Wholesale markets quarterly Q2 2023

April – June

July 2023

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Changes to our wholesale market reporting

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

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

Additional related regular reporting from the AER covers:

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

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

Electricity markets at a glance

Q2 2023

Spot prices

Average prices increased from Q1 2023 with the onset of winter, but remained well below Q2 2022 levels

Generator outages

Far fewer coal generator outages than in Q2 2022

Demand

With more rooftop solar, average demand was lower than Q2 2022 during the day but not in the evening peaks

Interconnectors

Planned network outages contributed to high prices in Queensland, NSW and South Australia

Coal station offers

More black coal capacity was offered than a year ago despite Liddell's exit in April

Outlook

Price expections for 2024 increased in Queensland and NSW but remain well below levels observed in 2022

Gas markets at a glance

Q2 2023

Spot prices

Spot prices averaged roughly $14.50/GJ. This was higher than Q1 but well below prices in Q2 2022

Supply constraints

Longford production was constrained during May, putting upward pressure on prices

International prices

International LNG prices continued to decline approaching the Northern Hemisphere summer

Upstream trade

Trade on the Gas Supply Hub has moved towards shorter-term products with little forward trade

Gas storage

Iona storage is nearly full heading into winter. It plays a critical role for managing supply-demand shocks over coming months

Gas flows

After constraints in May, pipeline capacity increased in June, supporting strong flows to the south

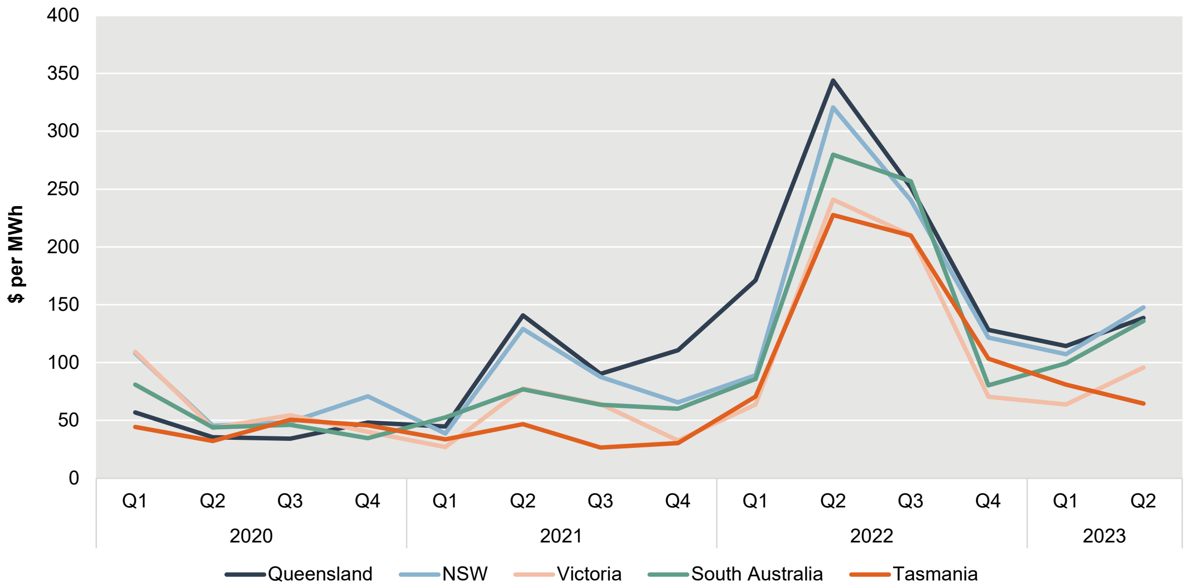
1 NEM prices remain well below Q2 2022 levels despite an increase since last quarter

Factors driving high prices a year ago were much less acute this quarter

Average NEM prices in Q2 2023 ranged from $65 per MWh in Tasmania to $148 per MWh in NSW. These were much lower in all regions than the levels reached in Q2 the previous year, when a range of factors contributed to record high prices. These included numerous baseload generator outages, high international coal and gas prices, and fuel supply constraints for some power stations.[1] This quarter, these factors were not present to nearly the same extent.

Nevertheless, average NEM prices did increase from the preceding quarter in mainland regions. This reflected higher demand, a seasonal decrease in solar generation, and a reduction in total coal capacity offered – partly due to the exit of Liddell power station in April. These factors drove a need for increased generation by more expensive gas and hydro power stations. In addition, significant price events also contributed to average prices being higher than in Q1 2023.

Figure 1 Average quarterly prices in the NEM



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

[1] AER, *Wholesale markets quarterly Q2 2022*.

In Q2 2023, 30-minute prices exceeded $5,000 per MWh on 4 separate days in May and 2 days in June and increased average quarterly prices in Queensland, NSW, and South Australia by around $10 per MWh. This was down from Q2 2022, but up from Q1 2023.

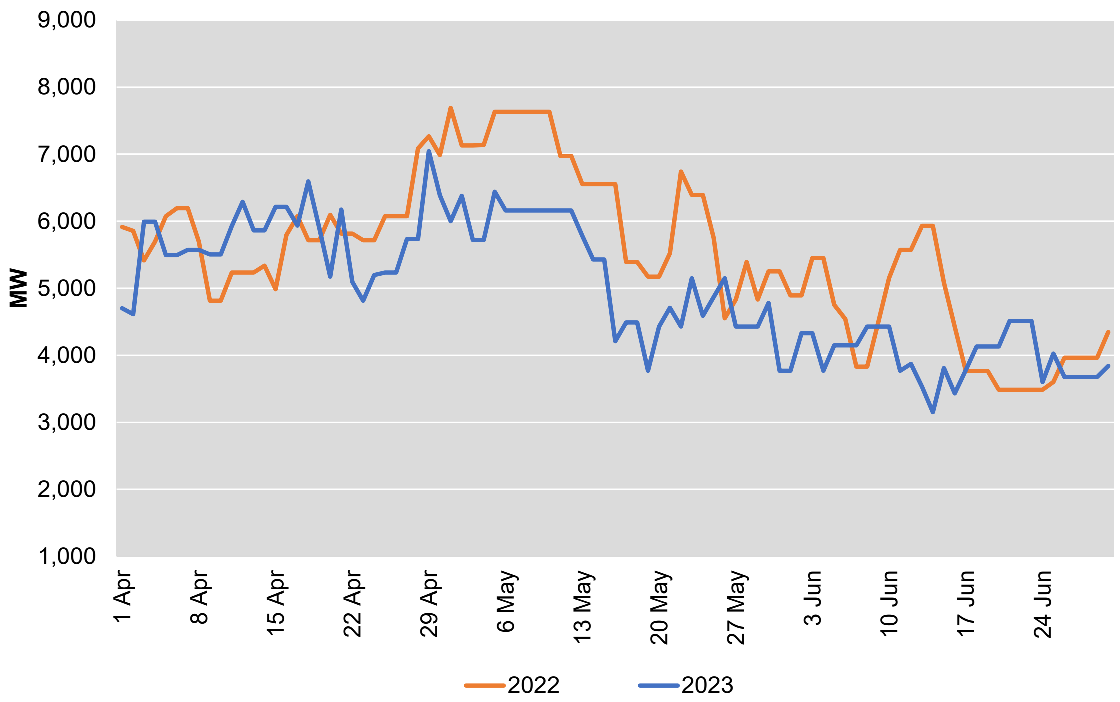
High demand and limited access to cheaper generation from other regions contributed to the price events. In particular, for 3 of the event days a planned line outage from Kangaroo Valley to Dapto prevented NSW and Queensland from accessing cheaper generation from Victoria. We will publish a separate report examining the drivers of these significant price events in more detail.

More black coal capacity was offered than a year ago despite Liddell's exit

More black coal capacity was offered into the market this quarter than in Q2 2022, due to a lower level of generator outages. This was despite Liddell power station exiting the market this quarter.

