Wholesale markets quarterly Q3 2023

July – September

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Changes to our wholesale market reporting

The AER’s wholesale markets quarterly report analyses trends in the electricity and gas wholesale markets, focusing on the most recent quarter, and alerts participants and stakeholders to issues of concern. The quarterly reports include discussion of prices, demand, generation, contracts, market outlook and new entry and exit. Since Q1 2023, our quarterly reports are more concise and made available sooner after the quarter’s end to address the need for timely market information, including reporting on the impact of the Australian Government’s Energy Price Relief Plan.

A comprehensive dataset for each quarter is available on our website, including additional charts not featured in this concise report.

Additional related regular reporting from the AER covers:

- details of significant high price events when the electricity spot market 30-minute price exceeds $5,000/MWh and whenever consecutive 30-minute prices exceed $5,000/MW in Frequency Control Ancillary Service markets
- the annual State of the energy market report, which presents an accessible, consolidated picture of the energy market
- the biennial Wholesale electricity market performance report, which provides longer term and more technical analysis of the performance of markets.

These scheduled reports will be supplemented by detailed special reporting on topics of interest and impact.

Wholesale markets at a glance

Q3 2023

Average electricity demand was lower than in Q2 2023. Both gas and electricity demand were on average much lower than the same quarter last year. In all cases, lower demand was largely due to warmer than average temperatures.

National Electricity Market (NEM) prices were under $100 per MWh in most regions, and less than half Q3 2022 prices.

East coast gas spot market prices averaged $10.44 per GJ after decreasing through the winter and into spring.

Minimum demand for electricity fell to record low levels in NSW, Victoria and South Australia.

Average electricity prices fell in all regions compared to Q2 2023.

Rooftop solar in September was 41% higher than last September, reducing demand from the grid.

More low-priced capacity was offered into the NEM this quarter than either last quarter or in Q3 2022.

The forecast El Niño summer increases the risks of high gas demand for generating electricity during the period of peak LNG exports. However, the ACCC projects domestic surplus over Q4 2023 and Q1 2024 and storage levels are high.

Forward gas prices for 2024 remain higher than 2023, but more recent trade has been at lower prices. This could suggest an improving outlook.

At the end of winter, Iona gas storage facility in Victoria is at record high levels.

In August, participants entered into a high volume of time-swaps. Domestic participants swapped away gas for the summer months in 2024 to export-linked participants and will receive gas in return over winter 2024.

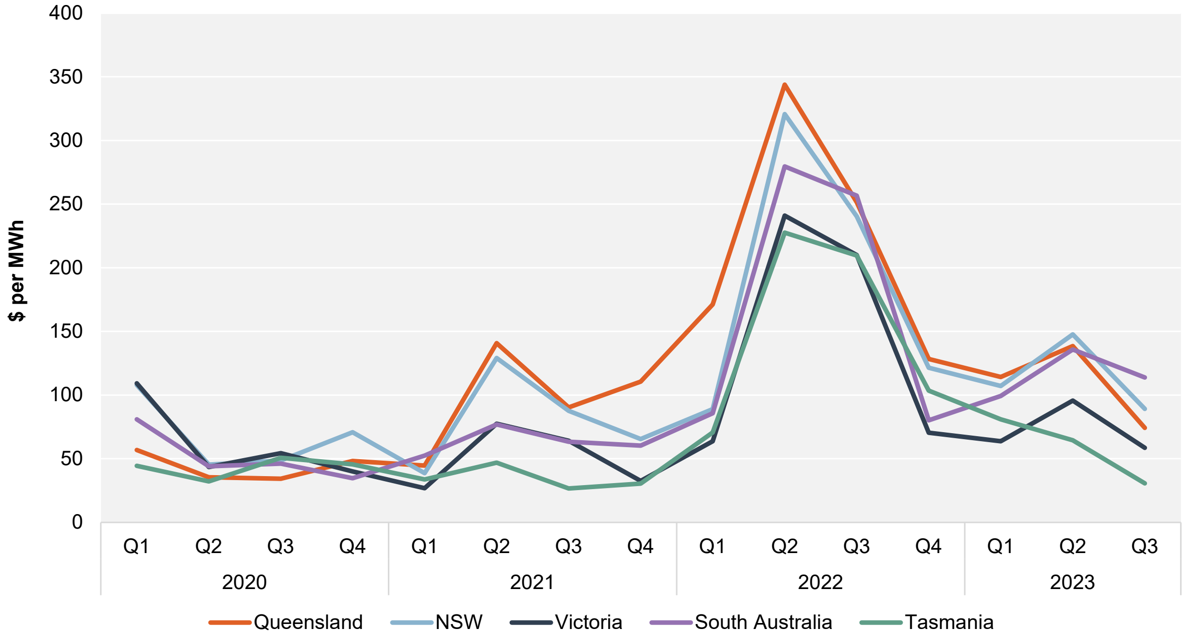
1 Increased low-priced offers and mild weather conditions drove moderate NEM prices in Q3

Prices were well below Q3 2022 levels and closer to long term Q3 averages

Average NEM prices in Q3 2023 ranged from $31 per MWh in Tasmania to $114 per MWh in South Australia (Figure 1).

In all regions, prices this quarter were also lower than the preceding quarter. This price decrease was most significant in NSW and Queensland, while South Australian prices fell less. The main driver of lower prices was an increase in low-priced offers. Lower demand was also a driver amid unseasonably mild weather conditions and high rooftop solar output.

Figure 1 Average quarterly prices in the NEM

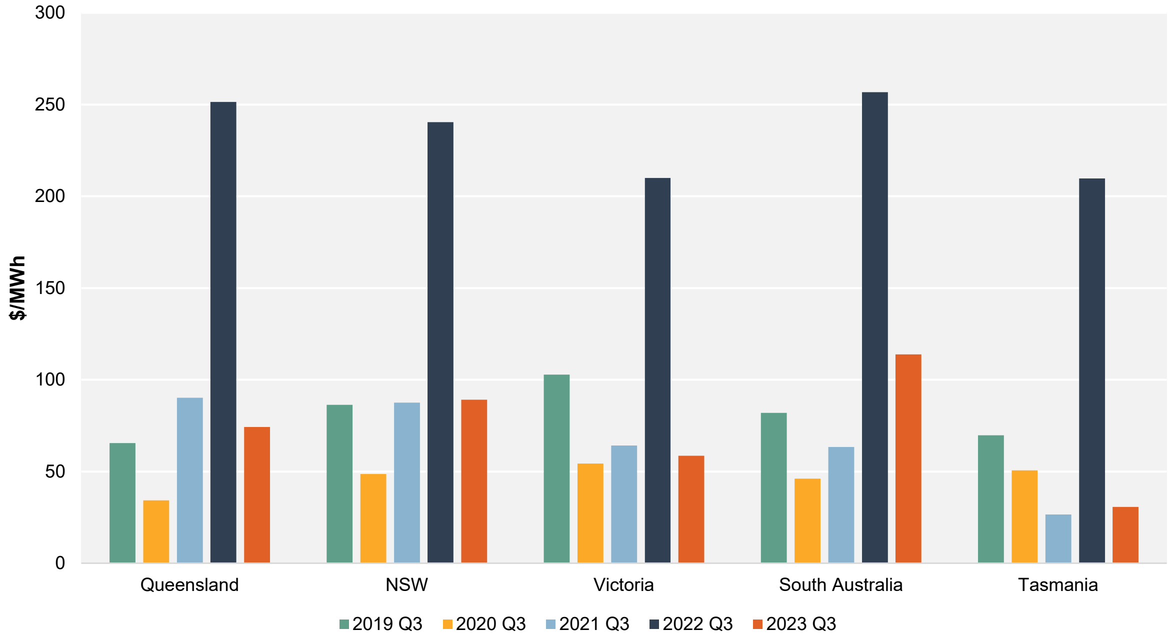


Note: This chart illustrates volume weighted average quarterly prices, meaning prices are weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.
Source: AER analysis using NEM data.

Prices were less than half the levels reached in Q3 2022 during which extreme July prices drove the highest Q3 prices on record. Factors contributing to last year's outcomes included significant coal generator outages, fuel supply issues, high international fuel prices and high demand. These circumstances did not repeat this quarter.

Compared to historical Q3s, prices this quarter returned towards average and were similar to Q3 2021 (Figure 2). The exception to this was South Australia, where prices were well above typical levels for a Q3.

Figure 2 Average quarterly prices in the NEM, Q3 comparisons



Note: This chart compares Q3 volume weighted average quarterly prices, meaning Q3 prices are weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.
Source: AER analysis using NEM data.

In part, South Australian prices were higher than other regions due to high price events. South Australian 30-minute prices exceeded $5,000 per MWh 8 times during the quarter – twice on 1 August and 6 times on 11 August. These prices contributed $20 per MWh to the average monthly price. Drivers of these price events included low wind and network constraints limiting cheaper imports from Victoria.

