Wholesale Markets Quarterly

Q1 2022

January – March

May 2022

AUSTRALIAN ENERGY REGULATOR

Australian Government

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Tel: 1300 585 165

Email: wholesaleperformance@aer.gov.au

Contents

Summary

This report highlights wholesale electricity and gas market outcomes for Q1 2022.

Electricity markets

Volume weighted average prices increased across all regions in Q1 2022 compared to the same quarter last year, at least doubling in most regions with prices ranging from $64/MWh in Victoria, to $89/MWh in NSW and quadrupling to $171/MWh in Queensland. While prices are typically higher in the first quarter due to increased demand for air conditioning during warmer weather, last year's mild summer drove record low prices. This has made the observed increase this quarter more pronounced.

Several factors appear to have driven the higher increase in Queensland prices relative to other regions. Demand reached near record highs in Queensland multiple times this quarter as La Nina conditions contributed to relatively high humidity and elevated overnight temperatures. At the same time, in an environment of higher fuel prices, generators shifted capacity to higher prices. Limits on the Queensland-NSW Interconnector (QNI) also reduced the availability of low priced energy at times. Looking forward, high future prices in Queensland and NSW over 2022–2024 suggest market participants expect higher prices in these regions to persist.

Across all regions, increased capacity resulted in the highest ever quarterly output by grid-scale solar generation. Despite rising fuel costs, gas output also rose this quarter, particularly in NSW as gas generators were dispatched in response to black coal outages. These shifts, supported by increased wind and hydro generation, saw further falls in coal generation. Black coal generation NEM-wide reached a record low 49% of total output, with a particular reduction in Queensland. Brown coal generation was also low, recording its lowest level for a January–March quarter.

There was also a significant change in offers, with black coal generators reducing capacity offered at prices below $50/MWh by 3,100 MW on average. Most of this was shifted to higher prices, contributing to both the lower reliance on coal generators and the higher prices at times coal was used. Some outages in Queensland and NSW also reduced the overall capacity available. As a result, Queensland became a net importer of electricity for the first time since QNI was first commissioned in 2001. In addition, QNI was constrained more often this quarter, which meant that Queensland had limited access to cheaper generation from NSW. This was particularly the case in the evening when demand was at its highest. However, unlike previous quarters, the limits were more often due to system normal constraints than due to outages relating to recent upgrades.

Fewer planned outages on QNI meant that Frequency Control Ancillary Services (FCAS) costs in Q1 2022 returned to lower levels, after being high for most of 2021. However, while costs were lower, there were some consecutive high FCAS prices in Queensland. We explore the drivers of these in our focus story this quarter.

Gas markets

Domestic gas prices were elevated in Q1 2022, averaging around $10/GJ and setting a new Q1 record. Prices began to increase at the end of Q1 and into Q2, with prices up to $55/GJ recorded in Victoria in May. While domestic gas prices remained much lower than international prices in Q1, there were days in May when the domestic price exceeded the LNG netback price.

As international gas prices hit record highs in Q1 2022, with new single day price records set in Europe ($88.61/GJ) and Asia ($70.88/GJ) in Q1 2022, the gap between domestic and international gas prices widened. Notably, the Asian spot LNG netback price at Wallumbilla averaged $36.80/GJ for deliveries over Q1 2022, which was over 3 times greater than the average domestic price.

Higher domestic prices in late March, April and early May, coincided with an increase in the volume of gas used to generate electricity and higher NEM prices, a ramp up of storage levels in the lead up to higher demand over the Australian winter, as well as high levels of international demand and robust exports.

Futures prices also increased in line with overall higher price expectations. At the start of May 2022, Victorian gas futures were trading on the ASX at $15.00/GJ for Q2 2022 and $17.50/GJ for Q3 2022. These prices are significantly higher than in 2021.

In response to high international prices, Q1 2022 saw near record LNG exports and high domestic gas production. Gas production hit a new record for Q1 at 5,357 TJ/day. High export levels were also facilitated by an increase in southern production flowing north to Queensland.

Our focus story analyses the performance of the Day Ahead Auction (DAA) and Capacity Trading Platform (CTP), and the relationship between them. The DAA continues to be a well utilised market to purchase spare, inexpensive, next day capacity. And to date, participants have not needed to seek additional short-term firm capacity through the CTP. However, this could change if the DAA continues to be over-subscribed and shippers who miss out on capacity through the DAA (due to higher bids) turn to the CTP for day ahead capacity.

Future reports will monitor international conditions as well as domestic production as we approach peak domestic winter demand.

Electricity markets at a glance

Q1 2022

30-min prices

Average prices increased in all regions compared to Q1 2021. Queensland had the most significant rise

Outlook

Contract prices have continued to increase, especially in Queensland and NSW

Demand

Queensland hit near record max demand. SA reached a new Q1 record minimum demand

Generation

Record grid scale solar generation in all mainland regions. Coal generation continues to fall

Interconnectors

For the first time, Queensland region imported more generation than it exported

FCAS

50 Hz

FCAS costs fell this quarter due to a break in QNI upgrades during January and February

Gas markets at a glance

Q1 2022

Spot prices

Domestic Q1 prices $10/GJ were lower than Asian netback prices $37/GJ

Spot Trade Downstream

Percentage traded dropped slightly through spot markets on east coast

Gas storage

Storage levels increased in preparation for winter months

International markets

Unprecedented LNG prices in Q1, near record LNG exports from QLD

Gas production and flows

Gas production continued to be robust, reaching record Q1 levels

Day Ahead Auction

Q1 2022 auction quantity won up 25% from Q1 2021

About this report

This report highlights wholesale electricity and gas market outcomes in Q1 2022.

The AER has a range of obligations to monitor and report regularly on the performance of the national wholesale electricity and gas commodity and capacity markets. Quarterly reporting on performance issues, including on some longer term trends, is a fundamental part of fulfilling these obligations. It bridges the gap between our shorter term high price event reports and our longer-term biennial *Wholesale electricity markets performance report*.

Importantly, the report draws on our online wholesale statistics which we update quarterly, and allows us to identify significant trends in the electricity and gas markets and independently evaluate developments as they emerge.

We also have obligations to report quarterly on outcomes in the frequency control ancillary services (FCAS) markets and report on prices over $5,000/MW in ancillary services markets. We fulfil both obligations in this report.

1. Electricity

1.1 Wholesale prices increased, most significantly in Queensland

Volume weighted average prices in all regions rose compared to Q1 2021 (Figure 1.1). Prices ranged from $64/MWh in Victoria to $171/MWh in Queensland. Queensland's price was the highest in the NEM since Q1 2019 and increased by 283% from the same time last year. This price was Queensland's second highest on record, with only the Q1 2017 price higher (at $194/MWh), and as of 15 May 2022 high wholesale prices are persisting into Q2 2022.

Figure 1.1 Average quarterly prices (VWA)

Source: AER analysis using NEM data.

Note: Volume weighted average price is weighted against native demand in each region. AER defines native demand as the sum of initial supply and total intermittent generation in a region.

High price events contributed to the increased quarterly prices in most regions this quarter. There were 12 30-minute prices above $5,000/MWh in Queensland, 2 in South Australia, and one each in Victoria and Tasmania.

The drivers of the high price events in Queensland included:

- near-record high demand, resulting from warm weather and particularly high humidity in northern Queensland
- limited access to lower priced capacity because of generator outages and reduced availability
- reduced ability to import cheaper capacity from NSW due to network constraints
- ramp limitations which reduced access to lower-priced capacity.

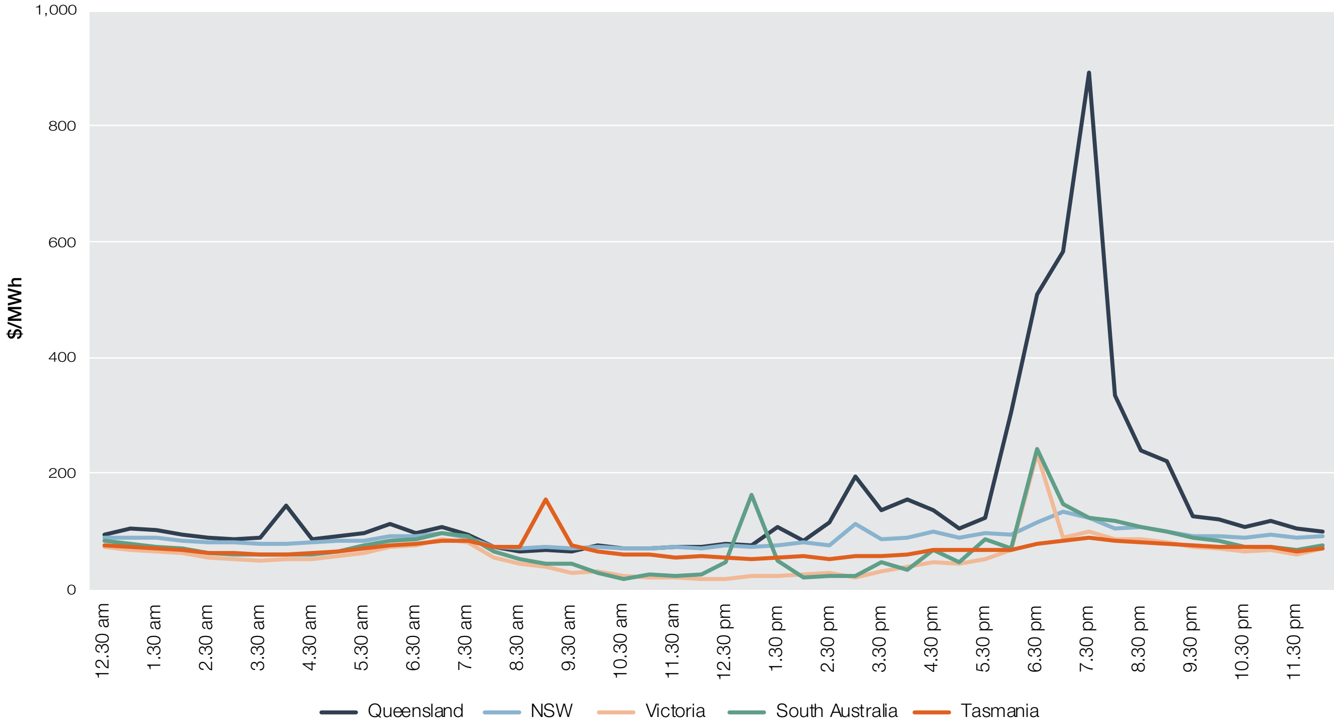
The reasons for high price events in other regions included:

- high demand
- low wind and solar generation or limited access to low priced capacity due to generator outages
- reduced imports from neighbouring regions
- interaction with FCAS markets
- participants' ramp-up rates limiting generators' responsiveness to high prices.

We publish detailed analysis of these events on our website.

In Queensland, these high price events mostly occurred in the evening between 6pm and 9pm. As a result, Queensland prices during this time averaged over $200/MWh in Q1 2022. Prices averaged highest at 7.30pm, when the quarterly average price was $892/MWh (Figure 1.2). But even without the high price events, average evening prices in Queensland remain far higher than any other region.

Figure 1.2 Average prices by time of day



Source: AER analysis using NEM data.

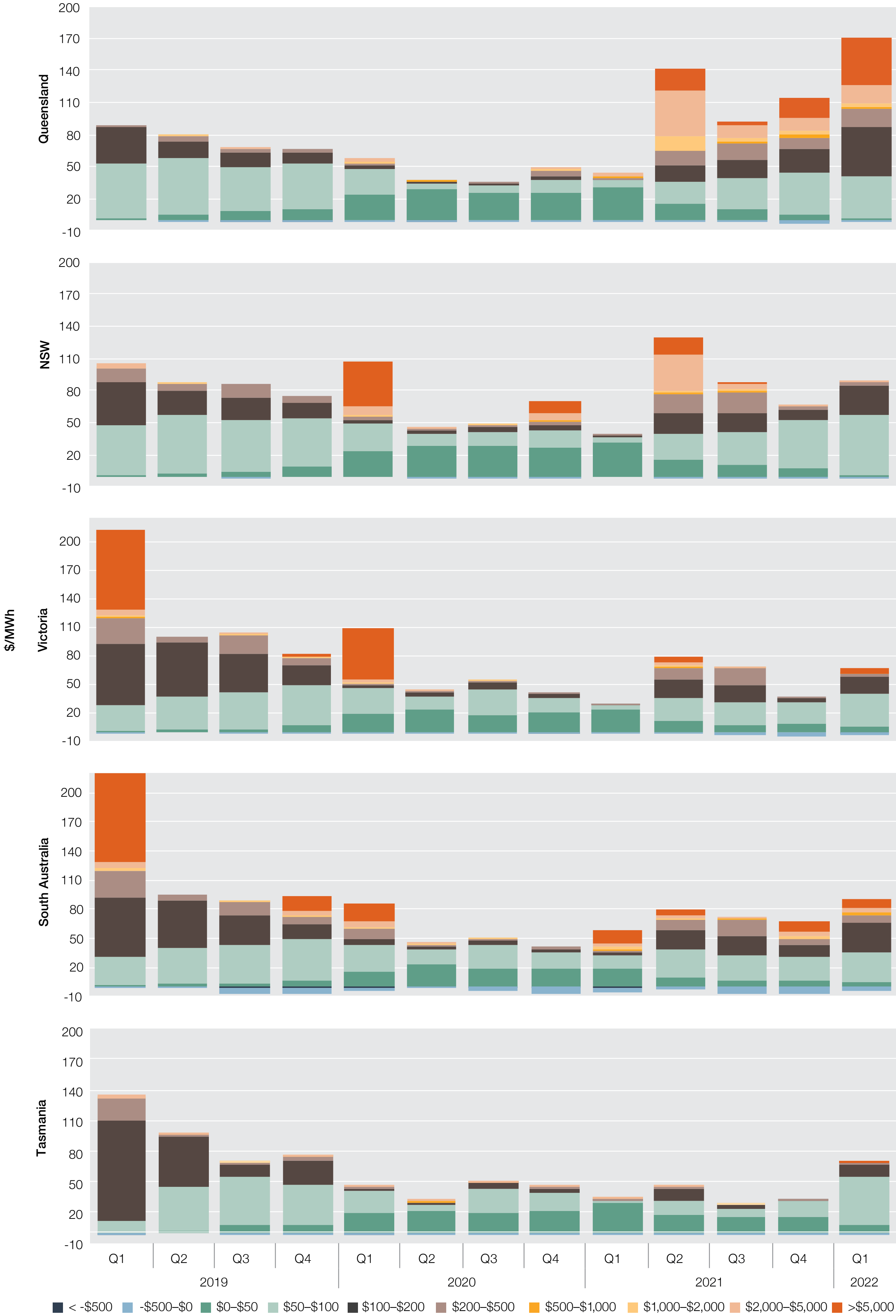
Note: Average prices by trading interval in Q1 2022, not volume weighted.

The Queensland price this quarter was characterised by a major growth in contributions from prices between $100/MWh and $200/MWh, and above $5,000/MWh (Figure 1.3). Higher prices had a significant impact on the final average, with prices above $500/MWh contributing $66/MWh to the Queensland quarterly price. While more expensive bands elevated the spot price in all regions, such a large contribution from prices above $500/MWh is unique to Queensland.

The drivers behind high Queensland prices this quarter, such as higher demand (section 1.3), changing generator offers (section 1.5), and interconnector limits (section 1.7), are explored in greater detail later in the report.

High wholesale prices have continued into Q2 2022. As of 15 May 2022, volume-weighted average prices in all regions are between $160/MWh and $283/MWh, with Queensland remaining the most expensive region. Across regions, generator outages and calm wind conditions have reduced the availability of lower priced generation. Planned and unplanned network outages have further restricted Queensland, NSW and South Australia's ability to access lower priced generation during times of peak demand, resulting in market volatility. As of 15 May, there have already been 16 30-minute intervals priced over $5,000/MWh in Q2 2022.

Figure 1.3 Contribution of different price bands to average quarterly prices



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.

More broadly, since Q1 2021, prices below $50/MWh have continued to contribute a smaller proportion to the final price in each region and have been largely replaced by prices between $50/MWh and $100/MWh.

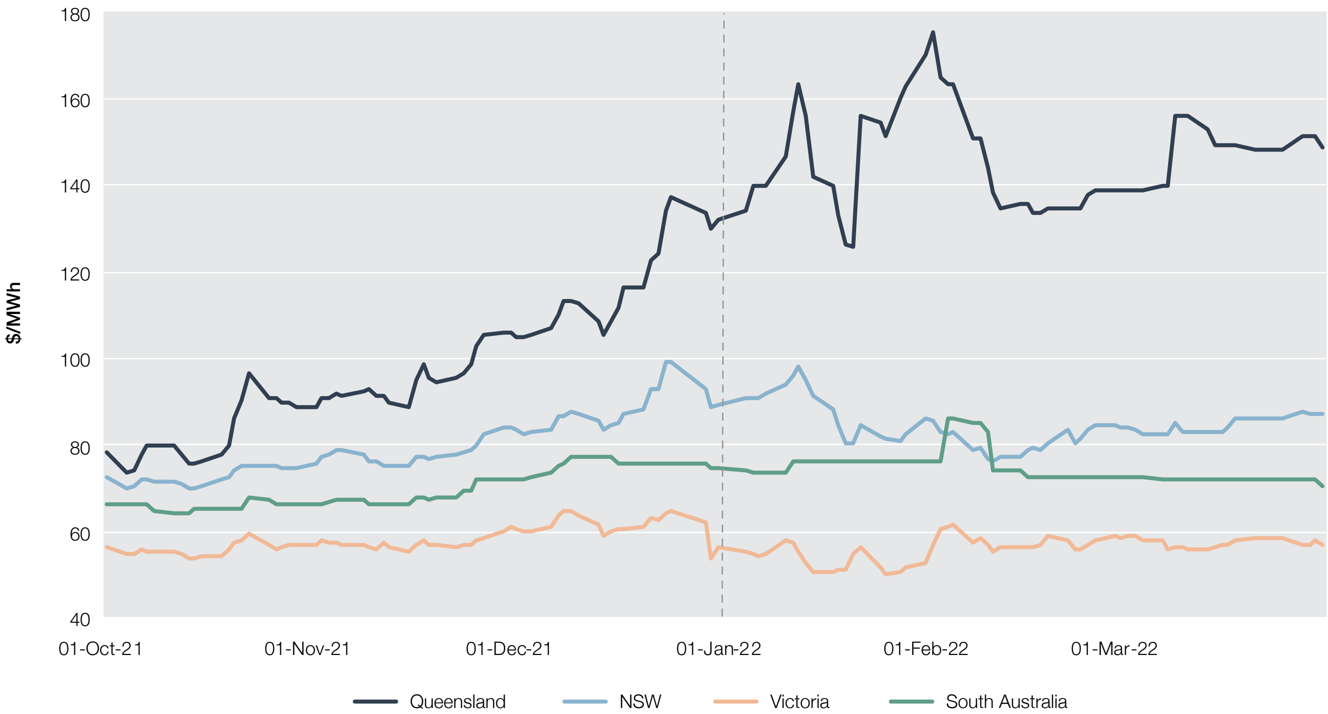
Negative prices in the NEM this quarter were more frequent than in Q1 2021, although far less so than in Q3 and Q4 2021. Prices were also increasingly less negative, as participants offered capacity closer to $0/MWh rather than at the price floor (-$1,000/MWh). In South Australia, this meant that negative prices did not significantly reduce the average quarterly price.

1.2 Participants priced uncertainty into the contract market

Queensland contract prices were significantly higher than the other three regions this quarter. Base future prices finished the quarter at $148/MWh, the second highest final base future price ever observed in Queensland (Figure 1.4). The record is $174/MWh set in Q1 2017. Cap prices finished the quarter at $46/MWh, the third highest final cap price ever in Queensland.

Final base future prices were much lower in the other regions, finishing the quarter between $57/MWh and $87/MWh. Prices were up in all regions compared to Q1 the previous year. In Q1 2021, the final base future price was less than $43/MWh in all regions.

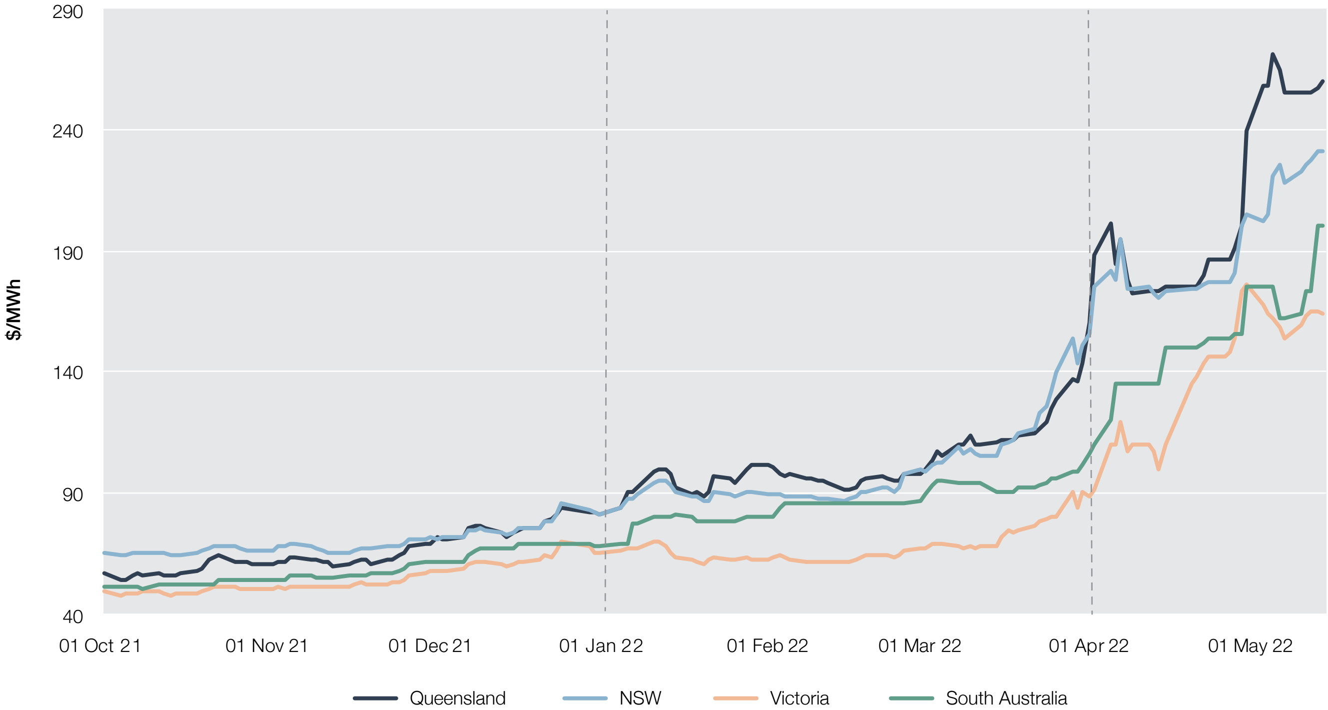
Figure 1.4 Base future prices, Q1 2022



Source: AER analysis using ASX Energy data.
Note: Daily settled price for Q1 2022 quarterly base futures.

Price expectations for Q2 2022 increased in all regions through Q1 and have continued to increase into Q2. The biggest increases have occurred in Queensland and NSW (Figure 1.5).

