases in average underlying and operational demand, and the southern regions of Victoria and South Australia recording all-time lows in average operational demands.
- Wholesale spot prices across the NEM averaged $48 per megawatt hour (MWh), a 48% reduction from $93/MWh over Q4 last year. While all regions experienced significant price reductions, there was clear separation between the regions, with prices in Queensland ($68/MWh) and New South Wales ($66/MWh) double those in South Australia ($33/MWh) and Victoria ($26/MWh). This price separation was driven by higher operational demand in the northern regions and ongoing network congestion on northward flows on the Victoria – New South Wales Interconnector (VNI).

Wholesale price pressures decreased with more capacity offered at lower prices

- Changing coal market conditions and policy interventions since last Q4 saw black coal-fired generators offering larger volumes of energy at lower prices, with an average additional 1,382 MW offered at price levels below $100/MWh. There was an increase in the frequency at which this generation set the price to 30% of dispatch intervals (from 28%), however this occurred at a much-reduced price of $58/MWh compared to $113/MWh in the same quarter last year.
- A record high of 20% of intervals experienced negative or zero wholesale spot prices across the NEM, with New South Wales and Victoria reaching their highest ever number of intervals with negative or zero prices, at 12% and 29% respectively.

Increases in renewable output set new minimum demand and instantaneous renewable penetration records

- The NEM's first negative operational demands were recorded in South Australia on 31 December 2023, with a new minimum demand record of -26 MW set in the half-hour ending 1330 hrs when distributed PV output represented 101.7% of underlying demand. Victoria also reached an all-time minimum demand record of 1,564 MW on the same day.
- Minimum operational demand records were also set for the NEM as a whole and in New South Wales on 29 October 2023, the same day that instantaneous distributed PV output across the NEM reached a record high of 51.3% of underlying demand.

- The increase in distributed PV output was accompanied by increasing grid-scale renewable output, and a new record for maximum instantaneous share of renewable energy generation of 72.1% was reached during the half-hour ending 1300 hrs on Tuesday 24 October 2023.

Record high grid-scale variable renewable output and record low black-coal fired output

- Grid-scale variable renewable energy (VRE) output reached an all-time quarterly average record high of 5,168 MW, 14% higher than this time last year. This increase was predominantly driven by new and recently commissioned units in New South Wales and Queensland lifting NEM average grid-scale solar output to a record high of 2,021 MW, up 23% from last Q4.
- Average NEM black coal-fired generation fell to a new quarterly low of 9,189 MW, despite an increase in total black coal-fired availability to 12,456 MW, with reduced outages offsetting the reduction in availability from the closure of Liddell in April 2023.
- The increase in renewable output drove NEM total emissions and emissions intensity to new all-time record low levels of 25.4 million tonnes of carbon dioxide equivalents (MtCO2-e) and 0.59 tCO2-e/MWh respectively.

Other NEM highlights

- The very fast frequency control ancillary services (FCAS) markets were introduced on 9 October 2023 and contributed $6.3 million (19%) to total FCAS costs while prices for other FCAS services generally dropped. Batteries and demand response were the main providers of the very fast services, increasing their shares of FCAS market supply to 50% and 12% respectively.
- Directions costs were reduced overall to $23.4 million compared to $29.5 million over the same time period last year, and the first system security direction in New South Wales occurred over 15 to 17 November 2023, requiring a coal unit to remain online to maintain system security when a further five units were unavailable due to planned and unplanned outages.
- At the end of Q4 2023, new capacity totalling 36 gigawatts (GW) was progressing through the connection process from application to commissioning. During Q4 2023, AEMO approved applications for 6.5 GW of capacity across 28 projects, a notable increase from 1.7 GW across 11 projects in Q4 2022.

East coast gas prices continued to trend lower, Queensland liquefied natural gas (LNG) demand increased

- East coast wholesale gas prices continue to trend downwards, averaging $10.83 per gigajoule (GJ) for the quarter, significantly lower than Q4 2022's $17.79/GJ, though slightly higher than $10.41/GJ in Q3 2022.
- Gas demand increased by 3% this quarter compared to Q4 2022, solely driven by higher demand for Queensland LNG exports (+24 petajoules (PJ)). AEMO markets demand decreased (-12 PJ) and there was slightly lower usage for gas-fired generation (-1 PJ).
- Domestic gas supply shifts observed in Q2 and Q3 2023 continued, again mainly driven by declining production from gas fields connected to the Longford Gas Plant in Victoria. Production from Longford fell by 20 PJ compared to Q4 2022, and it has now been overtaken by QCLNG's Woleebee Creek production facility in Queensland as the largest gas production facility on the east coast in terms of annual production. This supply decrease was offset by the reduction in domestic demand, with Queensland domestic supply also lower (-2.9 PJ).

- As in prior quarters of 2023, inventory held in the Iona underground gas storage (UGS) facility ended Q4 at its highest quarter-end balance since reporting began in 2017.

Western Australia electricity and gas highlights

New WEM commenced

- The commencement of the new Wholesale Electricity Market (WEM) on 1 October 2023 saw Western Australia's main power system move to a Security Constrained Economic Dispatch (SCED) market model. Among other changes, this includes network limits incorporated in the new Dispatch Engine (WEMDE) which co-optimises energy and new Frequency Co-optimised Essential System Services (FCESS) for Regulation, Contingency and Rate of Change of Frequency (RoCoF) control.

All-time high operational demand record set in spring

- A heatwave was experienced in and around Perth between 20 and 25 November 2023. A new all-time maximum average operational demand record of 4,046 MW was set on 23 November 2023, prior to the commencement of the Hot Season and associated Reserve Capacity processes on 1 December 2023. This supersedes the previous record of 4,006 MW set in 2016 and the previous spring maximum operational demand record by more than 800 MW.

Energy and ESS costs increase, new market continues to stabilise

- The average Energy price (Reference Trading Price) increased by 15% compared to Q4 2022 (Balancing Price) but was lower than average Balancing Prices in Q2 and Q3 2023.
- The overall cost of Energy and ESS (excluding FCESS Uplift) increased from $76.06/MWh to $98.35/MWh relative to Q4 2022, driven by increases to both Energy ($14.60) and ESS ($11.93).
- The cost of Contingency Raise and Lower rose significantly compared to Q4 2022, as pricing mechanisms changed fundamentally from an administered pricing mechanism (set by the Economic Regulation Authority) to a market-based mechanism.
- Regulation Raise and Lower costs increased significantly compared to historically low LFAS Up and Down prices in Q4 2022, but was only moderately higher than more typical historical prices.
- The new WEM introduced significant changes to Market Services, definitions, and pricing mechanisms. Market outcomes are still stabilising and caution should be exercised in drawing conclusions or comparisons based on limited data from the first three months of the new market.

Domestic gas production increases, consumption decreases and storage increases

- Domestic gas production increased in Q4 2023 to 105.4 PJ, a 1.7% increase compared to Q4 2022. A total of 96.5 PJ was consumed, a 3.7% decrease compared to Q4 2022.
- For the first time in 2023, there was a positive net flow of gas into storage in Western Australia.

Contents

1 NEM market dynamics

1.1 Electricity demand

1.1.1 Weather

In Q4 2023, Australia experienced warmer than average temperatures, evident across most regions through above average mean temperature levels (Figure 1). Northern regions of Queensland and New South Wales witnessed a rise in average maximum temperatures compared to both Q4 2022 and 10-year average. Conversely, the southern regions of Victoria and South Australia saw lower average maximum temperatures than their 10-year averages, despite slight increases on Q4 2022 (Figure 2).

In October, the national mean temperature was 1.05°C warmer than the 1961–1990 average, with most parts of Australia recording warmer than average mean maximum temperatures. It was also the fifth-driest October on record (since 1900), and the driest since 2002. All states and territories except Victoria had below average rainfall for October.

Above average temperatures continued into November, recording the ninth-warmest November on record (since 1910). Temperatures were above average for large parts of Australia, with the national area-average mean temperature sitting 1.58°C above the 1961–1990 average. Rainfall in November was also above average for much of the mainland, but below average for Tasmania.

December continued to be warmer than average, with the national mean temperature 1.60°C above the 1961–1990 average, recording the fourth warmest on record (since 1910). For Australia as a whole, December rainfall was 1.9% below the 1961–1990 average.

Figure 1 Warmer than average temperatures across Australia

Q4 2023 mean temperature deciles for Australia

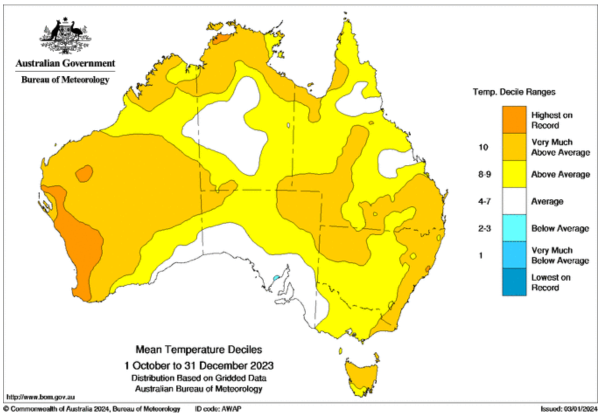
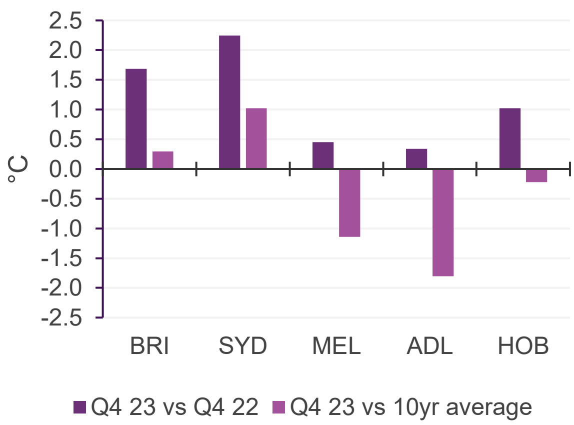


Figure 2 Maximums warmer than 10-year average in New South Wales and Queensland but down in Victoria and South Australia

Average maximum temperature variance by capital city



1.1.2 Demand outcomes

In Q4 2023, operational demand[1] across the NEM averaged 19,745 MW, a 315 MW (+1.6%) increase on Q4 2022, and the first year-on-year rise for a Q4 since 2015. Despite this, operational demand in Q4 2023 still stands as the second lowest average for any quarter since Tasmania joined the NEM in 2005, driven by ongoing growth in distributed PV output.

The increase this quarter was due to sharply higher underlying demand[2], which more than offset distributed PV output growth (Figure 3). NEM underlying demand increased by 820 MW (+3.7%) from Q4 last year to average 23,178 MW in Q4 2023, its highest Q4 average since 2009. Warmer than average weather conditions in the northern mainland regions (Section 1.1.1) were a major driver of this increase. Distributed PV output was 3,433 MW, 505 MW (+17%) higher than last Q4 and a new record for any quarter. Despite this, operational demand increased across most hours of the day (Figure 4).

Figure 3 Strong growth in underlying demand partially offset by record distributed PV output

NEM average underlying and operational demand – Q4s

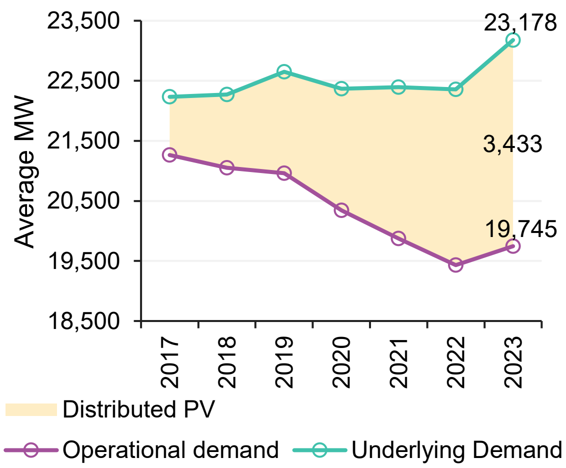
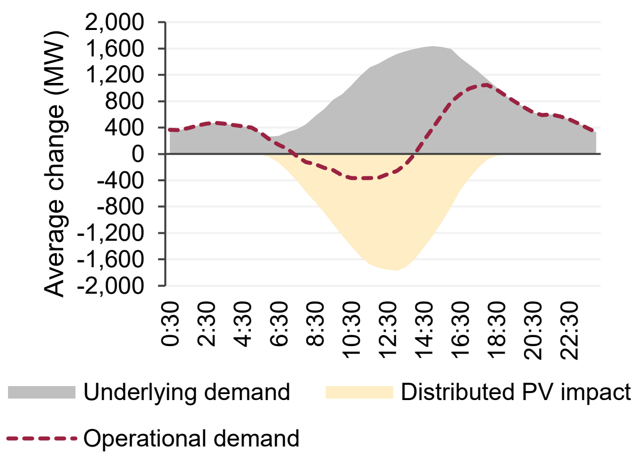


Figure 4 Significant increases in underlying demand during afternoon and overnight hours drove increased operational demand

Changes in operational demand – Q4 2023 vs Q4 2022



This quarter's underlying and operational demand increases arose entirely in the northern regions of Queensland and New South Wales (Figure 5). **Queensland**'s average operational demand increased by 400 MW (+7.0%) to 6,137 MW while in **New South Wales** the increase was 155 MW (+2.2%) to 7,037 MW. **Victoria** and **South Australia** saw all-time lows in average operational demands, at 4,366 MW and 1,089 MW respectively.

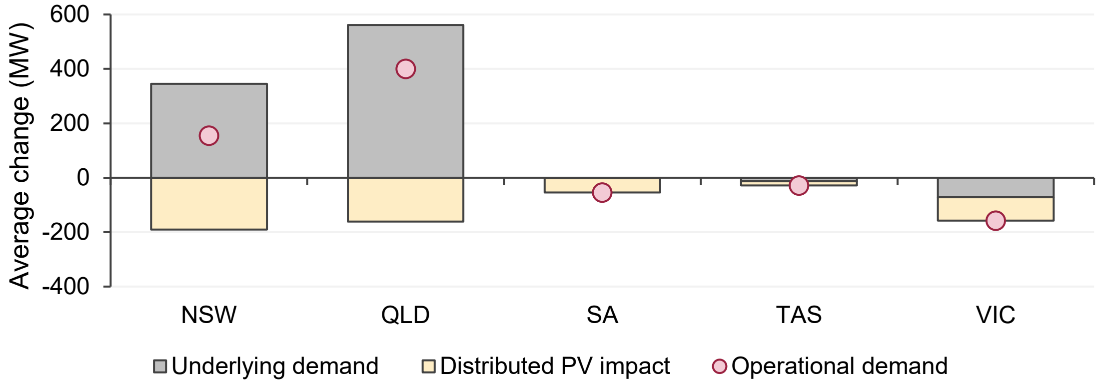
As illustrated in Figure 5, the rise in underlying demand was most evident in Queensland, with an increase of 561 MW (+8.5%) to average 7,200 MW in Q4 2023. New South Wales also witnessed growth of 345 MW (+4.4%), contrasting with lower underlying demand in other regions. Underlying demand increases in Queensland and New South Wales were most pronounced in December, with monthly averages up by 1,046 MW (+15.6%) and 802 MW (+10.2%) respectively.

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

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

Figure 5 Northern regions drive the NEM's operational demand increase

Changes in average demand components by region – Q4 2023 vs Q4 2022



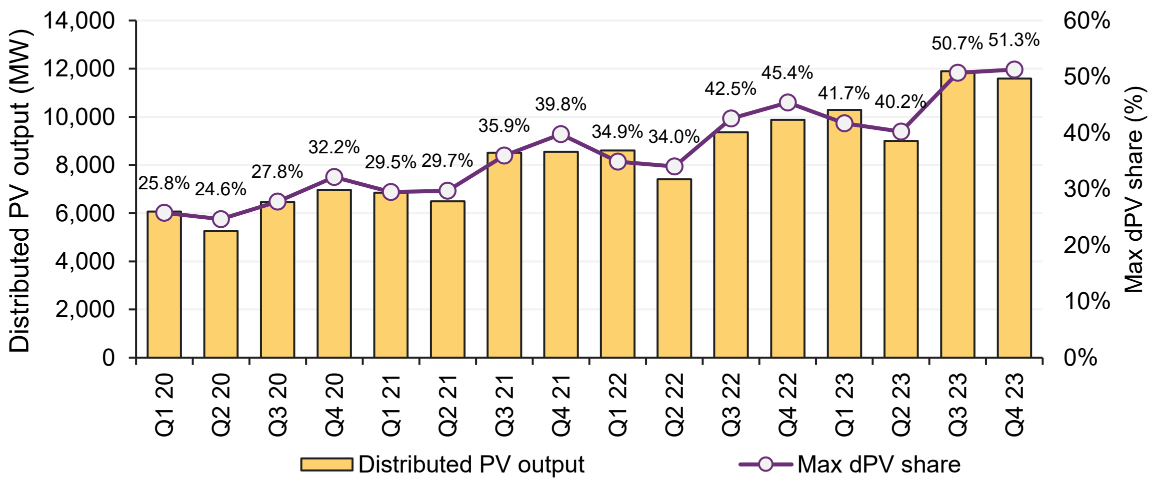
Distributed PV output reached record highs in all regions, with October yielding a particularly notable 44% year-on-year increase in monthly average for the NEM. By contrast, the NEM-wide November average rose only 7% year-on-year, with New South Wales and Queensland experiencing decreases on 2022 levels. In December, this position reversed, with monthly averages falling in Victoria and South Australia within a 7% NEM-wide increase.

At 17% for Q4 as a whole, year-on-year growth of distributed PV output was lower than in recent quarters which had recorded annual growth rates of around 30%. By region, **New South Wales** experienced a 20% increase in distributed PV output, reaching a quarterly average of 1,155 MW, while **Queensland** saw an 18% rise to average 1,063 MW.

Maximum instantaneous distributed PV share of underlying demand across the NEM reached a record high of 51.3% at 1330 hrs on Sunday 29 October 2023 (Figure 6). At this time, distributed PV output reached 11,583 MW while the underlying demand was at 22,592 MW. This was 0.6 percentage points (pp) higher than the previous record of 50.7% set on Saturday 30 September 2023.

Figure 6 Distributed PV supplied a record instantaneous share of underlying NEM demand

Distributed PV maximum instantaneous supply share (%) of underlying NEM demand and output at time of maximum (MW) - Quarterly



Maximum demand

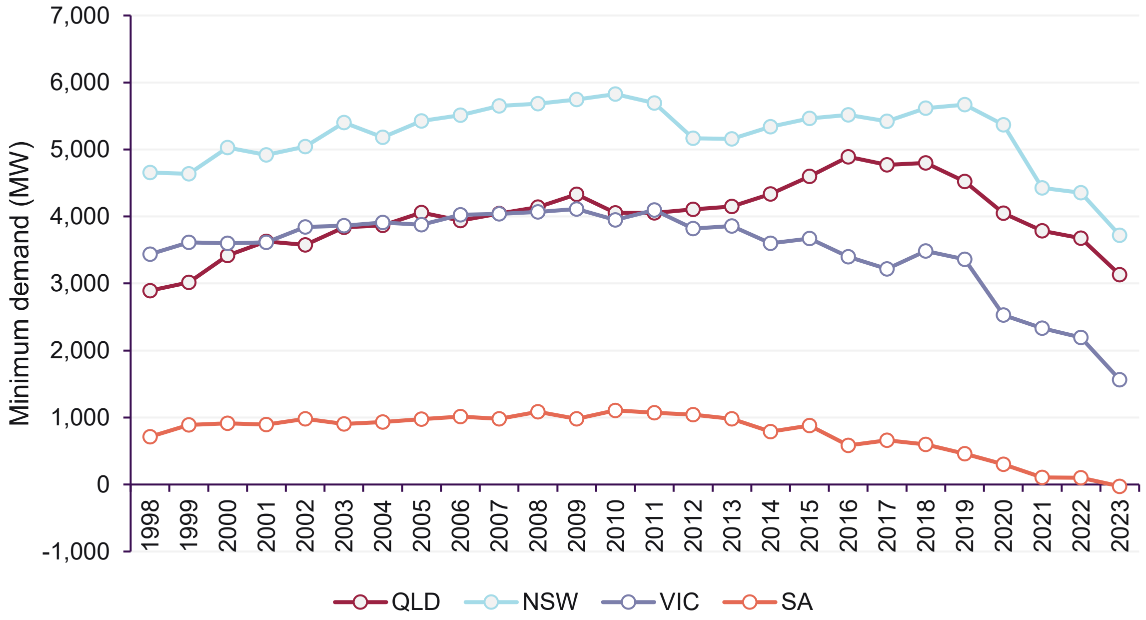
NEM maximum operational demand, at 30,180 MW this quarter, rose by 2,206 MW (+7.9%) relative to Q4 2022. **Queensland** recorded an all-time high Q4 maximum demand at 9,750 MW at 1730 hrs on 29 December 2023, which was 871 MW (+9.8%) higher than Q4 2022 and 248 MW (+2.6%) higher than the previous Q4 record set in 2018. No other NEM regions saw maximum demand records in Q4 2023. Compared to Q4 2022, maximum demand in **New South Wales** was higher by 3,262 MW (+33.2%) reflecting a very low peak level last year, whereas maximums in **Victoria**, **South Australia** and **Tasmania** were respectively 502 MW (-6.1%), 437 MW (-15.5%) and 31 MW (-2.1%) lower.

Minimum demand

The NEM saw its all-time[3] lowest minimum demand of 11,009 MW at 1330 hrs on Sunday 29 October 2023, 384 MW below the prior all-time low of 11,393 MW on Sunday 17 September 2023. At this time distributed PV accounted for 51.3% of the underlying demand across the NEM.

Figure 7 Minimum demands fell to record lows in New South Wales, Victoria and South Australia

Q4 minimum operational demands for mainland regions



New South Wales, **Victoria**, and **South Australia** also recorded all-time minimum demand records this quarter, driven by higher distributed PV output (Figure 7):

- **New South Wales'** operational demand reached a new record low of 3,719 MW in the half-hour ending 1200 hrs on Sunday 29 October 2023. This demand minimum was 382 MW less than the previous all-time low of 4,101 MW recorded on Sunday 24 September 2023. At the time, distributed PV accounted for 53.7% of the region's underlying electricity demand and grid-scale solar accounted for 51% of the region's operational demand.
- A new minimum demand record of 1,564 MW was set in **Victoria** at 1300 hrs on Sunday 31 December 2023. This was 504 MW less than the previous all-time low of 2,068 MW recorded on Sunday 24 September 2023.

[3] NEM-wide all-time records are computed based on demand data starting from 2005 after Tasmania joined the NEM.

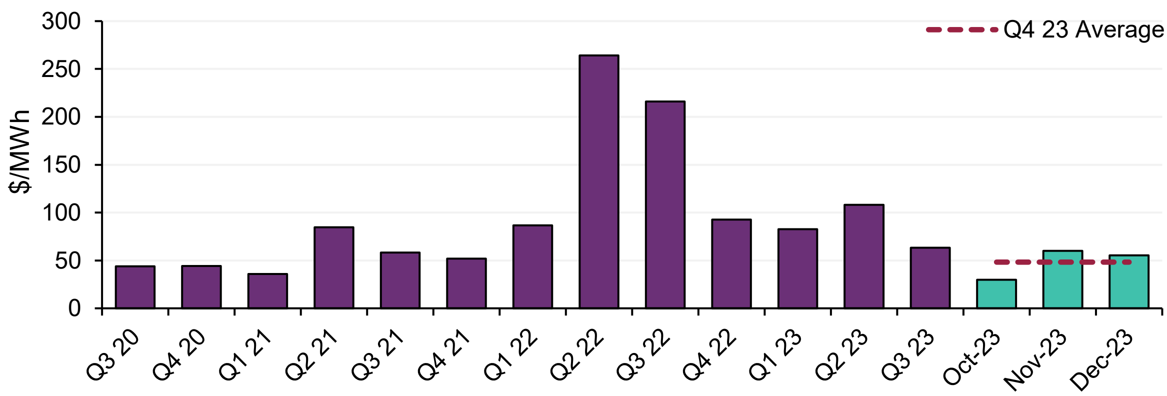
- On the same day at 1330 hrs, **South Australia** also set a new minimum demand record of -26 MW. This was 47 MW below the previous all-time lowest minimum demand of 21 MW recorded on Saturday 16 September 2023 (this previous record was broken multiple times during this quarter before recording the all-time low of -26 MW). At the time, distributed PV output of 1,538 MW accounted for 101.7% of the region's underlying electricity demand.
- At 1130 hrs on Sunday 1 October 2023, **Queensland** recorded its lowest operational demand since 2000, reaching 3,131 MW.

1.2 Wholesale electricity prices

In Q4 2023, wholesale spot prices across the NEM averaged $48/MWh[4], a drop of $44/MWh (-48%) from Q4 2022 and a $15/MWh (-24%) decline from Q3 2023. This was comparable to average price levels for Q4 2020 ($44/MWh) and Q4 2021 ($52/MWh). Following a dip to $30/MWh in October, average monthly prices rose sharply to $60/MWh in November, leveling off at $55/MWh in December (Figure 8).

Figure 8 Average NEM spot prices down by 48% on Q4 2022, and 24% on Q3 2023

NEM average wholesale electricity prices – quarterly since Q3 2020

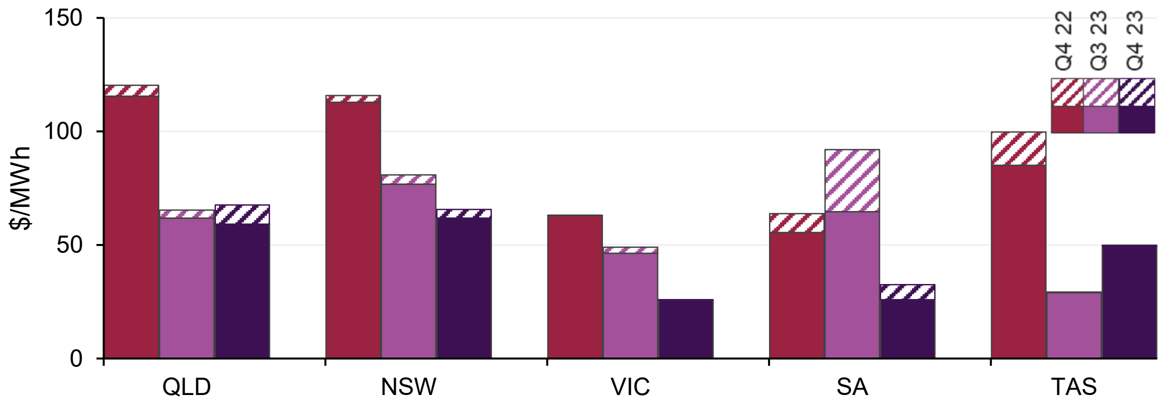


Compared to Q4 2022, price decreases in all regions exceeded 40%, despite higher operational demand averages in Queensland and New South Wales (Section 1.1.2). Regional average prices for Q4 2023 ranged from $26/MWh in Victoria to $68/MWh in Queensland, with South Australia, Tasmania and New South Wales averaging $33/MWh, $50/MWh and $66/MWh respectively (Figure 9).

[4] Time weighted average – simple average of regional wholesale electricity spot prices over each 5-minute dispatch period over the quarter

Figure 9 All regions saw price declines on Q4 2022

Average wholesale electricity spot price by region – energy[5] and cap return components for selected quarters



By region in Q4 2023:

- **Queensland** spot prices averaged $68/MWh, a drop of $53/MWh (-44%) from Q4 2022. The energy component of the quarterly average was $59/MWh while the cap return component was $8/MWh. This decline was most evident in October, when higher distributed PV generation reduced operational demand (Section 1.1.2). Monthly prices rose across the quarter, averaging $93/MWh in December, up $8/MWh from December 2022, driven by a sharp increase in underlying demand. Relative to Q3 this year Queensland saw a $2/MWh (+3%) increase in quarterly average price because of higher volatility, while averages fell in all other mainland regions.
- Quarterly average prices in **New South Wales** fell $50/MWh (-43%) from Q4 2022 to an average of $66/MWh in Q4 2023. Lower operational demand in October put downward pressure on prices. A year on year decrease in distributed PV in November, coupled with increased underlying demand, led to a rise in monthly operational demand. Both underlying and operational demand then increased strongly in December. Despite this, monthly average prices remained lower than in corresponding months of Q4 2022.
- **Victoria** experienced the largest percentage drop in quarterly average spot prices among all NEM regions with a reduction of $37/MWh (-59%) to an average of $26/MWh in Q4 2023. Lower operational demand, combined with higher VRE generation, eased the supply-demand balance, putting downward pressure on spot prices.
- In **South Australia**, spot prices averaged $33/MWh, down $31/MWh (-49%) from Q4 2022 on the back of higher distributed PV and grid-scale VRE output. South Australia's cap return component averaged $7/MWh, with 115 intervals of prices exceeding $300/MWh, but was down from its level in Q4 2022 and only about a quarter of the $27/MWh cap return component recorded in Q3 2023.
- **Tasmania's** spot prices averaged $50/MWh this quarter, a 50% drop from $100/MWh in Q4 2022, but up by $21/MWh (+70%) from Q3 2023's average of $29/MWh as the region switched from exporting energy to the mainland in Q3 to importing in Q4. Tasmania saw the largest drop in the cap return component of spot price, with a 99% reduction from the previous year's $15/MWh. Q4 2022 witnessed a number of price spike events in Tasmania caused by several transmission line outages.

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

As illustrated in Figure 10, NEM average prices decreased in nearly all hours despite increased operational demand (Section 1.1.2). The reduction was particularly notable during overnight hours, coinciding with increased wind generation (Section 1.3). Key factors influencing these price movements are further discussed in Section 1.2.1. During this quarter, net northward energy flows over VNI remained largely unchanged from last Q4, however, during daytime hours export limits on VNI (when binding) reduced northwards flows to near zero and at times forced flow southwards (Section 1.4, Figure 60). VNI reached its export limit in 44% of dispatch intervals during Q4 2023, leading to higher daytime price separation (Figure 11).

Figure 10 Average NEM prices lower across the day

NEM average wholesale electricity prices by time of day - Q4 2023 vs Q4 2022

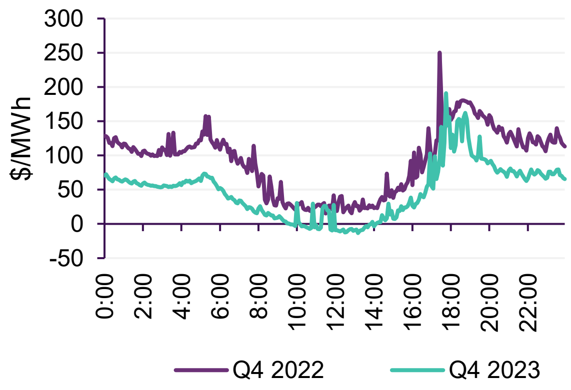
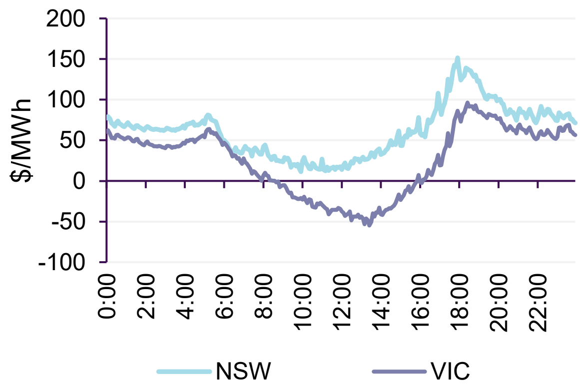


Figure 11 Price separation between Victoria and New South Wales widened in daytime hours

Average regional energy price by time of day – Q4 2023



1.2.1 Wholesale electricity price drivers

This quarter saw average wholesale electricity prices falling sharply compared to both Q4 2022 and Q3 2023. Key factors influencing the movement of prices throughout Q4 2023 are summarised in Table 1, with further analysis and discussion referred to relevant sections elsewhere in this report.