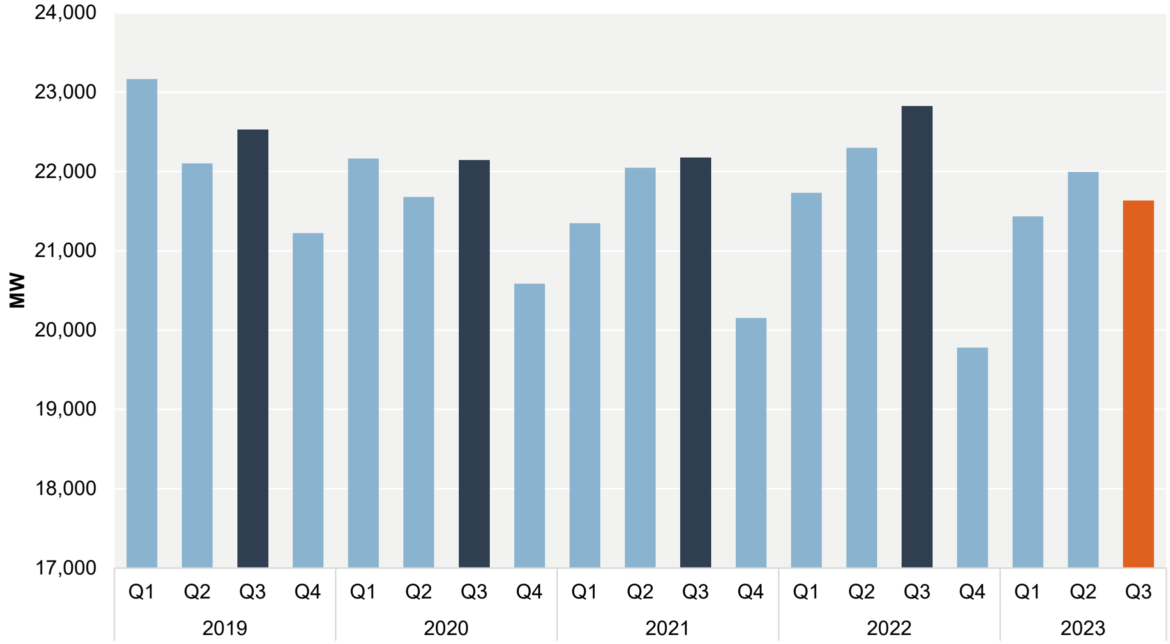
Prices also exceeded $5,000 per MWh in Queensland and NSW for one 30-minute period on 4 September. We will publish a separate report examining the drivers of Q3 significant price events in more detail.

The impact of significant price events in what was otherwise a benign quarter illustrates that, even when conditions are generally favourable to lower prices, market outcomes are vulnerable to short-term changes in conditions. As the market approaches an El Niño summer, this vulnerability presents a risk of more frequent high price events over the coming months.

Demand fell to record low levels

Demand in Q3 2023 was the lowest ever for a Q3, averaging about 5% (or 1,200 MW) lower than in Q3 2022 (Figure 3). At a regional level, the magnitude of the decrease ranged from 2% in Queensland to 10% in South Australia. It was also the first year where Q3 demand was lower than Q2 demand. Lower demand puts downward pressure on prices because less high-priced capacity is needed.

Figure 3 Quarterly average NEM demand



Notes: Uses quarterly average native NEM demand. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.
Source: AER analysis using NEM data.

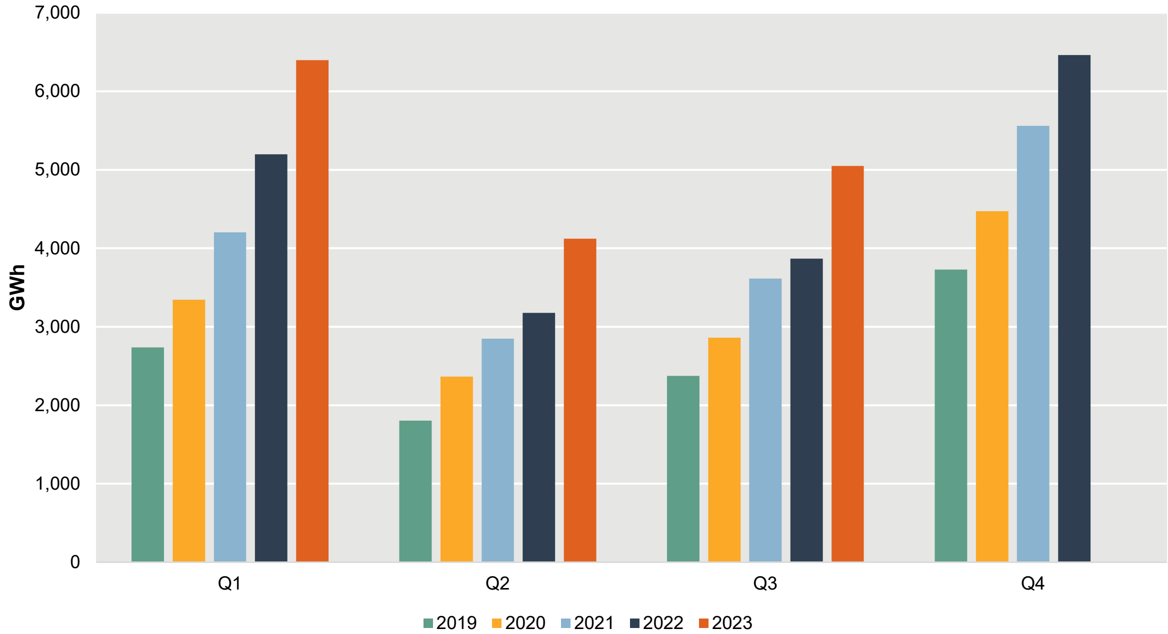
Minimum daily demand also fell to record low levels this quarter, including:

- a record low of 29 MW in South Australia on 16 September,
- record lows of 4,202 MW and 2,103 MW in NSW and Victoria, respectively, on 24 September.

Mild weather was a key driver of the historically low demand. Q3 demand is typically high in southern regions due to increased demand for heating in the winter months. However, this Q3, temperatures in all 3 months were well above average in all NEM regions.

Another factor contributing to lower demand was a huge increase in rooftop solar output. Rooftop solar generation, which is accounted as negative demand, was 31% higher than in Q3 last year (Figure 4). This was driven by continued rapid growth in rooftop solar installations as well as sunnier conditions. In September, rooftop solar output was 41% higher than the same time last year, and on 30 September output reached a record high level. Because of the growth in solar installations since last year, this record output will likely be surpassed in Q4.

Figure 4 Total rooftop solar generation in the NEM



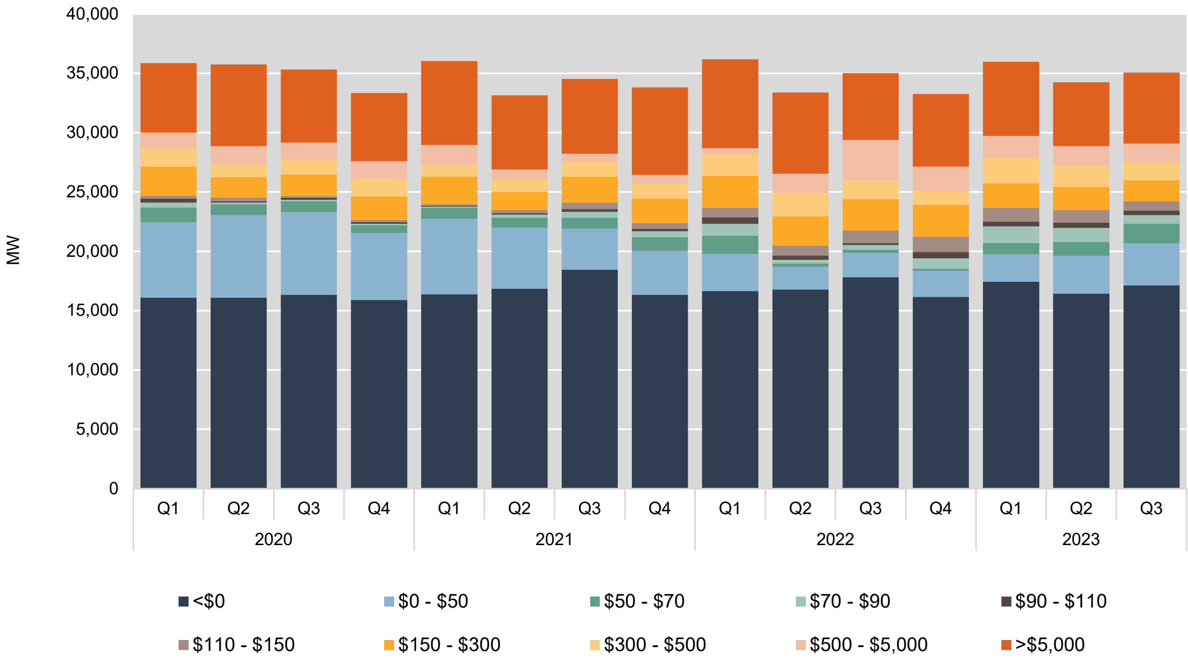
Note: Uses aggregated figures from half-hourly interval data.
Source: AER analysis using AEMO rooftop PV data.