Figure 1.5 Base futures, Q2 2022



Source: AER analysis using ASX Energy data.

Note: Daily settled price for Q2 2022 base futures.

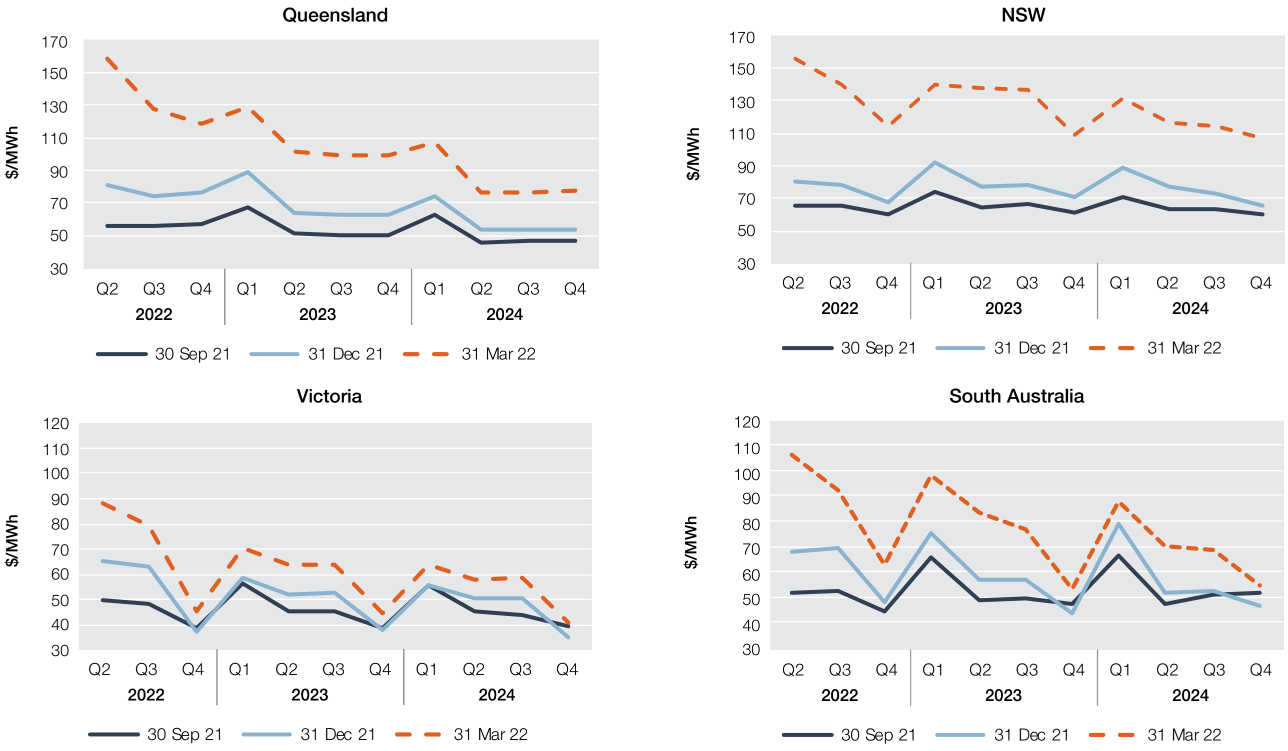
At the end of Q1 2022, Q2 base futures prices in Queensland and NSW were settling at $160/MWh and $156/MWh respectively. In both regions, these futures prices have almost doubled in only 3 months. By contrast, South Australia and Victoria Q2 base futures prices settled much lower at $107/MWh and $88/MWh respectively at the end of Q1 2021.

Since the start of Q2, prices have continued to increase dramatically. Base futures for Q2 2022 in Queensland reached a record high of $272/MWh in early May, up from around $84/MWh at the beginning of Q1. Similarly, NSW Q2 2022 products settled at a record high of $231/MWh. Prices have also significantly increased in South Australia and Victoria.[1]

For the upcoming 3-year horizon, base future prices increased across Q1 2022 in all regions for all quarters. While Queensland is the highest priced region in 2022, NSW has the higher price expectations for 2023 and 2024 (Figure 1.6). NSW base futures are currently settling at greater than $100/MWh in all quarters until the end of 2024.

1 Prices as of 15 May 2022.

Figure 1.6 Closing price of base futures, Q2 2022 to Q4 2024



Source: AER analysis using ASX Energy data.

Note: Closing price of base futures contracts for Q2 2022 to Q4 2024 on the last trading days of Q3 2021 (30 September 2021), Q4 2021 (31 December 2021) and Q1 2022 (31 March 2022).

The increased price expectations across all regions are likely being driven by several factors including increased fuel prices, geopolitical uncertainty, the upcoming closure of the final 3 Liddell power station units in early 2023, as well as general uncertainty around coal generator closure dates (as exemplified by the announcement of the earlier closure of Eraring).

1.3 Demand increased, reaching near records in Queensland

Demand increased in all regions on average compared to Q1 2021. Warmer temperatures this quarter, including higher overnight minimum temperatures associated with La Niña weather patterns, led to increased demand for cooling.[2]

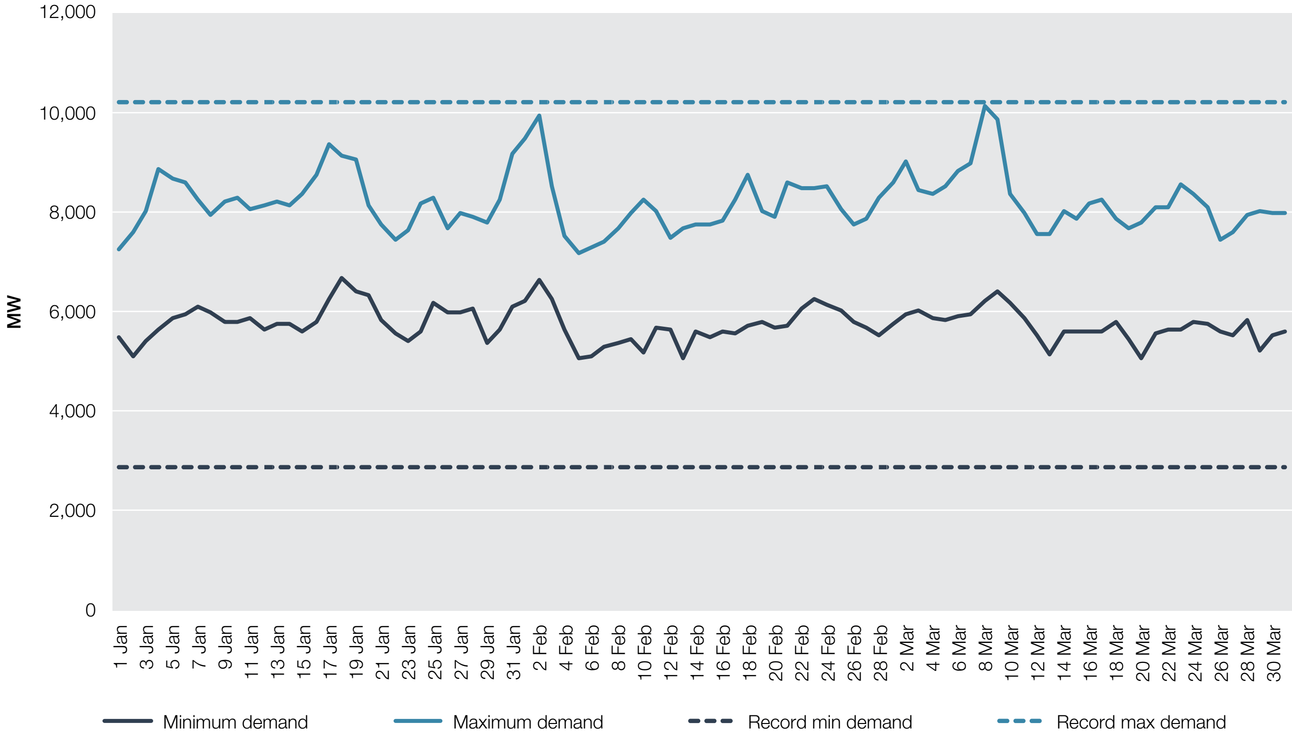
Queensland had near record maximum daily demand levels on 2 February and 8 March (Figure 1.7). On both occasions, consecutive days of extreme temperatures and high humidity increased demand for cooling. In the week beginning 30 January, Brisbane experienced 5 days with maximum temperatures above 30° Celsius in a row.[3] This resulted in increased demand for cooling which, combined with the outages at Kogan Creek and Callide power stations, meant that the Australian Energy Market Operator (AEMO) activated its Reliability and Emergency Reserve Trader (RERT) mechanism on 1 February to procure spare capacity.[4]

2 AEMO, Quarterly Energy Dynamics – Q1 2022, 29 April 2022.

3 Bureau of Meteorology, Daily Weather Observations, Brisbane Jan 2022 and Feb 2022.

4 AEMO, Quarterly energy dynamics – Q1 2022, April 2022, p 8.

Figure 1.7 Queensland daily maximum and minimum demand



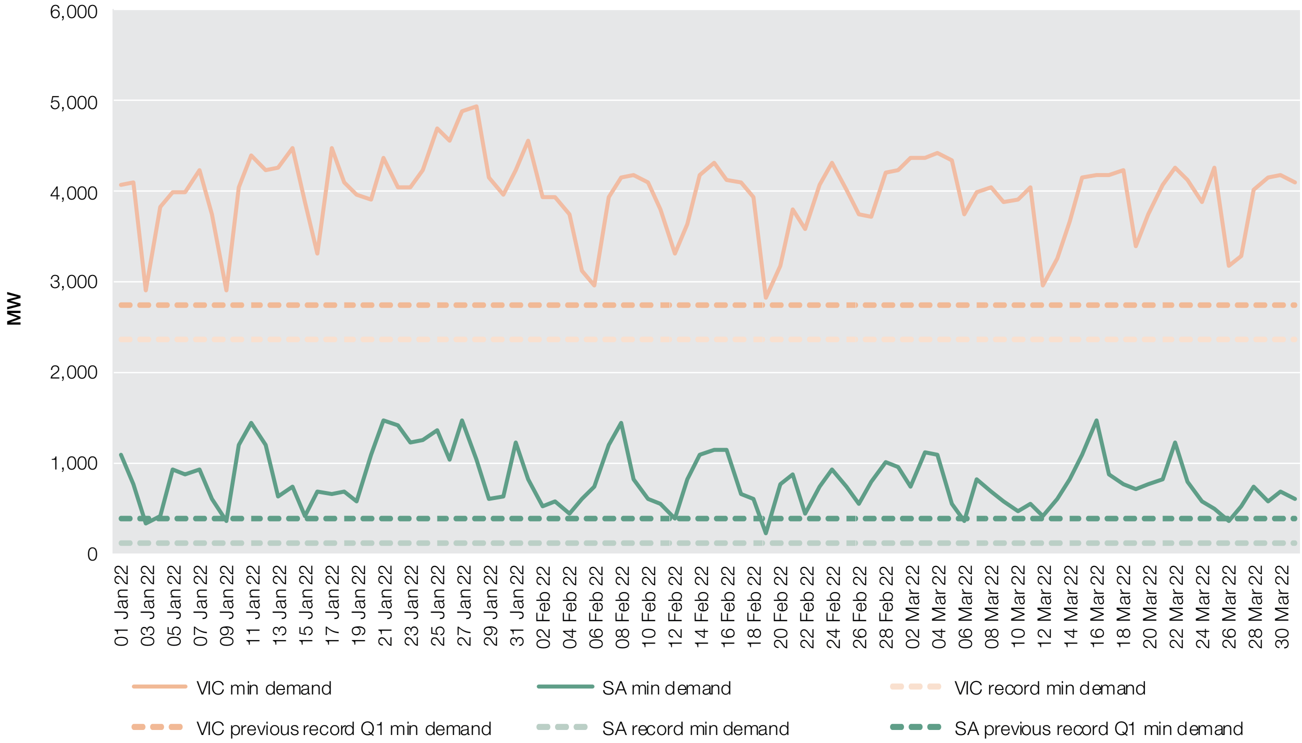
Source: AER analysis using NEM data.

Note: Uses daily minimum and maximum native demand.

While average demand grew in all regions compared to Q1 2021, demand from the grid fell during the middle of the day as rooftop solar output increased. In South Australia and Victoria this and milder temperatures led to low daily minimum demand levels (Figure 1.8). South Australia reached a new Q1 record for daily minimum demand on 19 February – at 216 MW – and broke the previous Q1 record on 4 other occasions. In the evening however, demand in both South Australia and Victoria was above Q1 2021 levels, primarily due to higher overnight temperatures, particularly in January and March.[5]

5 Bureau of Meteorology, Climate summaries, South Australia January and March monthly summaries.

Figure 1.8 Victoria and South Australia daily minimum demand



Source: AER analysis using NEM data.

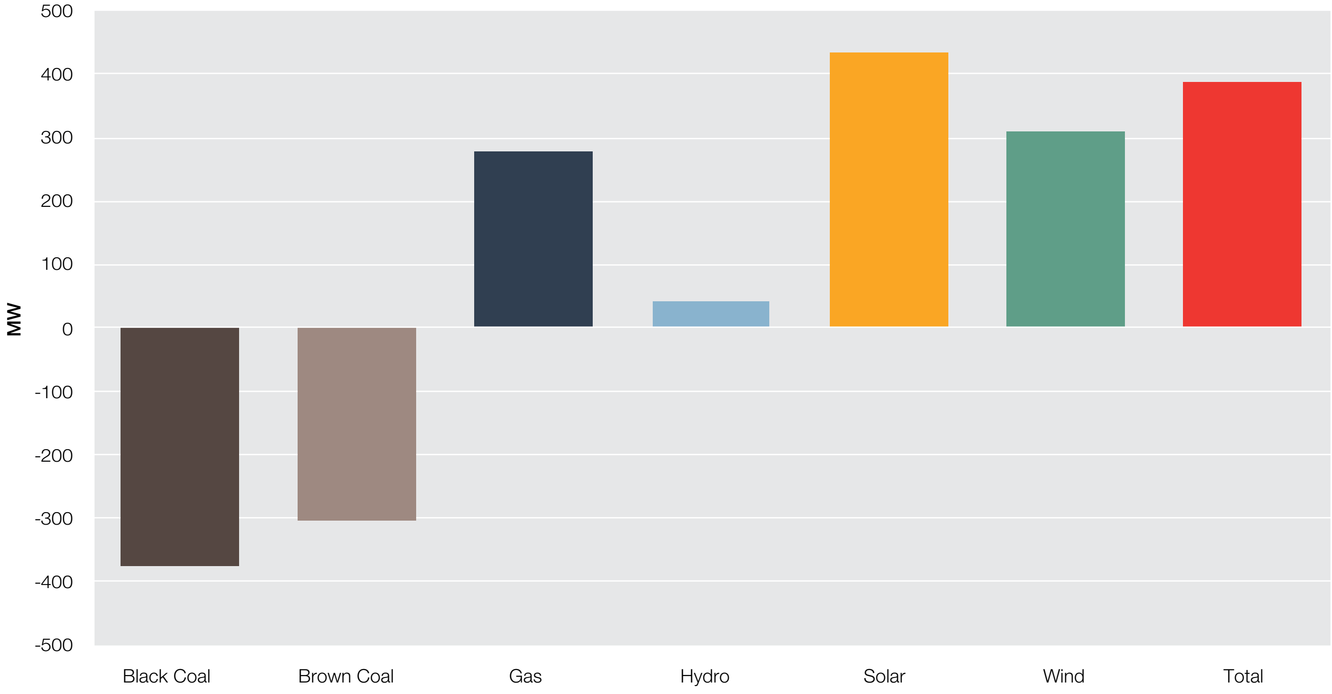
Note: Uses daily minimum native demand.

1.4 Record high grid scale solar and low black coal generation

Black coal generation NEM-wide was at a record low 49% of total output this quarter, with the largest reduction in Queensland. Similarly, brown coal output also fell to the lowest Q1 level since NEM start. Together, coal generators produced 678 MW less on average this quarter than in Q1 2021 (Figure 1.9). This decline can be attributed to a combination of generator outages, further new entry of low-priced renewable capacity, and coal generators shifting offered capacity to higher prices (section 1.5).

Compared to Q1 2021, black coal generator outages in Queensland and NSW, and brown coal outages in Victoria were more common (Appendix A). Coal units have the largest capacity of all generators in the NEM. Sustained outages, especially when unplanned, can have a significant impact on the supply of low-priced electricity and, when combined with high demand, higher offers and limited access to low-priced generation from other regions, can contribute to higher prices. In addition to expected outages like Callide C power station, there were multiple unplanned outages this quarter, especially at Kogan Creek, Gladstone, Liddell and Yallourn power stations. At the end of January around 20% of Queensland baseload capacity was unavailable due to outages.

Figure 1.9 Change in NEM average quarterly generation, Q1 2022 compared to Q1 2021



Source: AER analysis using NEM data.

Note: Change in average quarterly metered generation output by fuel type from Q1 2021 to Q1 2022. Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output. Total includes a small amount of battery and other generation.

Despite falling coal output, NEM-wide generation rose in line with the growth in demand this quarter, increasing 383 MW (2%) compared to the record low in Q1 2021. Queensland and Victoria were the only regions to record a decrease in generation this quarter, as the reduction in coal output outweighed increases in other forms of generation.

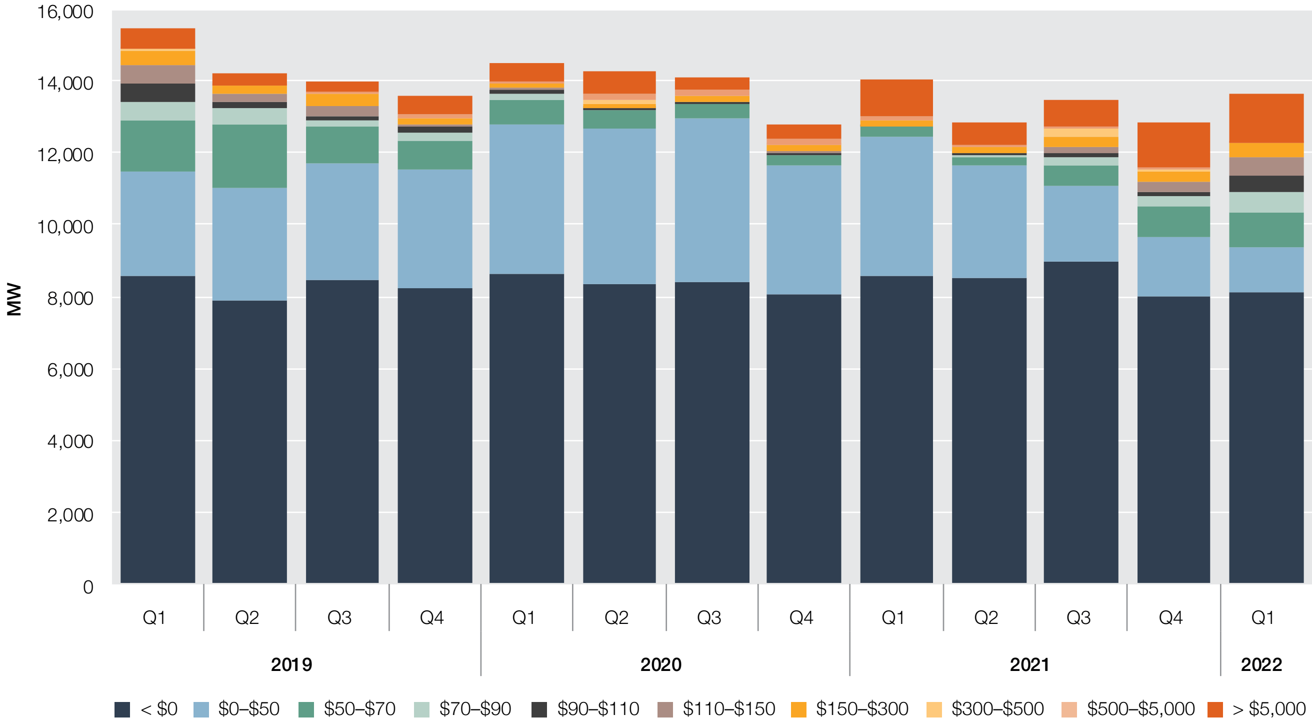
Grid-scale solar generation rose in all mainland regions, hitting a record high of 1,504 MW, which broke the previous record set in Q4 2021. Wind generation also rose in all mainland regions to a Q1 record of 2,686 MW. Together, solar and wind generation made up 19% of the generation mix.

Despite rising gas market prices, gas output also grew this quarter. The greatest growth occurred in NSW and Victoria, due to a change in offers at EnergyAustralia's Tallawarra and Newport power stations (section 1.5). Because this rise was from a record low base, gas generation was still at its second ever lowest level for Q1.

1.5 Black coal generators shifted offered capacity to higher prices

Across both Queensland and NSW combined, black coal offers priced below $50/MWh decreased by 3,100 MW compared to Q1 2021, with most of that capacity shifting to prices between $50/MWh and $300/MWh (Figure 1.10). Of this, around 440 MW was removed altogether, which is roughly the size of Callide C power station unit 4 which has been offline since May 2021.

Figure 1.10 NEM black coal offers



Source: AER analysis using NEM data.

Note: Average quarterly offered capacity by black coal generators in the NEM within price bands.

Black coal generators have changed their offers in response to low prices in the middle of the day when demand is lower and solar output is high. As cheap solar output increases in the middle of the day, coal generators have been shifting their capacity to higher prices to avoid uneconomic dispatch.