Table 1 Wholesale electricity price levels: Q4 2023 drivers

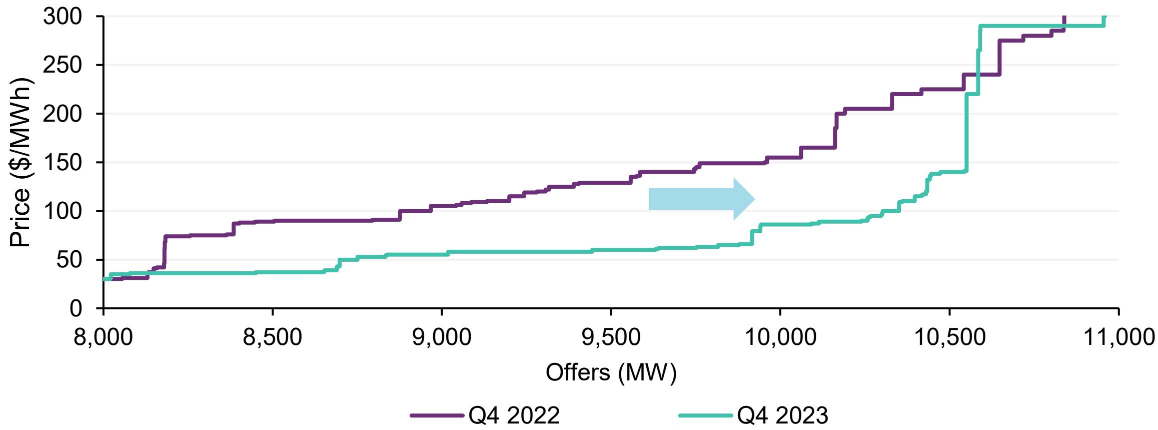
Lower black coal-fired generation offer prices	This quarter witnessed a notable increase in black coal-fired generation volumes offered to the spot market at lower price ranges (Figure 12). This correlated with the introduction of government policies capping domestic thermal coal prices and improvements in the fuel supply of certain key generators, collectively contributing to an overall decrease in marginal cost for black coal-fired generators. Consequently, the average spot price set by black coal units in the mainland region dropped from $113/MWh in Q4 2022 to $58/MWh in Q4 2023 (Section 1.2.4), contributing to lower average electricity prices this quarter.
Increased coal-fired generation availability	Despite Liddell's closure, total black coal availability increased by 282 MW, primarily attributed to reduced overall outages (both planned and unplanned) in Queensland and New South Wales compared to Q4 2022 levels (Section 1.3.1). In New South Wales, despite a clustering of forced outages in November, overall outages were 714 MW lower during the quarter. Reduced outages in Queensland (330 MW lower) also played a role in the overall decline of quarterly price across the NEM. Brown coal availability in Victoria increased by 79 MW this quarter.
Growing VRE output	In Q4 2023, grid-scale VRE output increased by 636 MW (+14%) to an all-time high of 5,168 MW (Section 1.3.4). Both grid-solar and wind saw significant year-on-year increases driven by new facilities and those progressing through their commissioning processes. Average distributed PV output also increased by 505 MW (17%) year-on-year to a record high of 3,433 MW (Section 1.1.2), contributing to lower operational demand in morning and early afternoon hours. Increased grid-solar and distributed PV drove daytime declines in coal and hydro output. Grid-scale solar set prices in 10% of the intervals this quarter (up 4 pp on previous Q4), at an average of -$35/MWh across the NEM, $7/MWh lower than in Q4 2022.
Record negative price occurrence during daytime hours	In this quarter, 20% of dispatch intervals were marked by negative or zero prices (Section 1.2.3). All NEM mainland regions, except South Australia, experienced more frequent negative price occurrences, primarily concentrated in daylight hours. October witnessed a substantial drop in operational demand across all regions, leading to over 100% year-on-year growth in monthly negative price occurrences. These increases were accompanied by a 10% increase in negative price impact, averaging $8.8/MWh in Q4 2023, exerting downward pressure on average spot price.

Lower operational demand in Victoria and South Australia	In contrast with strong growth in operational demand in Queensland and New South Wales, South Australia and Victoria witnessed all-time lows in average operational demands (Section 1.1.2). This led to a substantial increase in negative price occurrences between 1000 hrs and 1400 hrs, reaching 78% in South Australia and 73% in Victoria, ultimately contributing to significant reductions in regional prices.
Price separation between northern and southern regions	This quarter saw a notable price separation between New South Wales and Victoria during daytime hours (Figure 11). While net northward energy flows over VNI remained largely unchanged from last Q4, constraints affecting VNI reduced its export limit (when binding) to near zero and at times negative, during daytime hours (Section 1.4, Figure 60). During the quarter, VNI reached its constrained export limit in 44% of dispatch intervals, causing greater daytime price separation.

As illustrated in Figure 12, Q4 2023 saw an increase in black coal-fired generation volumes offered to the spot market at price levels between $50/MWh and $200/MWh. Despite the closure of Liddell in late April 2023, an additional 1,382 MW was offered below $100/MWh. Government policies capping domestic thermal coal prices and improved coal supply conditions collectively contributed to an overall decrease in marginal cost of coal-fired generators, resulting in more volume offered to the market at lower price ranges.

Figure 12 Increased volumes of black coal-fired generation offered between $50/MWh and $200/MWh

Black coal generation bid supply curve – Q4 2023 vs Q4 2022



1.2.2 Wholesale electricity price volatility

In Q4 2023, the cap return – which represents the contribution of spot prices in excess of $300/MWh to the quarterly average (aggregated across all five NEM regions) – decreased to $19/MWh from the previous Q4's $31/MWh (Figure 13). Notably, **Tasmania's** cap return dropped from $15/MWh to $0/MWh this quarter. Q4 2022 witnessed a number of price spike events in Tasmania caused by several line outages that led to regional separation. On the mainland, **Queensland** and **New South Wales** saw increases in cap returns of $4/MWh and $1/MWh, reaching $8/MWh and $4/MWh respectively. **South Australia's** cap return component decreased by $2/MWh to $7/MWh this quarter, while **Victoria** remained unchanged with minimal cap returns this and last Q4.

The overall number of intervals with spot price above $300/MWh fell from 1,328 in Q4 2022 to 731 this quarter. This represented 0.6% of total intervals in the quarter compared to 1.0% in the previous Q4. **Queensland** led this drop with 378 intervals yielding prices above $300/MWh, compared to 657 in Q4 2022, however its cap return component increased because this quarter's spot prices were significantly higher when above $300/MWh. **New South Wales** was the only region which saw a year-on-year increase in the number of intervals above $300/MWh with 182 intervals this quarter, 32 more than in Q4 2022.

Figure 13 Lower Q4 cap returns driven by falls in Tasmania and South Australia

Cap returns by region - quarterly

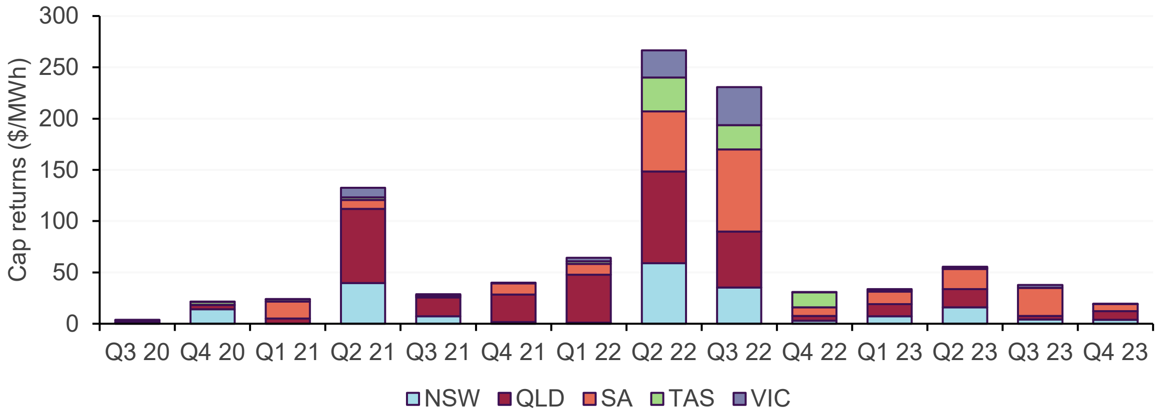


Table 2 summarises events of significant spot price volatility during Q4 2023.

Table 2 Significant volatility events in Q4 2023

Date	Region	Contribution to quarterly cap return ($/MWh)	Drivers
28-29 December	Queensland	3.62 (29 December 2023) 1.53 (28 December 2023)	Queensland experienced several price spikes during the evening peak period of these days, with six intervals above $13,000/MWh between 1655 hrs and 2035 hrs on 29 December and seven intervals above $1,000/MWh between 1755 hrs and 2005 hrs on 28 December. In these periods, grid-solar generation was gradually decreasing while operational demand remained mostly above 9,500 MW. Queensland – New South Wales Interconnector (QNI) flow into Queensland reached constrained limits, causing price separation between Queensland and New South Wales.
8 December	South Australia	3.32	Severe weather in South Australia led to a reclassification of non-credible contingency risks as credible, affecting the Heywood Interconnector and several other transmission lines. This led to sharply reduced import limits on the interconnector between 1055 hrs and 1400 hrs, initially from levels above 500 MW to 225 MW, then subsequently to between -50 MW (forced flow to Victoria) and 138 MW. Operational demand in South Australia was around 1,800 MW with 1,500 MW of grid-scale VRE availability. In the 11 dispatch intervals ending between 1055 hrs and 1145 hrs, South Australia experienced six instances of prices above $12,000/MWh with a maximum of $16,491/MWh. Weather-driven variations in distributed PV output during this period led to rapidly changing operational demand which also contributed to volatility.
	New South Wales	0.94	On the same day, constraints on flows related to line outages around the Snowy Mountains area's hydro generators led to two price spikes above $10,000/MWh in New South Wales.
9 November	South Australia	2.27	South Australia witnessed three intervals at the market price cap (MPC) of $16,600/MWh between 1845 hrs and 1855 hrs. Evening peak period operational demand above 1,600 MW and reduced solar generation coincided with Heywood flows being constrained below 50 MW due to a planned transmission outage, causing a price separation between Victoria and South Australia, resulting in a price spike.

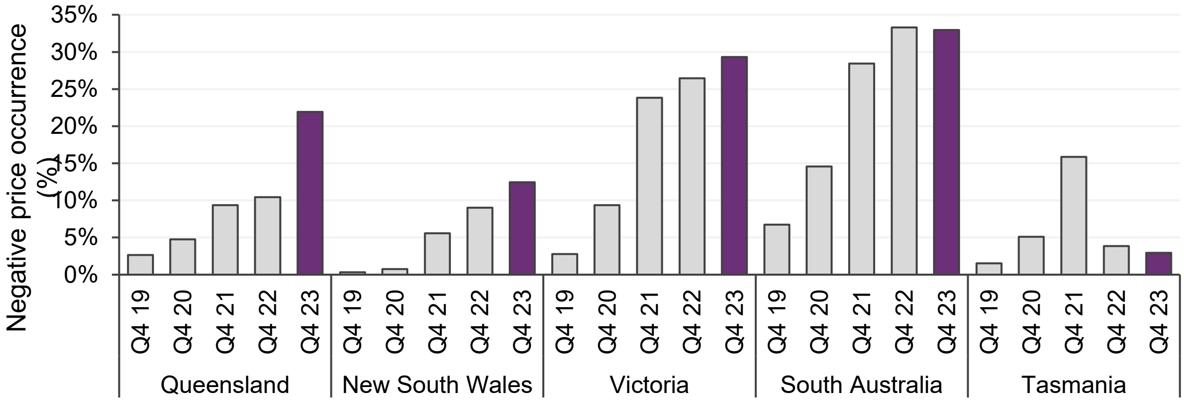
1.2.3 Negative wholesale electricity prices

In Q4, 20% of dispatch intervals across the NEM recorded negative or zero prices (jointly referred as “negative price occurrence”), marking a 3.3 pp increase compared to the same period last year and a new high for any quarter. All NEM mainland regions, except South Australia, experienced more frequent negative price occurrence, with October witnessing a substantial drop in operational demand across all regions, leading to over 100% year-on-year growth in monthly negative price occurrences.

New South Wales and **Victoria** reached their highest ever negative price occurrences at 12% and 29% respectively (Figure 14). **Queensland** recorded its second highest negative price occurrence at 22% and witnessed the largest increase in negative price occurrence this Q4 with a year-on-year jump of 11 pp. **South Australia** experienced 33% negative price occurrence, almost matching its record set in Q4 last year. **Tasmania** experienced a drop in negative price occurrence, to 3% of intervals this Q4 from Q4 2022’s 4%.

Figure 14 High Q4 negative price occurrence in all NEM mainland regions, except South Australia

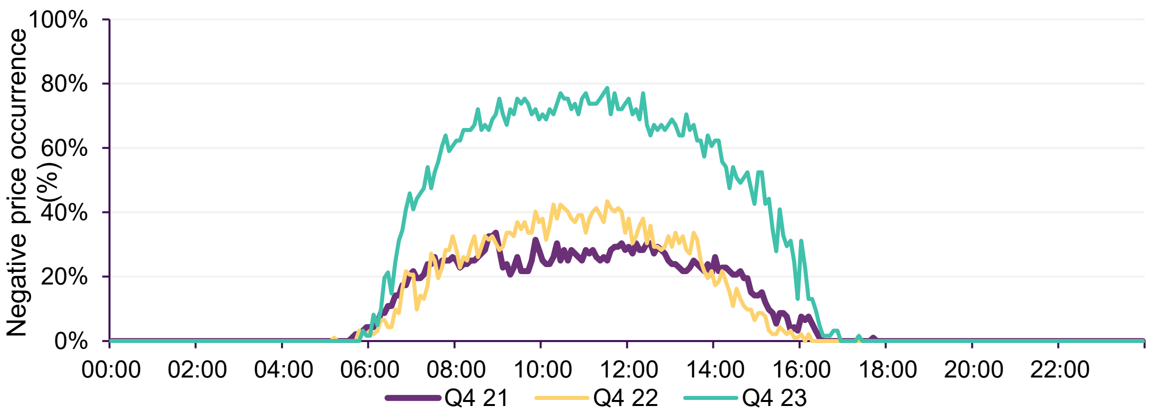
Negative price occurrence in NEM regions – Q4s



Negative price occurrence continued to be concentrated during daylight hours, reflecting higher grid-scale solar supply and reduced daytime operational demand due to the increasing output of distributed PV. Between 1000 hrs and 1400 hrs, negative prices occurred 78% and 73% of the time in **South Australia** and **Victoria**, increasing by 5 pp and 7 pp respectively from Q4 2022. **Queensland**’s negative price occurrence between 1000 hrs and 1400 hrs increased by 28 pp to 62% this quarter despite increased operational demand (Figure 15).

Figure 15 Record negative price occurrence in Queensland

Queensland’s negative price occurence by time of day – Q4s



Increases in negative price occurrence were accompanied by a 10% increase in negative price impact[6], reaching $8.8/MWh this quarter. All mainland regions except South Australia saw increased negative price impact this quarter. Although the frequency of negative prices in **South Australia** remained largely unchanged compared to last Q4, negative price impact fell by $4/MWh (from $22.6/MWh to $18.3MWh), indicating a decline in the average magnitude of negative prices in the region.

NEM-wide negative prices averaged -$44.4/MWh in Q4 2023, $4.2/MWh up from the previous year's -$48.5/MWh. This was driven by a reduced proportion of negative prices falling into very low price ranges. During this quarter, only 11% of negative prices fell below -$60/MWh, compared to 27% in Q4 last year. Q4 2023 saw no instances of prices reaching the market floor of -$1,000/MWh, compared to 18 intervals in Q4 2022.

1.2.4 Price-setting dynamics

This quarter showed a notable rise in the proportion of spot prices set by grid-scale solar across the NEM, increasing by 4 pp. Batteries set prices in 4% of intervals, increasing by 1 pp across both load and generation combined. Additionally, the proportion of prices set by black coal increased by 2 pp to 30% this quarter. Despite a slight decrease of 1 pp, hydro generation set price in the highest share of intervals at 35%, due its role in setting Tasmanian prices. Gas-fired generation saw the largest year-on-year drop in Q4 price-setting frequency, decreasing by 3 pp to 5%. The price-setting frequency of wind also fell by 2 pp while brown coal declined 1 pp.

By region (Figure 16):

- **Queensland** experienced a substantial increase of 13 pp in the proportion of time that grid-solar set the spot price, reaching 21% compared to last Q4's 9%. While the price-setting frequency of batteries remained largely unchanged, other fuel types saw reductions in their price-setting frequencies. Despite a 1 pp reduction, black coal remained the most frequent price-setter in Queensland at 46%.
- **New South Wales** saw an increase in the proportion of spot prices set by black coal and grid-solar, each increasing by 3 pp from the previous Q4. As in Queensland, black coal remained the most frequent price setter in New South Wales with 49% of prices set.
- **Victoria** and **South Australia** experienced rises in price-setting frequency by black coal-fired generation, increasing 4 pp and 5 pp respectively to 24% and 22%. Batteries set prices 6% of the time in South Australia and 5% in Victoria (both load and generation combined), each increasing by 3 pp. This was offset by the lower proportion of time that hydro set prices in both regions, declining to 26% (-6 pp) in Victoria and 24% (-4 pp) in South Australia.
- In **Tasmania,** hydro set prices in 79% of the intervals this quarter, increasing by 9 pp from Q4 2022. Brown coal price-setting frequency reduced 5 pp to average 5% this quarter.

Between 1000 hrs and 1400 hrs, grid-scale solar set the **Queensland** spot price 62% of the time in Q4 2023 compared to 30% in Q4 2022 (Figure 17). During these hours, the price-setting frequency of black coal generation dropped this quarter by 18 pp to average 25%.

[6] Negative price impact measures the contribution of negative prices to lowering the average spot price – a negative price impact of $5/MWh means that with all negative prices replaced by values of $0/MWh, the average would have been $5/MWh higher than actually recorded.

Figure 16 Grid-scale solar set prices more frequently across the NEM

Price-setting frequency by fuel type – Q4 2023 vs Q4 2022

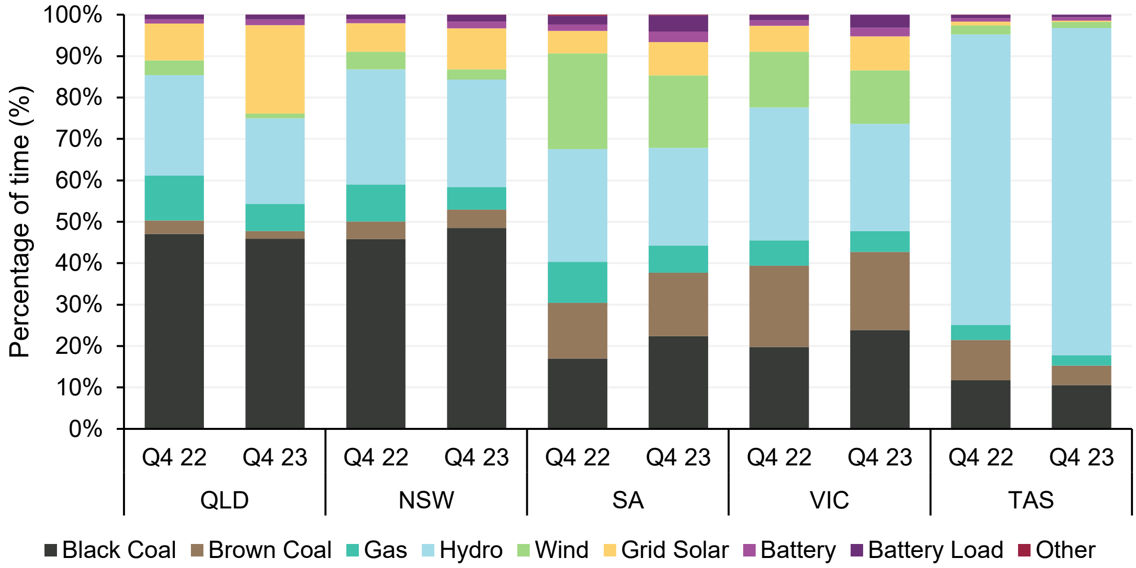
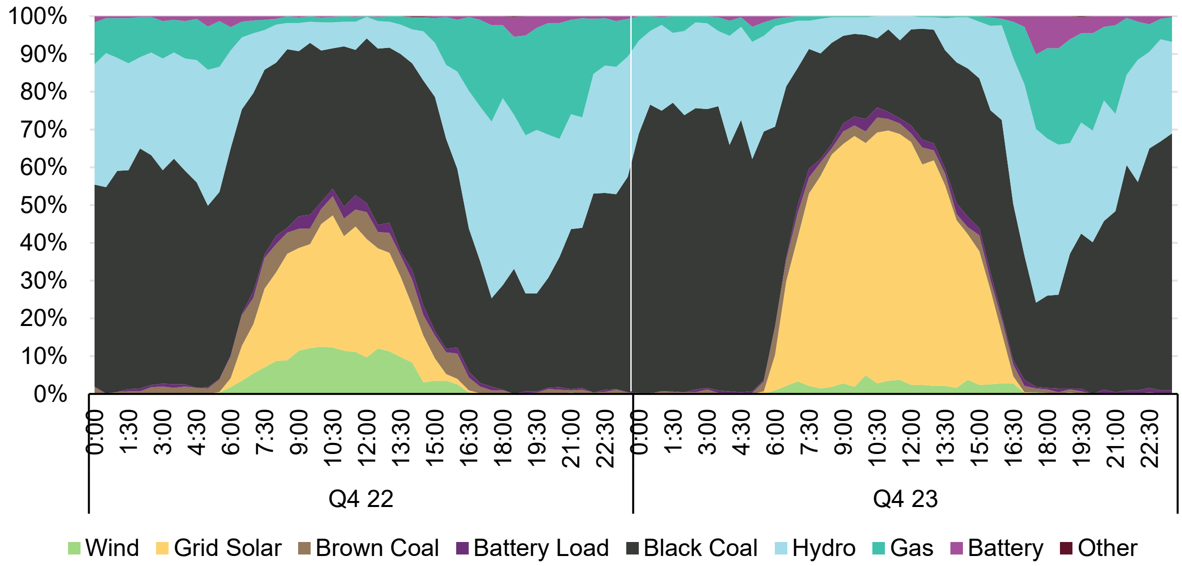


Figure 17 Grid-scale solar daytime price-setting frequency increased strongly in Queensland

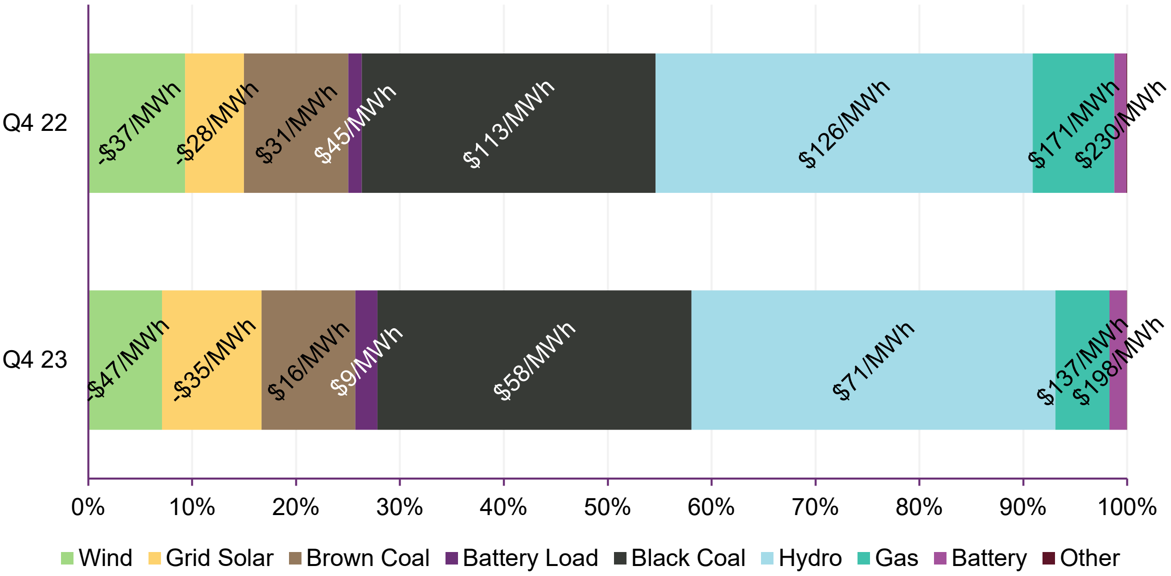
Queensland price-setting frequency by fuel type and time of day – Q4 2022 and Q4 2023



All fuel types witnessed declines in the average prices set across the NEM when they were the marginal supplier this quarter (Figure 18). The average price set by black coal when marginal decreased from $113/MWh in Q4 2022 to $58/MWh in Q4 2023, driven by increased offer volumes in lower price bands (Section 1.2.1), and a major contribution to lower spot prices given black coal's relatively high frequency as a price setter. Hydro followed with a $55/MWh drop in average spot price set when marginal, averaging $71/MWh this quarter. The average NEM-wide spot price set by brown coal-fired generation reduced by $15/MWh to $16/MWh, while for gas-fired generation, the decrease was $33/MWh to $137/MWh. The average spot price set by grid-scale solar dropped from -$28/MWh in Q4 2022 to -$35/MWh in Q4 2023, while wind reduced by $10/MWh to -$47/MWh.

Figure 18 Large decreases in average prices set by all major fuel types

NEM price-setting frequency and average price when price-setter by fuel type – Q4 2023 vs Q4 2022



1.2.5 Electricity futures markets

Electricity futures markets are centralised exchanges offering standardised 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 futures electricity pricing.

ASX forward base contract prices for the 2024-25 financial year (FY25) averaged $95/MWh across all mainland NEM regions over Q4 2023, marking a 6% decrease from the preceding quarter's average of $101/MWh and a 29% decrease from Q4 2022's average of $134/MWh.

New South Wales' average experienced the largest decline from Q3 2023, with a decrease of 8% to $111/MWh, while prices for **Queensland**, **Victoria** and **South Australia** averaged $95/MWh (-5%), $71/MWh (-4%) and $104/MWh (-6%) respectively.

During the quarter, FY25 prices in all regions generally followed a slow downward trend to close below end Q3 levels (Figure 19).

Prices for **New South Wales** and **South Australia** decreased significantly, closing below end Q3 levels at $101/MWh (-18%) and $96/MWh (-17%) respectively on 29 December 2023. **Queensland** and **Victorian** prices also ended Q4 below their Q3 closing levels at $92/MWh (-11%) and $69/MWh (-8%). Longer-term prices for FY26 and FY27 also closed the quarter at significantly lower levels for all mainland regions (Figure 20).

Figure 19 FY25 futures closed at lower levels to Q3 2023

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

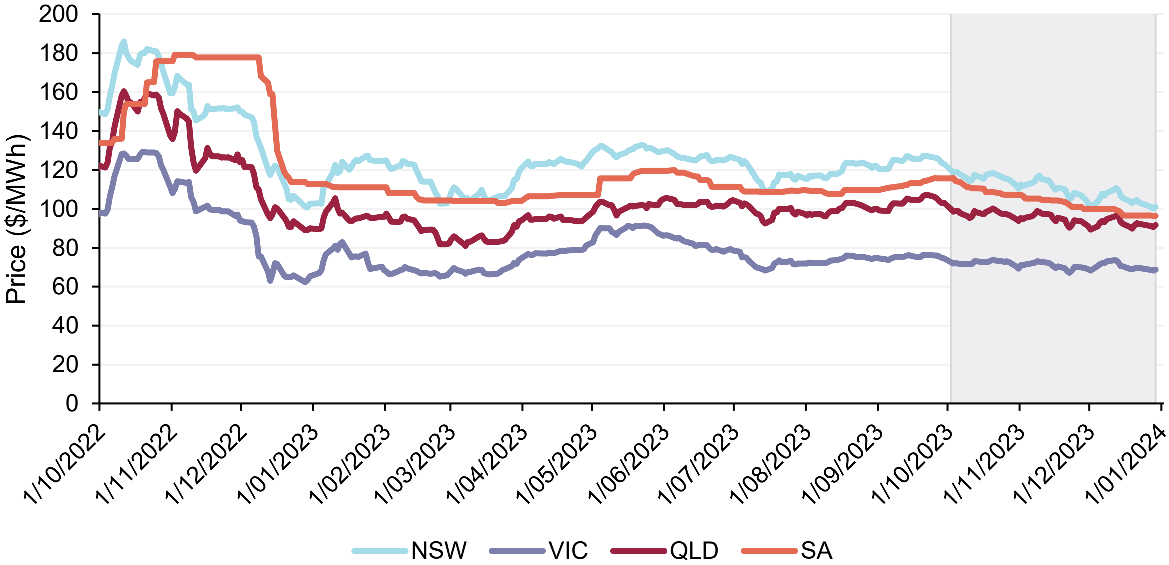


Figure 20 Future financial year contracts significantly lower in all regions

Financial year contract prices in mainland NEM regions – end of Q3 2023 vs end of Q4 2023

1.3 Electricity generation

During Q4 2023, total NEM generation[7] increased by an average of 806 MW, up 3.5% from 22,705 MW in Q4 2022 to 23,511 MW. This reflected the quarter's underlying demand increases discussed in Section 1.1.2.

Figure 21 shows changes in average NEM generation by fuel type compared to Q4 2022. In particular:

[7] Generation calculation is inclusive of AEMO's best estimates of generation from distributed PV. Generation also includes supply from certain non-scheduled generators and supply to large market scheduled loads (such as pumped hydro and batteries) which are excluded from the operational and underlying demand measures discussed in Section 1.1.2.

- Distributed PV, grid-scale solar, and wind output rose strongly with an aggregate increase of 1,141 MW. The increase in distributed PV represented 44% of the total uplift from solar and wind. Grid-scale solar and wind grew 377 MW and 259 MW respectively, driven by continued increases in installed capacity (mostly in **Queensland** and **New South Wales** – see Section 1.3.4).
- Black coal-fired generation output fell 29 MW compared to Q4 2022, while brown coal-fired generation in **Victoria** reduced by 63 MW. Output from peaking generation (gas and hydro) fell, reflecting significantly lower spot price levels and higher available output from lower-cost renewables. Gas-fired generation fell by 55 MW, mainly in **South Australia** and **Victoria**, while hydro output was down 219 MW driven by lower output in **Tasmania** and **Victoria**.
- With continued year-on-year increases in battery capacity, average generation from the NEM battery fleet increased 21 MW to reach 47 MW this quarter.

Figure 21 Solar, wind and battery output growth covered NEM demand increases while other sources reduced

Change in NEM supply by fuel type – Q4 2023 vs Q4 2022

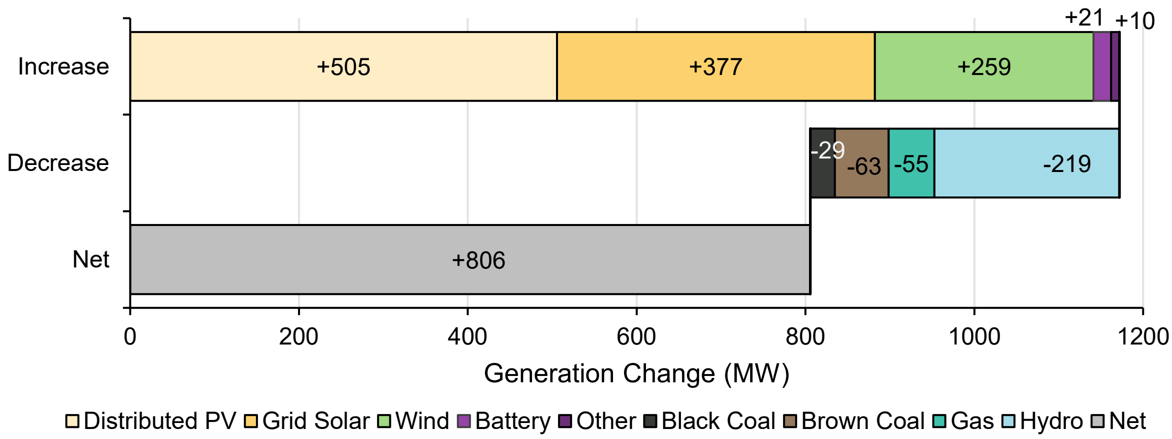


Table 3 summarises changes in the NEM generation mix by fuel type.

Table 3 NEM supply mix contribution by fuel type

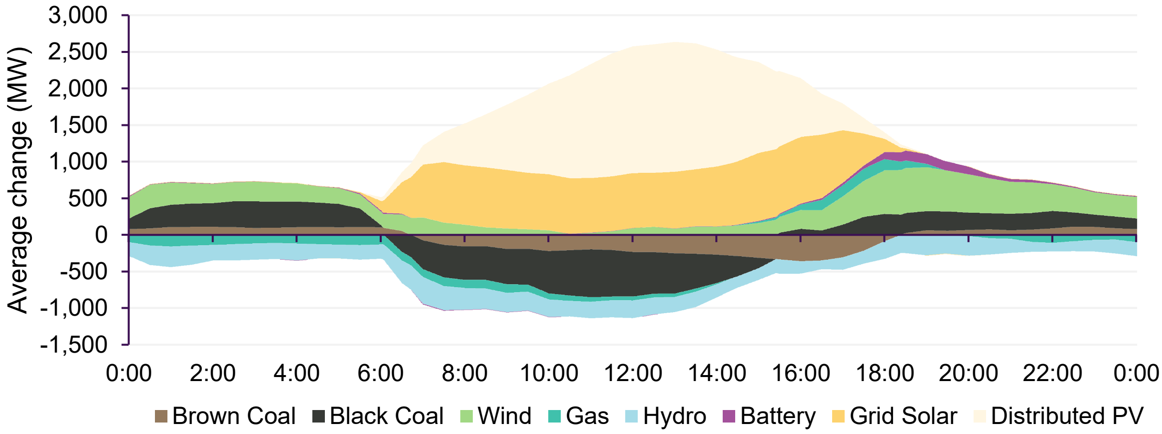
Quarter	Black coal	Brown coal	Gas	Wind	Grid solar	Distributed PV	Hydro	Battery	Other
Q4 2022	40.6%	14.8%	4.0%	12.7%	7.2%	12.9%	7.4%	0.1%	0.15%
Q4 2023	39.1%	14.1%	3.6%	13.4%	8.6%	14.6%	6.3%	0.2%	0.19%
Change	-1.5%	-0.8%	-0.4%	0.7%	1.4%	1.7%	-1.2%	0.1%	0.04%

Figure 22 shows changes in generation output from Q4 2022 to Q4 2023 by time of day and fuel type. Growing distributed PV and grid-scale solar drove daytime declines in coal-fired generation, gas, and hydro output. Changes outside daytime hours for these legacy sources varied, with coal-fired generation increasing in evening and overnight periods, gas-fired output down except for an increased contribution to early evening peaks, and hydro output lower in all hours.

Wind output increased at most times of day outside the peak solar period, with strongest growth in the evening and night-time hours. Batteries' growing contribution to meeting evening peaks is also evident this quarter between 1800 hrs and 2100 hrs (with an average generation of 174 MW during this period).

