Wholesale Markets Quarterly

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AUSTRALIAN ENERGY REGULATOR

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Summary

Recent months have been the most tumultuous in the history of Australia's energy markets. International and domestic pressures combined to drive dramatic price increases in both the wholesale electricity and gas markets. The extent and persistence of high prices, which reached record levels in June and July, triggered protective price caps, market interventions and spot market suspensions.

The AER was requested to report into energy market dynamics to support the work of Energy Ministers in August 2022. This Wholesale markets quarterly not only incorporates an assessment of these markets in Q2 2022, but also contains some analysis of more recent outcomes.

An unprecedented quarter in interconnected markets

As international coal and gas prices climbed sharply (driven by the war in Ukraine), domestic fuel supply concerns and plant outages meant participants offered less energy into the market. Wind and solar output was also lower than expected, and a very early start to winter created higher than expected demand. This 'energy squeeze' combined to put pressure on hydroelectric and gas generation to offer more into the market at a time when hydro generators faced environmental constraints and gas spot market prices were at record highs.

In the NEM, generators offered less capacity when impacted by fuel supply issues or outages. There were also higher priced offers (particularly coal and gas) where these generators were exposed to higher coal and gas prices. This offer behaviour generally appeared to reflect these underlying market dynamics, however we are still undertaking analysis of participant behaviour. The interacting market shocks combined with a lack of current transparency into participant contract positions means that this analysis is complex.

In gas spot markets, the first and most acute impact on participant behaviour occurred in Sydney following the failure of Weston Energy. Participant bidding behaviour in the Sydney short term trading market (STTM) from June reflected a reluctance to offer gas beyond their own needs. Low storage levels at Iona storage facility in Victoria resulted in Victorian retailers preserving storage by pricing injections at $800/GJ and reducing total volumes offered into the market.

Prices in both the NEM and gas spot markets have moderated in recent weeks. As we come out of winter into spring, generators should be able to start rebuilding energy supplies. Gas spot markets have seen an increase in the volume of supply offered.

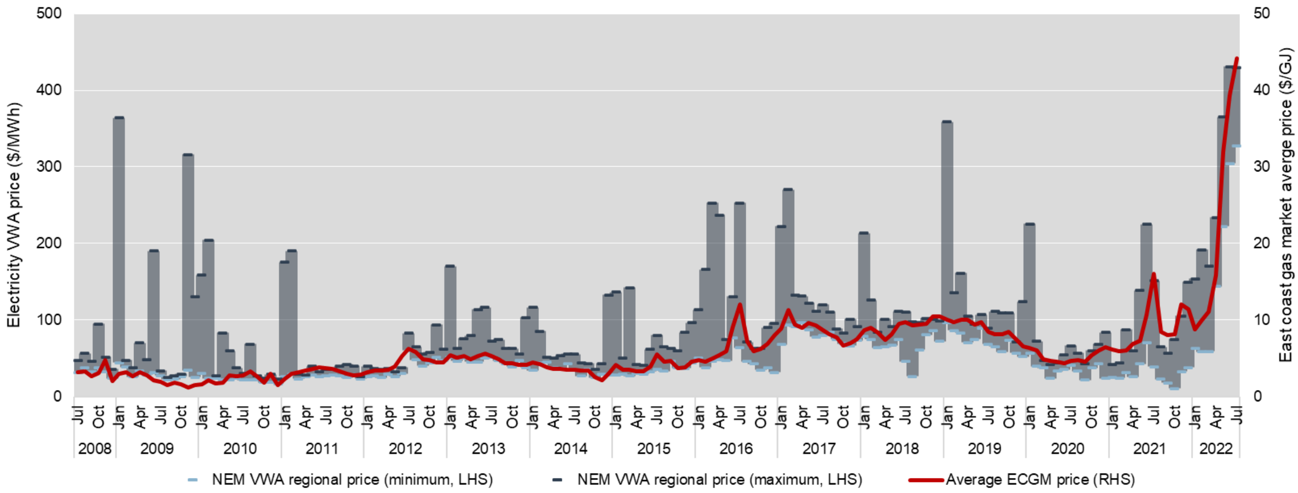
Still, expectations are for high prices to continue in coming years. High fuel costs are likely to continue as international coal and gas prices remain at historical highs. Generation closures, including the impending closure of Liddell power station in April 2023, and tight gas supply conditions, with a domestic gas supply shortfall projected for winter 2023, means that market conditions will remain challenging for some time.

1 Record high prices across all markets

1.1 Spot prices reached record highs in electricity and gas markets

Spot prices for east coast gas and electricity markets increased dramatically over Q2, reaching record levels in June and July (Figure 1.1). While intermittent regional price volatility is common, these high prices have continued for over 4 months and have impacted all regions.

Figure 1.1 Electricity and gas spot prices



Source: AER analysis using NEM data and gas data.

Note: The grey columns show the range of average monthly volume weighted wholesale electricity prices across the NEM regions. A large column illustrates a large variation between regions, while a short column shows prices are relatively similar across regions. NEM prices reflect the Administered Price Caps on prices (limiting prices to $300/MWh) from 15 to 24th June. The red line shows the average monthly east coast gas market (ECGM) prices. The prices in May onwards include periods of price setting and administered price caps.

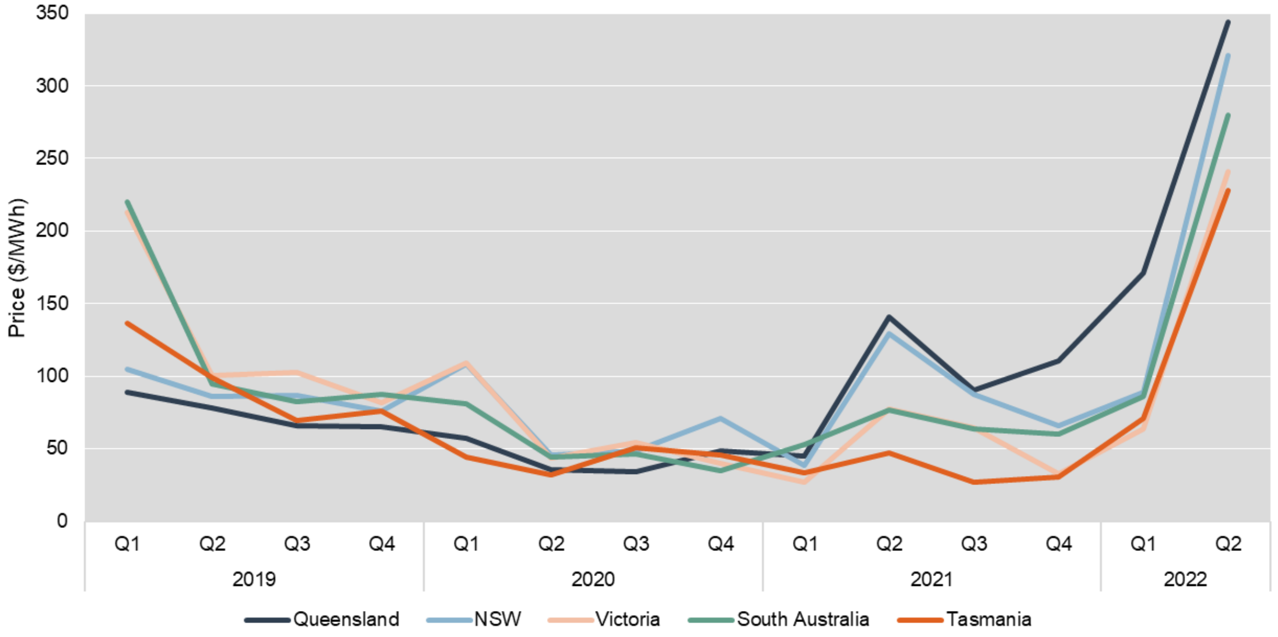
All trade in electricity markets takes place through the NEM, supported by contract markets, so these prices are likely to impact all participants and consumers either in the immediate or longer term as current contracts lapse. Similarly, all gas consumed within the Victorian and STTM gas markets must be traded through those markets, with this trade mostly supported by long-term contracts with producers to “fix” commodity prices—these contract prices are also increasing. Notably, some gas generators in the NEM over this period have reported needing to source gas from spot markets and so record high gas spot prices have been consequential.

1.2 High prices affected all NEM regions and trading hubs

High market average spot prices were driven by high prices in all NEM regions and trading hubs, rather than peaks confined to a subset of jurisdictions.

There has been sharp recent increase in average volume weighted prices across all NEM jurisdictions (Figure 1.2). In Q2, average quarterly prices reached record levels in all regions, ranging from $228/MWh in Tasmania to $344/MWh in Queensland.

Figure 1.2 Average quarterly electricity prices (VWA)

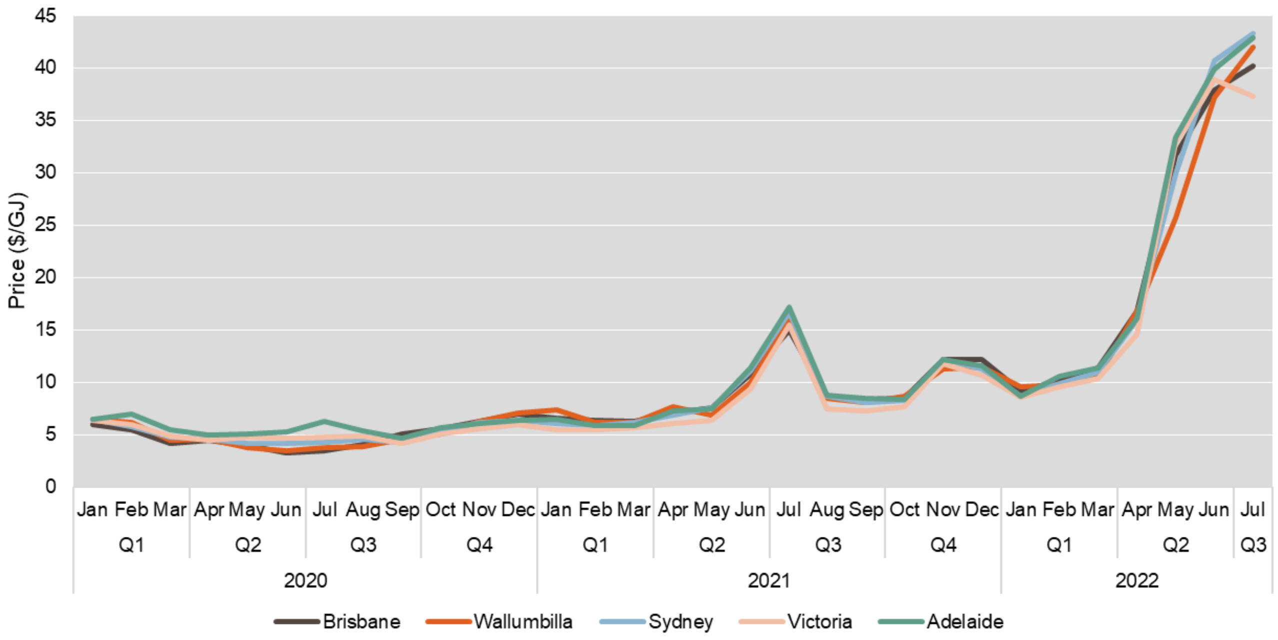


Source: AER analysis using NEM data.

Note: Volume weighted average 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.

Similarly, there have been sharp recent increases in gas spot prices, reaching record average prices exceeding $36/GJ in all regions (Figure 1.2).

Figure 1.3 Domestic gas spot prices



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

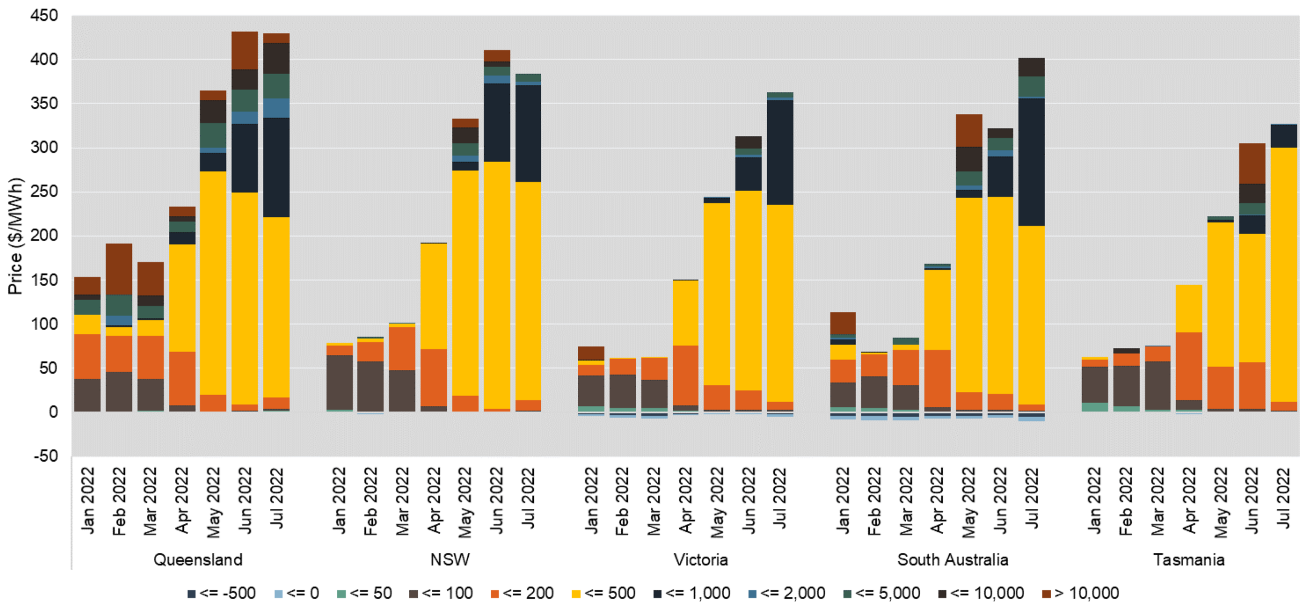
Note: The Wallumbilla price is the day-ahead price.