Increasing fuel prices may also have influenced black coal generators to offer their capacity at higher prices. Since mid-2020, Newcastle coal prices have risen significantly and this quarter rose as high as $436/tonne – more than triple the price in Q1 2021.[6] While we do not know to what extent participants are exposed to this price, or if this increase fully accounts for the shift in generator offers, this price can provide an upper bound to represent participant fuel input costs.[7]

Domestically, some generators are experiencing supply issues because of flooding in southern Queensland and northern NSW, which may be contributing to higher priced offers. For example, in April, trucks were required to cart coal from the Callide Mine to the Millmerran Power Station to address such a supply shortage.[8]

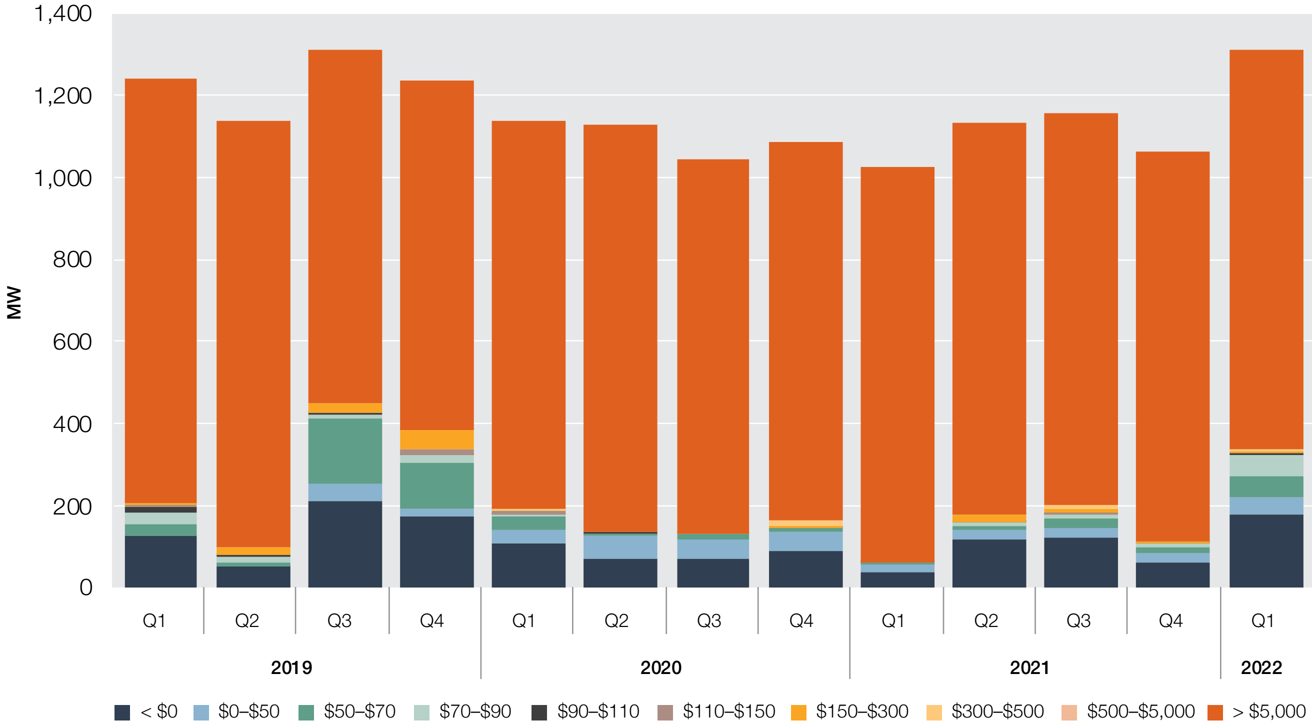
Average capacity offered by gas generators increased this quarter (Figure 1.11). While there were decreased offers in some regions, this was more than offset by a significant increase in capacity offered in NSW compared to Q1 2021. In NSW, participants offered an additional 260 MW capacity below $90/MWh, primarily due to EnergyAustralia shifting offers at Tallawarra power station to lower prices to cover for an outage at Mount Piper power station.

6 Black coal proxy input cost derived from Newcastle coal index (USD$ per tonne), converted to AUD$ using the RBA exchange rate.

7 Coal generators can source their fuel from a range of sources including directly and relatively cheaply from an attached mine, or through short or long term fuel contracts which bring coal in from further afield. Much of the coal used by NSW black coal generators is sourced through these coal supply contracts. Short-term supply contracts for coal are likely to align more closely with the prevailing international coal price. Generators may also be exposed to changes in the international coal price if long term contract negotiations coincide with fluctuating coal prices. For this reason, the price of coal at the Newcastle port is often used as a reference point for coal fuel costs.

8 Banana Shire, 'Increased Heavy Vehicle Traffic in the Area', 14 April 2022.

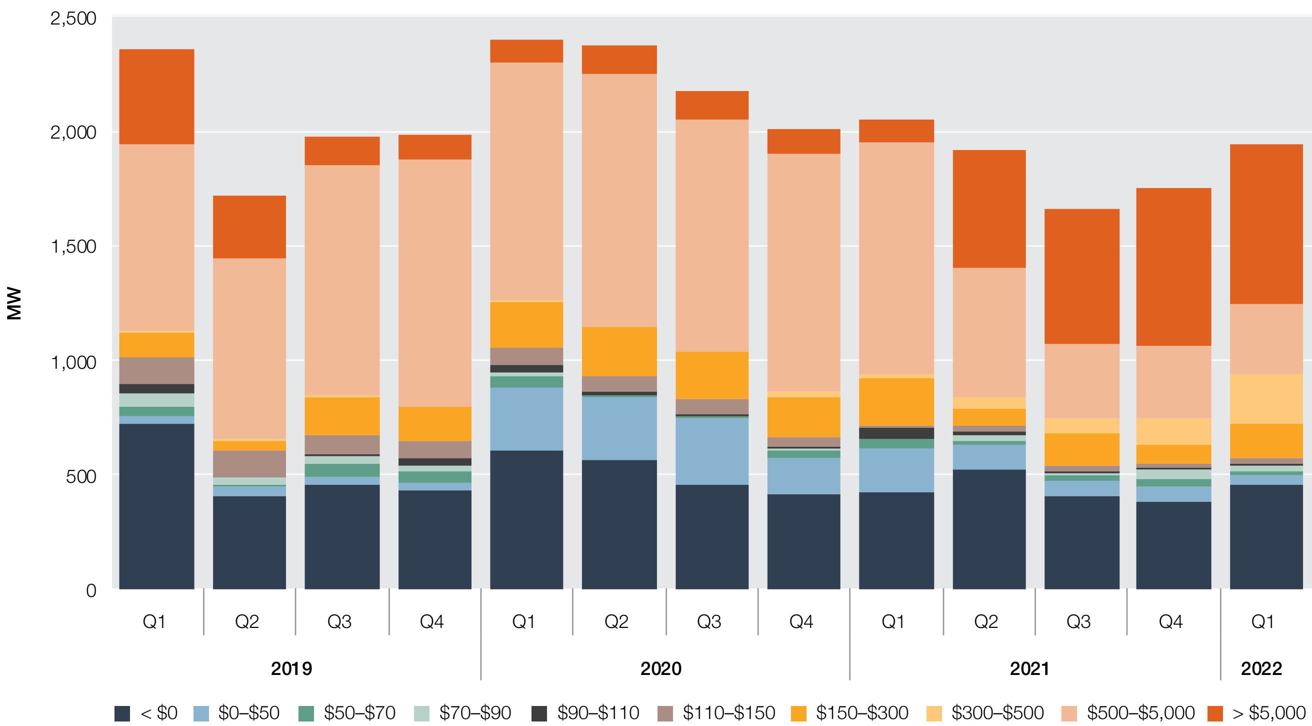
Figure 1.11 NSW gas offers



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

Compared to Q1 2021, Queensland gas generators shifted capacity from lower to higher prices, particularly above $5,000/MWh (Figure 1.12). This is a continuation of the trend since Q2 2021, where Queensland gas generators are offering capacity at higher prices in response to rising gas market prices. Gas fuel input costs increased almost $40/MWh across the quarter in all markets and are considerably higher than Q1 2021 (section 2.1).

Figure 1.12 Queensland gas offers



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

Generally, hydro generators shifted capacity priced between $0/MWh and $50/MWh to higher price bands this quarter, compared to Q1 2021. However in Queensland, CleanCo increased its offers of low priced capacity to make up for an outage at Swanbank E power station, shifting capacity that was previously priced over $5,000/MWh to prices between $150/MWh to $500/MWh.

Both solar and wind generators are offering more capacity into the market, reflecting new entry over the year (section 1.8). In NSW in particular, solar generators offered almost twice the amount of capacity offered in Q1 2021.

More generally, the introduction of 5-minute settlement on 1 October 2021 has also changed participant offer behaviour in response to high prices. Previously, as participants were paid an average 30-minute price, when prices spiked early in the trading interval, they had an incentive to rebid their capacity to low prices to receive a share. Now, as participants are paid each 5-minute price rather than a 30-minute average, this incentive has been removed and we no longer see the same behaviour.

1.6 High prices set by black coal and gas in Queensland

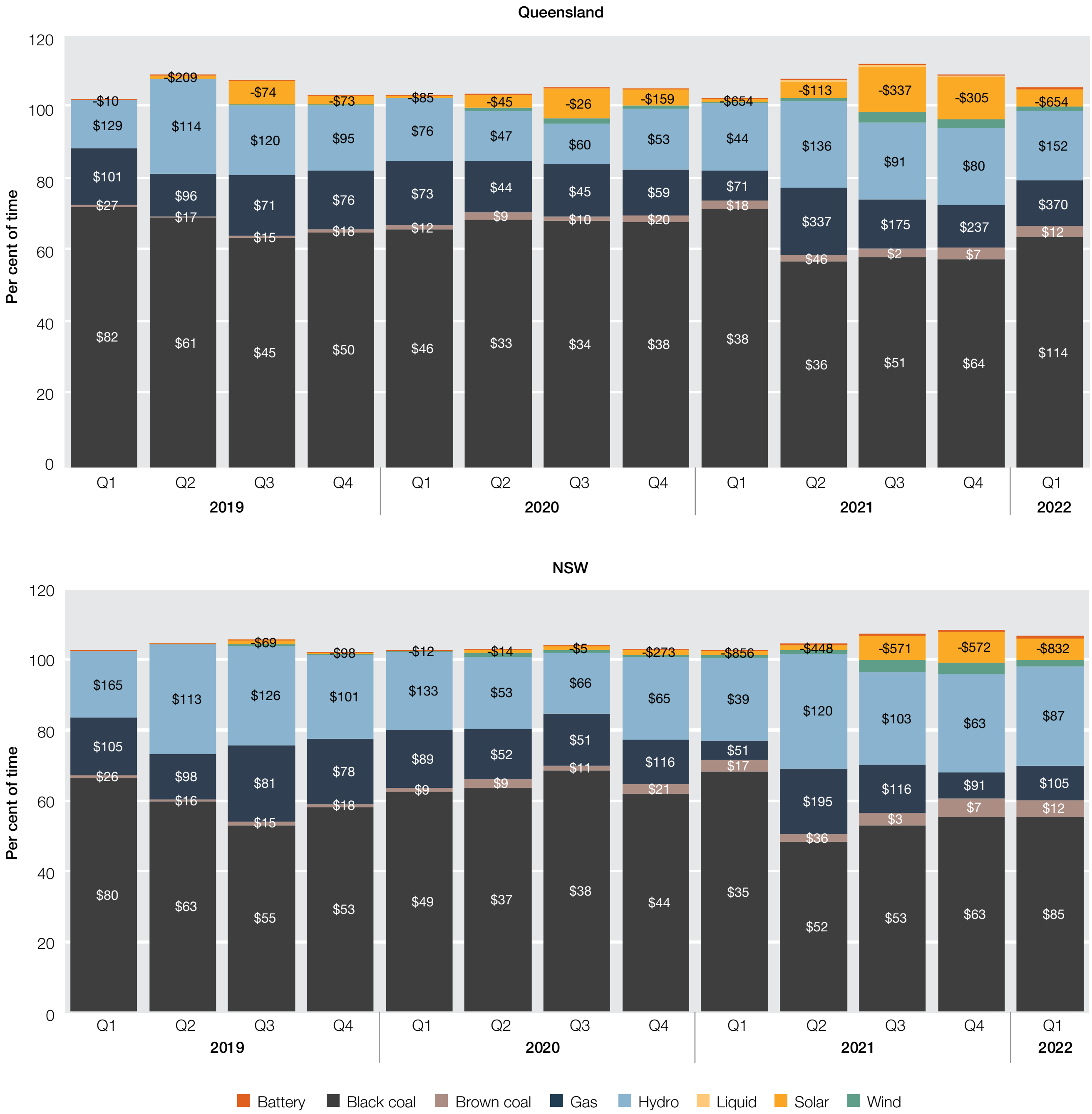
Black coal and gas generators set the price higher in most regions this quarter than in Q1 2021 (Figure 1.13). This increase was most significant in Queensland, where black coal generators set the price at $114/MWh on average, up from $38/MWh last year. This change reflects how participants have adjusted their offers, shifting cheaper capacity to higher prices (section 1.5). And, with several high price events this quarter, very expensive gas generation was needed to meet demand, resulting in gas generators setting the price at $370/MWh on average, up from $71/MWh.

Because Queensland black coal generators offered their capacity at higher prices, they set the price less often than in Q1 2021. Gas generators, however, set the price significantly more often this quarter reflecting their role in meeting the increased demand, despite setting the price at much higher levels.

Hydro, wind, and solar generation also set the price more frequently this quarter than in Q1 2021. Hydro generation set the price at $152/MWh, well below the average price set by gas. Hydro generators filled in for more expensive generation and set the price more frequently across the evening peak than in Q1 2021.

While NSW generators also set prices at higher levels, the increase was more modest than in Queensland. This is notable because as adjoining regions their prices are commonly aligned. In NSW, black coal generators set the price at $85/MWh, and gas generators set the price at $105/MWh. Like Queensland, hydro generators set the price below gas (at $87/MWh), setting the price more often in the evening.

Figure 1.13 Price setter by region, Queensland and NSW



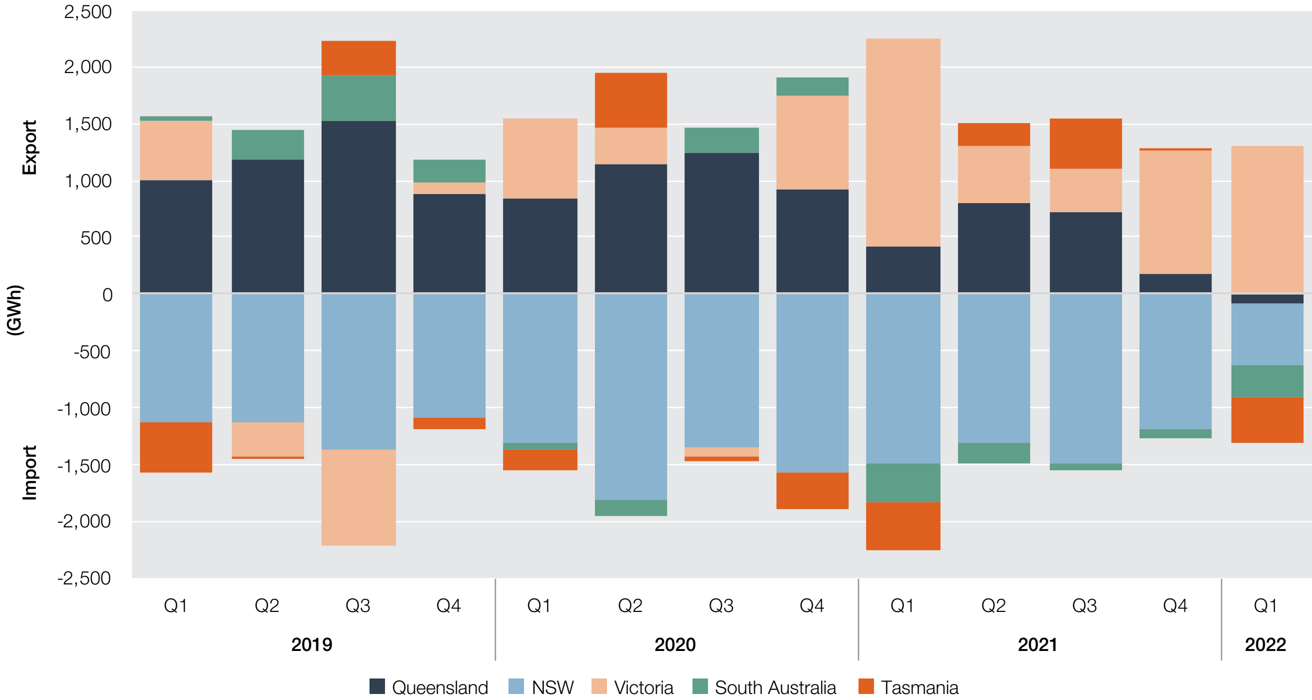
Source: AER analysis using NEM data.

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).

1.7 Queensland became a net importer for the first time

This quarter, Queensland imported more energy than it exported for the first time since the Queensland-NSW Interconnector (QNI) was commissioned in 2001 (Figure 1.14).

Figure 1.14 Net flows between regions (exports – imports)

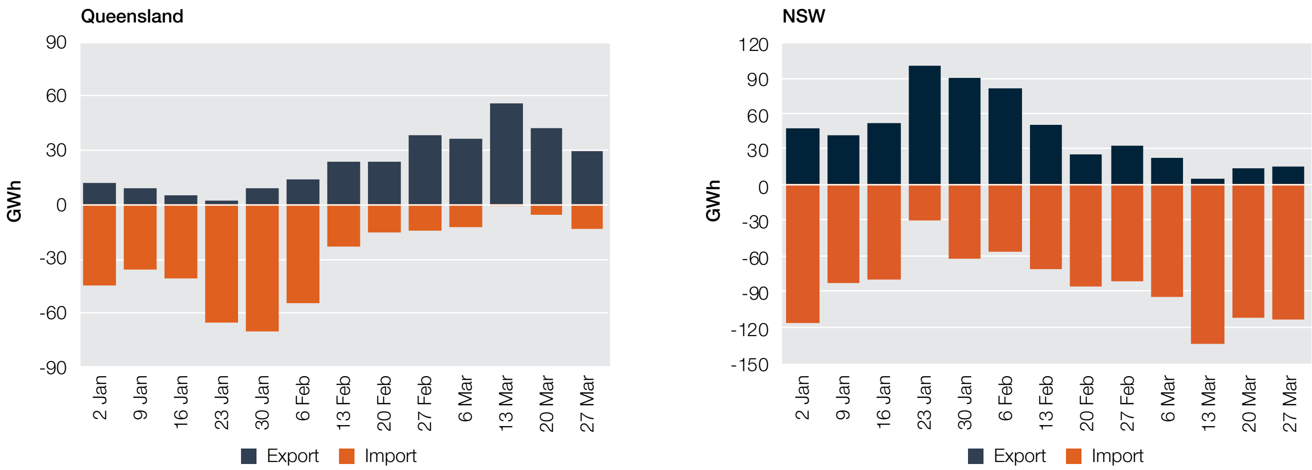


Source: AER analysis using NEM data.

Note: Net amount of energy either imported or exported each quarter by region.

Queensland's average imports more than doubled compared to last quarter as its high spot price meant that it brought in more lower-priced energy from NSW. This was most pronounced in the first half of the quarter and in particular, the week beginning 30 January which was characterised by high demand. As the quarter progressed, Queensland exported more and imported less, but this change was not enough to offset the imports earlier on (Figure 1.15).

Figure 1.15 Weekly flows in Queensland and NSW



Source: AER analysis using NEM data.

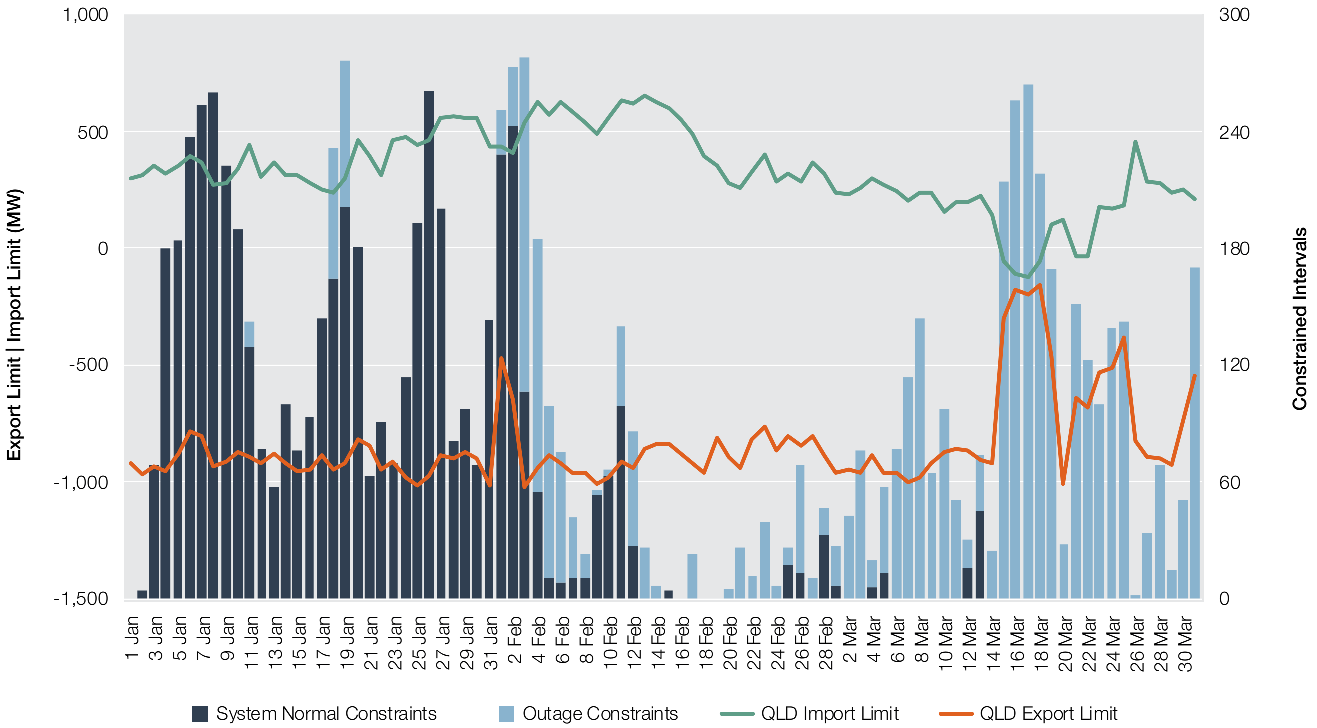
Note: Total interconnector exports and imports by week.

While Queensland was a net importer, QNI was constrained more often than in Q4 2021, being constrained 36% of the time. In contrast to previous quarters when upgrades to QNI restricted flows on the interconnector, more imports this quarter meant QNI reached its import limit more often, and consequently system normal constraints bound more frequently.[9] This occurred most often in January (Figure 1.16).

However in March, system normal constraints bound less, and constraints relating to planned outages in NSW were more frequent. Across the quarter, both system normal and outage constraints bound most often in the evening, coinciding with Queensland's high prices.

9 System normal constraints are always invoked and reflect network limits when there are no outages.

Figure 1.16 Queensland import limit and constrained intervals – by day



Source: AER analysis using NEM data.

Note: Queensland import limit and constraints by time of day for Q1 2022.

Victoria was the only net exporting region this quarter (Figure 1.14). Victoria had an abundance of solar and wind generation in addition to its lower-cost brown coal, which put it in a good position to export cheaper generation to neighbouring regions.

1.8 Almost 500 MW of new capacity entered the market

Almost 500 MW of new capacity entered the NEM in Q1 2022 (Figure 1.17), comprising:

- 154 MW of gas generation in South Australia
- 209 MW of wind capacity in Victoria
- 135 MW of solar capacity in NSW.

On the other hand, 50 MW of gas capacity was removed this quarter as the Hunter Valley Gas Turbines in NSW exited on 1 January. The first black coal unit (500 MW) at Liddell Power Station will exit in Q2 2022, with the remaining units to exit by Q2 2023, and the final Torrens Island A power station unit (120 MW) due to exit in September 2022.

Figure 1.17 New entry and exit

Source: AER analysis using NEM data.

Note: New entry is recorded using registered capacity of scheduled and semi-scheduled generators. Hashed areas reflect committed new entry and planned generator retirements according to the classification in AEMO Generator Information. The new entry date is taken as the first day the station produces energy. Closures are denoted below the line. Solar is large scale solar and does not include rooftop solar.