Figure 22 VRE output increased during the day, pushing down gas, coal, and hydro output

NEM generation changes by time of day – Q4 2023 vs Q4 2022



1.3.1 Coal-fired generation

Black coal-fired fleet

In Q4 2023, NEM black coal-fired generation recorded an all-time lowest average output of 9,189 MW, a 30 MW reduction (-0.3%) from Q4 2022's 9,219 MW (Figure 23). This was driven by low daytime prices and displacement by distributed PV and grid-scale solar, with black coal-fired generation decreasing within daylight hours and increasing outside daylight hours. While the closure of Liddell in April 2023 reduced coal-fired capacity in **New South Wales**, Liddell's lost output (averaging 705 MW in Q4 2022) was largely made up at other New South Wales units leading to a net output reduction of 116 MW in the region, further offset by an output increase of 86 MW at **Queensland** black coal-fired generators.

Black coal-fired availability in **New South Wales** reduced by 105 MW from 6,528 MW in Q4 2022 to 6,424 MW this Q4. This reduction was more than offset by a 387 MW availability increase in **Queensland** from 5,646 MW in Q4 2022 to 6,033 MW this quarter (Figure 24). Although **Queensland** saw higher unplanned outages during Q4 2023 (1,352 MW vs 943 MW in Q4 2022), overall outages reduced in Queensland and New South Wales relative to Q4 2022 levels (Figure 25).

Figure 23 NEM black coal-fired generation reduced to its all-time lowest record

Quarterly average black coal-fired generation by region (including decommissioned units) – Q4s

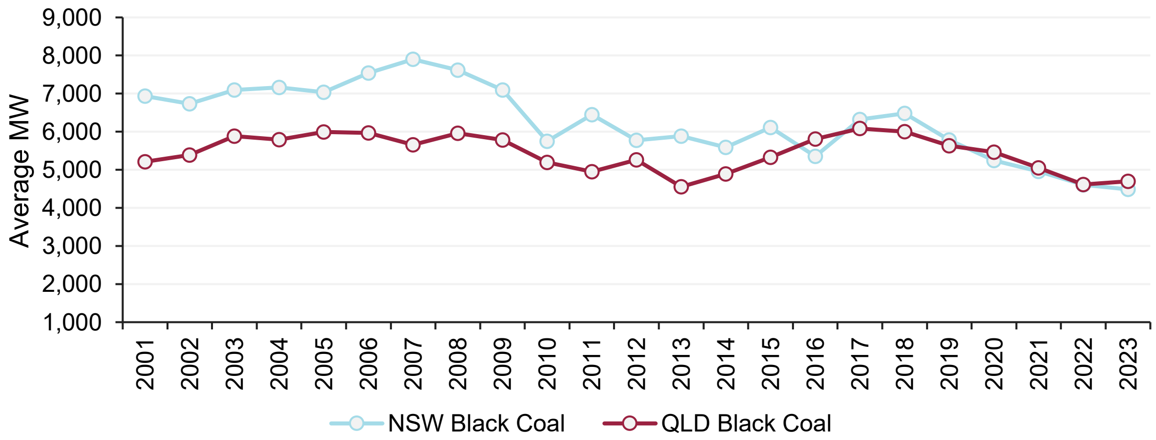


Figure 24 Higher coal-fired generation availability in Queensland

Quarterly average black coal-fired availability– Q4s

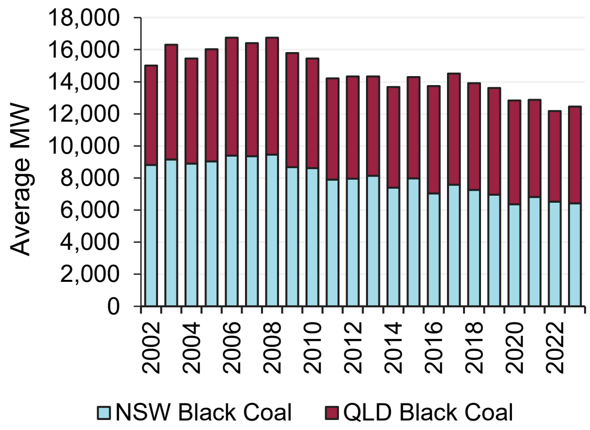


Figure 25 Coal-fired capacity on outage declined

Average coal-fired capacity on outages – Q4 2023 vs Q4 2022

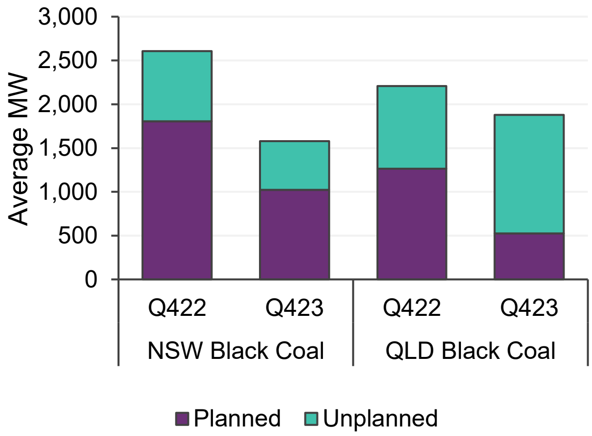
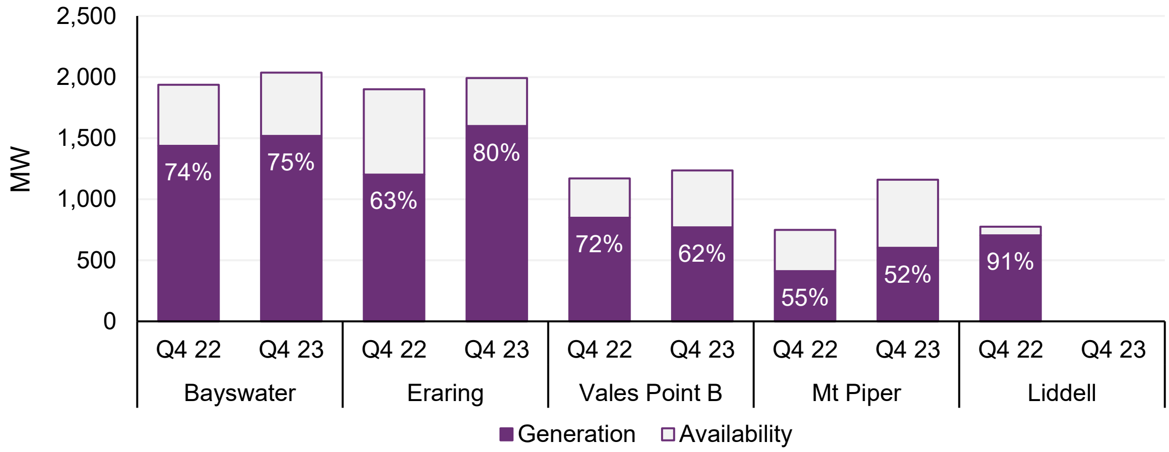


Figure 26 shows key changes in generation, availability, and utilisation rate for each black coal-fired power station in **New South Wales**.

Figure 26 Bayswater, Eraring, and Mount Piper increased output in the absence of Liddell

Average quarterly availability, generation and utilisation for New South Wales black coal-fired power stations – Q4 2023 vs Q4 2022



In particular:

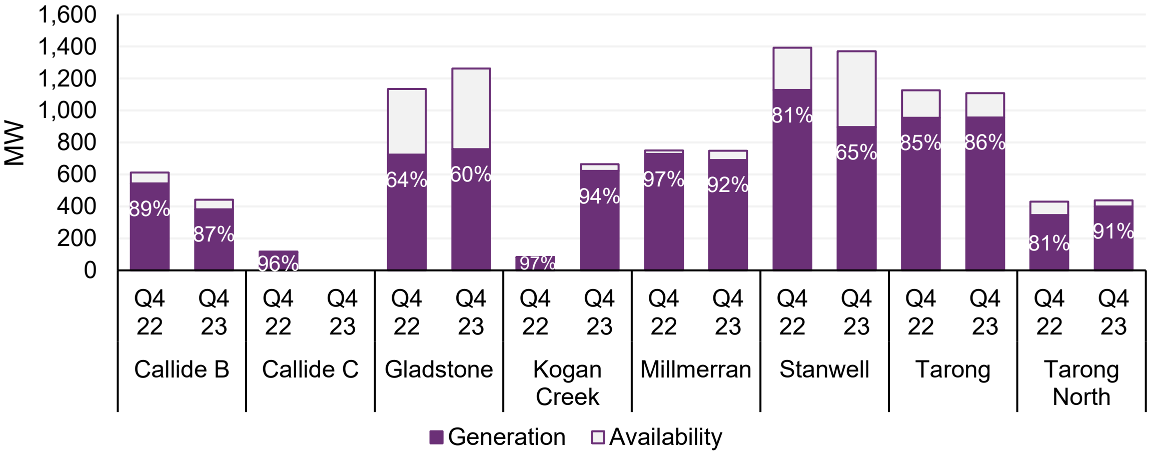
- Bayswater saw a slight increase in average generation from 1,437 MW in Q4 2022 to 1,518 MW this quarter. The utilisation of Bayswater (average generation as a proportion of availability during the quarter) increased by 0.3 pp from its Q4 2022 level of 74%.
- Despite only a slight increase in average availability (+91 MW), Eraring's average generation increased sharply from 1,202 MW in Q4 2022 to 1,598 MW during Q4 2023, representing a 17 pp increase in utilisation rate. The station's average output in all hours of the day increased.
- Vales Point experienced fewer outages (-34 MW) and accordingly higher availability (+68 MW) relative to Q4 2022. However, its generation reduced by 77 MW, leading to a 10 pp reduction in its utilisation rate.

- Availability at Mount Piper increased strongly to 1,160 MW this quarter from 747 MW in Q4 2022, when both its units experienced significant outages. Average output increased from 411 MW a year ago to 601 MW this Q4, representing a 3pp decline in utilisation.
- Liddell's Q4 2022 quarterly average generation of 705 MW fell to zero, with the decommissioning of the station's remaining three units on April 24, 26 and 28 2023.

Figure 27 shows the same statistics for each black coal-fired power station in **Queensland**.

Figure 27 Higher output from Kogan Creek offsets reductions at Stanwell and Callide stations

Average quarterly availability, generation and utilisation for Queensland black coal-fired power stations – Q4 2023 vs Q4 2022



In particular:

- Callide B saw reductions of 162 MW in generation and 172 MW in availability, yielding a 2 pp reduction in utilisation.
- With commencement of unit C3's long term forced outage in October 2022, Callide C produced no output this Q4 compared to an average of 114 MW in Q4 2022. CS Energy has advised the market of revised return-to-service dates for both Callide C units. Unit C3's full return has been delayed until 31 March 2024, with 50% capacity to return from 29 February 2024. Return date for the rebuilt C4 unit's full capacity has been revised to 31 July 2024, with 50% capacity expected from 30 June 2024[8].
- Kogan Creek was on a major outage for most of Q4 2022 with average availability of only 84 MW, increasing to 663 MW this Q4 with minimal outages. Its quarterly average output grew similarly, from 81 MW to 621 MW.
- Average generation at Stanwell dropped from 1,128 MW in Q4 2022 to 896 MW this Q4, despite only a small reduction in availability (-22 MW). Consequently, its utilisation fell 16 pp to 65%.
- Other coal-fired power stations in Queensland saw relatively small changes in availability and generation.

With increasing uptake of VRE in the NEM, black coal-fired output continued to decline during the middle of the day in both New South Wales and Queensland (Figure 28 and Figure 29). Outside these hours, however, Q4 2023 saw net increases in output, particularly in Queensland, driven by higher operational demand and increases in black coal-fired volumes offered at lower prices.

[8] See https://www.csenergy.com.au/news/update-on-progress-in-returning-callide-c-power-station-to-service.

Figure 28 Daytime black coal-fired generation continued to decline in New South Wales

New South Wales black coal-fired output by time of day – Q4s

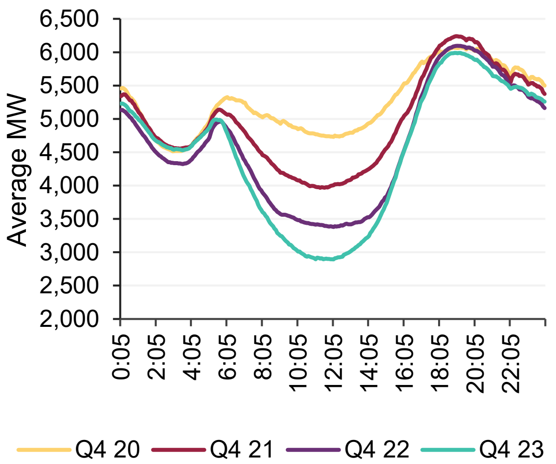
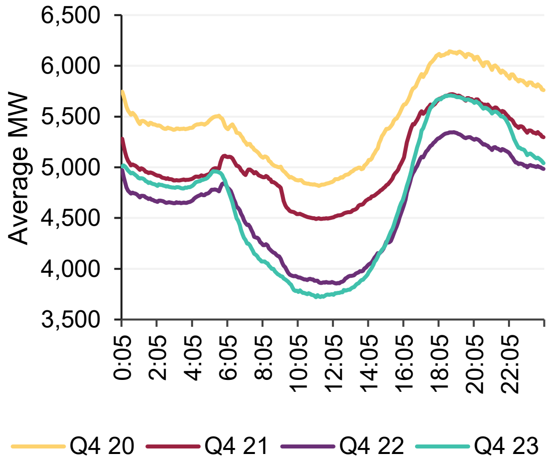


Figure 29 Queensland black coal-fired generation higher in peak and overnight periods

Queensland black coal-fired output by time of day – Q4s



The intraday difference between minimum and maximum average output from the black coal-fired fleet increased by 880 MW from 4,197 MW in Q4 2022 to 5,076 MW in Q4 2023. By individual station, Eraring with 1,020 MW, Bayswater with 993 MW, Vales Point B with 594 MW, Gladstone with 570 MW, and Mt Piper with 532 MW accounted for the largest intraday swings during Q4 2023.

Brown coal-fired fleet

During Q4 2023, brown coal-fired average generation reduced marginally to 3,306 MW, from 3,370 MW in Q4 2022. Average availability rose 79 MW (2%) from 3,807 MW in Q4 2022 to 3,886 MW in Q4 2023 (Figure 30). This was mainly driven by the noticeable reduction in outages at Loy Yang A (-145 MW).

Brown coal-fired generation output in **Victoria** continued to reduce during daytime hours. However, unlike Q4 2022, Q4 2023 saw a year-on-year increase in evening and overnight generation (Figure 31). This resulted in a 34% increase in intraday swing from 937 MW in Q4 2022 to 1,251 MW in Q4 2023 (+315 MW). All brown coal-fired generators in Victoria contributed to this higher intraday swing, with the largest individual increase by Loy Yang A at 221 MW from 438 MW to 659 MW year-on-year (Figure 31).

Figure 30 Increase in brown coal availability but ongoing reductions in output

Quarterly average generation and availability – Q4s

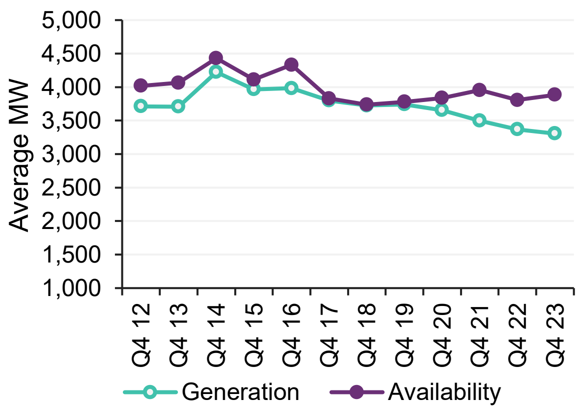
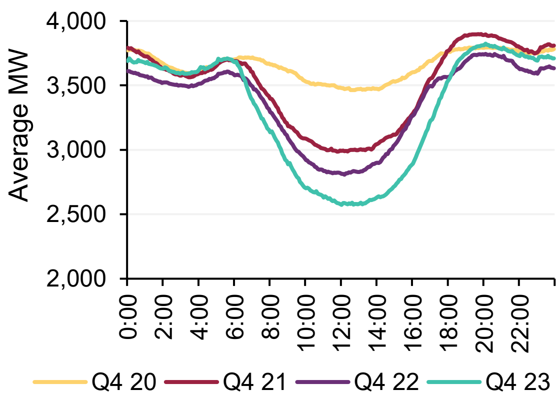


Figure 31 Increasing swing in brown coal-fired generation output

Brown coal-fired output by time of day – Q4s



As shown in Table 4, average availability and generation both increased at Loy Yang A, while both fell at Loy Yang B. There was a reduction of 4 pp in utilisation rate for Loy Yang A while Loy Yang B almost maintained the same utilisation rate year-on-year. Yallourn W saw a slight reduction in availability and generation, resulting in a 4 pp reduction in utilisation rate.

Table 4 Brown coal availability, output, utilisation, outage, and intraday swing by generator – Q4 2023 vs Q4 2022

Generator	Availability (MW)		Output (MW)		Utilisation		Outage (MW)		Intraday swing (MW)	
	Q422	Q423	Q422	Q423	Q422	Q423	Q422	Q423	Q422	Q423
Loy Yang A	1733	1872	1519	1557	88%	83%	457	312	438	659
Loy Yang B	1154	1116	968	927	84%	83%	1	35	394	421
Yallourn W	920	898	883	821	96%	91%	508	544	119	173

1.3.2 Gas-fired generation

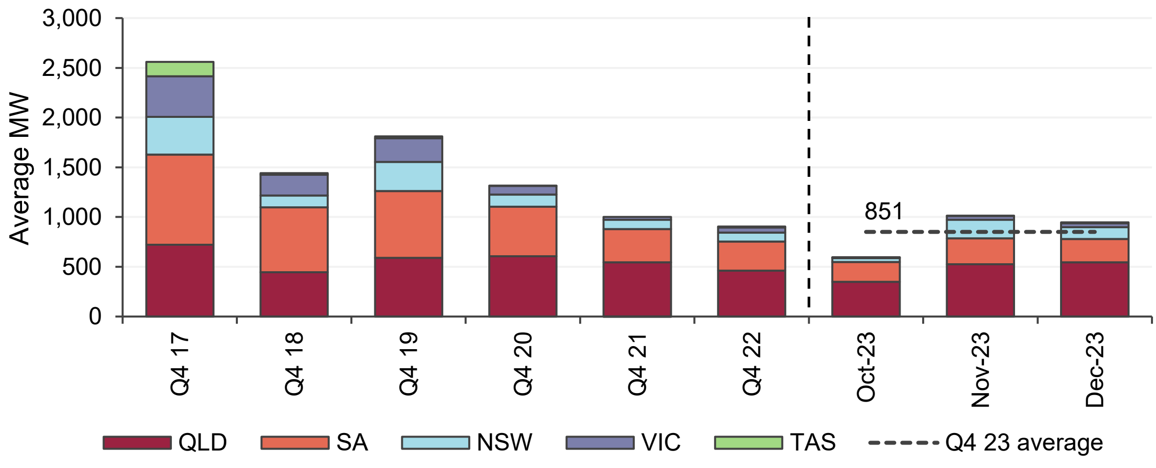
During Q4 2023, gas-fired generation across the NEM averaged 851 MW, a 6% drop from Q4 2022's 905 MW (Figure 32). This was the lowest average level for NEM gas-fired generation in any quarter since 2000.

The reduction was mainly driven by lower average wholesale electricity prices and fewer instances of price volatility this quarter than in Q4 2022. Output fell at both mid-merit and peaking stations (Figure 33). However, gas still saw an increase in output during the afternoon and early evening peak (see Figure 22).

Output was particularly low in October, averaging 598 MW, reflecting the month's low average spot price of $30/MWh. In contrast, higher prices in November ($60/MWh), increased operational demand and coincident outages at New South Wales coal-fired generators saw gas-fired generation increase to average 1,013 MW.

Figure 32 Gas-fired generation reached its lowest quarterly level since 2000

Average gas-fired generation by region – Q4s



Q4 2023 saw gas generators offering lower volumes in their bids at most price levels, relative to Q4 2022 (Figure 34). However slightly more volume was offered at prices below $150/MWh. This reflects some generators responding to lower spot electricity prices by lowering their own offer prices in order to be dispatched.

Figure 33 Both mid-merit and peaking plant output declined

Average gas-fired generation: mid-merit and peaking – Q4s

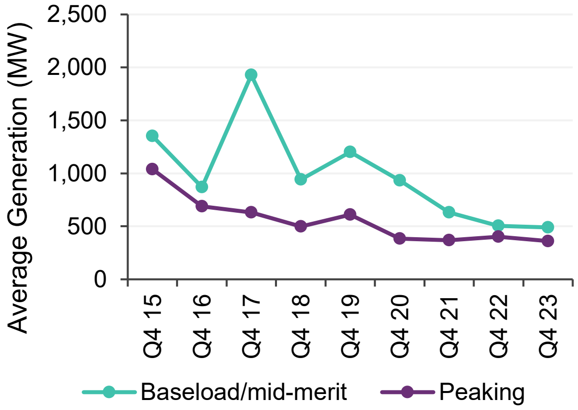
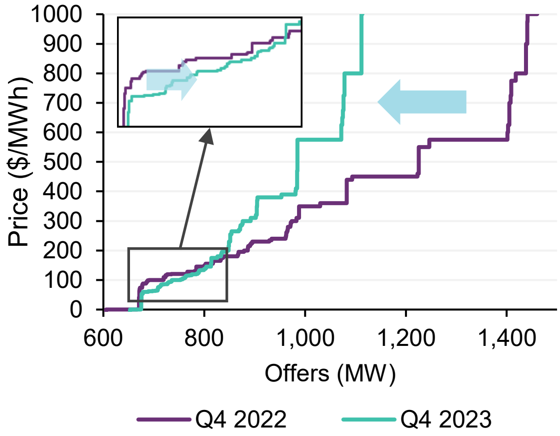


Figure 34 Lower gas offer volumes at prices higher than $150/MWh

Gas-fired generation bid supply curve – Q4 2023 vs Q4 2022



By region, changes in average quarterly gas-fired generation compared to Q4 2022 were:

- **New South Wales** saw a 22 MW output lift from 90 MW in Q4 2022 to 113 MW this quarter, a 25% increase. While Tallawarra A reduced output by 29 MW, Uranquinty saw an increase of 40 MW for the quarter. The region also saw the commissioning of Shoalhaven Starch's 54 MW gas-fired cogeneration facility (with an 8 MW contribution to Q4's quarterly average) and first test firing of EnergyAustralia's 320 MW Tallawarra B (zero generation for Q4).
- **Queensland** had a minor increase of 11 MW from 462 MW in Q4 2022 to 473 MW in Q4 2023. The largest change was at Darling Downs with 128 MW increase year-on-year, offsetting reductions at Braemar 2 (-47 MW) and Swanbank E (-61 MW).
- Gas-fired generation in **South Australia** fell to a new all-time low, averaging 231 MW, a 21% reduction from last Q4 at 293 MW. Torrens Island saw the largest drop of 34 MW year-on-year, from 84 MW to 50 MW.
- **Victorian** gas-fired generation fell 22 MW from 51 MW in Q4 2022 to average 29 MW this quarter. Newport's 19 MW reduction in output accounted for most of this fall.

1.3.3 Hydro

In Q4 2023, quarterly average NEM hydro generation[9] fell 219 MW (-13%) to 1,472 MW, down from 1,691 MW in Q4 2022 (Figure 35). Generation fell in **Tasmania** (-135 MW), **Victoria** (-110 MW), and **New South Wales** (-34 MW). Despite the outage of Barron Gorge Hydro Station in late December (due to major flooding) **Queensland** saw an increase of 54 MW relative to Q4 2022 levels with this increase occurring in non-daylight hours (Figure 36). As with gas-fired generation, the reduction in hydro output elsewhere occurred at almost all times of the day, reflecting similar economic drivers for the two forms of generation.

This quarter's lower spot prices saw hydro generators repricing their marginal bids downwards between $50/MWh and $200/MWh to ensure sufficient dispatch to manage water levels and release obligations (Figure 37).

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

Figure 35 Hydro generation dropped in all regions except Queensland

Average hydro output by region – Q4s

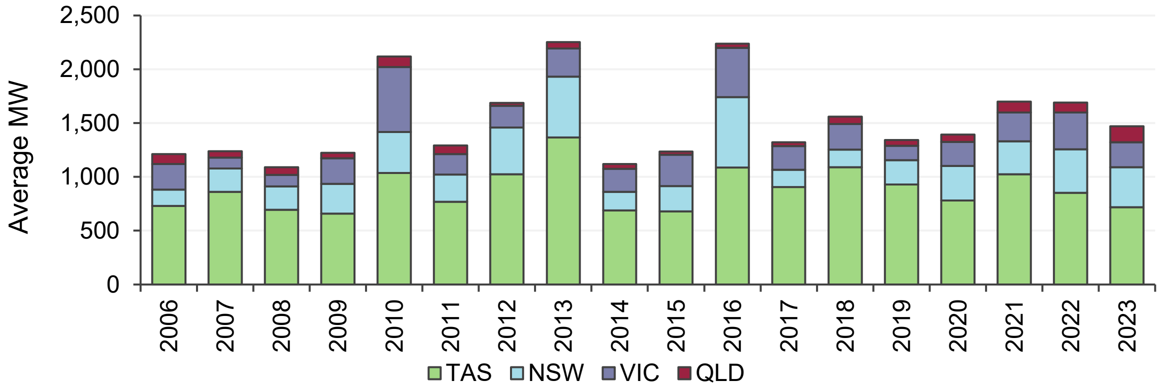


Figure 36 Significant increase in Queensland hydro outside daylight hours

Queensland's hydro output by time of day – Q4 2023 vs Q4 2022

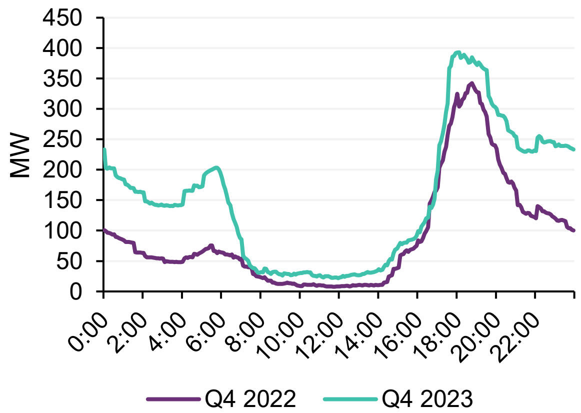
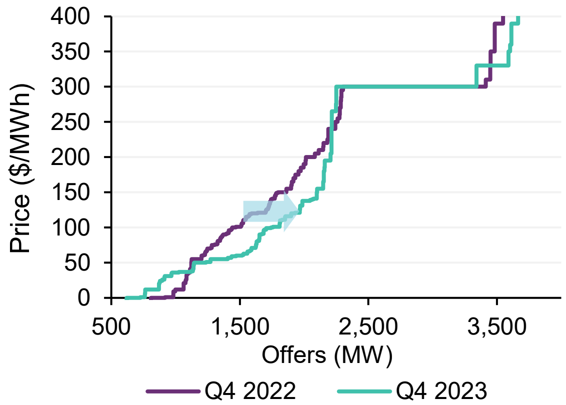


Figure 37 Hydro offer volumes increased at prices between $50-200/MWh

Hydro generation bid supply curve – Q4 2023 vs Q4 2022



Tasmania saw the biggest drop in quarterly average output from 852 MW in Q4 2022 to 717 MW in Q4 2023, a reduction of 135 MW (-16%). The majority of this reduction was from Gordon with a 56 MW reduction. Poatina saw a significant increase of 95 MW (from 95 MW in Q4 2022 to 190 MW in Q4 2023), partially offsetting drops at other hydro generators in Tasmania.

Victorian hydro saw a reduction of 110 MW in quarterly average generation from 342 MW in Q4 2022 to 232 MW in Q4 2023, with the biggest drops at Murray (-52 MW) and Eildon (-40 MW).

Queensland had an increase of 59 MW in quarterly average hydro generation, driven by the region's increased operational demand and higher evening peak prices than in other regions. The increase was mainly contributed by Kareeya (+43 MW) and Wivenhoe (+20 MW).

1.3.4 Wind and grid-scale solar

Grid-scale VRE average output reached an all-time quarterly record in Q4 2023 of 5,168 MW, an increase of 14% (636 MW) from 4,532 MW in Q4 2022 (Figure 38). Almost 60% of this increase arose from grid-scale solar, which saw an uplift of 377 MW from its Q4 2022 level of 1,644 MW to 2,021 MW during Q4 2023, an all-time record for grid-scale solar quarterly average output in the NEM. Average wind output increased 9% from 2,888 MW in Q4 2022 to 3,147 MW this year, a new high for any Q4.

Almost all the increase in grid-scale solar was in **New South Wales** and **Queensland**, with increases of 204 MW (+29%) and 163 MW (+26%) from Q4 2022 levels respectively (Figure 39). **Victoria's** wind output grew by 149 MW, reaching 1,233 MW in Q4 2023. **South Australia** and **Tasmania** saw only small changes in VRE outputs.

Figure 38 Steady VRE growth continued

Average quarterly VRE generation by energy source – Q4s

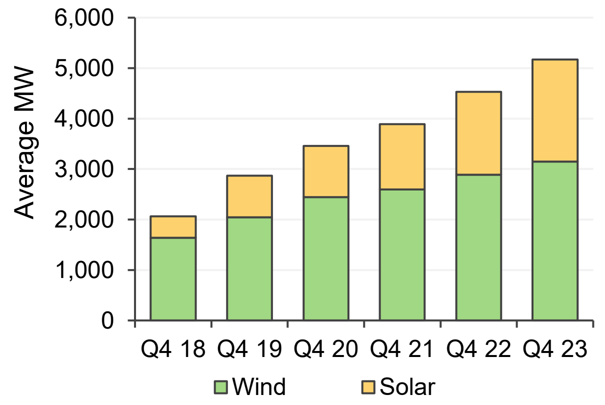
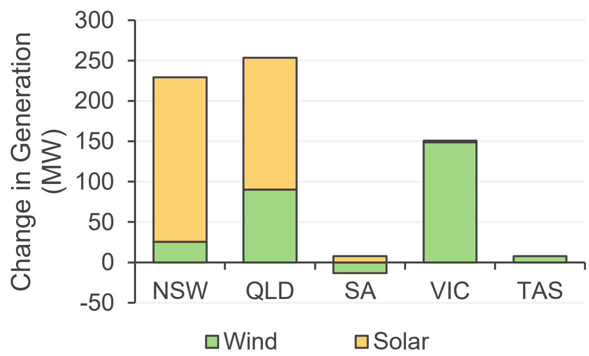


Figure 39 VRE increases led by solar in Queensland and New South Wales, wind in Victoria

Average MW change in output Q4 2023 vs Q4 2022



Increases in VRE output in Q4 2023 were driven by new facilities first connected after Q4 2022, and those progressing through their commissioning processes, which can extend over 12 months or longer. Figure 40 and Figure 41 show the compositions of changes in generation output from each VRE type.

As seen in Figure 40, new and commissioning grid-scale solar capacity respectively accounted for 299 MW and 217 MW increases in availability, while availability at existing facilities increased by 88 MW. These increases were partially offset by higher levels of curtailment by network constraints and economic offloading due to low spot prices, which together reduced by 227 MW the growth in available output that was actually delivered to the NEM, with offloading the dominant factor.

Wind generation was less curtailed in Q4 2023, potentially increasing by 44 MW the available output able to be delivered, but like grid-solar saw more offloading due to low spot prices. The net 259 MW increase in wind output essentially matched increases in available energy from new, commissioning and existing capacity (Figure 41).

Figure 40 Growth in grid-solar energy partially offset by higher curtailment and economic offloading

Changes in grid-scale solar generation – Q4 2023 vs Q4 2022

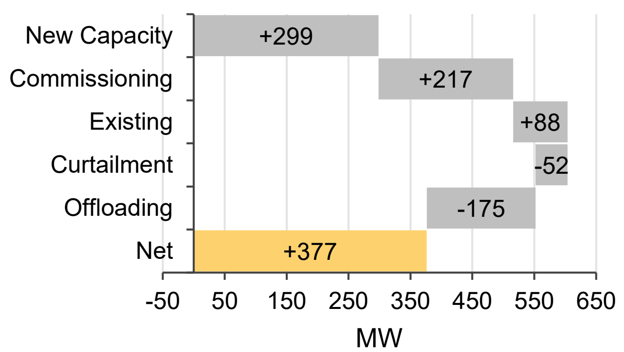
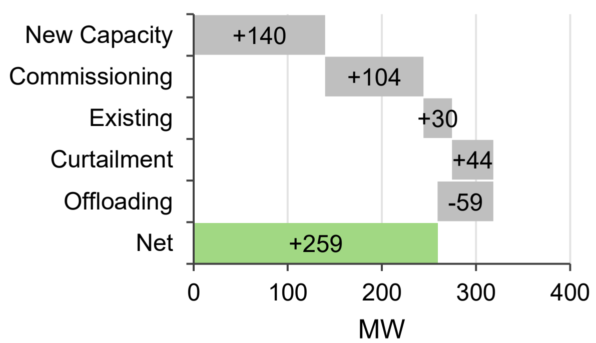


Figure 41 Wind output increases driven by new and commissioning capacity

Changes in wind generation – Q4 2023 vs Q4 2022



New and commissioning capacity

Relative to Q4 2022, this quarter saw increased available VRE from new and commissioning facilities, comprising average increases of 516 MW from grid-solar and 244 MW from wind. New VRE facilities connected since Q4 2022 provided the larger share of this increase (438 MW), with the balance from units which continued commissioning over the year (321 MW).