Generators offered more low-priced capacity

Generators offered into the NEM more low-priced capacity this quarter than either last quarter or in Q3 2022. This was a key driver of lower prices. Coal, hydro and large-scale solar generators contributed most of the increase in low-priced capacity.

Compared to last quarter, an additional 1,500 MW was offered below $70 per MWh (Figure 5). Part of this came from black coal offers and reflected the return to service of Tarong North and Millmerran power station units in Queensland, as well as the impact of market interventions. There was also an increase in brown coal offers in Victoria, reflecting fewer outages. Solar offers increased too, due to the progressive connection of new solar farms and sunny conditions. Finally, there was more low-priced hydro available this quarter than last quarter.

Figure 5 NEM offers by price bands



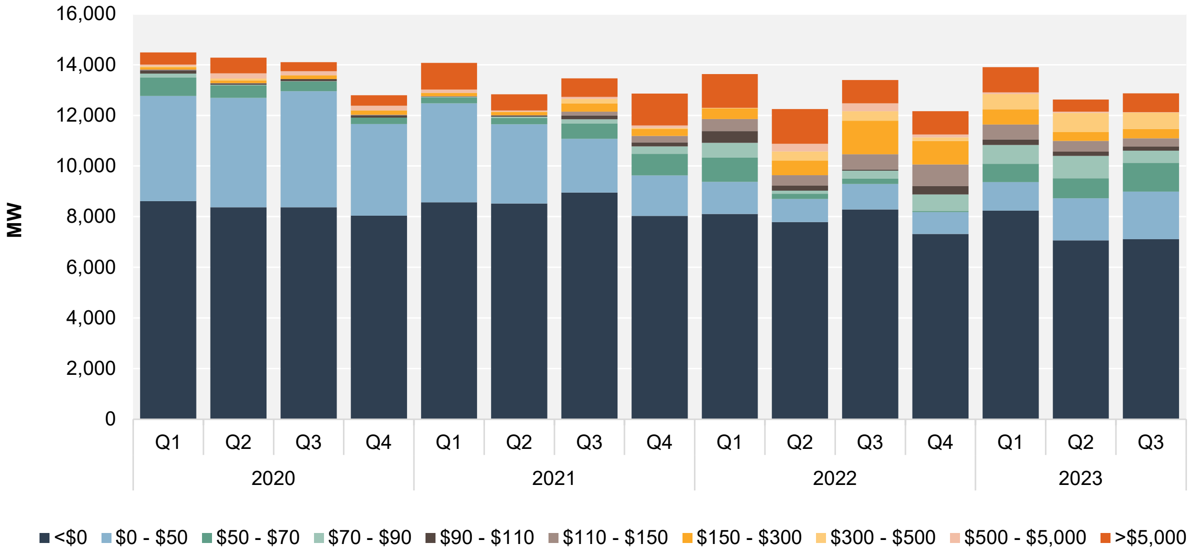
Note: Average quarterly offered capacity by price bands.
Source: AER analysis using NEM data.

Compared to a year ago, an additional 2,200 MW on average was offered below $70 per MWh. Last July in particular, coal generator outages, fuel supply problems and high coal spot prices significantly reduced the amount of cheap capacity available.[1] Market participants shifted capacity to higher prices to cover costs or to conserve fuel or water supplies. This Q3, these factors were greatly reduced. Meanwhile, the increase in solar capacity combined with sunny conditions also bolstered low-priced offers.

Black coal generators offered more capacity below $70/MWh than last quarter or in Q3 2022 (Figure 6). However, they offered less at this level than prior to winter 2022. This reflects a longer-term uplift in coal generation costs (despite cost reductions from a year ago). It also reflects the exit in April of Liddell power station, which historically offered a significant volume at low prices.

[1] Wholesale Market Quarterly Q3 2022, p. 2.

Figure 6 NEM black coal offers by price bands



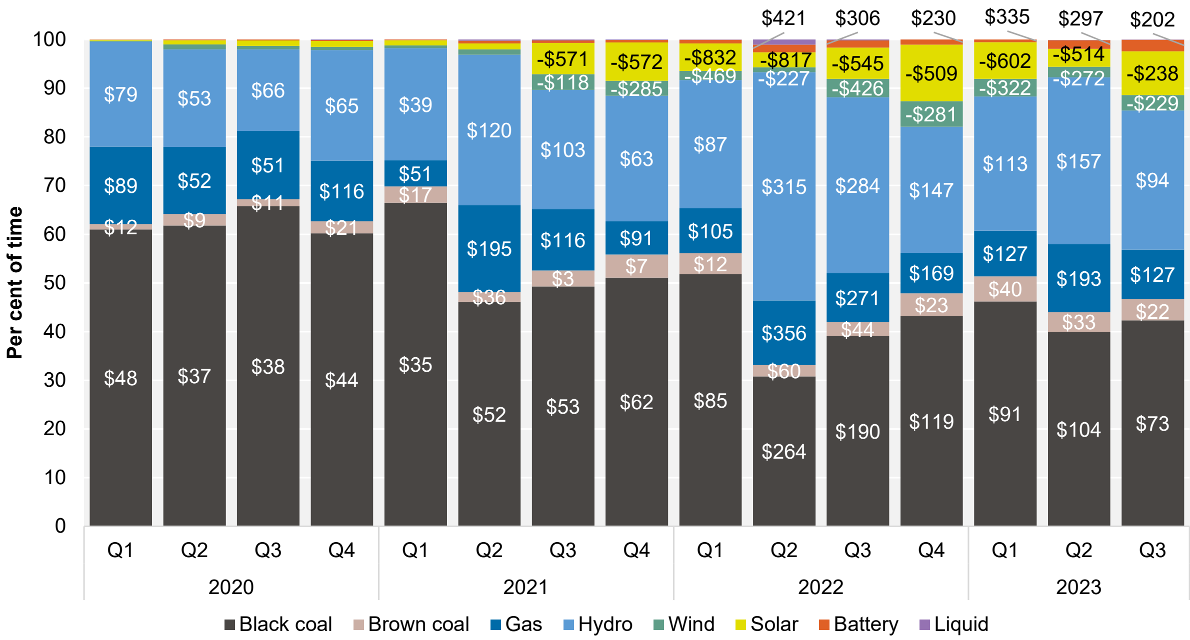
Note: Average quarterly offered black coal capacity by price bands.
Source: AER analysis using NEM data.

Coal, gas and hydro set lower prices while solar broke records in Queensland

The combination of lower demand and increased low-priced offers meant that most fuels set lower prices this quarter. Black and brown coal, gas and hydro generators all set lower prices in every region compared to both last quarter and Q3 2022 (Figure 7). Average prices set by wind and large-scale solar were higher than in previous quarters, but still well below $0 per MWh.

In general, cheaper fuels (wind, solar and brown coal) set price more often and more expensive fuels (such as gas and hydro) set price less often than both last quarter and Q3 2022. This led to prices being lower. Batteries were an exception to this, being an expensive fuel that set price more often.

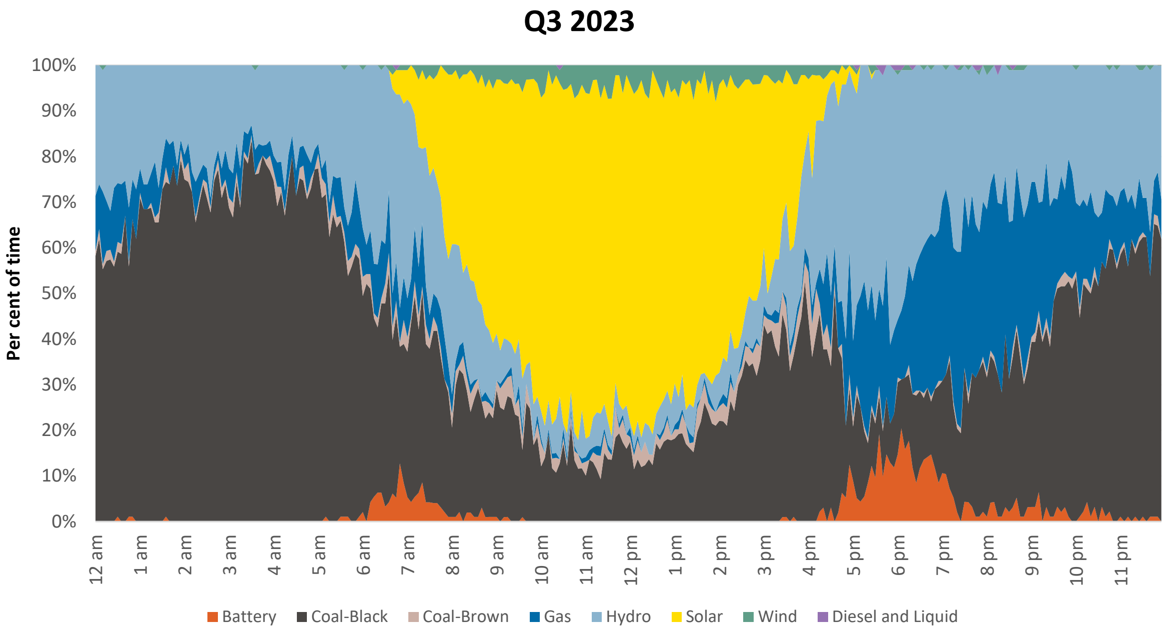
Figure 7 Price setting by generation source, NSW