For most of Q2 2023, more coal capacity was available than in Q2 2022 (Figure 2). Last year, a high level of planned and unplanned outages meant that at times there was 1,500 MW less capacity available than this quarter, even factoring in the exit of Liddell.

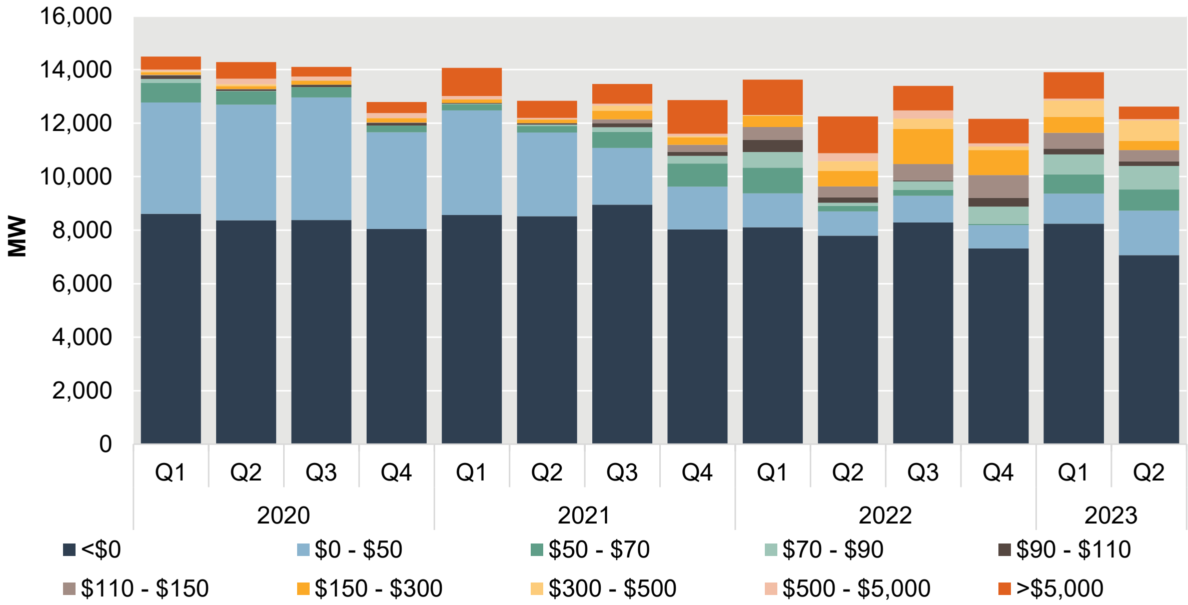
Figure 2 NEM baseload outages



Note: Outages are the sum of full day outages multiplied by the relevant registered capacity of the baseload unit and do not include part-day outages. Includes Swanbank E which is an efficient gas power station in Queensland. The closures of last 3 Liddell units in April 2023 are treated as outages.
Source: AER analysis using NEM data.

Not only was more coal capacity offered into the market compared to Q2 2022, but more of what was offered was priced below $90 per MWh. This reflects a downward trend in fuel prices as well as better fuel availability for some stations than last year, when various fuel supply constraints impacted generator offers. It also indicates that government interventions to implement price caps on black coal appear to have had a positive impact on coal generation offers.

Figure 3 NEM black coal offers by price bands



Source: AER analysis using NEM data.

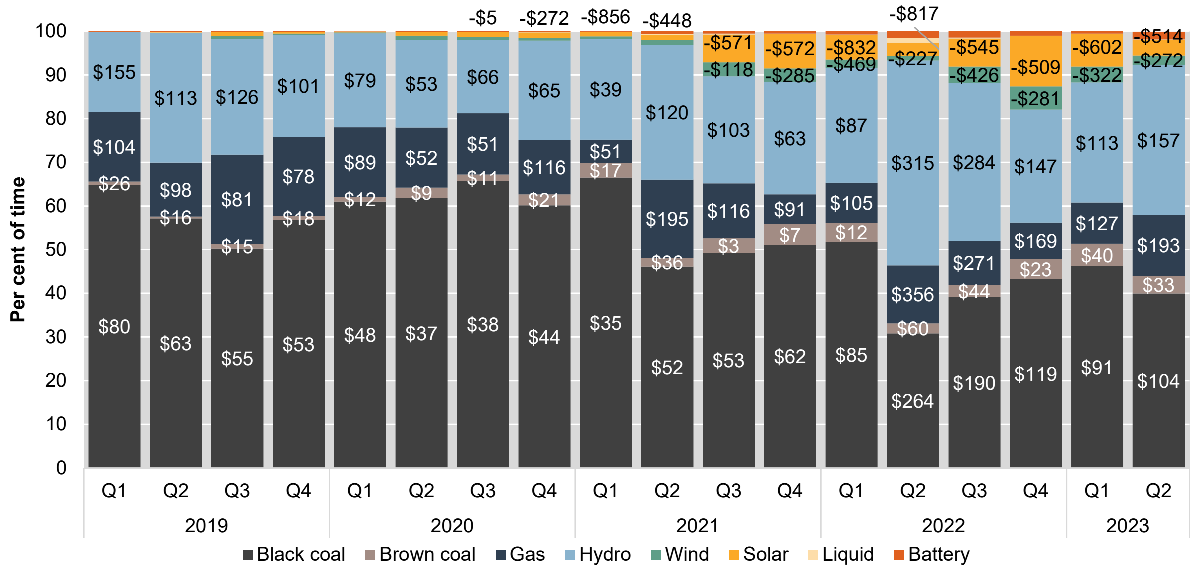
Despite the increase from Q2 2022, the amount of black coal capacity offered into the market fell compared to Q1 2023 in both Queensland and NSW. This included a significant reduction in capacity offered below $0 per MWh.

In NSW, the reduction in black coal capacity largely reflected Liddell power station's exit. Prior to closing, Liddell typically offered around 800 MW of capacity into the market, most of which was priced below $0 per MWh. While other black coal generators in NSW shifted some capacity to lower price bands, had Liddell's capacity still been available, prices would have been lower. In Queensland, reduced available capacity largely reflected outages at Millmerran and Tarong North power stations, both of which typically offer most of their capacity below $0 per MWh.

Cheaper fuels set price more often than in Q2 2022

Overall, changes in black coal offers contributed to the fuel type setting price more often, and at much lower prices, than in Q2 2022 in all regions (Figure 4). Meanwhile, cheap solar and wind set price more often than a year ago. Consequently, more expensive fuel types, such as gas and hydro, set price less often than a year ago, and at lower prices. These changes in price setting dynamics were reflected in much lower average prices this quarter than in Q2 2022.

Figure 4 **Price setting by generation source, NSW**



Notes: The pattern in price setting changes was broadly similar across mainland regions. Charts for other regions are available [on our website](#).
Source: AER analysis using NEM data.

Compared to Q1 2023, black coal set price less often and at slightly higher prices, while gas and hydro set the price more often and at higher prices. As a result, average prices were higher this quarter than last quarter.