1.3 High prices driven by generally higher supply offers rather than narrow high-price events

In recent years, high average electricity prices have generally been driven by high price events (such as a small number of price spikes above $5,000/MWh). However, while this quarter did see some of these high price events, the high prices were largely driven by a steady increase in the number of prices between $200 - $1,000/MWh.

Figure 1.4 shows that average price has been increasingly made up of prices in $200-$500/MWh and $500-$1,000/MWh price bands. In contrast, historically most market prices have been below $100/MWh. There have been very few prices below $100/MWh in recent months.

Figure 1.4 Contribution to average price, by price band

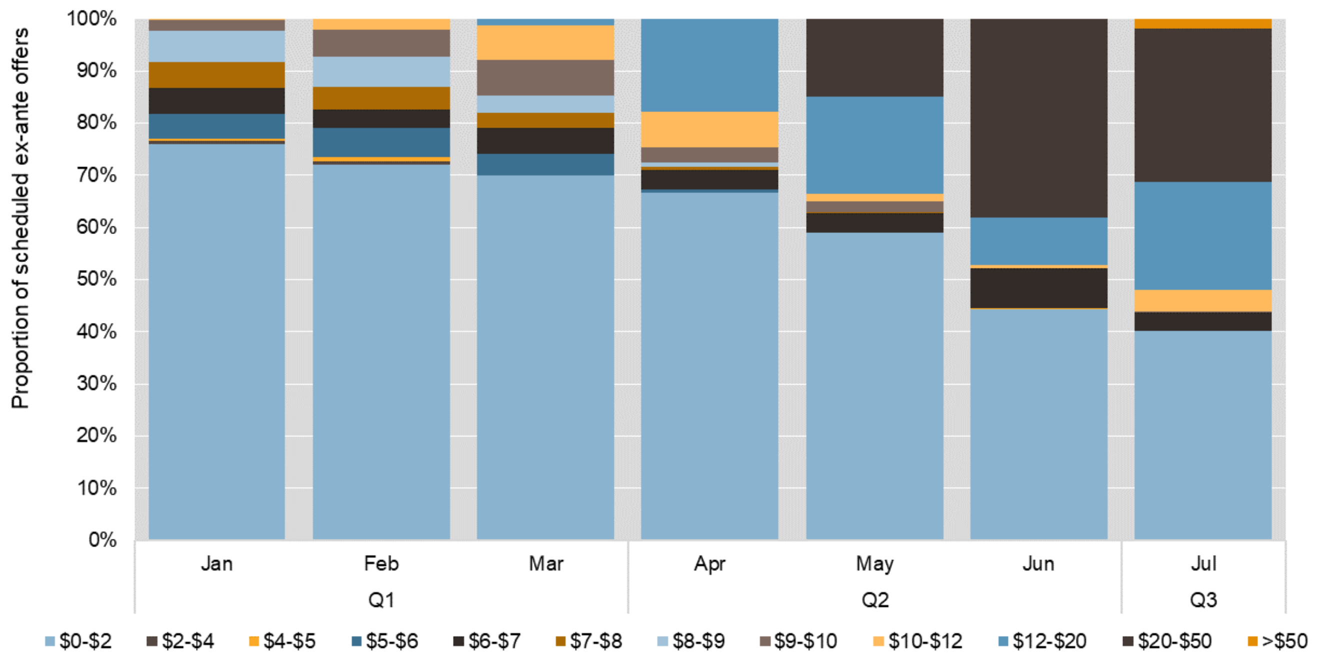


Source: AER analysis using NEM data.

Note: Shows extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in each region.

Figure 1.5 similarly shows that prices for gas in the Sydney STTM has been increasingly made up of participant supply offers in higher price ranges. The Sydney STTM has seen a significant decrease in the percentage of scheduled gas in the $0-$2/GJ offer range, most notably after April 2022. There has been an increase in scheduled gas offers in the $12-20/GJ and $20-50/GJ price bands in comparison to scheduled offers in January – April 2022.

Figure 1.5 Ex ante scheduled participant offers into Sydney STTM by price range



Source: AER analysis using STTM data.

Further, the volume of offers into the Sydney STTM reduced significantly after the Weston failure on 24 May. A key issue which industry highlighted in relation to the changed market behaviour was the uncertainty in the market during this period.

Retailers have indicated that during this period, there was a general sense of uncertainty and nervousness in offering gas into the market. There was uncertainty in relation to the outlook of gas prices as well as the possibility of retailer failures that would further impact their business. Most market participants offered gas into the Sydney market to cover their position however were reluctant to offer gas beyond their own requirements to cover for other participants' demand. Participants expressed their desire to retain the gas they had to supply their own customer load and gas-powered generation requirements.

1.4 Futures markets suggest these high prices were unanticipated, and will persist

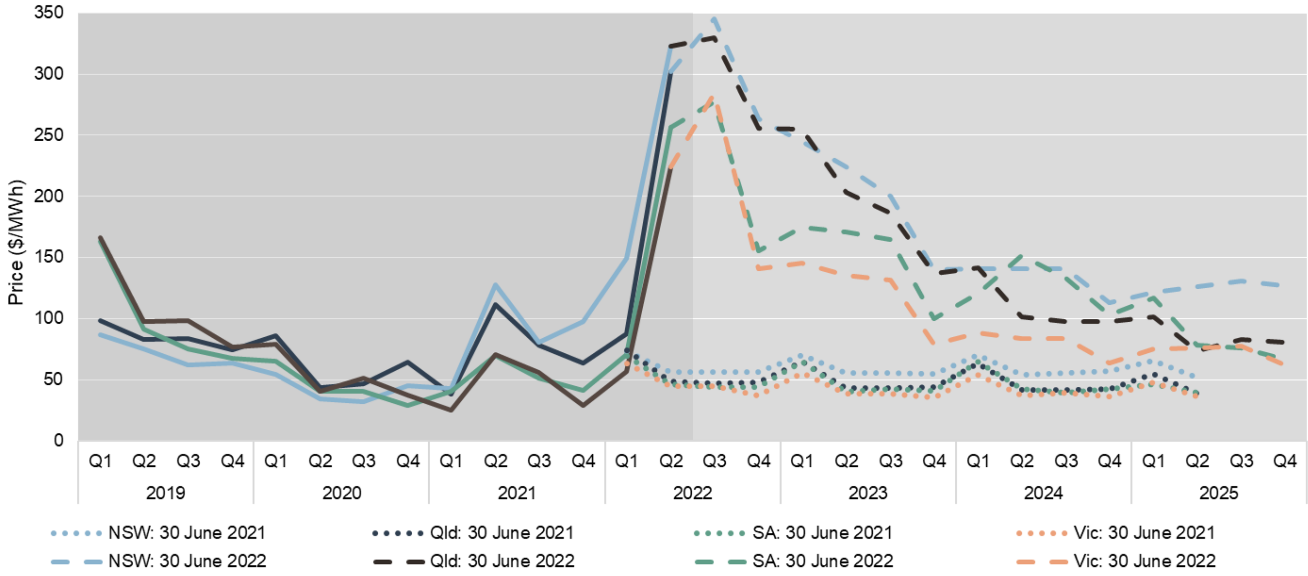
1.4.1 NEM contract markets

Publicly traded futures contracts suggest that recent high spot market prices were unanticipated by the market, have translated into much higher contract prices, and that these higher contract prices are likely to persist.

Figure 1.6 shows that:

- Contract prices for 2022-23 were low in June 2021 (the dotted line). This suggests that market participants did not anticipate the high prices that have eventuated.
- Contract prices for 2022-23 increased in April 2022 in response to the very high prices in the spot market and remained high as of June 2022 (the dashed line). Depending on the region, electricity base future contracts have increased by around 300-600% since the start of 2022.
- While prices for contracts beyond 2023 are more moderate, these contract prices were still trading at significantly higher prices in June 2022 than a year previously.

Figure 1.6 Electricity base future contracts



Source: AER analysis using ASX data.

Note: Daily settled price for Q2 2022 quarterly base futures.

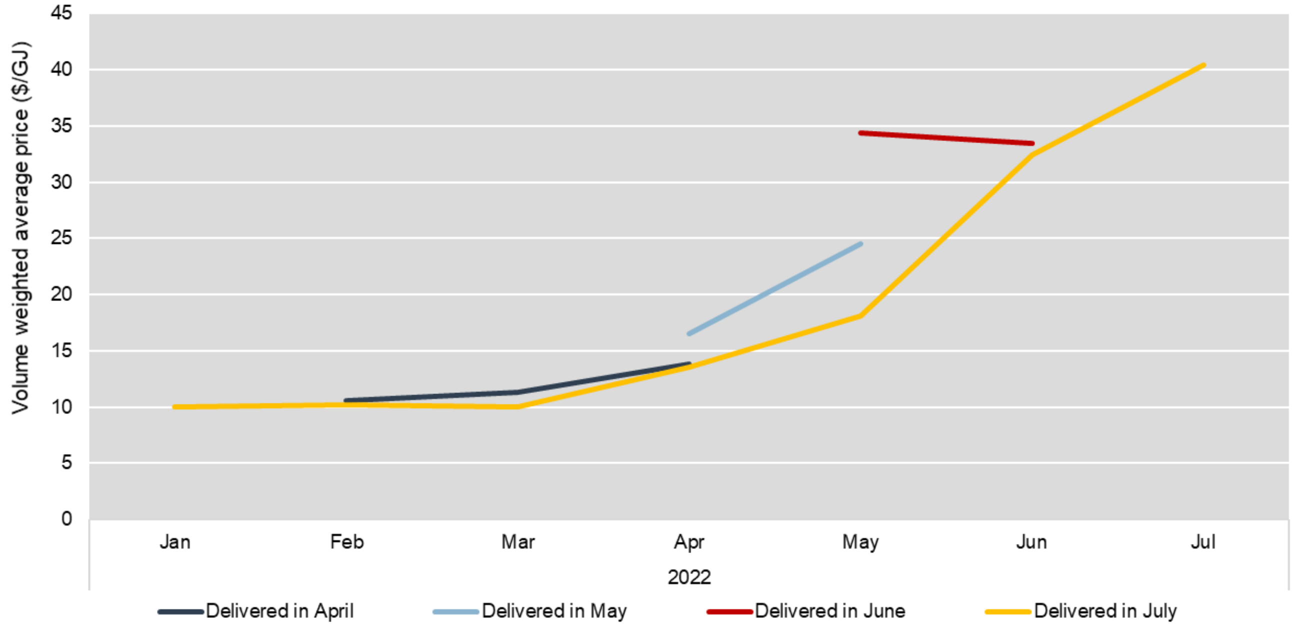
1.4.2 Forward gas prices

The Gas Supply Hub (GSH) exchange operates to facilitate the trade of gas supply up to 12 months in advance at Wallumbilla, adjacent to the east coast's largest source of gas production.

Although this exchange is lightly traded in comparison to long-term bilateral contracting for gas, it provides an indication of forward gas price trends. Gas prices appear to be rising for this quarter and future quarters.

Market participants who traded gas on the GSH during Q1 for delivery at Wallumbilla in Q2 did so before a jump in prices during the April – July period. Figure 1.7 shows that participants who waited until June to buy gas for delivery in July paid much higher prices than those who bought it earlier.

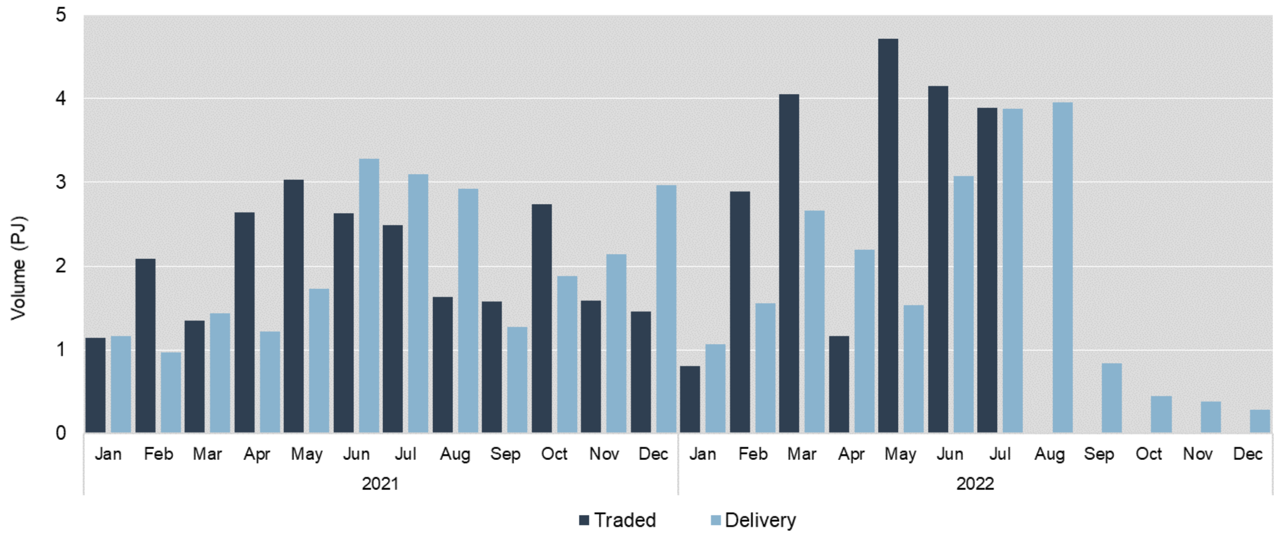
Figure 1.7 Gas traded on the Gas Supply Hub for delivery in April - July



Source: AER analysis using GSH data.

A record 4.7 PJ of gas was traded on the GSH in May 2022. Much of the volumes of gas traded in Q2 were for future delivery (Figure 1.8) with most recent trades for delivery in November and December 2022 being above $30/GJ, indicative of rising forward gas prices.

Figure 1.8 Gas Supply Hub – traded volume and volume for future delivery



Source: AER analysis of GSH data.

