Wholesale markets quarterly Q4 2022

October – December

February 2023

AUSTRALIAN ENERGY REGULATOR

Australian Government

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Summary

Over the course of 2022, wholesale electricity and gas market prices reached record levels, as we have detailed in previous quarterly reports. In Q4 2022, prices eased from those record highs, but remained elevated compared to historical levels. The relationship between gas and electricity prices was less impactful over Q4 as lower NEM demand contributed to a reduced need for gas-powered generation.

In electricity markets, mild spring weather that extended into December, coupled with strong rooftop solar output, contributed to record low NEM demand. This was complemented by high solar and wind output which, together with low demand, replaced traditional coal and gas generation. Generation from black coal continued its downward trend for Q4 to below 50% of total generation. As large-scale wind and solar play a greater role in the NEM, they are setting prices more often. As a result, we observed a record number of negative prices in Q4—mainly during the day. While underlying costs of fuel for coal and gas generators remained higher than historical levels, overall wholesale spot prices have eased from mid-2022.

As a further consequence of low demand for electricity, NEM gas generation was particularly low. This occurred alongside Queensland Liquified Natural Gas (LNG) exports falling to the lowest level over Q4 since 2018. In combination, these factors eased pressure on domestic gas spot prices. The outlook for 2023 reflects a mixture of positive indicators alongside some risks. A number of large-scale solar and wind farms came online in 2022 and will support supply in 2023. Combined solar and wind generation accounted for a record 23% of quarterly generation which is up 4 percentage points from Q4 2021. New large-scale solar and batteries are also expected to enter the NEM in late 2023.

In gas markets, relatively high southern production has contributed to the Iona gas storage facility in Victoria being refilled to its highest end-of-year levels since reporting commenced. Iona plays a key role in maintaining gas system stability and supporting southern supply on peak demand days. As a result, high storage levels coming into winter are important for market resilience.

Nonetheless, many of the risk factors which contributed to high 2022 prices remain. In January 2023, wholesale electricity prices across the NEM have started to increase with higher demand due to warmer weather. Underlying fuel costs for coal and gas generation remain high. International coal and gas prices similarly remain high and volatile, although the presence of price caps on coal and gas should mitigate high price risk in the domestic setting. We discuss the European gas outlook in more detail as a focus story. High-price events in South Australia and Tasmania also highlight specific risks where NEM interconnection is disrupted and we have examined them in another focus story.

Alongside these market dynamics, we have also considered whether the anticipation of policy intervention and the announcement of coal and gas price caps in December 2022 has put downward pressure on futures prices for 2023. These measures were implemented in December, so it is too early to reach a definitive view about their impact. However, the timing of price decreases in contract markets indicate that these interventions may have contributed to these movements in price. We will continue to monitor and report on the effect of these price caps and real time bidding behaviour of all participants, including those impacted by the caps, in future Wholesale Markets Quarterly reports.

Electricity markets at a glance

Q4 2022

Spot prices

Spot prices fell from previous quarter but are still elevated compared to Q4 2021.

Outlook

Price expectations for 2023 improved over Q4 – prices expected to be highest in NSW and lowest in Victoria.

Demand

Very low demand due to mild start to summer and record rooftop solar output.

Generation

Record combined wind and solar output together with low demand displaced coal.

Price setters

Prices set by coal, gas and hydro dropped from Q3, but higher than the same time last year. Wind and solar set price more often.

FCAS

50 Hz

FCAS costs decreased compared to Q4 2021, but there were higher local FCAS costs in SA and Tasmania.

Gas markets at a glance
Q4 2022

Spot prices

Local prices in October and November remained historically high around $20/GJ.

Regulated gas price cap

The $12 Gas Emergency Price Order came into effect on 23 December & applies to regulated gas trades for 12 months.

Gas Supply Hub

Delivered quantities remained high, sitting at the 2nd highest level following last quarter's record.

Day Ahead Auction

Q4 2022 auction quantity won for gas transportation capacity exceeds last quarter's record reaching 31 PJ.

Gas Storage

Southern gas storage refilled significantly in December which will assist with anticipated tightness of gas supply for Winter 2023.

International markets

International spot and oil prices reduced but 2023 LNG spot price forecasts are still close to $30/GJ, putting pressure on local prices.

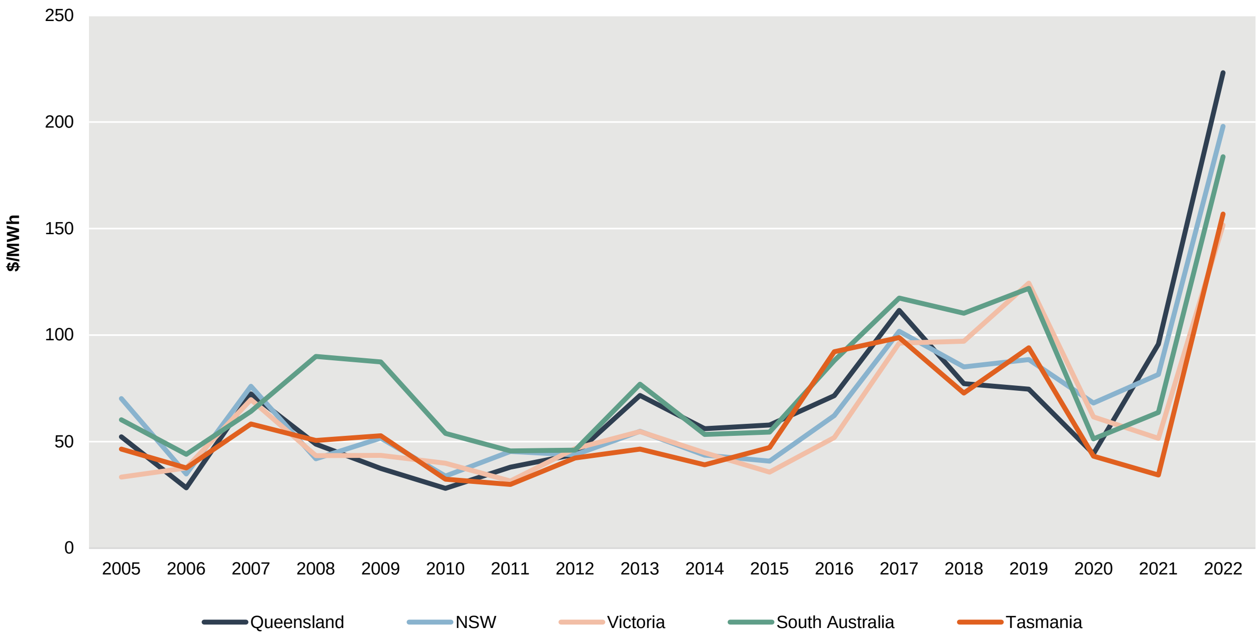
1 Spot market prices eased but remained high by historical standards

1.1 2022 saw record high average annual prices

In 2022, the annual volume weighted average (VWA) prices reached record high levels across all regions in the National Electricity Market (NEM) since 2005 (Figure 1.1). Average annual prices ranged from $152/MWh in Victoria to $223/MWh in Queensland.

The significant increase in average annual prices was driven by the record quarterly prices in Q2 and Q3 2022 due to a range of domestic and international pressures.[1]

Figure 1.1 Average annual electricity prices (VWA)



Source: AER analysis using NEM data.
Note: Volume weighted average annual price is 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.

These pressures also impacted gas markets with elevated price levels from April onwards resulting in yearly average prices for 2022 increasing above $20/GJ in all downstream markets, more than double that of the previous year (Table 1.1).

[1] AER, Wholesale markets quarterly - Q2 2022, August 2022; AER, Wholesale markets quarterly - Q3 2022, November 2022.

Table 1.1 Calendar year average prices ($/GJ)

	Wallumbilla	Brisbane	Adelaide	Sydney	Victoria
2021	10.64	9.12	9.25	9.07	8.24
2022	18.91	20.74	21.52	20.90	20.08

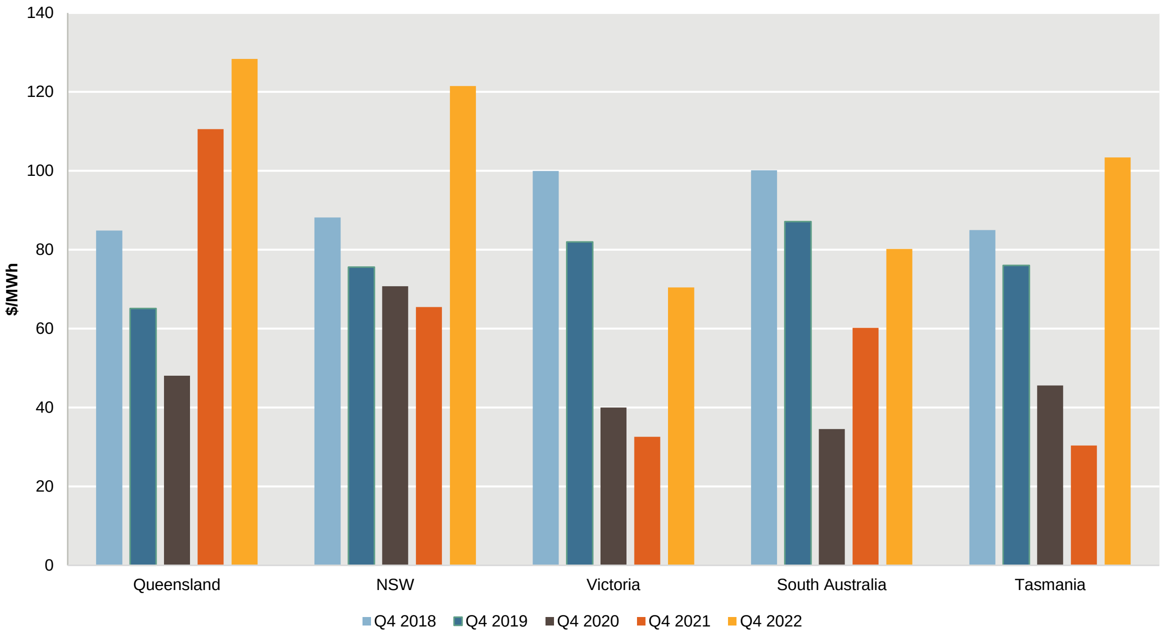
Source: AER analysis using DWGM, STTM and WGSH data.
Note: The Wallumbilla price is the day-ahead exchange traded price (volume weighted). volume weighted price. Adelaide, Brisbane, Sydney and Victoria are a simple average of daily price.

1.2 Q4 2022 prices eased compared to previous 2 quarters but were higher than prices in Q4 2021

Average quarterly VWA prices in Q4 2022 remained high in all regions compared to Q4 2021, reaching record Q4 levels in Queensland, NSW and Tasmania (Figure 1.2). Average quarterly prices ranged from $70/MWh in Victoria to $129/MWh in Queensland (Figure 1.3). While Victoria was the cheapest region in the NEM, even its average Q4 2022 price of $70/MWh was more than double its Q4 2021 price of $33/MWh. Tasmania's average Q4 2022 price of $103/MWh was more than triple the Q4 2021 price of $30/MWh.

On the mainland, there was a price divide between the northern regions and the southern regions, with Queensland and NSW recording higher average quarterly prices than Victoria and South Australia.

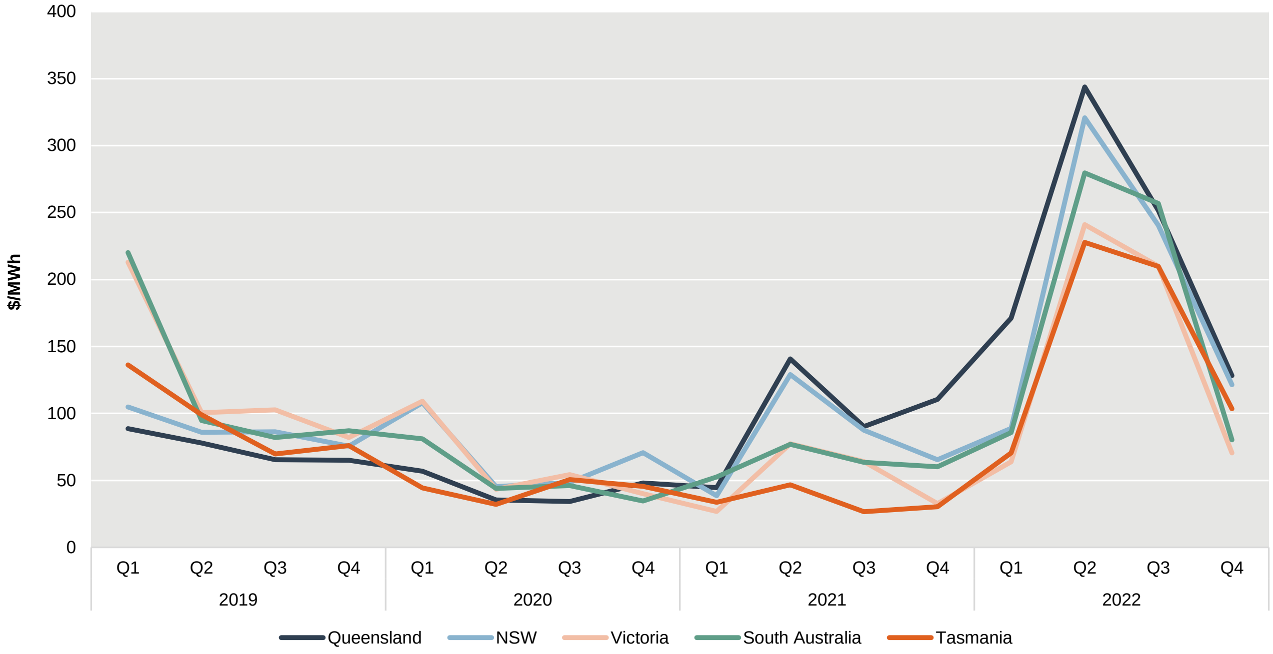
Figure 1.2 Comparison of Q4 average quarterly prices (VWA)



Source: AER analysis using NEM data.
Note: Comparison of volume weighted average Q4 price, using native demand in each region.

Despite the elevated prices compared to Q4 2021, average quarterly prices in Q4 2022 were significantly lower in every region compared to Q3 2022 (Figure 1.3).

Figure 1.3 Average quarterly prices (VWA)

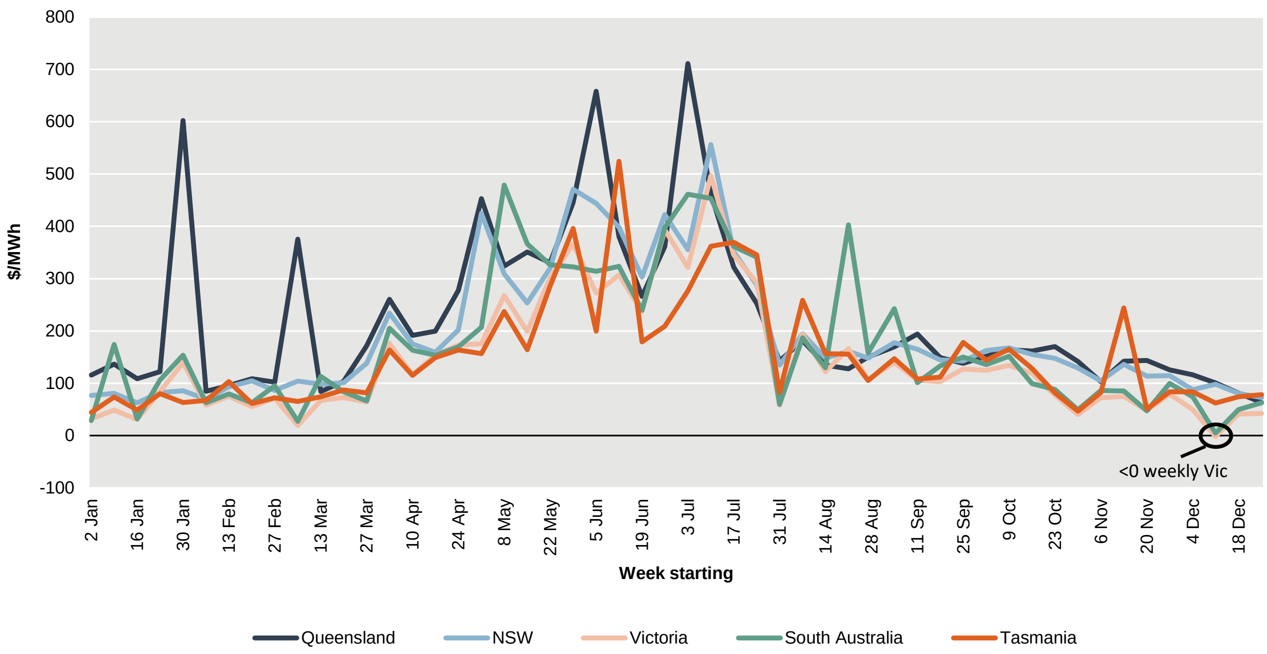


Source: AER analysis using NEM data.
Note: Volume weighted average quarterly price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Average weekly prices fell as the quarter unfolded, due to low demand coupled with higher wind and large-scale solar output over the quarter (Chapter 3). This was particularly pronounced in Victoria, where prices fell to a record low negative average weekly price of -$1.64/MWh in the week starting 11 December (Figure 1.4). This was due to low demand resulting from long daylight hours increasing rooftop solar output, mild weather conditions together with particularly strong wind output that week. This is the first time any region has seen a negative average weekly price (VWA). Spot prices can fall below $0/MWh when there is low demand and a high amount of cheap generation being offered[2].

[2] Wind and solar generators offer the majority of their capacity at negative prices because they have very low marginal cost and receive income from renewable energy certificates (RECs) for every MW they generate. They also generally sell their output through Power Purchase Agreements (PPAs) which further minimises their exposure to negative prices. AER, Wholesale Electricity Market Performance Report, December 2022, p. 74

Figure 1.4 Average weekly VWA prices

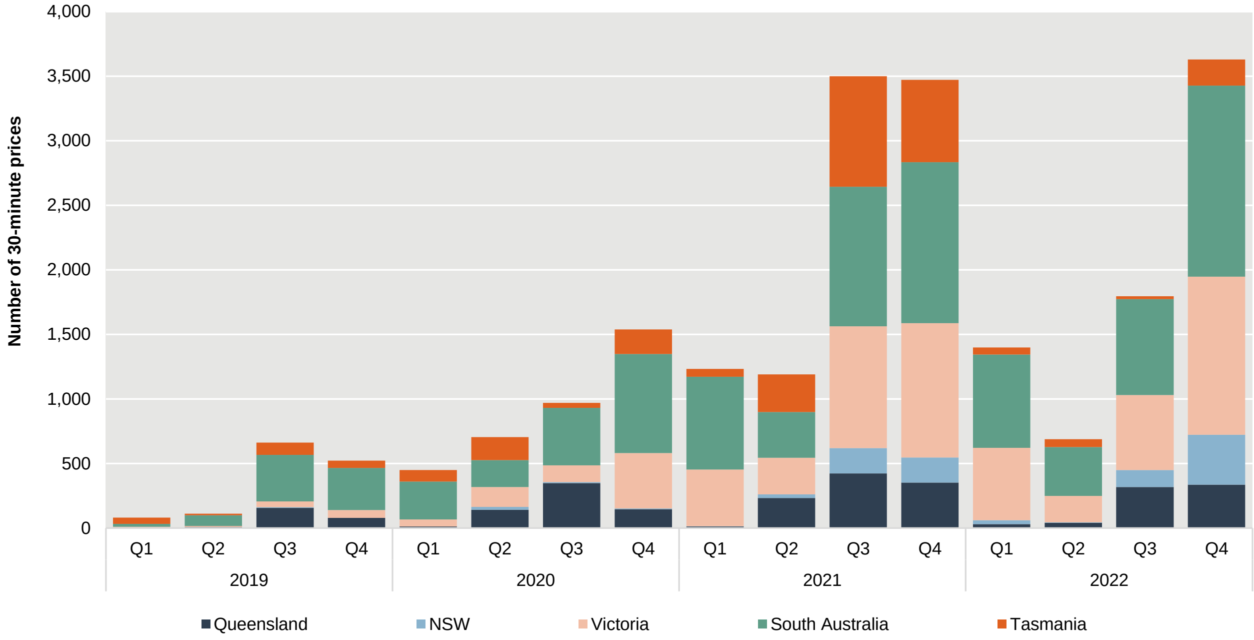


Source: AER analysis using NEM data.
Note: Volume weighted average weekly price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region. Weeks commence on Sunday.

1.3 Record number of negative NEM prices helped ease average prices in Q4 2022

In addition to Victoria experiencing the NEM's first week of average negative prices, there were a record number of negative price events in Q4 2022 totalling 3,629 instances of negative 30-minute prices (Figure 1.5). Three-quarters of those negative prices were in Victoria and South Australia and were due to low demand during the day (as a result of increased rooftop solar output) coupled with higher wind and large-scale solar output driving prices down.

Figure 1.5 Quarterly count of negative prices



Source: AER analysis using NEM data.
Note: Count is of 30-minute prices.

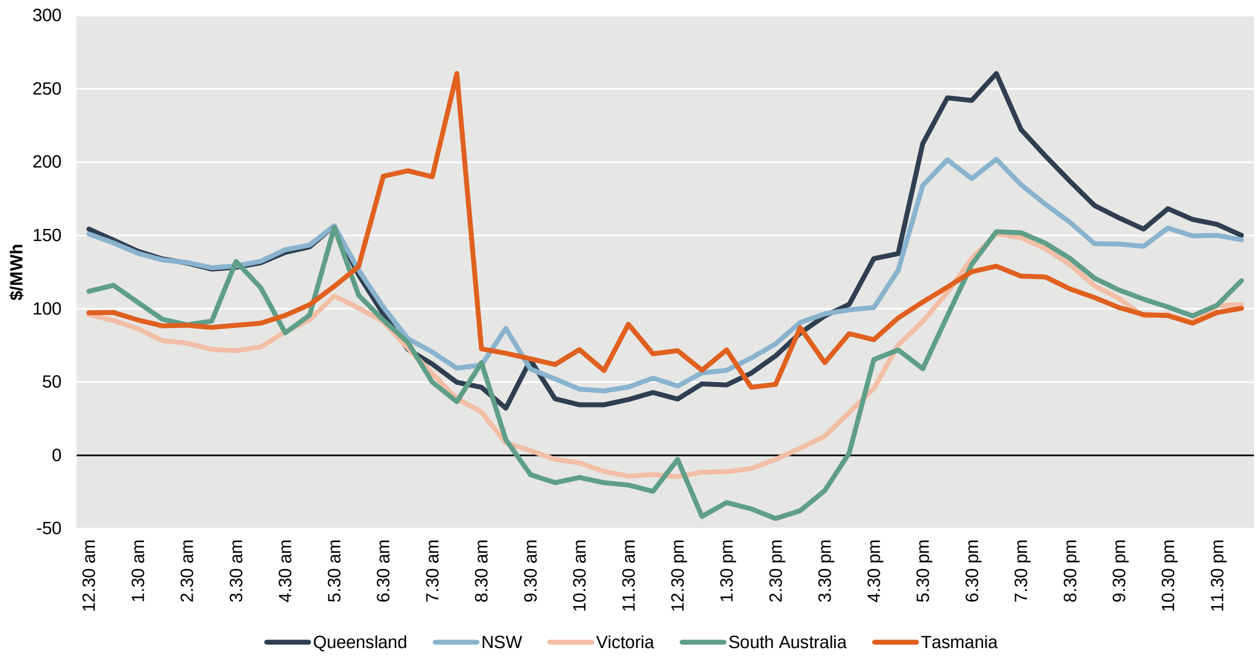
The average daytime prices in mainland regions were below $100/MWh (Figure 1.6).[3] Average prices tended to peak in the evenings, reaching $200/MWh or above in Queensland and NSW. The average prices were negative in South Australia between 9am and 4pm. In Victoria, average prices were negative between 9.30am and 2.30pm.

Increasingly high numbers of negative prices in the NEM presents commercial challenges for generators, which are essentially paying to generate when prices are below $0/MWh. Generators that have little to no flexibility face making losses during the middle of the day, when most negative prices occur. The price volatility which accompanies an increase in negative prices and a peaky load profile is also challenging for retailers to hedge against. The negative prices seen this quarter illustrate the growing nature of this trend.