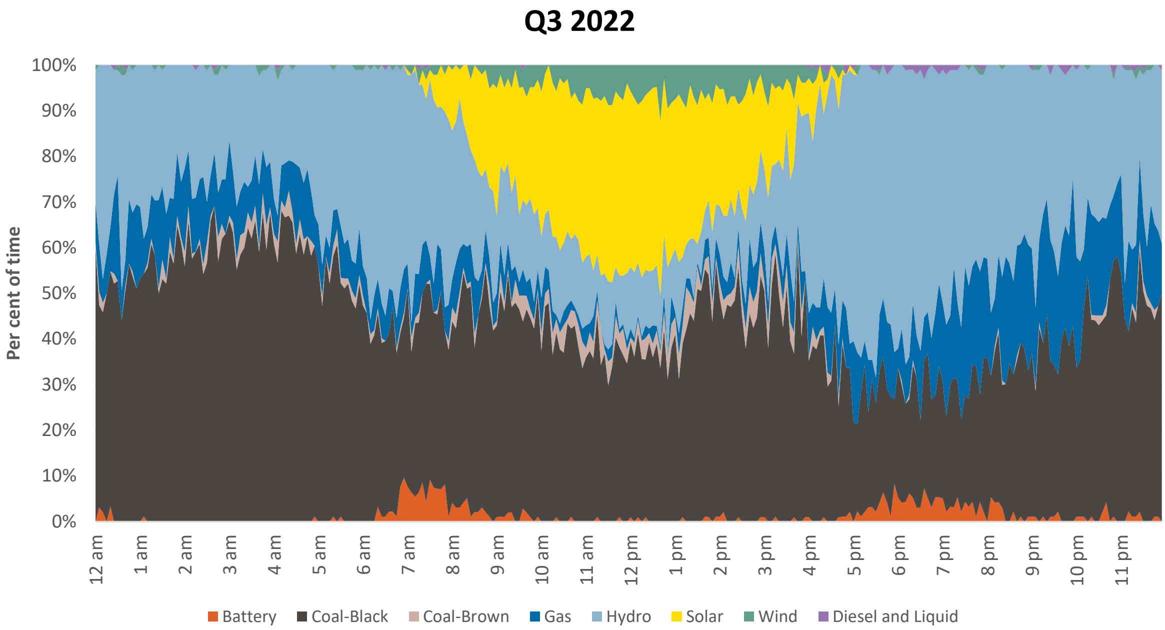


Notes: The height of each bar is the percent of time each fuel type sets the price, and the number within each bar is the average price set by that fuel type when it is marginal (that is, setting the price). The pattern in price setting changes was broadly similar across mainland regions. Charts for other regions are available on our website.
Source: AER analysis using NEM data.

In Queensland, solar set price a record 20% of the time. During daylight hours, it was the fuel that set price the most often, about three quarters of the time in the middle of the day (Figure 8). This was about twice as often as it set price this time last year. The low prices set by solar contributed to lower prices this quarter, as well as creating ideal charging conditions for batteries, which also set price more often (up to 20% of the time in the evening peak).

Figure 8 Queensland price setter by time of day, Q3 2023 vs Q3 2022





Notes: Price setter by fuel type at each time of the day in Q3 2023 above and Q3 2022 below.
Source: AER analysis using NEM data.

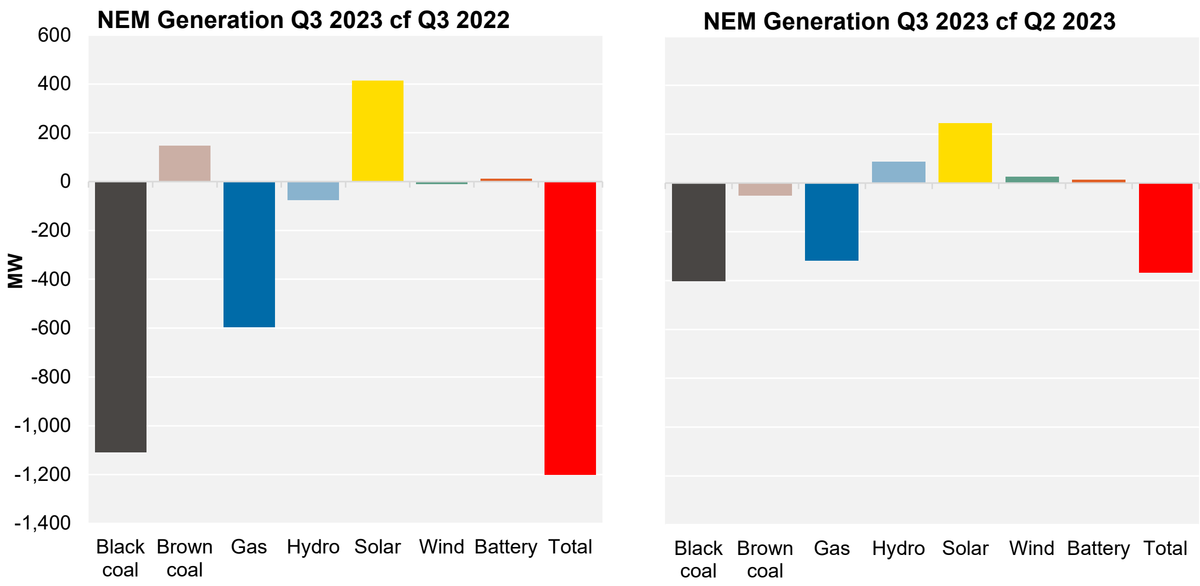
Cheaper fuels generated more output than a year ago

In general this quarter, more expensive fuels were dispatched less and cheaper fuels were dispatched more. Solar and brown coal generated higher output than a year ago (Figure 9). Solar output was influenced by the connection of new solar farms and by favourable weather conditions, while brown coal output reflected fewer generator outages.

Gas (an expensive fuel) and black coal (generally mid-priced) both generated less, due to lower demand and increased availability of cheaper fuels. Black coal contributed just 45% to total NEM output, its lowest share on record. This was despite an increase in low-priced black coal offers compared to both last quarter and Q3 2022.

Wind output remained about the same as last quarter and as in Q3 2022.

Figure 9 Change in NEM generation output by fuel source

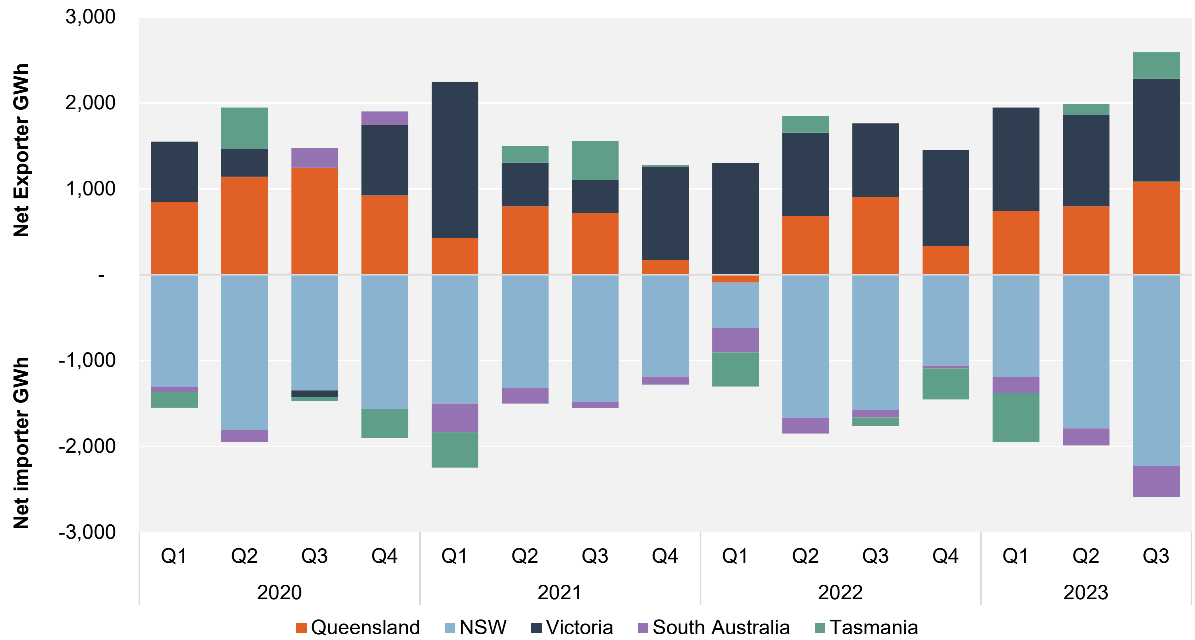


Notes: Change in average quarterly metered NEM generation by fuel type, Q3 2023 compared with Q3 2022 (left) and Q2 2023 (right). Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.
Source: AER analysis using NEM data

Exports from Queensland and Victoria increased

Interconnectors allow regions to import cheaper generation from outside their borders. Queensland and Victoria tend to be net exporters, providing surplus capacity to NSW and South Australia where cheap capacity is more often scarce. In Q3 2023, this general pattern intensified with NSW and South Australia importing more capacity than usual while Queensland and Victoria exported more (Figure 10). Tasmania, which varies between being a net importer or exporter, was a net exporter this quarter.