Rooftop solar leading to lower demand during the day

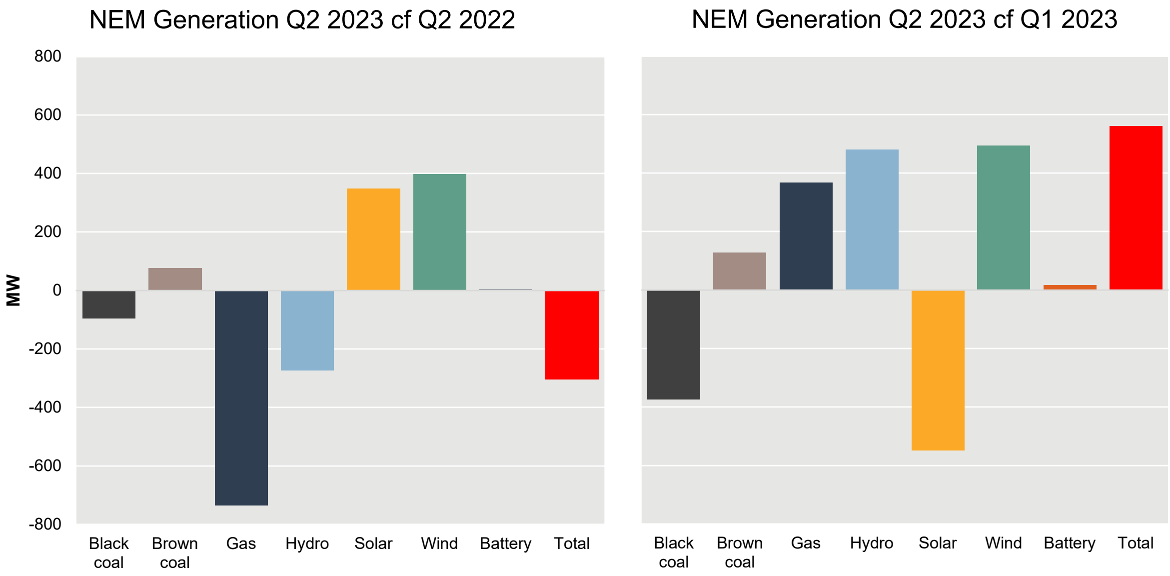
Demand in Q2 2023 was lower than in Q2 2022 due to an increase in rooftop solar generation. This continues a broader trend toward increasingly low demand in the middle of the day when rooftop solar is generating, even as demand remains high in the evening peaks and at night. Despite falling average demand, a large amount of capacity is still required for peak times.

Wind output reached record levels in June

Solar and wind combined output was on average 745 MW greater this quarter than in Q2 2022, reflecting strong investment in renewable generation and favourable wind conditions (Figure 5). Indeed, June saw record monthly wind output in the NEM, Victoria and South Australia. This, together with lower average demand, meant that less gas and hydro generation was needed. It also meant that coal output was similar to a year ago despite the increase in offers below $150 per MWh.

Compared to Q1 2023, however, seasonal factors meant that the story was different (Figure 5). With the onset of winter, demand increased while solar output fell. While this was partly offset by an increase in wind output, a fall in black coal output in Queensland meant more gas and hydro was dispatched.

Figure 5: Change in NEM generation output by fuel source



Source: AER analysis using NEM data

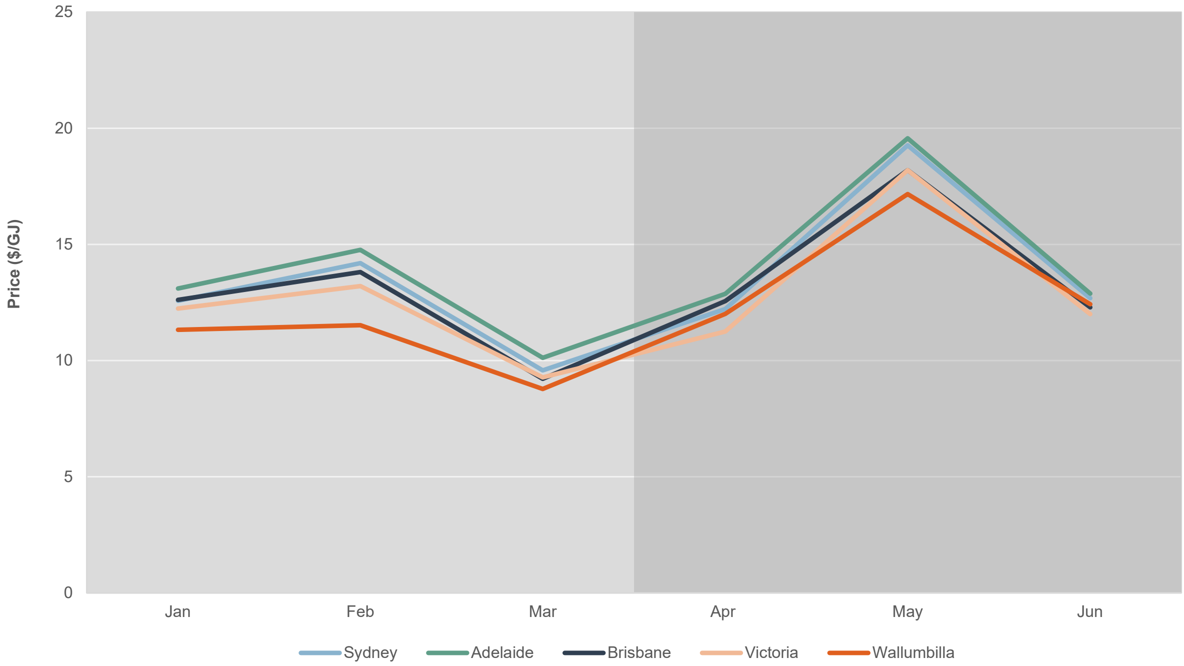
In NSW, higher demand driven by cold weather in June was largely met by increased imports from Victoria. As such, while black coal, gas and hydro generation in the region increased, this did little more than offset the decrease in solar output. Meanwhile, in Queensland, a substantial decrease in demand following the end of summer was offset by a similarly large decrease in black coal generation. In Victoria and South Australia, cooler weather conditions resulted in an increase in demand and shorter days to a decrease in solar generation. These changes were met by more wind and brown coal generation in Victoria and more gas generation in South Australia. In Tasmania, hydro generation increased to largely cover increased demand heading into winter.

2 Domestic gas spot prices increase but remain well below unprecedented 2022 levels

Gas spot market prices averaged roughly $14.50 per GJ

Over Q2, East coast gas market spot prices averaged roughly $14.50 per GJ, an increase from roughly $12 in Q1. This was caused mainly by higher prices in May across all markets (Figure 6).

Figure 6 East coast gas market average monthly prices



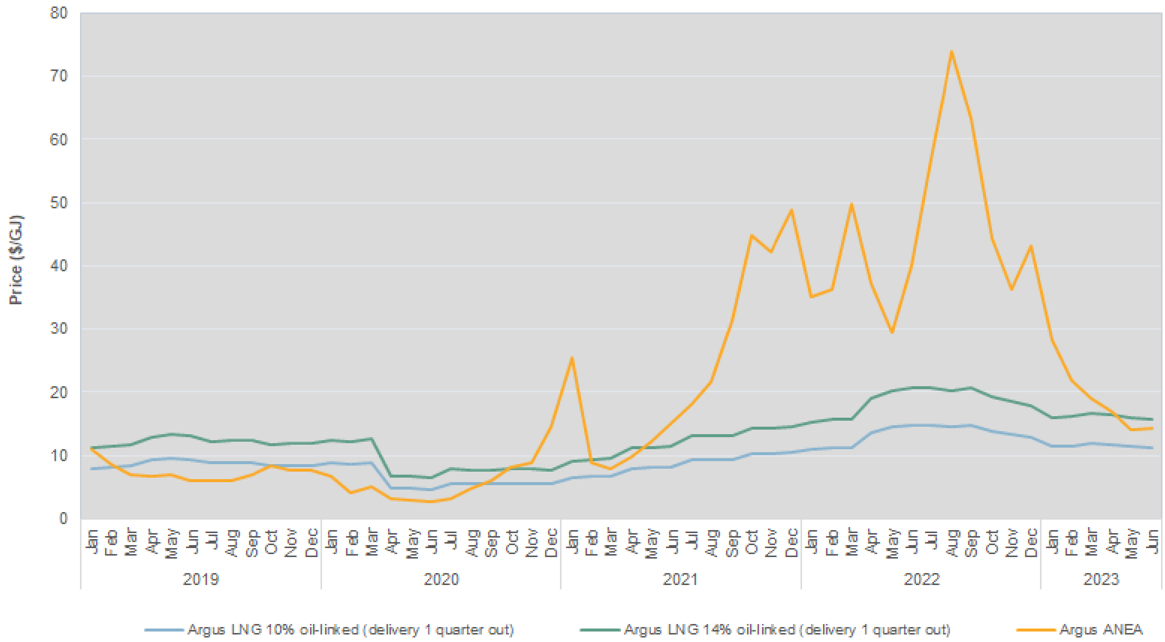
Note: The Wallumbilla price is the day-ahead exchange traded price.
Source: AER analysis using east coast gas market ECGM data (includes: Victoria, Adelaide, Brisbane and Sydney gas markets).