Tasmania's morning peak price spike anomaly was due to a series of high price events on 14 November driven by storm damage to the transmission tower at Tailem Bend in South Australia that electrically islanded the region from the rest of the NEM. The constraints managing the outage in South Australia also affected generation in Victoria and the Basslink interconnector to Tasmania. This led to high priced generation in Victoria setting the price in Tasmania above $5,000/MWh, thereby causing the spike in Tasmania's morning price. The high price events in Tasmania are explored further in the Electricity Focus Story (Chapter 11).

[3] Mainland prices were less than $100/MWh from 6:30am to 5:30pm in Victoria and South Australia and from 6:30am to 3:30pm in Queensland and NSW.

Figure 1.6 Average prices by time of day, Q4 2022

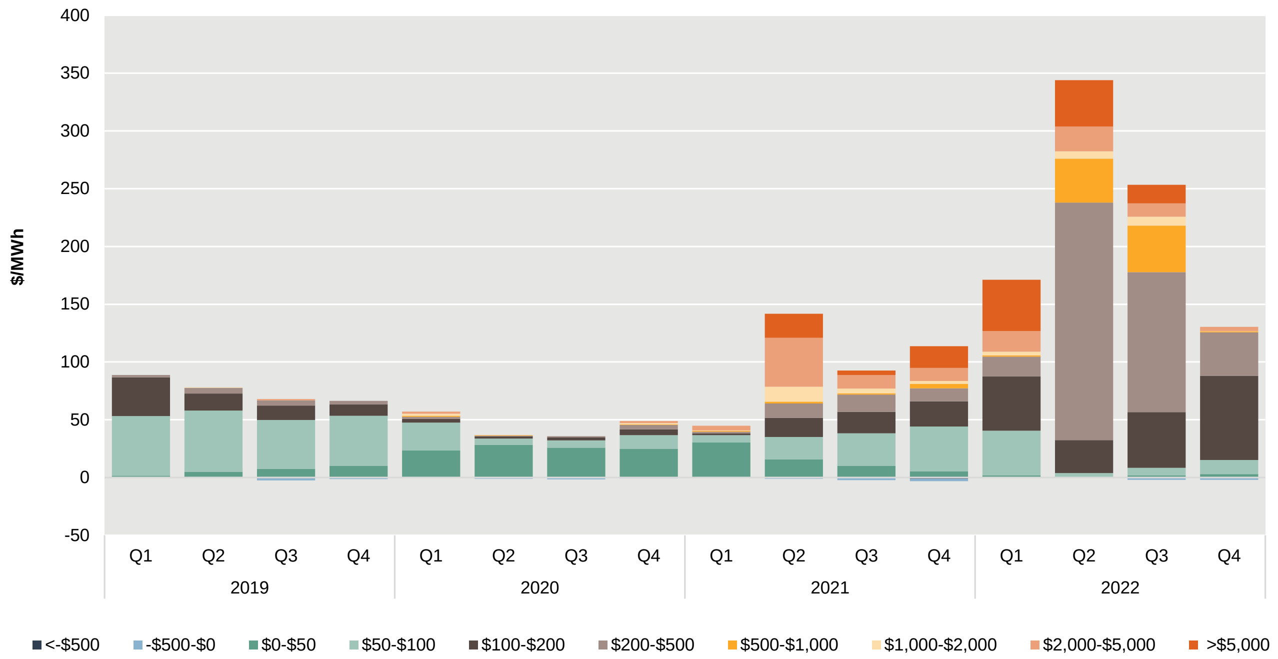


Source: AER analysis using NEM data.
Note: Prices are averaged by time of day in Q4 2022. Average prices may be negative.

1.4 Despite lower prices in the middle of the day, there has been a general uplift in prices in Q4 2022 compared to Q4 2021

There was general uplift in prices in Q4 2022 compared to Q4 2021. However, prices have eased in comparison to Q2 and Q3 2022 with most prices in Q4 2022 below $500/MWh in all regions. To illustrate this, Figure 1.7 shows the contribution of different prices, within defined bands, to the average quarterly price in Queensland for Q4 2022. The outcomes in NSW were similar to the outcomes in Queensland. In Victoria and South Australia, there were more prices below $200/MWh than in the northern regions.

Figure 1.7 Contribution to average quarterly price by price band - Queensland



Source: AER analysis using NEM data.
Note: Shows extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in the region.

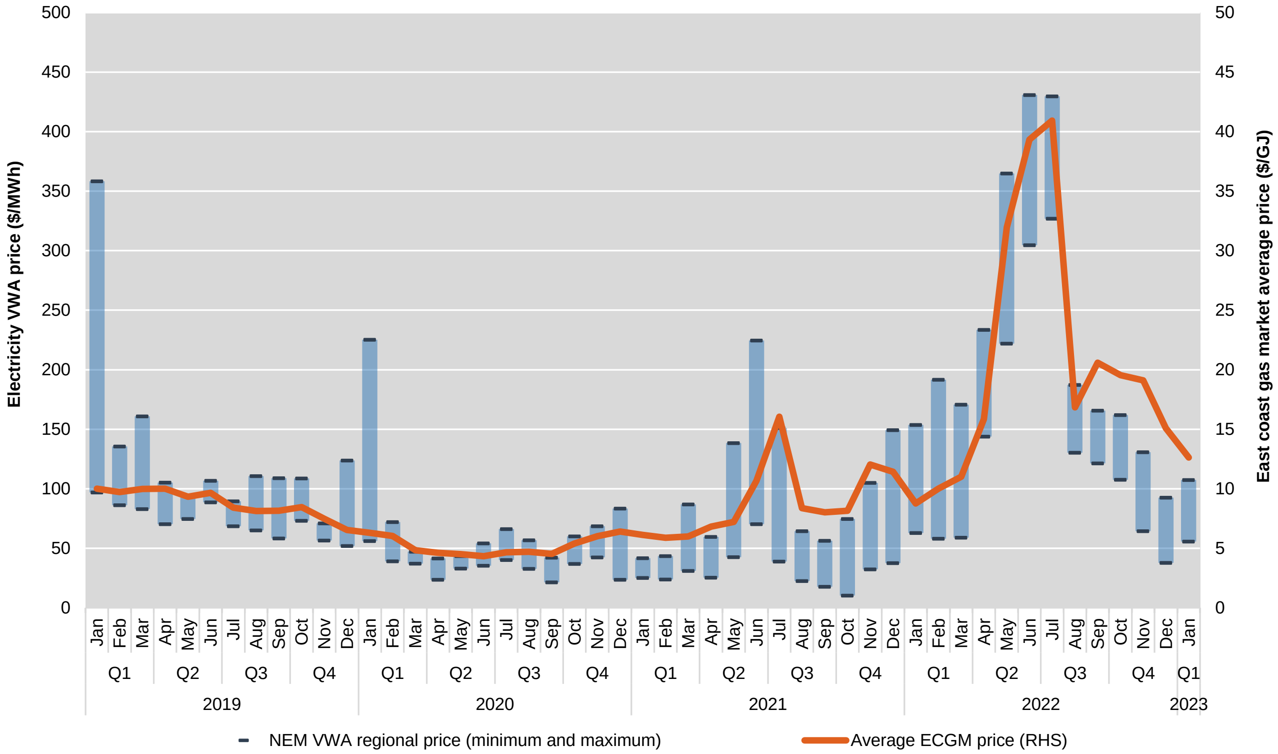
Despite this general uplift, prices over $500/MWh contributed less to overall price outcomes this quarter compared to Q2 and Q3 2022. This coincided with a general decrease in average prices across all regions from higher levels this quarter compared to the previous 2 quarters.

1.5 Gas spot prices remained elevated before falling from mid-December

Like the NEM, domestic gas prices were elevated for Q4 compared to previous Q4s, reaching record Q4 levels in all markets (Figure 1.8). This was influenced by high international prices and possible tight supply conditions next winter. While prices in October and November were comparable to the levels observed over the two months prior, prices decreased markedly from mid-December.

The relationship between electricity and gas spot prices in Q4 2022 was less strong than in other quarters in 2022. This was due to low NEM demand reducing the need for gas-powered generation.

Figure 1.8 Spot prices in electricity and gas markets remain historically high



Source: AER analysis using east coast gas market (ECGM: Victoria, Adelaide, Brisbane and Sydney gas markets) and NEM price data.
Notes: The blue columns show the range of monthly regional prices (VWA) in the NEM. The orange line shows the average monthly east coast gas market (ECGM) prices.

Spot gas prices eased significantly from mid-December, reducing the monthly average to around $15/GJ.[4] Prices typically ease late in the year due to reduced heating demand and holidays. This was the case from mid-December when prices fell towards $12/GJ. Lower market demand and gas generation in the NEM contributed to prices easing over the quarter, alongside easing of international prices.

[4] From 18 December, prices in downstream markets ranged from $9.19-12.40/GJ.

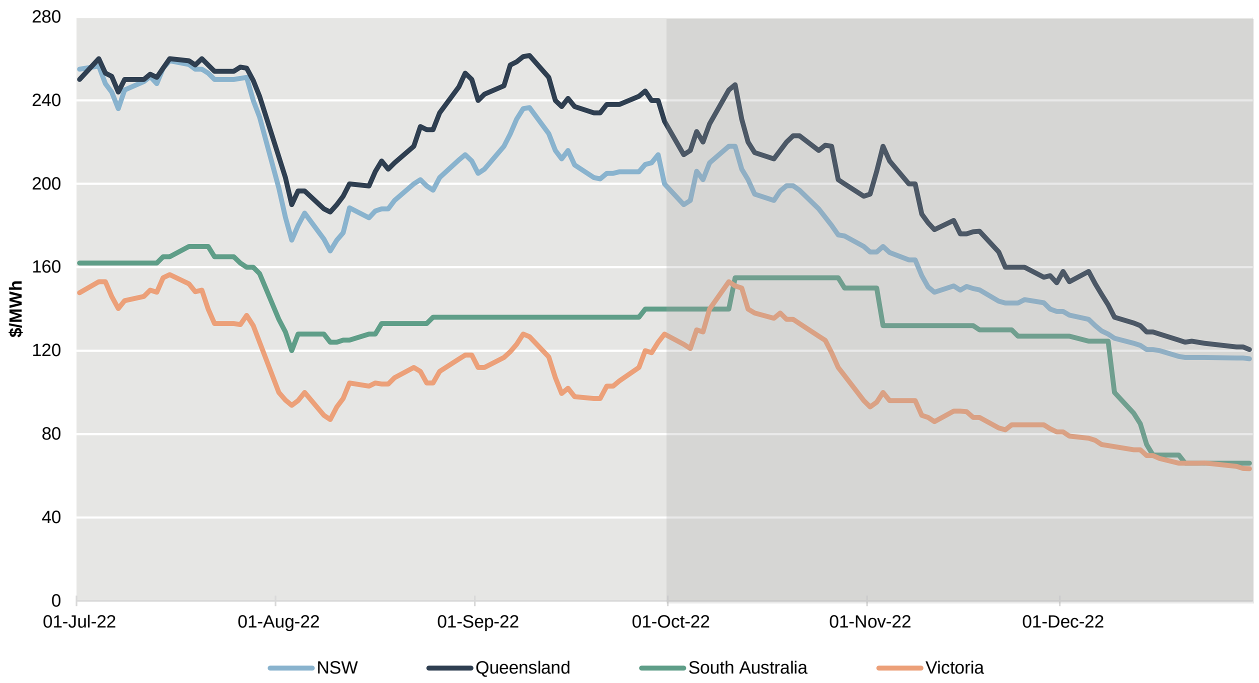
2 Contract prices also eased but remain high

Contracts are used as a hedging tool by both generators and retailers to reduce their spot market risk. Base futures are the most commonly traded contracts, allowing the buyer and seller to lock in a price for electricity in advance. The price of base futures gives us an indication of where market participants expect average spot prices to settle in coming periods.

Q4 2022 base future prices fell steadily during the quarter. These contracts were priced at between $123/MWh and $214/MWh at the start of the quarter before falling 39% to 54% during the quarter. Final base future prices were between $63/MWh and $120/MWh with Queensland and NSW final prices almost double those in South Australia and Victoria (Figure 2.1).

Queensland and NSW both recorded their highest ever Q4 final base future price despite final contract prices falling significantly compared to the previous 2 months. Final Q4 2022 prices exceeded $100/MWh for the first time in both regions. The South Australia and Victoria final contract prices were the highest since Q4 2019.

Figure 2.1 Q4 2022 daily base future prices

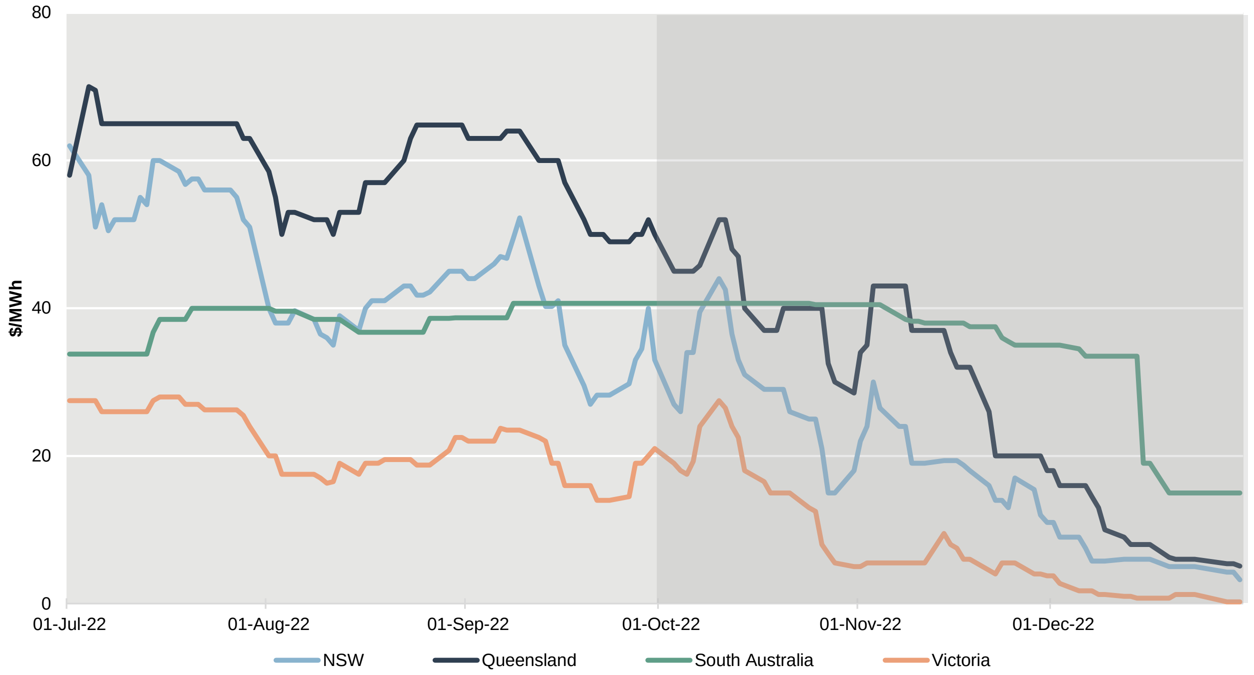


Source: AER analysis using ASX data.
Note: Daily settled price for Q4 2022 quarterly base future contracts.

Cap prices fell during Q4 as the risk of high prices (>$300/MWh) fell. At their height, market participants were valuing cap contracts for Q4 as high as $70/MWh in Queensland and $28/MWh to $67/MWh in the other regions. Lower cap prices are an indication that market participants perceived a reduced risk of high prices in Q4 compared to Q2 and Q3 2022.

Final Q4 2022 cap prices ranged from $0.08/MWh in Victoria to $8.32/MWh in South Australia (Figure 2.2). Cap prices were highest in South Australia as it experienced the majority of spot prices above $300/MWh following a severe weather event islanding South Australia from other parts of the NEM (Chapter 11).[5]

Figure 2.2 Q4 2022 daily cap prices



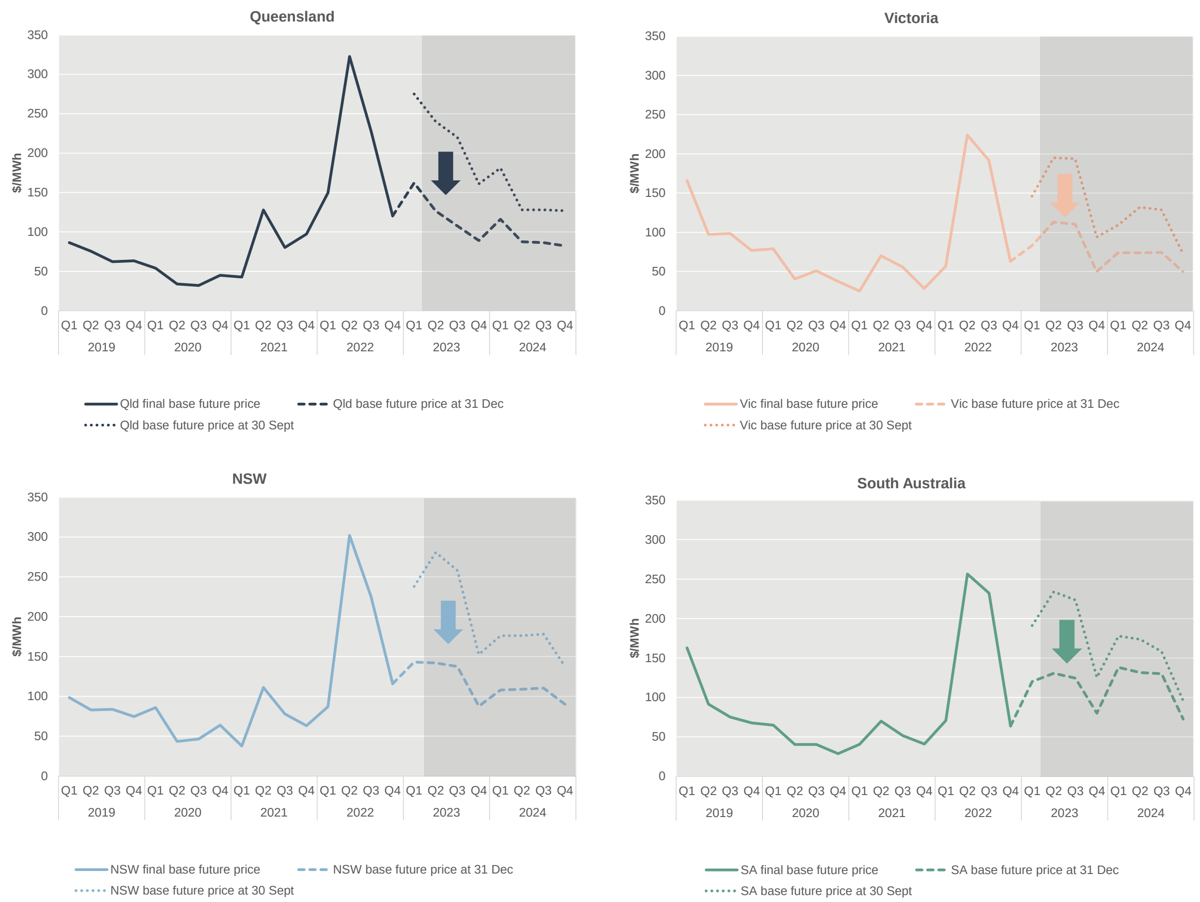
Source: AER analysis using ASX data.
Note: Daily settled price for Q4 2022 cap contracts.

2.1 Forward prices appeared to react to gas and coal cap announcements

In the week that followed the Budget, speculation about possible government interventions saw the forward contract price for financial year 2023–24 fall $33/MWh to $37/MWh (down 15% to 23%) in all regions except South Australia. Contract prices continued to fall in November. Low liquidity in South Australia saw prices unresponsive through October and November, with insufficient bids and offers to set a new daily settled price. South Australian prices fell in line with other regions in December once there were enough bids and offers to set a new price.

[5] The cap for cap contracts is $300/MWh.

Figure 2.3 Forward base future prices fall in Q4 2022



Source: AER analysis using ASX data.
Note: Prices for Q1 2018 to Q4 2022 base futures are final base future prices. Prices for Q1 2023 base futures and beyond are at 31 December 2022.

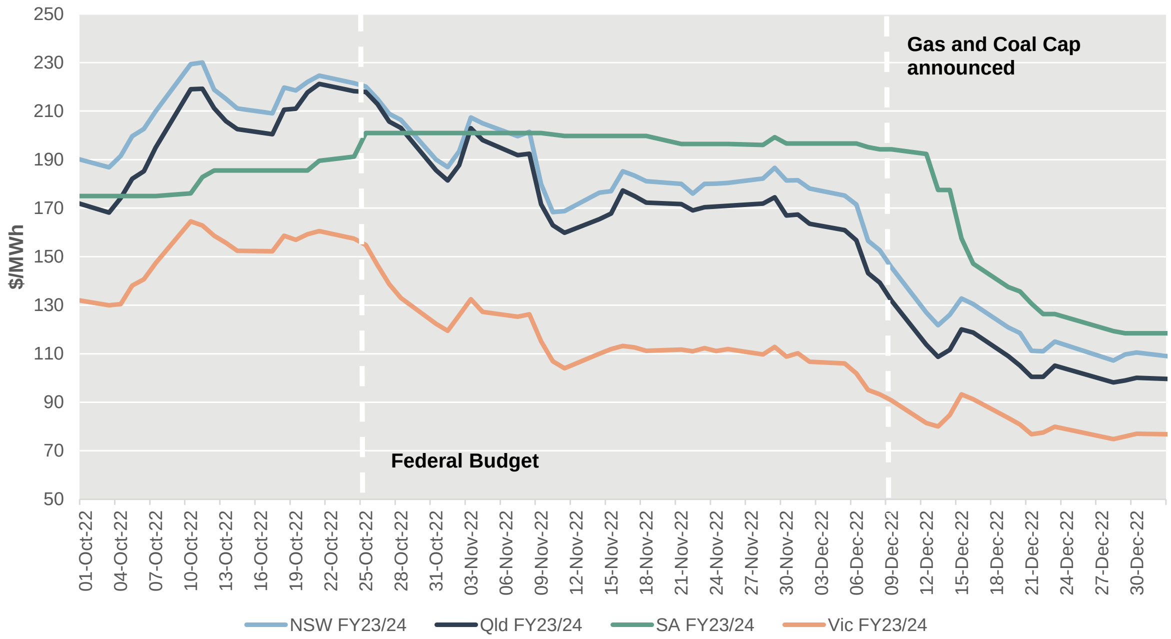
At 31 December 2022, the base future prices for financial year 2023–24 ranged from $77/MWh to $118/MWh. These prices represent a fall of between $83/MWh and $121/MWh (down 41% and 55%) compared to their highest points in October. Despite the dramatic price falls, prices still remain $28/MWh to $60/MWh higher than they were at the start of 2022 before the Ukraine conflict.

Following the Energy Minister's Meeting on 8 December and National Cabinet meeting on 9 December, the Prime Minister announced the Energy Price Relief Plan.[6] The Energy Price Relief Plan includes a number of measures including temporary caps on the price of gas contracts and of coal used by power stations in Qld and NSW. These measures were implemented on 23 December.

These caps were implemented relatively late in the quarter, and it is too soon to draw definitive conclusions about their impacts. The dynamics resulting in decreasing spot prices would likely also have contributed to easing contract prices. However, the timing and materiality of contract price changes indicate that these interventions may have contributed to these movements in price.

[6] Prime Minister, Treasurer, Minister for Climate Change and Energy, [Media release—Energy price relief plan](), 9 December 2022.

Figure 2.4 Financial year 2023–24 base future daily settled price



Source: AER analysis using ASX data.
Note: Daily settled price for financial year 2023–24 base future contracts.