2 Market interventions and administered pricing

Beyond high prices, electricity and gas markets over Q2 were volatile, breaching administered pricing thresholds and requiring a series of extraordinary interventions to stabilise them.

In gas markets:

- Following the suspension of Weston Energy on 24 May from gas markets, the Sydney market was administered[1] with prices set (not capped) at ~$30/GJ due to Weston's large customer load. A subsequent emergency notice from the NSW government directed a change in this administered state to apply an Administered Price Cap (APC) of $40/GJ for 1 – 7 June.
- This subsequent change in pricing reduced the incentive for gas traders to direct gas away from Sydney toward other markets. The APC remained in place until 14 June as a result of cumulative prices exceeding the cumulative price threshold (CPT).
- Also as a result of Weston Energy's suspension, prices were capped in the Brisbane market at the APC at $40/GJ from 24 May – 7 June (10 business days).
- Unrelated directly to Weston Energy's suspension, prices in the Victorian market were also capped at $40/GJ from 30 May to 1 August because of high cumulative prices exceeding the CPT.
- AEMO twice conducted industry conferences (on 1 June and 19 July) under the Gas Supply Guarantee (GSG) to ensure adequacy of gas supply. These were the first two uses of the Gas Supply Guarantee.

In electricity markets:

- On 13 June, prices in Queensland, NSW, Victoria and South Australia were capped at $300/MWh due to high cumulative prices.
- Generators advised that they withdrew capacity after the implementation of this APC due to the high cost of coal and gas generation combined with concerns about fuel availability. The NEM was not able to handle this large withdrawal of capacity, with 406 separate Lack of Reserve (LOR) conditions declared by AEMO in Q2 2022, compared with 36 in Q1 2022 and 73 in Q2 2021.
- On 15 June, AEMO for the first time suspended the wholesale electricity market in all regions of the NEM. During this period, AEMO manually determined spot prices and allowed for participants to apply for compensation if those prices did not cover their costs.
- On 22 June, AEMO removed the $300/MWh administered price cap when the cumulative price fell below the threshold again. Participants returned their generation capacity to the market and AEMO lifted the market suspension the following day.

[1] Prices were set using a rolling average of previous daily prices over the past 30 days.

3 Drivers of high prices and market instability

A combination of factors have contributed to recent high gas and electricity prices. The impacts of these factors on prices were amplified by the fact that many of these drivers were occurring at the same time.

3.1 Significant NEM baseload generation was unavailable

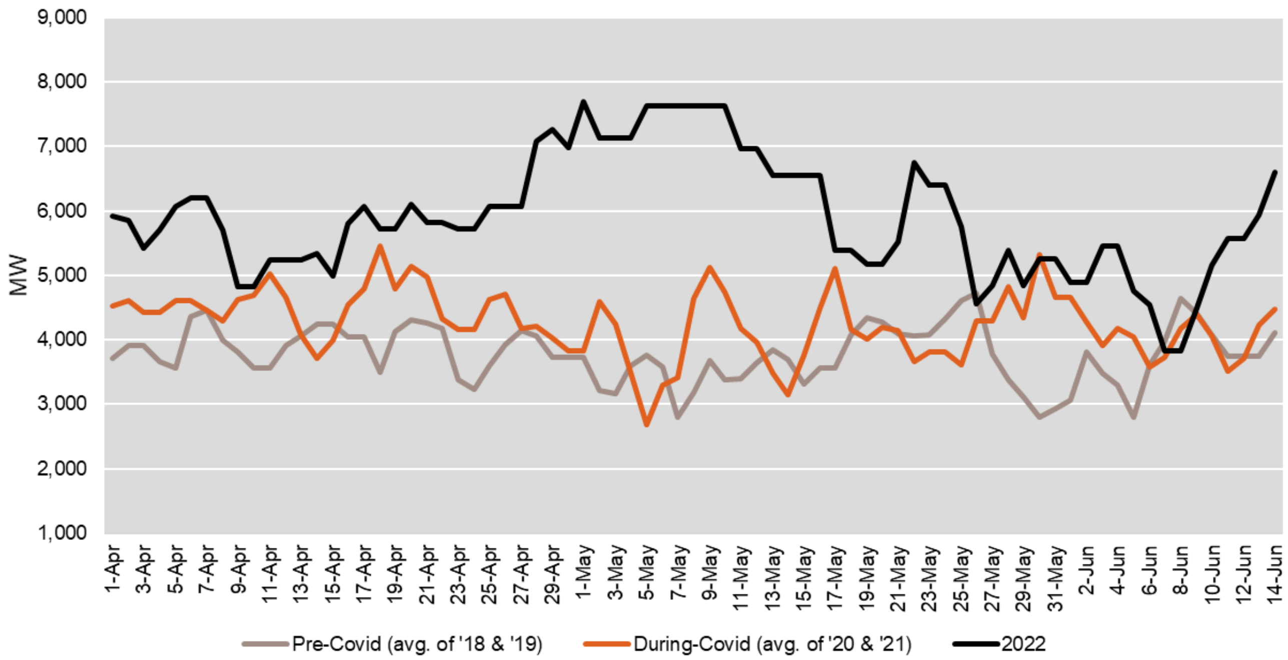
The majority of baseload generation capacity in the NEM is coal-fired generation.

Over Q2, a high level of scheduled and unscheduled coal generation outages--and to a lesser extent gas baseload outages—contributed to the tight supply conditions across several regions.

A high level of unexpected outages restricts available generation capacity, making the market less able to respond to shocks. It also means that more expensive generation may be required to meet demand more often.

To illustrate these impacts, Figure 3.1 sets out baseload outages across 3 time periods; pre-covid - 2018 and 2019, post covid - 2020 and 2021, and 2022.

Figure 3.1 Coal and baseload gas generation outage, Q2 comparisons



Source: AER analysis using NEM data.

Figure 3.1 highlights the significant level of coal generation outages in the NEM across April and May 2022. At times almost 8,000 MW of capacity was unavailable due to outages, much higher than in previous years.

While COVID changed some maintenance schedules, pushing more maintenance into 2022, overall outage levels in 2022 are still particularly high. Importantly, much of the coal-generation in the NEM is ageing and is becoming less reliable. This could be a factor in higher coal generation outages we have seen in 2022 and could be more of a factor in future years.

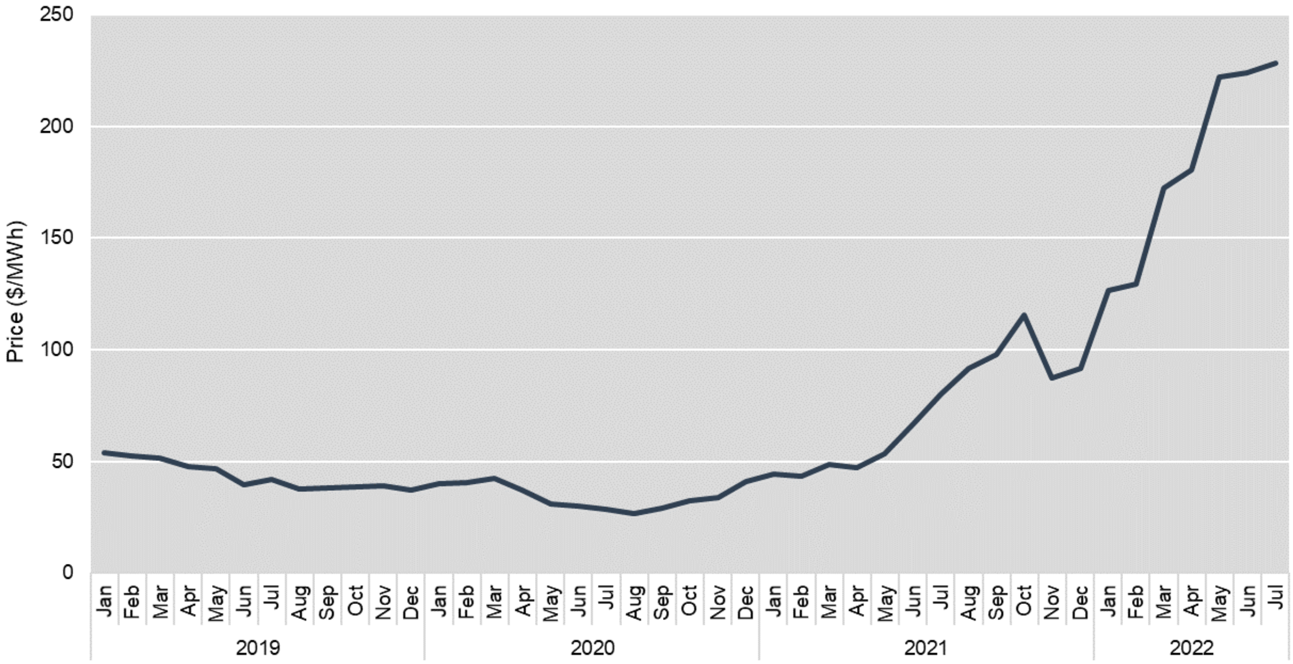
3.2 International fuel prices have increased sharply

International coal, LNG and oil prices have (often used as the price in longer-term gas contract pricing) increased significantly since late 2021 and remain elevated. This puts pressure on domestic fuel prices as exporters face stronger incentives to sell into international markets rather than supplying domestically.

3.2.1 Coal

Figure 3.2 shows the price of Newcastle coal (Australian export price) converted from price per tonne into an equivalent marginal cost to generate electricity (using a typical heat rate of 9t/MWh. It illustrates the marginal cost (i.e. the minimum price) for black coal generators to purchase spot market coal and sell into the NEM.

Figure 3.2 Newcastle coal prices



Source: AER analysis using GlobalCoal data.

Note: To convert coal prices from USD$ per tonne to AUD$ per MWh, we use the following formula: $ per MWh = coal cost (USD$ per tonne) x exchange rate (monthly average) x heat rate (GJ per MWh) / low heating value (GJ per tonne). For coal we use a constant heat rate of 9 GJ per MWh, and a low heating value of 23 GJ per tonne.

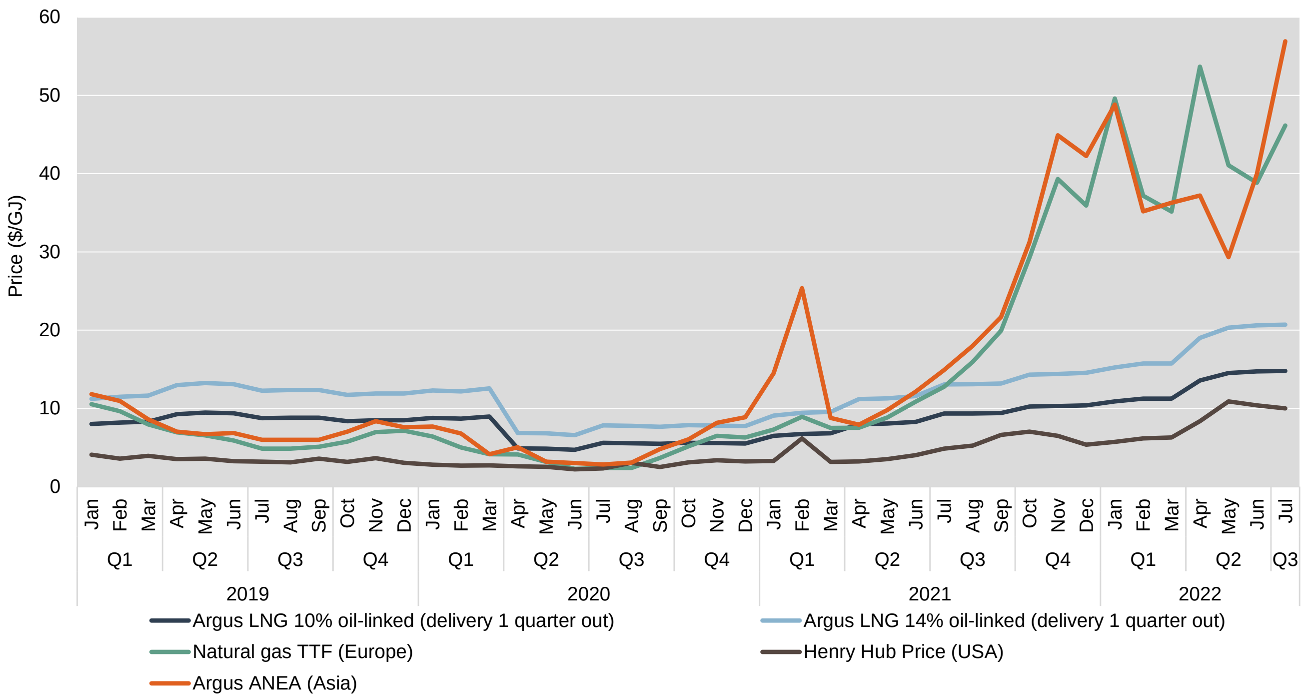
Figure 3.2 highlights that during the start of Covid and up to late 2020, the marginal cost to generate was below $50/MWh. However, as global economies emerged from Covid lockdowns, the demand for coal and the associated price has increased significantly. By June, the marginal cost to generate was above $225/MWh. This highlights that generators that need to source spot coal now require very high prices to generate.

3.2.2 LNG

Similar increases have occurred for international Liquefied Natural Gas (LNG) spot prices (Figure 3.3). The Asian gas price reached record levels in July and has continued to be volatile, ranging from $27.24/GJ to $63.12/GJ during April - July. Prices in Europe reached a daily maximum of $83.15/GJ during the same period.

International prices started out high in April, however dropped in May-June 2022. This coincided with the rebuild in European underground gas storage as flows from Russia to Europe remained stable. International prices increased again following the Freeport gas explosion which reduced US LNG exports. This occurred alongside reduced flows from Russia to Europe on the Nordstream 1 pipeline. In August, international prices have increased further, to record highs of $100.53/GJ in Europe and $77.16/GJ in Asia.

Figure 3.3 International gas and Brent oil prices



Source: AER analysis using Argus Media data and Bloomberg data.