Since the Wholesale Demand Response Mechanism was first introduced in Q4 2021, registrations for providers have continued to increase, with 11 participants currently registered to provide up to 58 MW of demand response.[10] The mechanism was used twice this quarter during times of high demand in Victoria and NSW.[11]

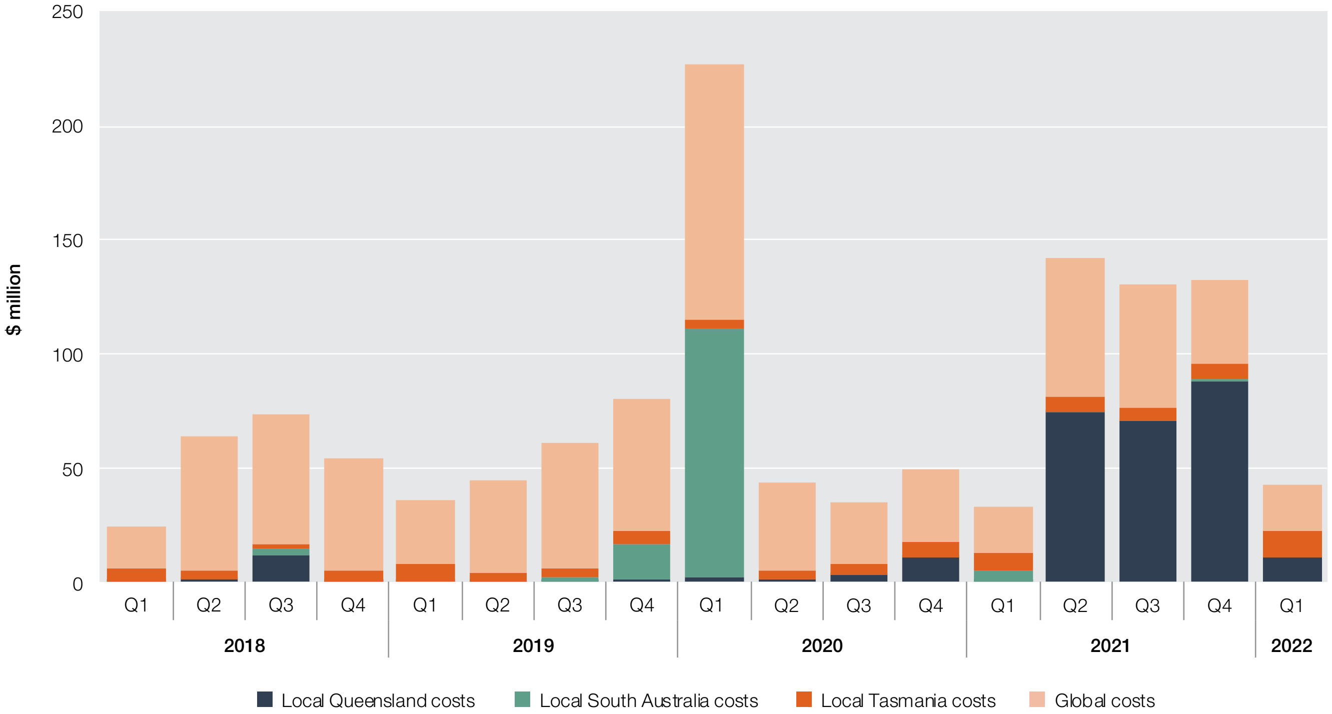
1.9 FCAS costs fell significantly in Queensland.

Total costs for Frequency Control Ancillary Services (FCAS) fell from recent highs to $43 million this quarter, the lowest quarterly cost since Q1 2021 (Figure 1.18).

10 The Wholesale Demand Response Mechanism was introduced on 21 October 2021 and allows registered demand response service providers to offer to adjust their consumption at certain prices in the same way generators currently offer to supply energy. Demand response service providers are paid based on their reduction from a baseline estimate at the prevailing electricity spot price.

11 AEMO, Quarterly energy dynamics – Q1 2022, April 2022, p 28.

Figure 1.18 Quarterly FCAS cost by local and global costs



Source: AER analysis using NEM data.

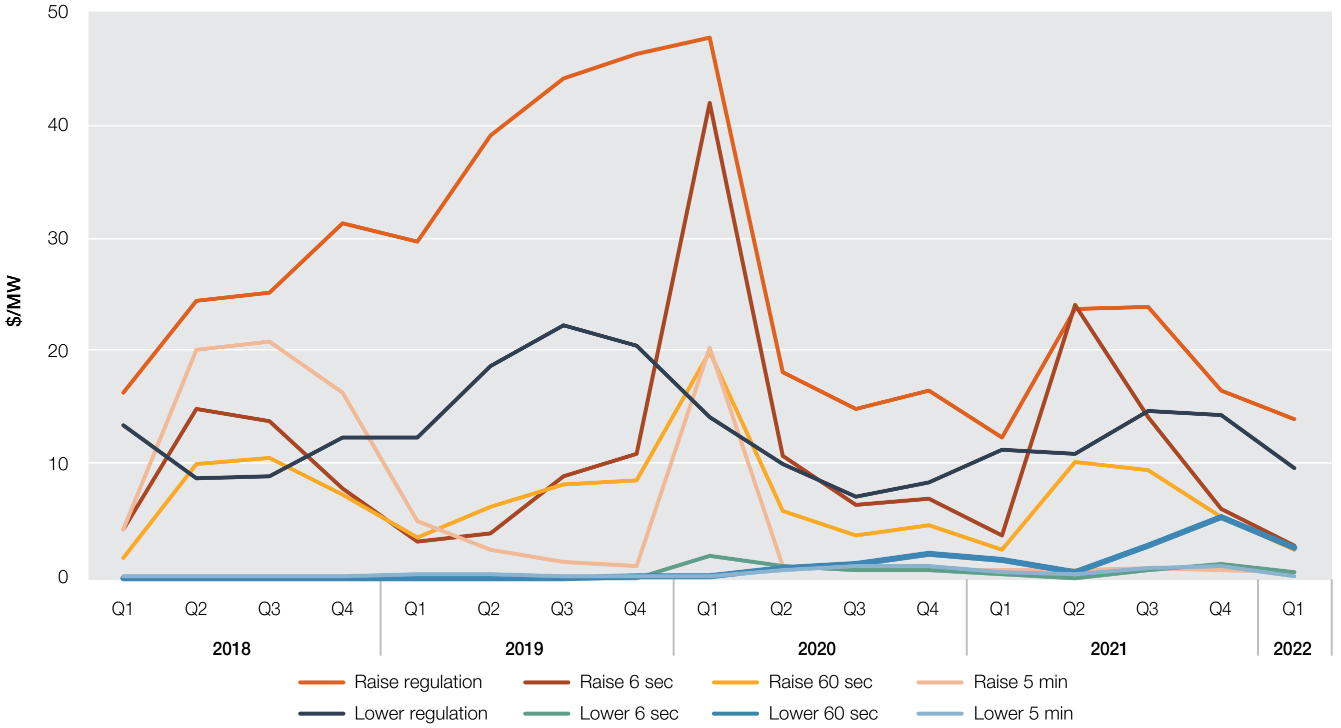
Note: Global and local FCAS costs, by quarter.

The reduction in FCAS was primarily driven by the fall in local Queensland costs. Local FCAS costs in Queensland fell from $89 million in Q4 2021 to $11 million this quarter. From Q2 to Q4 2021, Queensland FCAS costs were high due to outages relating to the upgrade of QNI, which required Queensland to supply its own FCAS between 13% and 24% of the time. Works on QNI eased in Q1 2022, leading to fewer planned outages, allowing Queensland to import ancillary services from the global FCAS market.

In contrast, local FCAS costs in Tasmania hit a record high of $11 million primarily due to raise 6 second service requirements. Tasmania often must supply its own FCAS because limits on the Basslink interconnector restrict its ability to import FCAS. However, this quarter was notable because there was an exceptionally high average local requirement for raise 6 second services. Since Q3 2021, the local raise 6 second requirement in Tasmania has increased and put upwards pressure on local FCAS prices as more expensive ancillary services were required. However, the impact of this increase in raise FCAS is limited as Hydro Tasmania not only pays for the service, it also provides the service. Therefore, increased FCAS costs incurred by Hydro Tasmania are offset by increased FCAS revenues.

Global prices for all ancillary services decreased this quarter, with the most significant reductions for lower 6, raise 6 and raise 60 second services, which fell by 50% compared to Q4 2021. While the total amount of FCAS that was procured in the NEM did not change materially, fewer local requirements in Queensland may have contributed to a more open market that put downward pressure on global prices.

Figure 1.19 Global FCAS prices by service, by quarter



Source: AER analysis using NEM data.
Note: Average quarterly global FCAS prices, by service.

Focus – FCAS prices greater than $5,000/MW in Queensland

While FCAS costs fell significantly in Queensland, this focus story details two high FCAS prices that occurred in Queensland in the quarter. This story illustrates that FCAS prices continue to be sensitive to work on QNI. On 16 March 2022, at 5 am and 5.30 am, local 30-minute Queensland prices for lower 6 second (L6) and lower 60 second (L60) services exceeded $5,000/MW (Table 1.1).

Table 1.1 30-minute average prices for local ancillary services

30-MINUTE PERIOD	ANCILLARY SERVICE	
	Lower 6 second ($/MW)	Lower 60 second ($/MW)
5.00 am	15,067	15,000
5.30 am	10,466	10,383

The cause of these high prices were constraints invoked by AEMO to manage a planned outage on the Tamworth to Armidale line (part of QNI), which:

- led to forced energy exports from Queensland into NSW
- meant all Queensland FCAS requirements had to be met exclusively by local supply.

The consequence of the outage was that Queensland's local requirement for lower services increased in line with its exports and more expensive ancillary services were needed.

AEMO constraints created tight market conditions for FCAS in Queensland

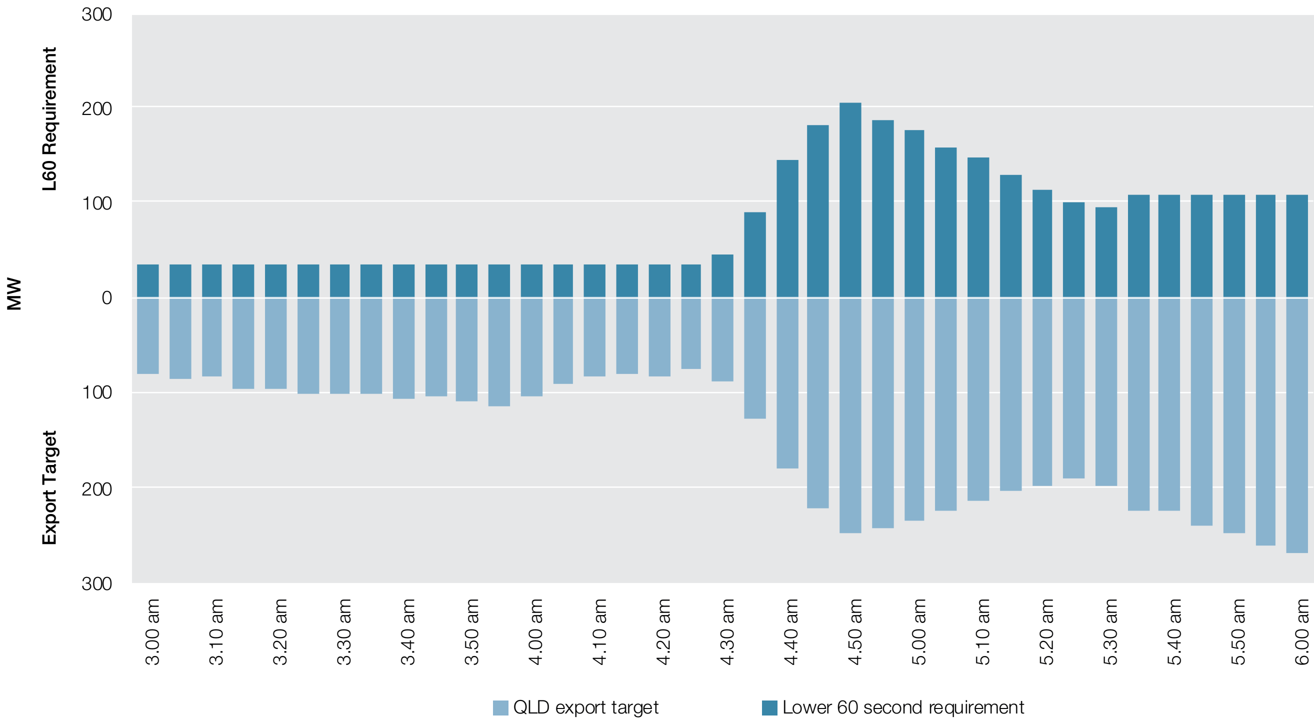
At 4.30 am on 16 March, AEMO introduced a constraint to prepare for a planned outage of the Tamworth substation in NSW. The constraint triggered an increase in Queensland's energy exports to manage voltage stability (Figure 1.20).

The Tamworth outage also created a credible risk that the Queensland to NSW Interconnector (QNI) would disconnect. If this occurred, Queensland would have been electrically isolated from the NEM in respect to FCAS because, while there are two interconnectors capable of sending energy to Queensland, ancillary services can only be transferred through QNI. AEMO therefore invoked a separate constraint, making Queensland source its FCAS locally, to manage this risk.

The combination of factors meant that Queensland was simultaneously exporting energy to NSW and enabling L6 and L60 services. In the event QNI tripped, Queensland's generation would exceed local demand because of its exports, leading to high frequency on the grid which can be rectified with lower ancillary services.

Consequently, as exports and the lower services requirement grew in tandem, there was upwards pressure on L6 and L60 services' prices because more expensive local FCAS had to be procured (Figure 1.21 and Figure 1.22). This was most evident for the 4.35 am and 4.40 am 5-minute intervals when both the L6 and L60 requirement rose by 45 MW and 55 MW in the respective times (Figure 1.20).

Figure 1.20 Export target and local lower 60 second services requirement in Queensland



Source: AER analysis using NEM data.

Note: The L6 and L60 requirement were the same for all the high priced intervals, excluding the 4.50 am interval which had a 5 MW difference.

Rebidding capacity did not cause the high prices

At 1.20 am, CS Energy rebid 30 MW of capacity at its Gladstone units, from under $5,000/MW to around the price cap for both L6 and L60 services. These rebids took effect for the 4.05 am interval.

Furthermore, Stanwell Corporation's initial offers for 4.05 am had 21 MW less capacity priced under $5,000/MW compared to 4 am, for both L6 and L60 services. These offers do not constitute 'rebids', however, they did contribute to a decline in low priced capacity at the time.

While shifting capacity reduced the amount of cheap FCAS available, this did not materially affect the price outcome because a large amount of expensive capacity was required to meet the requirement (Figure 1.21 and Figure 1.22). The peak L6 and L60 requirements, which occurred at 4.50 am, were 198 MW and 203 MW respectively, whereas the maximum capacity available under $5,000/MW was 89 MW for both services.

Energy market conditions reduced effective FCAS availability

The trade-off between the energy and FCAS markets can reduce the maximum availability of ancillary services to a lower effective availability. Demand was relatively low in Queensland at 4.35 am when the high price event began, indicating generators were running at a low or minimum load. When a generator's output is low, so is its effective capacity to provide lower services because it cannot reduce its production significantly. Effective capacity rises throughout the morning as grid demand increases and generators ramp up their production (Figure 1.22).

While effective availability for L60 services was on average 28 MW below the maximum availability for the first 6 high priced 5-minute intervals, the missing capacity was priced above $5,000/MW so this did not affect the price. Similarly, for L6 services, effective availability was roughly 10 MW below the maximum available for the first 2 high priced 5-minute intervals, although the unavailable capacity was priced high.

Figure 1.21 Maximum availability for lower 60 second services (LHS) and lower 6 second services (RHS)

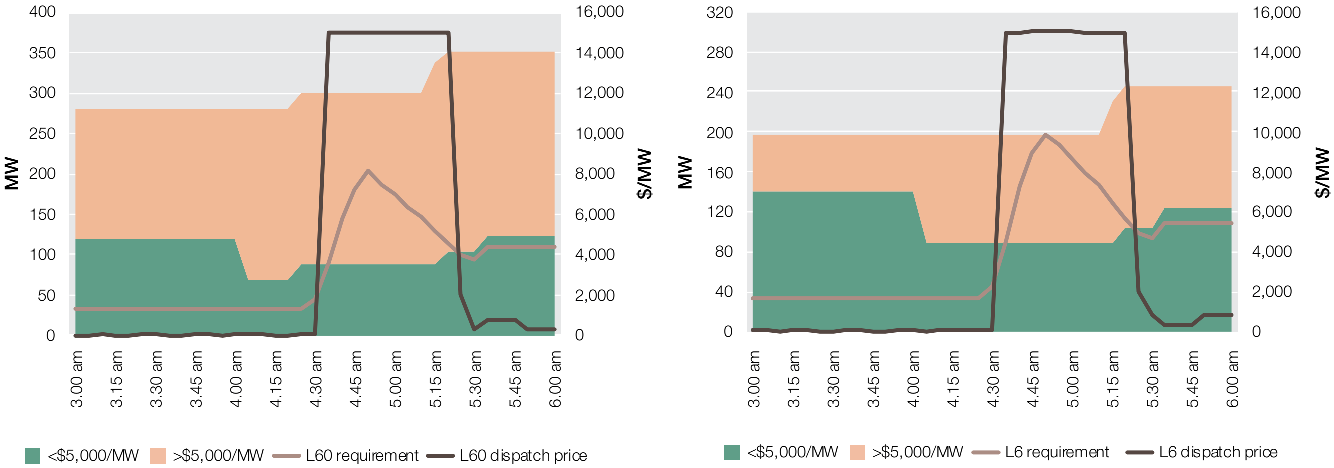
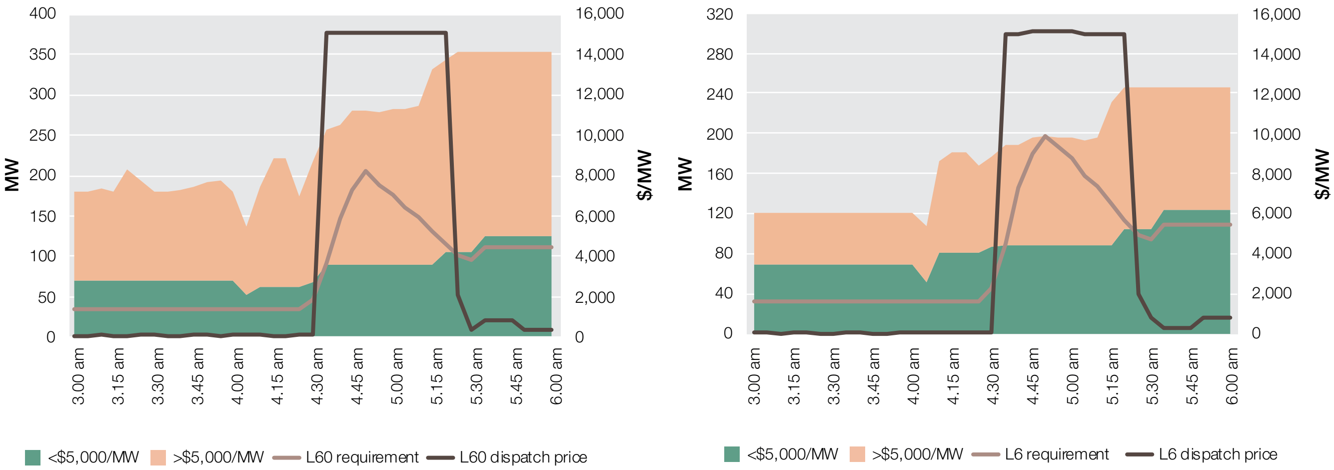
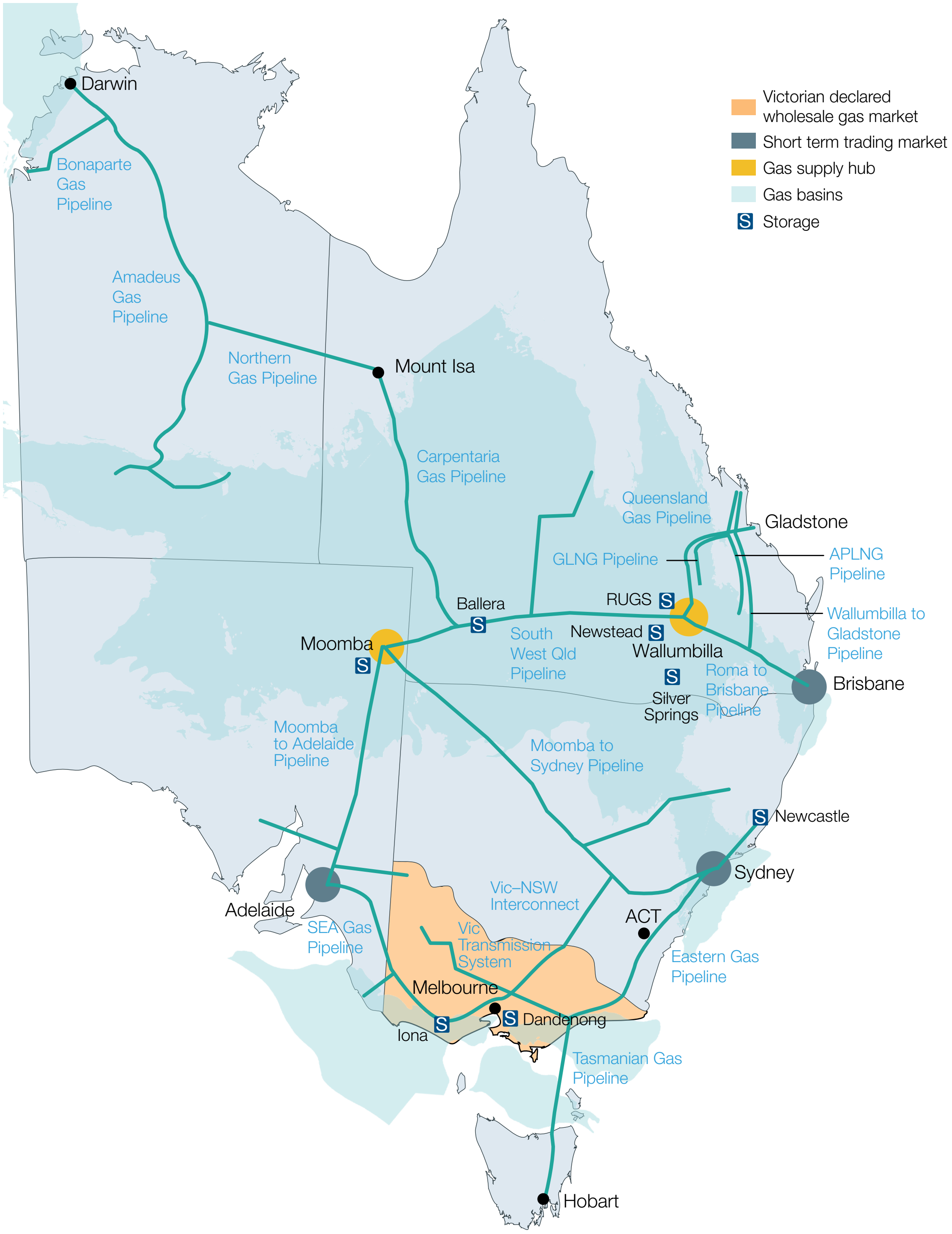


Figure 1.22 Effective availability for lower 60 second services (LHS) and lower 6 second services (RHS)



Source: AER analysis using NEM data.