In particular:

- New and commissioning wind facilities in **Queensland** increased available generation by 111 MW. The newly connected Dulacca Wind Farm in Darling Downs represented 68 MW of this increase, while the rest was due to commissioning increases at Kaban Green Power Hub (42 MW). The region saw a 249 MW increase in available grid-scale solar generation, with contributions from newly connected Edenvale Solar Park (+54 MW) and Wandoan Solar Farm 1 (+32 MW), while commissioning at Western Downs Solar Farm added 75 MW.
- **New South Wales** added 236 MW availability from new and commissioning grid-scale solar. The largest contributions were from newly connected facilities, including the two New England solar farms (each adding a quarterly average of 65 MW), Avonlie Solar Farm with 59 MW, and Wyalong Solar Farm with 13 MW. Commissioning at West Wyalong Solar Farm added 28 MW. The region also saw an increase of 52 MW in available wind generation from new and commissioning farms, with newly connected Rye Park Wind Farm (384 MW maximum capacity when fully commissioned later in 2024) adding 38 MW and commissioning at Bango Wind Farm adding 11 MW.
- **Victorian** grid-scale solar saw only 2 MW added, with recently connected Glenrowan Solar Farm first producing output towards the end of the quarter. The region, however, saw a 66 MW increase in available wind generation from new and commissioning capacity including Berrybank 2 (31 MW), and commissioning growth at Mortlake South (35 MW).
- **South Australia** saw minor growth from new (+9 MW) and commissioning (+36 MW) capacity, the largest contribution being 18 MW from the commissioning of Port Augusta Renewable Energy Park which is now operating at its full capacity.

Existing capacity

Existing (or established) capacity in this section refers to the wind and grid-scale solar facilities that were fully commissioned prior to Q4 2023[10]. During Q4 2023, total availability from existing VRE capacity slightly reduced for wind (-0.1 pp) but increased for grid-scale solar (+2.1 pp), relative to Q4 2022. Available output from established wind farms fell marginally in all regions except Victoria (Figure 42). **New South Wales** saw the largest reduction in quarterly volume-weighted available capacity factor[11] by -2.9 pp, followed by **Queensland** (-2.4 pp), **Tasmania** (-2.2 pp), and **South Australia** (-1.3 pp), while **Victoria** had an increase of 3.1 pp.

Higher solar irradiance in Q4 2023 yielded an increase in regional average available capacity factors for grid-scale solar facilities in all regions (Figure 43). **New South Wales** saw a quarterly volume-weighted availability capacity factor of 32.4%, 1.7 pp higher than Q4 2022. Victoria, Queensland, and South Australia, saw increases of 2.4 pp, 1.8 pp, and 1.3 pp during Q4 2023.

[10] Fully commissioned units do not show any ramping behaviour and have their maximum nameplate capacity in service. Note that Q4 2023 capacity factor calculations in Figures 42 and 43 may include farms that reached full commissioning between Q4 2022 and the start of Q4 2023. However, any such farms are included in the "Commissioning" category in Figures 40 and 41 because of their output growth between Q4 2022 and Q4 2023.

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

Figure 42 Marginal reduction in wind availability in all regions, except Victoria

Capacity-weighted regional wind available capacity factors[12] – Q4s

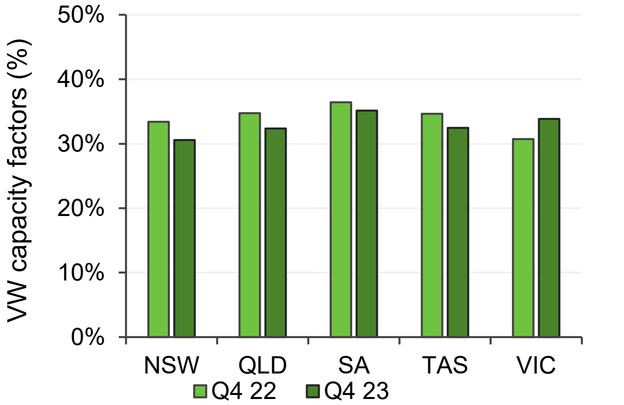
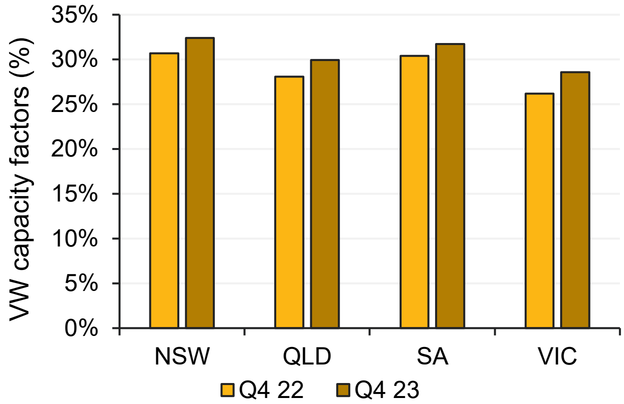


Figure 43 Grid-scale solar availability rose in all regions

Capacity-weighted grid-scale solar available capacity factors – Q4s

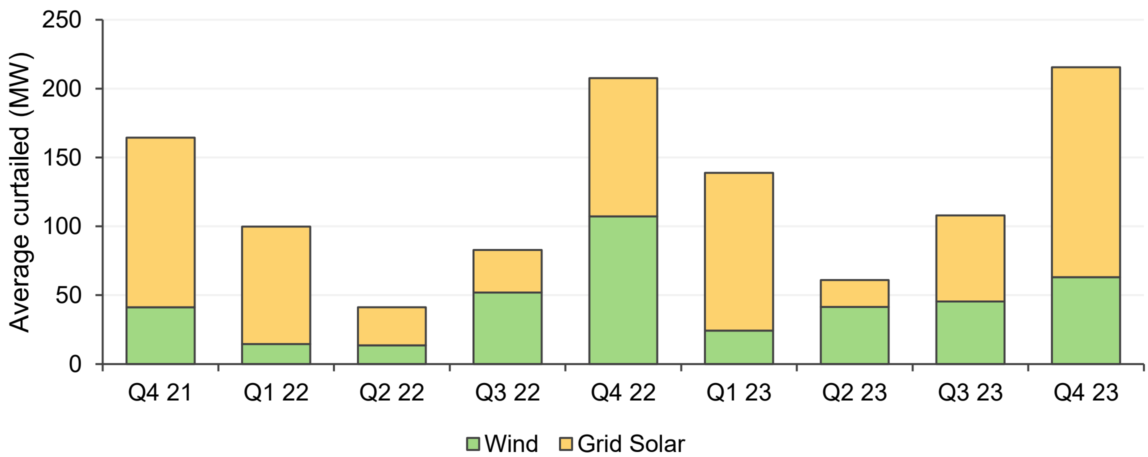


Curtailment

VRE quarterly average curtailment increased in total by 8 MW from 208 MW in Q4 2022 to 215 MW[13] in Q4 2023 (Figure 44). As a percentage of total available output this represented a reduction of 0.5 percentage points from 4.3% in Q4 2022 to 3.8% (2% for wind and 6.2% for grid solar) in Q4 2023.

Figure 44 Increased curtailment of grid-solar partially offset by lower curtailment of wind output

Average MW curtailment by fuel type



The largest share was in **New South Wales** with curtailment averaging 124 MW this quarter and where Limondale Solar Farm 1 and Sunraysia Solar Farm had the highest curtailments in the region, averaging 14 MW and 11 MW respectively. **Victoria** had the next highest average curtailment at 65 MW, followed by **South Australia** (22 MW), and **Queensland** (4 MW). **Tasmania** recorded only 0.6 MW of wind curtailment this quarter, a significant reduction from Q4 2022's 20 MW when extended transmission outages impacted the major 220 kilovolts (kV) transmission lines linking the north and south of the state.

[12] Available capacity factors for each established facility are weighted by maximum capacity to derive a state-wide weighted average.

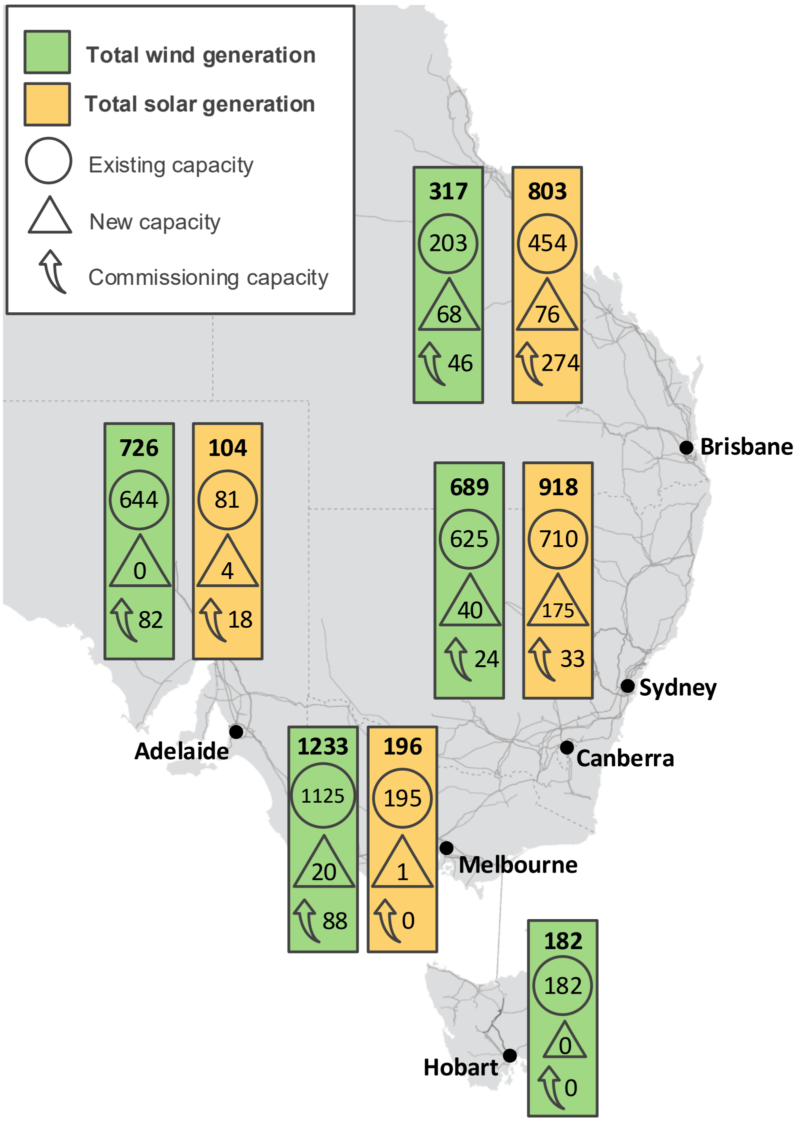
[13] Transmission outages around Wagga during early October 2023 resulted in some affected solar and wind generators in New South Wales and Victoria cutting offered availability to zero during the outage period (mostly between 6-11 October). While offering reduced or zero availability is not technically defined as curtailment, these reductions in availability and output were transmission-related. It is estimated that this may have added almost 40 MW to Q4 2023 quarterly average curtailment if captured.

The increase in total VRE curtailment was driven by the considerable increase in grid-scale solar curtailment, which saw an uplift of 52 MW year-on-year. On the other hand, wind saw a reduction of 44 MW in curtailment from 107 MW in Q4 2022 to 63 MW in Q4 2023.

The map in Figure 45 shows a summary representation of VRE output during Q4 2023. Numbers presented in this map are in megawatts and are calculated on a quarterly average basis. The existing, new, and commissioning components in the map refer to the contribution of the existing, new, and commissioning VRE capacity to the total quarterly average generation during the quarter.

Figure 45 Regional VRE generation summary during Q4 2023

Quarterly average generation (MW) by fuel type and region

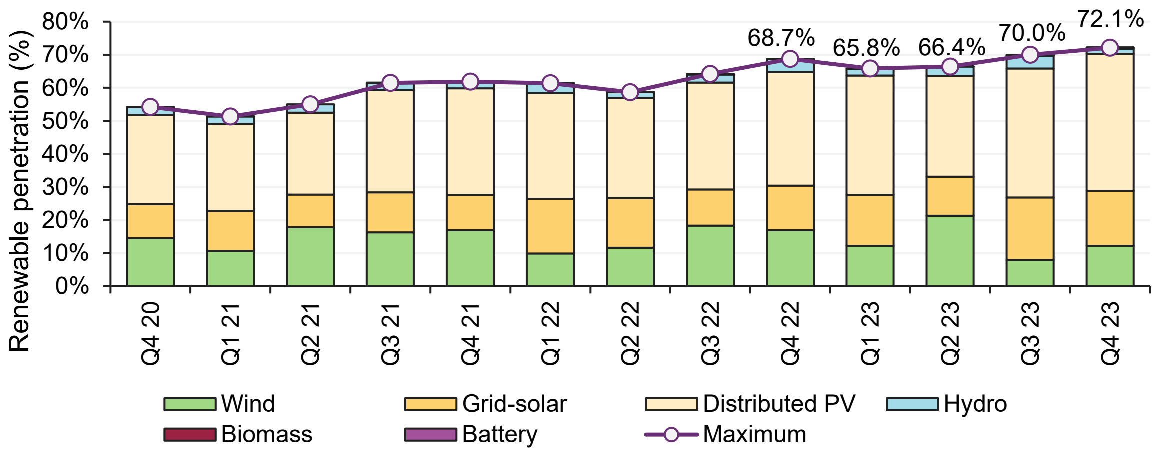


Instantaneous renewable penetration

In Q4 2023, the maximum instantaneous share of renewable energy generation[14] in the NEM reached a new record level of 72% during the half-hour ending 1300 hrs on Tuesday 24 October 2023. This was a 2.2 pp increase from the previous quarter's record which occurred on 21 September 2023, and an increase of 3.4 pp from the previous Q4 high of 68.7% reached on 28 October 2022 (Figure 46). The Q4 2023 record included a 41% contribution from distributed PV, 12% from wind, and 17% from grid-scale solar.

Figure 46 Instantaneous renewable penetration reached a new record level

Percentage of NEM supply from renewable energy sources at time of peak instantaneous renewable energy generation share

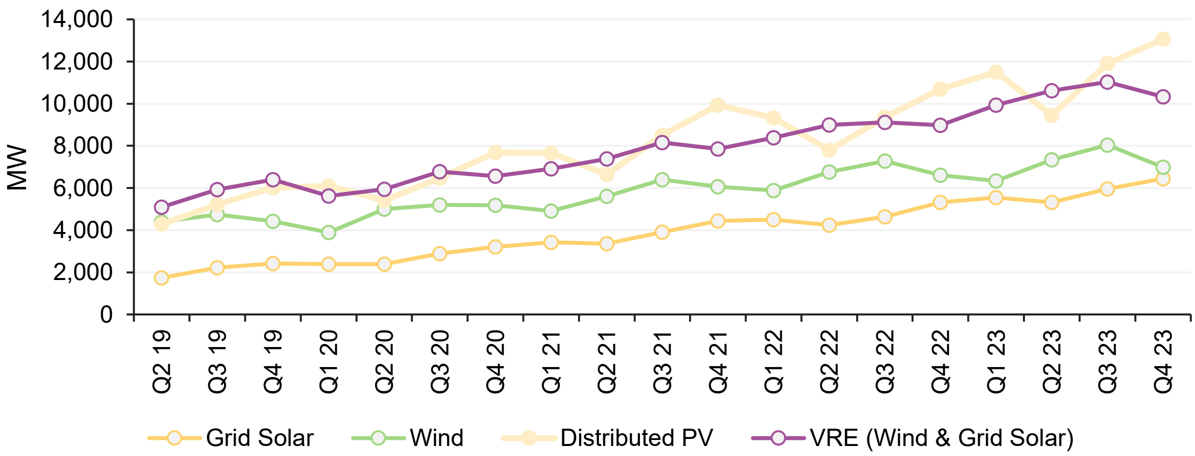


Distributed PV and VRE peak instantaneous outputs

Higher solar irradiation in New South Wales and Victoria, new and commissioning grid-scale solar capacity, and increases in distributed PV capacity and output led to record instantaneous highs for both grid-scale solar and distributed PV generation this quarter (Figure 47).

Figure 47 Record high instantaneous outputs for grid-scale solar and distributed solar in Q4 2023

Maximum quarterly instantaneous generation by fuel type



[14] Instantaneous renewable penetration is calculated using the NEM renewable generation share of total generation The 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 distributed PV generation.

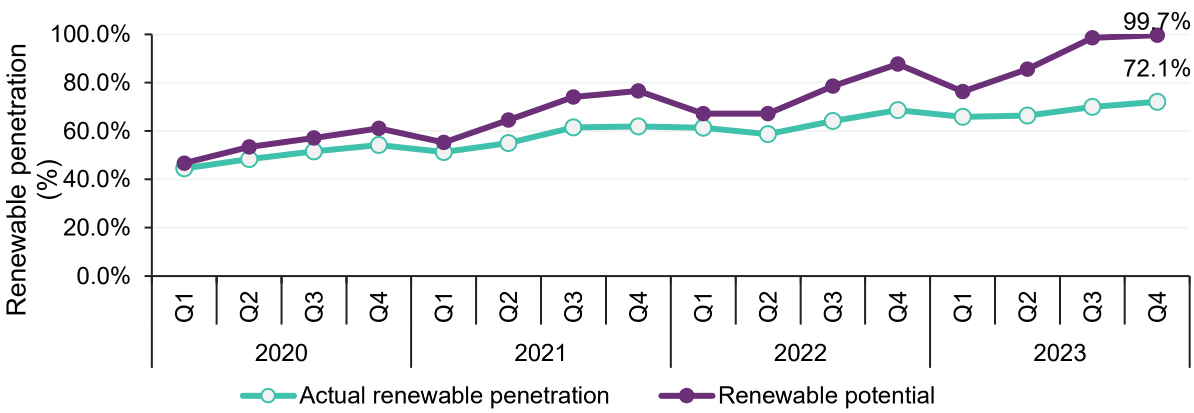
Distributed PV saw an uplift of 1,158 MW from its previous record high of 11,900 MW in Q3 2023 to reach 13,058 MW, a 10% increase. Relative to Q4 2022's maximum, this was an increase of 2,373 MW or 22%. Grid-scale solar maximum output reached 6,443 MW, up by 494 MW (8%) on the record set in Q3 2023, and by 21% on its previous Q4 high of 5,311 MW. Lower wind conditions yielded a lower maximum this quarter for wind instantaneous generation at 6,983 MW, well below the record level of 8,040 MW observed in Q3 2023 but 6% up on Q4 2022's 6,611 MW.

Renewable potential

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. The maximum renewable potential in Q4 2023 reached 99.7% on Sunday 1 October 2023 during the half-hour ending 1130 hrs (Figure 48).

Figure 48 Record high actual and potential renewable penetration

Quarterly maximum instantaneous actual renewable penetration and renewable potential



Achieving very high actual instantaneous penetration of renewables, at times up to 100%, is dependent on both market responses to energy and essential system services needs, as well as engineering and operational readiness enablers for secure and reliable power system operation at times without fossil fuels. AEMO's Engineering Roadmap[15] is a body of work that aims to remove barriers to running a secure and reliable power system at times of very high renewable penetration.

Renewable contribution to daily maximum operational demand

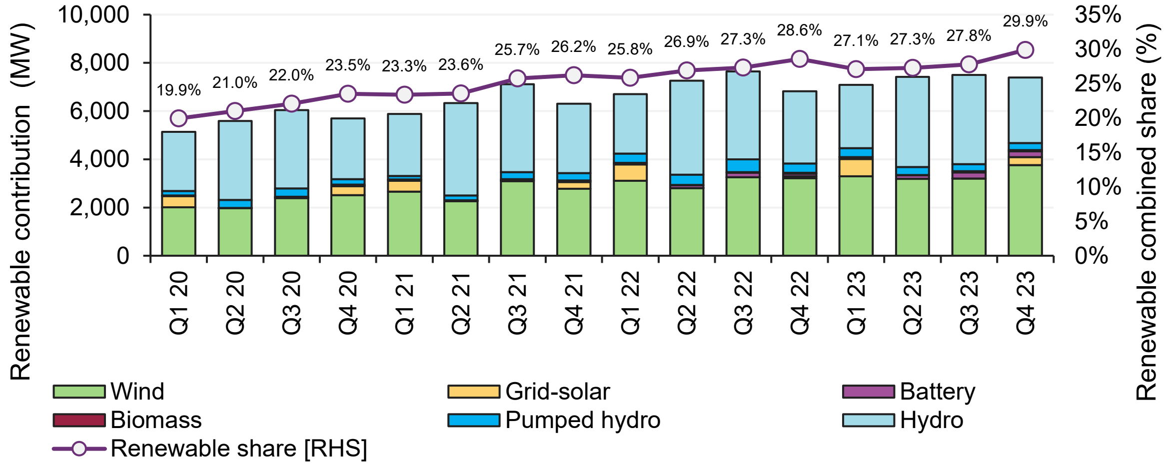
Figure 49 illustrates the contribution of large scale renewable generation in meeting daily maximum NEM operational demand, computed as an average across all days in each quarter[16]. In Q4 2023, the average renewable contribution to daily maximum operational demand reached a new high of 29.9%. The chart illustrates the fact that wind and hydro contributions currently dominate this measure, with increasing contribution from batteries, since maximum operational demand typically occurs at times of day when solar output is low or zero.

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

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

Figure 49 Growing renewable contribution to meeting daily maximum demand

Average renewable contributions (MW) and combined share (%) at time of daily maximum operational demand - Quarterly

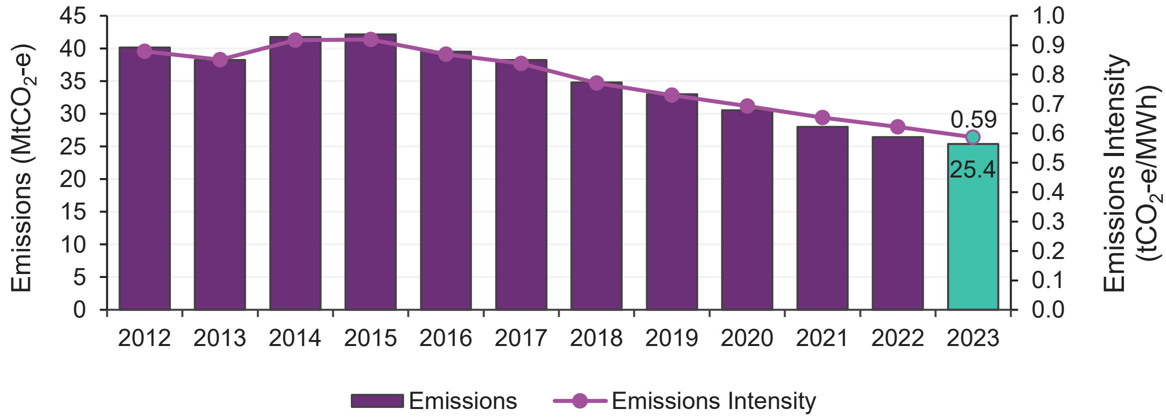


1.3.5 NEM emissions

Q4 2023 saw NEM total emissions and emissions intensity continue to reduce and hit a new all-time lowest record at 25.4 MtCO2-e and 0.59 tCO2-e/MWh, respectively (Figure 50). Emissions intensity excludes generation from distributed PV, taking into consideration sent out generation only from market generating units[17]. A year-on-year comparison sees carbon dioxide equivalent emissions lower by 1.1 MtCO2-e (-4%) and intensity down by 0.04 tCO2-e/MWh (-5.7%) relative to Q4 2022 levels. This reduction was essentially driven by increased VRE output more than covering the increase in operational demand and displacing a portion of fossil-fuelled generation.

Figure 50 Lowest Q4 emissions and emissions intensity on record

Quarterly NEM emissions and Intensity (Q4s)



[17] Sent out generation derived from metering data is combined with publicly available generator emission factors to provide a NEM-wide Carbon Dioxide Equivalent Intensity Index calculated on a daily basis.

1.3.6 Storage

Batteries

In Q4 2023, total estimated net revenue for NEM grid-scale batteries was $31.5 million, a reduction of $10.1 million (-24%) from Q4 2022's $41.6 million (Figure 51). While total battery revenue fell year on year, revenue from energy arbitrage[18] grew $6.0 million from $7.4 million in Q4 2022 to $13.5 million in Q4 2023. Due to the increased occurrence of negative prices throughout the quarter (Section 1.2.3), as part of their energy arbitrage earnings, batteries received higher payments for charging during negative priced intervals. This accounted for $3.3 million of total revenue in the quarter (a 94% increase year-on-year). Revenue from discharging energy totalled $12.8 million during the quarter, a 43% increase relative to $9.0 million in Q4 2022. The cost of charging at prices higher than $0/MWh was $2.6 million, lower than the $3.3 million earned from charging at negative prices, meaning that batteries, in effect, **earned** net revenue of $0.7 million from all charging activity.

With no recurrence of the transmission incidents and regional islanding events that affected Q4 2022, FCAS revenue for batteries reduced by $16.2 million (-$5.4 million in Regulation FCAS and -$10.8 million in Contingency FCAS markets).

As seen in Figure 52, 43% of the total NEM battery net revenue was derived from the energy market, marking a 25 pp increase year-on-year, with the balance originating from FCAS markets.

Figure 51 Battery net revenue down from Q4 2022 with decreased FCAS revenue

Quarterly revenue for NEM battery systems by revenue stream

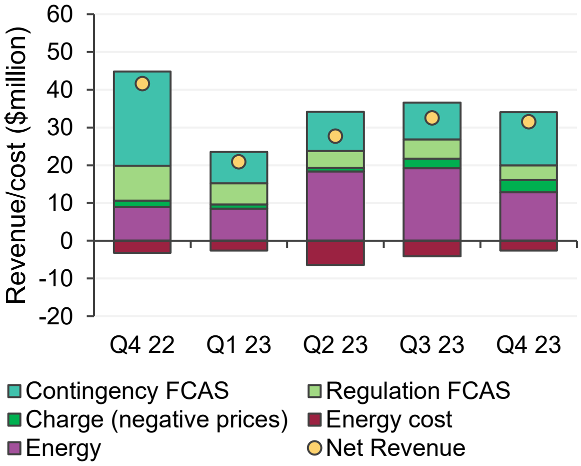
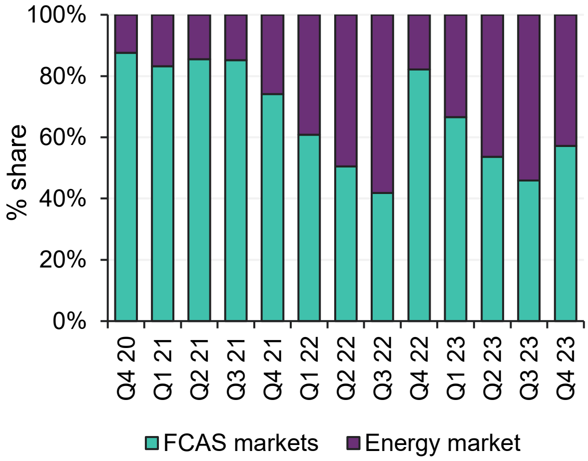


Figure 52 FCAS revenue share reduced but still the larger source of battery revenue for Q4

Percentage share of battery revenue – energy vs FCAS markets



By region:

- **Queensland** batteries saw an increase in net revenue from $3.8 million in Q4 2022 to $4.6 million in Q4 2023 (with $1.3 million increased energy markets revenue offset by $0.5 million reduction from FCAS markets).
- **New South Wales** battery earnings grew $3.3 million from $2.8 million in Q4 2022 to $6.1 million this quarter. The bulk of this uplift was from energy arbitrage which increased by $2.3 million from $0.4 million.

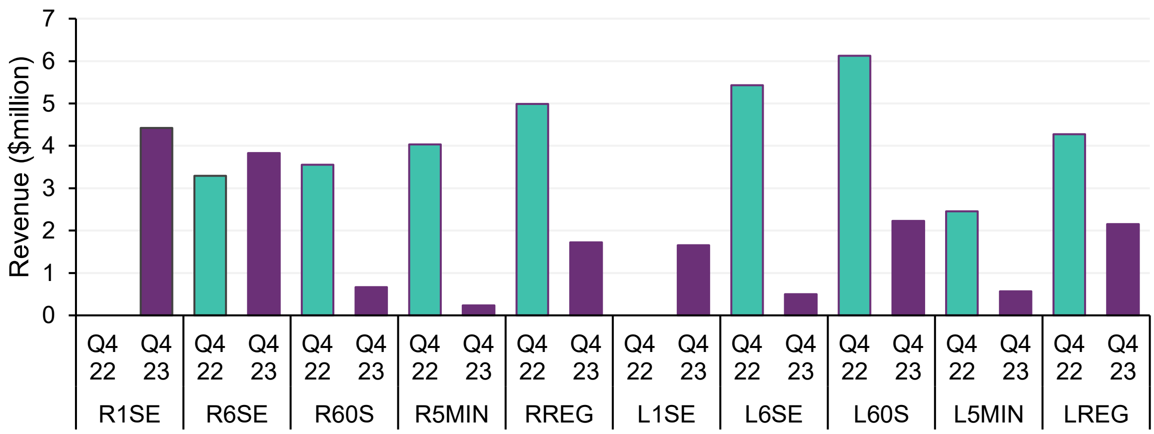
[18] Energy arbitrage revenue for batteries includes three components: 1) revenue from discharging (selling energy), 2) any revenue from recharging during negative priced intervals, and 3) cost of recharging at prices higher than $0/MWh.

- While **Victorian** batteries captured slightly higher revenue from FCAS markets at $6.7 million relative to $6.2 million in Q4 2022, energy market earnings increased by $1.1 million from $3.1 million in Q4 2022 to $4.2 million this quarter.
- **South Australia's** batteries saw a significant FCAS revenue reduction to a total of $6.4 million this quarter, compared to $23.7 million in Q4 2022 when South Australia was islanded for a duration of seven days (12 November to 19 November 2022) leading to very high FCAS prices.

With the introduction of the two new very fast FCAS services in October 2023 – Very Fast Raise Contingency (R1SE) and the Very Fast Lower Contingency (L1SE) markets, batteries earned a significant portion of their revenue from these two new services. Figure 53 shows that $4.4 million of FCAS revenue during this quarter was earned from provision of R1SE, the highest total amongst all FCAS services. In other FCAS markets, only six-second contingency raise (R6SE) yielded increased revenue for batteries this quarter, rising from $3.3 million in Q4 2022 to $3.8 million in Q4 2023. L6SE accounted for the largest drop, from $5.4 million to $0.5 million year-on-year. Regulation markets also saw a significant drop of $5.3 million from $9.3 million in Q4 2022 to $3.9 million this quarter; most of this drop (-$3.7 million) was in South Australia, where revenues fell to $0.9 million this quarter from $4.6 million in Q4 2022.

Figure 53 Significant battery FCAS revenue earned in the new very fast contingency markets

Battery quarterly revenue breakdown by FCAS markets



Pumped hydro

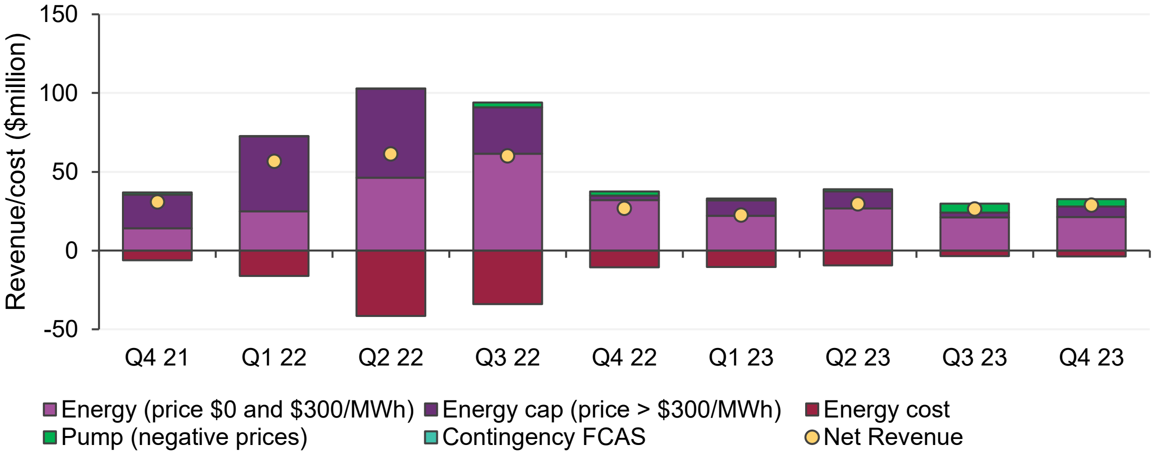
Total estimated net energy arbitrage revenue[19] for pumped hydro was $28.8 million this quarter, an uplift of $2.0 million from Q4 2022 at $26.8 million (Figure 54). While **Queensland**'s Wivenhoe achieved total revenue of $28.0 million, net revenue for Shoalhaven in **New South Wales** fell from $6.4 million in Q4 2022 to only $0.8 million in Q4 2023.

Due to lower energy prices and cap returns for the quarter, relative to previous Q4 levels, pumped hydro generation revenue dropped to $27.9 million this quarter relative to $34.8 million in Q4 2022. Frequent negative price incidence allowed storage facilities to be regularly paid for pumping, yielding revenue of $4.7 million. The cost of pumping at prices higher than $0/MWh totalled at $3.8 million during the quarter meaning that total pumping requirements yielded a net revenue of $0.9 million.

[19] As with batteries, pumped hydro net energy revenue includes three components: 1) revenue from generating energy, 2) revenue from pumping during negative priced intervals, and 3) cost of pumping at prices higher than $0/MWh.