Figure 10 Net interconnector flows by region



Notes: Net amount of energy either imported or exported each quarter by region.
Source: AER analysis using NEM data.

In Queensland and Victoria, an increase in available low-priced capacity contributed to the regions exporting more.[2] In Queensland, there was in increase in low-priced black coal and solar offers. Meanwhile in Victoria, there was an increase in low-priced wind and hydro offers.

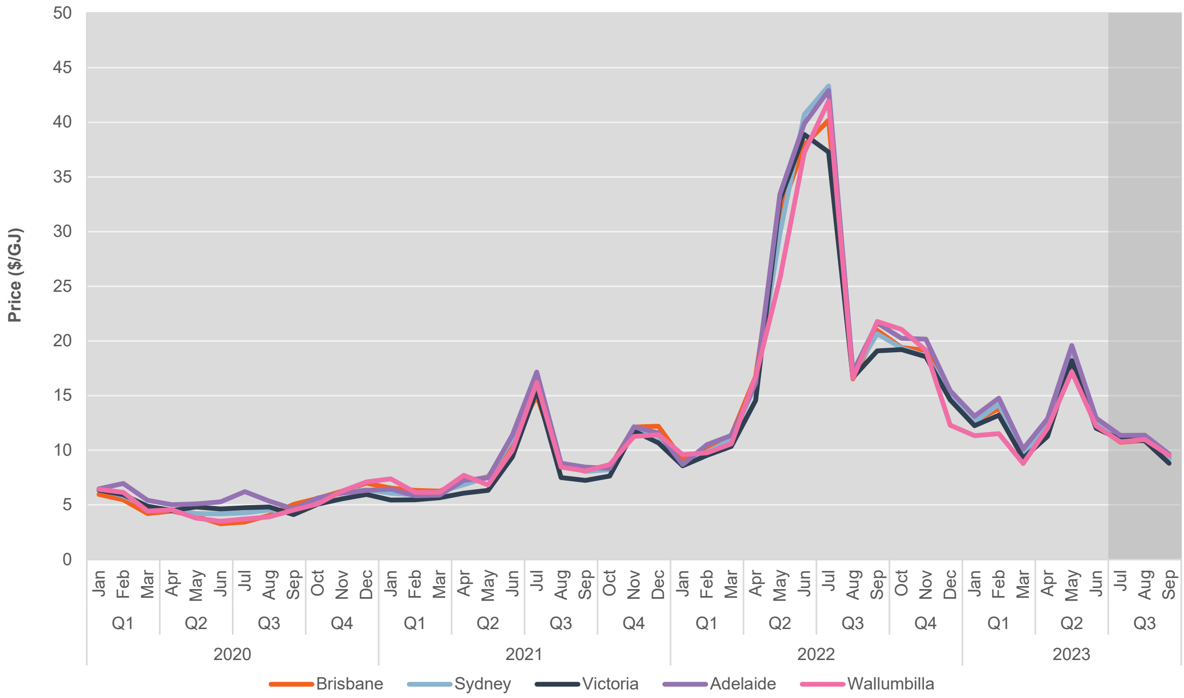
[2] More brown coal was offered in Victoria in Q3 than in any quarter since Q1 2021.

2 Domestic gas spot prices fell to Q3 2021 levels

Gas spot market prices averaged just above $10 per GJ

Over Q3, East coast gas market spot prices averaged $10.44 per GJ. This is a decrease of 28% from the previous quarter and 60% lower from Q3 2022 (Figure 11), reaching average levels last seen on a sustained basis in Q3 2021.

Figure 11 East coast gas market average monthly prices

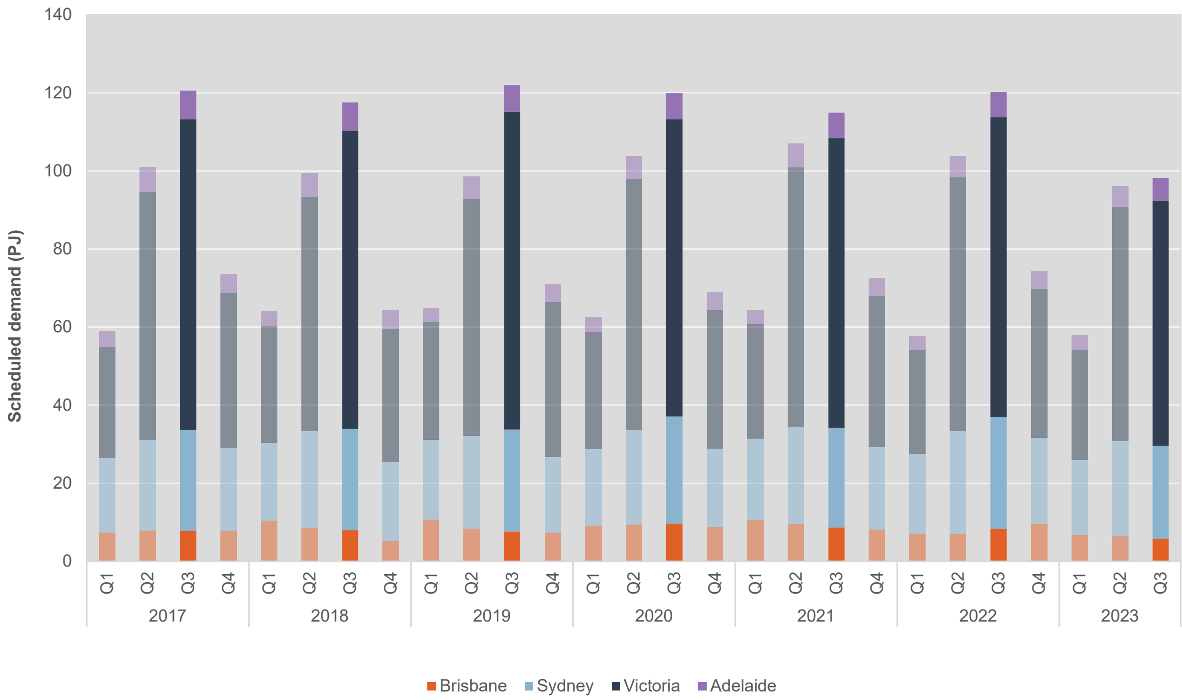


Note: The Wallumbilla price is the day-ahead exchange traded price.
Source: AER analysis using east coast gas market (ECGM) data (includes: Victoria, Adelaide, Brisbane and Sydney gas markets and Wallumbilla gas supply hub data).

Prices remained between $10 and $12 per GJ for most of Q3, before falling steeply in mid-September to as low as $5 per GJ in Victoria.

An unseasonably warm winter saw both residential and commercial gas demand fall more than 20 PJ lower than at the same time last year, resulting in the lowest Q3 demand in 10 years (Figure 12). Demand from Gas Powered Generators (GPG) was also particularly low in Q3.

Figure 12 Scheduled demand in east coast gas markets



Note: Scheduled demand based on beginning-of-day forecast demand data (6 am Victorian DWGM schedule and ex-ante STTM schedules for Brisbane, Sydney and Adelaide).
Source: AER analysis using east coast gas market (ECGM) data (includes: Victoria, Adelaide, Brisbane and Sydney gas markets).

Despite some planned maintenance, supply was also mostly unhindered as constraints on production at Longford, and capacity on the Moomba to Sydney pipeline were resolved. Relatively uninterrupted supply combined with historically low demand contributed to downward pressure on prices.

September saw the lowest spot prices in 3 years

Late September coincided with warmer weather and very low gas demand for the time of year. Gas prices fell sharply to end the month at or around $5 per GJ in some markets.

We understand that retailers have contracted minimum levels of gas (take or pay) based on higher gas demand expectations. To ensure that minimum levels of gas already contracted for (and obligated to be paid for) are dispatched, retailers have had to lower gas offer prices and sell into a low demand market. The alternative to lowering offer prices is worse, as retailers would both pay for contracted gas which is not dispatched and subsequently buy gas from the market to meet customer demand.