Notes: 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.

The Argus Natural gas TTF price is a month ahead delivered spot price calculated at the Title Transfer Facility (TTF) in the Netherlands.

The Henry Hub price is the average of end of day natural gas spot prices traded on the Henry Hub – sourced from Bloomberg.

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3.3 Supply constraints

3.3.1 Coal supply issues

In addition to there being outages, there were also coal supply issues for generators that were otherwise available. Figure 3.4 sets out a number of issues that arose resulting in issues with coal supply and ultimately coal stockpiles.

Figure 3.4 Coal supply issues

Under-delivery on contracts	• Numerous issues between individual mines not meeting forecast levels of deliveries to associated coal generators
Spot coal not readily substitutable	• There have been difficulties for some coal generators in replacing contracted coal/only limited mines sell coal that met the correct specifications
Logistic chains are a constraint	• Coal market is tight/logistic chains near capacity. Takes time to purchase coal and create new logistic chains (not instantly available)
Weather impacting coal quality	• Rain and floods
Low stockpiles	• This has resulted in a number of coal generators having dangerously low stock-piles going into winter and some having wet coal issues

Source: AER analysis.

Most coal generators operate coal stockpiles which allows for short term shocks to supply (such as wet season flooding) and for periods where generation demand may be particularly high and the logistics chain is unable to meet demand (for example across peak periods over summer and winter).

Due to the high outages in April, some individual plants operated at higher levels than anticipated. Coupled with supply distributions due to weather and technical issues with individual coal mines, stockpiles at some plants became dangerously low.

Similar to gas storage, not all of the stockpile will be usable; stockpiles generally require a minimum level to operate. A number of coal generators have told the AER that their stockpiles were forecast to drop below these minimum levels, and therefore these generators withdrew generation capacity, as they attempted to rebuild their stockpiles.

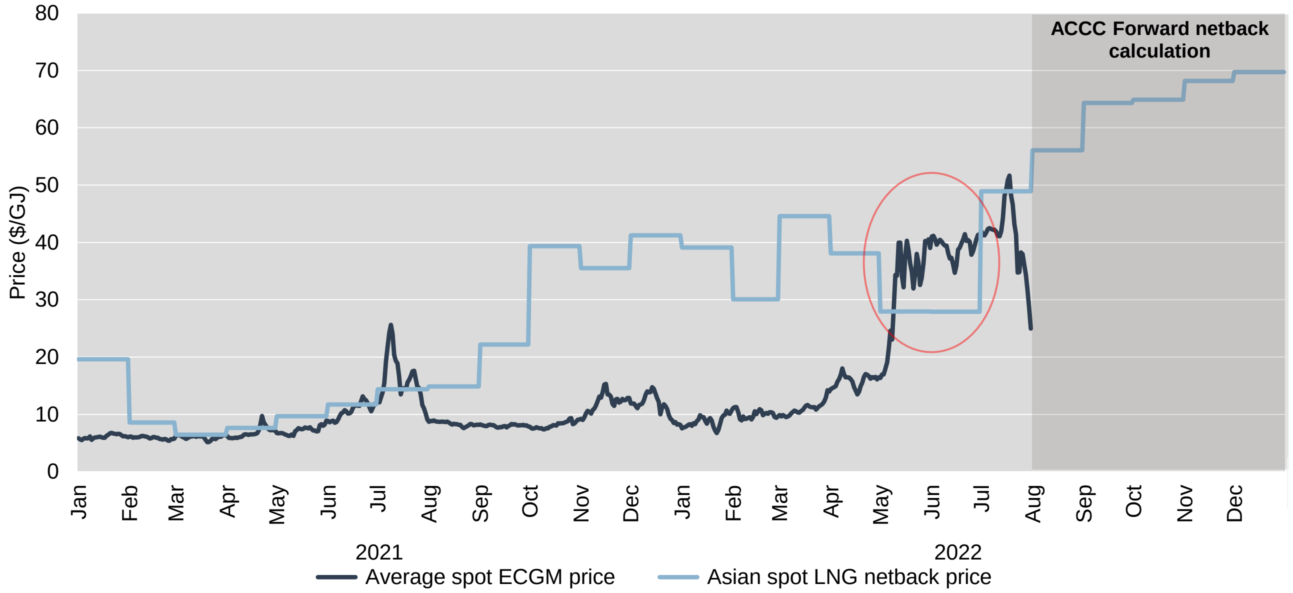
Further, individual plants are designed to operate with certain specified quality coal and each generator has its own unique logistic chain. Therefore, most coal generators have limited options to obtain additional coal. Coal unit stockpiles are not readily relocatable, so a plant outage also removes fuel from the system.

As discussed in section 3.2.1, the international price and demand for coal has also been very high. As a result, domestic coal mines have faced strong incentives to operate at capacity to supply the international market where possible. This further reduces the ability of the coal industry to respond to supply shocks and meet unanticipated domestic coal requirements.

3.3.2 LNG export pressure

The domestic price of gas sometimes moves with the Asian spot LNG netback price, suggesting linkage with international prices, but at others can be disconnected. For the previous two quarters (Q4 2021 and Q1 2022), domestic gas markets were largely insulated from high international prices. Based on the ACCC netback price, domestic prices were higher than international prices in May to June 2022 (Figure 3.5).

Figure 3.5 Domestic spot gas price and netback price



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

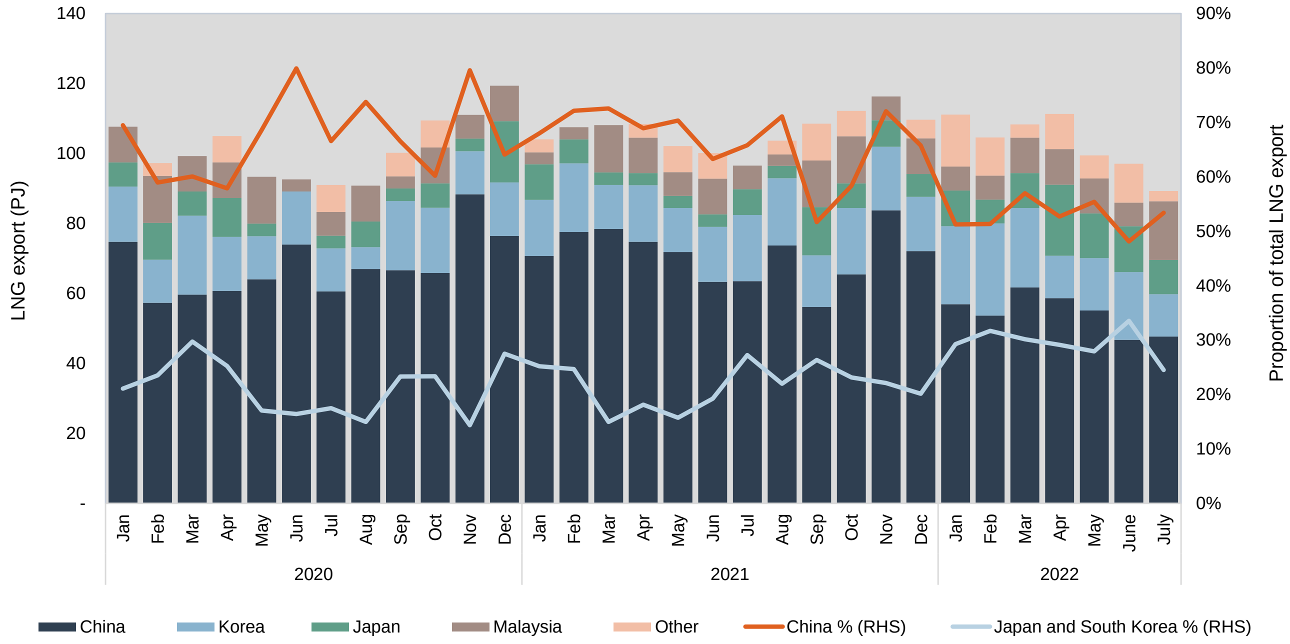
Note: The ACCC Forward Netback prices were assessed on 16 August 2022.

From May, domestic day ahead spot prices exceeded netback prices for the contemporaneous period of LNG prices assessments in May.

When domestic prices are higher than international prices, LNG producers should face greater incentives to sell into the domestic market and drive the domestic price down. It is not clear that this occurred in May to June 2022.

In fact, the opposite occurred with gas flowing north in May (Figure 3.7) to supply strong LNG exports from Gladstone in May and June 2022 (Figure 3.6). However, it may be the case that LNG producers committed to selling their available gas for export prior to May and could not supply to the domestic market despite the incentive of high prices. LNG producers maintained export volumes at a similar level to 2021 despite much higher domestic prices. This year, 30 cargoes of LNG were exported in May 2022 compared to 28 in 2021 and 26 in 2020.

Figure 3.6 LNG shipped from Gladstone Port by destination



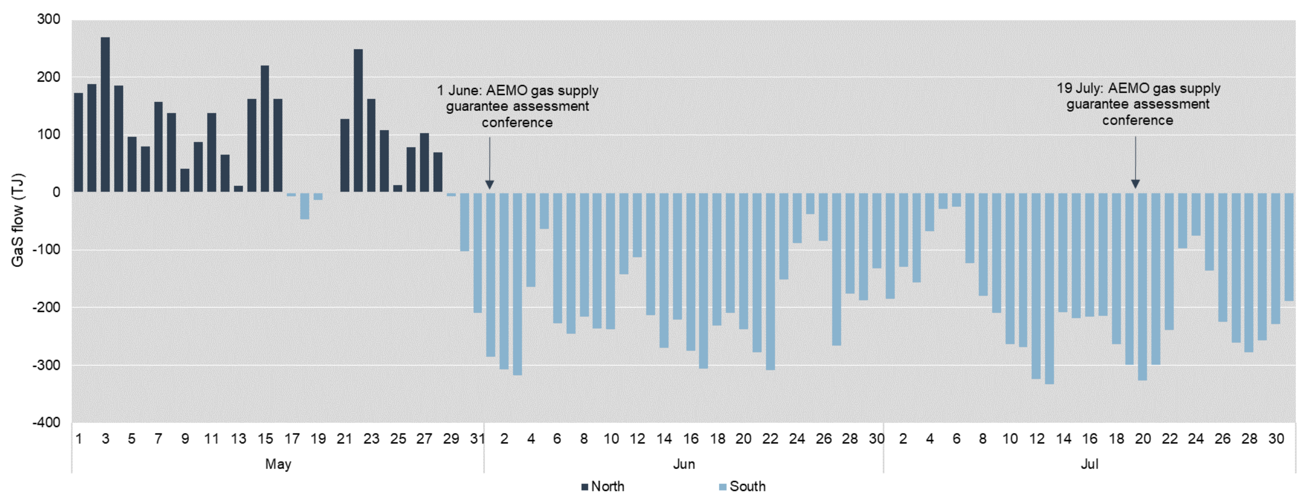
Source: AER analysis using Gladstone Port Corporation data.

AEMO has intervened in the gas market on two occasions, which has seen an increase in gas flows south (Figure 3.7). Increased flows south occurred from 1 June after AEMO called a Gas Supply Guarantee assessment conference. This event was triggered by low reserve conditions in the NEM and gas generators running on liquid fuel due to a lack of supply. Following AEMO intervention LNG exporters committed to offer gas to participants needing gas in the south.

Even without a Gas Supply Guarantee event, there were already pricing incentives in May (due to domestic prices being higher than international prices) for LNG exporters to bring gas south.

AEMO called another Gas Supply Guarantee assessment conference on 19 July which saw increased gas flows south in the couple of days after the event. LNG exporters again offered gas into the domestic market for participants to bring south.

Figure 3.7 Net daily gas flows north and south in May – July 2022



Source: AER analysis using the Natural Gas Bulletin Board.

Note: North–south flows depict net physical flows around Moomba – north or south.

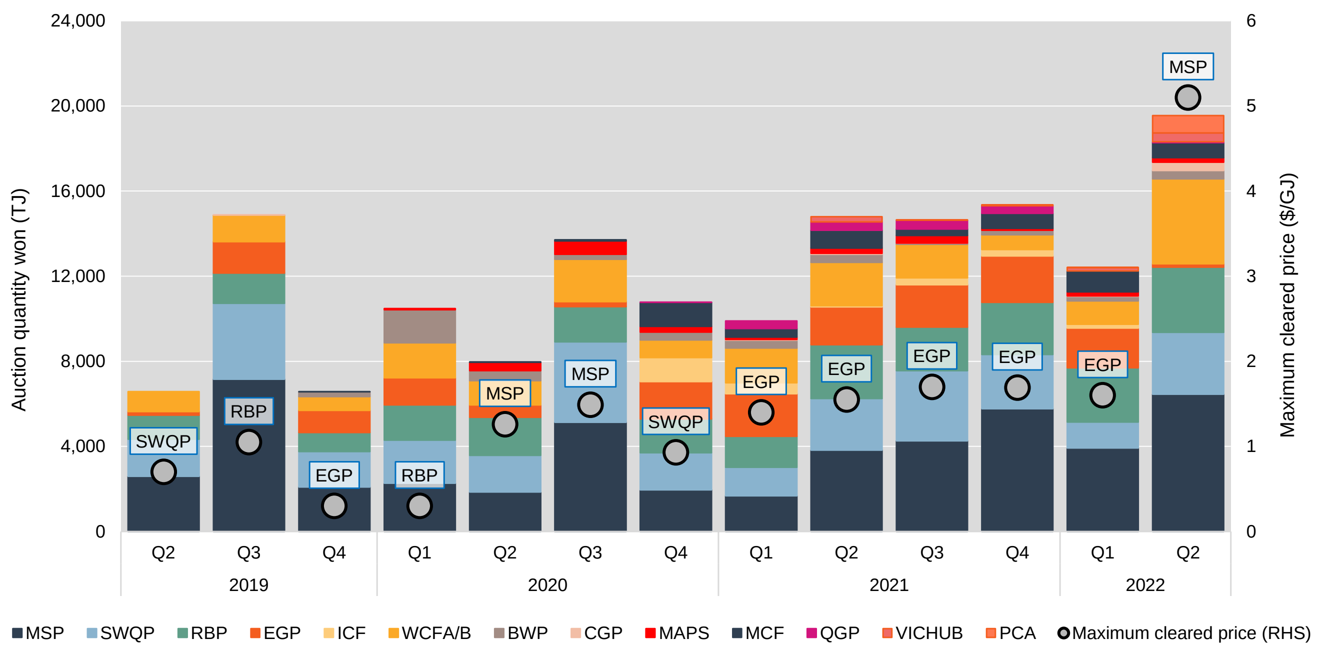
APLNG has taken one LNG train off-line for maintenance in late July to late August 2022 and QCLNG has taken one half to a whole LNG train offline from mid-June to mid-July 2022. Both LNG exporters have continued to produce gas from their gas fields[2]. This has resulted in additional supplies into the domestic market, providing an opportunity to increase storage levels and reduce prices. However, this impact may be short lived once the LNG trains are back to full production.