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

On 23 December, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months.[7]

- The Order introduces a price cap on gas of $12/GJ (and does not apply in Western Australia).
- Generally, the price cap applies to gas producers and affiliates of gas producers (Regulated 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).[8]
- Separate to the exceptions, the Order also allows the Minister to grant exemptions.
  - The Minister has delegated the power to grant a gas price cap exemption to the ACCC.
  - The delegation commenced on 23 December 2022.
- Further information on the price cap, the process of applying for an exemption (including information requirements), and the ACCC's process upon receiving an exemption application can be found on the ACCC's website.[9]

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

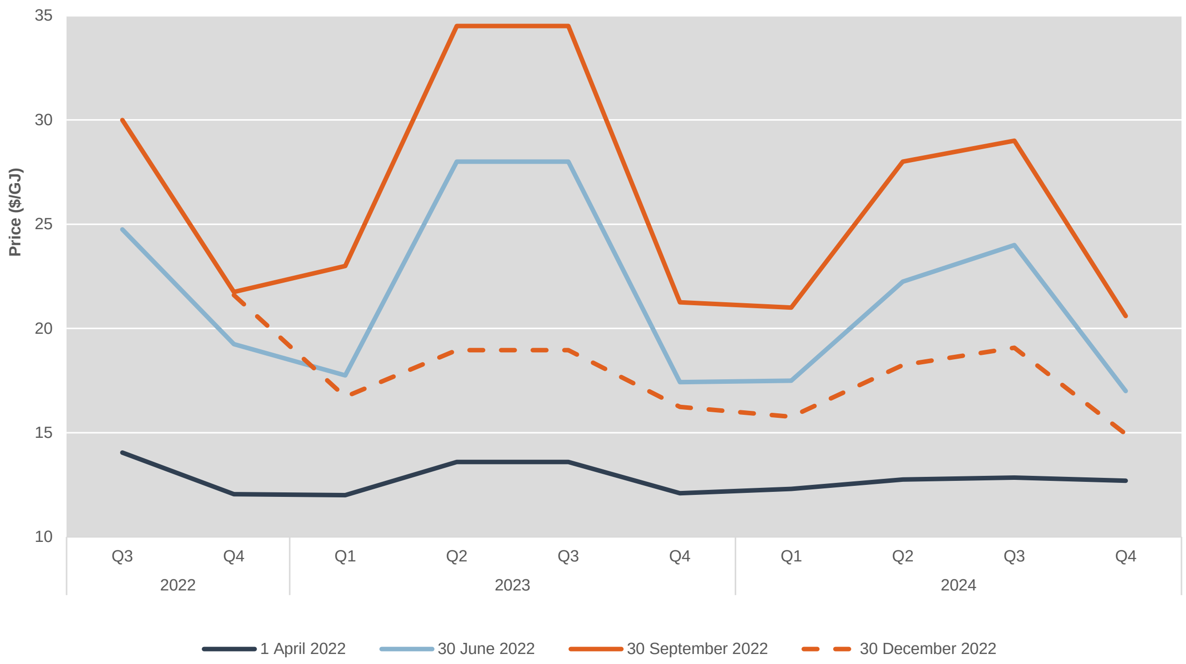
[8] Over 2022 spot trade in the downstream DWGM and STTM collectively averaged around 16% of the gas traded through the markets.

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

2.1.1 Forward gas trade prices reduce

Gas futures pricing have fallen since September 2022. Victorian gas futures settlement pricing in Q4 2022 indicated that traders expect prices to drop in 2023, with prices ranging from $16.24/GJ to $18.96/GJ. These decreases appear to reflect lower spot prices and expectations that international LNG spot prices should decrease.[10]

Figure 2.5 ASX Victorian gas futures pricing by date



Source: ASX Energy.

2.1.2 Latest capacity certificate auction for Victorian gas market increases diversity of capacity holders for 2023-2025

We have continued to monitor outcomes from capacity certificate auctions in the Victorian market (DWGM) through late 2022. These certificates provide injection and withdrawal rights for the Victorian gas market for 2023 to 2025 and are important to being able to bid gas into Victoria when there are constraints on injection point capacity. There is evidence market participants are using the auctions to ensure priority injection and withdrawal rights in the DWGM due to increased risk of outages at the ageing Longford production plant on constrained days.

The last auction for 2023 to 2025 rights was held in November 2022, following which a greater number of participants won capacity at injection points in Victoria – including at Gippsland (Longford). A significant volume of trading rights won were for the winter months (1,854 TJ), a majority (1,052 TJ) of which was for trading rights for the Gippsland entry point. These results highlight the importance of capacity certificate auctions in facilitating injection and withdrawal rights during constrained days.

[10] It should be noted that gas futures on the ASX are thinly traded and there is usually a large difference between bids and offers for these products on the exchange. Settlement prices for ASX gas futures usually reflect the lower part of this range but actual market expectations may be somewhat higher.

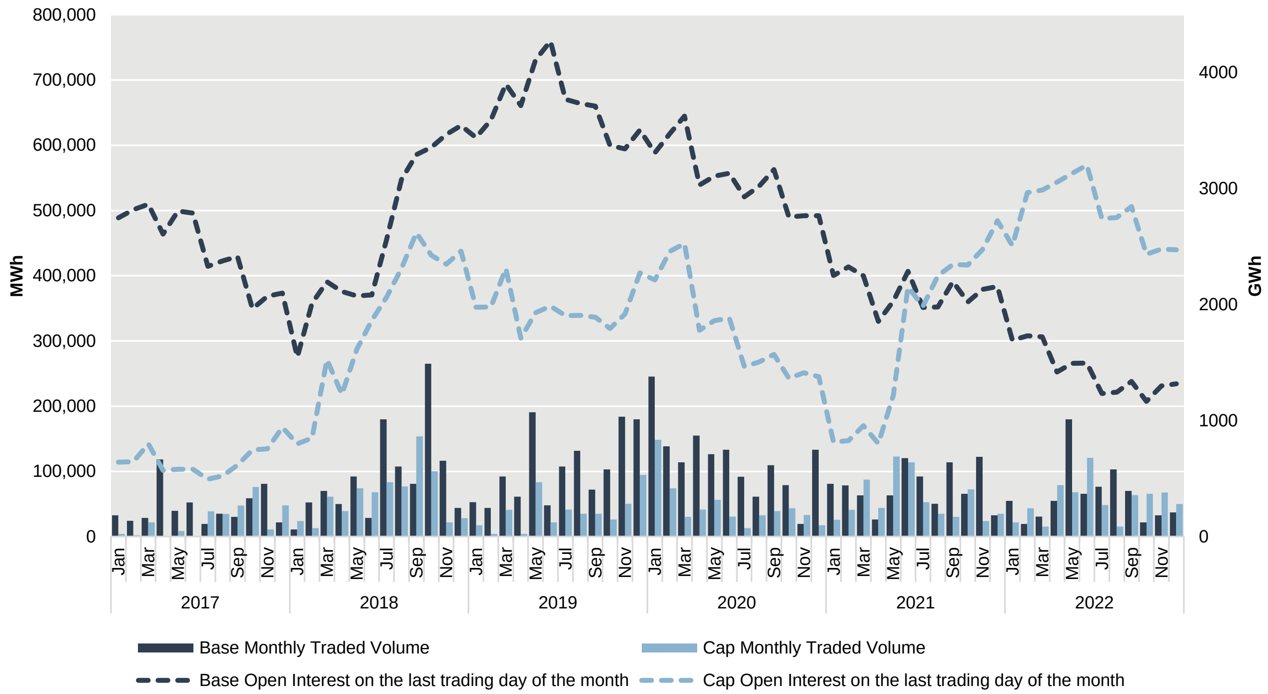
2.2 Liquidity in South Australia continued to decline

Open interest for South Australia base future contracts fell to its lowest level since 2011.[11] Open interest in base futures in South Australia is an indicator of liquidity, and has steadily declined since mid-2019. This illustrates that as contracts expire at the end of their contract period, new contracts are not being traded in equal volumes to replace them. Traded volumes in Q4 2022 were the lowest quarterly traded volume in South Australia since Q3 2017 and 59% lower than in the same quarter last year.

In contrast, open interest for cap contracts increased to its highest ever level in mid-2022 before falling back slightly in late 2022. For the first time ever, open interest for cap contracts is higher than open interest for base future contracts.

Participants are increasingly relying on cap contracts to hedge their South Australian load. Market participants have told the AER that there is a lack of supply of base future contracts available in South Australia. This could be due to a range of factors, including vertically integrated generators and retailers being able to hedge internally as well as the increasingly peaky nature of South Australian demand.

Figure 2.6 South Australia base future and cap monthly traded volumes and open interest



Source: AER analysis using ASX data.
Note: Open interest data is at the last trading day of the month.

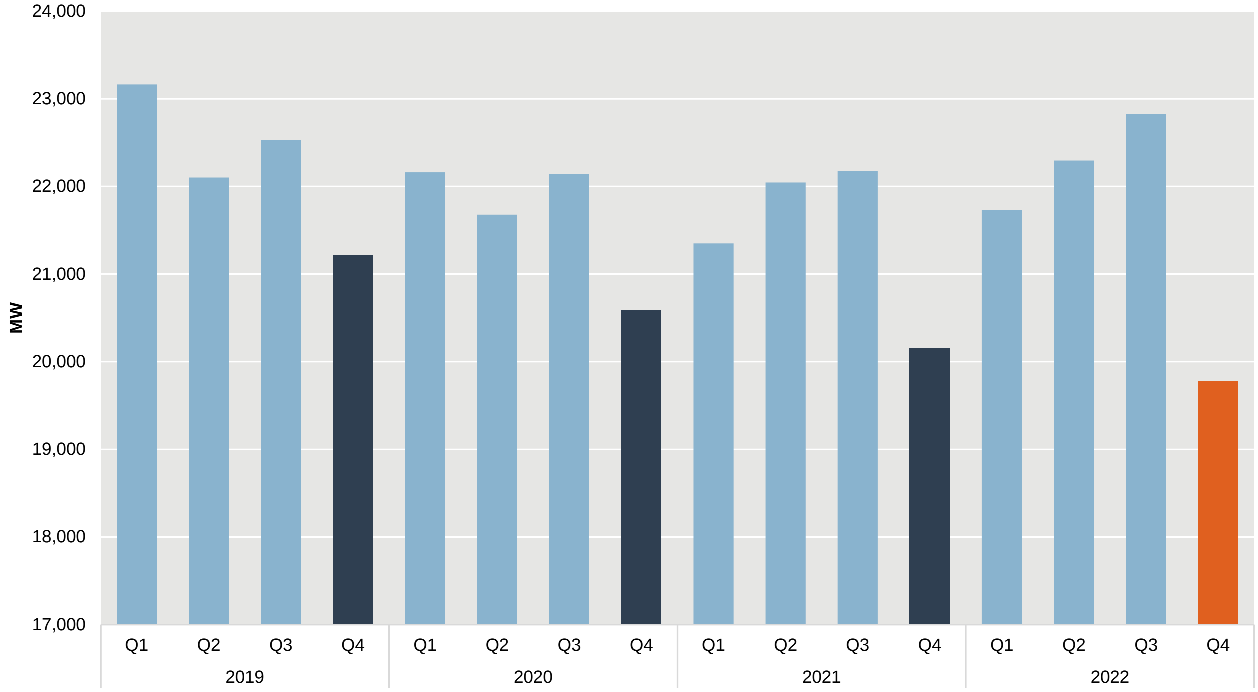
[11] Open interest is the total number of contracts that are actively held by market participants and have not yet been settled.

3 Record low demand helped ease prices in Q4 2022

The NEM's average quarterly demand in Q4 2022 reached its lowest level since at least 2006, falling to below 20,000 MW for the first time (Figure 3.1). This was largely driven by record rooftop solar output in every region and mild weather conditions in November and December, reducing the need for heating and cooling.

Average quarterly demand fell the most in Queensland, down by 6% from Q4 2021, followed by NSW which was down 1%. Average quarterly demand increased slightly in Victoria and South Australia.

Figure 3.1 Average quarterly NEM demand



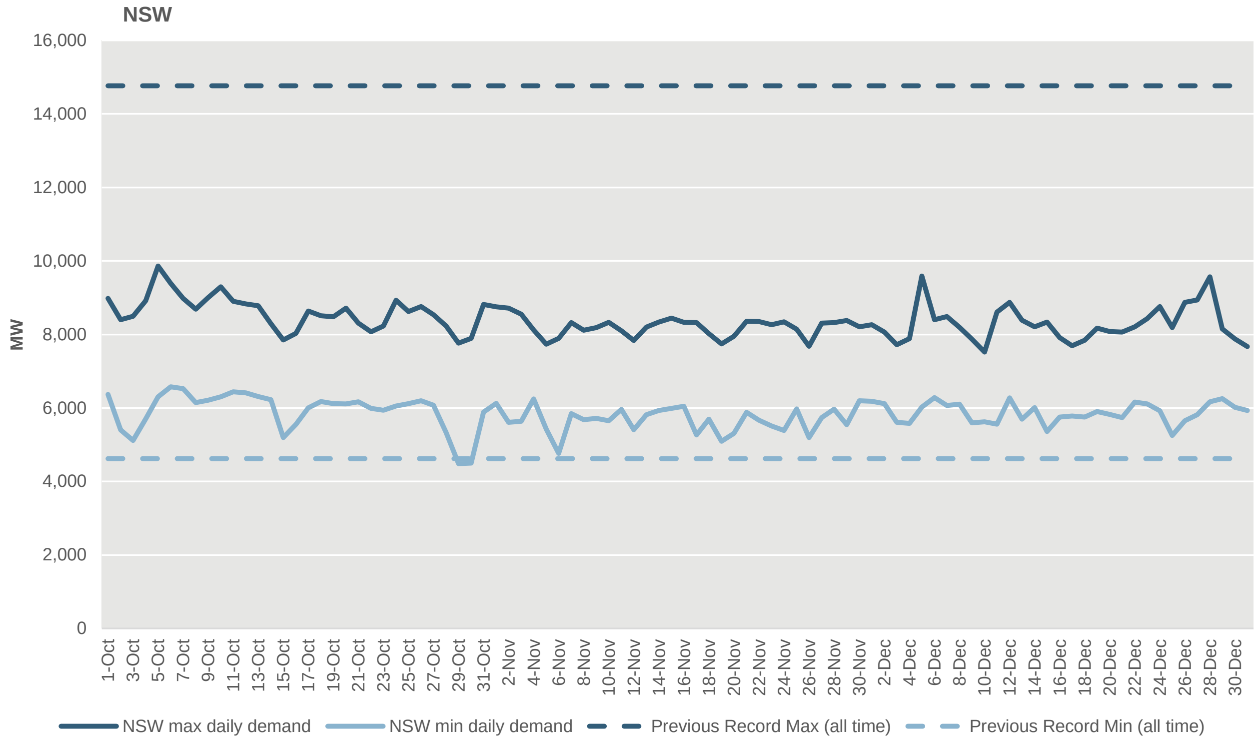
Source: AER analysis using NEM data.
Note: Uses quarterly average native NEM demand.

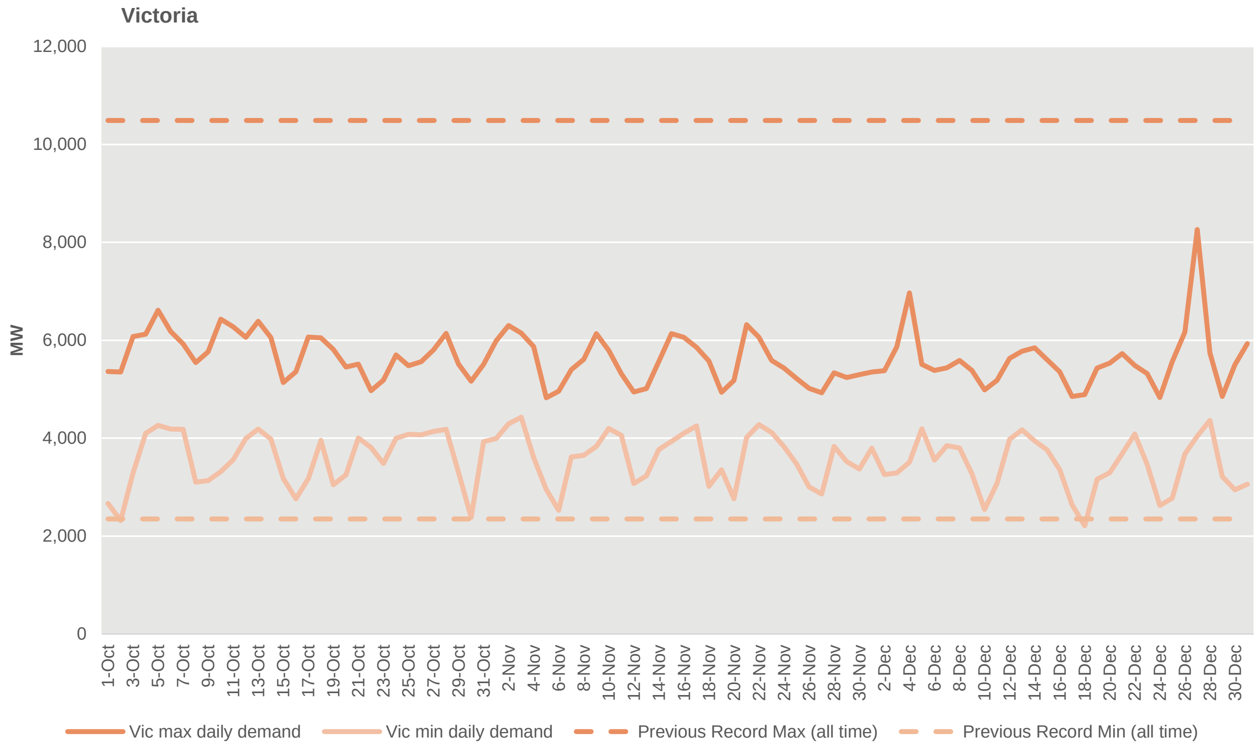
NSW and Victoria hit record all-time minimum demand in Q4 2022 (Figure 3.2). NSW beat the previous record low of 4,624 MW on 29 and 30 October recording demand levels of 4,483 MW and 4,498 MW, respectively. Victoria recorded its lowest demand on 18 December at 2,209 MW, beating its previous record low of 2,349 MW.

South Australia was close to record low demand levels at 123 MW on 5 November but did not quite reach the lowest level of 112 MW set 21 November 2021.[12] South Australia saw some days of higher demand in late December when temperatures reached 41 degrees.

[12] AEMO, Quarterly Energy Dynamics Q4 2022, January 2023, p. 4. AEMO reported record minimum demand in South Australia due to a different definition of demand.

Figure 3.2 NSW and Victoria minimum daily demand fell to record low



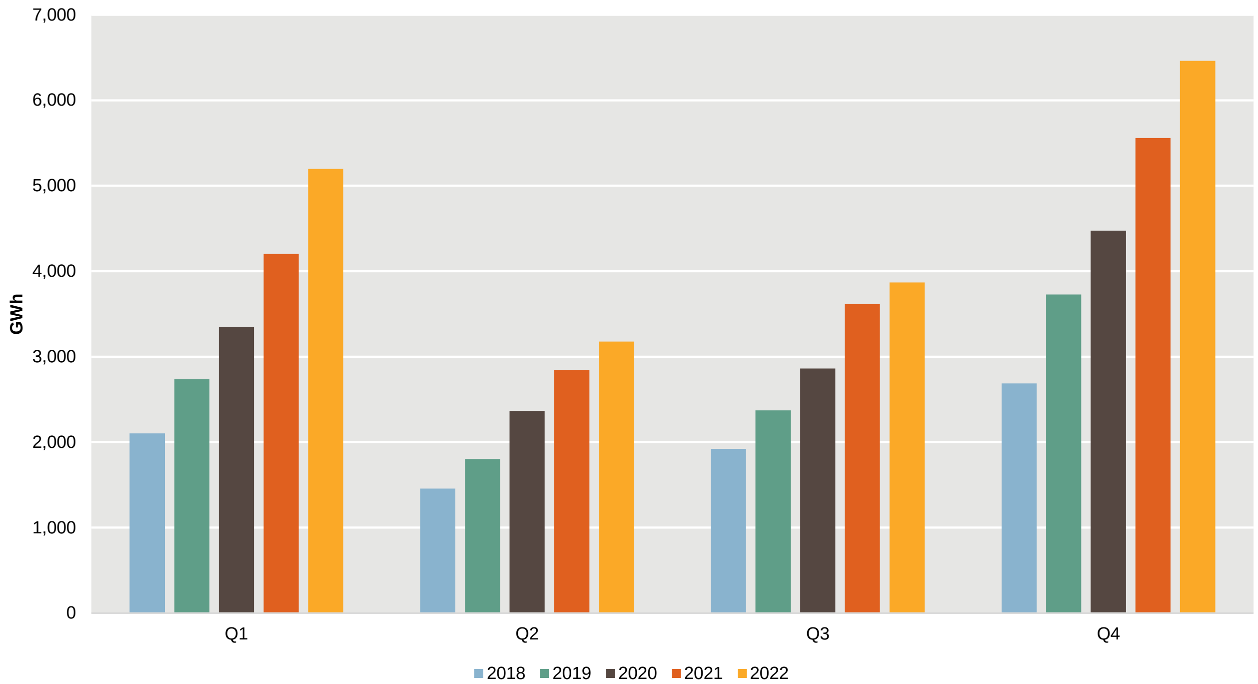


Source: AER analysis using NEM data.
Note: Uses daily minimum native demand.

3.1 Record rooftop solar

Rooftop solar output continued to increase in 2022, reaching over 18,000 GWh, up from just over 16,000 GWh in 2021. This was supported by growth in every NEM region, resulting in the highest ever levels of rooftop generation being reached in Q4 2022 (Figure 3.3). This record rooftop generation met 13% of total NEM demand this quarter, up from the previous high of 11% in Q4 2021.

Figure 3.3 Total rooftop generation in the NEM



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

3.2 Gas supply-demand conditions allows southern storages to refill

Total east coast demand was lower than Q4 2021, with a slight increase in market demand offset by lower gas generation and export demand over Q4 2022.[13] This enabled domestic gas production to fill southern gas storages ahead of winter 2023.

3.2.1 Lower LNG exports

LNG export demand increased moderately from Q3, but was significantly below levels from Q4 2020 and Q4 2021.[14] East coast exports to China, in particular, were significantly lower than in previous Q4s, contributing to the decline.

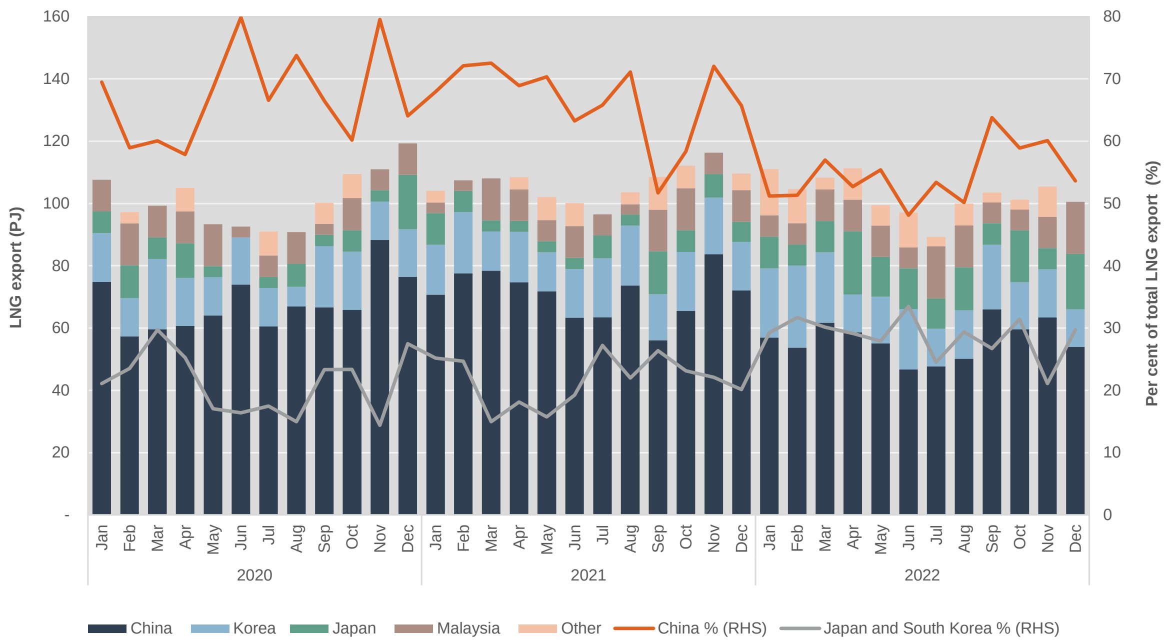
[13] Market demand refers to demand in downstream gas markets in Victoria, Sydney, Adelaide and Brisbane.

[14] Queensland exports fell to their lowest level over Q4 since 2018.

On an annual basis, exports to China were down by 177.5 PJ compared to 2021 levels.[15] This was partially the result of China importing less LNG from Australia while increasing its supply from Russia. At the same time, China's domestic LNG demand also diminished due to higher local production. Conversely, LNG exports to Japan increased by 67.8 PJ over 2022, with the country importing less from the US and Qatar.