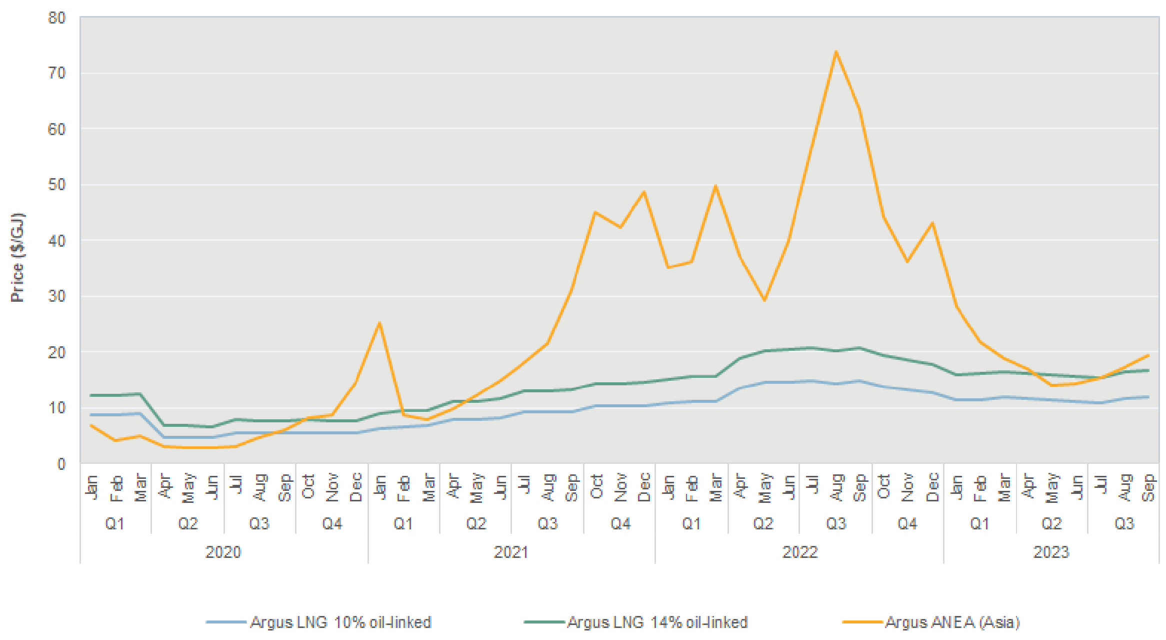
These low prices may be temporary as, at end September, gas flows had swung to deliveries from the domestic demand-heavy south to the exporting north. International spot netback prices are still well above $10, presenting potential arbitrage opportunities for exporters to buy gas domestically and increase export volumes.

International price pressures increased slightly

International LNG spot prices increased from Q2 but remain well below the record levels of 2022.

The price of Asian LNG (measured by the Argus LNG Northeast Asia price) declined materially from December 2022 through to May 2023, but has increased slowly since June to a September average of $19.41 per GJ (Figure 13).

Figure 13 International LNG spot prices



Note: The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4–12 weeks before the date of delivery.
The Argus LNG 14% and 10% oil linked contract prices are indicative of a 14% and 10% 3-month average Ice Brent crude futures slope.
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Source: AER analysis using Argus Media data.

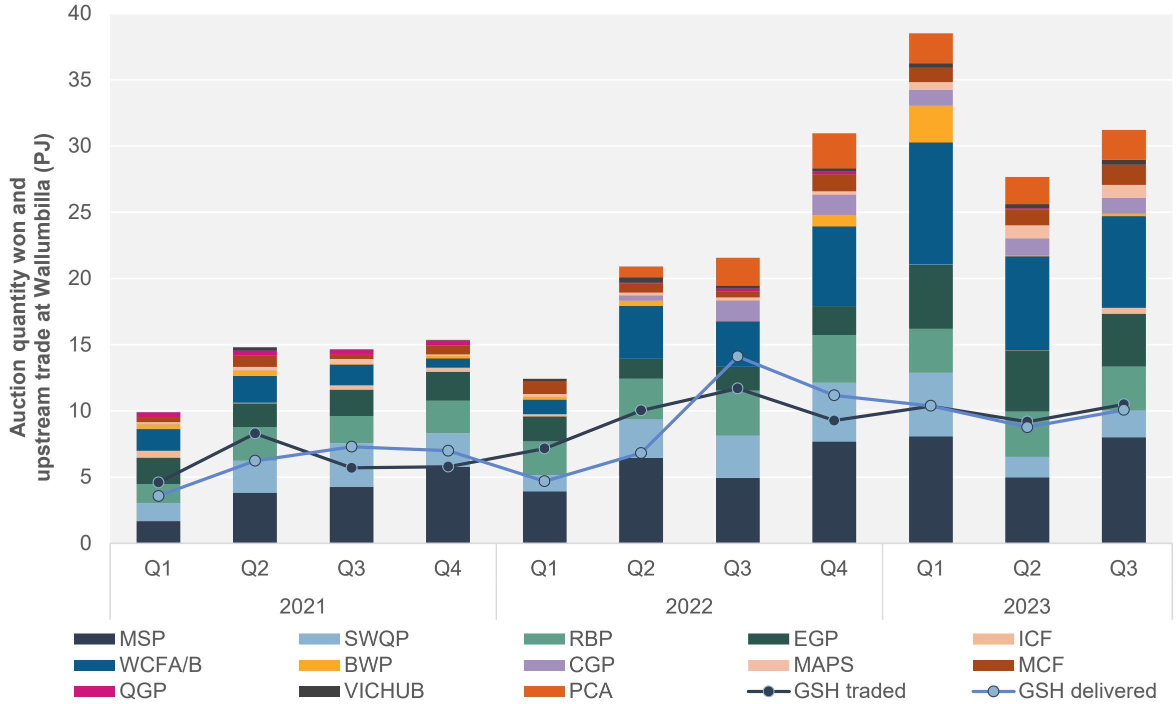
It is typical to see a continued increase in international prices as the Northern Hemisphere enters winter and heating demand rises. The impact of European winter on prices is likely to be mild compared to 2022, given that the European Union reached its target of filling gas storage facilities to 90% in August, more than 2 months ahead of the November deadline.[3]

[3] European Commission, EU reaches 90% gas storage target ahead of winter, August 2023

Gas Supply Hub trade was strong for Q3 but there was little forward trade

Trade on the Gas Supply Hub was again strong over Q3 with the second highest quarterly trade reported of 10.5 PJ, supported by record Q3 transportation capacity won on the day-ahead auction (Figure 14).

Figure 14 Day ahead auction transportation capacity won and gas supply hub trades



Note: MSP is Moomba to Sydney Pipeline. SWQP is South-West Queensland Pipeline. RBP is Roma to Brisbane Pipeline. EGP is Eastern Gas Pipeline. ICF is Iona Compression Facility. WCFA/B are Wallumbilla Compression Facilities A and B. BWP is the Berwyndale to Wallumbilla Pipeline. CGP is the Carpentaria Gas Pipeline. MAPS is the Moomba to Adelaide Pipeline System. MCF is the Moomba Compression Facility. QGP is the Queensland Gas Pipeline. PCA is the Port Campbell to Adelaide Pipeline.
Source: AER analysis using gas supply hub trades and day ahead auction data.

In Q3 2023 there was still very little forward trade through the Gas Supply Hub, a trend observed throughout this year.

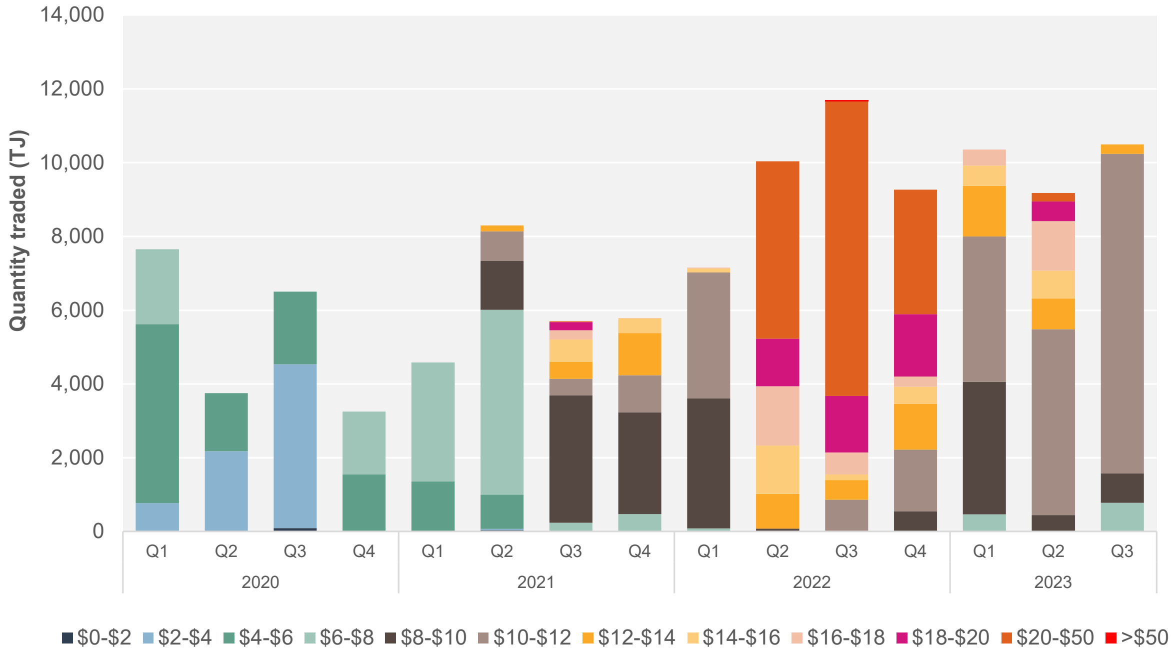
While exporters and producers have typically been net sellers of gas at the GSH, they became net buyers for delivery in Q3. In contrast, GPG Gentailers were net sellers.[4] This is another indication that domestic gas users have had more gas available, with lower gas demand allowing surplus gas to be sold to exporters and producers.