High May prices were largely the result of production constraints at Longford combined with pipeline capacity constraints on the Moomba to Sydney pipeline. This resulted in downstream prices in southern markets increasing above $19 per GJ, before pipeline capacity increases in June reduced upwards price pressure. June also saw the demand in the downstream markets lower compared to previous years. In combination, price pressures eased to the extent that some June trade took place below $10 per GJ.

International price pressures continue to decline

International LNG spot prices continued to decrease from Q1, and are well below the record levels of 2022. Asian LNG (measured by the Argus LNG Northeast Asia price) declined materially from December 2022 through to May 2023 before increasing slightly to end at $14.23 per GJ in June (Figure 7). In the Southern Hemisphere winter, it is typical to see a seasonal decline in international price pressures as Northern Hemisphere heating demand reduces.

Figure 7 International LNG spot prices



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

May price increases were caused by supply and transportation constraints during periods of high demand

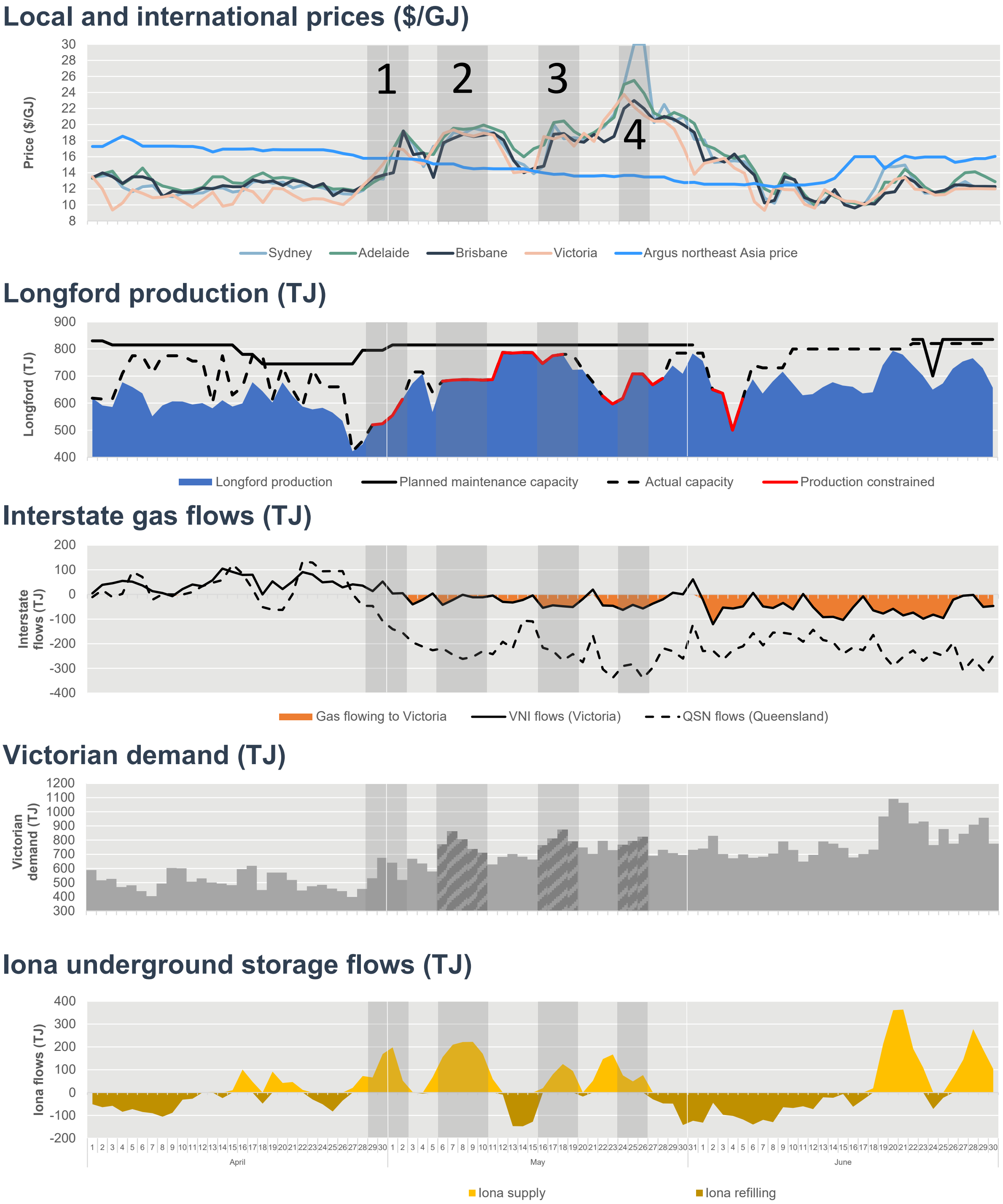
Gas spot market price increases over May tracked closely together between both downstream and upstream markets. Generally, increases in prices coincided with changes in:

- supply constraints at Longford
- transportation constraints on the Moomba to Sydney pipeline limiting interstate flows
- periods of higher Victorian demand.

During these periods, while there was still a significant quantity of supply coming south from Queensland — albeit there was demand for even more — this was largely providing gas into New South Wales with limited amounts flowing down to Victoria.

Figure 8 highlights these dynamics and their contribution to high prices over May, along with the use of the Iona storage facility to manage the peak periods of pricing pressure.

Figure 8 Domestic spot market price drivers during high price periods over May 2023



Note: The local and international prices chart shows prices in relevant spot markets, highlighting periods of high prices. The Longford production chart shows output from Longford's output compared to its capacity, highlighting periods where output was limited by capacity constraints. The interstate gas flows chart shows how the resulting supply limitations in Victoria translated to changing gas flows on key interconnectors. Positive numbers for VNI (Victorian NSW Interconnect) and QSN Link (Queensland-South Australia-NSW) represent flows moving gas north, with negative numbers indicating flows south. The Victorian demand chart highlights that during several periods these constraints occurred during periods of high demand. The Iona storage chart finally shows that, in response to the interaction of supply and transportation constraints and high demand, participants drew down supplies from Iona and replenished supplies when possible.

Source: AER analysis using downstream market data (DWGM and STTM), Argus ANEA prices, and Bulletin Board data.

Table 1 summarises key factors in each of the highlighted periods.

Table 1 Factors impacting gas spot market prices over May 2023

Period	Local factors	Upstream factors
1	An unplanned offshore compressor outage resulted in lower-than-expected Longford production and delayed planned maintenance. The facility did not ramp up closer to its expected capacity level (the target level during maintenance, still below full capacity) until after 10 May. The lower production output reduced available cheap supply, putting upward pressure on prices in Victoria with the effects flowing through to other markets.	Moomba to Sydney Pipeline (MSP) flows were constrained to 320 TJ per day, below its 445 TJ regular capacity. This limited the ability of participants in the south to source gas from upstream hubs in the north. The Day Ahead Auction for MSP transportation capacity was often fully subscribed across the month, indicating short-term transportation capacity was difficult to access. Although southern flows exceeded levels observed over May in previous years, and were above levels usually seen during winter, these constraints also put upward pressure on prices.
2&3	Cold weather drove higher Victorian demand. Longford supply increased, but not enough to offset the higher demand.	Pipeline constraints continued to limit access of southern markets to northern gas.
4	Longford was again producing at further reduced capacity, limiting supply into Victoria and putting upward pressure on the price of gas offered on the Eastern Gas Pipeline into Sydney.[2]	Constrained MSP supply impacted quantities scheduled in the Sydney Short Term Trading Market hub, preventing cheaper gas offered by participants from being scheduled and driving prices as high as $30/GJ.

Source: AER analysis using downstream market data (DWGM and STTM), Argus ANEA prices, and Bulletin Board data.