2. Gas



Victorian declared wholesale gas market
Short term trading market
Gas supply hub
Gas basins
Storage
Darwin
Bonaparte Gas Pipeline
Amadeus Gas Pipeline
Northern Gas Pipeline
Mount Isa
Carpentaria Gas Pipeline
Queensland Gas Pipeline
Gladstone
GLNG Pipeline
APLNG Pipeline
Ballera
RUGS
Wallumbilla to Gladstone Pipeline
Moomba
South West Qld Pipeline
Newstead
Wallumbilla
Roma to Brisbane Pipeline
Brisbane
Silver Springs
Moomba to Adelaide Pipeline
Moomba to Sydney Pipeline
Newcastle
Sydney
Adelaide
Vic–NSW Interconnect
ACT
SEA Gas Pipeline
Vic Transmission System
Eastern Gas Pipeline
Melbourne
Iona
Dandenong
Tasmanian Gas Pipeline
Hobart

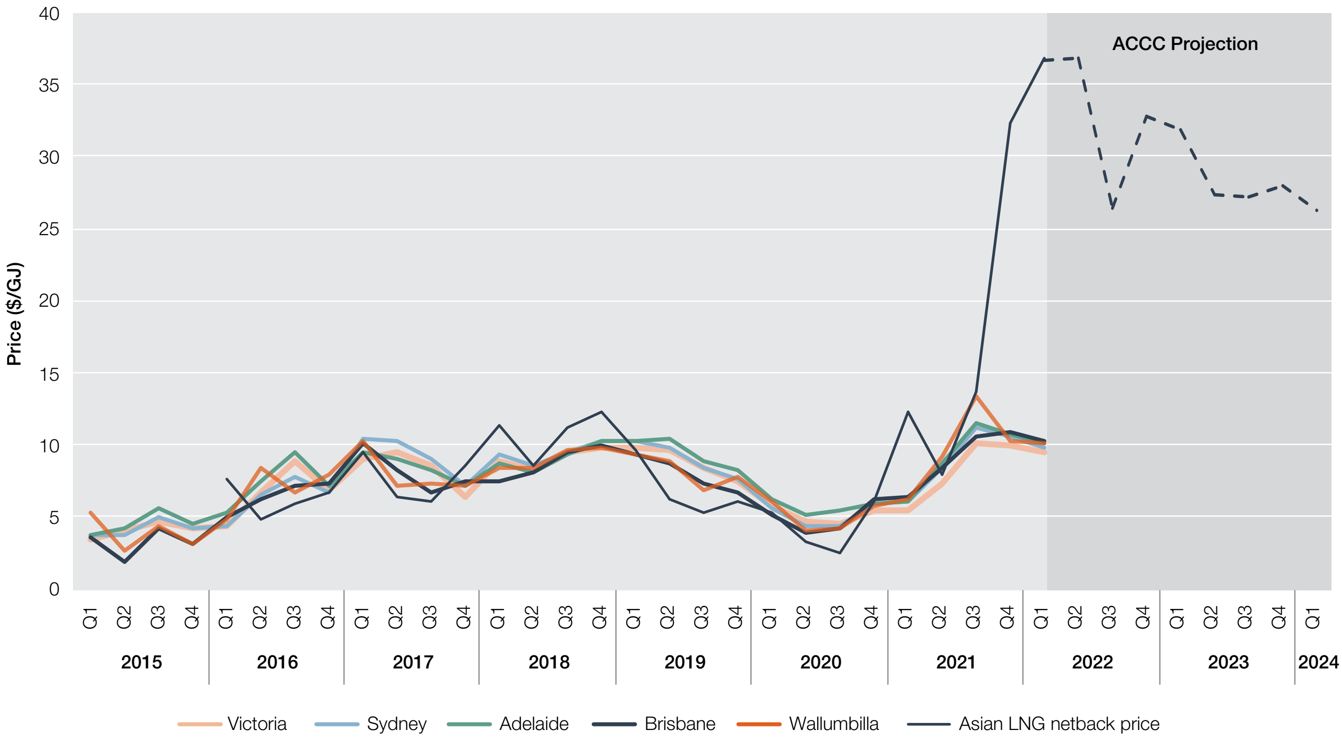
2.1 Domestic prices delinked to record international prices

Domestic gas prices remained elevated across the east coast with an average price of around $10/GJ, a record for a Q1 (Figure 2.1). Victoria recorded the lowest prices averaging $9.48/GJ for the quarter and Brisbane recorded the highest prices at $10.22/GJ. Prices increased as the quarter progressed, led by Queensland with $15/GJ to $17/GJ prices towards the end of March. This price rally continued into April and May, with prices up to $55/GJ recorded in Victoria in May (Figure 2.2).

High domestic spot prices post Q1 coincided with an increase in the volume of gas used to generate electricity and higher NEM prices (section 1.4).

Consistent with recent quarters, east coast gas markets continued to be largely insulated from unprecedented high international prices over Q1 2022 as prices continued to diverge (Figure 2.2). The LNG netback price averaged $36.81/GJ for the quarter marking a record high for this price series.[12]

Figure 2.1 Domestic spot prices and Asian LNG spot netback price

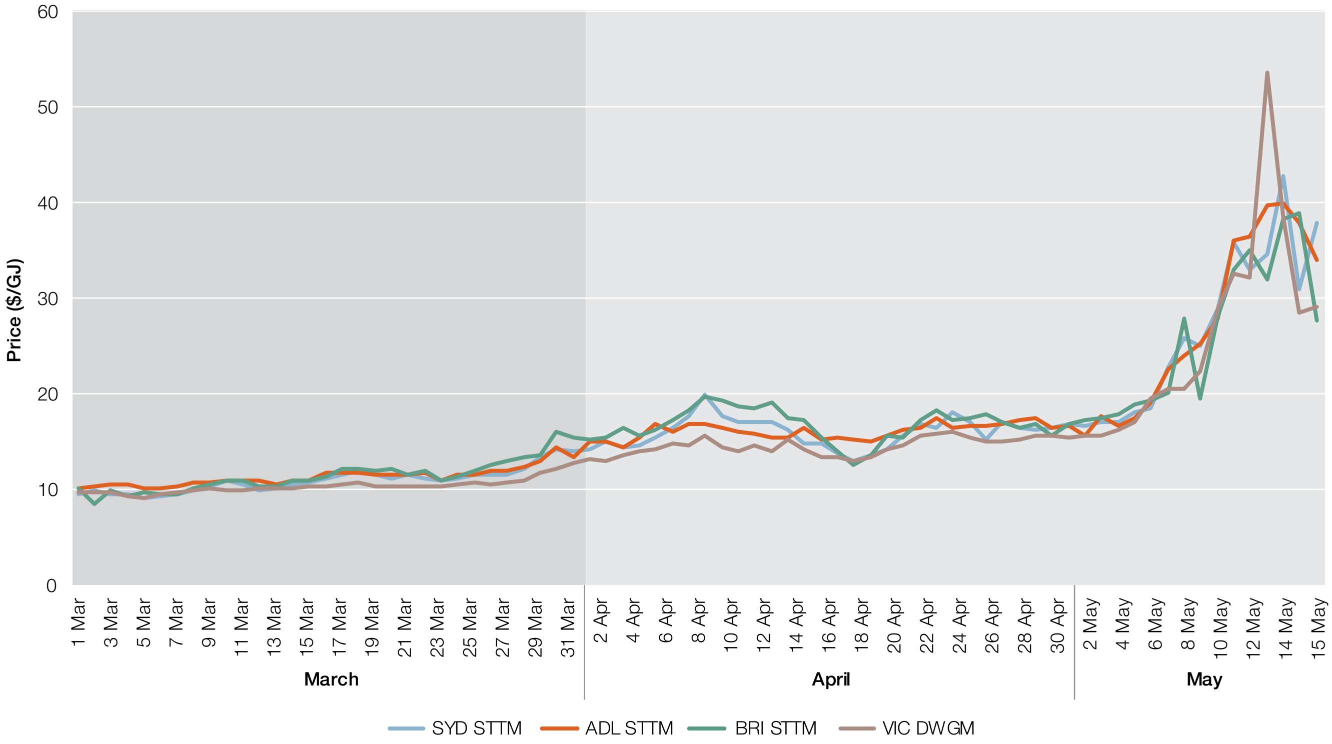


Source: AER analysis using DWGM, STTM and WGSH data, and ACCC netback price series.

12 The Asian LNG netback price is published by the ACCC. https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series.

Prices across all east coast capital city spot markets spiked towards the middle of May after rallying through April. Spot prices were driven by the need to supplement east coast production with high priced gas from storage to meet demand. There was also a lack of gas supplied from northern production sources to support spot markets, placing further pressure on gas storages.

Figure 2.2 Domestic spot prices in April-May



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

International LNG spot prices continued to be high and volatile (Figure 2.3). European and Asian gas prices reached record levels amid security of supply concerns due to the Ukraine conflict. Daily maximum prices reached $89/GJ in Europe and $71/GJ in Asia before falling back into the $30/GJ to $40/GJ range towards the end of the quarter.

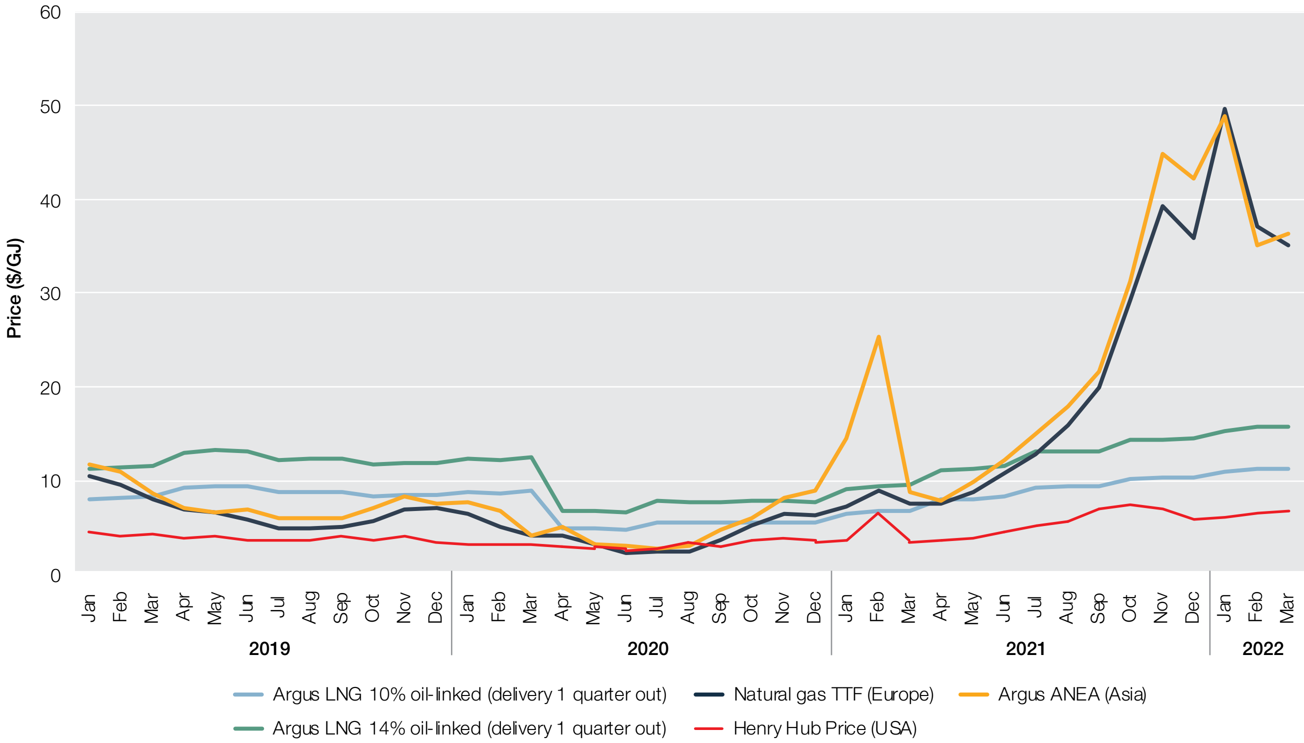
The prospect of Russian pipeline gas supply disruptions added greater urgency to Europe's attempt to rebuild its low gas storage levels, which put pressure on European prices this quarter. Europe started off the northern hemisphere winter with low gas storage levels. The EU commission proposed imposing a minimum gas storage obligation of 80% by November this year to reduce supply risks.[13] Despite restocking, at the end of the quarter, European underground storages were below average levels and the global demand for gas remained elevated.[14]

13 European Commission: Questions and Answers on the new EU rules on gas storage.

14 Japan Oil, Gas and Metals National Corporation: Natural gas and LNG related information.

International gas prices were higher than oil linked LNG prices for the third consecutive quarter, providing a strong incentive for LNG buyers to source gas under existing long term oil linked contracts (Figure 2.3). The divergence of oil and gas prices has led North Asian buyers to enter US Henry Hub linked LNG supply agreements, as buyers look for stable pricing amidst high volatility.[15] More future gas prices may be linked to the Henry Hub as the US increasingly acts as the global swing (or marginal) producer of LNG.

Figure 2.3 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.

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.

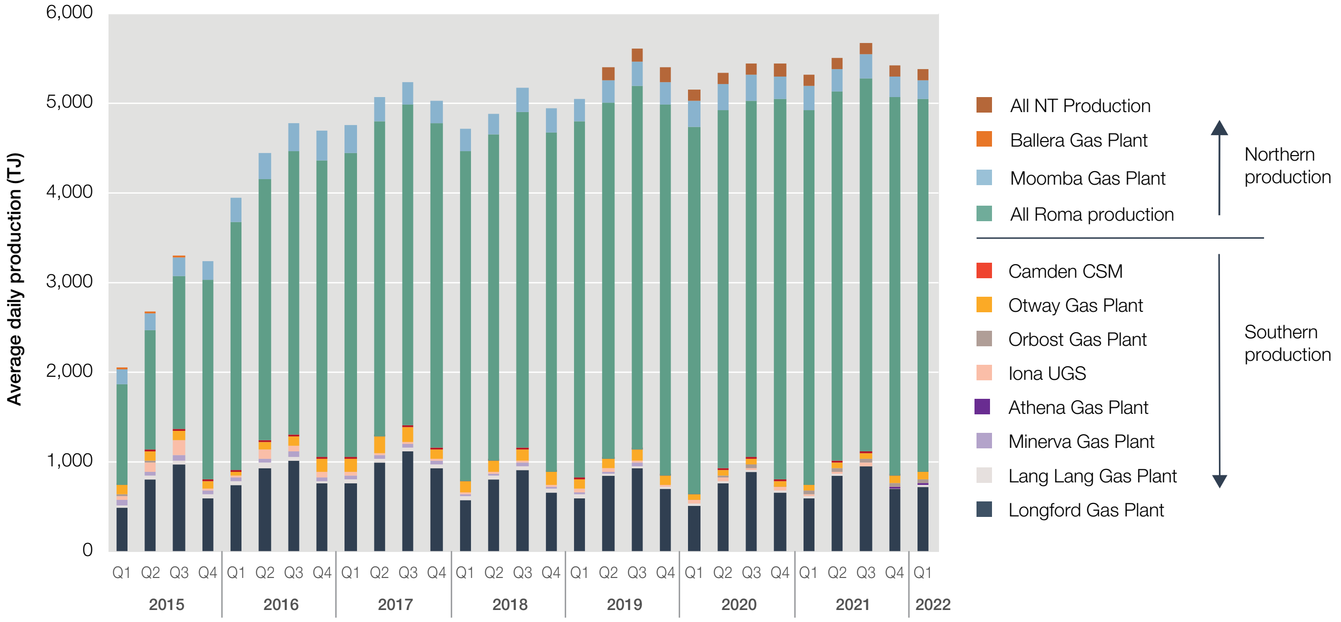
2.2 Gas production continues at record levels

Domestic gas production continued to be strong, as record gas production for a Q1 (5,351 TJ/day) supported LNG exports (section 2.3).

Levels were slightly down on Q4 2021, reflecting normal seasonal patterns (Figure 2.4). While Queensland gas production at Roma declined by 61 TJ/day, this was partly offset by an increase in Longford production of 28 TJ/day, as gas supplies flowed from the south.

15 Argus Media.

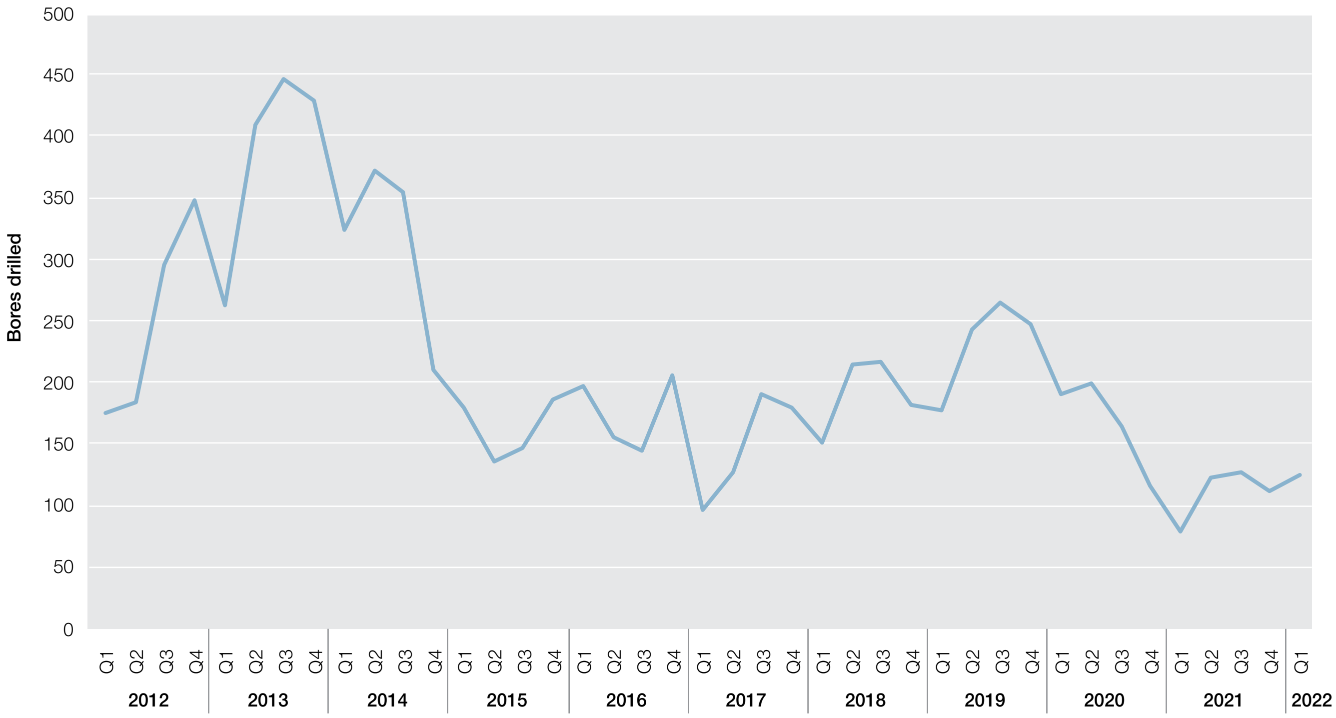
Figure 2.4 East coast production (including Northern Territory)



Source: AER analysis using Natural Gas Bulletin Board data.

Turning to future production, producers drilled 126 bores in Queensland in Q1 of 2022, a small increase on last quarter (Figure 2.5). Despite this increase, drilling rates have remained well below rates observed in previous years. Sustained high prices typically lead producers to increase drilling, as exporters seek to improve their inventory of gas reserves. However, this increase can lag the high prices due to the complexity of drilling operations.

Figure 2.5 Queensland coal seam gas bores drilled



Source: AER analysis using Queensland Department of Natural Resources, Mines and Energy.

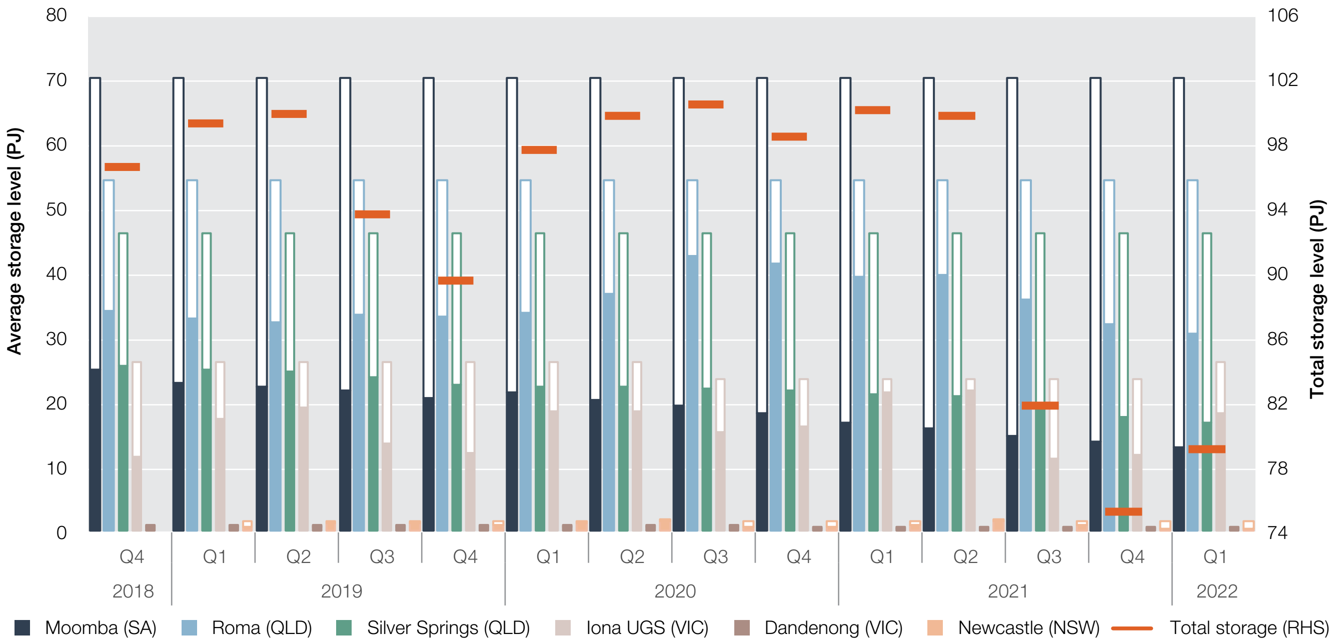
Total storage levels increased from very low levels in Q4 2021 as Iona storage levels increased (Figure 2.6).

Iona storage levels were very depleted coming into 2022 but increased by around 9 PJ over the quarter to close around 22 PJ (or over 90% full). Iona storage levels seasonally build over Q1 in preparation for the colder months. Levels then fall as Iona gas is used to meet winter demand.

Despite the recovery in Iona storage levels, total storage levels remained low in Q1 2022 due to the steady draw down of gas from the other 3 large east coast storage facilities. In contrast to Iona, storage volumes at Roma, Moomba and Silver Springs declined over the quarter.

In April, Iona continued to fill despite high spot prices. This indicates the market is saving gas for potentially higher prices in winter.

Figure 2.6 Storage volumes



Source: AER analysis using Natural Gas Bulletin Board data.

2.3 Queensland LNG exports a record for Q1

LNG exports continued to be very strong (Figure 2.7). The volume of LNG exported from Queensland in Q1 2022 was a record for a Q1 and the third highest on record. Exports are on track for another record year, consistent with high global demand and prices.