Total Australian exports (Western Australia, Northern Territory, Queensland) returned Australia to being the world's largest LNG exporter for 2022.[16]

Figure 3.4 LNG shipped from Gladstone Port by destination



Source: AER analysis using Gladstone Port Corporation data.

Gas flows into Queensland increased over the quarter (Figure 3.5). While flows predominantly delivered gas north[17] over the quarter, supply was intermittently reversed to flow south on the QSN link (at Moomba) and the Victoria–NSW gas interconnector, particularly during planned maintenance being carried out on the QCLNG export pipeline.[18] Complementing this, gas flows south from the Northern Territory also recommenced from 12 December, averaging 25 TJ per day of

[15] Total exports from the east coast decreased over 2022 compared to 2021, with Q4 exports over the northern hemisphere winter at their lowest level since 2018, consistent with lower international prices. This coincided with two unplanned QCLNG train outages from early-December. Lower export demand reduced supply requirements in Queensland, resulting in surplus Roma production despite reduced output, and lower levels of supply flowing north from southern markets.

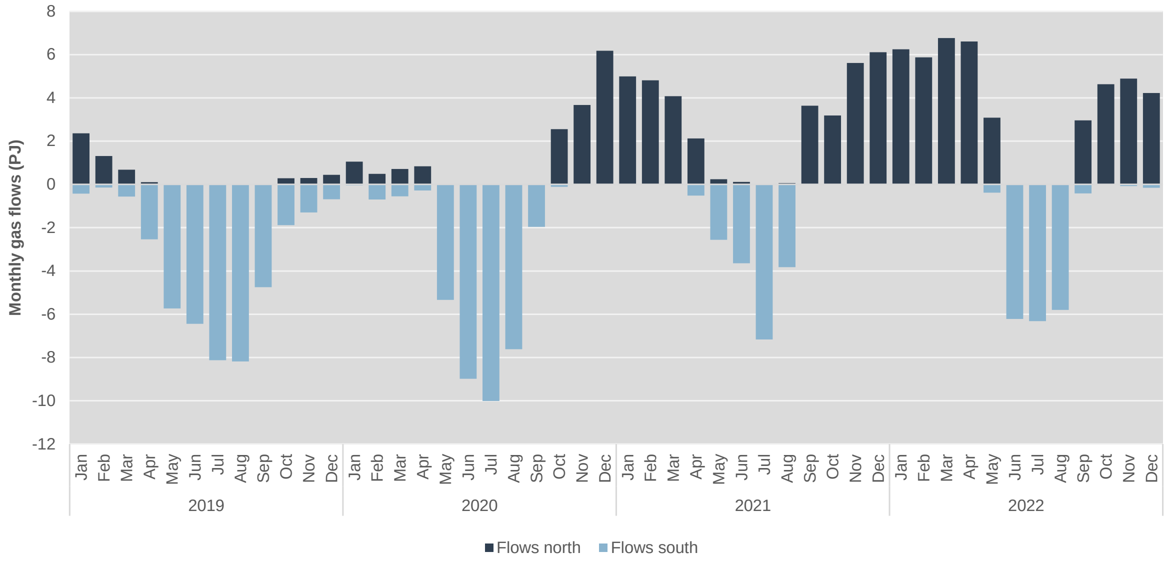
[16] Australia is on par with Qatar as the world's largest LNG exporter. DISER, Resources and Energy Quarterly, December 2022, p. 71.

[17] North-south gas flows typically supply gas into southern markets from Queensland during the high demand period over winter, reverting to northerly flows supplied by southern production sources as domestic demand decreases.

[18] A single train maintenance outage occurred on the Wallumbilla Gas Pipeline over 7 – 21 December, with an extension of maintenance activities occurring over 27 December – 19 January. Production exceeding export pipeline flows coming from Roma (Queensland) gas fields reduced to an average of 230 TJ per day over the quarter alongside lower production output, compared to an average of 480 TJ per day across the previous quarter, yet output continued at similar levels to that observed over September.

additional supply coming into Queensland. This followed a shutdown of the Jemena pipeline link as reduced output from the offshore Blacktip production field resulted in reduced pipeline pressure, requiring Mount Isa to be supplied from east coast production sources from early September.

Figure 3.5 North-south gas flows

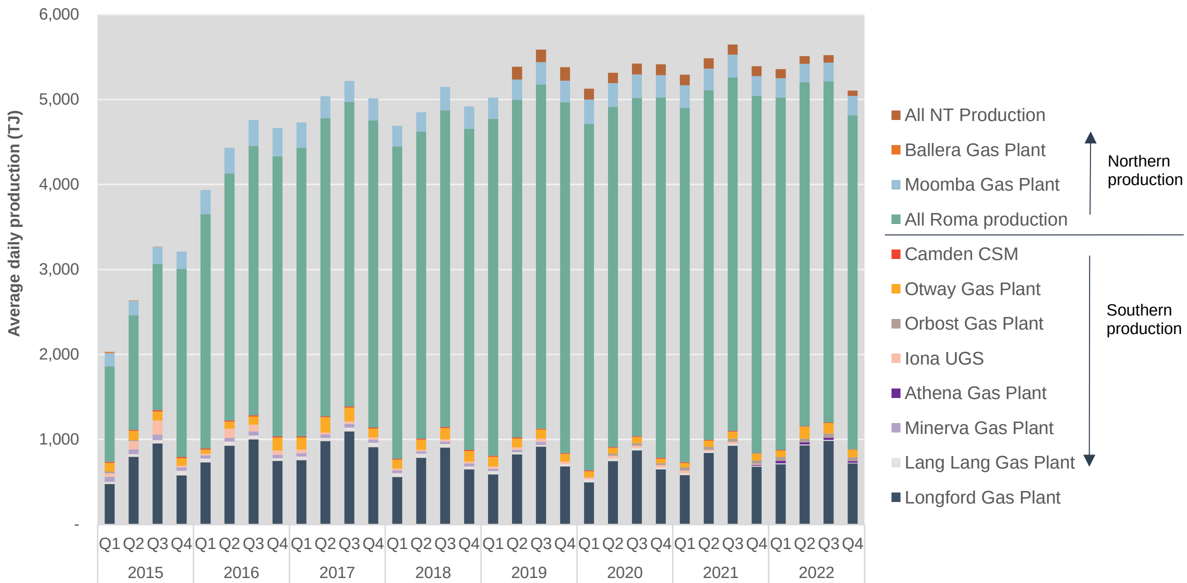


Source: AER analysis using Gas Bulletin Board data.

3.2.2 Southern storage at Iona refills

Overall, Q4 production levels were at their lowest point since 2018 which is to be expected given the decreased exports. Southern production was, however, higher than in Q4 2021.

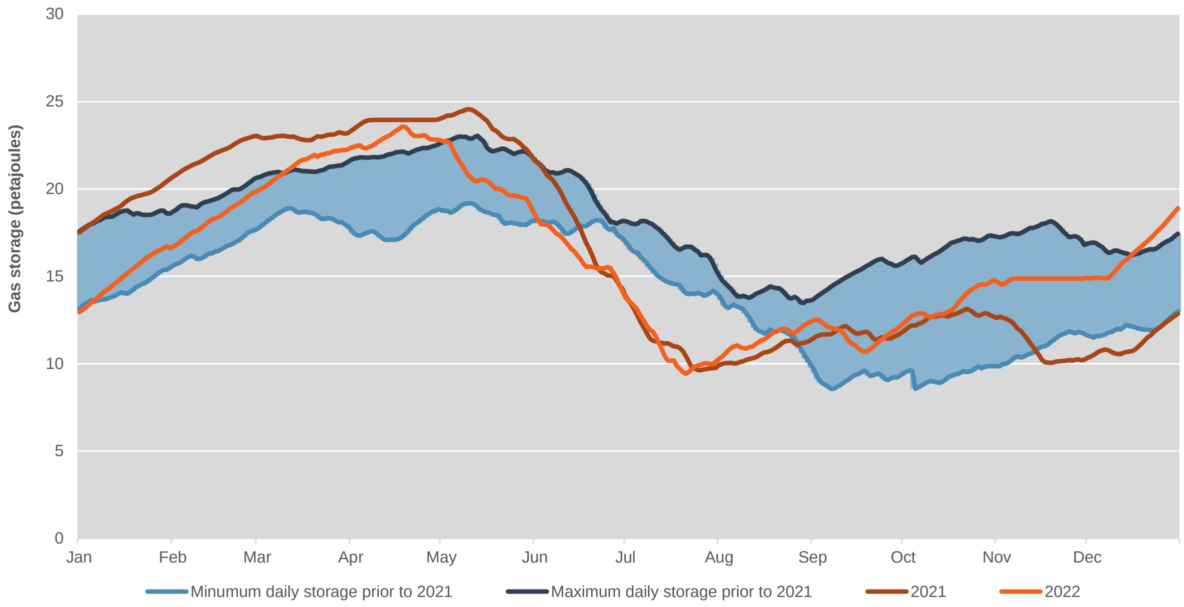
Figure 3.6 East coast production (including Northern Territory)



Source: AER analysis using Gas Bulletin Board data.

Increased southern production was required to meet slightly higher domestic market demand.[19] Colder weather drove higher than usual demand in Victoria over much of November, with demand above 400 TJ per day across half of the month. Higher southern production was also enough to allow Iona to refill to its highest end-of-year level since storage reporting commenced (Figure 3.7). Iona can provide significantly higher daily volumes of gas than other storage facilities across the east coast. As such, the facility can both draw down and refill significant quantities in relatively short timeframes and is relied upon as an important source of supply in Victoria over the winter period. The facility refilled significantly over December following a planned maintenance outage between7 to 29 November.[20]

Figure 3.7 Iona underground storage levels



Source: AER analysis using Gas Bulletin Board data.

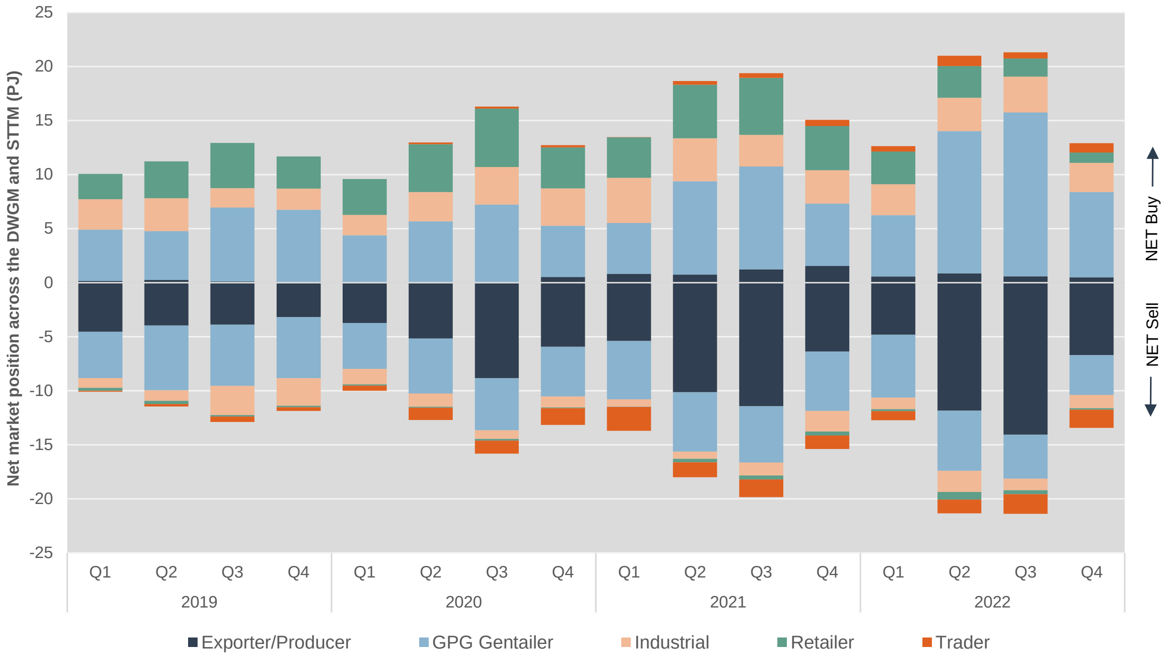
[19] While overall east coast demand was lower compared to Q4 2021, influenced primarily by lower export levels, demand in downstream markets was slightly higher than the previous year, up by 1 PJ.

[20] Iona's refill rate from 9 December averaged 174 TJ per day, while storage levels at the other larger storage facilities continued to steadily decline (at Roma, Silver Springs and Moomba).

4 Despite lower demand, upstream gas market trade remained strong

While net trade quantities in downstream markets dropped off, as is typical across the first and last quarter of the year, trading in upstream markets continued above normal levels following records set in the previous quarter (Figure 4.1). The reduced level of downstream market trade was largely driven by reduced quantities being purchased by gas-powered generators, in line with decreased gas generation demand.

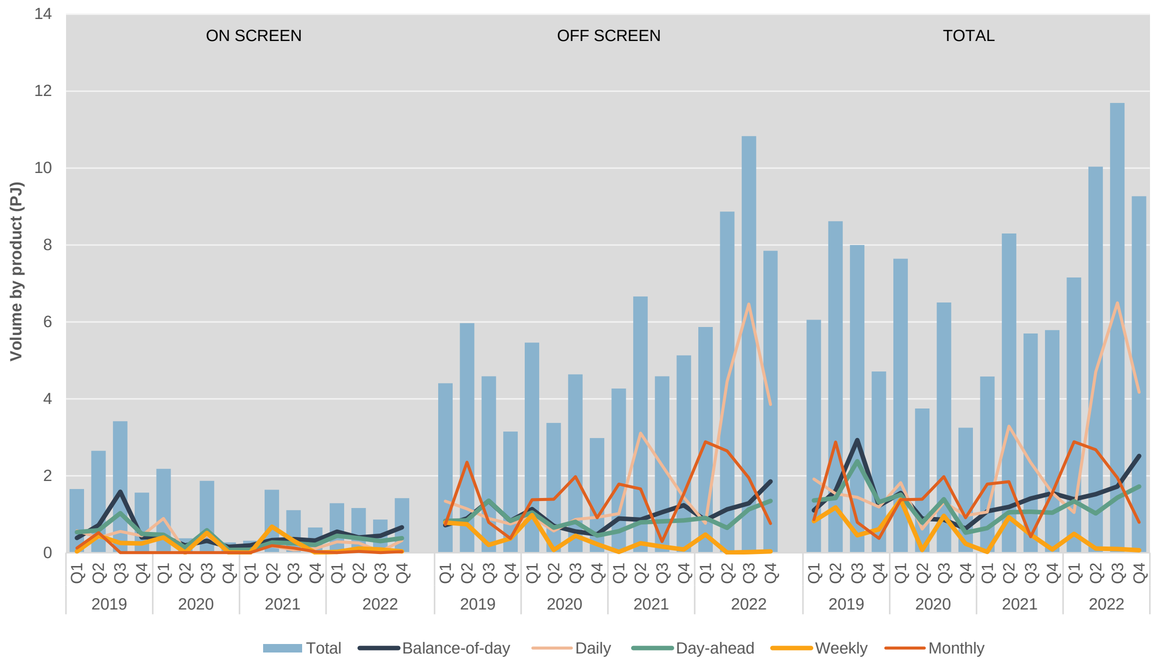
Figure 4.1 Net trade by participant group (PJ)



Source: AER analysis using DWGM and STTM data.
Note: Trade in the Victorian DWGM and Sydney, Adelaide and Brisbane STTMs has been estimated netting scheduled buy and sell quantities for each trading participant.

In the Gas Supply Hub, delivered quantities were at their second highest level on record at 11.17 PJ for the quarter following last quarter's record deliveries (14.1 PJ). High trade levels were dominated by off-market products at the Wallumbilla trading location, with traded quantities above levels previously observed across any Q4 (Figure 4.2).

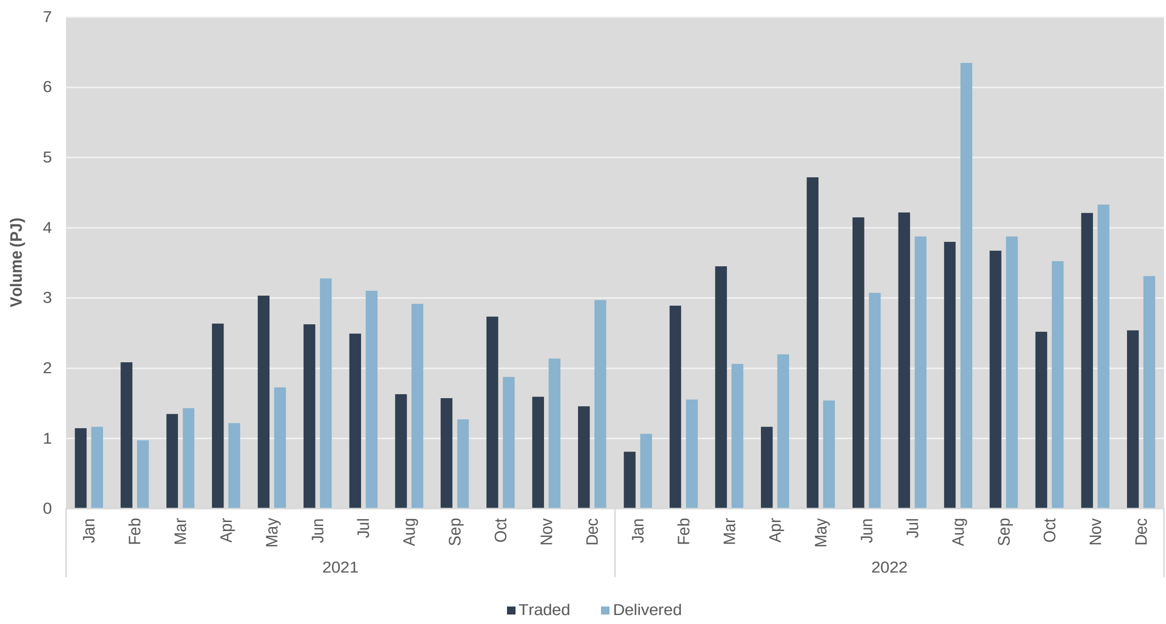
Figure 4.2 Gas supply hub – on-screen, off-screen and total trade by product



Source: AER analysis using Gas Supply Hub trades data.

The high level of gas purchased on the Gas Supply Hub for delivery over the quarter coincided with a rise in trading activity to procure pipeline capacity and compression services to move gas across the east coast. Prices for the 10.48 PJ of gas delivered at Wallumbilla across the quarter decreased from the high levels observed over winter. Gas trades in July at around $30/GJ (771 TJ) reduced to $20/GJ to $23.15/GJ over August and September (1.35 PJ), with further price reductions during Q4. Prices of volume weighted sales for the quarter traded in October and November ranged from $18.05 to $21.70/GJ (6.08 PJ), before reducing to $13.49/GJ for gas traded and delivered in December (2.1 PJ) (Figure 4.3).

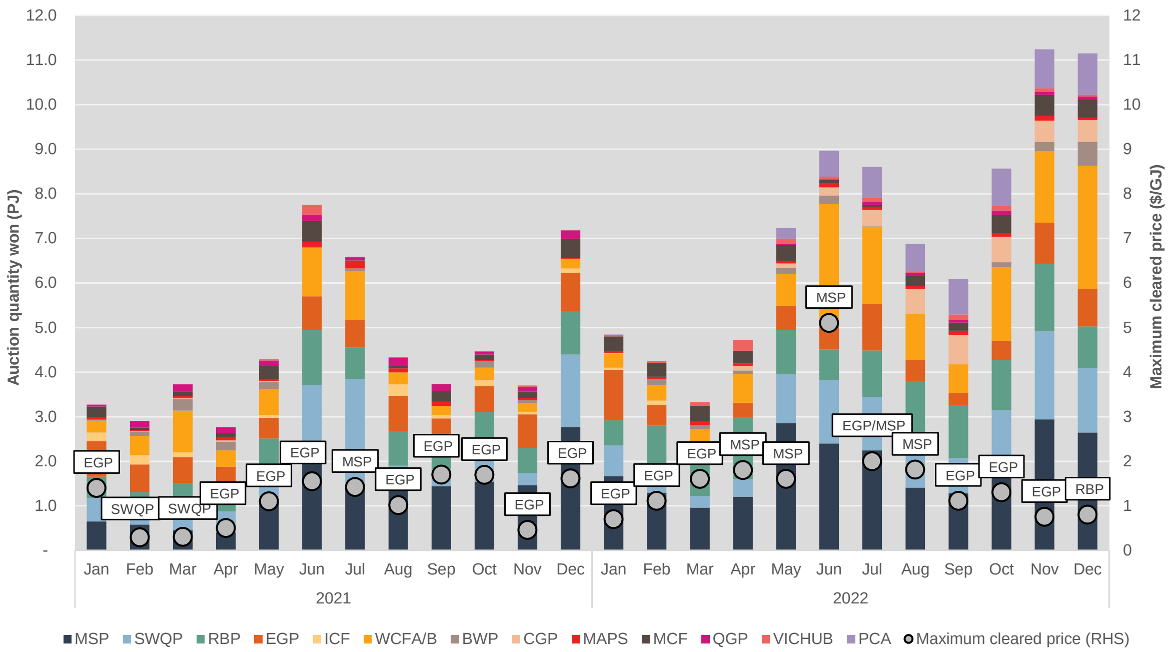
Figure 4.3 Gas supply hub – traded and delivered quantities



Source: AER analysis using Gas Supply Hub trades data.

Trade in the Day Ahead Auction for secondary gas transportation capacity increased significantly over the quarter, setting another record. The increase in capacity won on the auction allows participants to move more gas between upstream supply sources and demand locations. The 31 PJ of capacity won through the auction far exceeded last quarter's record of 21.6 PJ, with the maximum price cleared reducing to $1.30/GJ (set on the Eastern Gas Pipeline) and 82% of capacity purchased at the zero dollar reserve price. Most of the capacity was won on routes to bring gas south, with quantities procured doubling those of Q4 2021 (Figure 4.4).

Figure 4.4 Pipeline capacity won on the Day Ahead Auction and maximum clearing prices



Source: AER analysis using Day Ahead Auction data.

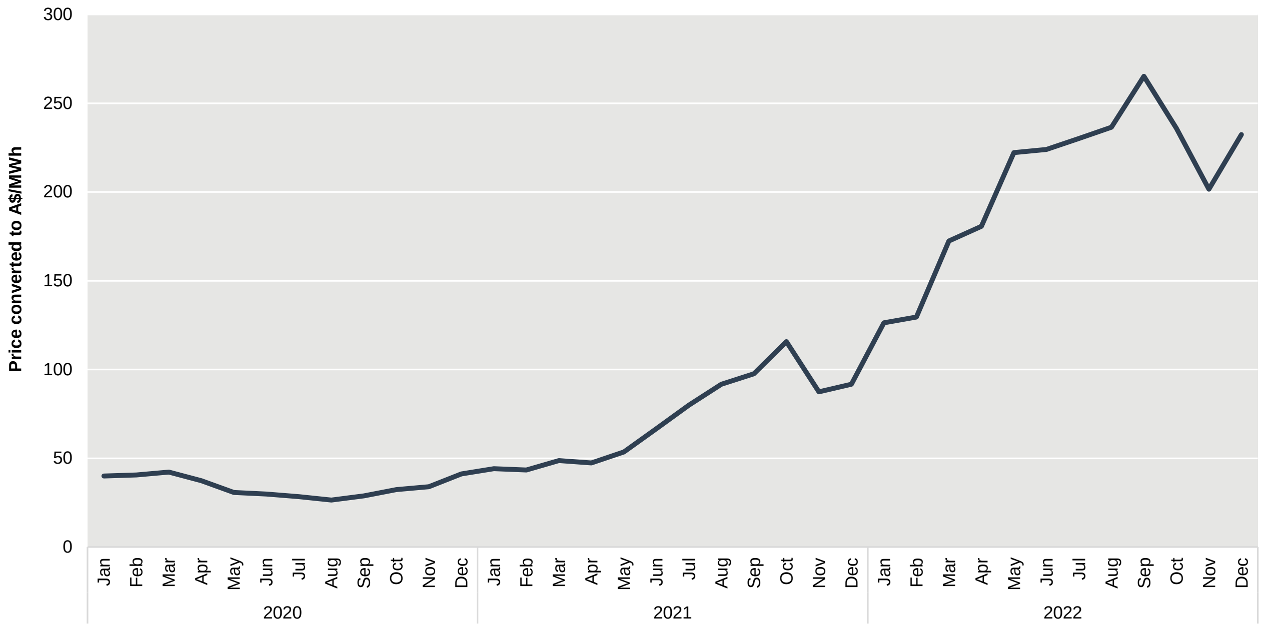
5 Some upward price pressures remain—fuel costs remain high

Through 2022, coal miners faced supply challenges as a result of heavy rain and persistent flooding in NSW and Queensland impacting the coal supply chain, flooding mine pits and disrupting freight rail linkages.[21] Coal producers have indicated that coal production costs increased in 2022 due to inflation, as well as increased labour and fuel costs.[22] We will continue to monitor domestic coal production costs to understand the drivers of coal generation offers into the market.