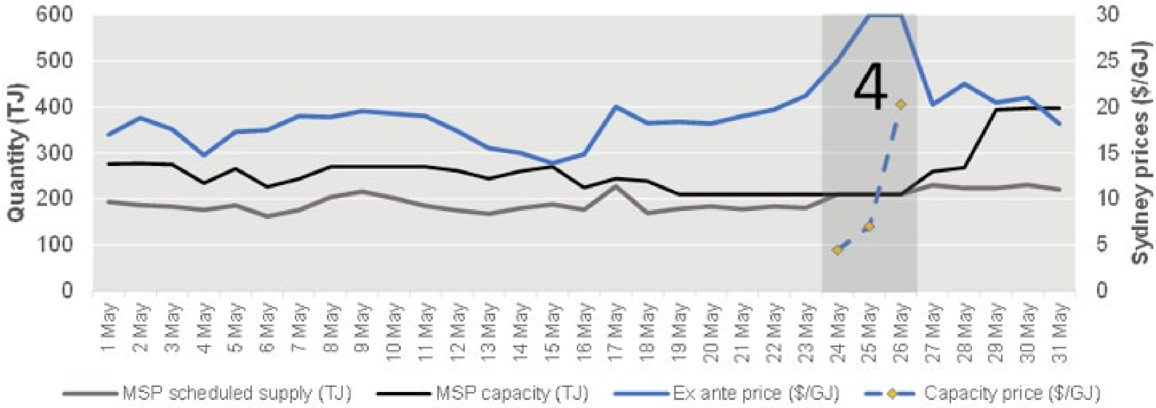
As a result of this combination of factors, participants drew down on Iona storage volumes, which provided around 2 PJ of gas to fill the supply gap. However, during periods of reduced demand and lower prices, storage volumes were replenished by roughly 0.5PJ by the end of May. Consequently, the facility is better equipped to assist participants managing winter peak days compared to this time last year.

The highest prices across any of the markets ($30/GJ) occurred in the Sydney Short Term Trading Market over 24–26 May. These peak prices occurred when scheduled supply on the Moomba to Sydney pipeline hit maximum capacity over 24 to 26 May, driving up both the

[2] Eastern Gas Pipeline (EGP) offers over 24-26 May between $0-15/GJ were significantly lower than previous days in May, coinciding with constrained Longford supply.

price of capacity as well as the market price (Figure 9). This meant that the Short Term Trading Market capacity constraint applied on this pipeline over that period.[3]

Figure 9 Impact of the Short Term Trading Market capacity constraint applied on the Moomba to Sydney pipeline



Note: The '4' in this chart identifies how the timing of this event aligned with the periods highlighted in Figure 8.
Source: AER analysis, Sydney STTM data.

Since May:

- Capacity on the Moomba to Sydney pipeline increased near the end of May, with the pipeline's capacity rising to 475 TJ per day (up 30 TJ from its previous nameplate rating).[4]
- Longford output increased but is in a longer-term trend of decline as gas fields are depleted. In its Winter Readiness Plan, AEMO forecast maximum 2023 winter output from Longford to be lower than its output over winter 2022. Importantly though, the forecast for 2023 was materially above what was anticipated in development of the 2022 Gas Statement of Opportunities.[5]

Gas Supply Hub trade was strong for a Q2 but there was little forward trade

Trade on the Gas Supply Hub was again strong over Q2, supported by record Q2 transportation capacity won on the day-ahead auction (Figure 10).

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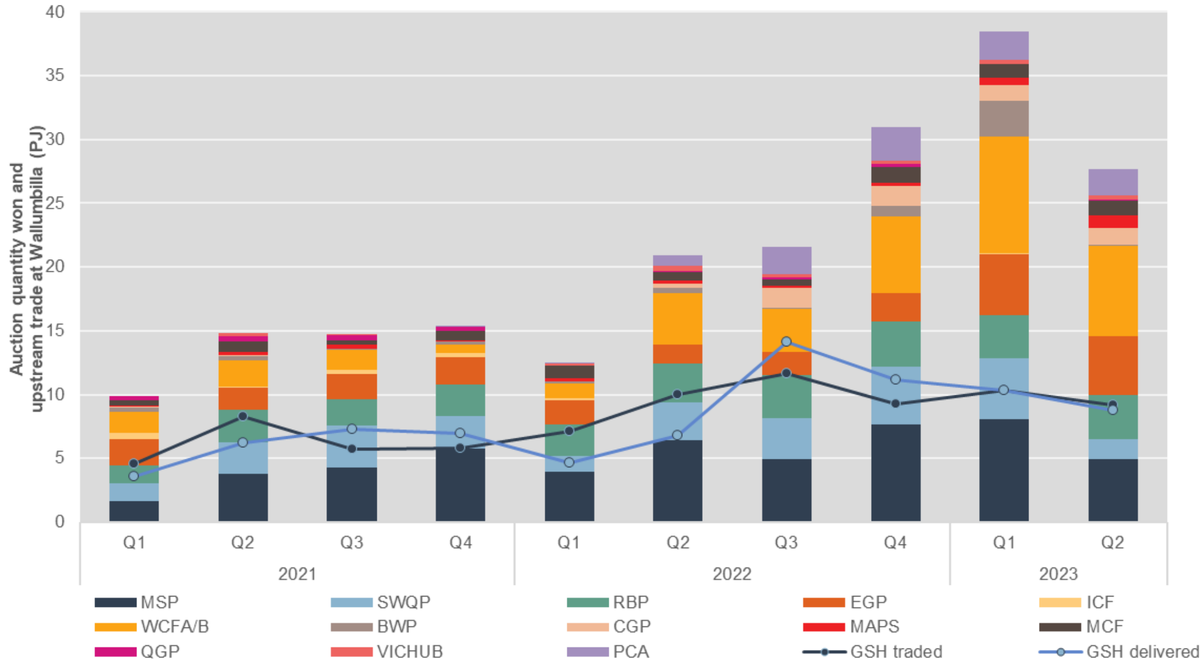
[3] The Capacity Constraint Price (CCP) forms part of a mechanism used to compensate shippers with firm transportation rights when unscheduled firm quantities resulting from constrained flows occur alongside scheduled as-available supply. On 24-26 May, CCPs impacted around 20-25 TJ per day, where shippers on as-available contracts compensated firm shippers (paying up to $20/GJ on 26 May).

[4] The Stage 1 expansion of the Moomba to Sydney Pipeline (MSP) was completed on 28 May, increasing the Sydney STTM daily delivery capacity to around 400 TJ. The South West Queensland Pipeline (SWQP) segment of the East Coast Grid project also increased capacity to flow gas south from Queensland in June, raising supply capability of gas coming from Reedy Creek by 49TJ to 453 TJ per day.

[5] AEMO, [Winter gas outlook—Winter 2023 adequacy](), May 2023.

Figure 10 Day ahead auction transportation capacity won and gas supply hub trades



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

In Q2 2023, approaching winter, there was very little forward trade through the Gas Supply Hub. This is markedly different from the same period in 2021 and 2022, during which trade at the Wallumbilla Gas Supply Hub materially exceeded gas delivered at that hub. This indicates a substantial volume of forward trade, which suggests participants sought lock in gas supply approaching winter. Less contracted gas suggests there may be greater reliance on spot market trade to meet demand over winter.

Most Gas Supply Hub trade exempt from the price cap

Over Q2, most gas trade on the Gas Supply Hub was exempt from the $12 per GJ price cap due to:

- trade being for delivery within three days and therefore being exempt; or
- trading participants being exempt either by type (i.e. not being Producers) or through being granted exemptions.

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

On 23 December, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months.[6]

- The Order introduces a price cap on gas of $12 per GJ (and does not apply in Western Australia).
- Generally, the price cap applies to gas producers and affiliates of gas producers.
- There are several exceptions (including gas to be exported as LNG, retailers that meet certain criteria, trades on the Short Term Trading Markets (STTMs) or Declared Wholesale Gas Market (DWGM), near-term (next 3 day) trades and offers on the Gas Supply Hub Exchange).[7]

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

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

Because Short Term Trading Markets and the Declared Wholesale Gas Market are exempt, the $12 per GJ price cap is able to exert downward pressure on prices directly through:

- bilateral sales of any length from non-exempt participants
- longer-term trade by non-exempt participants on the Gas Supply Hub.