That said, Queensland LNG exports decreased by 4.2% from the previous quarter, despite LNG netback prices averaging over $36/GJ for the quarter. Exports to China fell, while exports to Japan, Korea and other destinations increased.

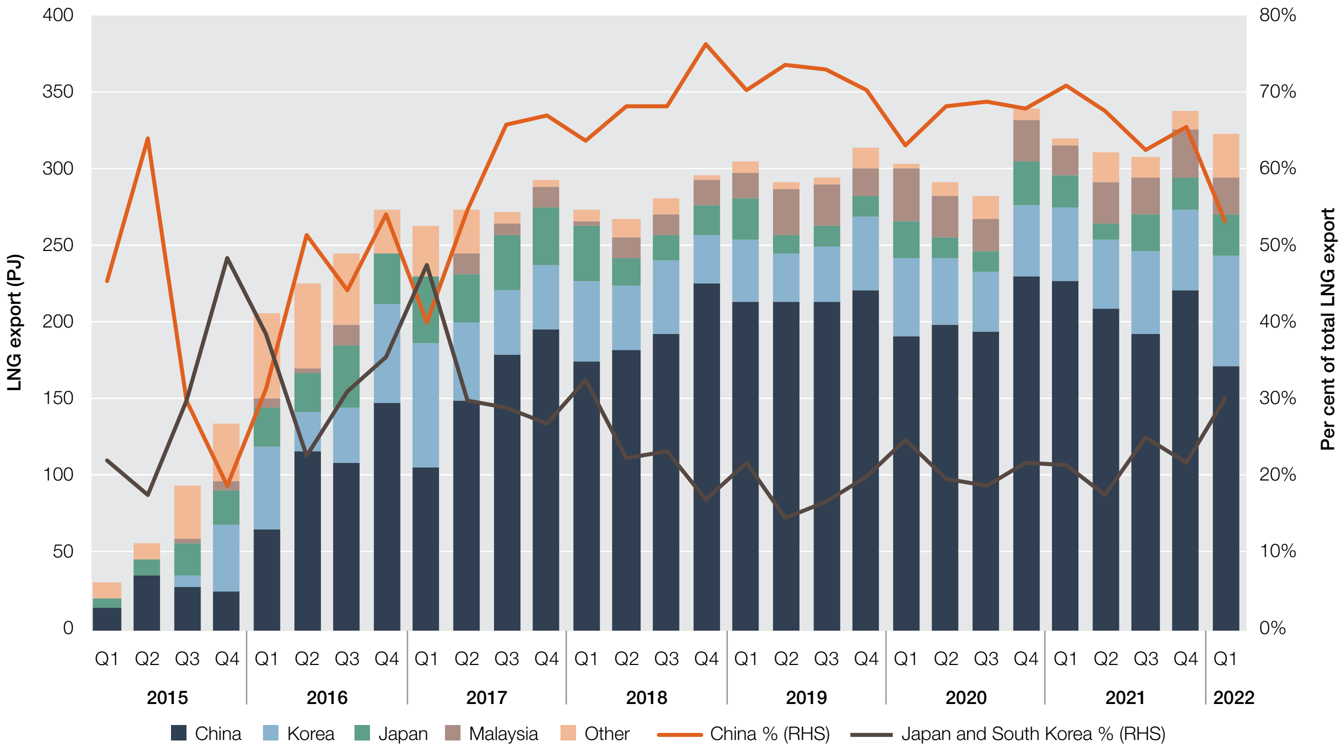
The Queensland LNG export plants undertook limited maintenance during Q1 2022 (Table 2.1). LNG producers prefer to schedule planned outages in Q2 and Q3 as export demand reduces during the northern hemisphere summer. Such downtime helps redirect gas from the export market to the domestic market to support Australian winter demand.

Table 2.1 LNG plant outage

FACILITY	PERIOD (PLANNED/ACTUAL)	CAPACITY OFFLINE
APLNG	22–25 March/18–23 March	0.5 train

Source: AER analysis using Natural Gas Services Bulletin Board data.

Figure 2.7 LNG shipped from Gladstone Port by destination



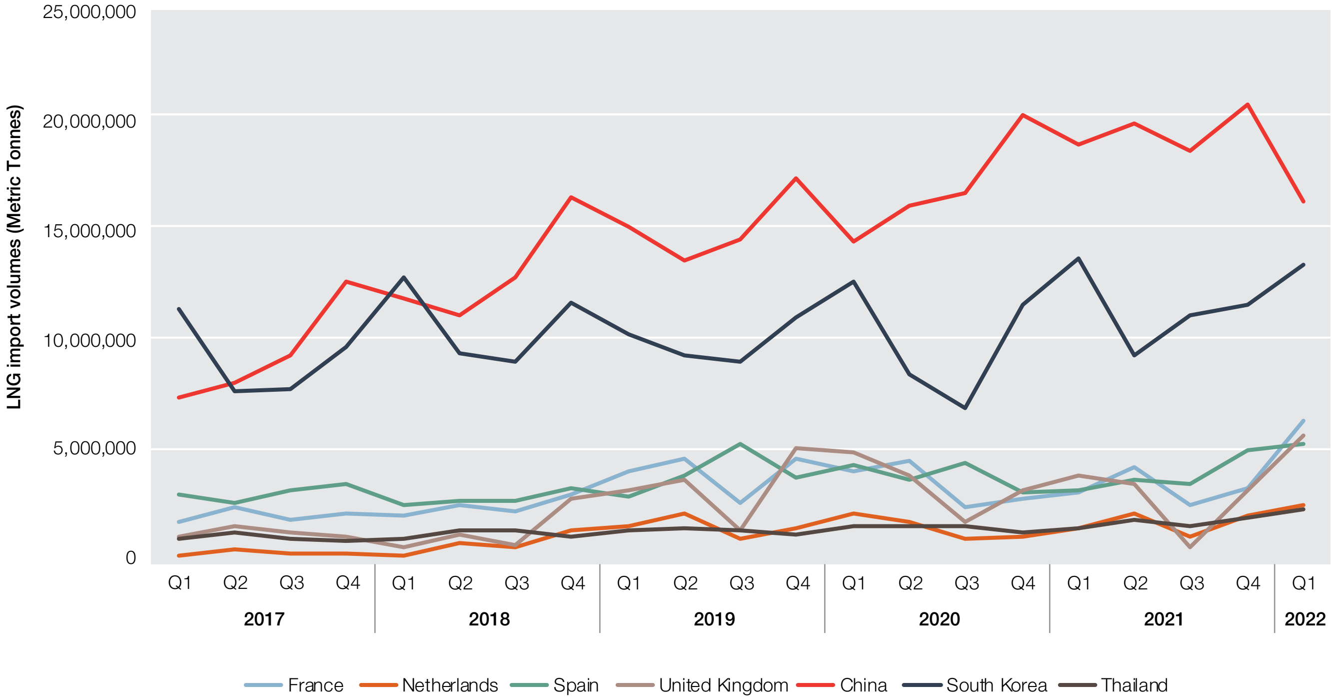
Source: AER analysis using Gladstone Port Corporation data.

Turning to the global market, overall LNG import volumes increased due to an increase in imports by European and Asian nations, other than China (Figure 2.8). This contributed to the high global prices.

Regarding the fall in Chinese LNG imports, there has been speculation that China may be receiving more piped gas from Russia, as Russia pivots away from supplying gas to Europe. However, gas flows from Russia to China are constrained by a lack of pipeline capacity. And while there is some capacity on the Power of Siberia pipeline, this capacity is not enough to accommodate the amount of gas Russia usually sends to Europe.[16] It is more likely that demand in China fell during Q1 2022 due to the Chinese Luna new year holidays, COVID lockdowns and reduced industrial activity to maintain air quality during the Winter Olympics.

16 Centre for Strategic and International Studies: Can Russia Execute a Gas Pivot to Asia?.

Figure 2.8 LNG imports by country



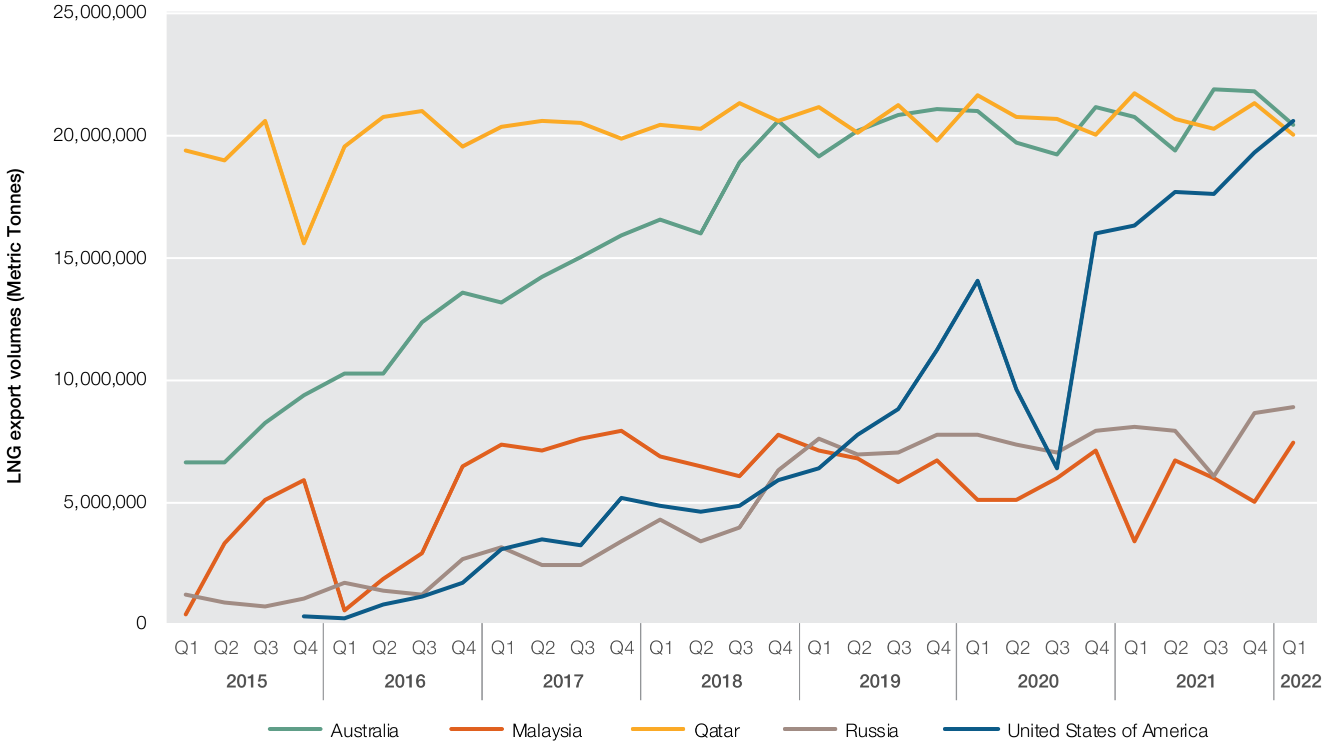
Source: AER analysis using Bloomberg data.

Major LNG exporting countries have been able to maintain exports in Q1 2022 to satisfy strong global demand. The US has continued to increase exports of LNG from the Gulf coast and has just replaced Australia as the world's largest LNG producer (Figure 2.9). Overall, however, export levels from the US, Australia and Qatar, the 3 largest exporters, were very similar. If current growth trends continue, the US will outstrip Australia and Qatar to become the world's dominant LNG producer. This reinforces the relevance of using the Henry Hub as a global reference price (section 2.1).

Despite the conflict in Ukraine, Russia was able to increase LNG output for the quarter, but its potential to expand production and rival the largest LNG exporting nations is limited. Foreign companies such as Shell and ExxonMobil have played a significant role in the growth of Russian LNG production as major investors in existing projects such as Sakhalin as well as pursuing the development of new projects. Russian LNG production is also reliant on imported equipment and vulnerable to western sanctions making the construction of new LNG plants difficult.[17]

17 https://www.reuters.com/business/energy/russias-lng-plans-face-rethink-after-eu-sanctions-equipment-analysts-2022-04-12/.

Figure 2.9 LNG exports by country

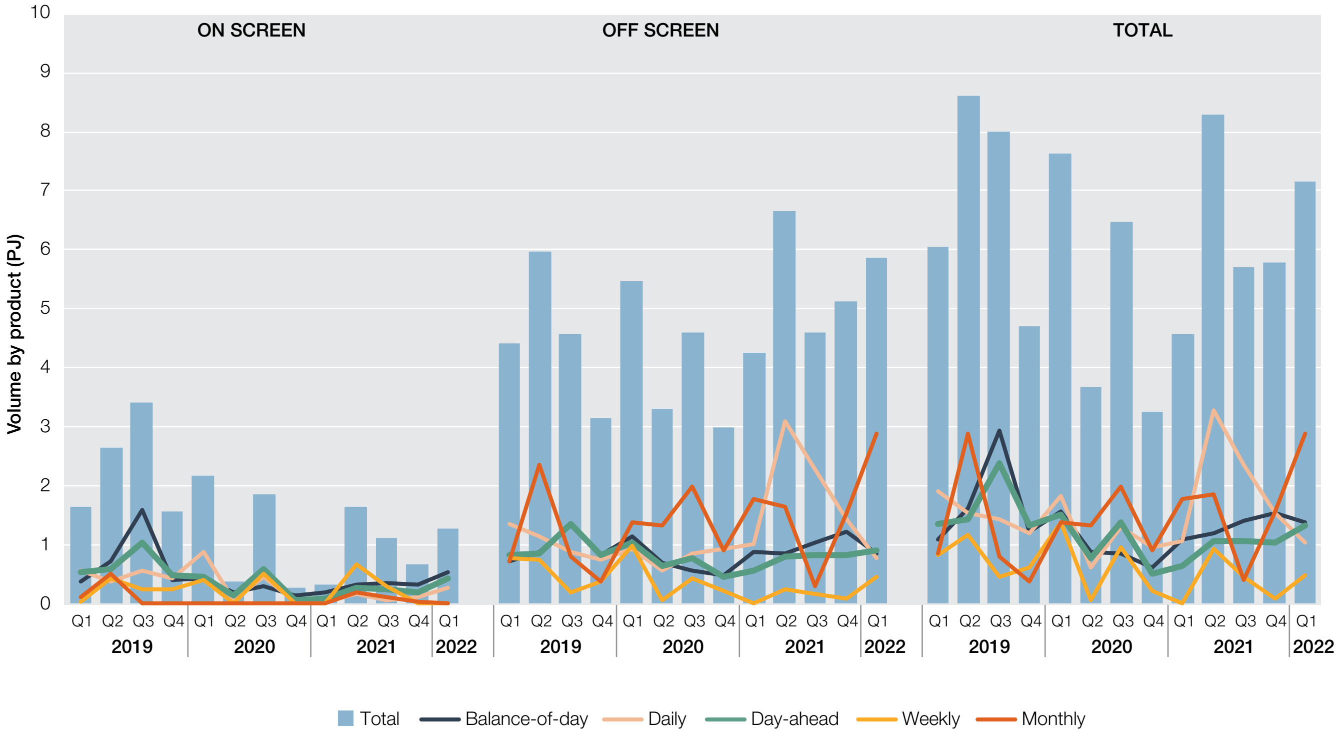


Source: AER analysis using Bloomberg data.

2.4 Gas Supply Hub trade bounces back with more monthly trades

Gas traded through the Gas Supply Hub in Q1 2022 was up from Q4 2021 levels to 7.2 PJ (Figure 2.10). This was mostly driven by more trades for monthly products, and to a lesser extent day ahead and weekly products. Trade in daily products continued to decline from its peak in Q2 2021. Most trades at the Gas Supply Hub are off screen bilateral trades that are subsequently settled through the exchange. For example, this quarter while monthly products were the largest source of trade by volume, all were off screen and none were on screen.

Figure 2.10 Gas Supply Hub – On screen, off screen and total trade volumes by product



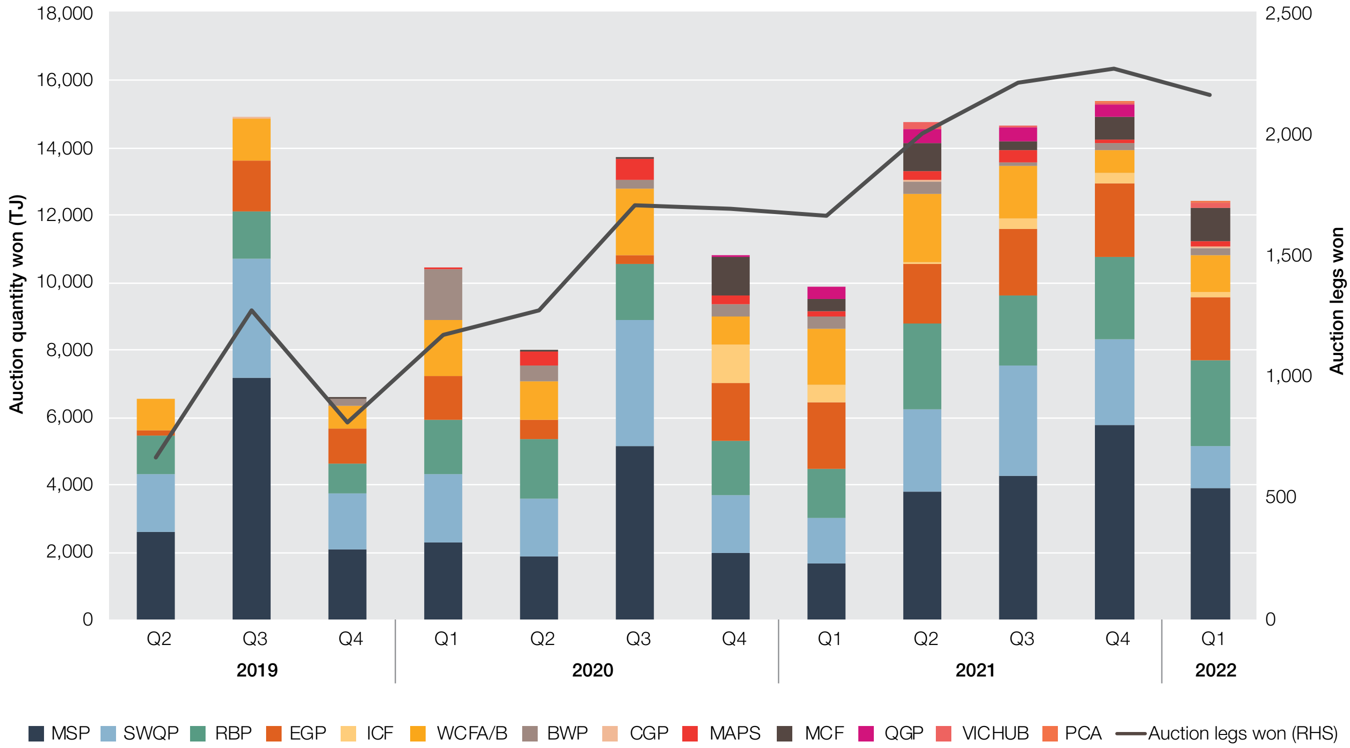
Source: AER analysis using Gas Supply Hub trades data.

2.5 Use of day ahead auction a record for Q1

Auction quantities were up 25% in Q1 2022 compared to Q1 2021 levels, with the quantity won a record high for this time of year. Q1 quantities were however lower than the previous 3 quarters (Figure 2.11).

Much of the auction capacity won was notional, involving shippers transporting gas south via the MSP against the actual direction of physical flow, which was northwards. These notional flows allow shippers to take advantage of high levels of contracted but unused capacity when transporting gas in the opposite direction to the primary flow. There was also a record 2.5 PJ of capacity won on the RBP moving gas towards Brisbane.

Figure 2.11 Pipeline capacity won on the Day Ahead Auction

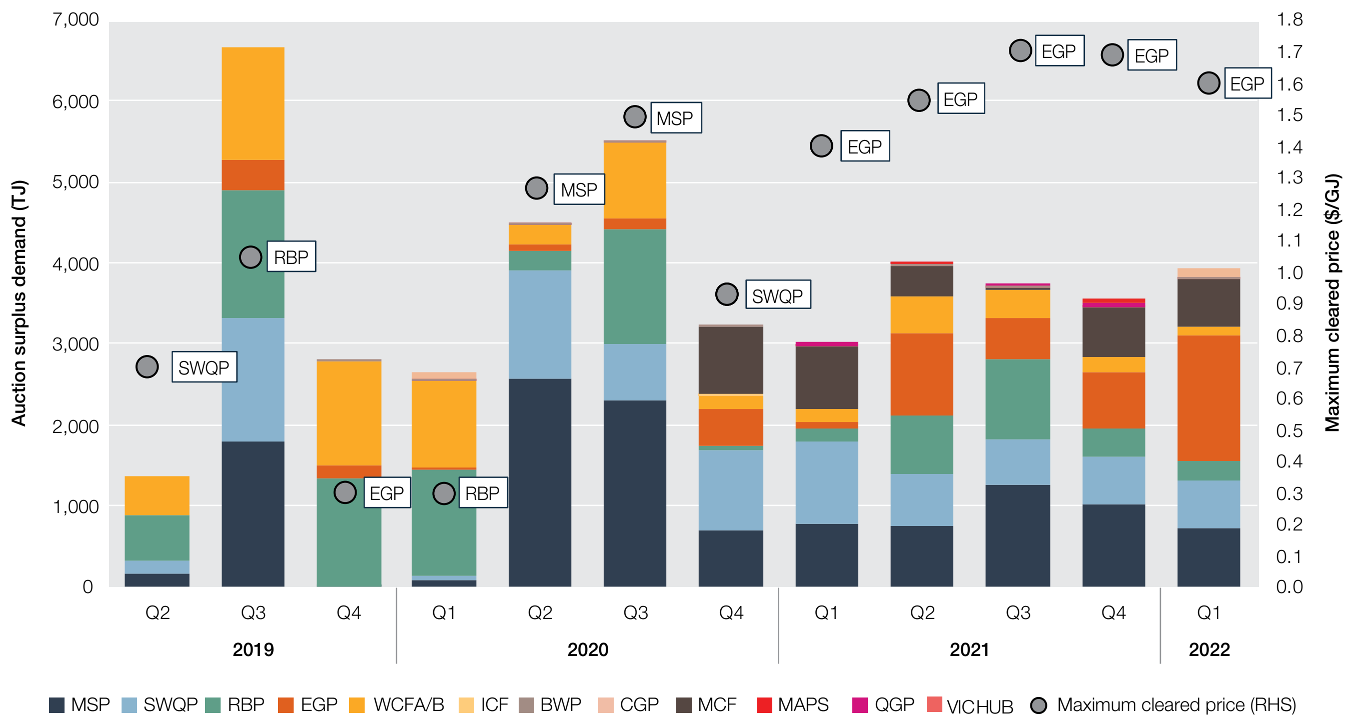


Source: AER analysis using DAA auction results data.

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.

The DAA remained popular on the EGP, resulting in auction prices up to $1.60/GJ (Figure 2.12). Much of the capacity won on the EGP supported flows to electricity generator delivery points. This suggests that DAA capacity on the EGP is highly valued by generators who require gas to respond to fluctuations in demand for electricity in the NEM.

Figure 2.12 Day Ahead Auction surplus demand and maximum clearing prices



Source: AER analysis using DAA auction results data.