International coal, gas and oil prices also remain high reflecting ongoing supply chain disruption (Figure 5.1 and Figure 5.2). These high prices influence domestic fuel prices as exporters face stronger incentives to sell into international markets rather than supply domestically. However, not all domestic supply of coal or gas is exposed to these price pressures.

Many coal-fired generators access coal through long-term contracts or direct mine-mouth access where supply cannot readily be diverted to the export market. Illustrating this, NSW black coal generators set NEM prices below $120/MWh in November and December. This was through a period in which the Newcastle thermal coal price was above $200/MWh (Figure 5.1).

Figure 5.1 Newcastle thermal coal price remains high



Source: GlobalCOAL.
Note: Data converted from $US to $AUD using the monthly average exchange rate for that month.

[21] DISER, Resources and Energy Quarterly, December 2022, p. 66.

[22] Banpu, 3Q22 Investor and analyst update, 16 November 2022; Financial Review, Coal mining costs now double 2016 levels, 9 November 2022

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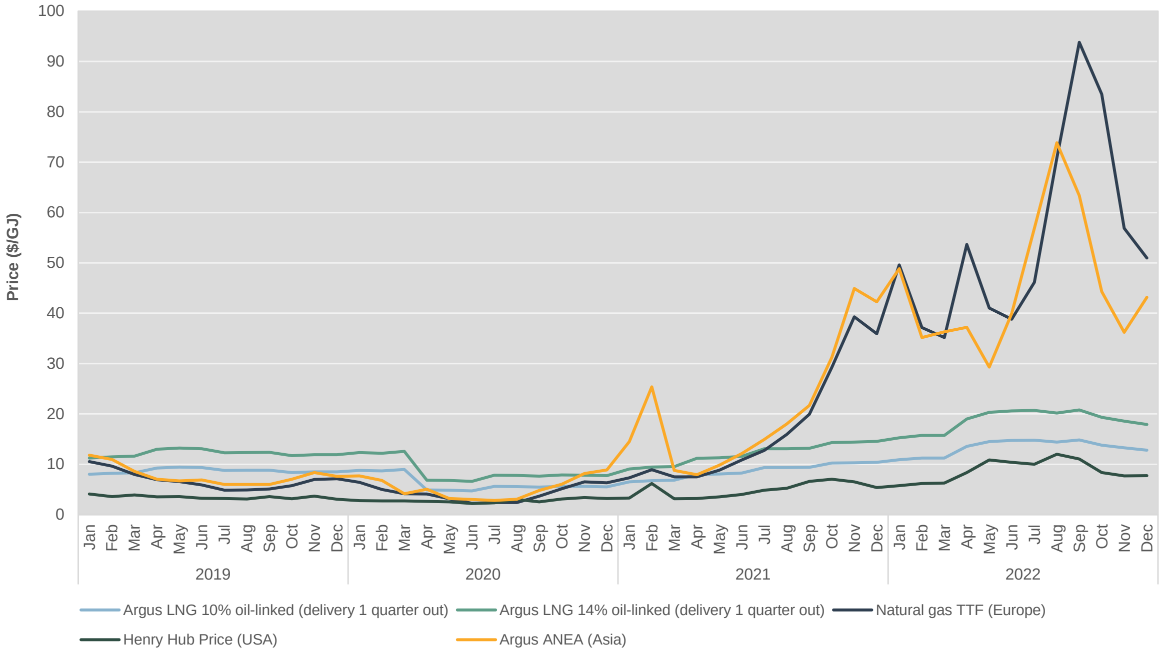
On 23 December 2022, the NSW Government introduced a price cap of $125/tonne on NSW coal suppliers, in order to ease the impact of international price pressures on electricity prices.[23] Queensland's state-owned generators have also been directed to sell electricity as though the coal cost no more than $125 a tonne.[24] We will monitor the impacts of these caps over coming quarters.

International gas prices have moderated since record highs set in Q3 2022 but also remain high by historical standards (Figure 5.2). In Q4 2022, they averaged AUD$64/GJ in Europe and AUD$41/GJ in Asia. LNG netback prices have declined alongside these lower prices but remain higher than domestic prices. A significant proportion of gas bid through the spot markets is also underpinned by contracts linked to oil prices. A fall in oil prices therefore directly contributes to lower domestic gas prices.

We discuss international gas price developments in more detail in the first Gas Focus Story (Chapter 12).

Figure 5.2 International gas and Brent oil prices



Source: AER analysis using Argus Media data and Bloomberg data.
Note: More detailed Argus, TTF and Henry Hub price descriptions are provided in the accompanying spreadsheet to this report. The AER obtains confidential proprietary data from Argus Media under license, from which data the AER conducts and publishes its own calculations and forms its own opinions. Argus Media does not make or give any warranty, express or implied, as to the accuracy, currency, adequacy, or completeness of its data and it shall not be liable for any loss or damage arising from any party's reliance on, or use of, the data provided or the AER's calculations.

[23] Energy and Utilities Administration Amendment Bill 2022.

[24] Prime Minister's press conference- Transcript, 9 December 2022.; The Australian, Rio Tinto and partners net $450m from Albanese's governments coal cap, 28 December 2022; North West Star, Qld power plant set for coal cap compo, 28 December 2022; Courier Mail, National electricity price cap plan will see average family $320 better off a year, 24 December 2022.

Most domestic gas supply is sourced through long-term supply arrangements which, in the short-term, are not sensitive to changes in international prices except where supply arrangements are being renegotiated.

For fuel needs beyond what is sourced via contracted supply arrangements, gas generators also source gas from spot markets. Spot market prices at times exhibited linkage to international prices and can therefore be sensitive to export pressures.

6 The generation mix continued to change, with wind and solar displacing coal

All fuel types, other than black and brown coal, saw an increase in average generation in 2022 compared with 2021, with large-scale solar generation increasing by 29% and wind generation increasing by 13%. Combined solar and wind generation increased at similar rates to the previous 3 years and reached a record 20% of average total NEM generation in 2022.

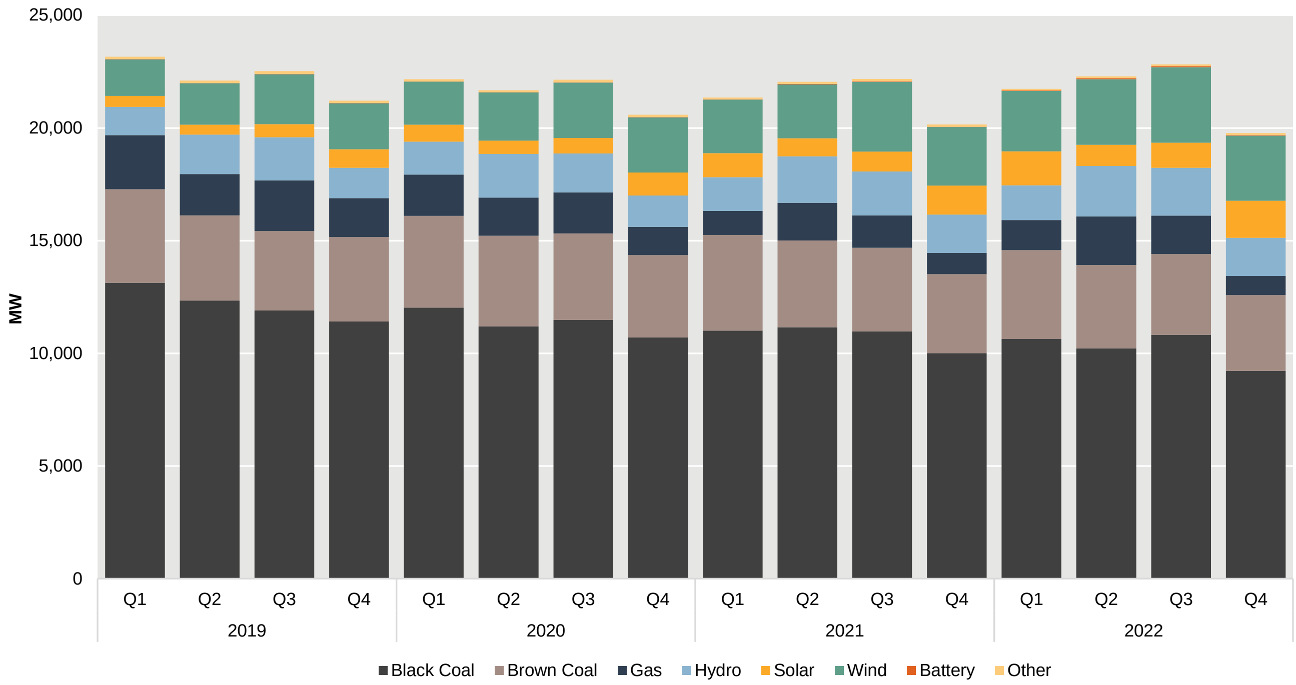
Generation from black coal and brown coal saw its largest annual decline since 2010, with black and brown coal both decreasing from 2021 generation levels. Combined black and brown coal generation recorded a record low of 64% of total generation in 2022, down from 68% in 2021. With the upcoming closure of Liddell in April 2023, coal will play an increasingly smaller role in the overall annual generation of the NEM. However, it remains the largest source of generation in the NEM, making up over half of overall generation and a higher proportion of dispatchable generation. As a result, it will continue to have significant impacts on NEM outcomes as the market transitions.

Gas generation also increased in 2022 by 18% compared to 2021, mainly due to increased demand in Q2 and Q3 of 2022.

6.1 Q4 coal output dropped to a quarterly record low

As a result of lower demand over the quarter, this quarter saw the lowest average generation for any quarter since at least 2005, falling below 20,000 MW for the first time to 19,778 MW (Figure 6.1). The November 2022 average generation, at 19,528 MW was the lowest monthly average since 2019.

Figure 6.1 Average NEM generation by fuel type



Source: AER analysis using NEM data.
Note: Average quarterly metered NEM generation by fuel type. Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.

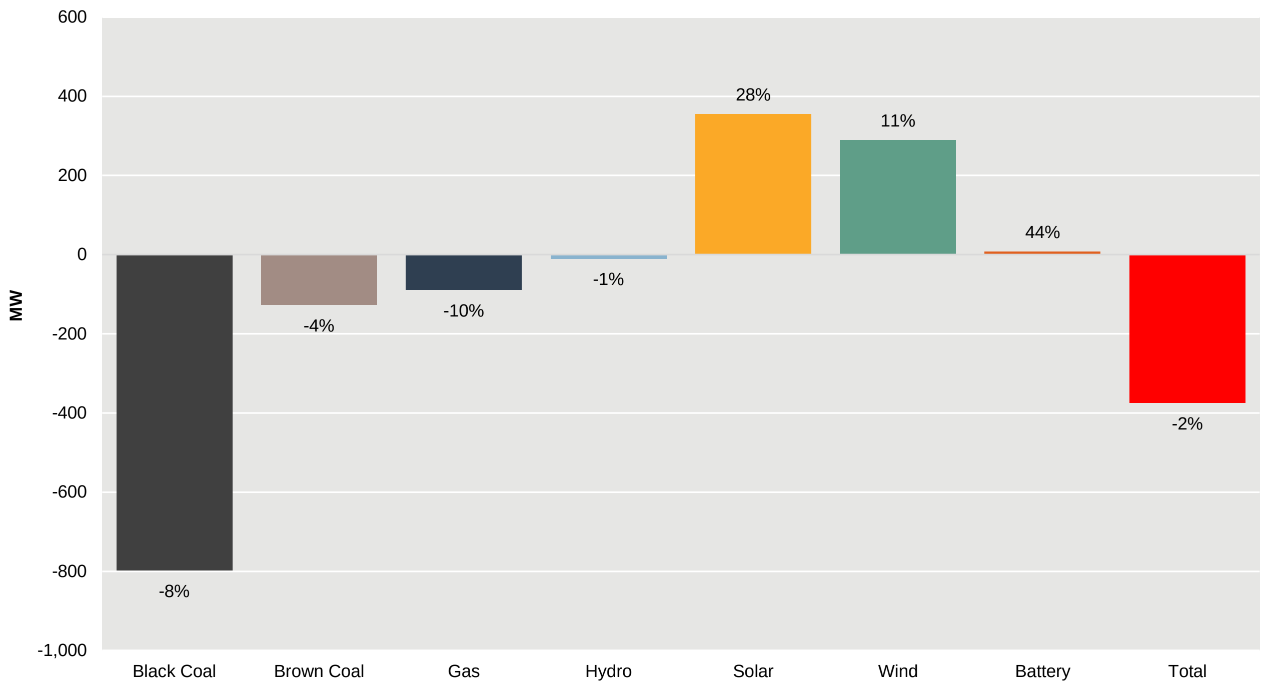
Combined solar and wind generation accounted for a record 23% of quarterly generation, which is up 4% from Q4 in 2021. This was attributable to a 28% increase in solar output and an 11% increase in wind output for the quarter (Figure 6.2).

Overall, Q4 saw an average increase in solar and wind generation of 645 MW. The higher solar and wind generation, coupled with lower demand saw coal and gas generation decrease by an average of 1,015 MW.

The share of black coal generation continued to decline to 47% of total generation, which is a new Q4 record low. The previous low was in Q4 2021 at 50%. Output from black coal decreased by 8% and there was a 4% decrease in output from brown coal (Figure 6.2). Notably, the average monthly NSW black coal output reached a new low of 4,544 MW in November and then beat this figure again in December with 4,366 MW.

At a regional level, both South Australia and Victoria experienced increases in wind generation compared to the same quarter last year. South Australian solar and wind reached 74% of average quarterly generation. All other regions experienced a decrease in average wind generation.

Figure 6.2 Change in NEM generation – Q4 2022 compared to Q4 2021

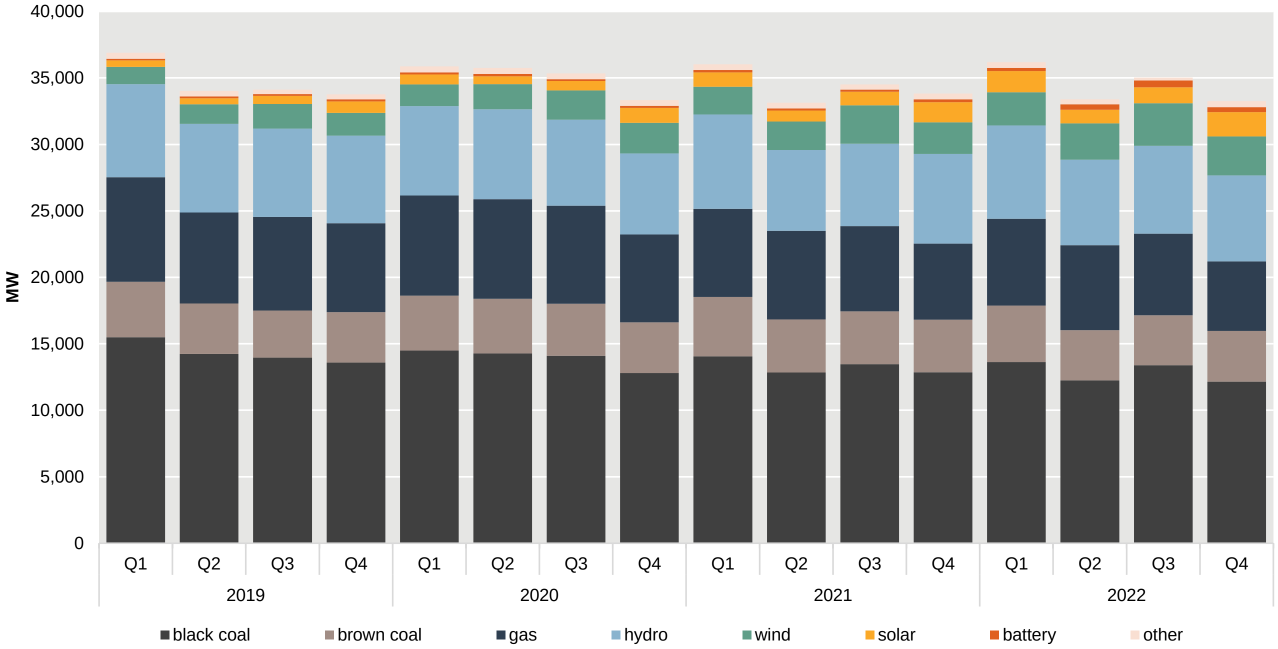


Source: AER analysis using NEM data.
Note: Change in average quarterly metered NEM generation by fuel type, Q4 2022 compared to Q4 2021. Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.

6.2 Black coal offered less capacity than in previous quarters

Overall, less capacity was offered this quarter compared to the same quarter in 2021. While there was an increase in the capacity offered by wind and solar, there was an even larger reduction in offers from coal and gas generators (Figure 6.3). Coal generators had a number of planned outages this quarter which contributed towards its low amount of offers. The high price of gas is likely to have contributed towards a lower amount of gas generation being offered.

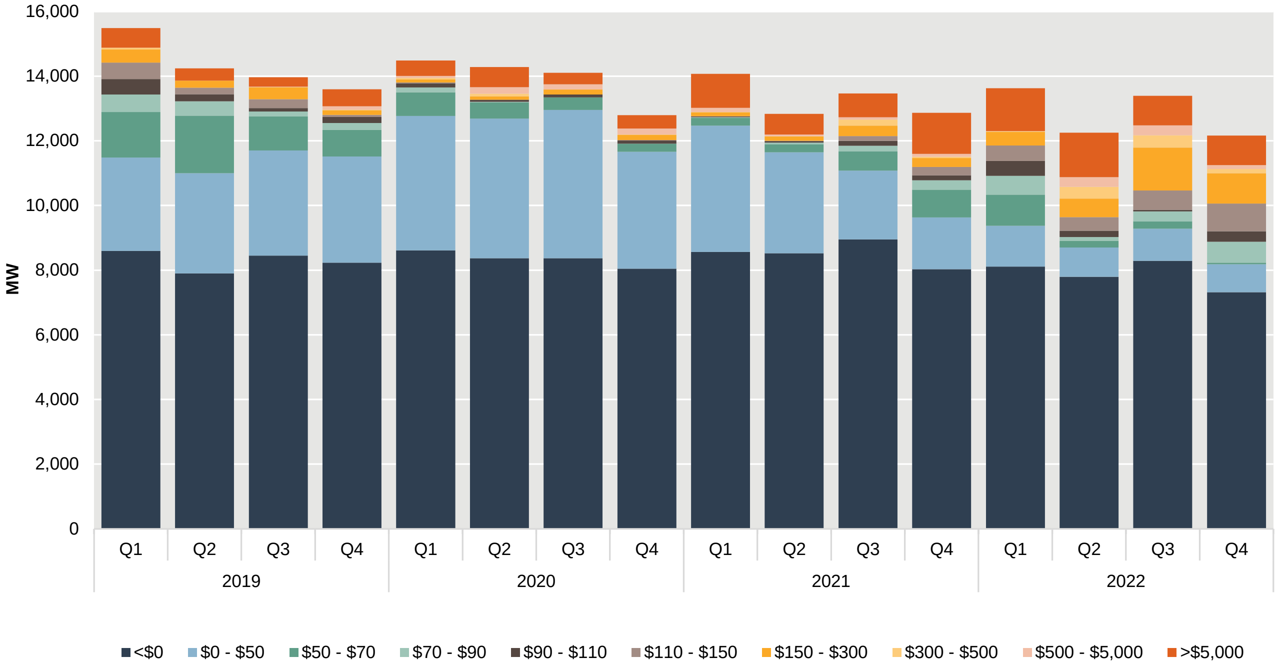
Figure 6.3: NEM quarterly offers by fuel type



Source: AER analysis using NEM data.
Note: Average quarterly offered capacity by NEM generators of different fuel types.

This quarter saw the lowest total capacity being offered by coal generators since at least 2013, with less capacity being offered at below $50/MWh. Compared to Q4 2021, coal generators offered less capacity at prices below $50/MWh. Also, compared to Q3 2022, coal generators offered more capacity between $90/MWh and $150/MWh (Figure 6.4). This may indicate domestic coal production costs have increased (Chapter 5).

Figure 6.4 Average quarterly black coal offers in the NEM, by price band



Source: AER analysis using NEM data.

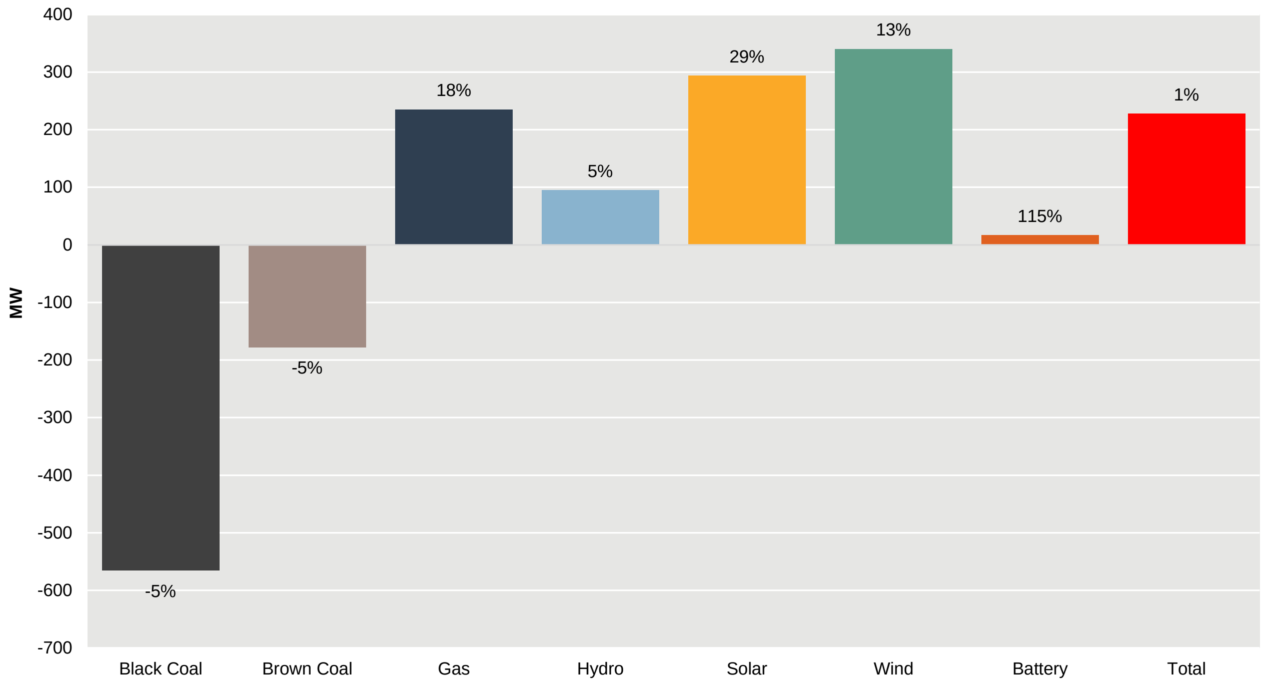
6.3 Baseload generator outages did not significantly impact Q4 2022 prices

Q4 2022 saw a high number of baseload generator outages compared to Q4 2021. However, this did not have a significant effect on overall wholesale electricity prices in the NEM.

Several factors may have contributed to mitigate the effects of outages on wholesale prices:

- Demand was lower than average over Q4 2022, with mild weather mitigating market stress.
- A significantly larger portion of outages were planned relative to Q2 (where the majority of outages were unplanned), allowing other participants to factor outages into their offers.
- Favourable conditions for renewables, particularly solar, offset loss of baseload capacity due to outages.