Over Q2, there were relatively low levels of forward trade on the Gas Supply Hub with nearly all trade being for intra-day or next day delivery (i.e. 'near-term' trade for the purposes of exemptions). [9] This is a marked change from trading patterns observed in previous years, where Gas Supply Hub trade typically included a higher proportion of monthly, weekly trades and also daily trades in "strips" over bespoke periods e.g. 10 days. Over the year we have observed that the percentage of trade through the Gas Supply Hub to which the price cap does not apply consistently exceeds 80%.

There have been specific domestic factors which might explain at least some part of the proportional increase in shorter-term trading compared to longer-term contracting. For example, in March, growth in near-term trading appeared to be driven by increased short-term gas availability during unplanned LNG outages. In addition over May, when prices in downstream markets — which are exclusively near-term — reached $30 per GJ, producers faced financial incentives to sell into these markets at prices above $12 per GJ.[10] The relatively higher proportion of near-term trade on the Gas Supply Hub may also be influenced

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

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

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

[9] Overall Gas Supply Hub trade for Q2 2023 was 9.2 PJ compared to 10 PJ in Q2 2022.

[10] Producer/exporters selling near-term exempted products received an average price of $16.66 per GJ during May 2023.

by producers choosing to conduct near-term trade on the hub, where it is exempt from the cap, rather than bilaterally, where it is not.

Similarly, of the upstream trade outside the Gas Supply Hub reported on the Gas Bulletin Board, in this quarter there were relatively lower volumes of forward sales for Q3 2023. This is markedly different to March (during Q1) in which large volumes of gas were traded bilaterally at $12 per GJ by Producers covered by the price cap.[11] Q1 forward trades included both gas for delivery over the winter months as well as deliveries in Q4 2023. They appeared to include the volumes from the January expression of interest by Shell's QGC business to sell 8 PJ of gas for delivery in 2023.[12]

[11] In March 2023 almost 2.7 PJ was traded for delivery in Q3 2023, while in the whole of Q2 2023 only 0.82 PJ was traded for delivery in Q3 2023.

[12] Shell, Shell announces expression of interest for domestic customers, 23 January 2023.

3 Electricity and gas market outlooks over winter are better than winter 2022

Electricity forward prices fell in Q3 2023 but increased in Q1 and Q2 2024

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

The same drivers that saw lower than expected spot prices in Q2 2023 contributed to a fall in Q3 2023 base future prices (Figure 11). These included warmer than expected winter temperatures and increased wind output (discussed in Chapter 1). With a strong chance of El Nino conditions returning, the Bureau of Meteorology indicated a greater chance of above average temperatures this winter.[13] Added to this, the ongoing impact of coal market interventions and stable gas prices (supported by good storage levels) are also expected to contribute to lower Q3 2023 spot and base future prices.

Victoria experienced the most significant decrease, trading lower by $32 per MWh. NSW, South Australia and Queensland also saw falls while Q4 2023 base future prices remained stable.

In contrast to Q3 2023, base future prices in Q1 and Q2 2024 increased, particularly in Queensland, but also NSW and South Australia. The Queensland cap price for Q1 2024 also saw a significant increase during Q2 2023, rising by $28 per MWh or around 62%. This likely reflected the potential risks of volatile spot prices in Q1 2024.

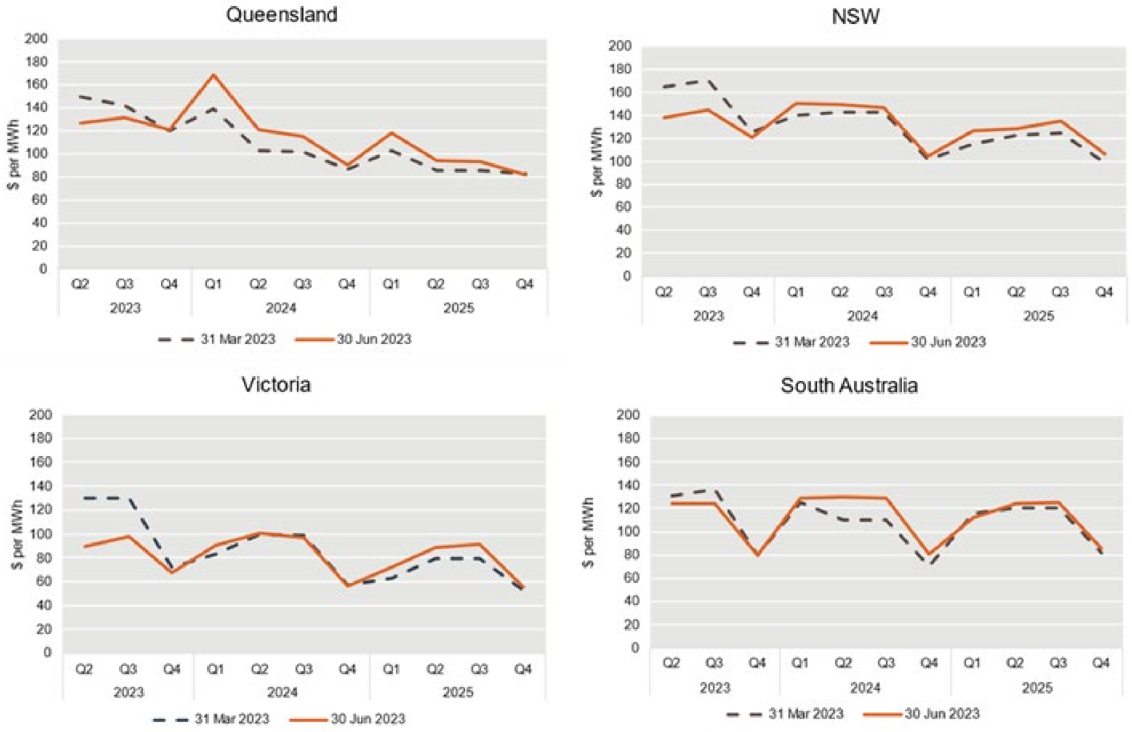
These increases to both the base futures price and cap price are likely the result of the following factors:

- The announcement in late May indicating the return to service of the Callide Units 3 and 4 would be further delayed. Unit 3 is now expected to return to service commencing in early 2024 and Unit 4 is expected to return between May and July 2024.
- Expectations regarding the continuing El Nino weather pattern resulting in higher-than-expected summer temperatures and lower than average rainfall is also likely contributing to increases in Q1 and Q2 2024 base future prices. The relationship between high temperatures and high price events during Q1 2023 can be seen in the latest AER report on prices greater than $5,000 per MWh.[14]
- Unplanned outages, interconnector and transmission constraints, and variability in renewable generation increase the risk incorporated into the forward prices.

[13] Bureau of meteorology, Overview—Summary - Climate Outlooks, accessed 6 July 2023.

[14] AER, Prices above $5,000/MWh - January to March 2023, June 2023.