Our new gas market monitoring powers will enable us to better understand the interaction and behaviour of market participants relating to the trade-off between sales of gas for domestic and export purposes. Additional information from market participants will be reported by the AER from the end of 2022.

3.3.3 Record Day Ahead Auction activity brought gas south to meet demand

Market participants turned to secondary capacity to meet their short-term transportation requirements this quarter. Auction quantities traded were at a record high in Q2 2022 (Figure 3.8). This quarter, pipeline capacity won on the Wallumbilla compression facilities, the Moomba to Sydney Pipeline (MSP) and the South West Queensland Pipeline (SWQP) increased significantly. These facilities and pipelines are commonly used to bring gas south using secondary capacity as they have been close to fully contracted.

Figure 3.8 Pipeline capacity won on the Day Ahead Auction



Source: AER analysis using DAA auction results data.

Note: Quantities shown are the monthly sum of auction products allocated on each pipeline and do not necessarily represent the physical volumes of gas that actually flowed for each gas day.

There was a record high maximum auction price of $5.10/GJ recorded on the MSP. This trade was for the transportation of 1,650 GJ of gas south, from Sydney to Culcairn. A significant portion of the capacity won on the MSP (6.45 PJ) was to bring gas south from Moomba (2.9 PJ).

2 QCLNG has had a sizable outage at one of their corresponding production facilities for a significant part of the LNG train outage.

3.4 Solar and wind generation output has been lower than expected

Alongside the reduced availability and fuel constraints impacting baseload generation, solar and wind generation has been lower than anticipated.

This is linked to the weather conditions (La Nina) which generally resulted in less solar radiation and lower wind conditions than anticipated.

The mix of solar and wind resources varies across the NEM. For example, Queensland has strong large scale solar generation, but relatively low wind generation. In contrast South Australia's wind generation is very important relatively to its solar generation.

Solar and wind tends to be offered into the market at low prices, so when it is not available more expensive generation tends to be required.

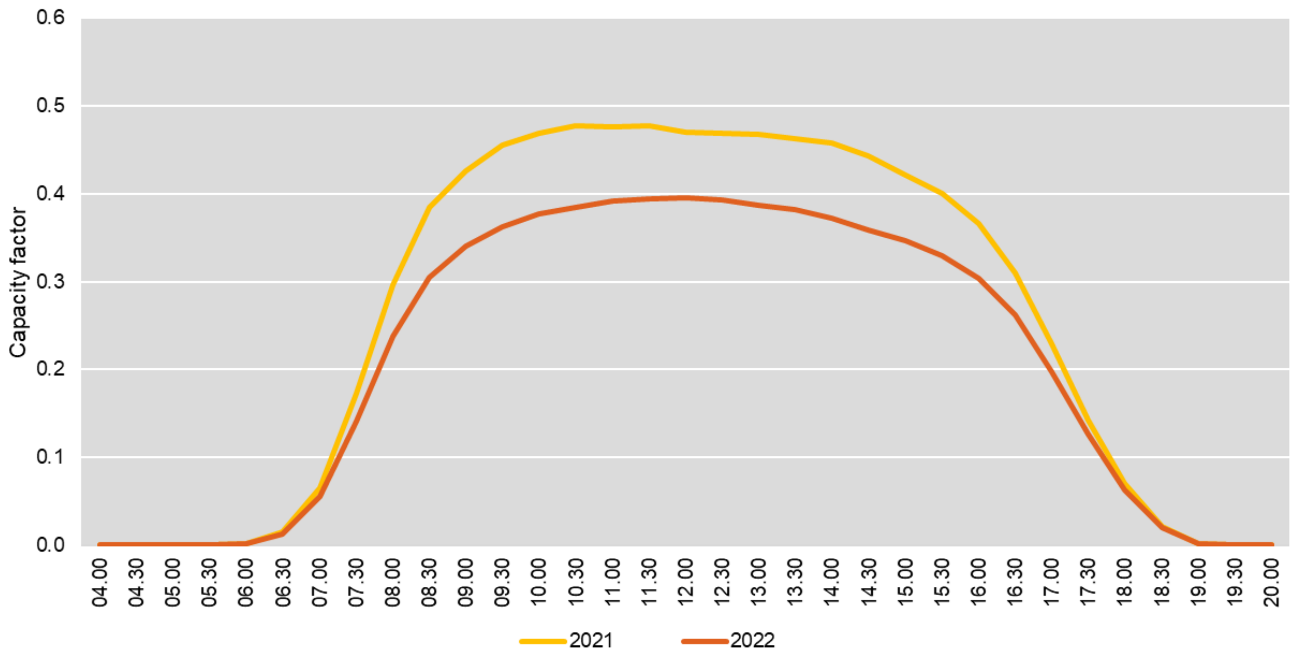
3.4.1 Solar

Solar generation has dual impacts on the electricity market. Firstly, there is large scale solar generation which feeds directly into the grid. Additionally, we have very large amounts of rooftop solar generation which reduces demand on the grid.

This rooftop generation has had significant impacts on the electricity market, such as drastically reducing demand during the middle of the day, shifting peak demand to later in the evening, and generally reducing growth in demand.

However, despite an increase in installed large scale solar capacity of around 1,000 MW Queensland, actual output in 2022 was similar to 2021. Figure 3.9 compares the solar capacity factor for Queensland in 2021 and 2022 from January to June.

Figure 3.9 Solar capacity factor in Qld – January to June



Source: AER analysis using NEM data.

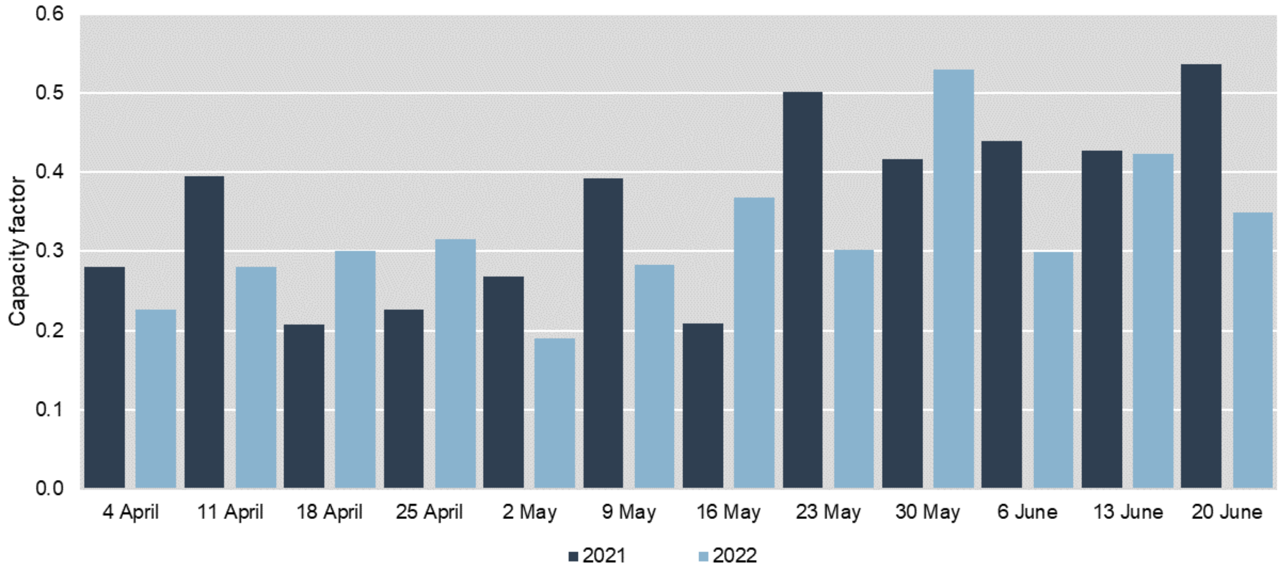
Figure 3.9 clearly illustrates that on average, there was less solar electricity generated per MW of capacity in 2022 than 2021. This pattern is consistent with impacts in other regions. This not only impacts large scale solar generation but also rooftop solar generation (effectively increasing demand).

This resulted in other generators needing to operate at higher levels than anticipated to meet demand.

3.4.2 Wind

There was a similar trend for wind as for solar. Figure 3.10 compares the varying capacity factor for SA's wind generation from April to June for 2021 and 2022 at a weekly level.

Figure 3.10 Q2 wind capacity factors in South Australia



Source: AER analysis using NEM data.

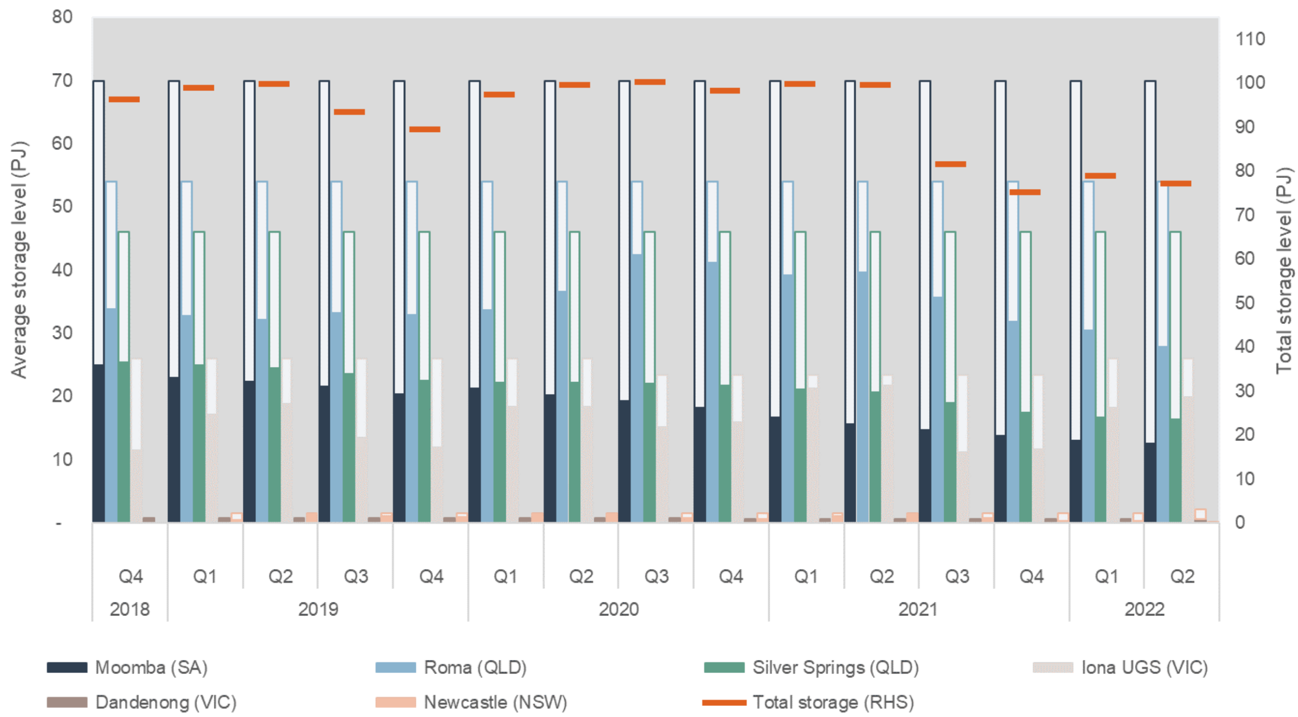
While wind output levels vary markedly from week to week, average output from wind in SA was down for two-thirds of the weeks of the quarter. Wind levels were particularly low in the week leading up to market suspension. In weeks where wind is low, other generators need to operate at higher levels to meet demand.

4 Gas storage levels are critically low

Demand in winter for gas is significantly higher than for the rest of the year. In particular, to meet winter demand in Victoria, gas from storage facilities is drawn down. This is because gas production and pipeline capacity to transport gas to demand centres is not always sufficient to meet daily demand. Therefore, increasing storage in preparation for winter months is crucial.

Figure 4.1 sets out the level of storage by facility and highlights overall storage levels (RHS). Usually, total storage levels in Q1 and Q2 are considerably higher than levels in 2022. Overall storage levels have decreased since 2018, driven by a gradual reduction in the Moomba and Silver Springs storage levels.