Note: Surplus demand indicates the volume of auction bids which were unsuccessful because the total bids exceeded the available auction quantity, the Auction Quantity Limit (AQL), or a bid was unsuccessful due to a paired bid with another constrained facility. Surplus demand is calculated on auction routes where auction capacity was bid on.

Constraints on the supply of auctioned pipeline capacity mostly affected capacity flowing north as well as capacity on the EGP (Figure 2.13). The SWQP was less constrained than at the same time last year. The SWQP plays a critical role in allowing north/south gas flows so a reduction in the degree to which it is constrained is positive for market efficiency and liquidity.

Figure 2.13 Frequency of Day Ahead Auction constraints quarter on quarter comparison

		Q1 2020			Q1 2021			Q1 2022		
PIPELINE	DIRECTION	JAN	FEB	MAR	JAN	FEB	MAR	JAN	FEB	MAR
BWP			45%	42%			13%		7%	3%
EGP		3%		3%	23%			68%	71%	48%
MSP	South from Moomba	3%	7%	7%						
	Towards Moomba				3%		3%	55%	25%	13%
	Within NSW East						3%	3%	11%	3%
	Within NSW West							19%	18%	7%
QGP	Towards Wallumbilla					4%	3%			
RBP	East						3%		14%	
	West	36%	100%	68%	3%		26%		43%	7%
SWQP	North SWQP				87%	89%	32%	42%	46%	23%

Not constrained	<20%	20–40%	40–60%	60–80%	>80%

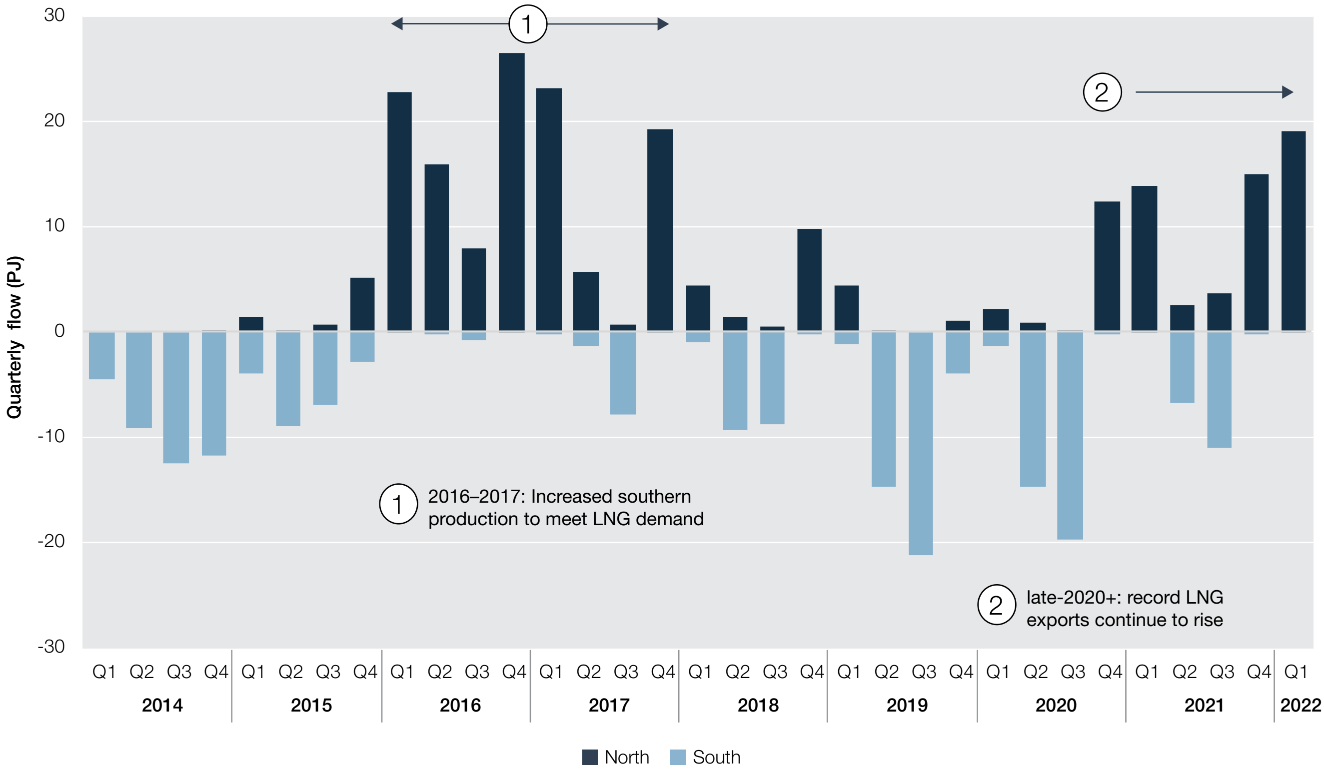
Source: AER analysis using DAA auction results data.

Note: Constraints can be caused by individual pipeline segments, delivery or receipt zones, physical receipt or delivery points, or a combination thereof. The constraint percentage reflects the frequency in a given month where the auction demand exceeded the auction capacity or where auction demand matched the auction capacity resulting in an auction clearing price greater than $0/GJ.

2.6 Gas flows north to Queensland

In Q1 2022 gas flowed north at the highest rate since 2017 when southern gas was used to supplement the ramp up of LNG production at Gladstone (Figure 2.14). 18.9 PJ of gas flowed north this quarter; an increase of 5 PJ compared to the same time last year which can be attributed to a 5.5 PJ increase in gas flowing from Sydney along the MSP. Such northward gas flows are consistent with high demand in Queensland and strong LNG exports.

Figure 2.14 North-South gas flows

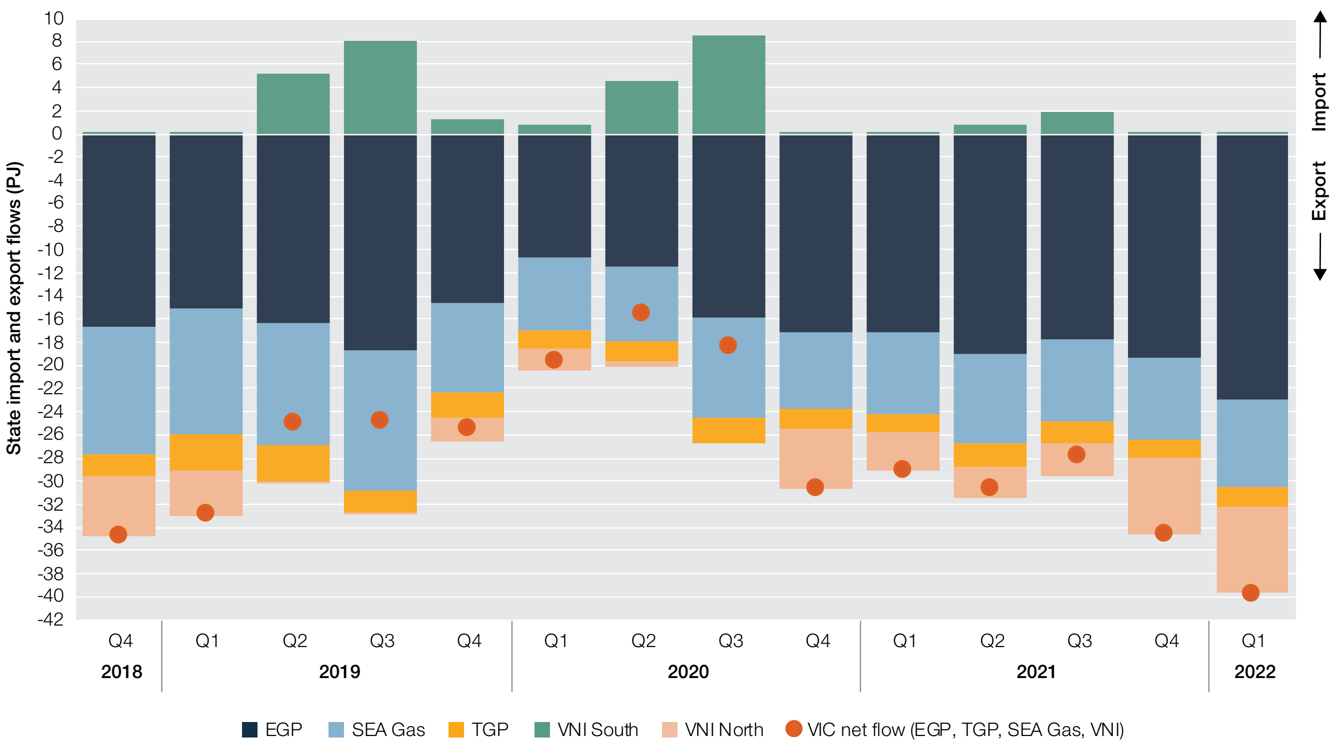


Source: AER analysis using the Natural Gas Services Bulletin Board.

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

Victoria exported more gas which is also consistent with higher flows from south to north (Figure 2.15). Northern exports on the VNI increased by 1 PJ compared to the previous quarter while southerly VNI flows ceased. Flows to Sydney on the EGP increased by 3.6 PJ, supporting increased exports from Sydney along the MSP. Victorian exports west to Adelaide along the Sea Gas pipeline also increased by 0.5 PJ.

Figure 2.15 Victorian import and export gas flows

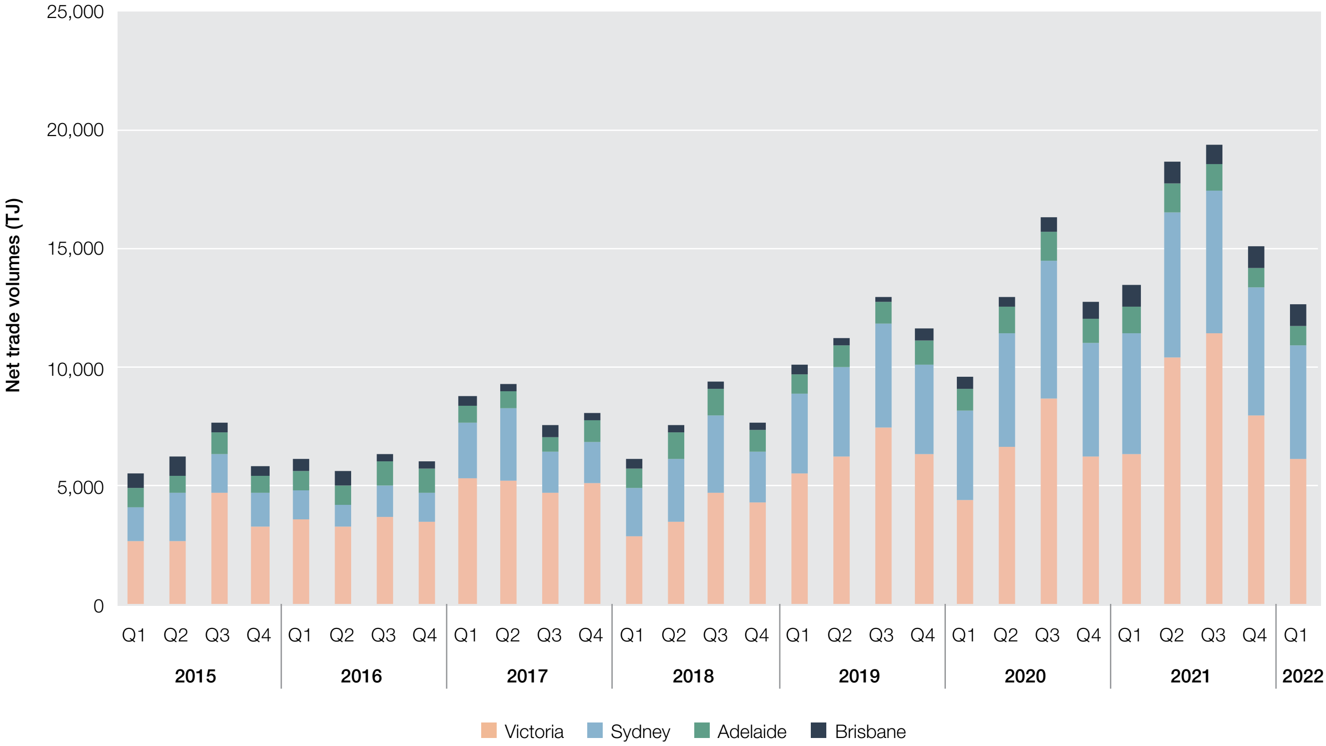


Source: AER analysis using the Natural Gas Services Bulletin Board.

2.7 Spot market trade declines

Gas trading in the east coast spot markets declined in Q1 2022 compared to the previous quarter with reductions in all markets except Brisbane (Figure 2.16). Falls were largest in Victoria and Sydney which is consistent with a net flow of gas from those states to the north. Trade in Victoria declined by 1.8 PJ and trade in Sydney declined by 0.6 PJ. While the level of trade was lower than in 2021, it was higher than Q1 trading volumes up to and including 2020 and is consistent with the overall trend towards higher spot market liquidity.

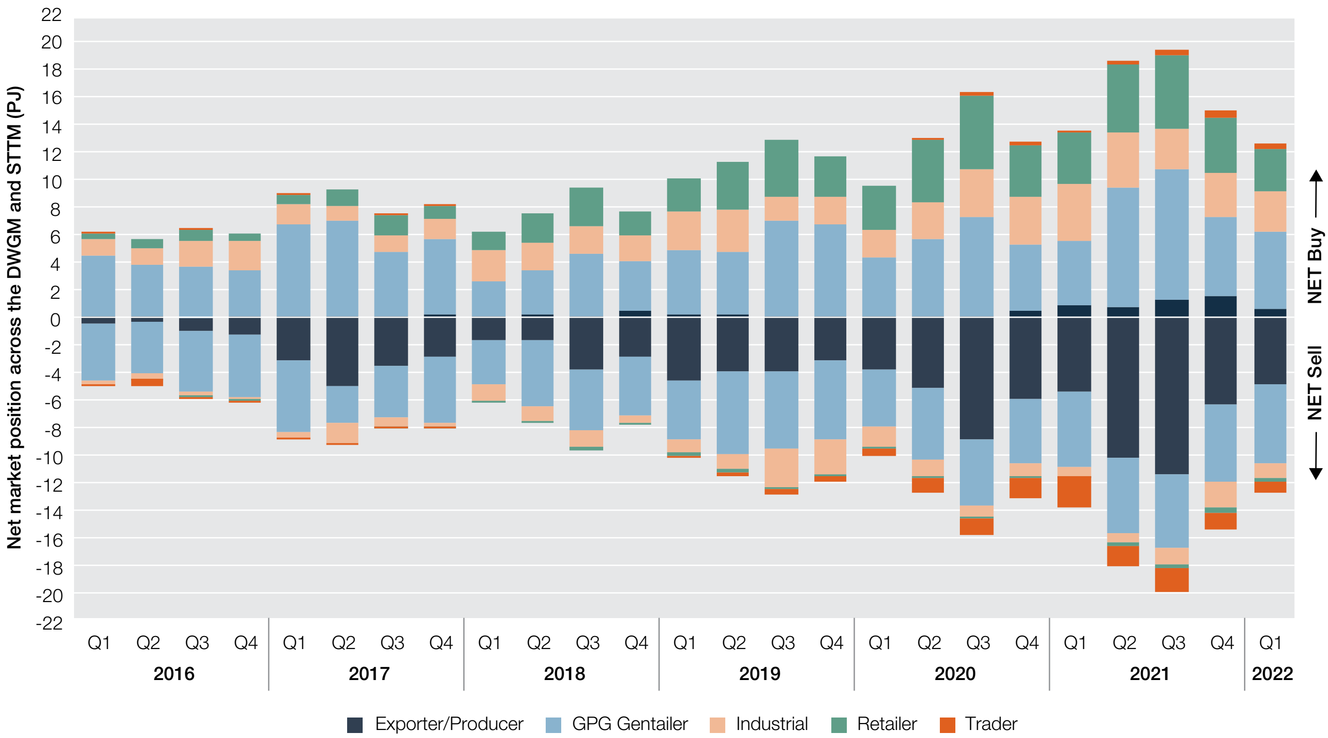
Figure 2.16 Spot trade liquidity



Source: AER analysis using DWGM and STTM data.

There was a reduction in both buying and selling on the east coast spot markets by all participant groups, except GPG gentailers which sold 0.3 PJ more gas in Q1 compared to the previous quarter (Figure 2.17). The largest reductions were attributed to exporter/producers which sold 1.6 PJ less gas in the quarter and industrials which sold 0.8 PJ less gas. The amount of gas traded on spot markets is impacted by the amount of gas consumers take under gas supply agreements. When gas consumers nominate close to the daily limits allowed under their supply contracts with producers, exporter/producers have less surplus gas to trade on spot markets, reducing overall trade levels.

Figure 2.17 Net trade by participant



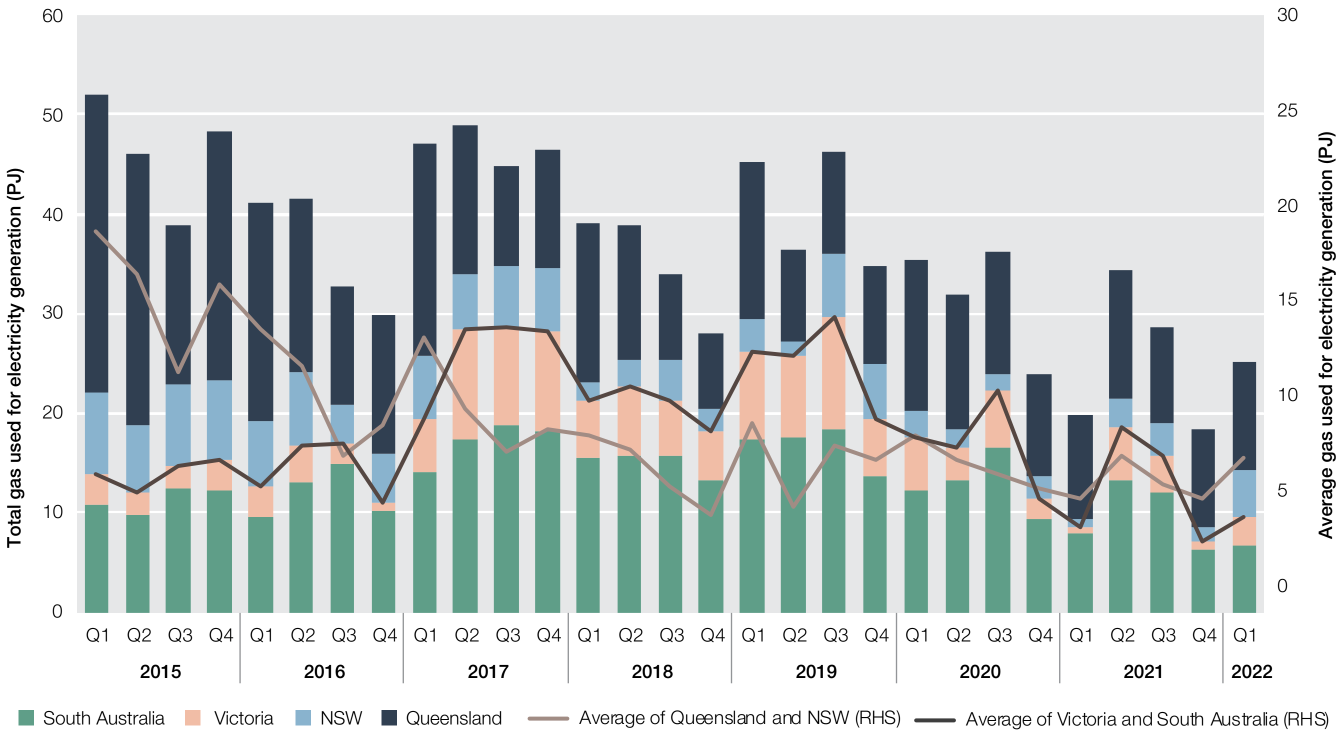
Source: AER analysis using DWGM and STTM data.

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.

2.8 Electricity generation drives gas demand

Gas powered generation trended higher across the east coast during the quarter with the most significant increases in Victoria and NSW (Figure 2.18). Gas used for electricity generation increased by 3.1 PJ in NSW and 2.2 PJ in Victoria while smaller increases of 1 PJ and 0.3 PJ were recorded in Queensland and South Australia respectively. This increase was from a low base in the previous quarter and is notable since the amount of gas used for electricity generation has been trending down for several years with the growth in renewable generation.

Figure 2.18 Gas used for electricity generation



Source: AER analysis using NEM data.

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

2.9 Victorian gas futures traders expect gas prices to rise

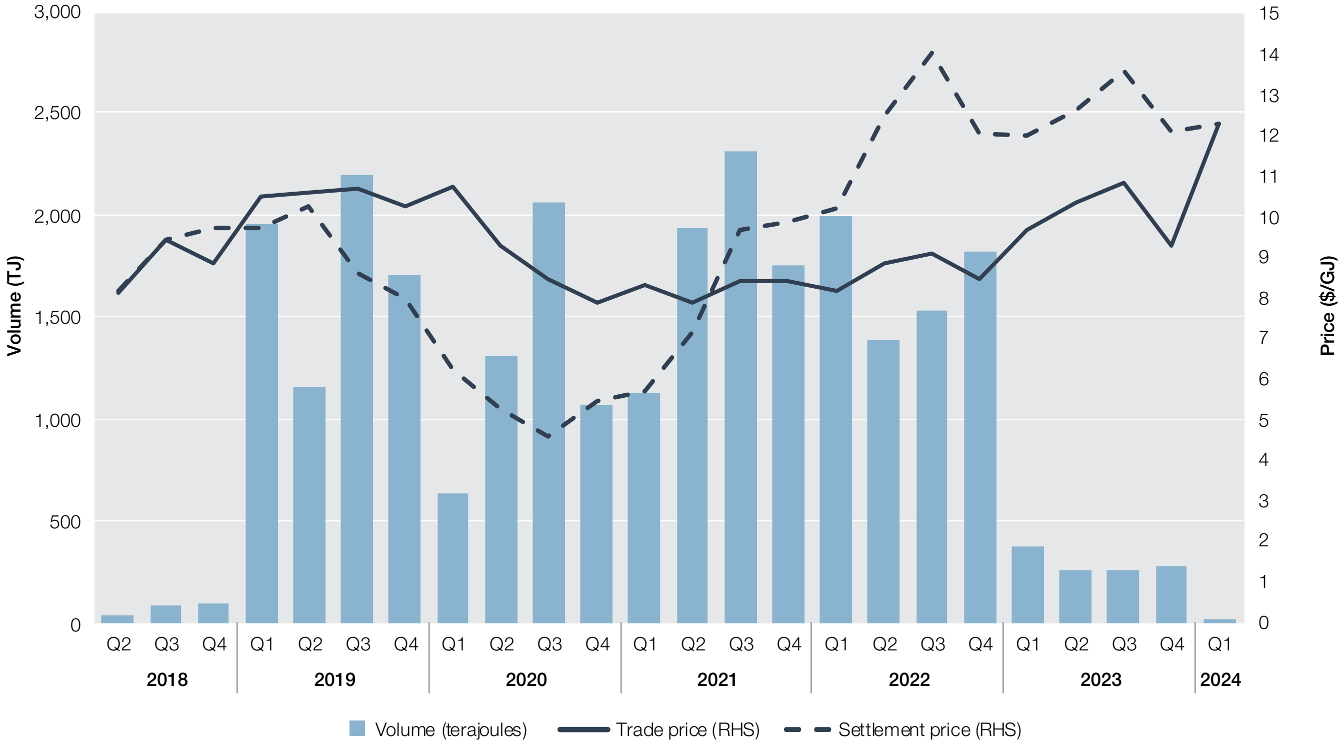
Victorian gas futures traded in Q1 2022 indicated traders expected gas prices to increase over the year. Settlement prices were highest for Q3 contracts, reaching $14.10/GJ and averaging $12.20/GJ over the year (Figure 2.19).