Figure 54 Pumped hydro net revenue increased from Q4 2022

Quarterly revenue from NEM pumped hydro by revenue stream

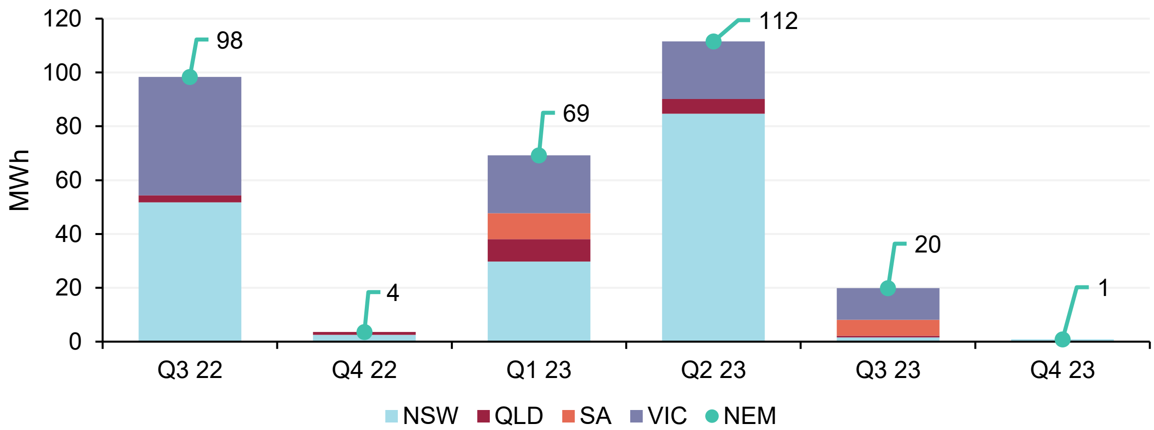


1.3.7 Wholesale demand response

Q4 2023 saw minimal dispatch of Wholesale Demand Response (WDR) capacity, with only 1 MWh dispatched in New South Wales on 14 November 2023 (Figure 55).

Figure 55 Reduction in Wholesale Demand Response to only one dispatch event

Total quarterly WDR energy dispatch



1.3.8 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[20] monitored by AEMO to track the progress of projects going through the connections process include application, pre-registration, registration, commissioning, and model validation.

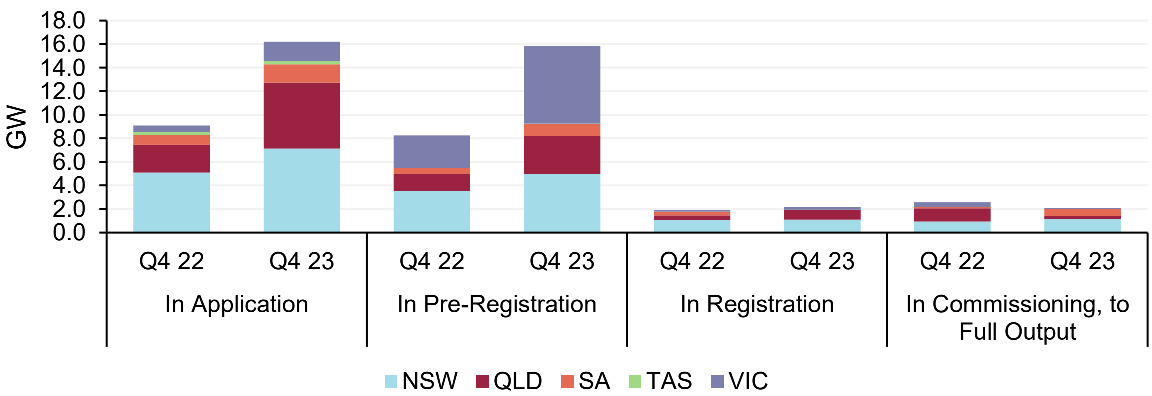
At the end of Q4 2023, AEMO's snapshot of connection activities in progress shows that:

[20] Application stage establishes technical performance and grid integration requirements. In pre-registration 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.

- There was 36 GW of new capacity progressing through the end-to-end connection process from application to commissioning; this is a 63% increase in capacity compared to 22 GW at the end of Q4 2022. Around 40% of this capacity is in **New South Wales**, and 25% in both **Queensland** and **Victoria** (Figure 56). The majority of these projects are in the early stages of development with 90% of new connection capacity in either application or pre-registration stages.
- The total capacity of in-progress applications was 16.2 GW, compared with 9.1 GW at the same time last year. During Q4 2023 there were 16 connection applications received, totalling 3.7 GW. The average project size for new applications, 0.23 GW, has been fairly consistent for the past five quarters, but notably larger than the average of 0.14 GW during the five quarters to Q3 2022. Approximately 45% of new connection applications were received from **New South Wales** and 30% from **Queensland**, with the remainder split equally between **Victoria** and **South Australia**.
- An additional 15.9 GW of new capacity projects are finalising contracts and under construction (pre-registration), with more than 70% of projects in **Victoria** and **New South Wales**. This compares to 8.2 GW at the end of Q4 2022.
- There is 2.2 GW of new capacity progressing through registration; 50% of this is in **New South Wales**.
- There is 2.1 GW of new capacity in commissioning to full output, compared to 2.6 GW at the end of Q4 2022. This commissioning measure considers all plant in commissioning up to the plant reaching its full output.

Figure 56 Increase in connection applications and projects under construction (pre-registration)

Connections snapshot as at end Q4 for 2022 and 2023



During Q4 2023, approvals achieved included:

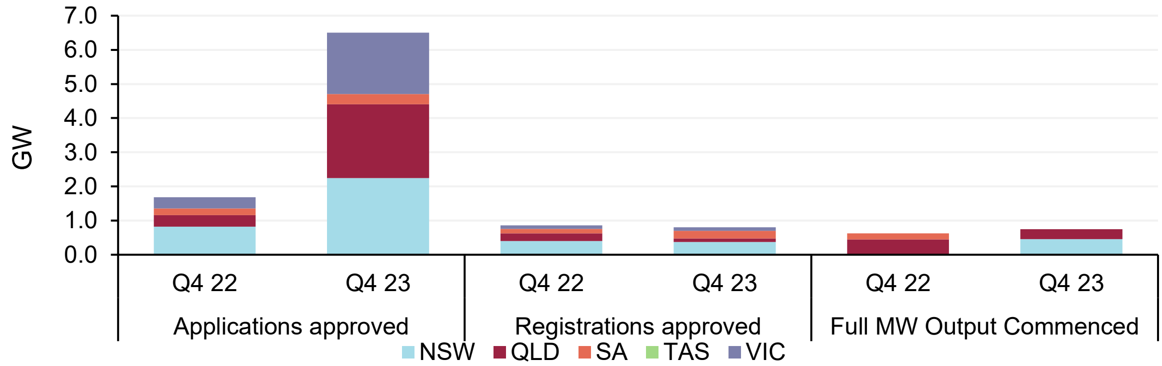
- 6.5 GW of applications across 28 projects (Figure 57), which includes a monthly record of 4.7 GW of new connection **applications approved** in the month of December. Of the applications approved, 32% (2.1 GW) were battery projects. In Q4 2022, 1.7 GW of applications were approved across 11 projects. The notable increase in applications approved was expected given the influx of new connection applications received during the last year.
- 0.8 GW across seven projects was **registered and connected** to the NEM in Q4 2023 and is ready to start commissioning. This included Tallawarra B Power Station (0.3 GW) in **New South Wales**, and Goyder South 1B Wind Farm (0.2 GW) in **South Australia**. The surge in connection application approvals is yet to be observed in the registration and commissioning stages, as projects can typically take between 12-24 months to reach financial close and complete construction.

- 0.8 GW of plant across four projects progressed through **commissioning to reach full output**; 50% of this capacity was from New England Solar Farm in **New South Wales**. In Q4 2022, 0.6 GW across eight projects reached full output.

The connections scorecard[21] is published monthly and contains further information.

Figure 57 Substantial Increase in application approvals

Comparison of applications approved, registrations and commissioning in Q4 for 2022 and 2023



1.4 Inter-regional transfers

Total inter-regional energy transfers were 3,383 gigawatt-hours (GWh), a 10% increase from Q4 2022. Compared to Q4 last year, net transfers into **New South Wales** from **Queensland** increased by 21%, but compared to the strong southward flows experienced in Q3 2023, this was a reduction of 63%. Net transfer into **New South Wales** from **Victoria** was at a similar level to Q4 last year with only a 4% increase, but again, compared to the previous quarter's high transfers into New South Wales, flows decreased by 34%.

Net transfer directions between all regions were the same as in Q4 2022, with Basslink reversing the net northward flows to **Victoria** experienced in Q3 2023 (Figure 58).

Figure 58 Flows between regions similar to Q4 2022 levels, with flows into New South Wales down from Q3

Quarterly inter-regional transfers

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

Key outcomes by regional interconnector included:

- **Queensland – New South Wales Interconnector (QNI)** – flow on QNI followed a similar pattern to that in Q4 2022. Southward flow increased by just 20 MW and northward flow decreased by 8 MW compared to Q4 2022 (Figure 59). The reduction in northward flow was most evident in the evening peak, with New South Wales less able to support Queensland. QNI was its import limit for 16% of dispatch intervals, a reduction from Q3 2023 when QNI was at is import limit for 21% of dispatch intervals. The reduction in southward flow between Q3 and Q4 2023 is consistent with seasonal weather and demand patterns, with Queensland typically experiencing higher operational demands during Q4 than during Q3, and New South Wales typically experiencing higher operational demands during Q3 than during Q4.
- **VNI** – net flow northward from Victoria to New South Wales was 339 MW in Q4 2023, similar to the 328 MW in Q4 2022. VNI flowed at its export limits for 44% of dispatch periods during Q4 2023 (also similar to Q4 2022), with export limits regularly reducing northwards flow to near zero, or even forcing flow southwards, during daytime hours (Figure 60).
- **Basslink** – net flows southward increased by 89 MW to 252 MW compared to Q4 2022, and Basslink was at its import limit in 63% of dispatch intervals in Q4 2023, compared to 54% in Q4 2022, consistent with the reduction in Tasmania hydro generation (Section 1.3.3) and the higher prices in Tasmania (Section 1.2).

Figure 59 Less export from New South Wales to Queensland on QNI during evening peak

Average QNI flow (New South Wales to Queensland), by time of day

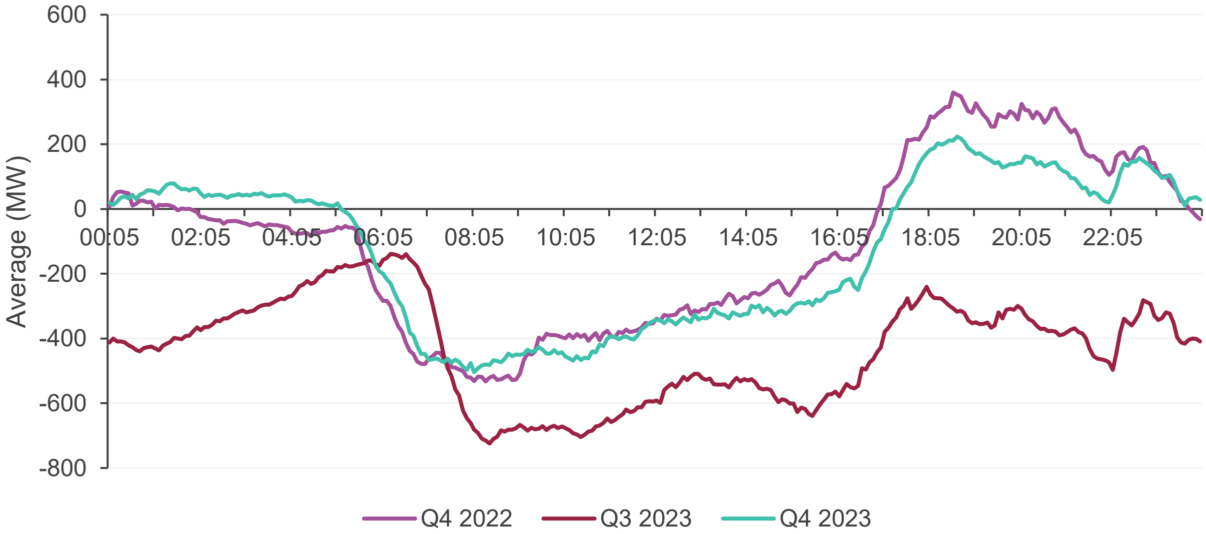
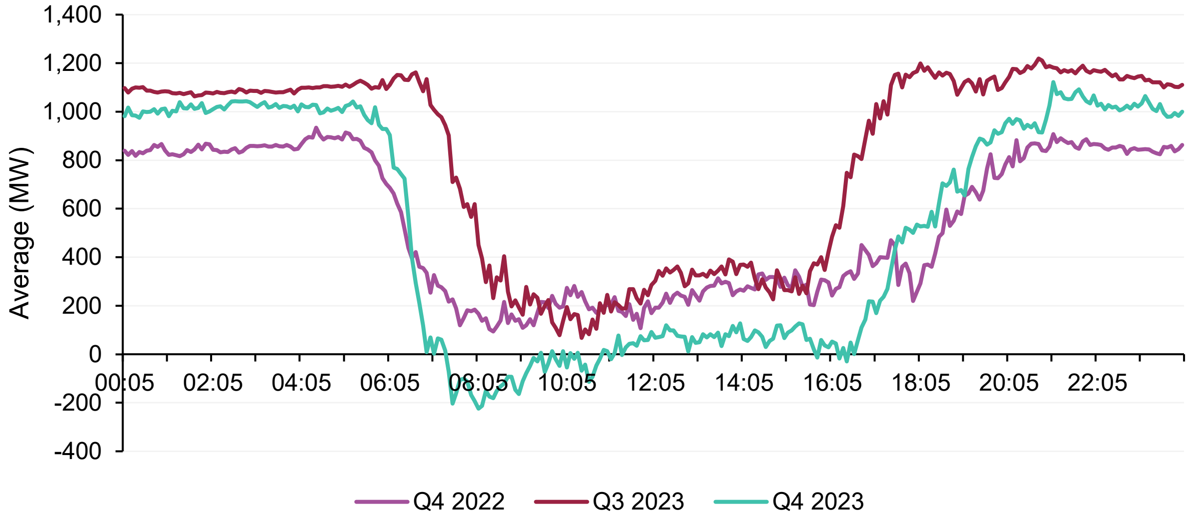


Figure 60 VNI export limit averaging negative for periods during daylight hours

Average VNI export limit (Victoria to New South Wales) when binding, by time of day



1.4.1 Inter-regional settlement residue

Positive inter-regional settlement residue (IRSR) totalled $69 million, down from $97 million last Q4 (Figure 61).

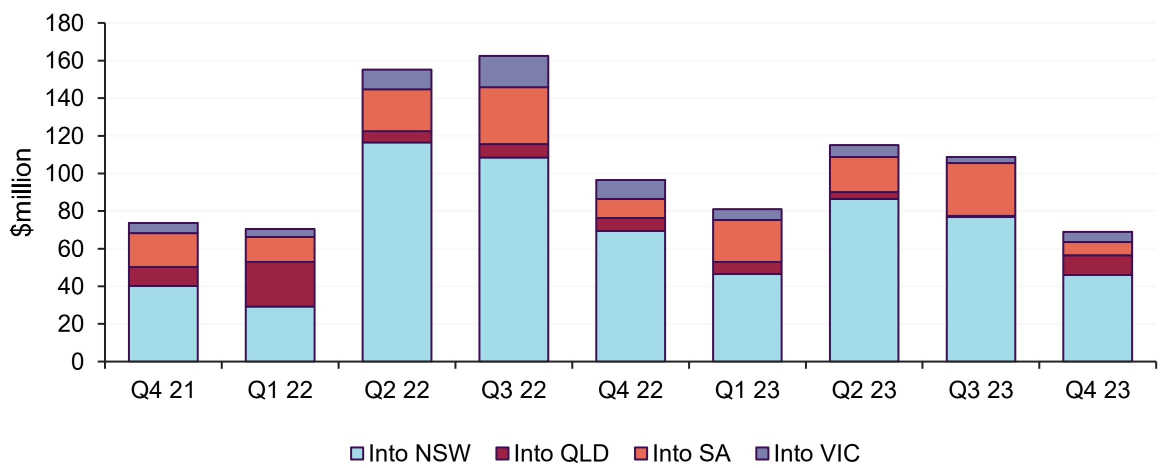
Compared to Q4 2022, positive IRSR decreased for all interconnectors apart from QNI, with residues into **New South Wales** from **Queensland** increasing $7 million to $19 million and residues into **Queensland** from **New South Wales** increasing $4 million to $11 million. More than half of the residues into Queensland accrued in the final week of the quarter with residues from 25 to 31 December 2023 totalling $6.2 million, mainly driven by the price volatility events discussed in Table 2.

Despite its higher residues on QNI imports, **New South Wales** experienced the largest regional reduction in positive IRSR, with residues from **Victoria** decreasing by $31 million to $27 million.

Positive IRSR into **South Australia** from **Victoria** was the lowest it has been in recent quarters at $7 million, with relatively low spot prices in both regions and limited periods of price separation.

Figure 61 Lowest positive IRSR in recent quarters

Quarterly positive IRSR values



Negative residue management

Negative IRSR totalled $15 million, the highest since Q1 2017 (Figure 62). Negative IRSR into **Victoria** reached an all-time quarterly high of $14 million, due to an increase in counter-price flows from **New South Wales** to **Victoria**. This reflects the impact of network constraints forcing VNI flows southwards in a growing proportion of daylight hours (see Figure 60 above), despite Victorian spot prices typically being much lower than those in New South Wales.

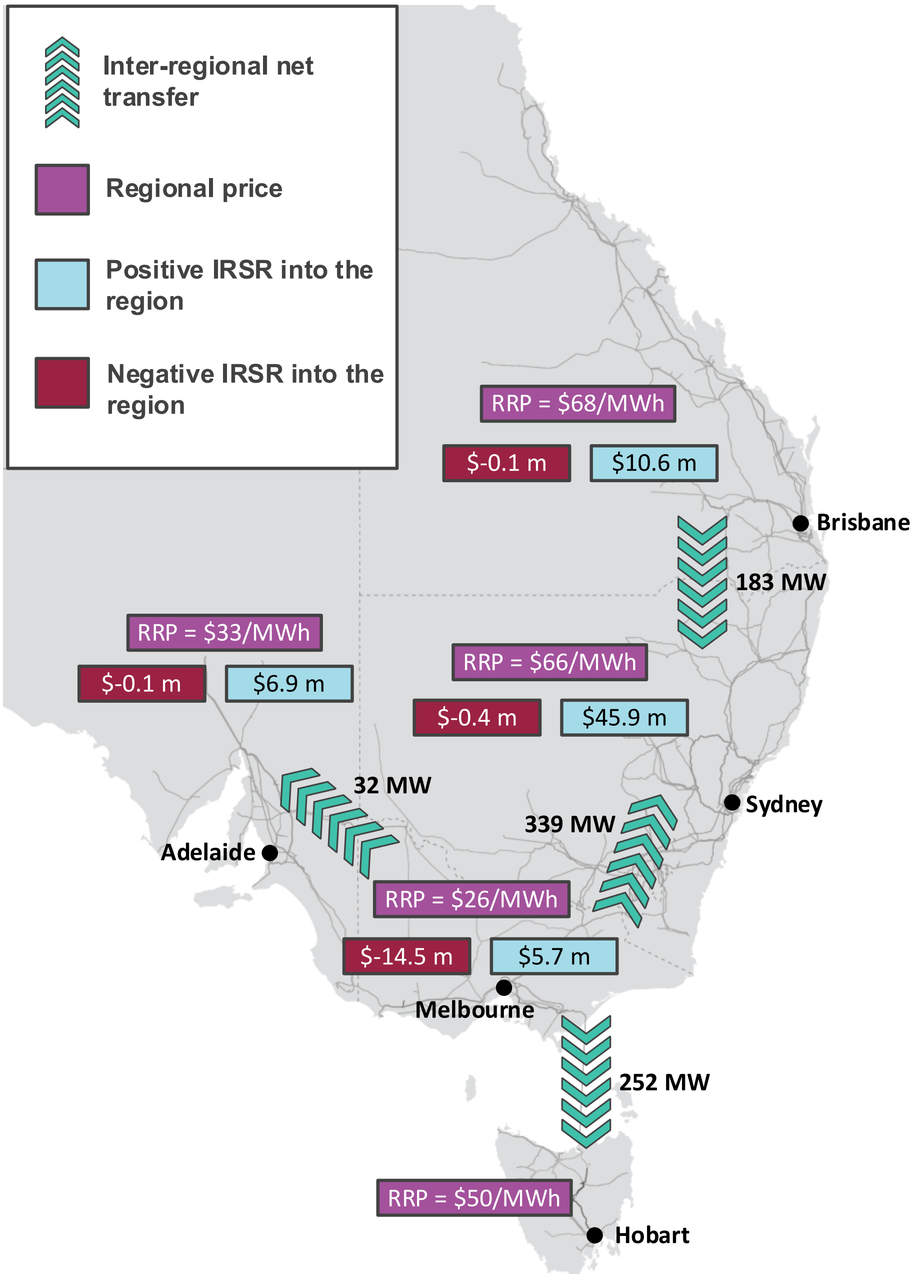
Figure 62 Highest negative IRSR in recent quarters driven by counter-price VNI flows

Quarterly negative IRSR values

The map in Figure 63 shows a summary representation of inter-regional exchanges during Q4 2023. Regional reference prices and the inter-regional net transfers are shown on a quarterly average basis. The positive and negative IRSR numbers refer to the total IRSR into the region from its neighbouring regions.

Figure 63 Inter-regional transfers, regional reference price, and settlement residues

Quarterly average net inter-regional transfer (MW), quarterly average regional reference price ($/MWh), and quarterly total IRSRs per region ($ million)



Counter-price flows on VNI

During Q4 2023, daytime target flows on VNI were increasingly southward when the price in New South Wales exceeded the Victorian price; these counter-price flows occurred for 24% of total dispatch periods compared to 15% in the same quarter in 2022.

The seven network constraints that set the binding negative export limit for the majority (95%) of those dispatch periods in Q4 2023 were (Figure 64):

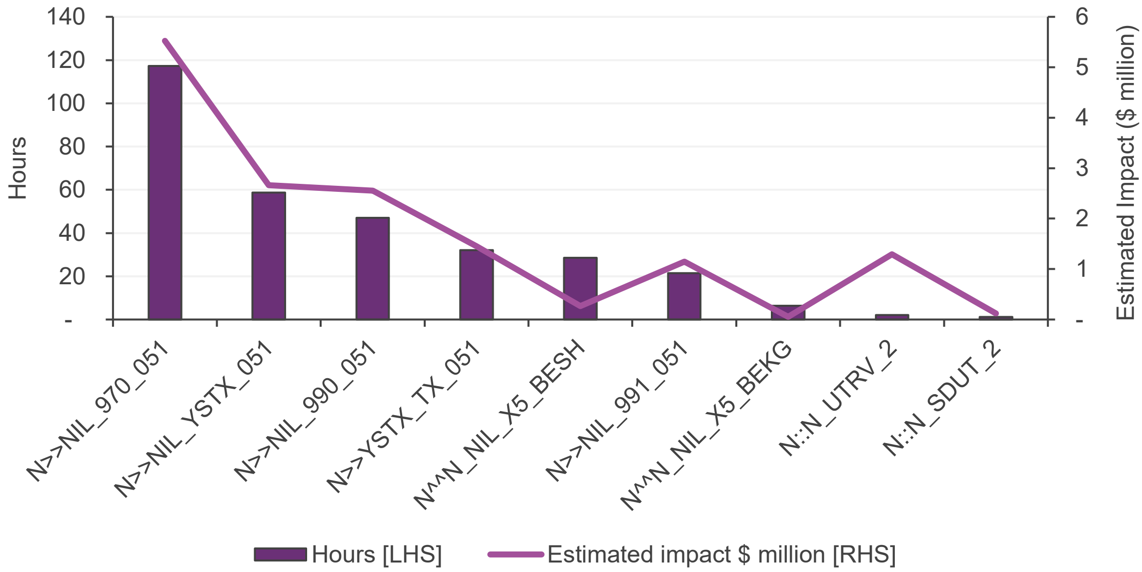
- Four thermal system normal[22] (**N>>NIL**) constraints and one thermal outage constraint (**N>>YSTX**) to avoid overload on the 132 kV network around Wagga and Yass for the trip of the Wagga to Lower Tumut (051) line.
- Two voltage stability system normal (**N^^N**) constraints limiting transfer from Balranald to Darlington Point (X5) to avoid voltage collapse at Balranald in the event of a 220 kV line trip in north-west Victoria.

These constraints contributed 86% of the estimated impact on negative IRSR accrued over Q4 2023, when considering the average target flow on VNI and the average price differential between New South Wales and Victoria during the counter-price flow intervals when the constraint was binding.

Two transient stability outage (**N::N**) constraints invoked to maintain stability during line outages around the Snowy Mountain area contributed an additional 9% to the estimated impact on negative IRSR.

Figure 64 Network issues causing counter-price flow

Number of binding hours and estimated negative IRSR impact of network constraints during VNI counter-price flow intervals



1.5 Frequency control ancillary services

Total FCAS costs for the quarter were $33 million, a $6 million reduction from Q3 2023, and a significant reduction of $64 million (-66%) from $98 million in Q4 2022, when costs were high due to transmission events affecting South Australia and Tasmania (Figure 65).

Two new contingency services were introduced during Q4 2023, with the Very Fast Raise Contingency and the Very Fast Lower Contingency markets commencing operation on 9 October 2023. Payments for the new one-second contingency raise (R1SE) contributed $4.6 million (14%) to total FCAS costs in Q4 2023, and payments for the new one-second contingency lower (L1SE) contributed $1.8 million or 5% (Figure 66).

[22] These four thermal constraint equations were first introduced in January 2023.

Figure 65 FCAS costs slightly lower than previous quarters, but significantly reduced from Q4 2022

Quarterly FCAS costs by region

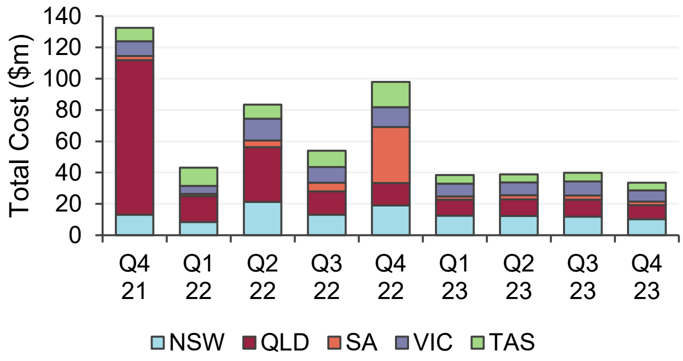
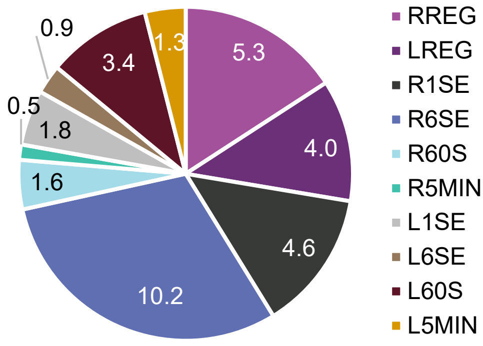


Figure 66 R6SE and RREG the highest shares of FCAS costs

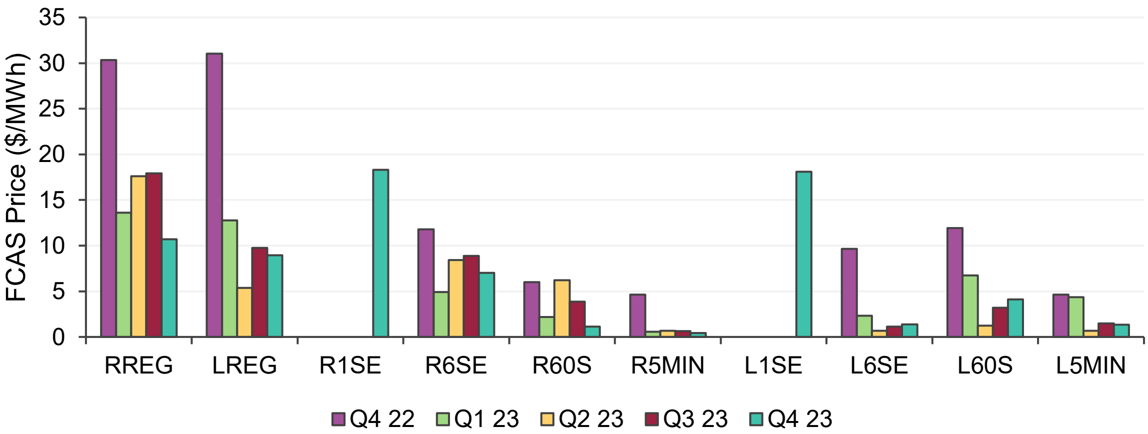
NEM quarterly FCAS cost by market – Q4 2023 ($m)



In the first quarter of the very fast FCAS markets operation, the NEM-wide average price for one-second contingency raise was $18.3/MWh, the highest out of all the FCAS services for Q4 2023, followed by one-second contingency lower at $18.1/MWh (Figure 67). NEM-wide average Q4 2023 prices for the existing FCAS services were generally lower than in preceding quarters.

Figure 67 L1SE and R1SE average NEM prices highest out of all FCAS services in Q4 2023

NEM average FCAS prices by service – quarterly since Q4 2022



Batteries continued to be the dominant technology providing FCAS, with a market share of 50% (Figure 68), increasing from their 40% volume share in Q3 2023 and 38% in Q4 2022. This increase was driven by both the new very fast FCAS service and from construction and full commissioning of new batteries, with growth since Q3 2023 led by increased provision from Hazelwood (+163 MW), Riverina (+125 MW) and Torrens Island (+84 MW).

Figure 69 shows that batteries and demand response (DR) increased in quarterly average enablement, by 355 MW and 44 MW respectively compared to Q4 2022. Hydro had the greatest reduction in enablement, by 195 MW, mainly driven by a reduction in contingency lower enablement in Tasmania which was high in Q4 2022, partly due to transmission-related events.

Figure 68 Batteries further grew FCAS market share

FCAS volume market share by technology – Q4 2023

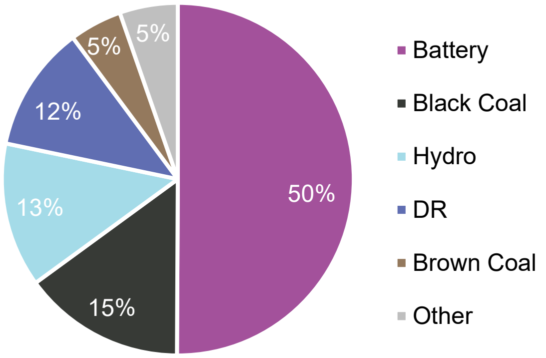
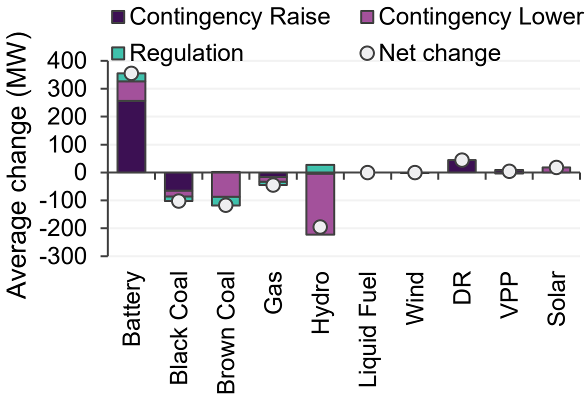


Figure 69 Increased enablement for batteries and DR

Change in FCAS enablement by technology – Q4 2023 vs Q4 2022



Very fast frequency response market

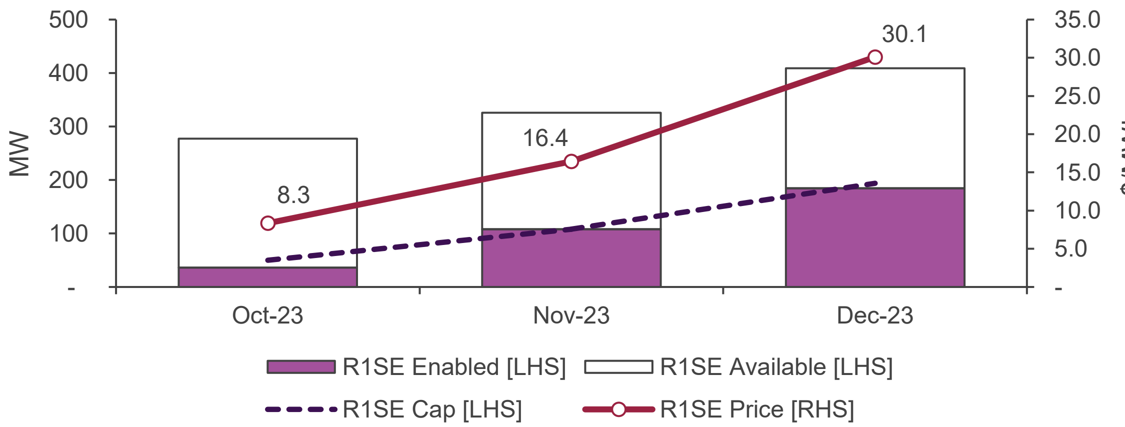
The very fast FCAS markets both commenced operation on 9 October 2023 at 1:00 pm (market time) and contributed $6.3 million (19%) between them to the total FCAS costs over Q4 2023.

Under the new market transition approach, both very fast services commenced with a 50 MW cap on enablement volumes with a fortnightly review to determine if these volumes could be incremented. The uncapped underlying very fast FCAS requirements are made visible to the market via non-binding constraints, and these demonstrate that the underlying requirement is higher for the R1SE service than for the L1SE service.

The R1SE cap increased four times over the quarter to reach 225 MW by the end of the quarter. Over the quarter, the average enablement of the R1SE service increased in line with the cap, and the average monthly price increased from $8.3/MWh in October 2023, to $30.1/MWh in December 2023 (Figure 70).