Figure 6.5 Change in NEM generation – 2022 compared with 2021



Source: AER analysis using NEM data.
Note: Change in average annual metered NEM generation by fuel type, 2022 compared with 2021. Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.

7 Price setting in the NEM returned to more familiar dynamics, but coal, gas and hydro set higher prices than in Q4 2021

Generators offer to supply quantities of electricity in different price bands for each period of the day. The NEM selects the generators with the lowest offers first and then progressively more expensive offers until enough electricity can be dispatched to meet demand. The generator that provides the last megawatt needed to meet demand (or the marginal generator) sets the price for the 5-minute dispatch interval. Given the diversity of fuel sources and offers, even a small change in the level of demand can strongly influence which generator sets the price and at what level.

Price setting dynamics in Q4 2022 returned to those generally seen in quarters before winter 2022. During Q2 and Q3 2022, black coal set prices a lot less often and hydro generation set prices more often. At the same time, these fuels set much higher prices (Figure 1.3).[25] In Q4, black coal returned to setting the price more often and coal, gas and hydro set lower prices than in Q2 and Q3.

Compared to the same quarter last year, however, black coal set the price at around double the price it set in Q4 2021. For example, in NSW, black coal set the price at $119/MWh, compared to $62/MWh the previous year (Figure 7.1). Given black coal sets the price 40% to 50% of the time in NSW and Queensland, if black coal sets a higher price, this will have a direct impact on overall price outcomes in both regions. In Victoria and South Australia, which do not have local black coal generators, black coal set the price far less often via transmission interconnectors. Average quarterly prices in both these regions were significantly lower than in Queensland and NSW (Figure 1.3).

Gas-powered generators also set significantly higher prices in Q4 2022 than in Q4 2021, almost doubling in all regions except Queensland. For example, in NSW, gas set the price at $169/MWh compared with $91/MWh in Q4 2021. In Queensland, gas set lower prices in Q4 2022 than in Q4 2021 due to high price events in that quarter. Gas generators typically do not set prices often. This is because its relatively higher running costs and flexible start/stop mean it only bids during peaks, when it can run for short periods at higher prices.

Hydro generation often sets the price somewhere between black coal and gas. It also set much higher prices in Q4 2022 than in Q4 2021, more than doubling in most regions. For example, in NSW, hydro set the price at $147/MWh, compared to $63/MWh the previous year. Hydro set the price in mainland regions between 22% and 29% of the time, comparable to Q4 2021. Price offers for hydro generation can vary based on its water management practices and whether it needs to ration its water usage.

Brown coal generators also set higher prices in Q4 2022. For example, in Victoria, brown coal set the price at $16/MWh compared to $7/MWh in Q4 2021.

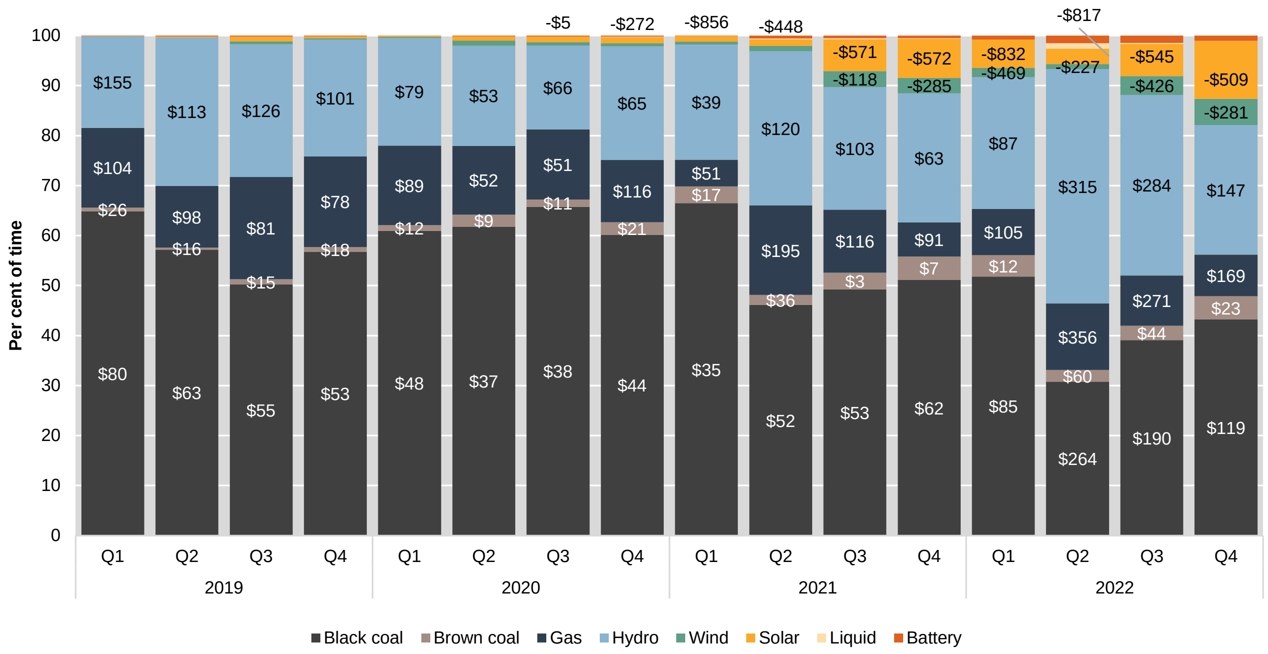
When wind and solar set prices, they set negative prices and wind and solar set prices more often in Q4 2022 than in Q4 2021 in every mainland region. For example, in Victoria, wind and solar set the price 24% of the time in Q4 2022, up from 18% a year earlier. This helped to partially offset

[25] AER, Wholesale markets quarterly Q3 2022, November 2022.

higher prices set by black coal, gas and hydro. Wind and solar set the price more often in Victoria and South Australia (30%) than they did in Queensland and NSW (17%). This contributed to lower prices in the southern regions.

As wind and solar increasingly set the price more often, black coal is setting the price less often. For example, in Q4 2020, black coal set the price 60% of the time in NSW, in Q4 2021, 51% of the time and in Q4 2022, 43% of the time.

Figure 7.1 NSW price setters

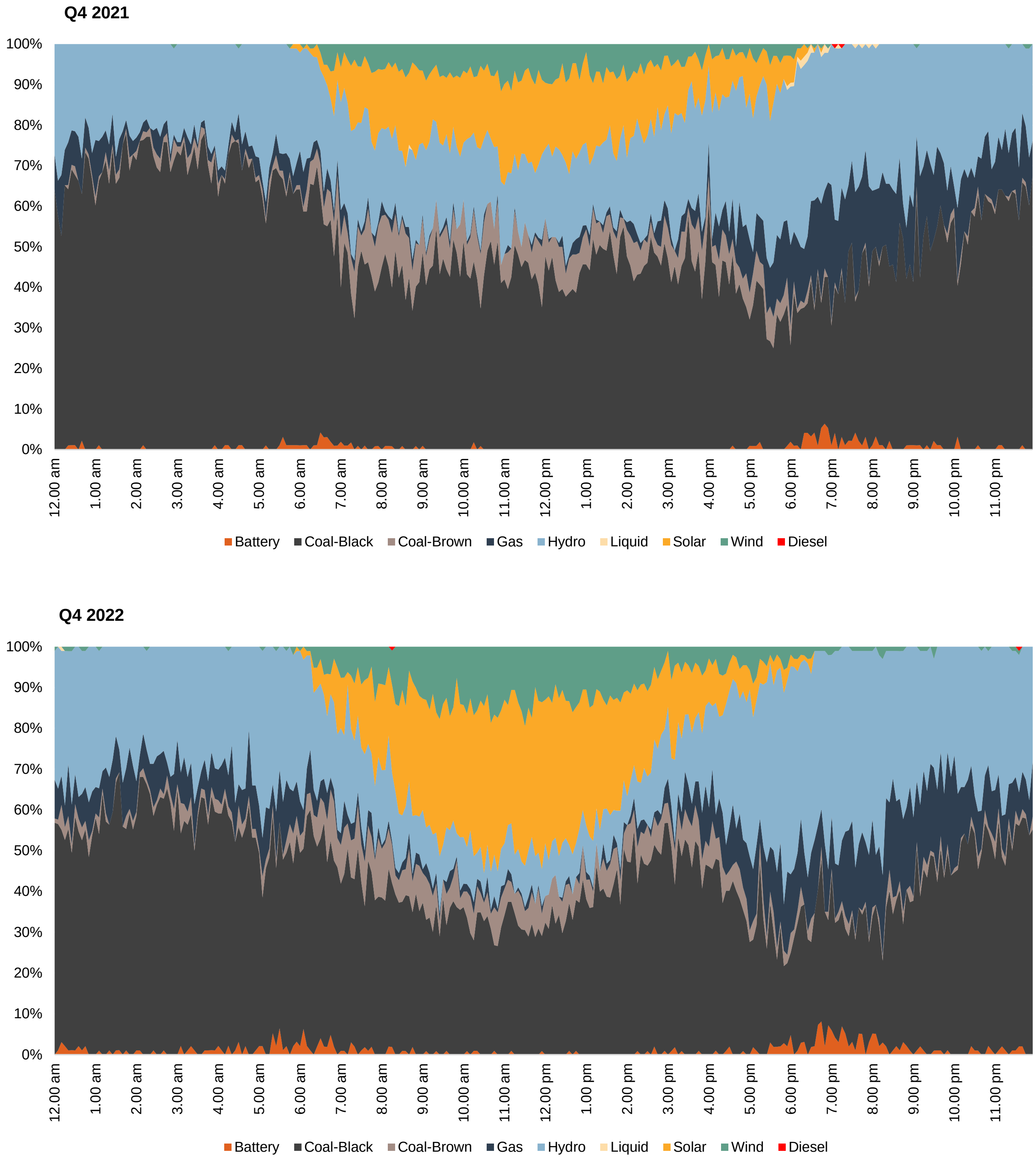


Source: AER analysis using NEM data.
Note: The height of each bar is the percent of time each fuel type sets the price. And the number within each bar is the average price set by that fuel type when it is marginal (i.e. setting the price). Data for Q2 2022 impacted by the 2-week market suspension in June.

Price setting dynamics across the day continue to change as the market transitions to more renewable generation.[26] In the middle of the day, wind and solar continue to set the price more frequently while black coal and hydro set the price less often (Figure 7.2). At these times, negative prices have become increasingly common (section 1.3). However, when the sun starts going down, black coal starts setting the price and as evening demand increases further, more expensive fuels such as gas and hydro are needed and set the price more often. Batteries continue to have a small but increasing role setting the price during the morning and evening peaks.

26 AER, Wholesale electricity market performance report, December 2022, chapter 2.

Figure 7.2 NSW price setter by time of day – Q4 2021 compared with Q4 2022



Source: AER analysis using NEM data.
Note: Price setter by fuel type at each time of the day in Q4 2021 above and Q4 2022 below.

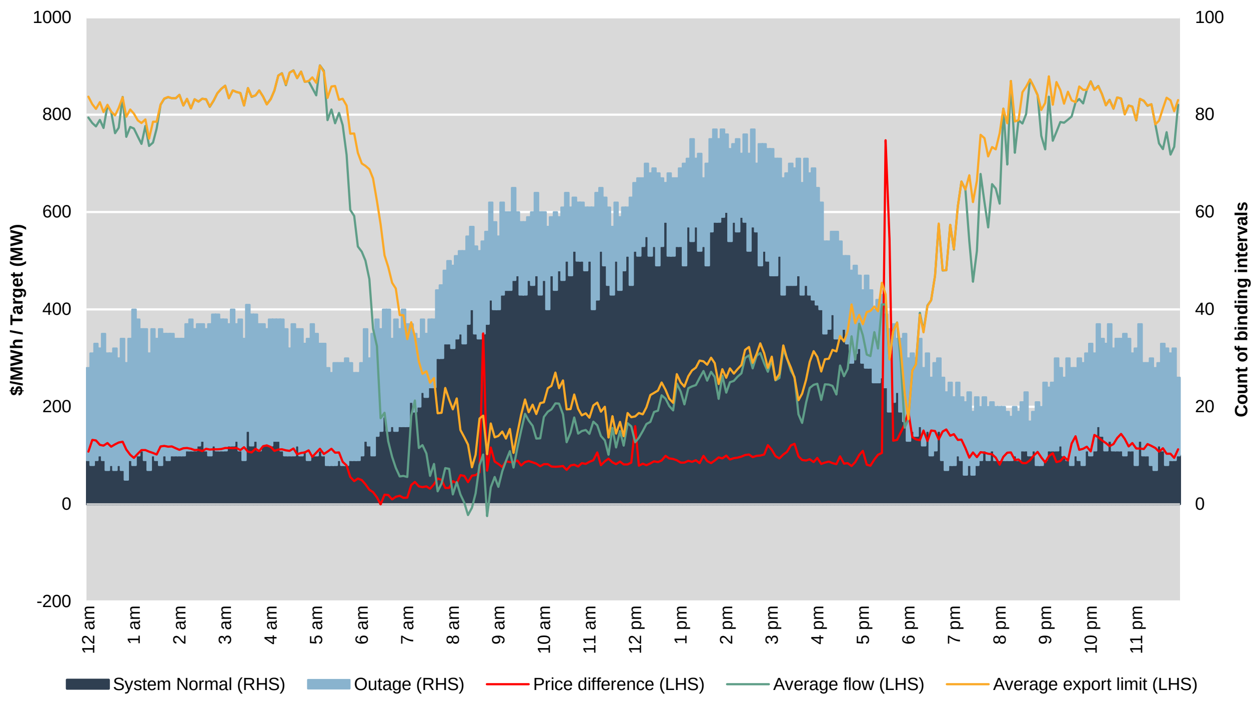
8 Limited flows on interconnectors restricted access to cheap generation

Limited flows on the Victoria-NSW Interconnector during Q4 2022 meant NSW and Queensland were unable to access cheaper southern generation almost half the time.[27]

Interregional transfers are an important aspect of the market. However, these transfers are impacted by congestion when flows over the interconnectors are constrained by physical or system limitations. There are 2 types of congestion: system normal and outage. System normal is when the network is limited by the normal operation of the grid, while outage congestion is when the network is limited by line outages.

Over half the time, the Victoria-NSW Interconnector congestion occurred under system normal constraints. These occurred more frequently in the middle of the day when average prices in Victoria were negative due to high renewable output and low demand (Figure 8.1). This contributed to higher prices in the northern regions and kept prices lower in the southern mainland regions. The remainder of the time, the congestion on the Victoria-NSW Interconnector occurred during outages.

Figure 8.1 Average export limits, flows and price difference across the Victoria to NSW interconnector when it was binding in Q4 2022



Source: AER analysis using NEM data.
Note: This chart shows average flows, constraints, limits, and price difference between NSW and Victoria by time of day when the interconnector bound.

[27] Most congestion on the Victoria-NSW Interconnector during Q4 2022 (where the interconnector reached maximum capacity) occurred at its export limit – meaning NSW was importing as much cheap energy from Victoria as constraints would permit.

Looking at flows between regions compared to Q4 2021 – Victoria was the strongest exporter, exporting more than double any other region. However, exports from Victoria decreased compared to Q4 2021. Queensland was the only other net exporter, doubling its net exports to NSW. NSW remained the most significant net importer, but as it exported more than in Q4 2021, its net imports decreased. South Australia was also a net importer, but only by a small margin, tending to import during the night and export during the day. Tasmania was the second largest net importer, and at times, the interconnector forced flows into the region.

We explore in greater detail as a focus story (Chapter 11) transmission tower storm damage at Tailem Bend in South Australia on 12 November. This impacted the Heywood Interconnector between Victoria and South Australia and electrically islanded South Australia for 7 days.

9 Wind and solar continued to enter the market

New entry in Q4 2022 comprised 3 wind and 3 solar farms, totalling 780 MW of new capacity, which will be ramping up to full output in 2023.

Looking back over 2022, almost 2.5 GW of new capacity entered the market, while 670 MW exited (Figure 9.1).[28] Large-scale solar farms, which were largely located in Queensland, comprised well over half (1,450 MW) of the new connections. The remainder was mostly made up of wind, but also included the Snapper Point gas power station (150 MW) in South Australia and a small battery in NSW. 44 MW of demand response was also registered across Queensland, NSW and Victoria during the year. The first unit (500 MW) of the Liddell black coal power station closed in April 2022, followed by the final unit (120 MW) of the Torrens Island A gas power station in South Australia. The Hunter Valley Gas Turbines, which have not been operating for several years, also officially closed.

Looking forward to 2023, 2.5 GW of new entry has been committed, however, this will be largely offset by the closure of the remaining 3 Liddell units on 1 April (1,500 MW) and the Osborne gas power station (180 MW) in December 2023.

Expected new entry in 2023 includes 1,200 MW of batteries and almost 900 MW of solar, as well as the Tallawarra B gas power station (320 MW).[29] Of the 8 new batteries expected in 2023, the Eraring Big Battery-stage 1 is expected to be the largest (460 MW). Batteries to date have mainly participated in FCAS markets, however, there is already some indication they started to supply more energy to the market in 2022 (Figure 6.2 and Figure 6.5). We will continue monitoring to see if this trend continues.[30]

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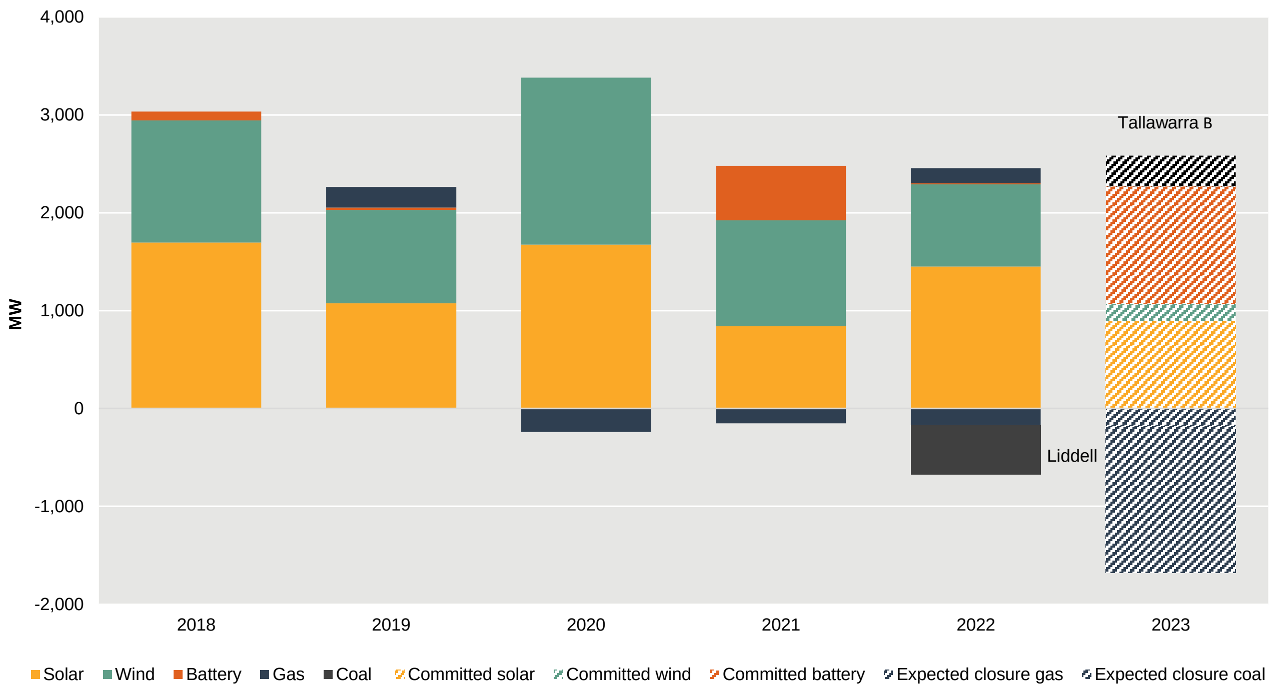
[28] We take the date of new entry to be AEMO's first dispatch date. As a result, we included Stockyard Hill wind farm (530 MW) and Western Downs Green solar farm (400 MW) as new entry in 2021, not in 2022.

[29] Tallawarra B start date in October 2023 is based on information in AEMO's 2022 Electricity statement of opportunities.

[30] AER, Wholesale electricity market performance report, December 2022, chapter 9.

Figure 9.1 New entry and exits, actual and anticipated



Source: AER analysis using NEM data.
Note: We record new entry using registered capacity, except for solar where we use maximum capacity. The new entry date is taken as the first day the station produces energy. Solar is large scale solar and does not include rooftop solar. Closures are denoted below the line. Hashed areas reflect committed new entry and planned generator retirements according to the classification in AEMO Generator Information.

10 Total FCAS costs fell but there were local FCAS costs in South Australia and Tasmania

After steadily increasing over the past 8 years, Frequency Control Ancillary Services (FCAS) costs in 2022 ($279m) fell from record levels in 2021 ($438m). The fall was driven by decreasing costs of raise 6 second and raise 60 second costs. These are contingency services which act to raise and stabilise the frequency of transmission lines in response to a significant decrease in grid frequency.

FCAS costs were lower in Q4 2022 ($98m) than in Q4 2021 ($133m) (Figure 10.1). However, there were substantial local FCAS costs in South Australia ($34m) and record local costs in Tasmania ($14m). Local costs occur when FCAS imports from other regions via interconnection become unavailable, while global costs refer to FCAS costs which are shared across regional borders.

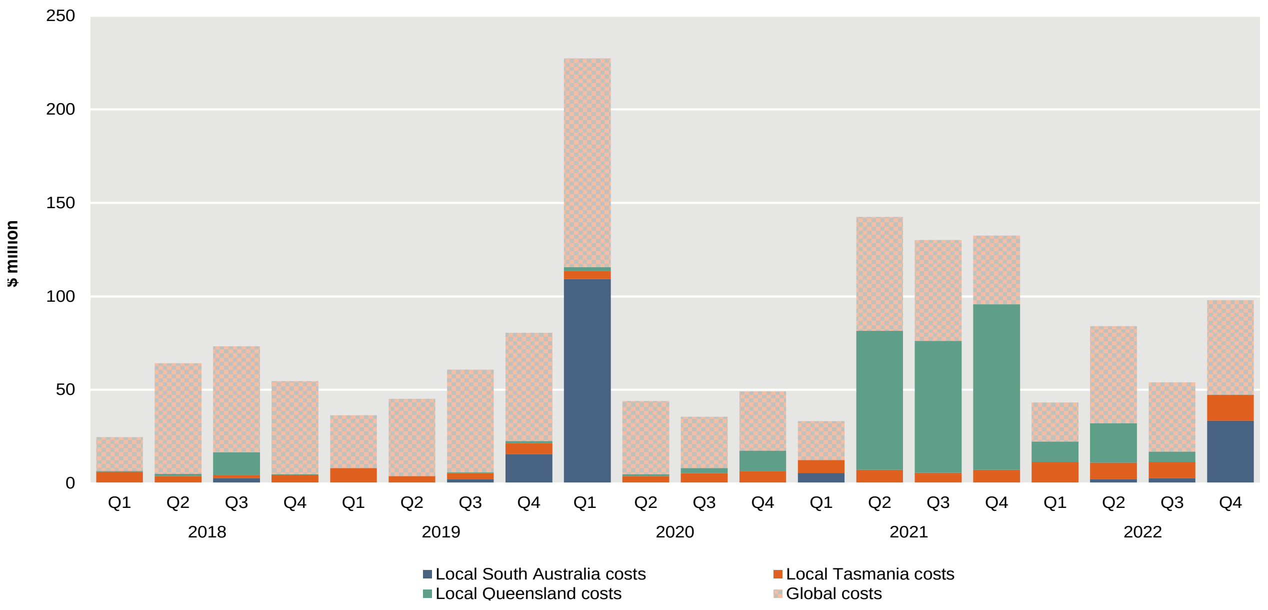
The local FCAS costs in South Australia were largely driven by the outage at Tailem Bend on 12 November 2022, when a severe storm islanded the region for 7 days. As a result, South Australia was required to supply its own FCAS. Separation events often cause volatile FCAS prices as demand for local FCAS spikes and access to NEM-wide FCAS is reduced.

To meet the local requirements in South Australia in November, capacity offered at prices above $5,000/MW was needed. As prices breached the cumulative price threshold, AEMO implemented administered pricing on 14 November 2022, capping South Australian FCAS prices at $300/MW. Administered pricing ended on 26 November 2022, 12 days after being implemented. This is explored further in the Electricity Focus Story in Chapter 11 below.