In Q3 the percentage of trade exempted from the price cap fell from 89% to 81%, driven by September in which exempt trade fell to 65%, the lowest since introduction of the cap. However, despite the majority of trade still being exempt from the price cap, almost all gas

[4] Net trade in the GSH is calculated by netting buy and sell quantities for each trading participant on a daily delivered basis for all product types and all trade locations.

sold for prices below it. Nearly all (97.5%) of trades were under the $12 per GJ cap, regardless of their exemption status.

Figure 15 Gas Supply Hub price bands



Source: AER analysis using Gas Supply Hub (GSH) trades data

Box 1: Regulated gas price cap of $12 per GJ

On 23 December, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months.[5] From 11 July, the Australian Government implemented a Mandatory Gas Code of Conduct replacing the Order.[6] The key elements of the Code include:

- A price cap on gas of $12 per GJ (and does not apply in Western Australia) to be reviewed by 1 July 2025.
- Generally, the price cap applies to gas producers and affiliates of gas producers.
- There are several exceptions (including gas to be exported as LNG, retailers that meet certain criteria, trades on the Short Term Trading Markets (STTMs) or Declared Wholesale Gas Market (DWGM), near-term (next 3 day) trades and offers on the Gas Supply Hub Exchange).[7]
- Transparency obligations to increase visibility of uncontracted gas production and its expected availability to the domestic market.

[5] Australian Government, Competition and Consumer (Gas Market Emergency Price) Order 2022, December 2022.

[6] DCCEEW, Mandatory Gas Code of Conduct, Department of Climate Change, Energy, the Environment and Water, 11 July 2023.

[7] Over 2022 spot trade in the downstream DWGM and STTM collectively averaged around 16% of the gas traded through the markets.

- Conduct provisions aimed at reducing bargaining power imbalances between producers and gas buyers and establishing minimum conduct and process standards for commercial negotiations.

Separate to the exceptions, the Order also allows the Minister to grant exemptions. The Minister has delegated this power to the ACCC.

Further information on the price cap and the process of applying for an exemption can be found on the ACCC's website.[8]

Lower levels of forward trade on the Gas Supply Hub have been present since the introduction of the price cap in late December 2022. While the price cap appears to have influenced a move toward shorter term trades that are exempt from the $12 per GJ price order, it is likely that expectations of low demand for Q4 2023 and Q1 2024 are also limiting incentives to engage in forward trade.

The ACCC has forecast surplus gas supply over Q4 2023 and Q1 2024, projecting that this will be the case even if no further uncontracted gas is sold domestically. [9] Market participants may feel confident in their ability to source gas from spot markets over summer 2023–24, resulting in reluctance to pay a premium for guaranteed delivery in the future.

[8] ACCC, Gas cap price exemption, December 2022.

[9] ACCC, Gas inquiry September 2023 interim report, September 2023; ACCC, Gas inquiry June 2023 interim report, June 2023

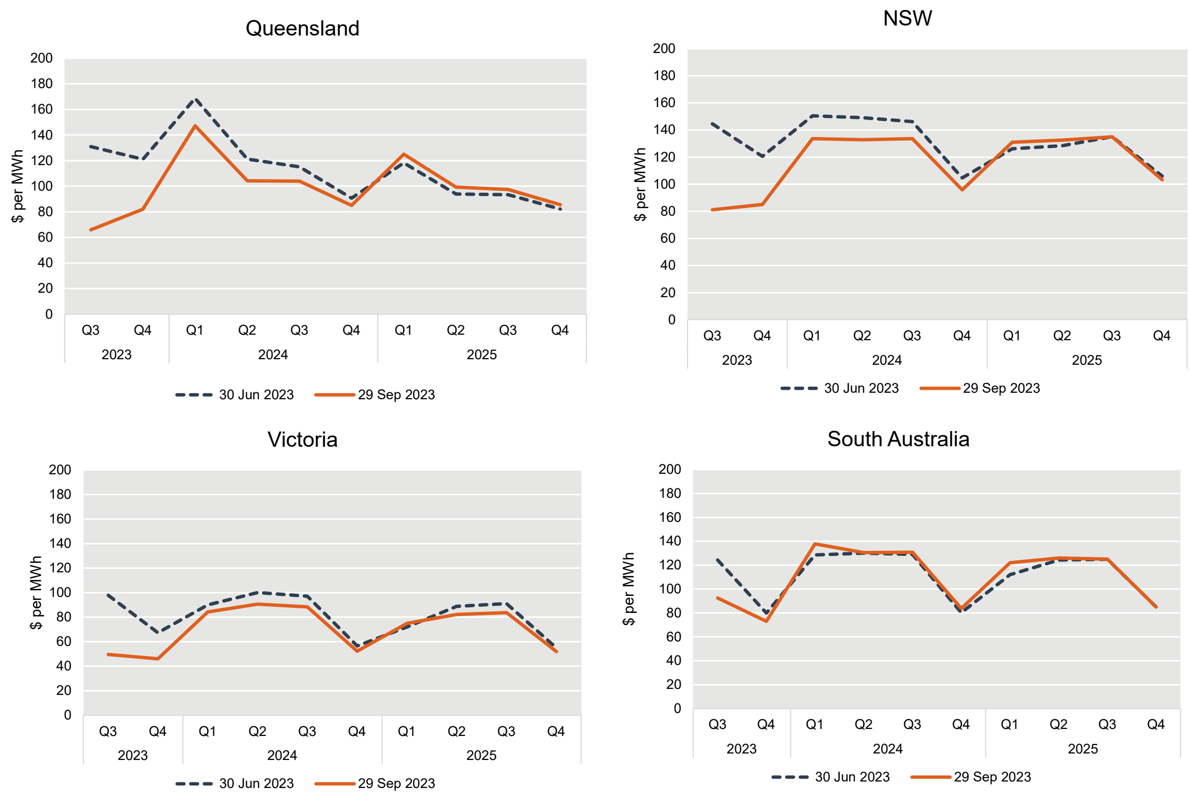
3 Electricity and gas market outlooks

Electricity forward prices for 2024 fell over the quarter

Generators and retailers enter derivative contracts to fix the price of gas or electricity in the future. This function is integral to protecting both parties against price fluctuations in the spot markets resulting in the physical market and contracts markets being inextricably connected. Forward base futures prices illustrate price expectations for electricity spot prices in future periods.

Base futures prices for Q3 2023 fell over the course of the quarter, due to lower-than-expected spot prices (Figure 16). Forward prices also fell for Q4 2023 and for 2024, likely reflecting the impact of mild spot price outcomes this quarter on price expectations for the near future. Looking further ahead, base futures prices for 2025 remained steady. This may reflect tighter supply/demand conditions within the contract market, which would be expected if generators are selling fewer contracts due to uncertainty around plant reliability.