Figure 70 Raise 1 Second price increased over the quarter

Average R1SE cap, enablement, actual availability, and price – monthly for Q4 2023

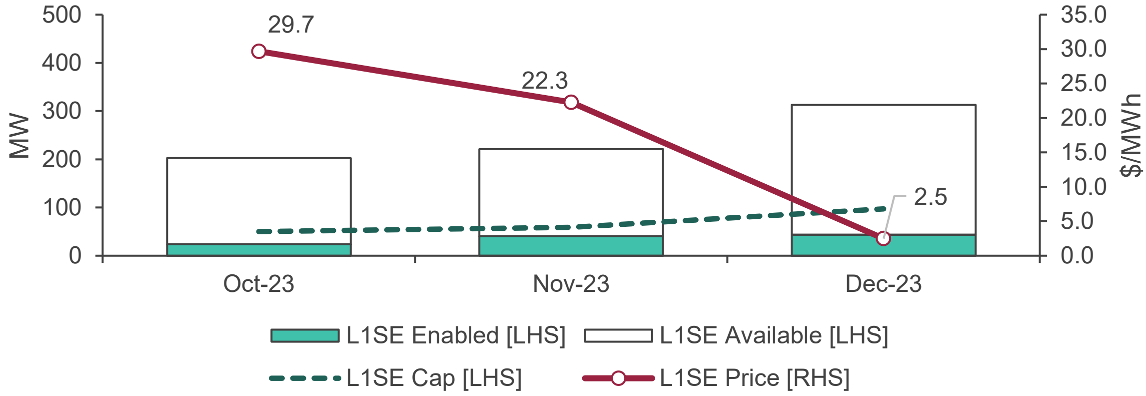


The L1SE cap increased twice over the quarter to reach 100 MW at the end of the quarter. The average enablement remained relatively constant, and prices decreased over the quarter starting at a high of $29.7/MWh in October reducing to $2.5/MWh in December (Figure 71).

For both services there was an increase in availability from late November, with Torrens Island BESS commencing offering services from 21 November 2023.

Figure 71 Lower 1 second price decreased over the quarter

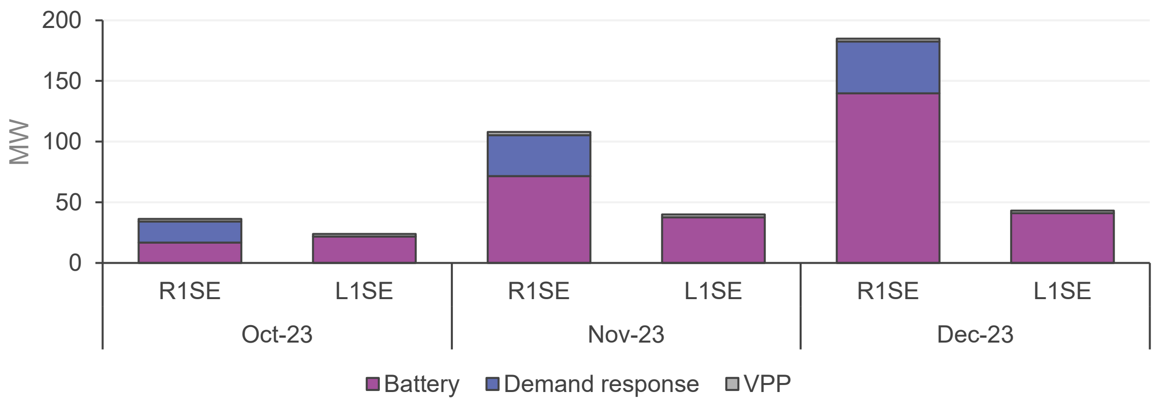
Average L1SE cap, enablement, actual availability, and price – monthly for Q4 2023



Batteries and demand response supplied the majority of volumes enabled for the new very fast FCAS services, with average quarterly enablement of 110 MW for batteries (76 MW raise and 33 MW lower) and 31 MW for demand response (all raise). Virtual power plant (VPP) was the only other technology supplying this service, with average enablement of 2 MW for both raise and lower (Figure 72).

Figure 72 Batteries and demand response providing the majority of the very fast FCAS services

Average enablement by technology for R1SE and L1SE – monthly over Q4 2023



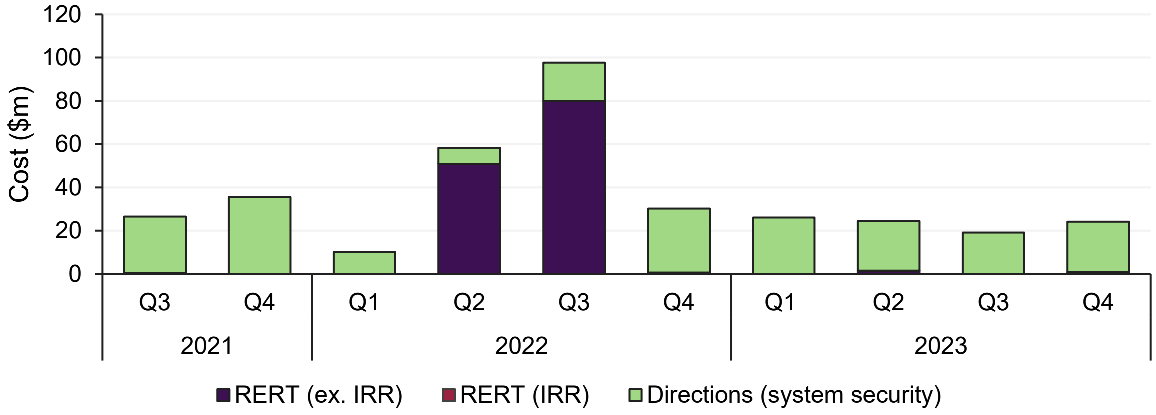
1.6 Power system management

Power system management costs were $24.1 million over Q4 2023, a $5.0 million increase from the previous quarter, but $5.4 million lower than Q4 2022 (Figure 73). The Reliability and Emergency Reserve Trader (RERT) is a function conferred on AEMO to ensure reliability of supply by securing the availability of reserves using reserve contracts. AEMO entered into interim reliability reserve (IRR) agreements with various providers for the regions of Victoria and South Australia for the period from 1 December 2023 to 31 March 2024[23]. Payments from 1 December 2023 to the end of the quarter were $0.7 milliion. Additionally, AEMO entered into a reserve contract to maintain the power system in a reliable operating state from 17:30 to 19:30 on 14 December 2023. However, these reserves were not required to be activated or dispatched due to changing lack of reserve conditions.

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

Figure 73 System security costs in line with previous quarters

Estimated quarterly system costs by category

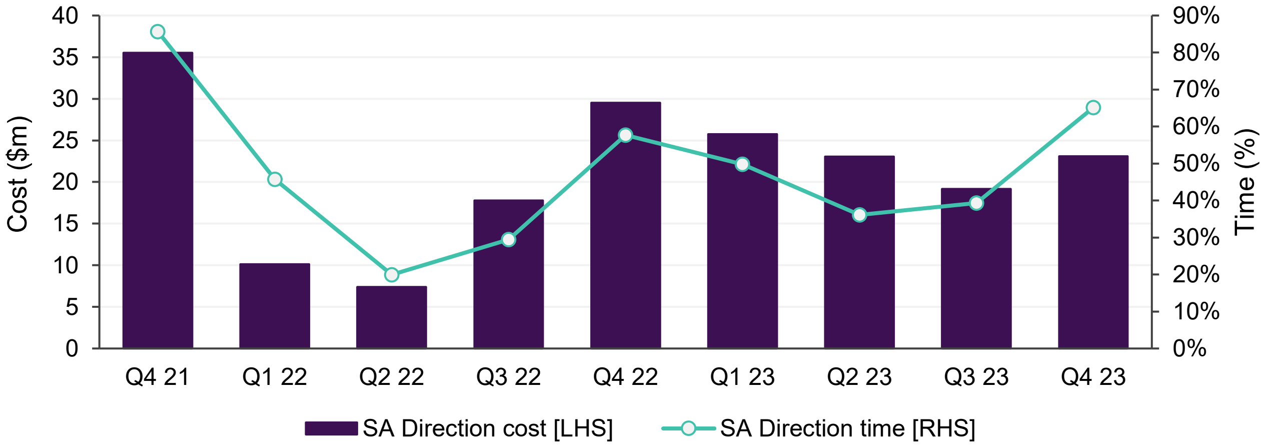


1.6.1 South Australian system security directions

Directions were in place for 65% of dispatch intervals in Q4 2023, higher than Q4 2022's 58% and Q3 2023's 39% (Figure 74). However, direction costs reduced from $29.5 million in Q4 2022 to $23.1 million, reflecting a lower average quarterly direction compensation price[24] of $188/MWh compared to $349/MWh in Q4 2022.

Figure 74 Decline in South Australian system security cost despite increased direction time in Q4 2023

Time and cost of energy only system security directions – South Australia Q4 2021 to Q4 2023



With South Australia having its all-time lowest average operational demand of 1,089 MW, and electricity spot prices averaging $33/MWh in Q4 2023, compared to $64/MWh in Q4 2022, average gas-fired generation in South Australia reduced to 231 MW from 293 MW.

These factors led to an increase in directions required to maintain minimum synchronous generation levels to ensure system security.

The directed proportion of gas-fired generation in **South Australia** consequently increased, with the directed proportion of their total quarterly output reaching 20%, an increase from the 15% in the same quarter last year. The average directed volume of 46 MW was slighter higher than in Q4 2022, but a more significant increase from recent quarters in line with the reduction in overall gas-fired output (Figure 75).

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

Although the directed volume was largely consistent with Q4 2022, there was an increase in the percentage of dispatch periods in which two units were directed simultaneously, rising from 35% last Q4 to 48% this year (Figure 76) reflecting a pattern of directing multiple units at lower levels of output more frequently.

Figure 75 Increase in share of directed South Australian gas volumes

South Australian gas-fired generation directed – volume and share

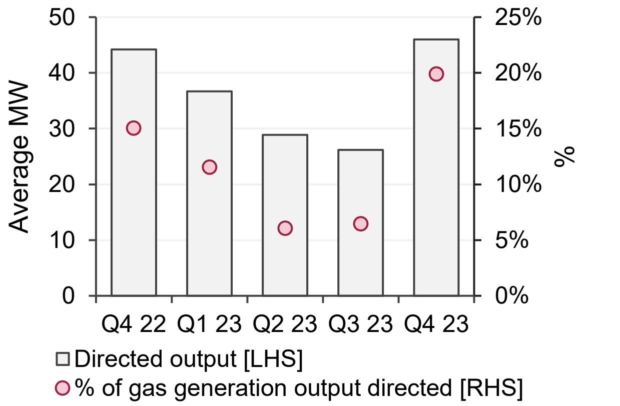
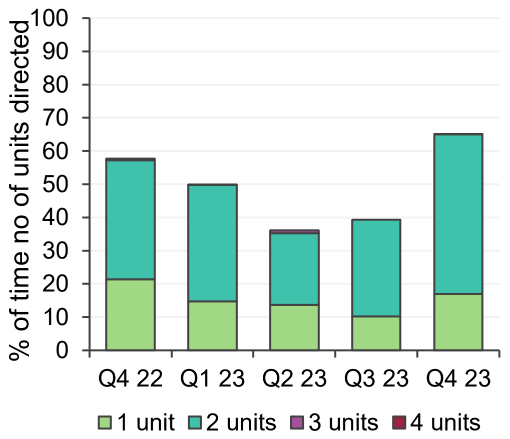


Figure 76 More frequent two-unit directions

Number of units simultaneously directed – proportion of quarter

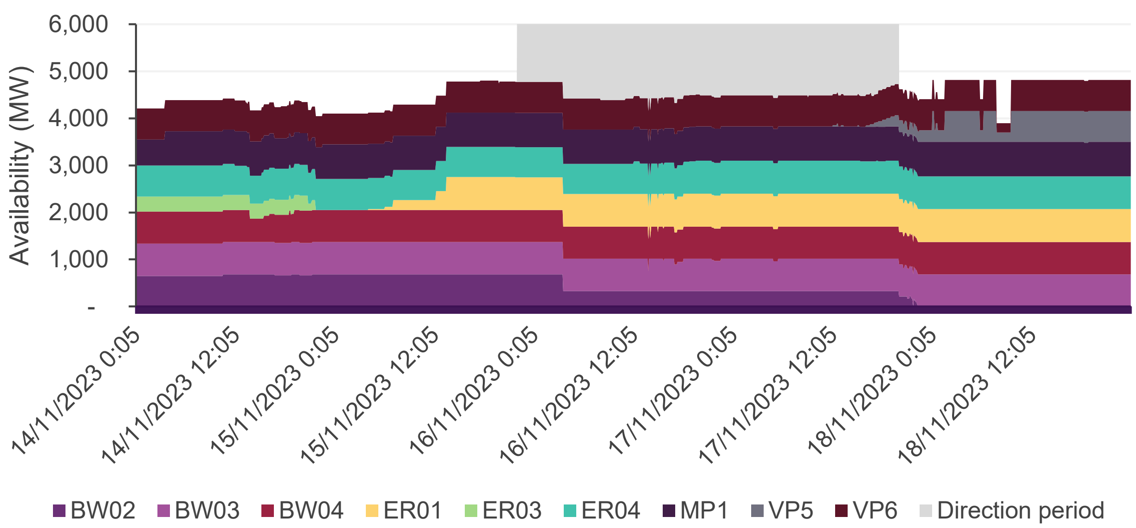


1.6.2 New South Wales system security directions

On 15 November 2023, the first system strength security direction was issued in **New South Wales** to maintain the power system in a secure operating state. In the lead up to the direction, there were five coal units in New South Wales offline due to planned or unplanned outages, with a sixth unit planning to commence a staged outage from 22:00 hrs on 15 November 2023, leaving just six units remaining online from 3:00 hrs on 16 November 2023. AEMO issued the direction to commence from 2205 hrs on 15 November which applied until 2000 hrs on 17 November 2023 when one of the units on outage returned to service. Figure 77 shows that there were on average seven coal units online in New South Wales in the lead up to the system security direction period which lasted until Vales Point 5 (VP5) unit returned to service.

Figure 77 New South Wales black-coal generator unit availability over system security direction

New South Wales black-coal fired generation availability – 14 November to 18 November 2023



2 Gas market dynamics

2.1 Wholesale gas prices

Quarterly average prices increased slightly compared to Q3 2023 but were 40% lower than Q4 2022. The average price across all AEMO markets was $10.83/GJ compared to $17.79/GJ in Q4 2022 (Table 5).

Table 5 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q4 2023	Q3 2023	Q4 2022	Change from Q4 2022
Declared Wholesale Gas Market (DWGM)	10.40	10.26	17.43	-40%
Adelaide	11.23	10.78	18.61	-40%
Brisbane	10.92	10.33	17.86	-39%
Sydney	10.82	10.34	17.71	-39%
Gas Supply Hub (GSH)	10.74	10.33	17.33	-38%

Key factors influencing the movement of prices throughout Q4 2023 are summarised in Table 6, with further analysis and discussion referred to relevant sections elsewhere in this report.

Table 6 Wholesale gas price levels: Q4 2023 drivers

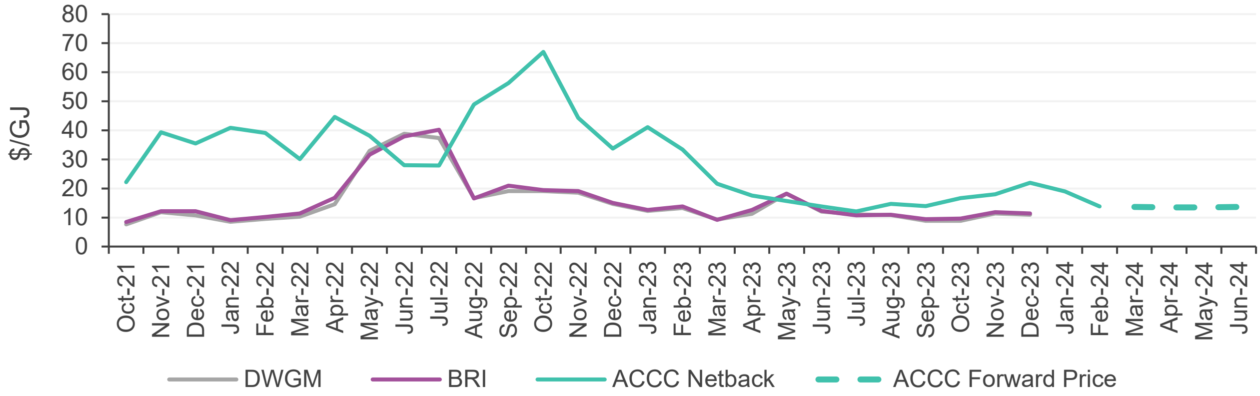
Lower offer prices into DWGM and Short Term Trading Market (STTM)	Q4 2023 saw a large increase in the proportion of volumes offered into the domestic spot markets at prices below $14/GJ compared to Q4 2022 (Figure 79). As noted in the Australian Competition and Consumer Commission (ACCC) Gas Inquiry[25], this has coincided with prices offered by producers continuing to trend downwards since their peak of $49/GJ in August 2022. As the ACCC report states, since the introduction of the price cap on 23 December 2022, through to 8 August 2023, producers have sold gas to the domestic market under short-term contracts at or below $12/GJ for 2023 supply.
Increased supply, combined with a reduction in domestic demand	Residential and commercial demand saw a large decrease, particularly in Victoria and Brisbane (Section 2.2). This was combined with an increase in supply in Queensland and from the Moomba Gas Plant, which more than offset the supply decrease in Victoria, and an increase in Queensland LNG exports. (Section 2.3).
Lower international prices	An increase in international LNG supply, coinciding with milder weather in the northern hemisphere, has contributed to lower LNG prices across the globe (Section 2.1.1). International prices play a role in influencing the domestic price, with many domestic supply offers linked to the world price.
Tanker problems at APLNG's export facility	From 24 November to 2 December 2023, the LNG tanker Cesi Qindao was unable to move from APLNG's facility due to a power failure. As a result, APLNG was unable process waiting tankers until the ship was towed out of port. During this period domestic prices saw a notable decrease; while production associated with the APLNG was reduced, the nature of coal seam gas means production cannot cease, with the additional supply causing prices to fall. This caused APLNG's LNG exports to reduce compared to Q4 2022 (Figure 84).

International prices continued to rise during the quarter, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, although corresponding forward prices have decreased below $15/GJ in Q1 2024, where previously they were closer to $20/GJ. The divergence of domestic prices from the ACCC netback price (Figure 78) is likely a result of lower demand conditions combined with ample supply.

[25] ACCC Gas Inquiry 2017-2030, December 2023, https://www.accc.gov.au/system/files/Gas%20Inquiry%202017-2030%20-%20December%202023_0.pdf

Figure 78 Slight divergence between domestic prices and the ACCC netback price for Q4

ACCC netback and forward prices[26], DWGM and STTM Brisbane average gas prices by month

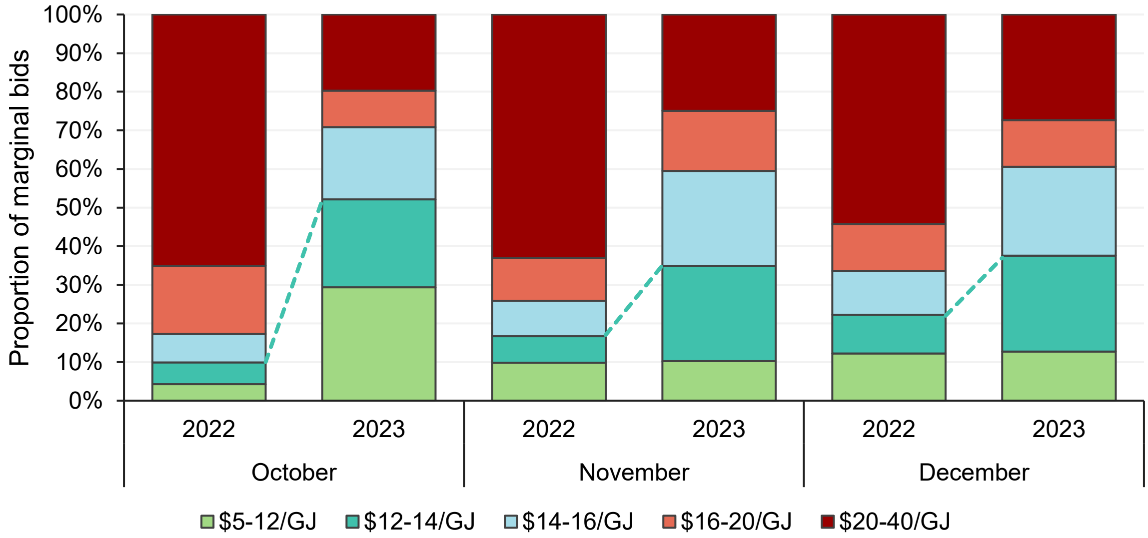


Prices across all markets began the quarter below $6/GJ, mainly due to unplanned outages at Queensland LNG export facilities, combined with mild weather and low gas-fired generation demand. Prices quickly increased, however, due to a combination of cooler weather and higher gas-fired generation demand leading to higher domestic demand, as well as a return to regular operations across the LNG export facilities, with prices peaking at over $13/GJ in mid-November. Prices subsequently decreased in late November due to an issue at the APLNG facility (see Section 2.2) which led to surplus supply available to the market, and prices dropped below $10/GJ. Once the APLNG issue was resolved, prices ranged from $11-12/GJ for most of December.

Compared to Q4 2022, there was a significant increase in the proportion of Declared Wholesale Gas Market (DWGM) bid volumes below $14/GJ (Figure 79). Factors contributing to this included lower domestic demand and increased southward flows from Moomba, helping offset lower supply from Longford.

Figure 79 Larger proportion of DWGM bids at lower prices for Q4 2023

DWGM – proportion of marginal bids[27] by price band – Q4 2023 vs Q4 2022 by month



[26] ACCC 2023, LNG netback price series, https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series

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

2.1.1 International energy prices

Newcastle export coal prices averaged $208/tonne this quarter, 64% lower than the high levels experienced in Q4 2022 due to weather and sanctions on Russian exports (Figure 80). Thermal coal prices this quarter have remained consistent with those in recent quarters, largely reflecting high stockpiles in China[28].

Figure 80 Thermal coal remained well below Q4 2022 levels

Newcastle export thermal coal A$/Tonne daily

Source: Bloomberg ICE data

Asian spot LNG prices rose sharply in the middle of October as China's regulator requested their state-owned natural gas suppliers to fill up their storage facilities prior to the peak winter heating season[29]. This call to increase demand along with some supply concerns due to the ongoing Middle East conflict caused the Asian LNG price to reach its highest level since mid-Jan 2023.

The price rally was short-lived, as can be seen in Figure 81, showing the Asian LNG price continued to slide, ending the year under $20/GJ. This has been largely due to healthy LNG supply from Qatar and Australian producers as well as Egypt restarting LNG exports after a halt in the immediate period following the outbreak of conflict in Gaza as well as milder (than average) weather conditions in Asia[30].

Brent Crude oil price averaged A$128/barrel this quarter; this was down slightly by A$3/barrel from Q3 2023 (Figure 82). While the average was only slightly lower (quarter on quarter), the price reached A$113/barrel at the end of the year. The spike at the start of the quarter was largely due to Saudi Arabia's extension of voluntary supply curtailment, however weaker global demand growth was the largest driver of the price slide throughout Q4[31].

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[28] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly December 2023: Resources and energy quarterly: December 2023 | Department of Industry, Science and Resources

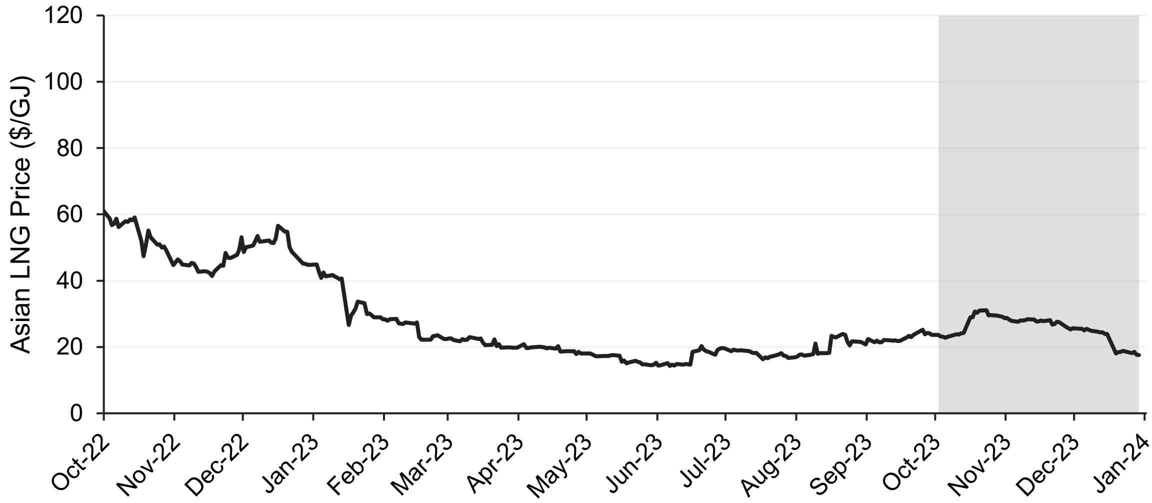
[29] Bloomberg, 2023: https://www.bloomberg.com/news/articles/2023-10-18/china-tells-gas-suppliers-to-fill-storage-tanks-ahead-of-winter

[30] Reuters, 2023: https://www.reuters.com/markets/commodities/asia-spot-lng-prices-fall-7-week-low-tepid-demand-improved-supply-2023-12-01/

[31] International Energy Agency, 2023 Oil Market Report – December 2023, https://www.iea.org/reports/oil-market-report-december-2023

Figure 81 Asian LNG rose in October before drifting downwards

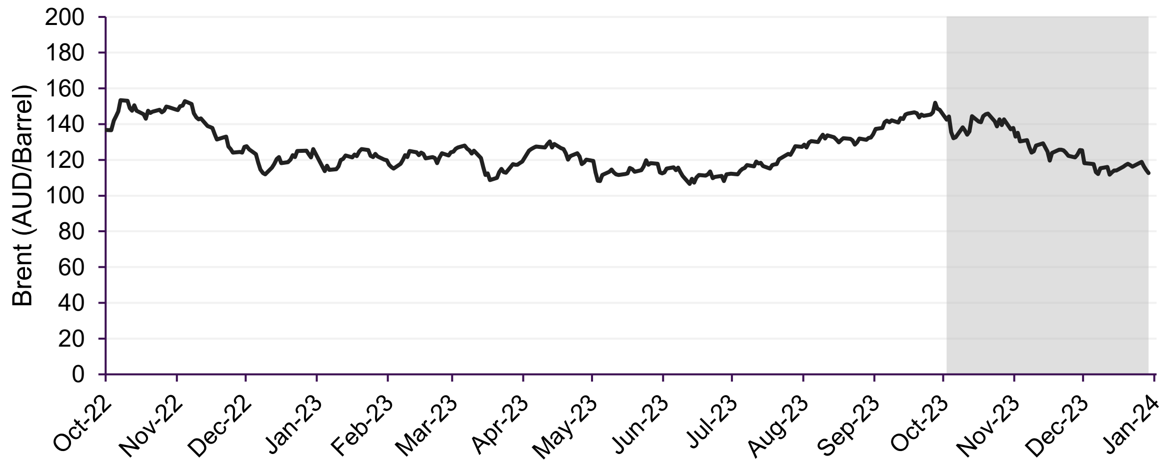
Asian LNG price in A$/GJ daily



Source: Bloomberg ICE data

Figure 82 Brent Crude oil prices slide over the quarter

Brent Crude oil in A$/Barrel daily



Source: Bloomberg ICE data

2.2 Gas demand

Total east coast gas demand increased by 3% compared to Q4 2022 (Figure 83 and Table 7), solely due to an increase in Queensland LNG production (+24 PJ). In the domestic market there were large falls in demand from AEMO markets (-11 PJ), and a small decrease in gas-fired generation (-1 PJ). All markets experienced lower demand, with the largest decrease of 5 PJ in Victoria's DWGM due to warmer temperatures combined with lower commercial and industrial demand. Brisbane Short Term Trading Market (STTM) volumes recorded a decrease of 4.5 PJ, primarily due to the shutdown of Incitec Pivot's Gibson Island facility in January 2023.

Figure 83 Higher gas demand solely due to increase in LNG exports

Components of east coast gas demand change – Q4 2022 to Q4 2023

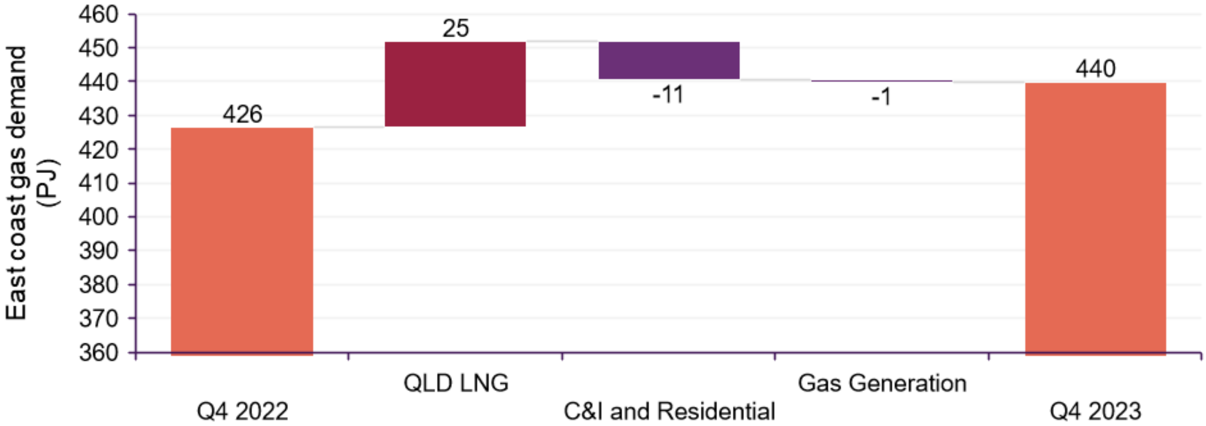


Table 7 Gas demand – quarterly comparison

Demand (PJ)	Q4 2023	Q3 2023	Q4 2022	Change from Q4 2022
AEMO markets *	57.5	91.4	68.7	-11 (-16%)
Gas-fired generation **	16.8	23.0	17.8	-1 (-5%)
Queensland LNG	365.3	341.5	339.9	+25 (7%)
Total	439.6	455.9	426.4	+13 (3%)

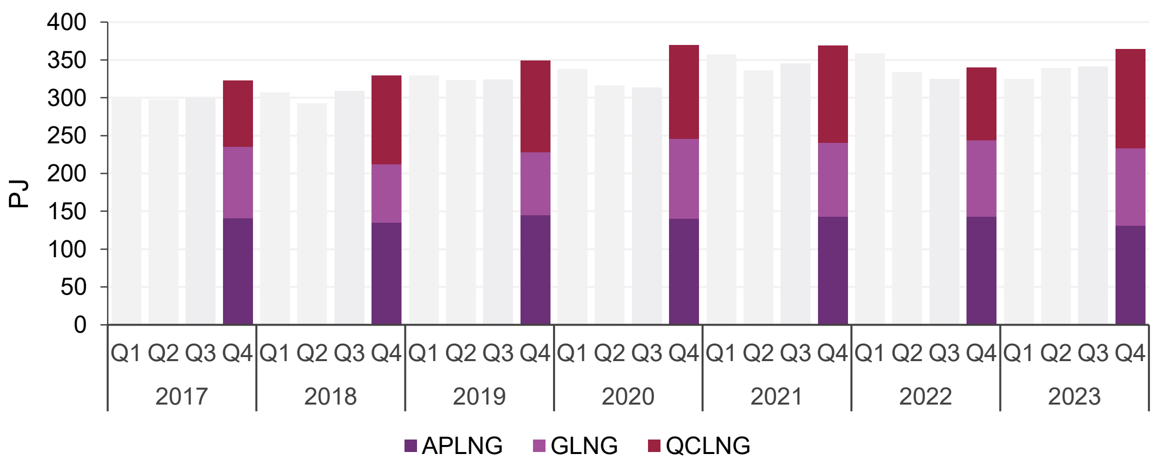
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand continued to increase, mainly due a large increase from QCLNG ramping up production, with a smaller increase from GLNG (Figure 84). QCLNG experienced multiple unplanned outages in Q4 2022 which led to atypically low demand. APLNG demand decreased due to LNG tanker Cesi Qindao being unable to leave the loading facility due to a complete power failure on the ship on 24 November. The tanker was towed out of Gladstone port on 2 December, resulting in a backlog of LNG tankers waiting at anchorage.

By participant, in comparison to Q4 2022, QCLNG demand increased by 34.7 PJ, GLNG increased by 1.9 PJ, and APLNG decreased by 12.2 PJ. There were 95 LNG cargoes exported during the quarter, up from 88 in Q4 2022.