Figure 4.1 Gas storage levels

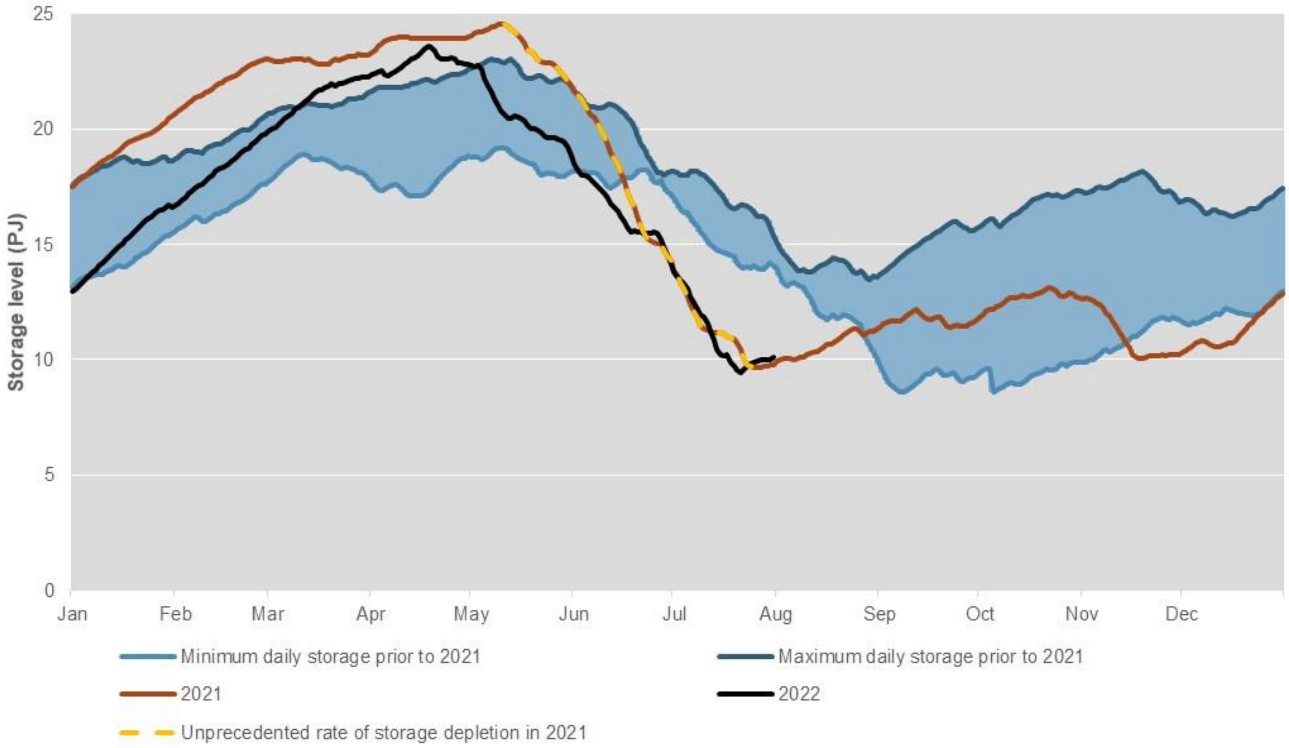


Source: AER analysis using the Natural Gas Bulletin Board.

4.1 Bidding activity at Iona storage for preservation of gas

The Iona storage facility in Victoria is the key storage for the supply of gas into southern markets. This storage facility is usually used to store gas volumes during periods of lower demand which are then withdrawn in winter to meet peak demand. Total storage at Iona depleted rapidly June and in July was on trend to deplete to the point where it would have been unable to support the gas distribution network (Figure 4.2).

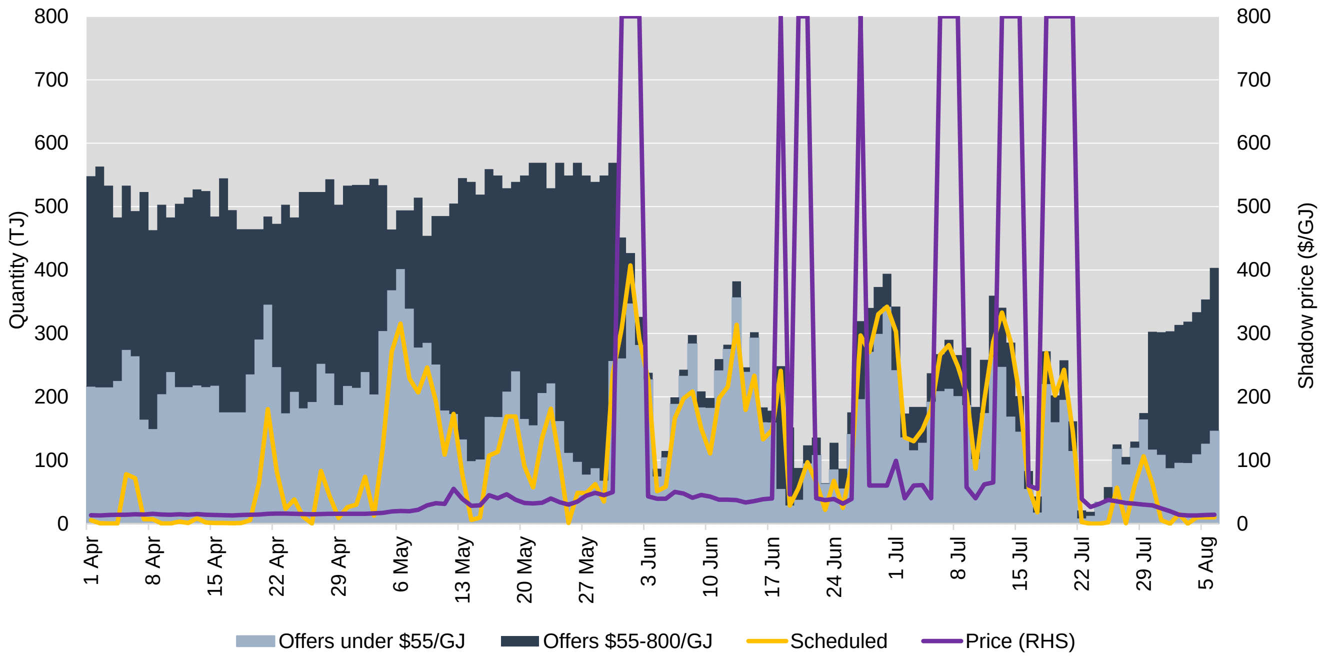
Figure 4.2 Iona storage levels



Source: AER analysis using the Natural Gas Bulletin Board.
Note: Due to confidentiality, the underlying data is not published

Low storage levels resulted in retailers preserving storage by pricing injections from the Iona storage facility at $800/GJ and reducing total volumes offered into the market (Figure 4.3). This bidding behaviour also kept the cumulative price calculation in Victoria above the cumulative price threshold for the period 31 May – 1 August, resulting in a price cap of $40/GJ during this period.

Figure 4.3 Injection bid price bands at Iona storage facility



Source: AER analysis using DWGM injection data.

From the start of August, total volumes offered into the market from Iona storage increased. The lower pricing from 1 – 15 August (~$16/GJ) aligns with lower priced deals entered into months ago (~$20/GJ) at the Wallumbilla GSH, most likely reflective of gas sales associated with excess gas during LNG train maintenance.

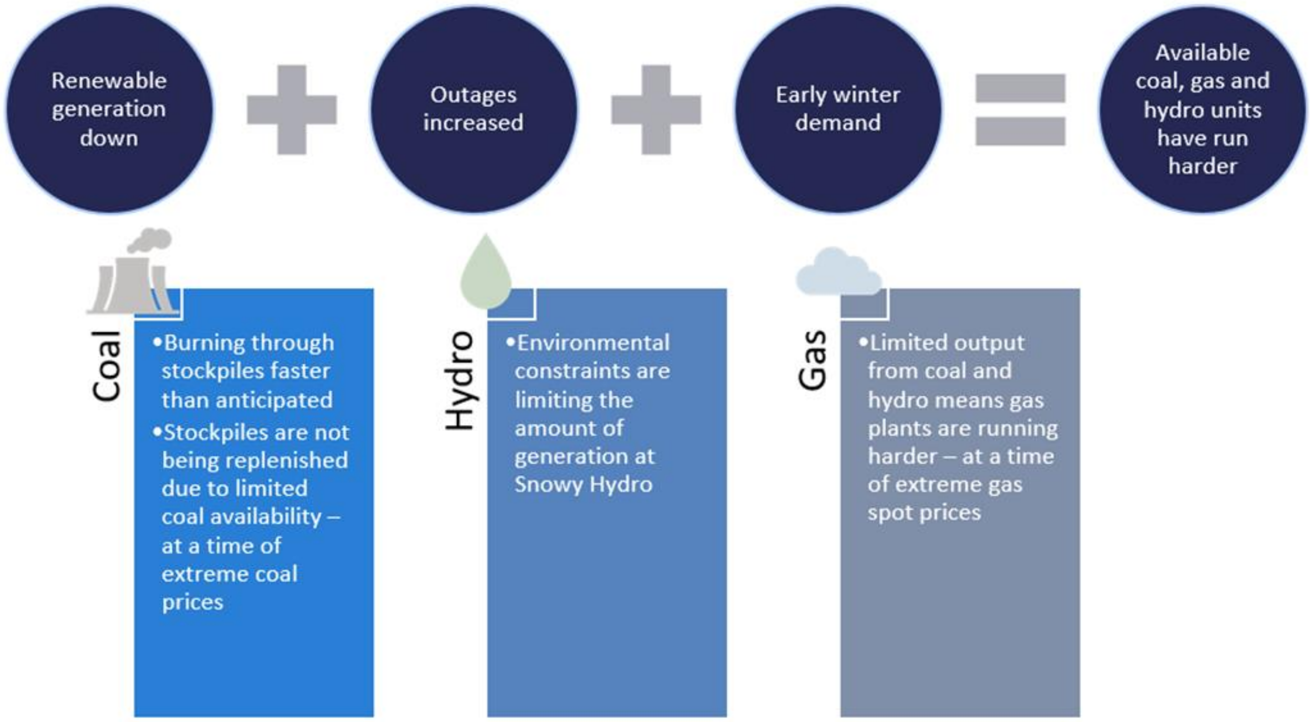
However, high price pressures still exist and remain a concern for gas supplies to southern markets for the coming months. August international LNG prices are at a historical high and gas storages have been significantly depleted.

This winter, AEMO has issued Threat to System Security (TTSS) notices, with a majority in relation to the inventory depletion at Iona storage introducing the risk of supply shortfalls. On 11 July, AEMO issued a TTSS notice for the Victorian market, asking market participants to cease purchasing gas via controllable withdrawals that are not supported by corresponding gas supply. This direction is no longer in effect due to increased storage inventory, however, the risk for Iona inventory depletion still exists.

5 Gas and hydro generation has been forced to run harder

The lower than anticipated generation arising from coal, solar and wind resulted in pressure on available coal, gas and hydro generators to run harder to meet demand.

Figure 5.1 Pressure for available generators to run harder

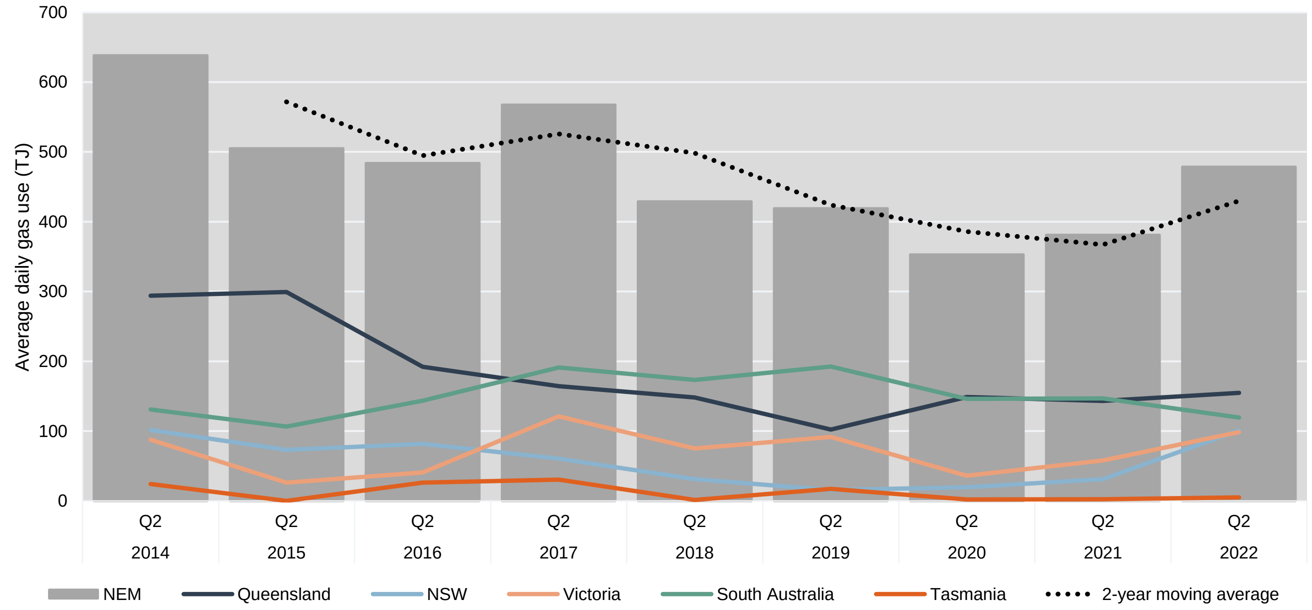


Source: AER analysis

5.1 Higher gas-powered generation demand breaks downwards trend

In recent quarters, gas-powered generation has been required less to meet electricity demand due to an increase in lower cost renewable generation displacing gas.