In Tasmania, storm damage to transmission lines on 14 October 2022 led to the region having to supply its own FCAS and incurring local FCAS costs.

Global costs were higher in Q4 2022 ($51m) compared with Q4 2021 ($37m) but have remained relatively stable across the last 5 years. Regulation FCAS costs were double those in Q4 2021, while contingency costs were lower.

Figure 10.1 Quarterly FCAS costs fall in Q4 2022 compared to Q4 2021



Source: AER analysis using NEM data. Note: Global and local FCAS costs, by quarter.

11 Electricity focus – High price events in South Australia and Tasmania

Severe weather and strong winds in South Australia on 12 November 2022 caused a transmission tower to collapse. The tower was located between Tailem Bend and the South-East substation, near the Heywood interconnector. As a result, Heywood was unable to transfer FCAS from Victoria to the majority of South Australia. The smaller interconnector linking South Australia to Victoria, Murraylink, was still operational but is unable to transfer FCAS. As a result, South Australia had to provide its own FCAS, leading to competing demands for FCAS and energy. During this period, South Australia's FCAS prices exceeded $5,000/MW for 42 30-minute intervals with prices ranging from $5,128/MW to the price cap of $15,500/MW (Table 11.1). These sustained high FCAS prices triggered protective price caps (Cumulative Price Thresholds) which capped South Australia FCAS prices at $300/MW.

The outage also impacted the wholesale price of electricity which exceeded $5,000/MWh for one 30-minute interval in South Australia and four 30-minute intervals in Tasmania (Table 11.2) When local FCAS prices increased in South Australia, multiple generators in the region rebid their energy offers from lower prices to $15,500/MWh to avoid being dispatched and incurring high FCAS costs.

The constraints managing the outage in South Australia also affected generation in Victoria and the Basslink interconnector which led to high priced generation in Victoria setting the price in Tasmania above $5,000/MWh.

Table 11.1 Count of high price events in the South Australian FCAS market

Date	Lower 5 minute	Lower 6 second	Lower regulation	Raise 5 minute	Raise 60 second	Raise 6 second	Raise regulation
12 Nov				1	2	1	
13 Nov	1	1	17	4	2	1	11
14 Nov	1						
Total	**2**	**1**	**17**	**5**	**4**	**2**	**11**

Table 11.2 High price events in the spot market

Date	Region	Time	Price ($/MWh)
13 Nov	South Australia	3.30 am	5,503
14 Nov	Tasmania	6.30 am	7,381
	Tasmania	7.00 am	8,212
	Tasmania	7.30 am	9,667
	Tasmania	8.00 am	14,356

Source: NEM data.

11.1 Outage led to high FCAS prices South Australia

The need for South Australia to provide its own FCAS led to volatile local FCAS prices. FCAS 30-minute prices exceeded $5,000/MW 42 times between 12 and 14 November, across all FCAS except lower 60 second.

Lower regulation had the highest number of 30-minute intervals above $5,000/MW, all of which occurred on 13 November. On that day there were 17 30-minute intervals where lower regulation prices were between $5,300/MW and $15,500/MW.

- Between 3 am and 10 am, the driver of the high lower regulation prices was due to the competing demands for FCAS and energy. During this period, up to 330 MW of lower regulation services was offered, however only one third of this could effectively make it to the market due to its output in the energy market. At the time, gas generators were running at low levels and were unable to provide much lower services because they could not reduce their output sufficiently. As a result, high priced lower regulation services needed to be dispatched.
- From 10.15 am, availability of lower regulation and raise regulation services was further reduced after Neoen withdrew 78 MW of capacity from the Hornsdale battery due to a forecast change in its state of charge. This capacity was priced below $300/MW in both the FCAS and energy markets.

The sustained high prices breached the cumulative price threshold for South Australia lower regulation services on 14 November at 12.50 pm and triggered a $300/MW price cap for all FCAS services until 26 November. Even though repairs to the transmission tower were completed on 19 November and South Australia no longer had to provide its own FCAS, the price caps stayed in placed until the cumulative price fell below the threshold.

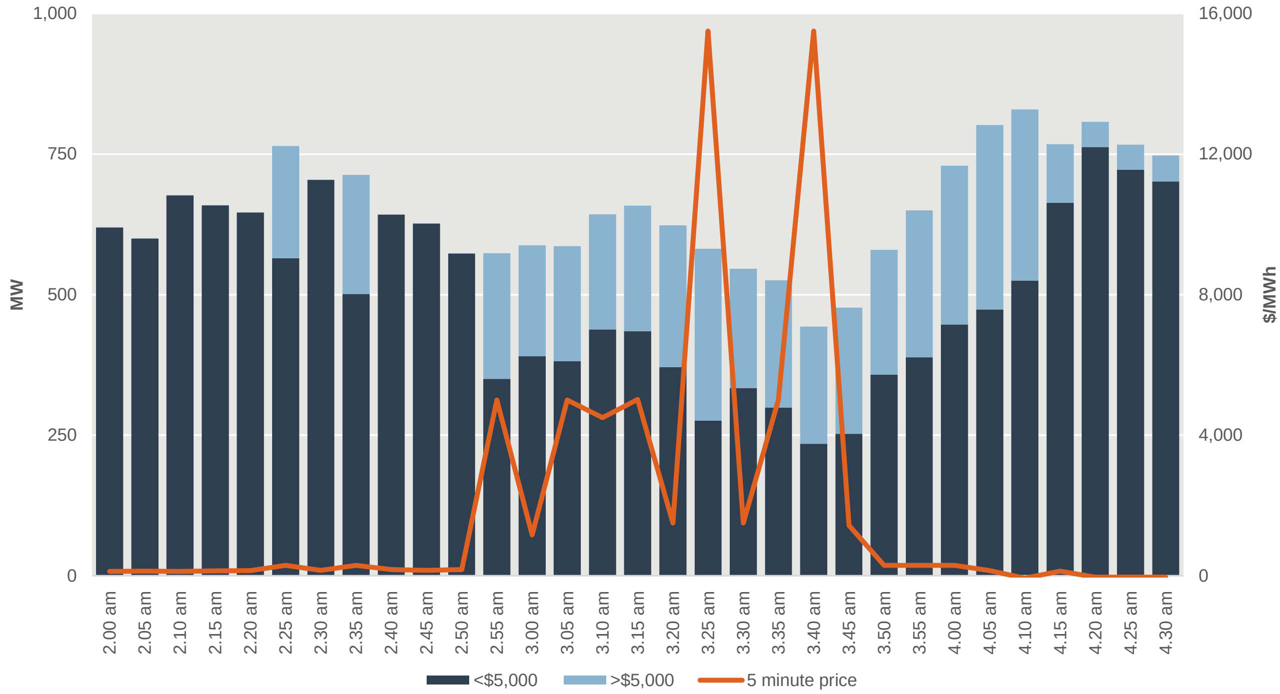
11.2 High FCAS prices contributed to high energy prices

High FCAS costs impacted energy prices in South Australia. This was because wind farms rebid capacity between lower and higher price bands in response to high FCAS costs and there were technical limitations on some other units.

On the morning of 13 November, FCAS prices exceeded $5,000/MW between 2.55 am and 3.45 am. In response, wind generators shifted around a third of their offers from below to above $5,000/MWh (Figure 11.1). This caused 5-minute energy prices to jump - fluctuating between $1,165/MWh and $15,500/MWh. At 3.25 am the energy price reached the cap of $15,500/MWh because 16 MW of high-priced energy was required to meet demand. This contributed to the 30-minute energy price (ending at 3.30 am) exceeding $5,000/MWh.

Generally, solar and wind generators do not provide FCAS, so do not receive FCAS revenue but are required to contribute to FCAS costs if generating. When FCAS prices are high, the cost of FCAS to a generator can exceed the revenue earnt in the energy market. Therefore, it is not unusual for a generator to offer capacity at high prices to avoid being dispatched and having to pay high FCAS costs. For example, we noted in our Q4 2021 report that solar generators in Queensland had an incentive to rebid their energy offers to high prices to reduce their exposure to raise FCAS costs.[31]

Figure 11.1 South Australia wind offers in energy market on 13 November



Source: AER analysis using NEM data.
Note: Total wind offers (less than and greater than $5,000/MWh) in the South Australia energy market between 2am and 4:30am on 13 November 2022, and the 5-minute spot price.

Rebidding at 3.25 am, 13 November 2022

At 3.25 am, multiple wind generators in South Australia rebid their energy offers from negative prices to $15,500/MWh to avoid dispatch and incurring high FCAS costs. Neoen also removed 80 MW of capacity priced at the price floor from the Hornsdale battery due to a forecast change in its state of charge. Table 11.3 shows significant rebids made for 3.25 am when the 5-minute price reached the cap.

[31] AER, Wholesale Markets Quarterly Q4 2021, February 2022.

Table 11.3: South Australia rebids at 3.25 am 13 November

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.56 am	3.05 am	EnergyAustralia	Waterloo Wind Farm	130	-84	15,500	Band adj to FCAS DP
2.57 am	3.05 am	Trustpower	Snowtown North Wind Farm	144	<-145	15,500	Band adj to FCAS DP
2.57 am	3.05 am	Trustpower	Snowtown South Wind Farm	126	<-115	15,500	Band adj to FCAS DP
3.07 am	3.15 am	AGL Energy	Barker Inlet Power Station	30	176	15,500	040 Chg in AEMO DISP~45 Price increase vs PD [SA] $4500.01 03:10 vs $140.11 30minPD 03:30
3.09 am	3.15 am	Lincoln Gap Wind Farm	Lincoln Gap Wind Farm	103	4,500	15,500	Co-optimisation of energy revenues & CR-FCAS costs - SL
3.13 am	3.20 am	Engie	Willogoleche Wind Farm	119	5,018	15,500	Constraint Management: SA_TBSE1. SL
3.15 am	3.25 am	Ratch Australia	Starfish Hill Wind Farm	35	-995	15,423	Change in FCAS costs resulting in negative revenue $-1544.47 in the current interval, estimated negative revenue for the next 5 dispatch intervals
3.16 am	3.25 am	Neoen	Hornsdale Power Reserve	-80	-1,000	N/A	Change in forecast SOC

In addition, around 200 MW of capacity priced less than $5,000/MWh was effectively unavailable because of technical reasons like being unable to start within 5 minutes or because a generator's output was limited by a constraint.

11.3 Tasmania prices were impacted by South Australia outage

In Tasmania energy prices exceeded $5,000/MWh for 4 consecutive 30-minute intervals on 14 November, from 6.30 am to 8 am. At the time, there was a constraint managing the line outage in South Australia which included all interconnectors into Victoria and much of the region's generation. However, output from certain generators in Victoria and flows from Tasmania into Victoria on Basslink were most effective in relieving the constraint.

During this time, there was little to no capacity offered above $5,000/MWh in Tasmania and some Tasmanian generation was constrained down due to local network issues. At times, to maintain system security, the constraint managing the outage in South Australia forced flows from Tasmania into Victoria and on occasion every megawatt in Tasmania was dispatched.

As a result of the constraint and the conditions in Tasmania, the least cost solution for the NEM, as determined by the market operator's dispatch engine, was to have generation from other regions setting the price in Tasmania. Consequently, units in Victoria and South Australia set the price in Tasmania above $5,000/MWh for the majority of the 5-minute intervals between 6.05 am and 8 am.

These high price outcomes in the FCAS markets in South Australia and energy markets in South Australia and Tasmania highlight the connection between energy and FCAS markets. It also highlights the important role interconnectors play connecting markets. By enabling generation to flow (or FCAS to be transferred) from one region to another, interconnectors can help reduce prices in both energy and FCAS markets by balancing supply and demand across regions.

12 Gas focus I – Global LNG spot prices and forecasts

Global LNG spot prices have influenced gas prices on the east coast of Australia since LNG export facilities were constructed in 2015 in Gladstone, Queensland. Low global prices led to relatively cheap gas in mid-2020[32], however surging global prices were a factor in high east coast prices in mid-2022[33]. Currently, global markets are forecasting lower prices over 2023 than for 2022 including over winter when global spot prices have historically influenced domestic pricing most.

At the two main LNG demand 'hubs' in Europe and Asia, weak demand from Asia and healthy storage levels in Europe are supporting lower prices in 2023. While global gas pricing was volatile over 2022, there has been a recent sustained trend downwards. This has likely influenced a fall in ASX Victorian futures pricing for winter.

12.1 Factors influencing declining global LNG spot prices and forecasts

Asian and European markets are primarily made up of gas buyers with insufficient domestic production to meet their own gas demand. Both key demand centres compete for LNG cargoes, creating price competition in the international spot LNG market.

12.1.1 Weak LNG demand from Asia

LNG demand from Northeast Asia has been muted due to high storage inventories and mild winter conditions. It is anticipated that buying interest in Asia will grow as China emerges from its Covid-zero policy and as countries that were priced out during record high prices emerge to bid for lower-priced gas.

12.1.2 Healthy European storage inventories

International LNG spot prices have reduced in Q4 2022 (Figure Figure 12.1 Natural gas TTF (Europe) and JKM netback price (Asia to Wallumbilla, Queensland)) following record highs in August and September 2022. The Title Transfer Facility (TTF) spot price for gas in Europe has fallen, as has the ACCC-calculated JKM netback price reflecting the price of spot LNG in Asia minus shipping costs from Queensland. In June 2022, the European Union set gas storage targets of 80% capacity by November 2022 before the northern-hemisphere winter in preparation for severe winter conditions and 90% capacity by November in subsequent years beyond 2022[34]. Storages were able to exceed this target without recourse to piped gas from Russia (Figure 12.2 European gas inventory levels).

Higher than usual temperatures in winter have also muted demand for gas in Europe.

Through January, forward JKM netback prices for 2023 and 2024 have further moderated with price expectations almost halving and the latest expectations for average 2023 prices being $25.76/GJ compared to the mid-December 2022 forward price assessment averaging $45.44/GJ (Figure 12.1). The drop in forward JKM netback prices coincides with higher confidence that there may be

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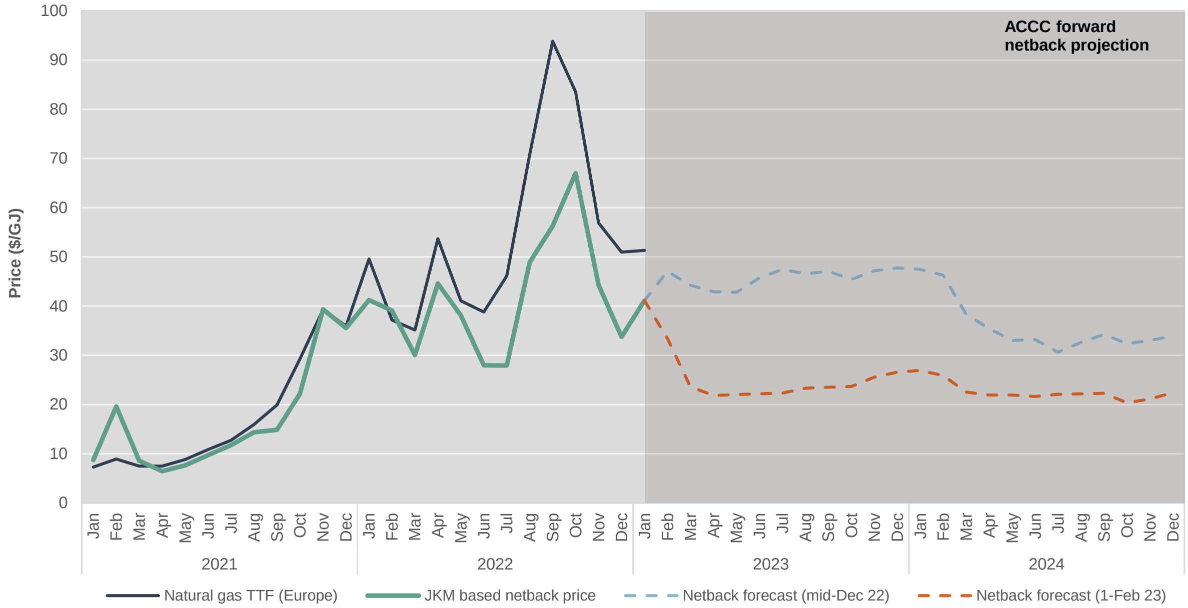
[32] AER, Wholesale Markets Quarterly Q3 2020, November 2020.

[33] AER, Wholesale Markets Quarterly Q3 2022, November 2022.

[34] European Commission, New EU rules on gas storage, June 2022.

sufficient European storage inventories post-winter. Due to the record high LNG spot prices and plans to phase out Russian gas, there has also been demand reduction and fuel switching in Europe.

Figure 12.1 Natural gas TTF (Europe) and JKM netback price (Asia to Wallumbilla, Queensland)



Source: AER analysis using Argus Media data and ACCC netback price calculation
Note: The Natural gas TTF and JKM based netback price is based on the price of gas for delivery in that month.
The Argus Natural gas TTF price is a month ahead delivered spot price calculated at the Title Transfer Facility (TTF) in the Netherlands.
The AER obtains confidential proprietary data from Argus Media under license, from which data the AER conducts and publishes its own calculations and forms its own opinions. Argus Media does not make or give any warranty, express or implied, as to the accuracy, currency, adequacy, or completeness of its data and it shall not be liable for any loss or damage arising from any party's reliance on, or use of, the data provided or the AER's calculations.

Box 2: Regulations to cap high European prices for 2023

Caps are being imposed to limit gas prices in Europe. Gas traders are likely to take these regulations into account when forming expectations about future gas prices.

European Union ministers reached a political agreement in December 2022 to impose a gas price cap, set to apply from 15 February 2023 for a year. If the gas cap is triggered, front-month, three-month and front year TTF contracts across the European Union will be sold at a level equal to or below the international price of LNG plus €35 per megawatt hour (~$15/GJ).

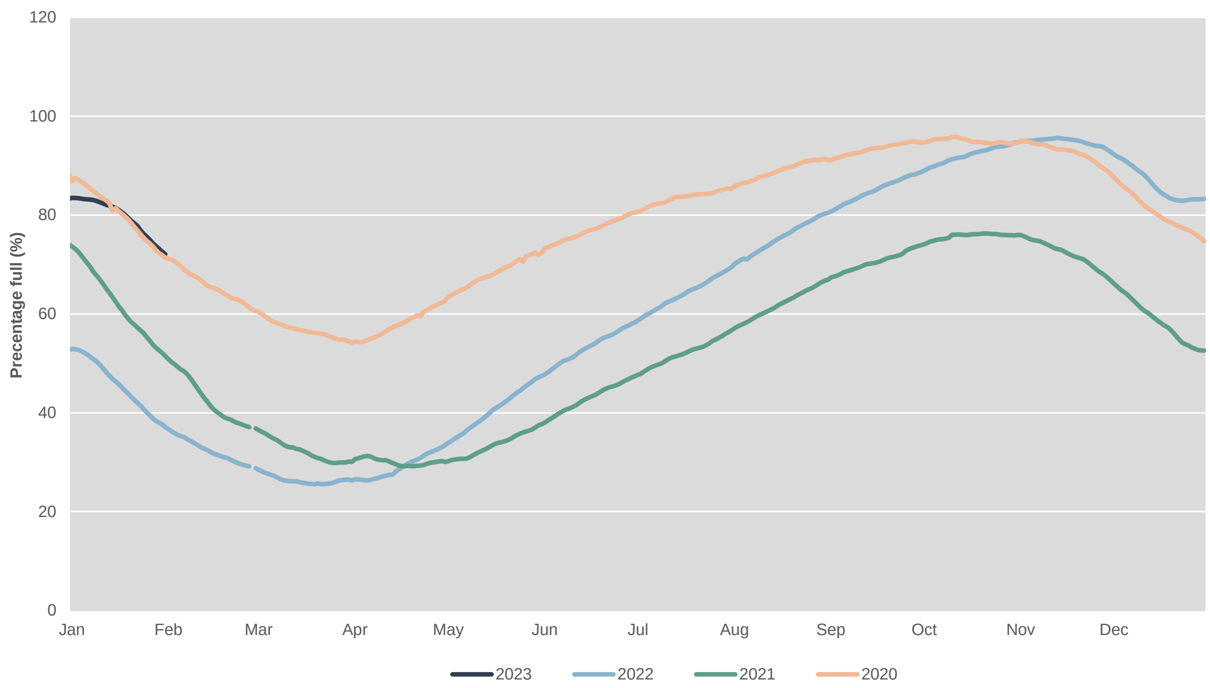
The gas price cap is designed to act as a safeguard from exorbitant high prices while allowing the cap trigger to fluctuate with international spot LNG prices. This will allow Europe to still bid in gas at competitive prices from the international market.

Gas will be capped if:

- the month-ahead TTF price exceeds €180 per megawatt hour (~$78/GJ) for 3 working days, and
- the month-ahead TTF price is €35 per megawatt hour (~$15/GJ) higher than a reference price for LNG on global markets for the same 3 working days.

The cap will last for at least 20 working days and will be deactivated if prices fall back below €180 per megawatt hour.

Figure 12.2 European gas inventory levels

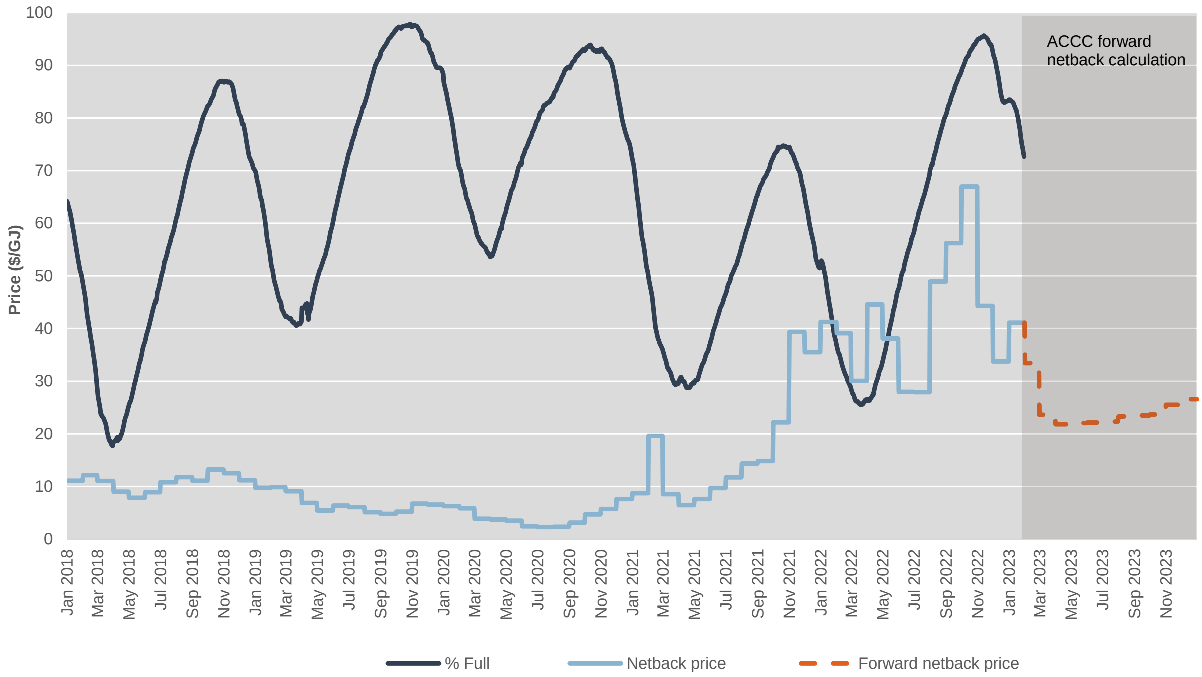


Source: AER analysis using Gas Infrastructure Europe aggregated gas storage inventory data.

In the absence of unusually cold weather, there seems to be enough gas supply based on expectations for heating demand in Europe. Gas inventory levels stood at 83% full at the end of 2022, higher than levels in 2021 (53%) and 2020 (75%). The likelihood of a storage overhang post-winter may see international markets well supplied.

At the end of January 2023, storage levels are similar to 2019-20 levels when there were milder winter conditions in Europe. There is a significant difference between the netback price in January 2020 of $6.29/GJ in comparison to January 2023 of $41.11/GJ but LNG futures markets indicate that netback prices will fall further (Figure 12.3). Forward prices also account for risks such as supply outages and unseasonably cold weather. Consequently, if such outcomes do not eventuate, actual prices may decline below levels indicated by futures markets.