Figure 84 APLNG production decrease due to unplanned outage but Queensland LNG production higher

Total quarterly pipeline flows to Curtis Island



2.3 Gas supply

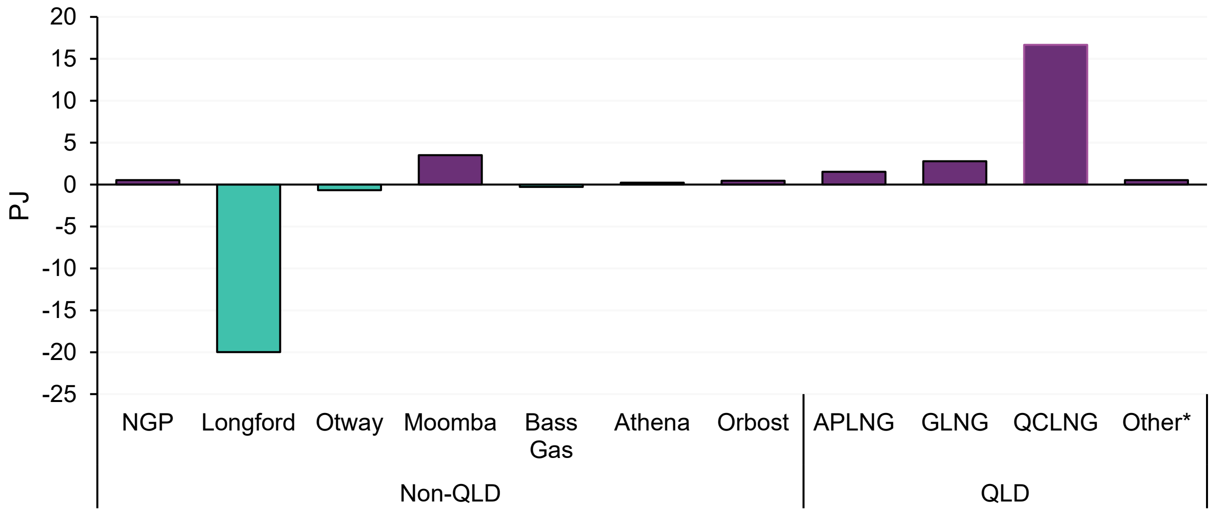
2.3.1 Gas production

East coast gas production increased by 5.3 PJ (1%) compared to Q4 2022 (Figure 85). Key changes included:

- Decreased Victorian production (-20.3 PJ), mainly driven by lower production at Longford (-20 PJ)
- Increased Queensland production (+21.5 PJ), with assets operated by QCLNG increasing by 16.7 PJ, GLNG operated assets by 2.8 PJ, and APLNG operated assets by 1.5 PJ. Gas demand for Queensland LNG exports increased by 24.4 PJ, meaning supply associated with Queensland LNG projects into the domestic market was 2.9 PJ lower compared to Q4 2022.
- Increased Moomba production (+3.5 PJ), continuing the increase observed in Q2 and Q3 2023. As previously reported, increased production has coincided with an increase in the number of wells drilled in the Cooper Basin throughout 2023.

Figure 85 Production continues to fall at Longford

Change in east coast gas supply – Q4 2023 vs Q4 2022



2.3.2 Longford production and capacity

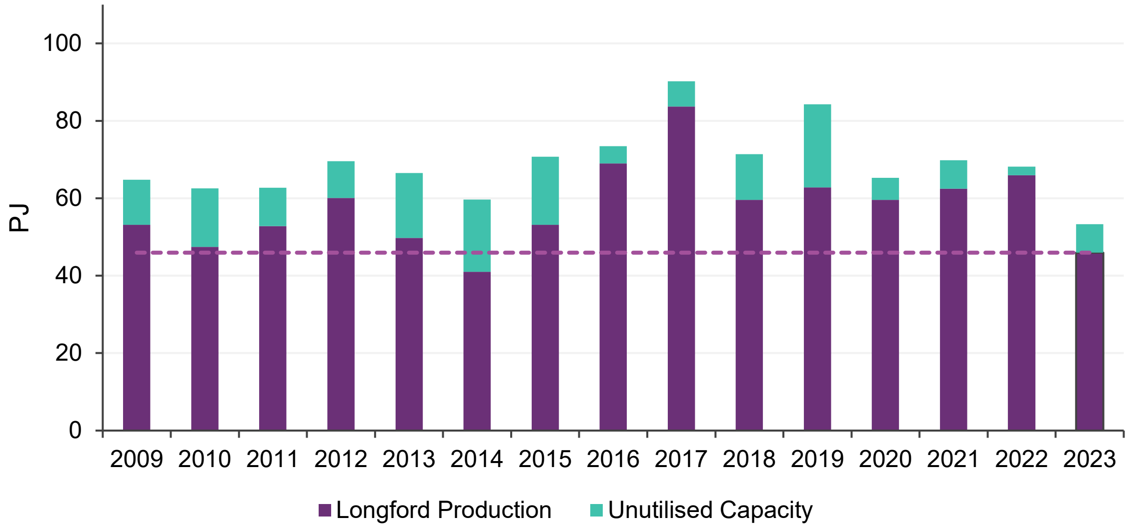
Q4 continued the decline in Longford production and capacity observed throughout 2023. Longford's production of 46 PJ was the second lowest Q4 since data commenced on the Gas Bulletin Board (GBB) in 2009 (Figure 86). Production in 2014 dropped to 41 PJ due to commissioning of the Queensland coal seam gas production projects which saw a large short-term increase in Queensland supply to the domestic market prior to the commencement of LNG exports.

Longford's available production capacity of 53 PJ in Q4 2023 was its lowest Q4 level since data reporting began. As noted in previous QED reports, the capacity decrease mostly reflects declining gas reserves in the Bass Strait fields connected to Longford, and has been forecast in AEMO's *Victorian Gas Planning Report* and *Gas Statement of Opportunities*[32].

[32] See https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report and https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Figure 86 Second lowest Longford Q4 production and lowest capacity since data reporting began

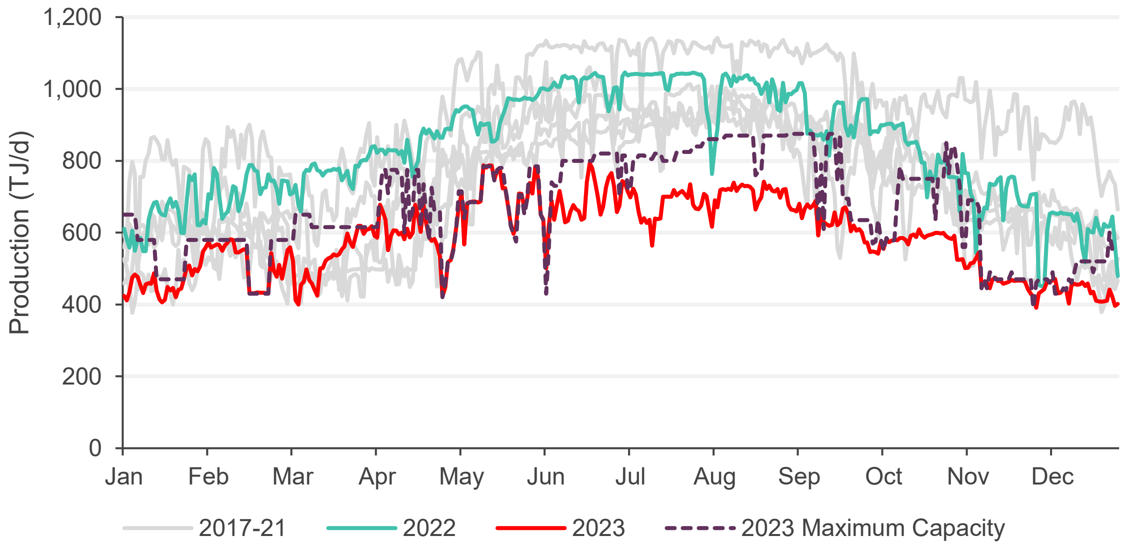
Longford Q4 production versus unutilised capacity



Daily production for much of October was well below available capacity (Figure 87), although with a large decrease in capacity in November due to planned maintenance, production was at available capacity for most of the next month. Production remained steady in December despite an increase in available capacity. Some of this gap was driven by reduced demand, as well as an increase in Longford supply offer prices above the daily DWGM and Sydney STTM price outcomes.

Figure 87 Daily Longford production continued to decline

Daily Longford production 2017-2023, maximum capacity profile 2023



For over 40 years, Longford has been the largest gas production facility across the East Coast. For the first time, the QGC operated Woleebee Creek production facility in Queensland overtook Longford as the largest gas production facility on the East Coast on an annual production basis (Figure 88). Woleebee Creek was commissioned in 2014 and achieved its highest annual production of 235 PJ in 2023, surpassing Longford's 213 PJ. The QGC operated Ruby Jo gas plant was the next highest at 129 PJ.

Figure 88 Woleebee Creek surpassed Longford as the largest production facility on the east coast

Annual Woleebee Creek vs Longford production

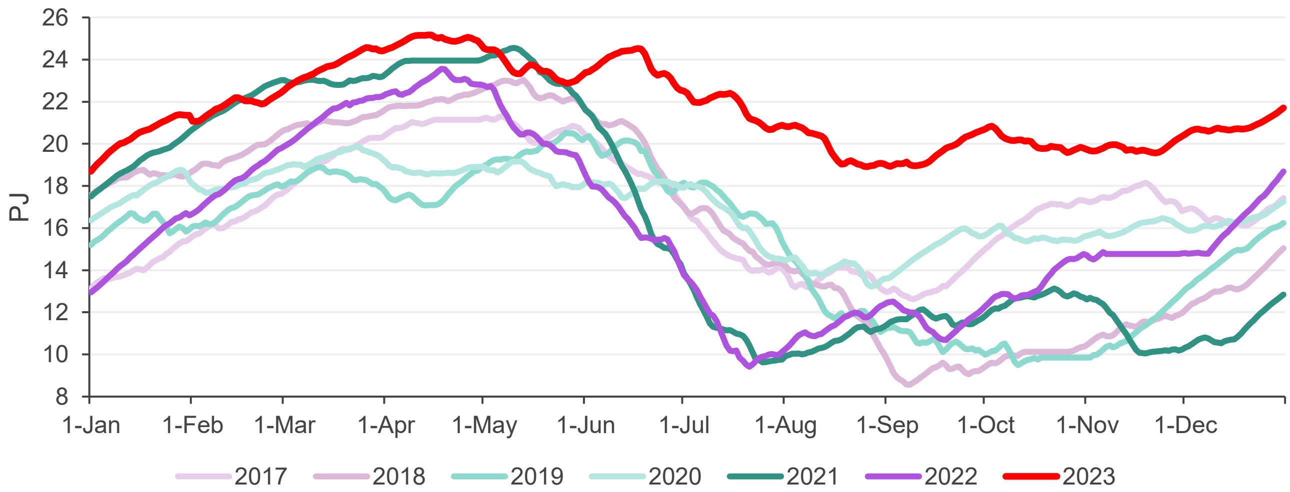
2.3.3 Gas storage

The Iona UGS facility finished the quarter with an inventory of 21.7 PJ, 2.9 PJ higher than at the end of Q4 2022 (Figure 89), and the highest end to a Q4 since reporting began in 2017.

Storage inventory filling slowed during the quarter and inventory levels decreased in October and November, primarily due to a slowdown in supply from Queensland to the southern markets, combined with reduced Longford capacity. Storage levels increased from late November, however, aided by an increase in supply from Queensland to the southern markets, then lower demand traditionally associated with the holiday period later in December.

Figure 89 Iona storage at its highest end to Q4 since storage levels began reporting

Iona storage levels

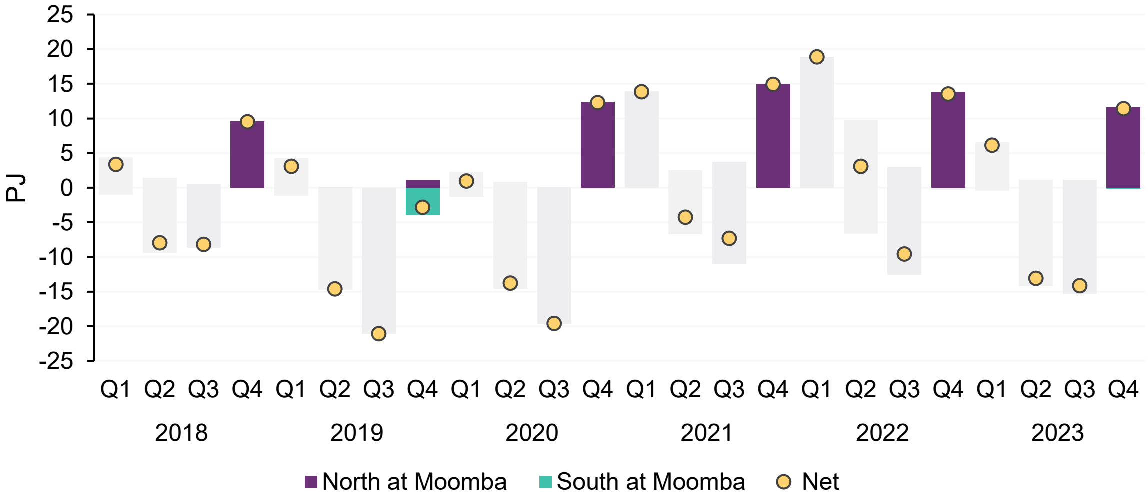


2.4 Pipeline flows

Compared to Q4 2022, there was a 2.1 PJ decrease in net transfers north from Moomba on the South West Queensland Pipeline (SWQP, Figure 90) which represents the lowest flow north from Moomba for a Q4 since 2019. This decrease reflects the large reduction in Longford production, combined with an increase in Moomba production flowing south to partially offset Longford's decline.

Figure 90 Net Q4 flows north on SWQP decreased to lowest level since 2019

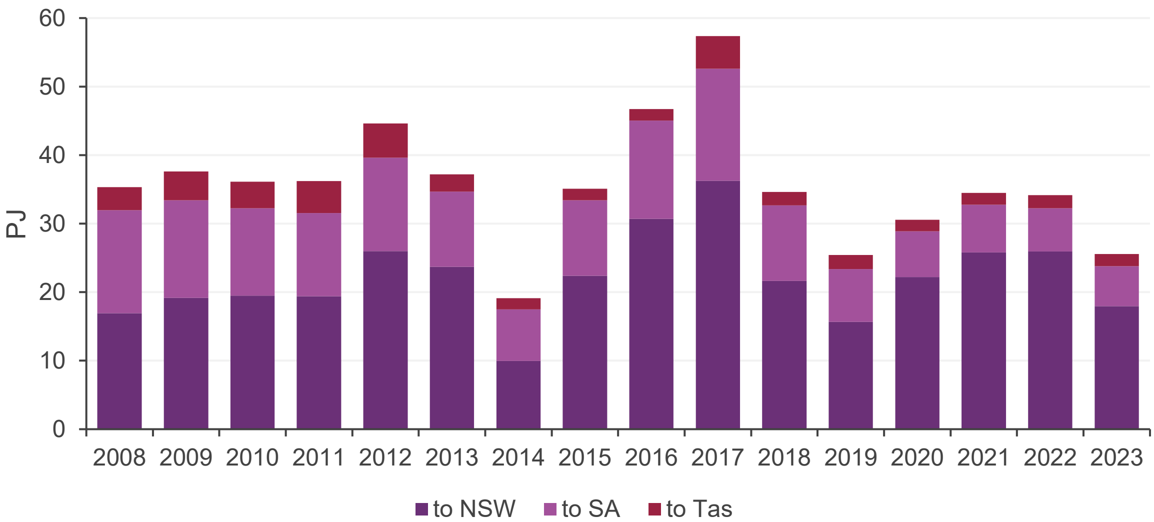
Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states decreased by 8.6 PJ from Q4 2022 levels, due to lower Longford production, increased Moomba production, and increased production in Queensland. Only 2019 (0.1 PJ lower) and 2014 (6.4 PJ lower) saw lower Q4 net transfers out of Victoria since data reporting on the GBB began in July 2008 (Figure 91).

Figure 91 Third lowest Victorian Q4 exports since data reporting began

Victorian net gas transfers to other regions – Q4s



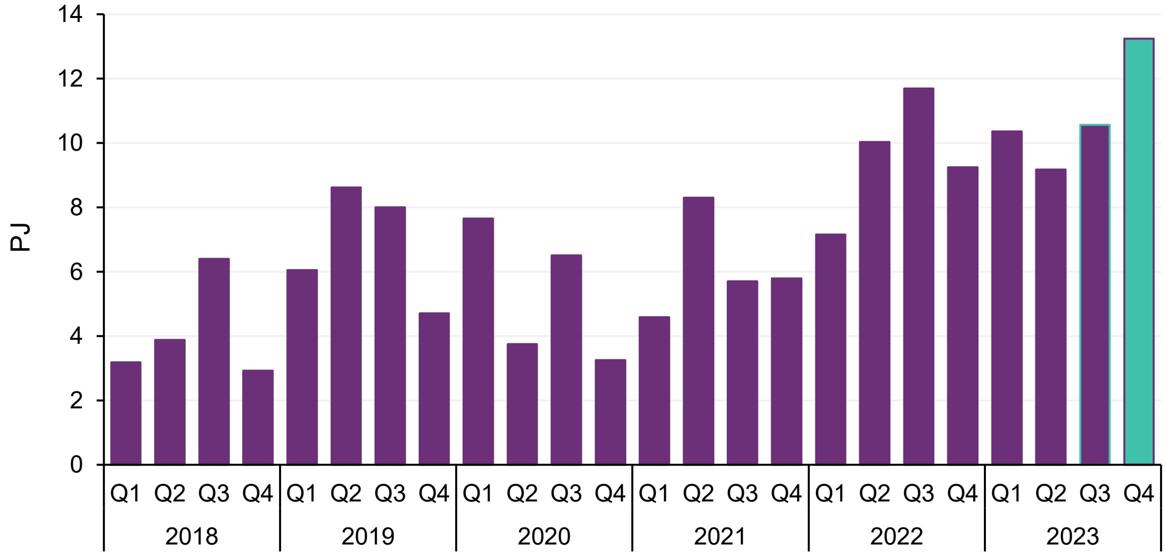
Net flows from Victoria to New South Wales decreased 8.0 PJ in comparison to Q4 2022 levels; there was a 2.3 PJ decrease in net flows via Culcairn and a 5.7 PJ decrease in flows via the Eastern Gas Pipeline (EGP). Instead, Sydney STTM demand was met by increased flows from Queensland. Flows from Victoria to South Australia decreased by 0.5 PJ from Q4 2022 levels, while there was a 0.2 PJ decrease in flows to Tasmania.

2.5 Gas Supply Hub (GSH)

In Q4 2023, traded volumes on the GSH increased by 4.0 PJ in comparison to Q4 2022 (Figure 92). The traded volume this quarter was 13.2 PJ and represented the highest volume on record. In addition, December was the highest monthly traded volume on record at 6.8 PJ. Contributing to the higher traded volume was a large volume transacted for delivery across 2024.

Figure 92 Highest GSH traded volumes on record

Gas Supply Hub – quarterly traded volume



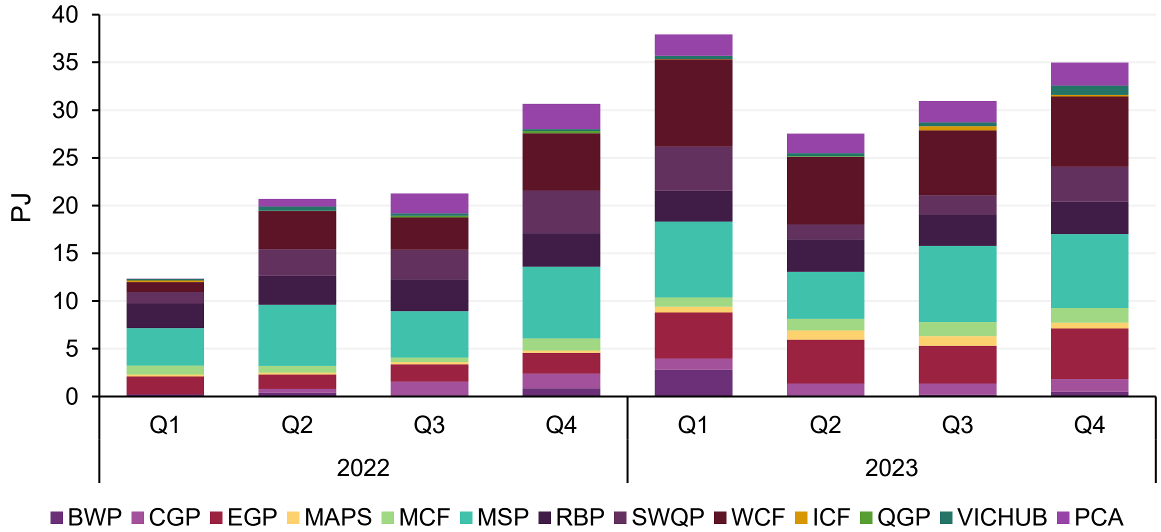
2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes set a new Q4 record of 35.0 PJ, 4.3 PJ higher than the previous Q4 record of 30.7 PJ set in 2022 (Figure 93). Compared to Q4 2022, the largest increase occurred on the Eastern Gas Pipeline (EGP, +3.1 P). A large increase in auction volume also occurred on the Wallumbilla Compressor (WCF, +1.4 PJ).

Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were the EGP, which averaged $0.08/GJ, the Roma to Brisbane Pipeline (RBP) which averaged $0.03/GJ, and the SWQP which averaged $0.02/GJ.

Figure 93 Highest Q4 Day Ahead Auction utilisation since market start

Day Ahead Auction volumes by quarter



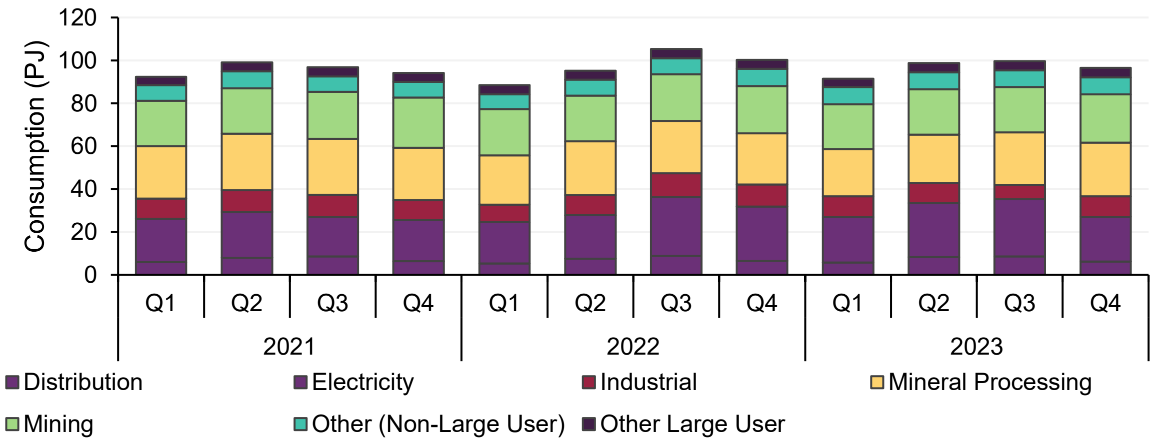
2.7 Gas – Western Australia

2.7.1 Gas consumption

A total of 96.5 PJ was consumed via pipeline in the Western Australian domestic gas market in Q4 2023 (Figure 94). This is a continuation of the downward trend that was observed in Q3 2023. Compared to the previous quarter, Western Australia consumed 3.2 PJ less gas (-3.2%). It is also a decrease compared to Q4 2022 when consumption in Western Australia totalled 100.2 PJ (-3.7%)

Figure 94 Western Australian domestic gas consumption reduced from both Q4 2022 and Q3 2023

WA quarterly gas consumption by sector – Q1 2021 to Q4 2023



The main drivers for this reduction in consumption compared to the previous quarter were:

- Decreased usage of gas in the electricity sector. This was down by 5.7 PJ (-21.6%), driven by a reduction at Cockburn Power Station (down by 64%) and Kemerton Power Station (down by 63%).

- Decreased usage in gas for distribution. This was down by 2.5 PJ (-28.7%), as distribution in 'Metro' reduced by 1.6 PJ and in the 'South West' reduced by 0.6 PJ.

Both reductions in consumption are aligned with Q3 2023. The reduction in gas usage in the electricity sector is also reflected in the change in fuel mix in this quarter (see Section 3.3.1).

While gas consumption in general has come down, it increased by 40.9% in the industrial sector as the Yara Pilbara Liquid Ammonia Plant increased its usage by 2.9 PJ or nearly 70% compared to Q3 2023.

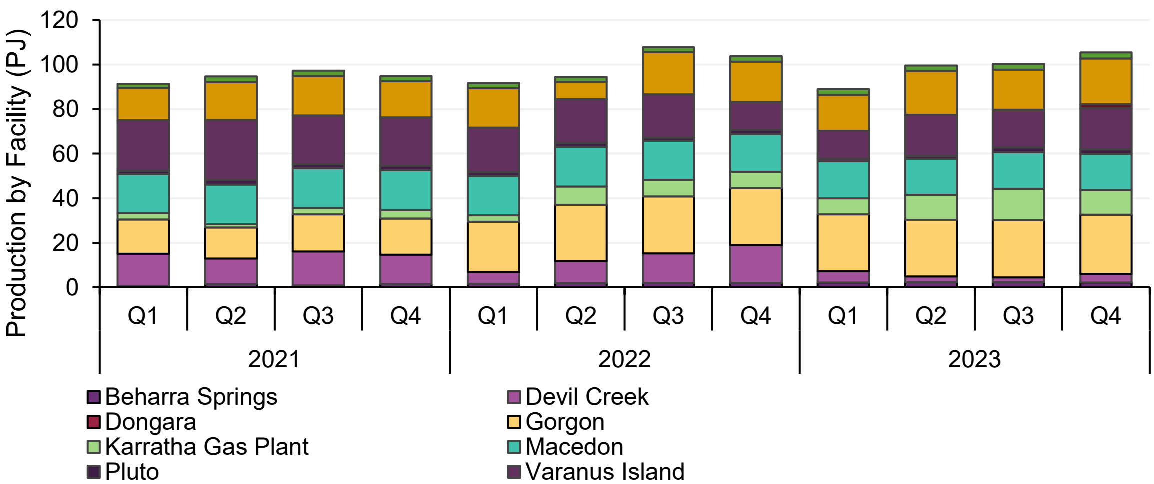
2.7.2 Gas production

Domestic gas production increased in Q4 2023 to 105.4 PJ. This is an increase of 5.1 PJ compared to Q3 2023 (5.1%) as well as compared to Q4 2022 (1.7%) (Figure 95). Key drivers of the changes in gas production in Western Australia compared to the previous quarter included:

- Wheatstone increasing production by 2.5 PJ. Wheatstone had periods of no production in Q3, which it did not experience in Q4 2023, accounting partly for this difference. It also increased its daily production by approximately 15 TJ in this last quarter to almost 230 TJ/d.
- Production commenced at Strike Energy's Walyering Production Facility late Q3 2023 and continued for the full quarter in Q4 2023. As a result, production levels were higher this quarter accounting for an increase of 1.8 PJ. Production currently has not yet reflected the Facility's nameplate capacity of 33 TJ/d.
- Devil Creek increased production in Q4 2023 by 1.7 PJ, an increase of 79%. This is to be expected as the Facility was not producing at all for 54 days in Q3 2023. Despite this increase in Q4, production levels remain well below levels observed in all quarters in 2021 and 2022, reflecting the declining reserves of the Reindeer gas field supplying the facility.
- Karratha Gas Plant was down significantly by 3.1 PJ (-22%) compared to last quarter. However, it was up by 3.7 PJ (51.2%) compared to Q4 2022. Despite production being lower than last quarter, Karratha Gas Plant's production has been considerably higher the last three quarters than it has been since 2020.

Figure 95 Western Australian domestic gas production increased from both Q3 2023 and Q4 2022

WA quarterly gas production by facility – Q1 2021 to Q4 2023

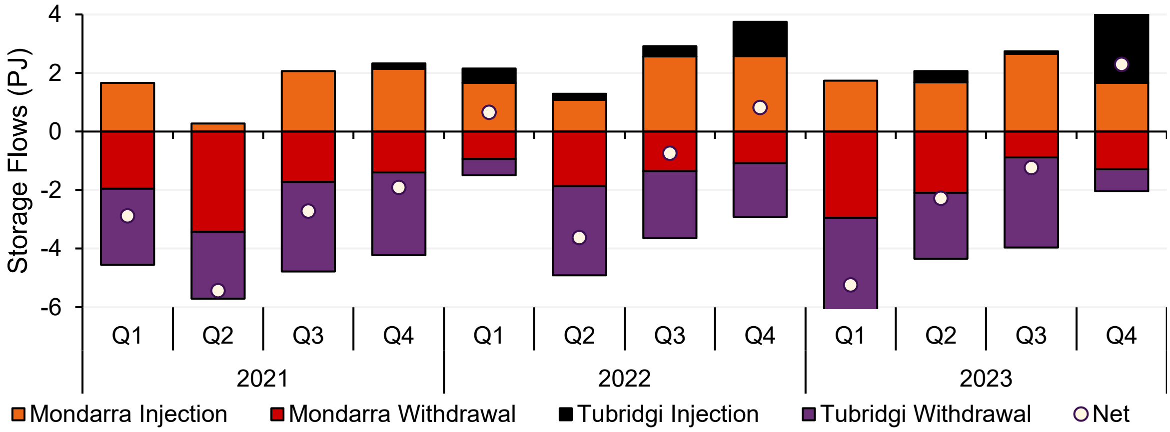


2.7.3 Storage facility behaviour

For the first time in 2023, there was a positive net flow of gas into storage in Western Australia. At the end of Q4, the net flow of gas in Mondarra and Tubridgi combined, accounted for 2.3 PJ; an increase of 3.5 PJ compared to Q3 2023 and 1.5 PJ to Q4 2022 (Figure 96). The main driver for this positive net flow, was the stark increase in gas in storage in Tubridgi this quarter, up by 2.6 PJ and a decrease of 2.3 PJ in withdrawals from this same storage facility.

Figure 96 Net positive storage flows in Q4, for the first time in 2023

WA gas storage facility injections and withdrawals – Q1 2021 to Q4 2023



3 WEM market dynamics

3.1 Introduction to the new Wholesale Electricity Market

The WEM is evolving with higher levels of renewable energy and new technologies, including grid-scale battery storage. To facilitate these changes, the Western Australian government is progressing its Energy Transformation Strategy, including reforms to the WEM.

The commencement of the new WEM on 1 October 2023 saw Western Australia's main power system move to a Security Constrained Economic Dispatch (SCED) market model. In this model, Network Limits are respected when calculating the lowest cost dispatch. When Network access is on a constrained basis[33], more low-cost renewable energy can connect to the grid. A constrained dispatch model also better reflects actual physical constraints of the Network and therefore provides great visibility and decreases the need for intervention in the dispatch process. The new WEM also includes new Essential System Service (ESS) markets to support the security and reliability of the power system as it transitions to higher levels of renewable and distributed energy.

The SCED market model co-optimises the delivery of energy and ESS required for frequency control, to maintain the power system in a stable and secure operating state at the lowest cost. The new market also includes the inclusion of a new Rate of Change of Frequency (RoCoF) control service aimed at addressing the growing challenge of maintaining system inertia within the power system.

Frequency Co-optimised Essential System Services

As of 1 October 2023, a new framework for Frequency Co-optimised ESS (FCESS)[34] was implemented. FCESS is procured to maintain the system-wide frequency within its normal operating bands. These services are being procured in the Real-Time Market where they are co-optimised with energy in the newly developed WEM Dispatch Engine (WEMDE). In every five-minute dispatch interval, a megawatt quantity for energy and each FCESS is procured in a way that maximises economic efficiency, while respecting power system constraints and FCESS requirements. The WEM now has five FCESS markets (Table 8).

Table 8 WEM FCESS markets

FCESS service	Function
Regulation • **Raise** • **Lower**	• Functions to keep the South West Interconnected System (SWIS) Frequency close to 50 Hz by offsetting minor mismatches between electricity supply and demand. • It is provided by Facilities capable of receiving Automatic Generator Control (AGC) signals from AEMO. Facilities can provide Regulation Raise service, Regulation Lower service, or both.
Contingency Reserve • **Raise** • **Lower**	• Functions to arrest, stabilise, and restore the SWIS Frequency after a Contingency Event occurs. • It is provided by Facilities which hold capability in reserve to rapidly adjust output or consumption in response to significant changes in their local frequency. • Facilities can provide Contingency Reserve Raise service, Contingency Reserve Lower service, or both.
Rate of Change of Frequency (RoCoF) Control	• Functions to slow the RoCoF to within the RoCoF Safe Limit. It is provided by Facilities which contribute Inertia when synchronised to the power system.

[33] Network access on a constrained basis removes the obligation for new entrants to fund augmentation, reduces barriers to entry, and increases the utilisation of the Network.

[34] For more information see https://www.wa.gov.au/system/files/2021-05/Information%20Paper%20-%20Non-Cooptimised%20Essential%20System%20Services%20.pdf

Non-Cooptimised Essential System Services

As part of WEM Reform, a framework for Non-Cooptimised Essential System Services (NCESS) went live prior to the new market. This new framework replaces historical frameworks for Network Control Services (NCS) and Dispatch Support Services (DSS).

System Restart Services (SRS) are a specific form of NCESS. AEMO procures SRS to enable it to restart the South West Interconnected System (SWIS) in the unlikely event of a widespread blackout. AEMO procures these services contractually under the framework in the WEM Rules.

Other Non-Cooptimised Essential System Services are defined and procured a case-by-case basis by AEMO or the Network Operator, on approval or direction from the Coordinator. They are required to support other system and network needs, such as locational services used to substitute for network upgrades or to provide capabilities during periods of low operational demand. These are procured by the relevant entity through contestable contracts from capable providers.

For the first time, services procured by AEMO under the new NCESS framework were available in the SWIS in Q4 2023. AEMO procured 84 MW of minimum demand support service for the 12 months commencing 1 October 2023, to assist in managing the ongoing reductions in minimum system load as continued strong installations of distributed solar PV offsets demand from large-scale generation in the SWIS.