Figure 5.2 Q2 gas-powered generation demand



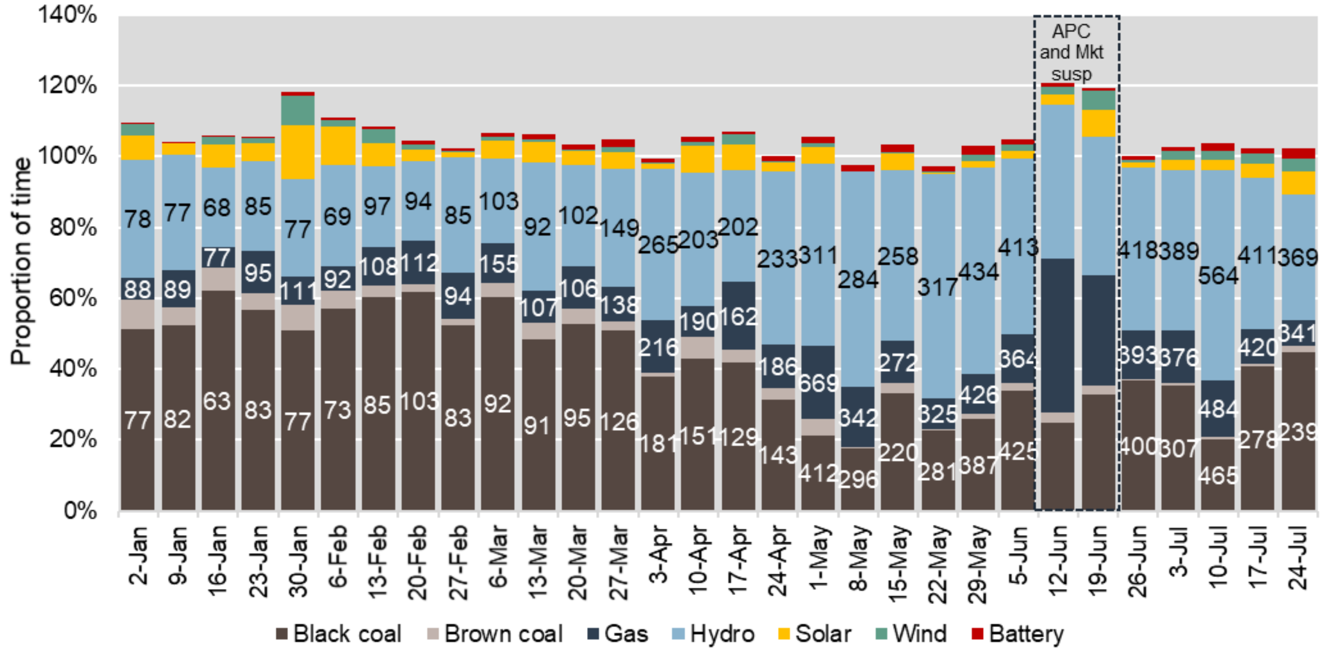
Source: AER analysis using NEM data.

Note: Gas use estimates are conversion of electricity generation output using average heat rates (GJ/MWh).

This trend was reversed in Q2 (Figure 5.2). A reduction in availability of coal fired electricity generation and low renewables generation has led to increased use of gas-powered generation. Increased gas-powered generation demand was particularly prominent in NSW and Victoria in Q2 2022 with gas-powered generation usage increasing most significantly in NSW (225%) compared to Q2 2021.

5.2 Gas and hydro set NEM prices more often

Figure 5.3 NSW Price setter



Source: AER analysis using NEM data.

Hydro generation, and to a lesser extent gas, have been setting prices more frequently in recent months (Figure 5.3). While this chart shows NSW outcomes, similar trends are evident in Victoria and Queensland. Hydro in January and February 2022 was setting the price around 30% of the time, but by May and June was setting price far more often (around 55% of the time).

Importantly, all key price setting fuel types were setting price at much higher levels than they were earlier in the year.

Underlying market conditions clearly explain the majority of these changes. Increases in coal and gas input costs and environmental constraints impacting hydro generators have played a significant role in these outcomes.

However, this is another important example of where a lack of visibility over contract markets limits our ability to fully determine the incentives underlying offer behaviour and the extent to which this may be a concern.

5.3 Hydro generation has run harder but faced environmental constraints

However, hydro generators have limited ability to increase generation to cover the shortfalls in other generation types, as they generally have limited water in storage and environmental obligations on flows. Pumped hydro uses price arbitrage to cover the cost of refilling the head storage.

Hydro generation is required to plan its generation over the year, considering opportunity costs of consuming water now compared to later in the year. It will be more likely to have higher levels of generation across high demand periods like summer and winter.

A participant reported record hydro generation this quarter while trying to balance storage levels for later in the year. They also faced environmental constraints that limited generation output. During periods of high flows and flooding, there were restrictions on the ability to release water from certain dams, to help reduce flooding downstream.

When hydro increases generation above what's planned their ability to generate later in the year may be restricted. This explains why a hydro generator's offers into the market will be closely linked to the offers of other generators. When the offers of coal or gas generators increase, hydro generators must also increase their offers or else they run the risk of depleting their water reserves for peak periods.

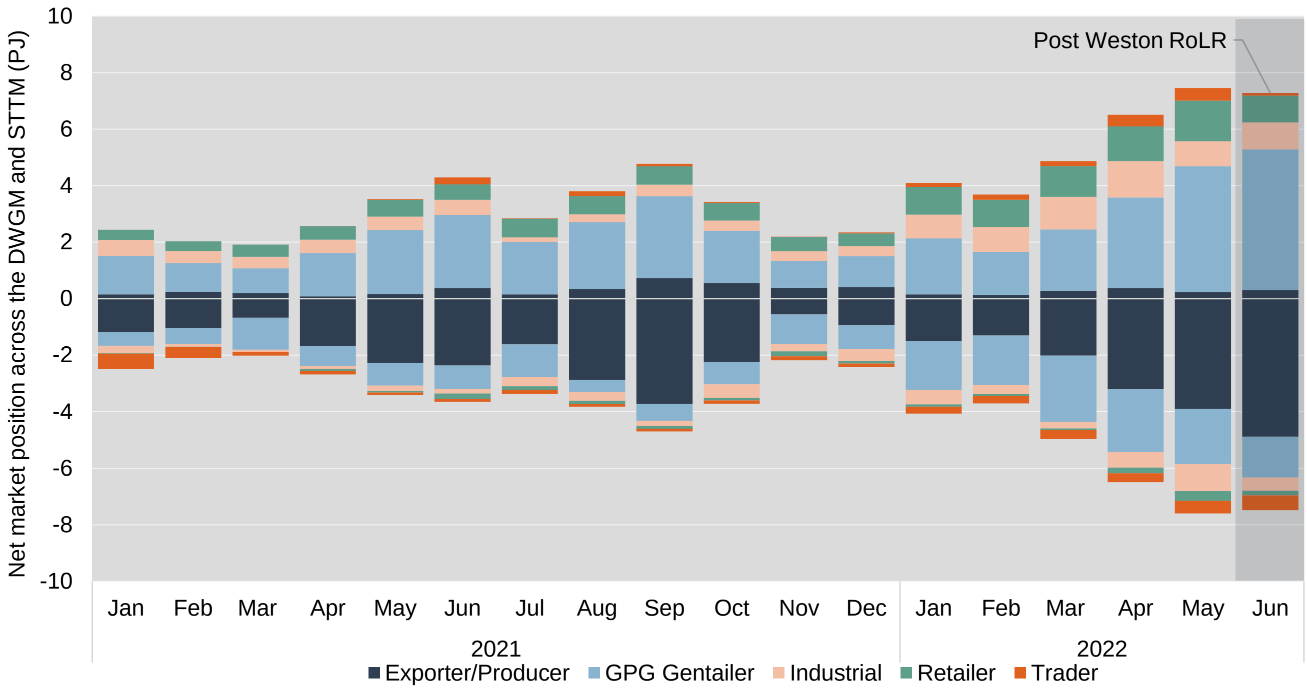
5.4 Record high spot gas market purchases by generators

Notwithstanding that overall demand for gas has not changed significantly, gas generators are responsible for a significant increase in spot gas purchases, driven by the need to run their gas units at far higher output.

Further, several market participants have told the AER that they have used their gas generators to supplement baseload outages where they would otherwise use peaking assets.

Figure 5.4 sets out the purchases (withdraws – positive) and selling (injections – negative) for various type of gas market participants.

Figure 5.4 Participant purchase and selling of gas



Source: AER analysis using DWGM and STTM data.

Note: Trade in the Victorian DWGM and Sydney, Adelaide and Brisbane STTMs have been calculated by netting scheduled buy and sell quantities for each trading participant.

Figure 5.4 illustrates that gas generators (GPG Gentailer) are buying gas off the spot market (light blue) at record levels (either for gas generation or for other gas customers).

Spot purchases are a relatively small percentage of most participants' total gas demand as most gas is sourced under long term contracts. However, a range of market participants have told the AER that they have limited contracts to cover unplanned generation. The fact that gas generators are purchasing gas off the spot market at record levels supports the fact that they don't have contracts to support this additional gas generation and are therefore exposed to the high spot prices.

Increases in prices in the NEM incentivise gas generators to purchase additional gas, notwithstanding the high price of gas, as the spark spread between gas and electricity remains positive. This willingness to purchase additional high price gas allows generators to outbid retail customers and industrial users for gas, especially when there is limited gas supply available.

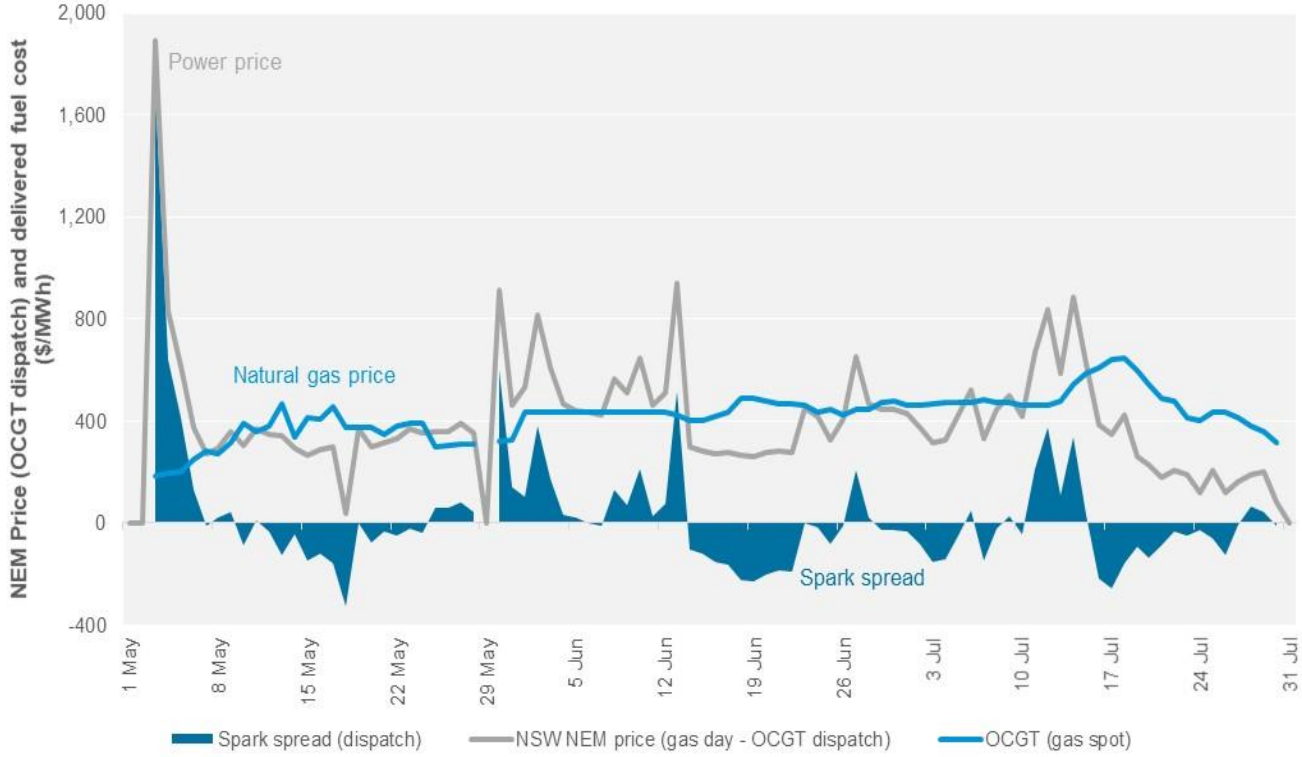
5.5 Gas powered generators have faced positive 'spark spreads'

Gas and electricity prices are, to a certain extent, interrelated. Gas is a key fuel for electricity generation and is expected to become an increasingly important source of generation as coal-fired generation retires[3]. Therefore, it is important to review the gas and electricity markets together, as similar variables have impacted both markets over the quarter. It should also be noted that many retailers sell electricity and gas, and many consumers, especially in Victoria, purchase both gas and electricity.

[3] AEMO, *Integrated system plan (ISP) 2022*, 30 June.

Figure 5.5 shows that there were periods in the quarter where the power price was significantly greater than the natural gas price. This indicates that it would be profitable to burn gas as an energy source. The profitability of gas-powered generation at the beginning of May might have contributed to the decrease of gas storage levels in the south that occurred in May (see section 4).

Figure 5.5 Gas spot price, NEM price and dispatch cost, May to July 2022



Source: AER analysis using NEM data.

Notes: The natural gas price is a delivered fuel cost for OCGT using that day’s spot price (in $/MWh)

The power price is a NEM price for dispatch intervals when OCGT was on during the day.

There were times when gas powered generators appeared incentivised to purchase gas and generate electricity, especially during the morning and evening electricity peaks. For example, on 6 June, the NEM prices were consistently around $450/MWh during the evening peak and up to $600/MWh (5 pm to 8 pm). Even at a purchase price of $40/GJ, gas peaking stations would likely be earning a positive “spark spread", during which the price received from the power is higher than the price of the fuel.

A similar opportunity arises for coal generation (noting that coal logistic chains can be more localised reducing the ability to on-sell coal in some instances), where coal generators / coal mines are required to decide whether to use coal for electricity generation or sell the coal internationally. This decision is referred to as a dark spread.

6 High and volatile spot prices are impacting contract markets

Generators and retailers enter contracts to fix the price of gas or electricity over the course of a year, or several years. This is done to protect both parties against price fluctuations in the spot market. If the spot price rises in the future, a retailer will benefit from having a contract in place. If the spot price falls in the future, a generator will benefit from having a contract in place. Some retailers operate their own generation assets as another way to hedge the spot price.

Market participants will typically acquire energy through a mix of contracts, generation assets, and spot market purchases. The composition of this mix will depend on their risk appetite.

The contract market is vital to understanding market participant behaviour within the spot market.