Figure 12.3 European gas inventory and netback price series



Source: AER analysis using Gas Infrastructure Europe aggregated gas storage inventory data and ACCC netback price series data.
Note: The ACCC forward netback prices were assessed on 1 February 2023.

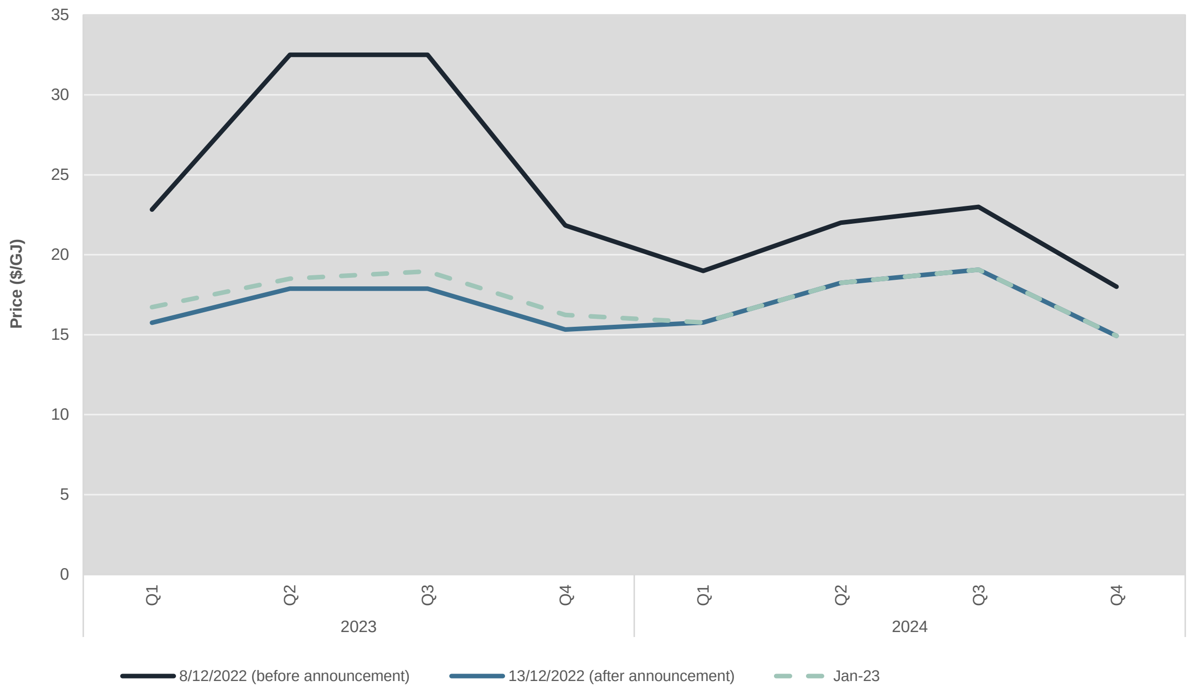
12.2 Potential impact on domestic gas prices

Lower international LNG prices theoretically offer exporters a stronger incentive to sell uncontracted volumes into the domestic gas market. However, there remains a divergence between international and domestic prices. ACCC's forward netback price calculation (representing a price in Queensland for gas that can be exported) from February to December 2023 is between $22/GJ and $33/GJ. In comparison, VIC futures pricing in December 2022 for 2023 gas is between $16/GJ and $19/GJ (Figure 12.4). This price difference cannot be accounted for by transportation costs between the regions, which is around $2/GJ to $3/GJ under firm contract pricing.

The $12/GJ regulated gas price cap may be one of the contributing factors to the divergence between current forward netback prices and Victorian futures pricing for 2023. Victorian futures pricing for Q2 and Q3 2023 fell (45%) following the announcement of the gas price cap in December, although this also coincides with falls in the outlook for international prices[35].

The Australian Government also signed a new heads of agreement with East Coast LNG exporters in September 2022. This includes commitments from LNG exporters to first offer 157 PJ of uncontracted gas on competitive terms and reasonable notice to the domestic market for delivery in 2023. As a result of these commitments and the price cap, there may be increased access to cheaper gas before winter 2023.

Figure 12.4 ASX Victorian futures pricing before and after price cap announcement



Source: ASX Energy.

[35] It should be noted that gas futures on the ASX are thinly traded and there is usually a large difference between bids and offers for these products on the exchange. Settlement prices for ASX gas futures usually reflect the lower part of this range but actual market expectations may be somewhat higher.

13 Gas focus II - $14/GJ significant price variations in Brisbane and Sydney STTM

In accordance with the National Gas Rules (the Rules), the AER is required to publish a report whenever there is a significant price variation (SPV) in the Victorian Declared Wholesale Gas Market (DWGM) or Short Term Trading Markets (STTM). The AER has published guidelines setting out what constitutes a SPV event.[36] Outcomes that constitute a SPV in the STTM include when there is a variation of greater than $14/GJ between the price 2 days prior (D-2 provisional) and the price the day before (ex-ante or D-1 day ahead) the gas is required.

While the instances of large gas spot market price variations decreased on the east coast from winter 2022[37], there were two instances this quarter when the difference between the D-2 provisional and ex-ante prices was greater than $14/GJ in Sydney on 17 November and Brisbane on 18 November.

The causes of these price variations were:

- Volatile prices over this week as the QCLNG outage finished
- Rebidding

13.1 Volatile prices following finish of QCLNG outage

Gas spot markets have been volatile with prices hitting record November highs in all domestic spot markets on the east coast. However, since record high prices in July 2022, prices have been more subdued with less demand, reduced LNG export pressures and increased supply into the domestic spot markets.

Following peak demand in winter 2022, overall demand for gas in the downstream spot markets reduced. This was driven by seasonal factors and a reduction in gas generation demand.

Shell's Queensland Curtis LNG (QCLNG) project experienced an LNG train[38] outage from 17 October to 13 November. The outage created additional domestic supply as forecast production levels were maintained. Following the end of the outage, prices jumped from a weekly average of $11.77/GJ to $20.34/GJ. Prices were also volatile, ranging from $11.36/GJ to $35/GJ in the downstream spot markets (Figure 13.1). Additional exporter/producer supply has the potential to have a significant impact on market pricing.

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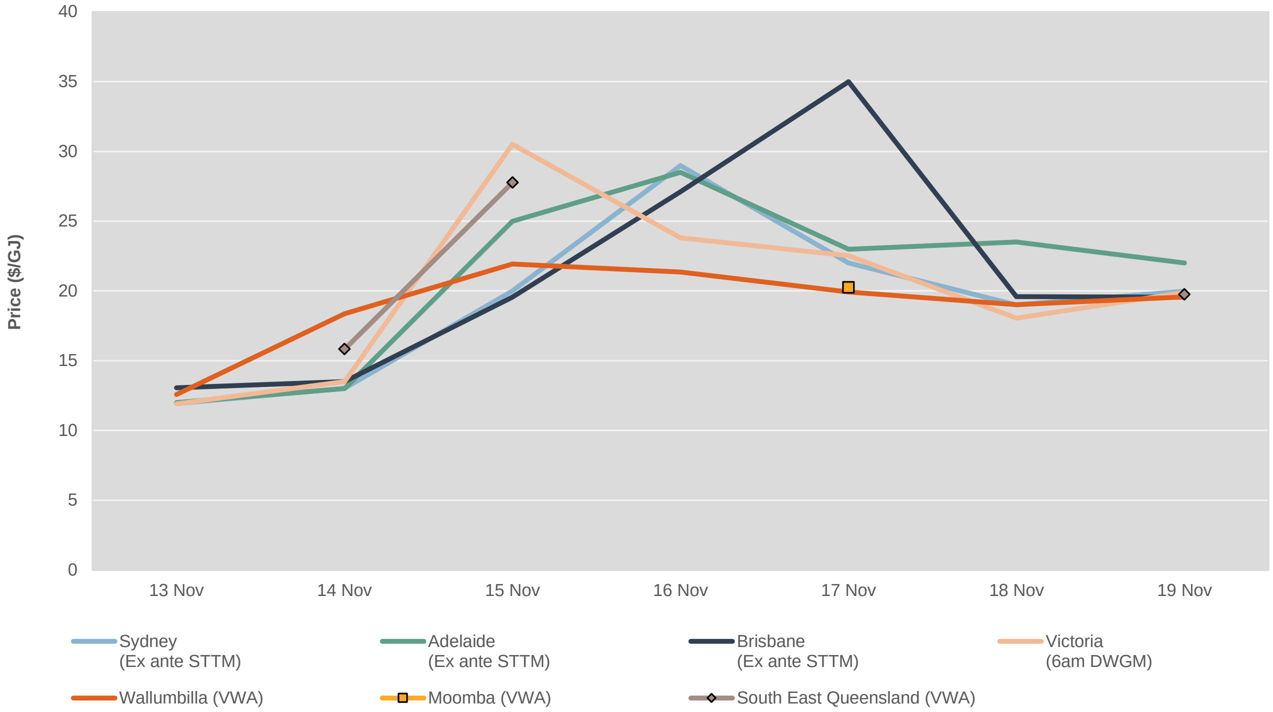
[36] Under Rule 355 of Part 19 of the National Gas Rules (Gas Rules), the AER is required to identify and report on any significant price variations (SPVs) in the DWGM. The Victorian SPV reporting triggers are published in the DWGM Significant Price Variation Guideline.

Under Rule 498 of Part 20 of the Gas Rules, the AER is required to identify and report on any significant price variations (SPVs) in the STTM. The STTM reporting triggers are published in the STTM Significant Price Variation Guideline.

[37] AER, Significant price variation report – May to August 2022, September 2022.

[38] Queensland has 3 LNG exporters, each utilising 2 'trains' (or pipeline delivery services) to deliver gas to LNG liquefaction facilities. A full train outage reduces total liquefaction capability of an individual exporter to half of their full export processing potential.

Figure 13.1 Volatile prices following finish of QCLNG outage



Source: AER analysis using DWGM, STTM and GSH price series data.

13.2 Impact of rebidding

On 17 and 18 November there were instances where price variations between the provisional and ex-ante schedule breached AER reporting thresholds. Both instances were due to variations in the price from D-2 to D-1 (Table 13.1).

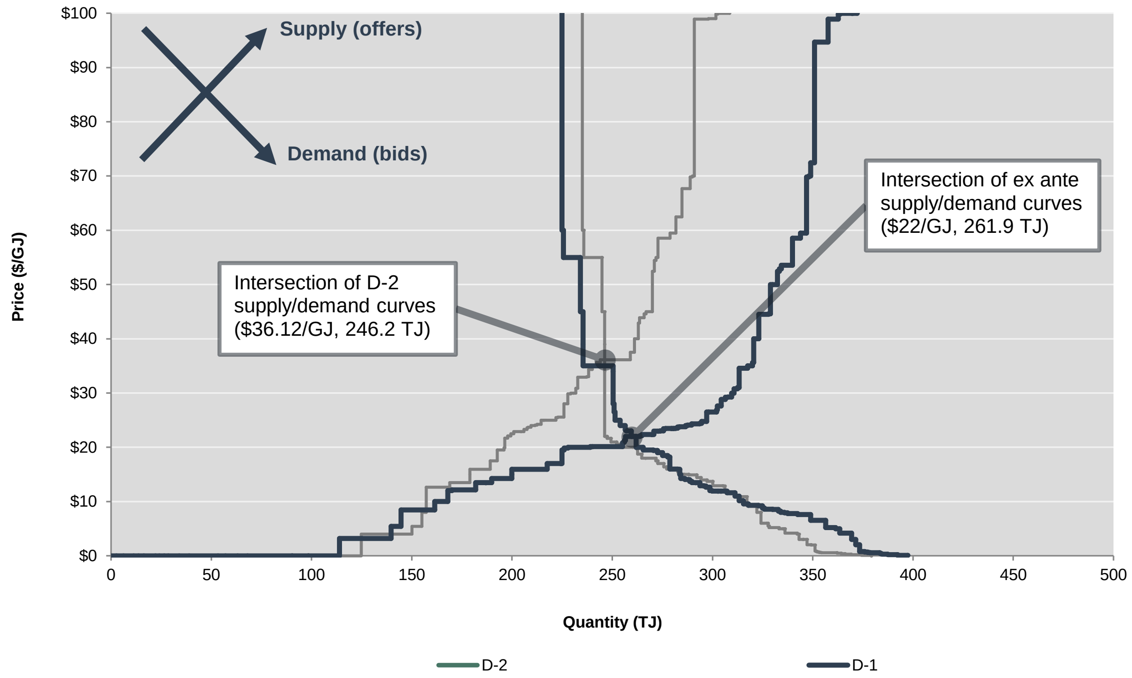
Table 13.1 Significant price variation threshold breaches

Gas day	Market	D-2 provisional price ($/GJ)	D-1 ex-ante price ($/GJ)	Schedule price variation ($/GJ)	Threshold breach description
17 Nov	Sydney	36.12	22	-14.12	Supply offer bid
18 Nov	Brisbane	35	19.6	-15.4	Supply offer bid

13.3 Sydney STTM – 17 November

On 17 November, a large price variation downwards between the provisional ($36.12/GJ) and ex-ante ($22/GJ) schedule price occurred in the Sydney market. Rebidding of supply on the ex-ante schedule drove lower ex-ante prices on 17 November. Exporter/producers and traders were the main contributors to the increased availability of lower priced supply in Sydney (Figure 13.2). An additional 31.9 TJ of supply was offered at $12/GJ to $20/GJ in the ex-ante schedule.

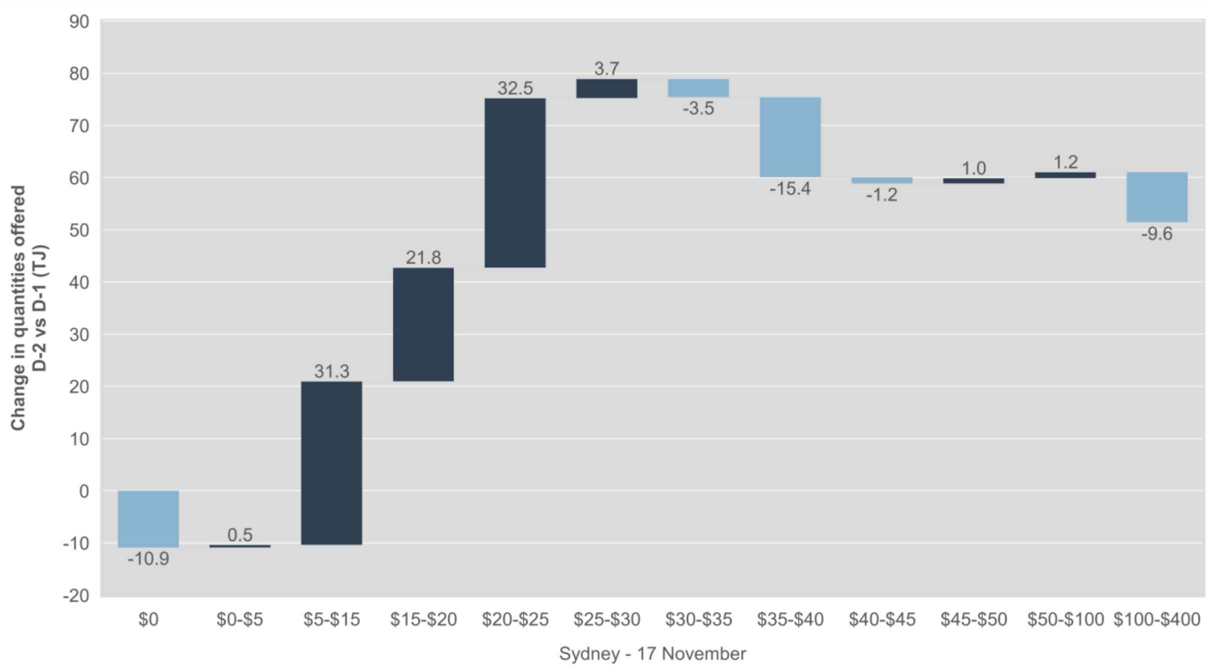
Figure 13.2 Sydney provisional and ex-ante bid and offer curves



Source: AER analysis using STTM data.

The shift in supply and similar demand levels reduced the ex-ante price by more than $14.12/GJ below the D-2 provisional schedule price. The majority of additional supply capacity at $15/GJ to $20/GJ (21.8 TJ) was offered by AGL on the EGP and Shell on the MSP (Figure 13.3).

Figure 13.3 Change in gas offered between D-2 and D-1 schedule in Sydney

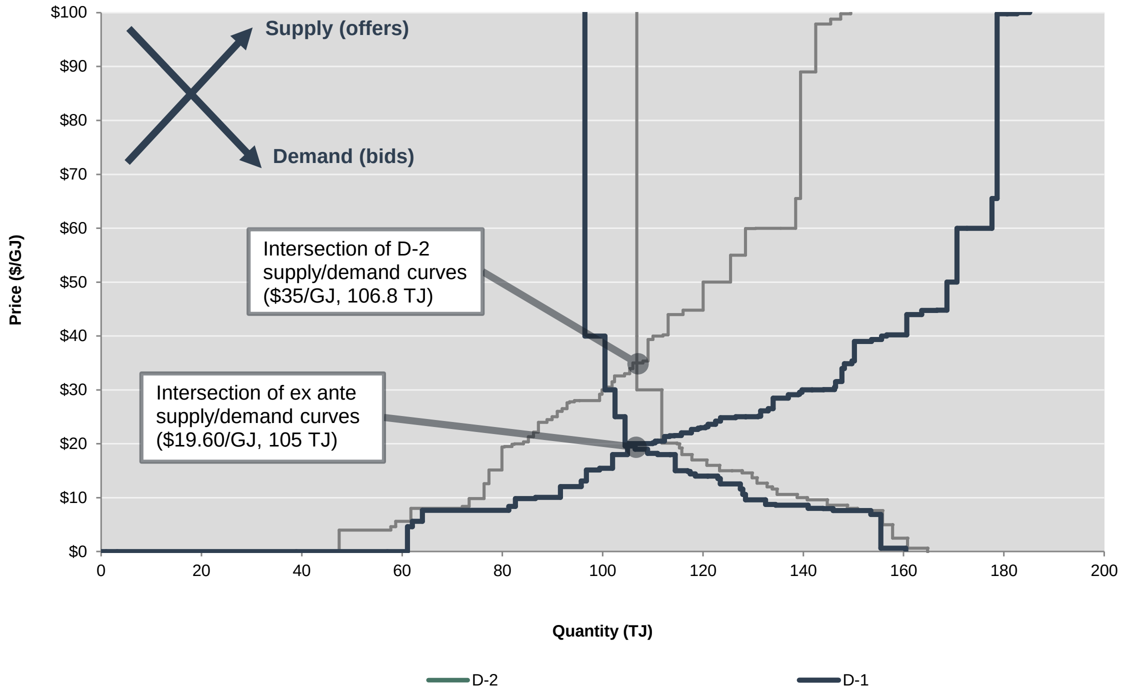


Source: AER analysis using STTM data.
Note: The change in quantities between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the change in quantities is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative change in quantities indicates the opposite.

13.4 Brisbane STTM – 18 November

On 18 November, a large price variation downwards between the provisional ($35/GJ) and ex-ante ($19.6/GJ) schedule price occurred in the Brisbane market. Rebidding of supply bids on the ex-ante schedule was the primary driver of lower ex-ante prices. Lower priced gas supply in the ex-ante schedule were largely provided by a trader and exporter/producer. An additional 37.6 TJ of supply was offered below $25/GJ in the ex-ante schedule, reducing the ex-ante price by $15.40/GJ below the D-2 provisional schedule price (Figure 13.4).

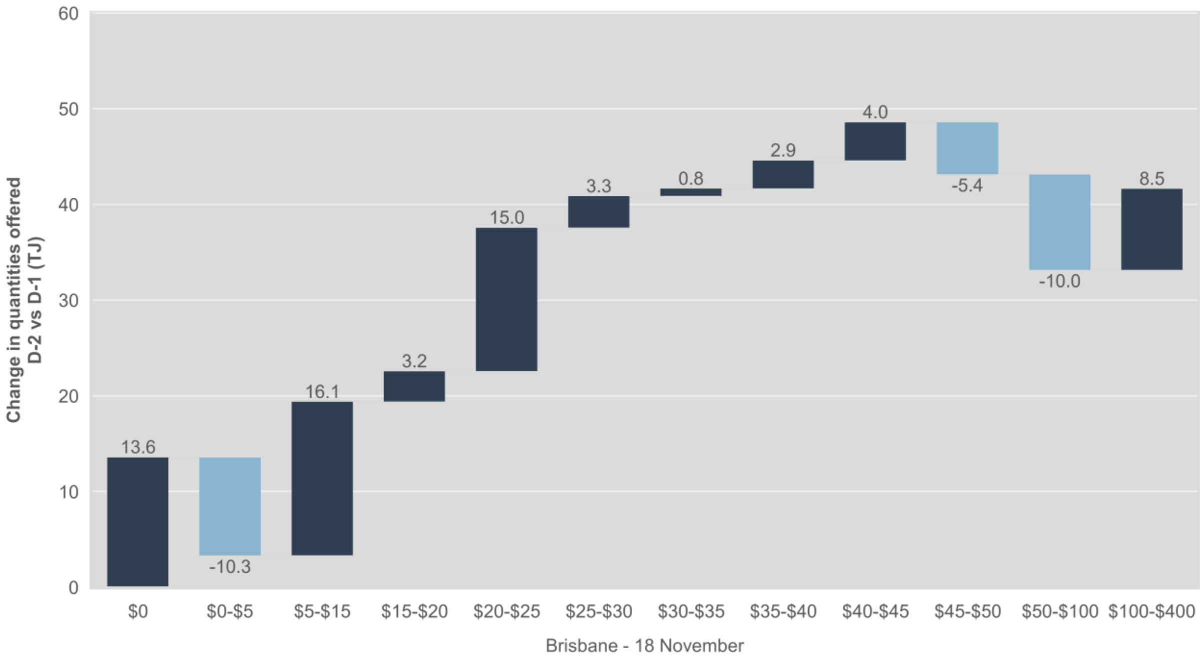
Figure 13.4 Brisbane provisional and ex-ante bid and offer curves



Source: AER analysis using STTM data

More supply capacity offered by a GPG gentailer at the price floor of $0/GJ (16.2 TJ) was a significant driver of the price decrease (Figure 13.5). The AER is currently investigating this event as a potential compliance concern. Additional supply was also offered by a trader at $10.05/GJ (5 TJ) and an exporter/producer at $18/GJ (3 TJ).

Figure 13.5 Change in gas offered between D-2 and D-1 schedule in Brisbane



Source: AER analysis using STTM data.
Note: The change in quantities between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the change in quantities is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative change in quantities indicates the opposite.

Next Steps

In general, market outcomes are optimised when market participants have access to information as early as possible. The AER will continue to monitor the market and may issue further public guidance with respect to when gas supply offer quantities should be included in the provisional schedule.

Common measurements and abbreviations

Electricity		Gas	
MW	Megawatt	GJ	Gigajoule
MWh	Megawatt hour	PJ	Petajoule
TW	Terawatt	TJ	Terajoule
FCAS	Frequency control ancillary services	STTM	Short Term Trading Market
NEM	National Electricity Market	DWGM	Declared Wholesale Gas Market
VWA	Volume weighted average	WGSH	Wallumbilla Gas Supply Hub
AEMO	Australian Energy Market Operator	DAA	Day Ahead Auction
		BWP	Berwyndale to Wallumbilla Pipeline
		CGP	Carpentaria Gas Pipeline
		EGP	Eastern Gas Pipeline
		ICF	Iona Compression Facility
		MAPS	Moomba to Adelaide Pipeline System
		MCF	Moomba Compression Facility
		MSP	Moomba to Sydney Pipeline
		NGP	Northern Gas Pipeline
		PCA	Port Campbell to Adelaide Pipeline
		PCI	Port Campbell to Iona Pipeline
		QGP	Queensland Gas Pipeline
		RBP	Roma to Brisbane Pipeline
		SWQP	South West Queensland Pipeline
		TGP	Tasmanian Gas Pipeline
		VicHub	Eastern Victorian supply/demand point
		WCFA	Wallumbilla Compression Facility A
		WCFB	Wallumbilla Compression Facility B

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