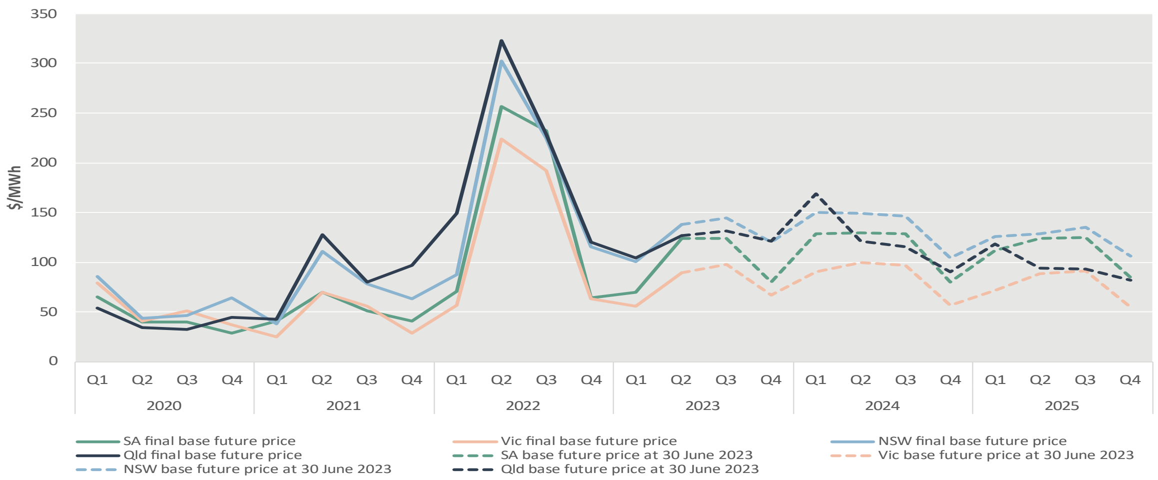
Figure 11 Base quarterly electricity futures prices



Source: AER analysis using ASX data

Despite these increases, forward quarterly base futures prices are well below levels seen in Q2 2022 (Figure 12).

Figure 12 Forward base future prices remain well below those seen in 2022



Note: Prices for Q1 2019 to Q2 2023 base futures are final base future prices. Prices for Q3 2023 base futures and beyond are as at 4 July 2023.
Source: AER analysis using ASX data.

Liddell coal station exited the NEM in April

In April, the last 3 units of Liddell coal station exited the NEM removing 1,500 MW of baseload capacity (Box 2). The units were turned off on 24, 26 and 28 April.

Box 2: After 52 years, Liddell power station exits the NEM

Liddell Power Station was commissioned from 1971 – 1973. At the time, with 4 units capable of generating 500 MW of capacity each, it was Australia's biggest generator. Liddell operated for over 50 years before unit 3 closed in April 2022 and the remaining 3 units closed in April 2023.

As its closure date approached, Liddell began to operate at lower capacity, typically generating around 800 MW on average in its final months. Nevertheless, its exit constitutes a significant reduction in NEM baseload capacity.

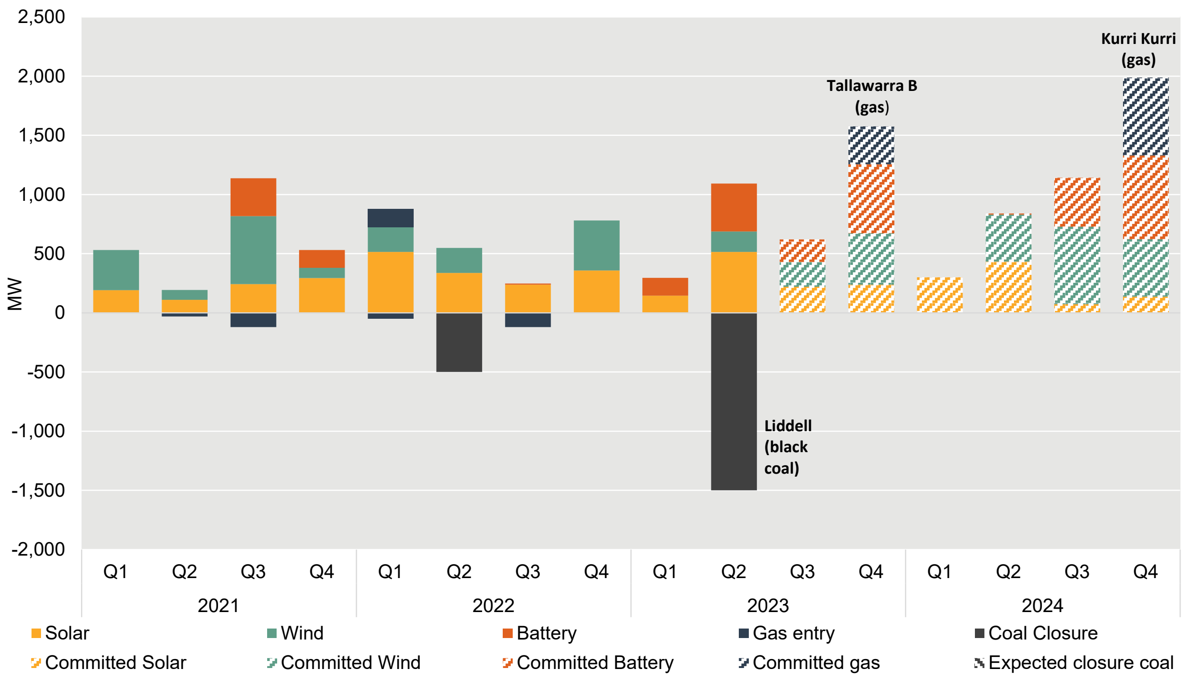
For NSW, which is already a net importing region, there is now less capacity available – particularly on less windy evenings. The region is now more vulnerable to constraints limiting imports from other regions and to outages among the remaining coal generator fleet.

Over coming quarters, significant new generation will come online. But while Liddell represented dispatchable, baseload power, much of the new generation is intermittent with output dependent on sunny or windy weather conditions. This new capacity needs to be backed by storage (such as batteries or pumped hydro) or by dispatchable peaking generation (such as gas) to meet energy demand in the market.

The transition is well underway, with numerous battery and pumped hydro projects in progress, as well as two new gas plants. AGL itself has plans to build a 500 MW battery at the site of the closed Liddell power station. This investment will need to continue and accelerate as coal power stations continue to exit the market over the coming years.

The exit of Liddell was partly offset by the entry of about 500 MW of solar, 170 MW of wind and 400 MW of batteries during the quarter for a total of around 1,100 MW of new capacity.

Figure 13 New entry and exit



Note: Uses registered capacity, except for solar and batteries where we use maximum capacity. The new entry date is taken as the first day the station produces energy. Solar reflects large scale solar and does not include

rooftop solar. The 3 units of Liddell had a registered capacity of 1,500 MW but were not producing at full capacity in the months leading up to closure.
Source: AER analysis using AEMO Generator Information.

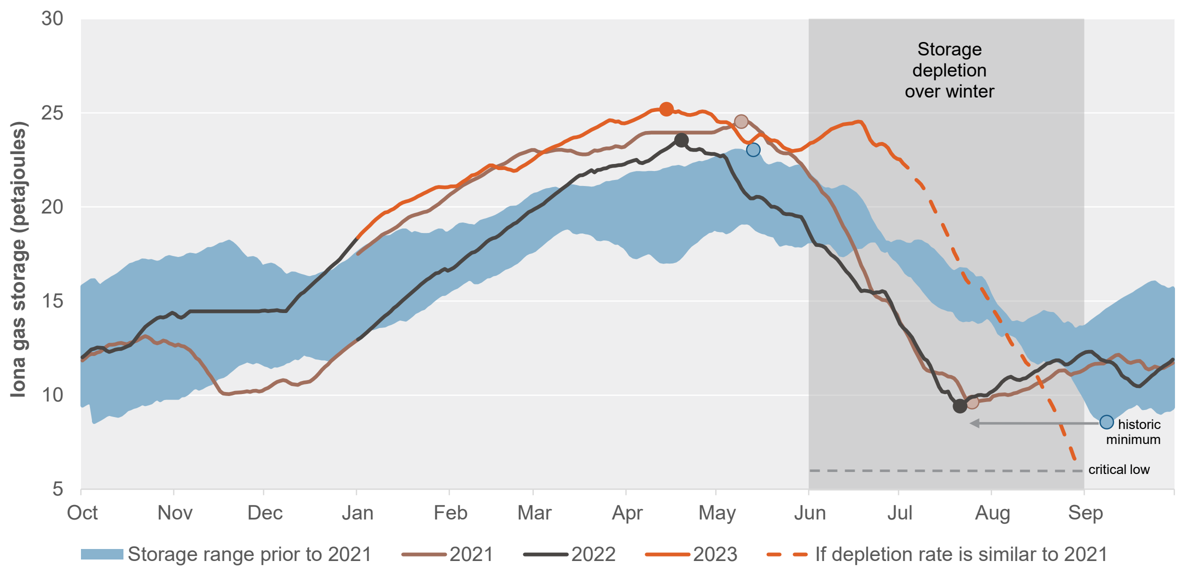
Looking forward, AEMO anticipates up to 5 GW of new wind, solar and battery capacity will enter the NEM by the end of 2024. In addition, the 320 MW Tallawarra B gas power station is planned to come online in Q4 2023, while the 660 MW Kurri Kurri gas power station is planned to come online in Q4 2024.