3.2 Weather observations and electricity demand

Similar to Q3 2023, Q4 was characterised by 'above average' to 'record warm' temperatures (Figure 97). October 2023 saw mean maximum temperatures that were 2.8°C higher than the 30-year average for this month and December was 1.5°C higher. Even though both of these months were already warmer than would normally be expected, it was November 2023 that set several new records. In November, the mean max temperatures were 3.5°C above normal temperatures, at an average of 30.2°C.

These high temperatures set a new November record, exceeding the previous record of 29.6°C in 2007, with records commencing in 1897. A heatwave was experienced in and around Perth between 20 and 25 November, with Perth recording six days in the month where daily maximum temperatures were above 35°C. It was the first time a heatwave has reached 'severe intensity' in November[35]. It was also the first time that Perth's mean minimum temperature in November was over 17°C (17.1°C), with the previous highest being 16.9°C in 1983.

The severe intensity heatwave in November led to a new all-time maximum average operational demand[36] record in the WEM on 23 November 2023 (0), prior to the commencement of the Hot Season and associated Reserve Capacity processes on 1 December. During the 17:55 dispatch interval, maximum operational demand reached 4,046 MW[37], superseding the previous record of 4,006 MW set in 2006. It also superseded the previous spring maximum operational demand record by more than 800 MW, underlining how unusually hot the weather was for this time of the year.

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[35] http://www.bom.gov.au/climate/current/month/wa/archive/202311.perth.shtml

[36] Average Operational Demand is defined as the average total injection (sent out, MW) from all registered Facilities in the WEM over a Dispatch Interval (5 min period) based on non-loss adjusted SCADA. Note that this metric is distinct from Operational Demand as defined in the WEM Rules, which is an instantaneous, end of interval measurement used for dispatch purposes.

[37] Correction: AEMO previously reported the record maximum demand on 23 November 2023 was 4,041 MW. This value was the average unscheduled operational demand and is the net of withdrawal from registered Facilities. Going forward AEMO will report average operational demand, which only considers injection from registered Facilities, see footnote 31 for further definition.

Figure 97 Warmer than average temperatures across Australia

Q4 2023 mean temperature deciles for Australia

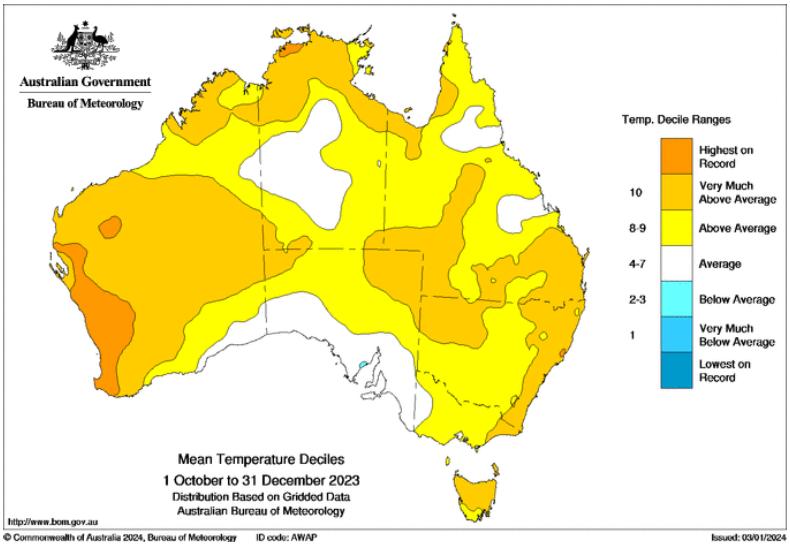
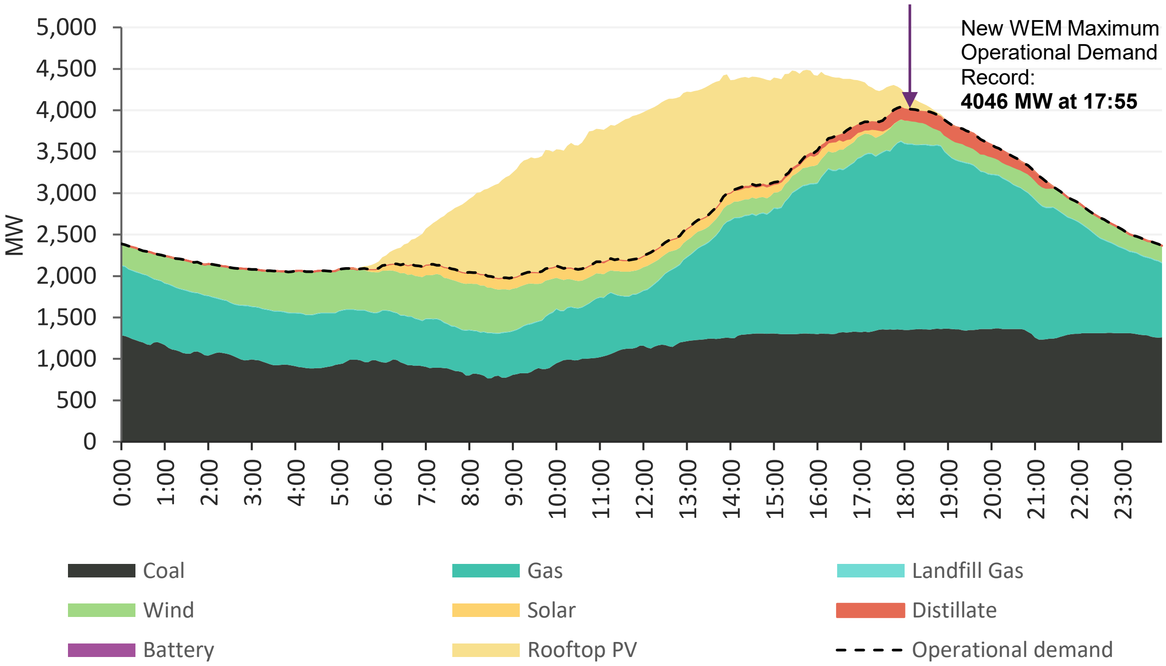


Figure 98 All-time WEM maximum average operational demand recorded: 4,046 MW on 23 November 2023

Fuel types contributing to WEM maximum average operational demand by time of day – 23 November 2023



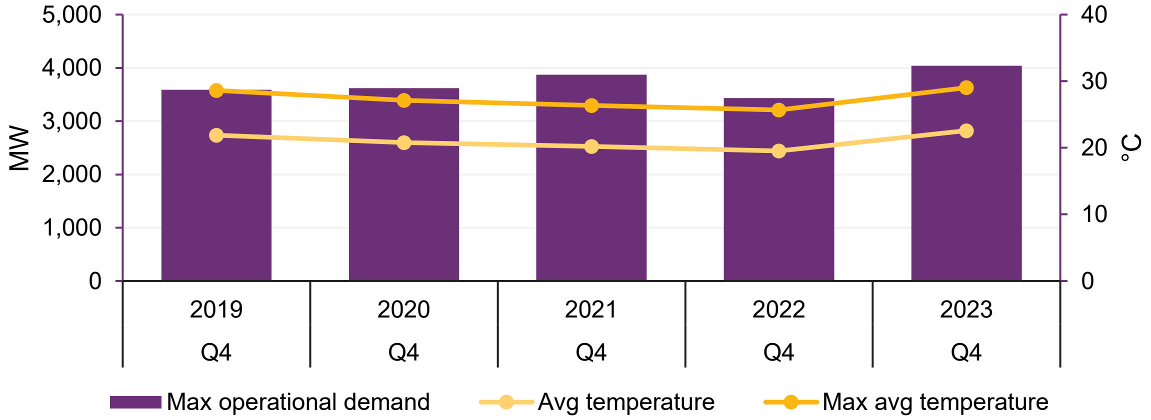
The relationship between the record warm temperatures and the maximum average operational demand per quarter is clearly observed in Figure 99.

The impact of the record high temperatures is also visible in the WEM quarterly average operational demand figures. In Q4 2023, average operational demand was 1,888 MW, representing an increase of 165 MW (+9.6%) compared to 1,723 MW in Q4 2022. Average underlying demand[38] also increased significantly; in Q4 2022 it was 2,205 MW, and it increased by 227 MW (10%) to 2,432 MW in Q4 2023.

[38] Underlying demand is an estimated measurement of the total load on the SWIS, including behind-the-meter demand. Underlying demand is measured as operational demand adjusted to remove the impact of distributed PV output.

Figure 99 Record warm temperatures led to new all-time average operational demand record

Maximum demand and average temperatures year on year – Q4s



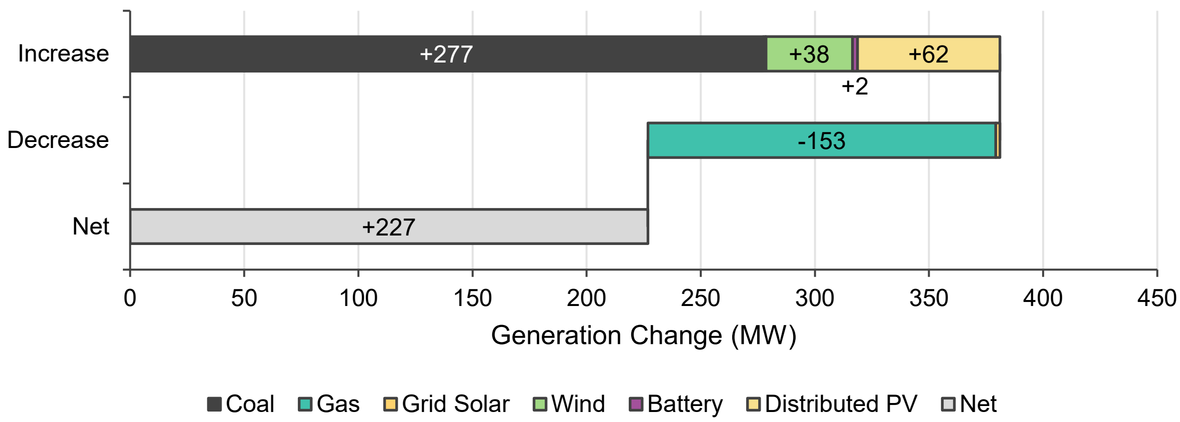
3.3 Electricity generation

3.3.1 Change in fuel mix

The total average generation output in the WEM over Q4 2023 was 227 MW (10%) higher than Q4 2022, driven by the overall increase in underlying demand (see Section 3.2). The increase was met by all fuel types, except by gas-fired generation and grid solar, which decreased compared to Q4 last year.

Figure 100 Coal-fired, distributed PV and Wind generation offset a decrease in gas-fired generation

Change in quarterly average generation – Q4 2023 vs Q4 2022



Changes in generation by fuel type, compared to Q4 2022 (Figure 100) were:

- Average coal-fired generation reached 715 MW, an increase of 277 MW (+63%) on Q4 2022. This can be attributed to the need to preserve coal and assuring adequate stockpiles in Q4 2022 for the peak summer period. This resulted in several forced outages in the SWIS in Q4 2022.
- Estimated distributed PV continued its growth trend as expected, increasing by 62 MW (+13%) on average.
- Average gas-fired generation reached 673 MW, a reduction of 153 MW (-18%) compared to Q4 2022.
- Wind generation increased by an average of 38 MW (+10%) to 434 MW.

- Distillate levels increased by almost 1 MW (489%) on average which is considerably high, noting that it is almost five-fold of the distillate levels observed in Q4 2022.
- KBESS[39], the first registered large-scale battery operating in the SWIS, has been operating for most of Q4 2023 and has as such added an average 2 MW into this generation change.

Table 9 Table WEM fuel mix Q4 2022 and Q4 2023

Quarter	Coal	Gas	Distillate	Grid solar	Landfill gas	Wind	Battery	Distributed PV
Q4 2022	19.9%	37.4%	0%	2.5%	0.4%	18%	N/A	21.8%
Q4 2023	29.4%	27.7%	0%	2.2%	0.4%	17.9%	0.1%	22.4%
Change (pp)	+9.5%	-9.7%	0	-0.3%	0	-0.1%	+0.1%	+0.6%

3.3.2 Renewable penetration

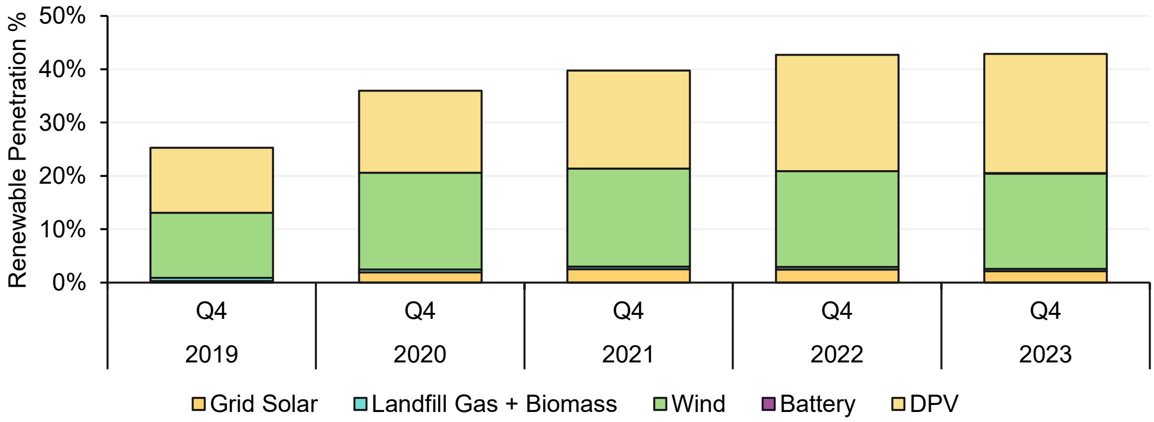
The maximum renewable penetration in Q4 2023 was 79.6%, which was recorded at 12:00 hrs on 16 November 2023. This sits below the all-time record of 84% set on 2 December 2022.

The SWIS did, however, set an all-time record for maximum renewable generation[40] of 2,592 MW at 11:55 hrs on 22 November 2023. This eventuated during the heatwave in November when demand was high. The new record supersedes the previous record of 2,501 MW set on 3 February 2023.

The quarterly average renewable penetration only slightly increased from 42.7% in Q4 2022 to 42.9% in Q4 2023 (Figure 101), due to similar growth in underlying and operational demand to increases in renewable generation from existing facilities, KBESS and DPV.

Figure 101 Average renewable generation share increased to 42.9% in Q4 2023

Renewable penetration components – Q4s



39 KWINANA_ESR1

40 Maximum Renewable Generation is defined as the average injection (sent out, MW) from grid solar, landfill gas + biomass, wind, battery and estimated DPV over a Dispatch Interval (5 min period) based on non-loss adjusted SCADA.

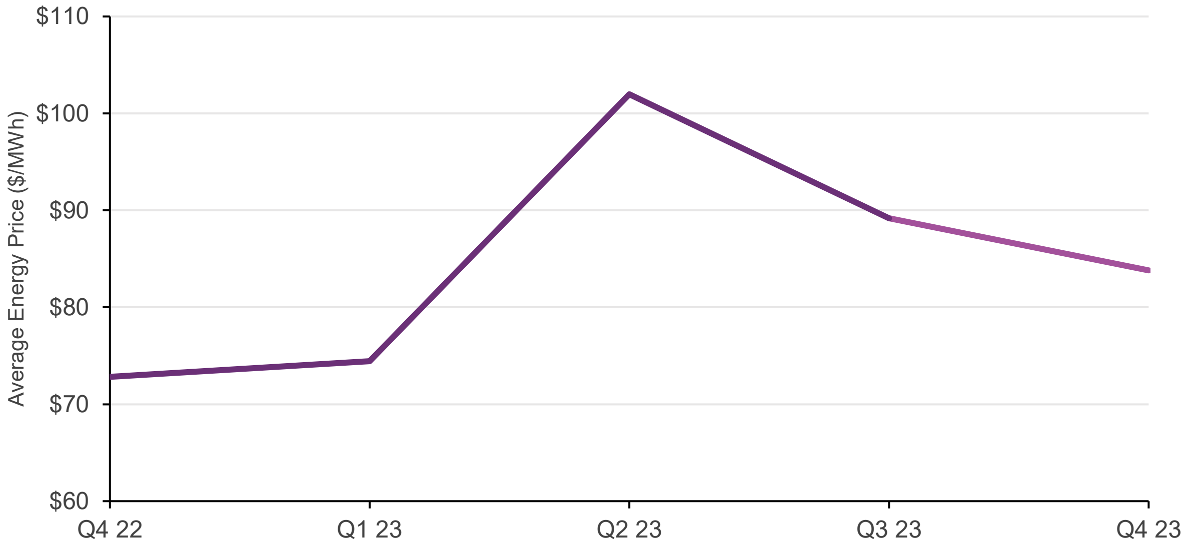
3.4 WEM prices

3.4.1 Real-Time Market price dynamics

The average Final Reference Trading Price was $83.83 in Q4 2023, an increase of 15% in comparison with the average Balancing Price in Q4 2022, but lower than historically high Balancing Prices observed in Q2 and Q3 2023, which peaked as a result of tight conditions in these quarters driven by high winter demand and high generation outages (Figure 102).

Figure 102 Balancing and Real Time Energy Prices

Quarterly Average Prices from Q4 2022 to Q4 2023



The total cost of ESS and Energy Uplift[41] in Q4 2023 increased by 370% compared to costs for Ancillary Services (AS) and Constrained Compensation in Q4 2022 (Figure 103). This was driven by significant increases in costs in all FCESS Market Services compared to their equivalents in the previous market, most significantly Contingency Raise which cost $31.3M over the quarter – representing 50% of total ESS and Energy Uplift Costs – compared to $2.1M for the equivalent Spinning Reserve Ancillary Service (SRAS) in Q4 2022.

Significant increases to the cost of Contingency Raise and Contingency Lower are driven by a fundamental shift in the framework for cost determination, from an administered pricing framework to a market-based mechanism. Prior to October 2023, pricing for SRAS (equivalent to Contingency Raise) was determined as a percentage of the Balancing Price based on margin values set by the ERA, while costs for Load Rejection Reserve (LRR, equivalent to Contingency Lower) were based on the Cost_LR parameter set by the ERA. These parameters were intended to represent direct and opportunity costs associated with providing these services. In contrast, in the new market prices are determined via a market mechanism based on participant-submitted prices, optimised by the new WEMDE. As such, this increase in prices may be more reflective of the true cost of Essential System Services in the WEM.

The cost of Regulation Raise and Lower (equivalent to LFAS Up and Down) in Q4 2023 roughly doubled and tripled respectively compared to Q4 2022. However, the cost of LFAS Up and Down was historically low during the period Q3 2022 to Q3 2023, and this increase is less extreme if compared with more typical historical prices

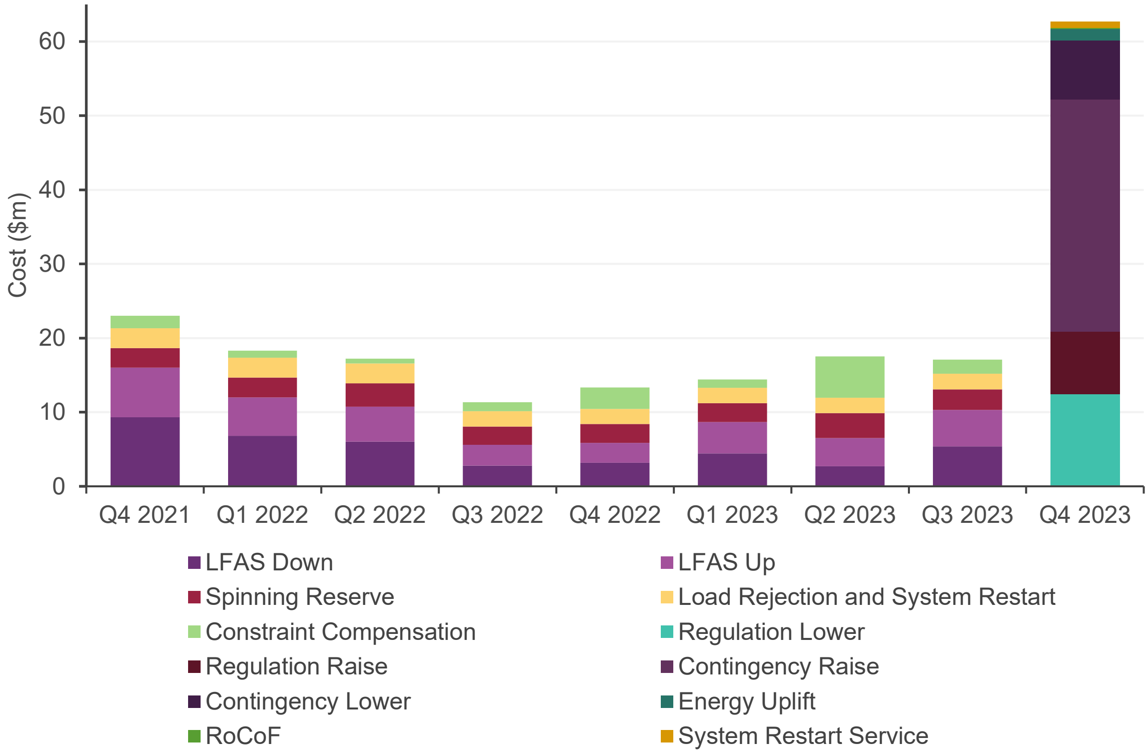
[41] FCESS Uplift costs have been excluded from this QED due to significant changes in FCESS Uplift cost calculations which are expected to be processed for Q4 2023 in upcoming Adjustment Invoices. FCESS Uplift will be discussed in future QEDs.

from before mid-2022; for example, if compared to Q4 2021, these costs only represent an increase of 26% and 33% respectively.

RoCoF Control Service is a new Market Service which did not exist in the previous market. It had a total cost of $0.2 million, almost exclusively driven by a single Dispatch Interval in which the Market Service cleared at $300/MWs (dollars per Megawatt-second). In all other Dispatch Intervals, the service cleared at or below $0.01/MWs.

Figure 103 Total costs increased for Essential System Services in Q4 2023

Total Cost for AS Q4 2021 to ESS Q4 2023



Although ESS costs have risen significantly compared to Q4 2022, when seen in the context of total costs in the WEM the impact is not as dramatic. Figure 104 presents these Energy and ESS costs as a price-per-MWh normalised by total energy consumed [42], providing a better picture of total costs in the WEM and enabling a more direct comparison of costs between Energy and ESS (and between new and previous markets).

The total cost of the Real-Time Market (Energy and ESS except FCESS Uplift) rose from $76.04/MWh in Q4 2022 to $98.35/MWh in Q4 2023, an increase of 34%. This was driven by an increase of $14.60 in the average Energy price and $11.93 for ESS compared to AS. Overall, ESS represented 4% of the total cost in Q4 2022, rising to 15% of total costs in Q4 2023. Note that these costs do not include Reserve Capacity, Supplementary Reserve Capacity (SRC), or NCESS costs.

However, given this is a new market and system, WEM outcomes are still stabilising as system performance and participant understanding improves. Therefore, more time and data are required before conclusions can be drawn

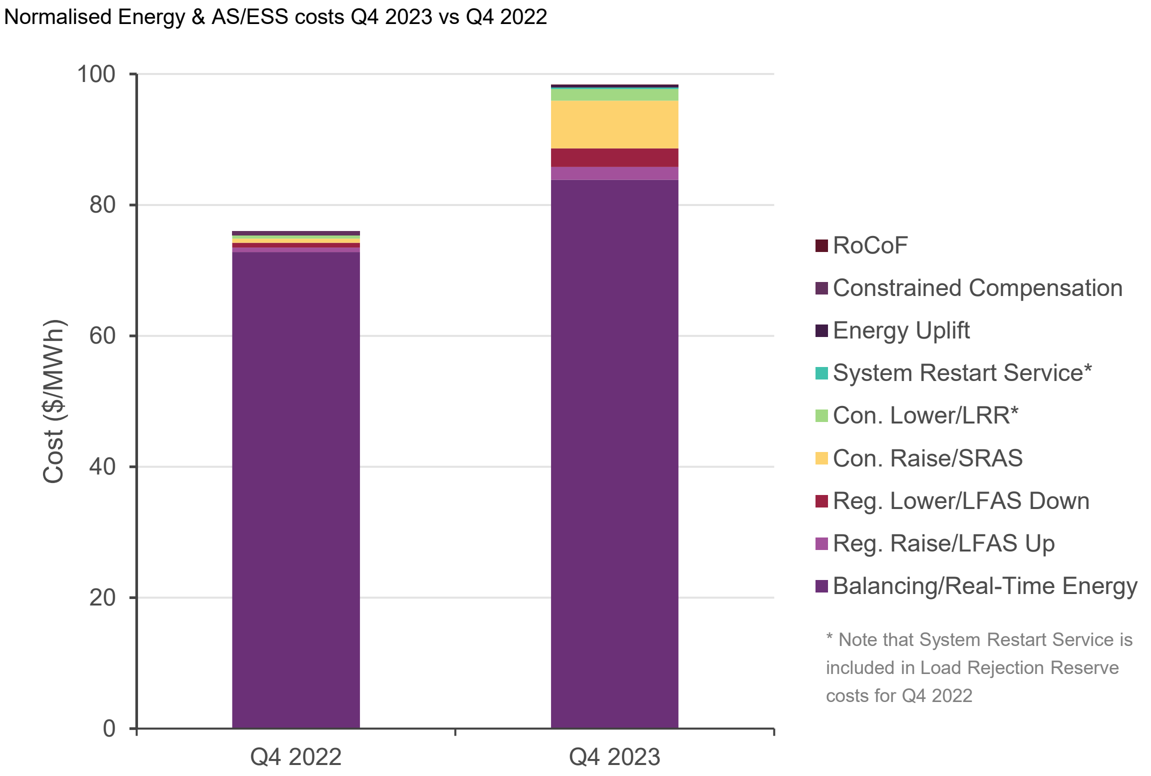
[42] To calculate a dollar per MWh of energy consumed, AEMO divided the total segment cost by total gross consumption in the WEM, calculated as:

- For the new market: the sum of CCQ_P_I
- For the old market: the sum of (MSNDL_P_I - ABSLOAD_P_I)/2 + min(MS_F_I of Registered Facilities, 0).

Capacity costs are excluded from this calculation.

around the drivers, dynamics, and trends of the new market, and market outcomes for Q4 2023 – representing only the first three months of the new market – should be treated with caution.

Figure 104 Total cost of Energy and ESS normalised per MWh consumed in the WEM



3.4.2 Non-Co-optimised Essential System Services

In Q4 2023 AEMO entered five NCESS Contracts with two Market Participants to provide up to 84 MW of Minimum Demand Service for a maximum one year duration[43]. The service provided is to increase Withdrawal or decrease Injection as required by AEMO during the hours of 9.00 am to 3.00 pm (generally 10.00 am to 2.00 pm).

The payment structure for each NCESS Contract is:

- For a Registered Facility and Unregistered Equipment – an availability payment for making the service available; and
- For Unregistered Equipment – an activation payment when activated.

The total cost of the Minimum Demand Service in Q4 2023 was approximately $2.7 million.

3.4.3 STEM market

The weighted average Short-Term Electricity Market (STEM) price[44] for Q4 2023 was $87/MWh, a $3/MWh (-4%) decrease compared to Q3 2023, but a $3/MWh (+3%) increase compared to the same quarter last year (Figure 105). The quarterly average quantity of energy cleared in the STEM decreased from 53 MWh in Q3 2023

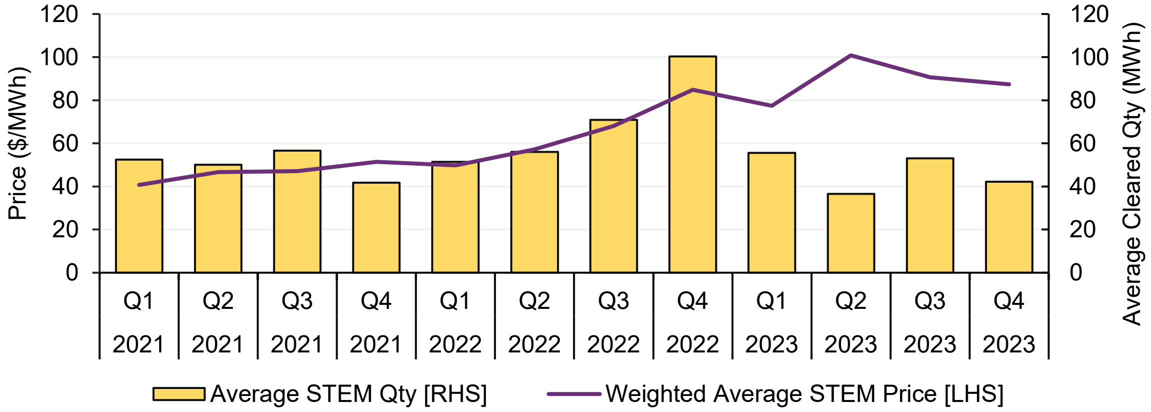
[43] See https://aemo.com.au/en/consultations/tenders/tenders-and-expressions-of-interest-for-ncess-minimum-demand-service-wa

[44] The weighted average STEM Price is a measure of the average STEM Price that puts greater weighting on intervals where greater quantity is cleared. This is to reflect the average STEM Price more accurately against quantity of electricity cleared, rather than against intervals. Weighted average STEM Price is sum(STEM Price * Qty Cleared)/sum(Qty Cleared) across the quarter.

to 42 MWh, a reduction of 20%. The decrease compared to the same quarter last year is even more significant, down by 58 MWh or 58%. It should be noted that last year's quantities traded in the STEM were high.

Figure 105 Both the Weighted Average STEM price and the quantities cleared in STEM reduced from Q3 2023

WEM weighted average STEM Price and quantity cleared in STEM – Q1 2021 to Q4 2023



4 Reforms delivered

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

Table 10 provides a brief description on the implementation of reforms delivered across the NEM over the last quarter.

Table 10 Reforms delivered Q4 2023

Reform initiative	Description	Reform delivered
WEM Reform	AEMO has delivered 11 implementation projects, covering 26 work packages, for the new WEM Go Live on 1 October 2023. It also created, or updated, 50 WEM Procedures and changed 80% of AEMO's IT systems, with 37 systems developed, rebuilt, or repurposed. As part of WEM reform, AEMO introduced the new Real-Time Market (RTM) which co-optimises Energy and ESS. To support this SCED market, AEMO also developed the WEM Dispatch Engine. Reference: https://aemo.com.au/initiatives/major-programs/wem-reform-program	October 2023
Fast Frequency Response	AEMO has introduced two new market ancillary services in the NEM, in the form of very fast services to operate alongside the existing contingency FCAS markets. Market participants with eligible facilities for participation in the Very Fast FCAS markets can register their services. These new services will help maintain a secure future power system and control system frequency following contingency events. Reference: https://www.aemo.com.au/initiatives/major-programs/fast-frequency-response	October 2023
Increased MT PASA Information	AEMO has amended its Reliability Standard Implementation Guidelines (RSIG) and the Medium Term Projected Assessment of System Adequacy (MT PASA) process description and systems in accordance with the 'Enhancing information on generator availability in MT PASA' rule change. Scheduled generator and integrated resource system participants are now required to provide status codes and recall times for periods of generator unavailability via their MT PASA submissions. Reference: https://www.aemo.com.au/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology	October 2023
Five Minute Load Profile (5MLP)	AEMO has implemented the adjusted 5MLP formula. The 5MLP creates a profile shape, which is used to convert 30-minute and 15-minute interval metering data into 5-minute trading intervals. Sections 12.4 and 12.5 of the Metrology Procedure Part B have also been updated to provide details of how positive and negative 5MLP values are applied to 15-minute and 30-minute metering data for a profile area (no change to 5MLP calculation). Reference: https://aemo.com.au/consultations/current-and-closed-consultations/load-profiling-methodologies-consultation	October 2023
Consumer Data Right (CDR): Tranche 3 and Last Consumer Change Date (LCCD)	Tranche 3 of the CDR rule came into effect in November requiring retailers with more than 10,000 customers (and others who opt-in) to now support CDR for simple requests. There have been no procedure changes made by AEMO for CDR Tranche 3. In addition, the LCCD procedure also came into effect, requiring financially responsible market participants to now update the LCCD field upon becoming aware the account holder has changes at their premises, thus allowing for a longer-term view of a consumer's energy data and enabling consumers to eventually access up to two years of energy usage data, regardless of whether they have switched retailers. Reference:https://aemo.com.au/en/initiatives/major-programs/cdr-at-aemo	November 2023
MSATS Standing Data Review (MSDR): Compliance Holiday	As part of the ongoing MSDR project phase 2, the compliance holiday ended in November for Meter Register Standing Data Items. As a result, Distributed Network Service Providers (DNSPs) are required to populate ConnectionConfiguration and Meter Manufacturer, Model and Use fields. Reference: https://aemo.com.au/-/media/files/electricity/nem/5ms/systems-workstream/2023/msats---technical-specification---november-2023.pdf	November 2023

Reform initiative	Description	Reform delivered
Automated Procedures for Identifying Manifestly Incorrect Inputs to FCAS	In December 2023, AEMO implemented an automated procedure for identifying trading intervals that are subject to review manifestly incorrect FCAS inputs. Reference: https://aemo.com.au/en/consultations/current-and-closed-consultations/consultation-on-the-amendment-of-automated-procedures-for-determining-a-manifestly-incorrect-input	December 2023

List of tables and figures

Tables

Figures

Abbreviations

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

Abbreviation	Expanded term
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TJ	Terajoule
UGS	Underground Storage Facility
VRE	Variable renewable energy
VNI	Victoria – New South Wales Interconnector
WEM	Wholesale Electricity Market
WEMDE	Wholesale Electricity Market Dispatch Engine
WDR	Wholesale demand response