The National Electricity and Gas laws provides AER with the ability to investigate and report on the spot market, but the AER has limited powers regarding the contracts market. This lack of visibility significantly constrains our ability to:

> understand the drivers of market outcomes and the effectiveness of the market

> understand market participant incentives and behaviour

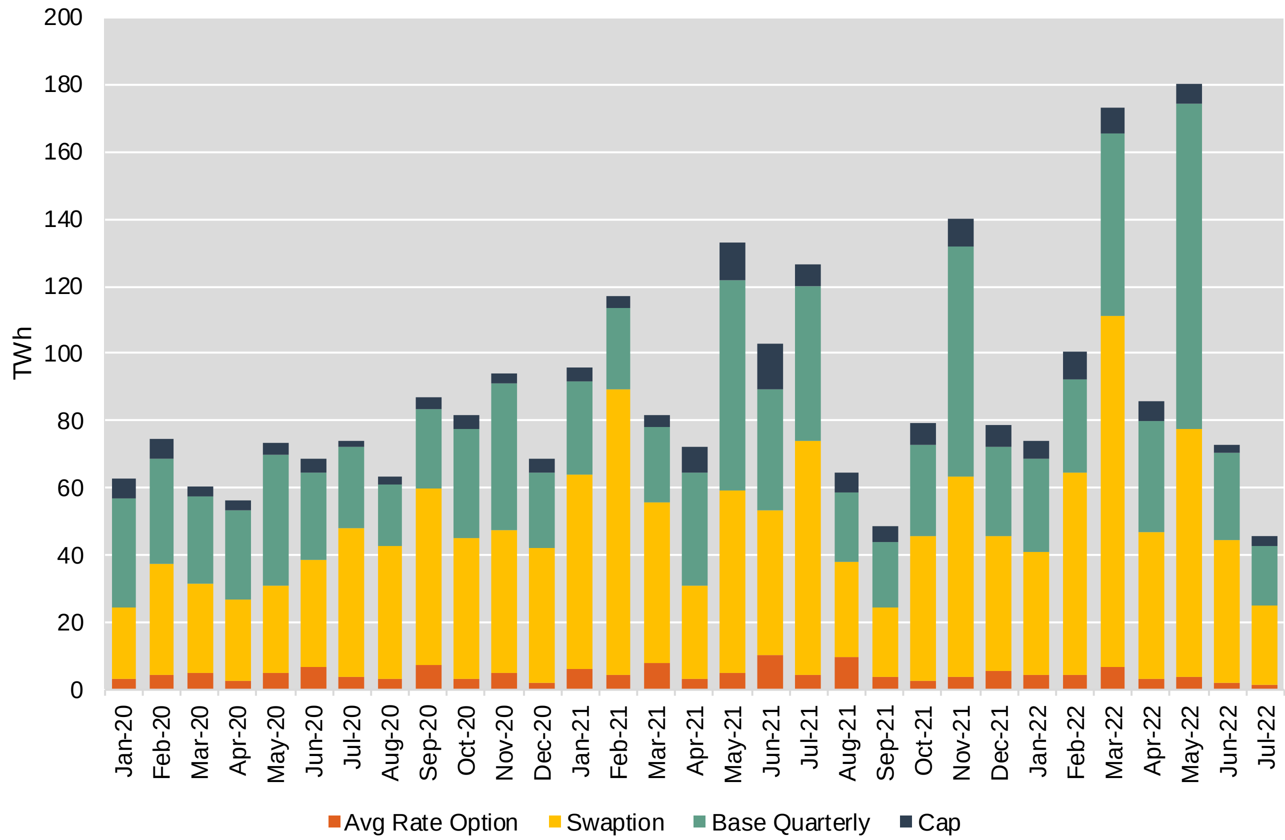
> assess potential breaches of rules.

6.1 NEM contract market liquidity has decreased in recent months

Liquidity in contract markets is an indicator of market strength and high liquidity will mean contract prices better reflect changes in supply and demand. The volume of contracts traded is a common indicator of market liquidity.

Over recent months, market participants have told us that there are less bids and offers available to buy and sell contacts, a sign that liquidity is worsening. Consistent with this, traded volumes visible through the ASX have also fallen sharply in June and July (Figure 6.1).

Figure 6.1 Monthly traded volumes of ASX contracts



Source: ASX data, AER analysis.

If retailers and generators are unable to hedge their positions by buying and selling contracts, they will be forced to take on additional financial risk.

Reductions in hedging now may have flow on effects in the coming years.

> Retailers may be unwilling to lock in contracts at such high prices in hopes prices will come down in the future. For smaller generators, which typically contract 6-12 months ahead, this may mean that they are facing the possibility of exposure to the spot market in the coming year. There is a real risk that generators may be unable to find affordable hedging if contract prices remain elevated into 2023.

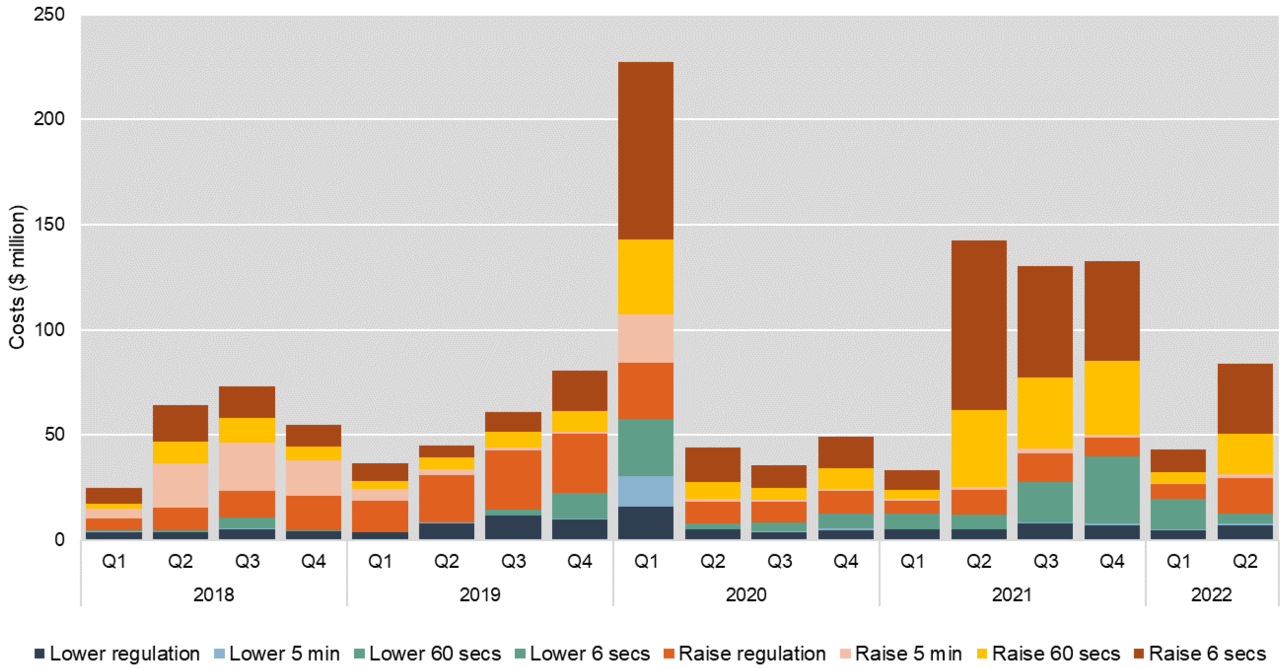
> Generators may be hesitant to contract and risk exposing themselves to potentially high margin calls as are required by the ASX or may be still dealing with the cash flow issues caused by the current increase in contract prices.

7 FCAS

As part of our quarterly reporting, we have ongoing obligations to report on frequency control ancillary services (FCAS).

Total FCAS costs for rose to $84 million this quarter, up from $43 million the previous quarter.

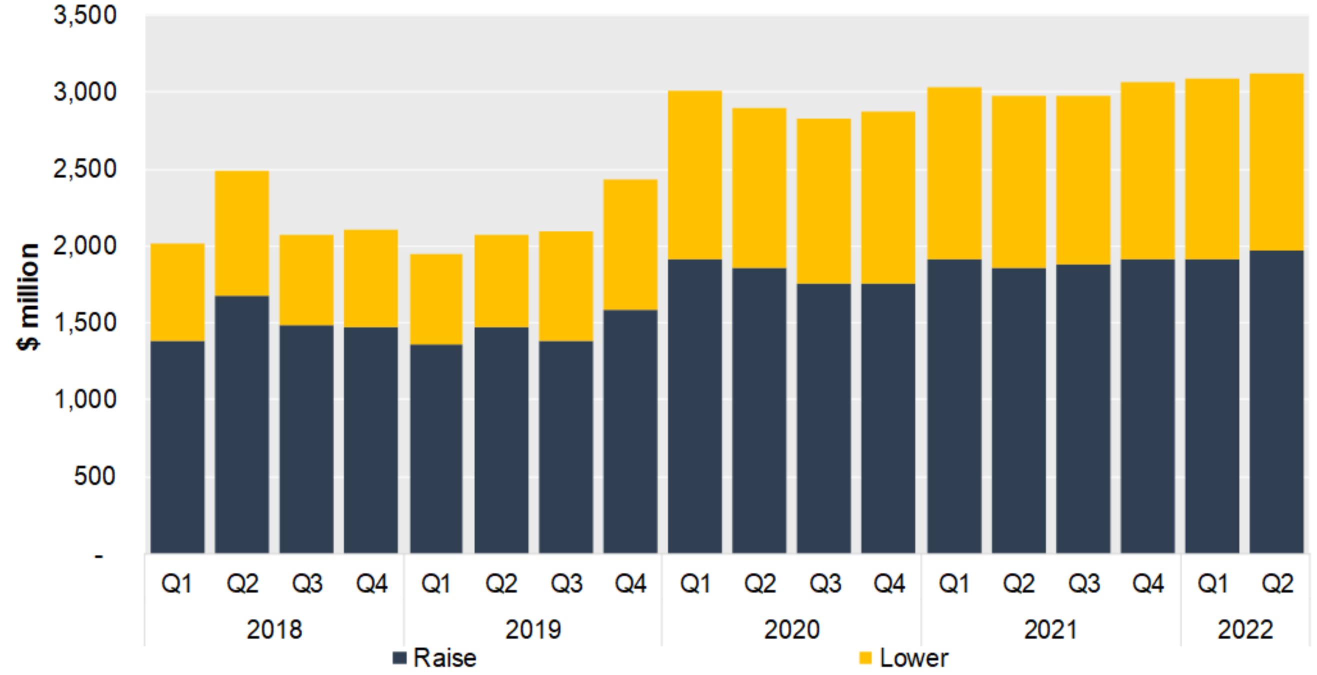
Figure 7.1 Quarterly FCAS costs by service



Source: AER analysis using NEM data.

Of the $84 million, raise services accounted for $71 million of the total costs. While the amount of raise services procured was comparable to all other quarters, since 2020, the price pressures in the energy market meant less low-priced raise services were available.

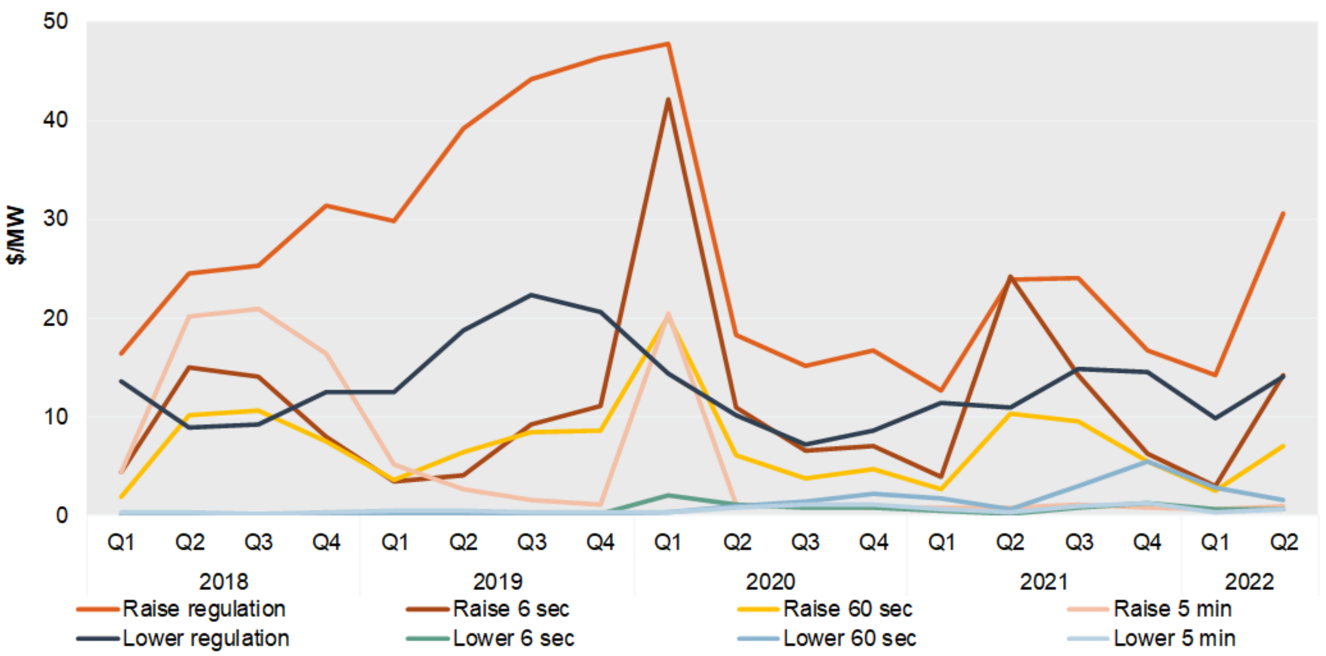
Figure 7.2 Raise and lower services enabled



Source: AER analysis using NEM data.

Compared to the last quarter, average prices increased in all raise services. Instead, they were on par with the previous 3 quarters.

Figure 7.3 Average quarterly FCAS prices



Source: AER analysis using NEM data.