Iona storage ended Q2 at its highest ever level

In Q2, Iona experienced a much smaller than usual drawdown, assisted by lower-than-usual June demand. Its volume in storage declined only slightly from the record high in Q1, and as a result Iona enters Q3 with close-to-full storage. This is important for Victorian Gas Markets, which typically need excess supply from the facility during winter months.

Highlighting this, Iona has experienced a net-drawdown in Q3 for the last 6 years. In July 2022, capacity was withdrawn at such a rate that AEMO was forced to intervene, preventing levels falling below 6PJ at which level pressure constraints limit the rate at which gas can be delivered to market. With a larger than usual gas stockpile this year, the Iona storage facility is better equipped to supplement supply during such risk events than in previous quarters. Even if draw-down of storage mirrors the notably fast draw-down in 2021, Iona would not reach the 6PJ threshold over the remainder of Winter (Figure 14).

Figure 14 Iona underground gas storage levels in Victoria



Note: The dotted orange line illustrates the hypothetical draw-down of Iona over winter if gas was withdrawn in line with the rate over winter 2021—during which there was a notably fast draw-down.
Source: AER analysis using Gas Bulletin Board data.

New reporting improved transparency of bilateral gas trade including forward price expectations

New gas market transparency measures, which commenced in March, make possible greater insights into East Coast bilateral trades. That is trade directly between parties, conducted outside of the AEMO-facilitated markets.[15] This information materially improves the comprehensiveness of data available on gas trade up to a year in length, of which bilateral trade is the majority.

Of this newly reported trade, the volume weighted average price for gas delivered in Q2 2023 was $13.8 per GJ. Prices of individual trades for delivery over Q3 and Q4 2023 varied between $13.1 per GJ and $15.2 per GJ (Table 2). This suggests price expectations over the remainder of 2023 in line with the range of trades observed over Q2 2023.

Looking forward at reported transactions into 2024 and as far out as 2027, prices have been reported closer to $18 per GJ, materially above current levels. This could suggest market expectations of enduring upward price pressures. However, it may also indicate that buyers have been willing to pay a premium to secure longer-term gas.

Table 2 Forward pricing for short term supply transactions

Period	VWA ($ per GJ)	Range ($ per GJ)	Delivered quantity (PJ)
Q2 2023	13.8	11.5 – 16.2	10.7
Q3 2023	14.7	13.1 – 15.3	7.5
Q4 2023	13.9	13.2 – 14.2	9.6
2024	17.5	16.2 – 19.1	13.1
2025-2027	17.7	16.9 – 18	4.6

Note: The above prices and quantities are based on the actual delivered dates of the reported transactions and include all reported supply transactions and pricing structures. The VWA price range is the minimum and maximum price accounting for all transactions on specific days of trade within that period.
Source: AER analysis using Natural Gas Services Bulletin Board data.

As this data comes from a new set of reporting requirements, we are still testing initial reporting and working to understand how participants are approaching the requirements (Box 3). We will supplement this with a standalone report in Q4 to provide more insights and transparency into the short term bi-lateral trades and swaps now being reported on.

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

Box 3: AER observations of short term transactions reporting to the Bulletin Board

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in east coast gas markets. One of the priorities for the 2023-24 related to gas markets is to:[16]

- Clarify obligations and monitor compliance with reporting requirements under the new Gas Market Transparency Measures.

The AER is working closely with AEMO and market participants to ensure accurate reporting of short-term transactions to the Bulletin Board. In May the AER engaged with several market participants to clarify some of the reporting observed. The following observations highlight some of the issues we have identified which may impact the comparability of reporting, and the accuracy of insights set out in this section:

- Some transactions have initially not been reported to AEMO mostly related to late registrations. Where possible, participants have started to retrospectively report these transactions.
- We have identified errors in participant's reporting related to prices and pricing structures including misreporting of $0 prices (subsequently amended)
- We have observed participants amending or even cancelling reported transactions, in line with changes in contractual outcomes. This however underscores that prices and volumes reported are accurate at a point in time.
- Both sides of swap transactions have in some instances not been reported and in other cases it appears some counter parties have incorrectly reported swap transactions as supply transactions.
- Participants have often not provided information on the pricing structure to AEMO. We have assumed that non reporting of this information reflects fixed price agreements. In speaking to participants, it has mostly been confirmed that this is the correct assumption, but we requested participants where possible to provide this information more explicitly in their reporting to ensure more accurate price reporting.
- Some transactions reported are part of master sale agreements where fixed prices (over $12 per GJ) were agreed to before the $12 price cap commenced[17]. Prices reported are therefore not purely reflecting current market conditions.
- Other transaction pricing has been linked to agreements struck before the price cap to link volumes requested to downstream spot market prices – this pricing also has been above $12 and not necessarily reflective of prices which could be charged under new contracts under the price cap[18].

We will continue to work with participants over the coming months to ensure reporting quality and accuracy.

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[16] AER, AER compliance and enforcement priorities 2023–24, June 2023.

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

[18] A set of transactions was also linked to an Oil Price, no pricing linked to JKM has so far been reported.

As well as offering insights into forward trade, the trades reported so far since commencement of these reporting requirements on 15 March 2023 suggest that: [19]

- Most upstream trade takes place bilaterally — outside of the AEMO facilitated markets. Participants reported to the Bulletin Board supply transactions totalling 47 PJ compared to only 12.4 PJ traded through the GSH.[20]
- Producers (56%) and GPG Gentailers (40%) sold the highest volumes of gas through reported bilateral trade. [21]
- GPG Gentailers have been the most active buyers of gas (58%), with a further 20% sold to Industrials, 13% sold to Retailers and the remainder almost equally split between Traders and Producers.[22]
- Participants make extensive use of swaps, which they are also required to report. Almost 26 PJ of swap transactions were reported to the Bulletin Board so far.[23]
- The majority of swap transactions are location swaps within Queensland as well as between Queensland and Victoria where the majority of East Coast gas production is concentrated.[24] In May, when Longford experienced production constraints coupled with constraints on the MSP and higher demand, we observed swap transactions between Wallumbilla and delivery locations into the southern states that facilitated moving gas from north to south.

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[19] This comparison is based on all trades between 15 March 2023 and 30 June 2023 reported as a short term transaction to the Bulletin Board or traded through the GSH.

[20] 30.4 of the 47 PJ reported in 2023 are for delivery in 2023.

[21] In this category, Energy Australia, Origin and Shell by volume sold the most and reflected almost 80% of Gentailer sales; the other participants the AER classified as Gentailers are Alinta, AGL, CleanCo, Engie and Hydro Tasmania.

[22] This category of Retailers includes mostly smaller retailers not classified as Gentailers which don't have generation assets with the highest purchases by Sumo Gas, Pacific Blue Retail and Tas Gas Retail.

[23] Sellers when reporting short term transactions to the Bulletin Board are required to identify if it is a supply transaction, location swap, time swap or swap of both time and location. Both parties to a swap transaction are required to report the transaction with the associated location and price information attached to the swap transaction.

[24] The most popular swap locations in Queensland are the Wallumbilla high pressure trading point and the Roma to Brisbane in pipe trading point, while in Victoria most location swaps are at Longford. In New South Wales most of the location swaps are to Wilton, a delivery point into the Sydney STTM.