Figure 16 Base quarterly electricity futures prices



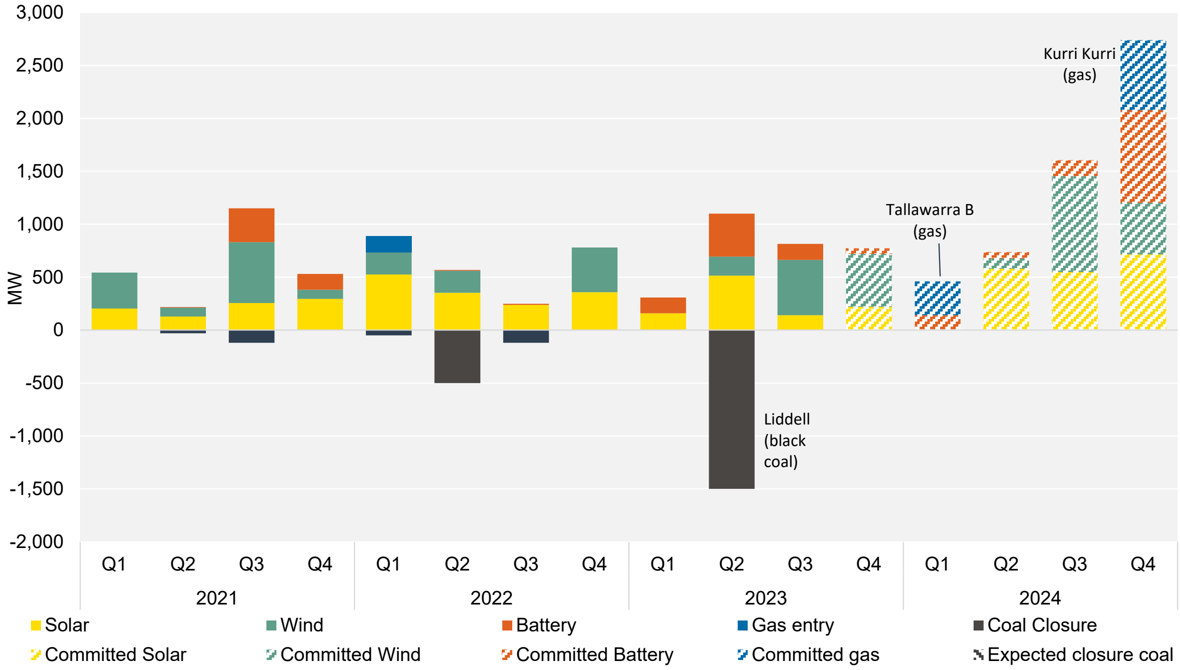
Notes: Base future prices for each quarter as of 30 June 2023 (end Q2) and 30 September 2023 (end Q3).
Source: AER analysis using NEM data.

New capacity entered the market, but more is needed

Across the NEM, 2 windfarms, 2 solar farms and 2 batteries commenced generating this quarter. While these will constitute over 800 MW of capacity once fully commissioned (Figure 17), it will take some time before they reach full output. Rye Park windfarm, which began generating this quarter and will be the largest windfarm in NSW when complete, is not expected to reach full output until mid to late 2024.

Overall, the rate of new entry into the market is not in line with what the market needs to transition. In Victoria, for example, no new capacity has entered the market since April. AEMO's 2023 Electricity Statement of Opportunities (ESOO) identified forecast reliability gaps for all mainland regions over the next 10 years.[10] With 8.3 GW of firm capacity scheduled to exit the market in the next decade as coal plants retire, there is a pressing need for new investment to be realised across the NEM.

Figure 17 New entry and exit



Note: Uses registered capacity, except for solar and batteries where we use maximum capacity. The new entry date is taken as the first day the station receives a dispatch target. Solar reflects large-scale solar and does not include rooftop solar.
Source: AER analysis using AEMO Generator Information.

Iona storage ended Q3 at record high level

Iona storage facility ended Q3 with record high storage levels for the time of year, having experienced minimal drawdown compared to recent winters (Figure 18). The smaller than average drawdown was driven by historically low Q3 demand for gas due to above average temperatures over winter. Additionally, minimal constraints on gas transportation saw market participants less reliant on the facility.

2021 and 2022 saw Iona experience rapid drawdown to 10PJ by mid-winter, prompting AEMO to intervene before the facility reached critically low pressure. In contrast, at the end of September 2023, Iona storage had only fallen to 19PJ, a seasonal record high.

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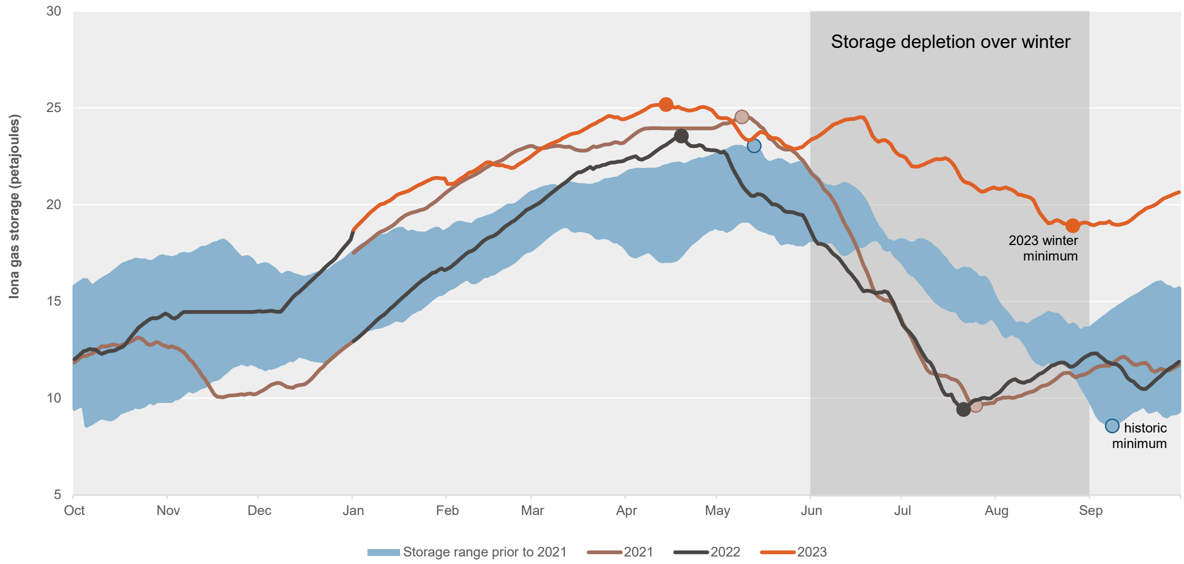
[10] AEMO, *2023 Electricity Statement of Opportunities*, Australian Energy Market Operator, August 2023.

Upgrades to Iona prior to winter also increased its storage capacity. As of June 2023, Iona has a nameplate capacity of 24.4 PJ and a delivery capability of 570 TJ per day. There is planned additional pipeline compression and additional capacity work via the Western Outer Ring Main (WORM). This would place Iona in a stronger position with additional gas flow and allow it to supply and refill at faster rates.

With high storage levels and forecast gas surplus conditions, participants are better placed to manage GPG demand peaks in the coming summer, should they materialise.

Figure 18 Iona underground gas storage levels in Victoria



Source: AER analysis using Gas Bulletin Board data.

Domestic participants swapped large volumes of summer 2024 gas for deliveries in winter 2024

New gas market transparency measures, which commenced in March, have made greater insights into East Coast bilateral trades possible. Bilateral trade is negotiated directly between parties and conducted outside of the AEMO-facilitated markets.[11] This information has materially improved the completeness of data available on gas trade up to a year in length, of which bilateral trade is the majority.

August saw the largest quantity of bilateral time swaps since reporting on such trade began. Domestically focused participants swapped around 9 PJ of gas with exporters and producers which was mostly due for delivery during the summer months of 2024 for gas to be delivered in Q2 and Q3 of 2024. Exporters and producers usually favour higher export volumes during Australian summer when domestic demand is low and export prices are highest due to Northern Hemisphere winter. These swaps, along with a forecast gas surplus over the coming summer, suggest that at least some domestically focused participants consider their supply for the remainder of 2023 to be sufficient.

[11] From 15 March 2023, as part of the Gas Market Transparency reforms, short term transactions with a contract length of 12 months and less are required to be reported to the Bulletin Board.

In contrast, forward prices for supply transactions in 2024 are higher than in 2023 (Table 1). However, these forward supply transactions for delivery in 2024 took place in Q3 at prices roughly 15% below those in Q2. This suggests that participant expectations over 2024 may be improving, or the level of price uncertainty decreasing.

Table 1 Forward pricing for short term supply transactions

Period	VWA ($ per GJ)	Range ($ per GJ)	Delivered quantity (PJ)
Q3 2023	**12.38**	**10.44 – 13.51**	**21.5**
QLD	*11.68*	*9.52 – 12.56*	*14.9*
VIC	*13.08*	*11.96 – 13.62*	*2.4*
Q4 2023	**13.63**	**11.92 – 14.20**	**14.0**
QLD	*12.64*	*10.76 – 13.00*	*7.6*
VIC	*12.76*	*12.19 – 12.93*	*4.7*
2024	**16.36**	**15.58 – 17.81**	**23.2**
QLD	*16.17*	*14.07 – 17.85*	*3.3*
VIC	*15.43*	*13.80 – 16.15*	*15.1*

Note: The above prices and quantities are based on the actual delivered dates of the reported transactions and include all reported supply transactions and pricing structures. For Q3 and Q4 2023 the pricing is further broken down for Queensland and Victoria where most of the trade has occurred. The VWA price range is the minimum and maximum price accounting for all transactions on specific days of trade within that period. Where there is not enough trades or participants reporting in a period the data is aggregated to a longer time frame.
Source: AER analysis using Natural Gas Services Bulletin Board data.

We are intending to publish a standalone report in Q4 to provide more insights and transparency into the short term bilateral trades and swaps being reported on.