Beyond Q1, gas futures prices have continued to increase with gas futures traded in early May for Q3 delivery settled at $17.55/GJ.[18] These increases reflect increased spot prices and expectations that higher prices are likely to be sustained in the short to medium term.[19] Peak Victorian winter demand typically occurs in Q3, and it is likely traders are taking possible tight supply/demand conditions over that period into account.

18 https://www2.asx.com.au/markets/trade-our-derivatives-market/derivatives-market-prices/energy-derivatives accessed 9 May.

19 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. For example, the offer price for a Victorian gas futures contract for Q3 delivery was $25/GJ in early May.

Figure 2.19 ASX Victorian futures trade



Source: ASX Energy.

Note: Trading volumes are organised by contract expiry date.

Focus – Pipeline capacity trading update

Since 2019, participants have had access to pipeline capacity through two new markets: the Day Ahead Auction (DAA) and the Capacity Trading Platform (CTP).[20] The AER published a two year review of these mechanisms in April 2021.[21] This update finds that the DAA continues to facilitate cheaper 'next day' gas pipeline access to gas shippers who use it to move gas in response to NEM conditions and east coast gas market locational pricing. However, the CTP has been little used, with just one trade since it started. This focus story explores the relative popularity of the two mechanisms and how they interact.

20 These markets were introduced through reforms to national gas legislation. Changes to Part 22 of the National Gas Rules facilitating the capacity trading platform and changes to Part 24 and 25 of the National Gas Rules facilitating the Day Ahead Auction.

21 See our Pipeline capacity trading – Two year review, https://www.aer.gov.au/wholesale-markets/performance-reporting/pipeline-capacity-trading-two-year-review.

Box 2.1 The Capacity Trading Platform and Day Ahead Auction – reform and interaction

The Capacity Trading Platform (CTP) is voluntary and allows shippers to make bids and offers for spare, short term "secondary capacity", up to 3 months before the shipping date. The platform is facilitated by AEMO and CTP proceeds go to the seller. Shippers can trade for capacity for a future gas day or longer period. The cut-off for next day purchases is the evening before the following gas day.

After this cut-off, a mandatory Day Ahead Auction (DAA) commences of spare shipper capacity (that is, capacity that is contracted but not scheduled for use). DAA sales proceeds go to the pipeline operator.

This revenue allocation is intended to incentivise shippers to sell capacity through the CTP before the DAA occurs. However, this hasn't happened in practice. As an example:

1. A shipper may have rights to 20 TJ of pipeline capacity under a long-term contract which it is unlikely to use on a pipeline (Route Z) for the next 3 months.
2. The shipper might unsuccessfully offer to sell that capacity via the CTP for a price of $X (greater than zero).
3. Meanwhile the zero-reserve price DAA operates daily on Route Z and shippers purchase this DAA capacity for zero dollars over the 3 months.

In this example, significant capacity is acquired through the DAA but none through the CTP. To date, shippers seeking capacity have been able to access it more cheaply through the DAA when they want it.

DAA popularity continues to increase

Over the third year of the DAA (1 April 2021 to 31 March 2022), the number of participants using the auction has grown (Figure 2.21). Total volumes won at auction also increased, boosted by record Q4 2021 quantities. In particular Exporter/Producers increased the volume won on the DAA.

The auction continues to be used for deliveries of gas to, and between, wholesale spot markets as well as to gas powered generators. Almost 80% of all auction capacity was won on 4 key pipelines: the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP) which facilitate gas flows south and north between spot markets; the Eastern Gas Pipeline (EGP) and the Roma Brisbane Pipeline (RBP) which facilitates flows to gas powered generators (Figure 2.20).

Over the past 3 years around 140 PJ of auction capacity has been won across 14 of 22 auction facilities (Figure 2.20). The routes that were not traded do not join to spot markets or gas powered generators, and do not feature many participants (they have only 2 parties with contracts).[22]

Historically, supply has been under-subscribed on the DAA, resulting in 80% of auction volumes being cleared at the auction reserve price of zero dollars.

In the last 12 months, however, demand has exceeded supply more often, resulting in more clearance prices above zero, with the EGP emerging as the highest priced route.

The progression of the DAA

There were 25 participants registered for the auction on 31 March 2022 and we have divided these into 3 groups:[23]

- Exporter/Producers: Arrow, APLNG, Esso, Santos, Senex, Shell/Walloons, Westside
- Gentailers: AGL, Alinta, CleanCo, Energy Australia, Engie, Origin, Shell Retail
- Industrial/Trader/Retailers: Incitec, Infrabuild, Qenos, Tarac, Visy, Eastern Energy, Macquarie, Petrochina, Strategic Gas Market Trading, Weston Energy.

The 3 groups reflect:

- Different parts of the industry – Exporters/Producers are upstream and can sell gas into downstream markets or for delivery to Gladstone LNG facilities and on to global markets.

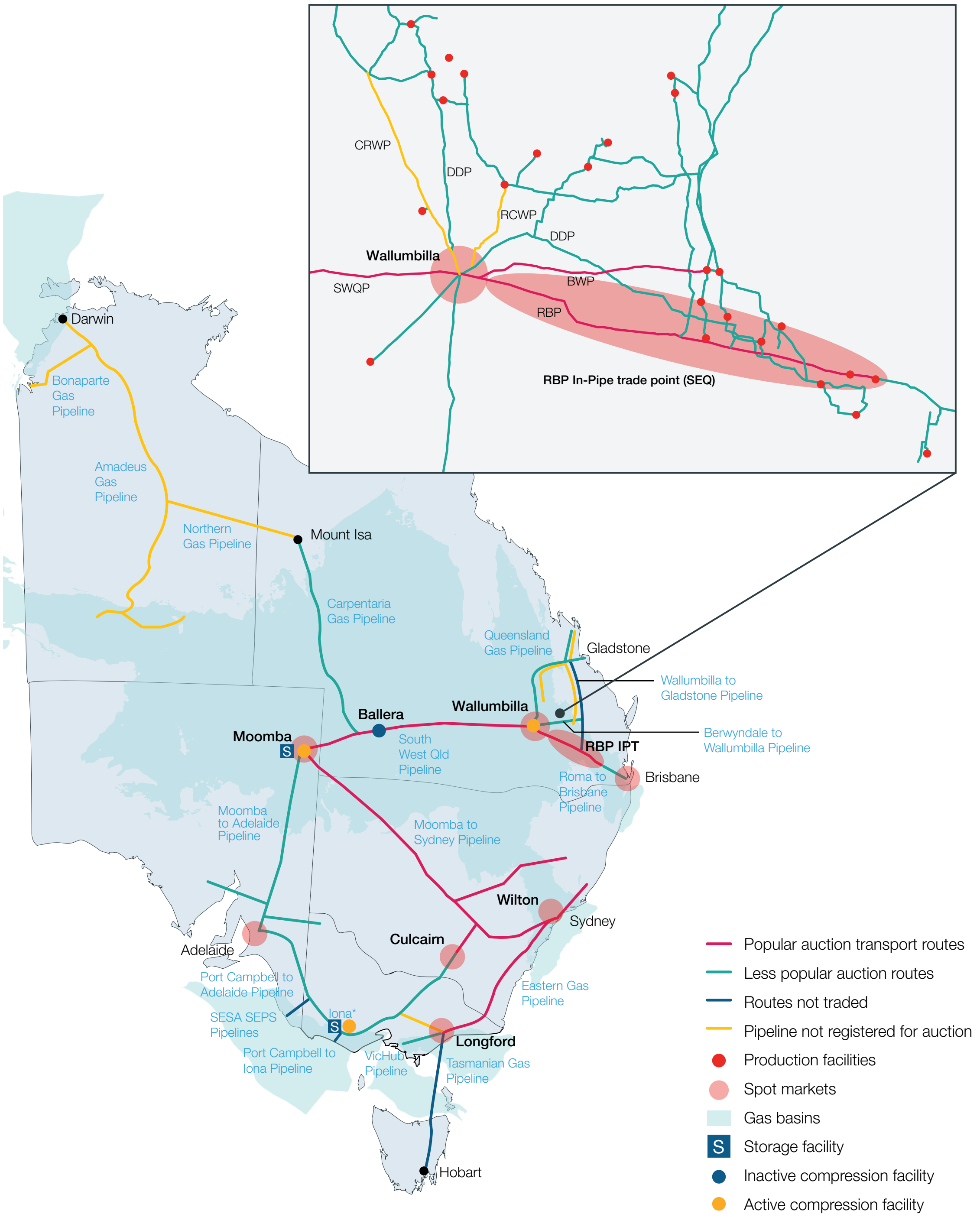
22 The 22 Auction facilities are noted in current version 1.9 of the AEMO register document: https://aemo.com.au/energy-systems/gas/pipeline-capacity-trading-pct/specification-of-service-points-zones-and-segments.

23 The AER does this to preserve the confidentiality of anonymously traded DAA outcomes. The participation of these businesses in related downstream markets or through the upstream gas supply hub exchange appears in Appendix C.

- Different levels of sophistication – Industrials /Traders /Retailers are typically smaller by trade volume in gas markets than Gentailers and don't buy gas for electricity generation.
- Different business focus – Gentailers on the other hand, buy gas and capacity for own electricity generation requirements as well as gas demand and sales.

We use these groupings to inform our analysis and may alter them over time, as the participant mix changes. We welcome feedback on these groupings.

Figure 2.20 DAA Facilities and Major gas trading locations



Source: AER analysis using Gas Supply Hub, DWGM and STTM data. GEOScience Australia.

Notes: 1. *Iona storage and compression facility.

2. The Roma pipeline located near the Roma township in Queensland and the Darling Downs Pipeline (DDP) connecting Spring Gully to Wallumbilla to Darling Downs in Queensland are not shown on this map.

3. Routes on the Roma Pipeline and the DDP have not been traded on despite the facilities being registered for the DAA.

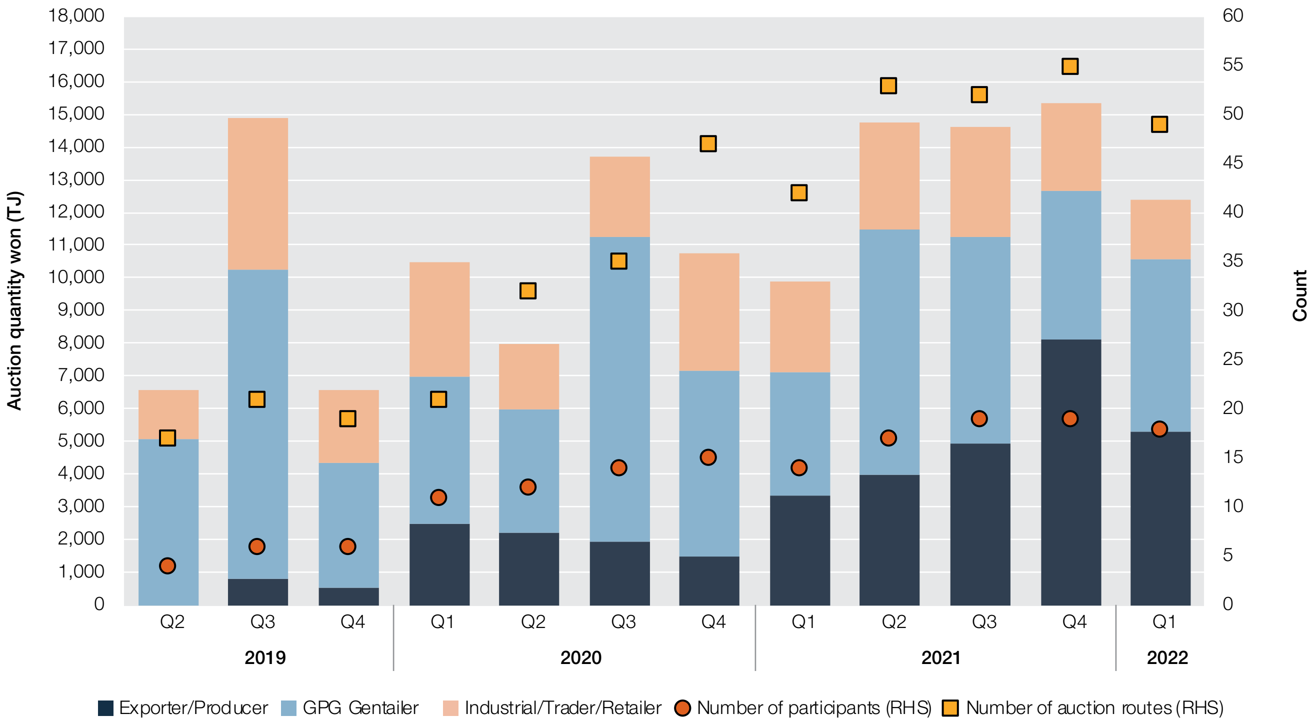
Box 2.2 How the DAA works

The auction provides access to individual service points (receipt and delivery points), zones (groupings of service points) and pipeline segments (transportation paths between zones). Participants can submit individual bids for capacity, or paired bids across multiple facilities. Used for coordinating gas delivery further afield, paired bids will not clear unless capacity is available to service each of the bids contained within.

AEMO publishes the available auction capacity daily, along with previous day pricing, to inform participant bidding. The lowest accepted bid price in the auction determines the clearing price on days when demand exceeds available capacity. However, when there is more capacity available than participant bids, the auction is cleared at the reserve price of $0/GJ, regardless of the price of the lowest bid price. Since on most days, on most routes, supply has exceeded demand in the DAA, participants have won auction capacity for $0/GJ around 80% of the time.[24]

The use of the DAA has continued to increase each year: the number of active participants has increased from 4 in Q2 2019 to 19 by the end of 2021 and the number of auction routes participants have won capacity on has grown by more than 150% over the same period (Figure 2.21).

Figure 2.21 DAA auction all facilities – Volumes won by participant groups (LHS), number of participants and auction routes (RHS)



Source: AER analysis using DAA auction results data.

Note: Total auction quantity won is the quarterly sum of auction products allocated on each pipeline and do not necessarily represent the physical volumes of gas that actually flowed each gas day. The number of participants and auction routes is based on bidding data into the DAA. The auction commenced in March 2019 with 2513 TJ of auction capacity won in the first month across four auction facilities.

The demand for auction capacity is historically the highest in Q3 on auction routes moving gas from the north to south to meet southern peak winter demand. However, in 2021 the demand for auction capacity remained strong over Q4, particularly on the SWQP and MSP between Wallumbilla and southern spot markets (Figure 2.23 and Figure 2.24). Participants also won increased capacity on RBP routes flowing west towards Wallumbilla. Combined, this resulted in a new quarterly record of 15.4 PJ in Q4.

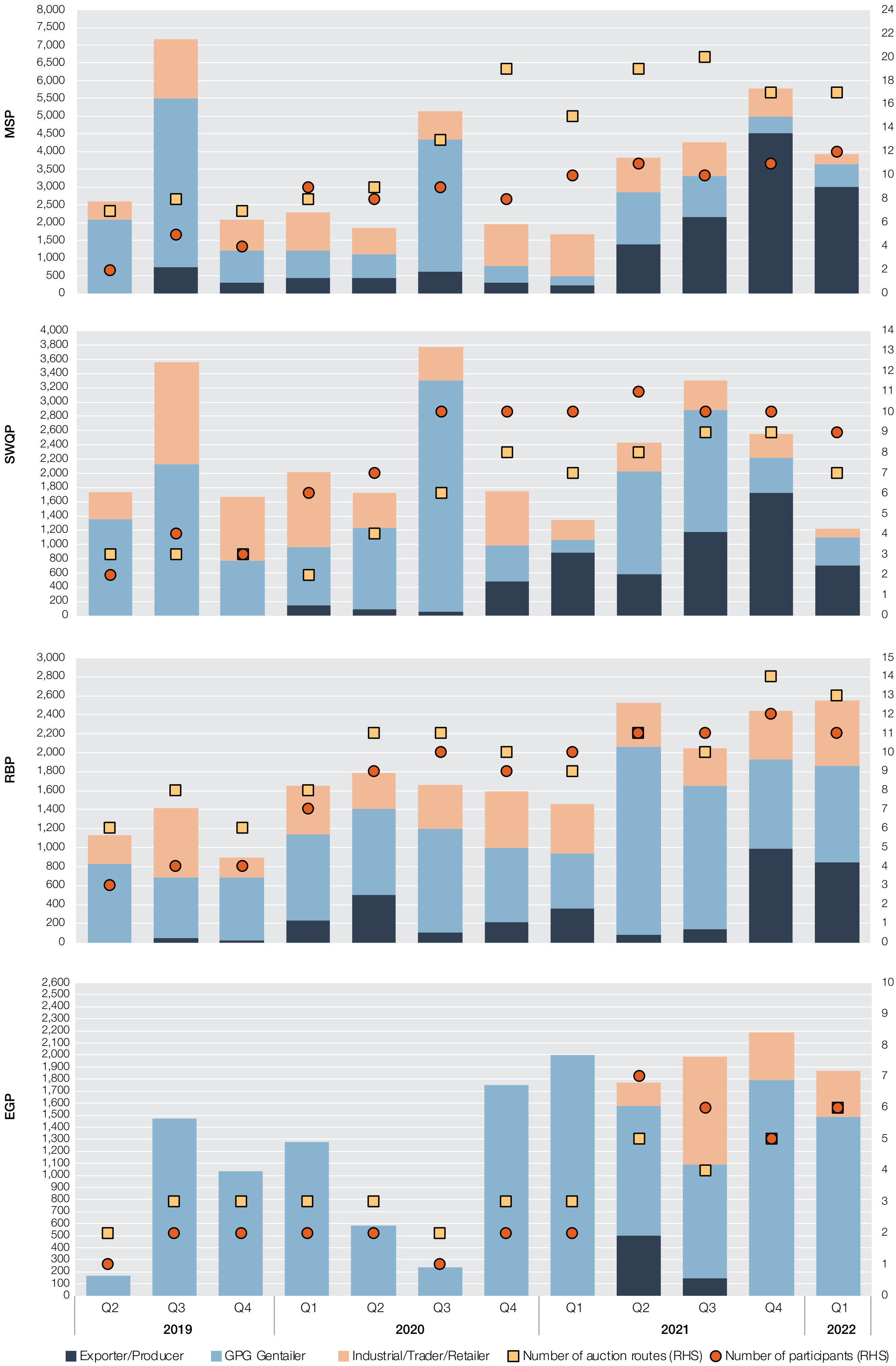
In 2021 there was a significant increase in the use of the auction by Exporter and Producer participants. In 2019 this group made up only 5% of all auction capacity won, whereas by Q4 2021 this peaked at 53%.

24 Additional fees associated with the usage of DAA services can make the actual cost slightly higher. However, some initial fees have been reduced, and in some cases are now zero. On the most popular route to date – SWQP-MSP on APA pipelines, APA has reduced its fess to zero for this financial year in accordance with the cost recovery framework set out under the National Gas Rules. Previously its fee had been 13 cents per auction facility used. https://www.apa.com.au/globalassets/our-services/gas-transmission/tariffs-terms-and-offers/current-tariffs-and-terms/apa-capacity-trading-and-auction-fees.pdf.

Most popular DAA facilities

Since the market started, 78% of all auction capacity has been won on 4 auction facilities: the MSP, SWQP, RBP and EGP. These pipelines move gas between the major northern and southern markets in Victoria, Sydney, Brisbane, as well as linking to the Wallumbilla supply hub in Queensland – a transition point to southern markets and LNG export pipelines to Asia. As the market continues to mature, the number of participants (and diversity of participant type) as well as the number of auction routes participants are bidding on is steadily increasing on these major facilities (Figure 2.22).

Figure 2.22 Auction capacity won on 4 most popular auction facilities by participant groups (LHS), number of participants/auction routes (RHS)



Source: AER analysis using DAA auction results data.

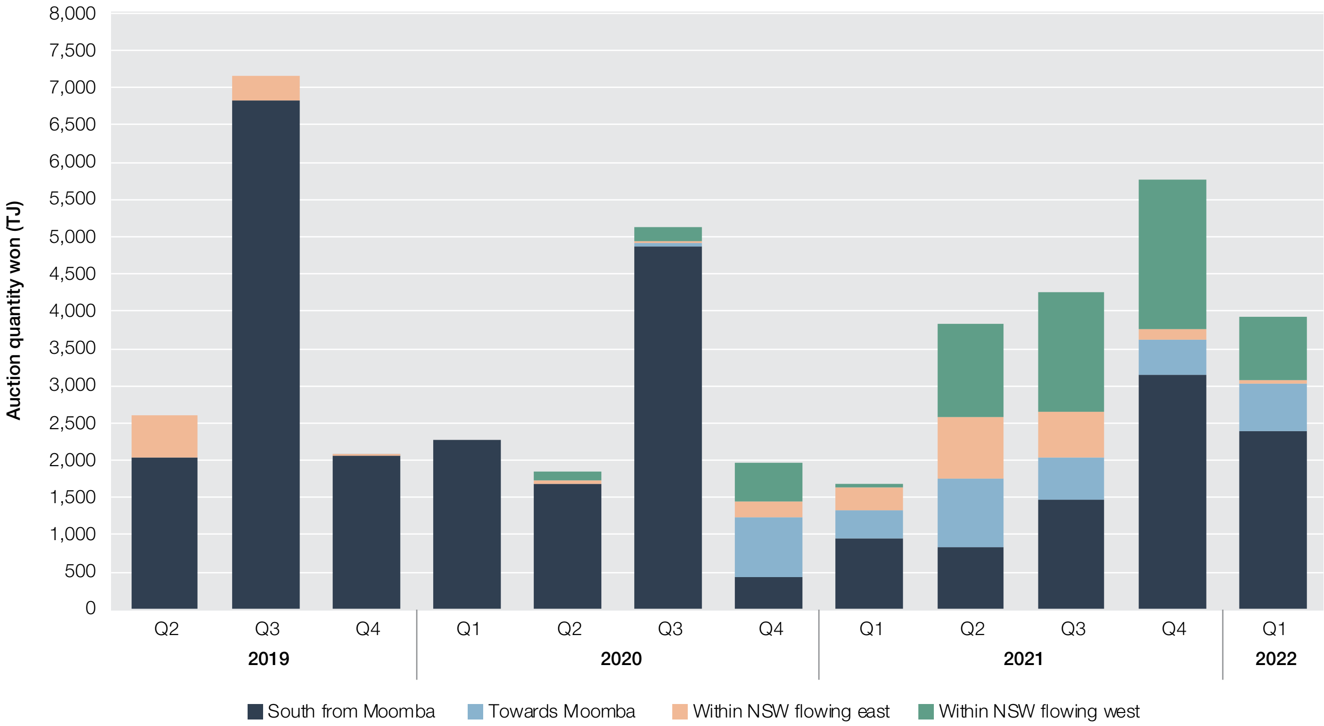
Note: The number of participants and auction routes is based on bidding data into the DAA.

SWQP & MSP – Moving gas between markets

Exporter and Producers won a greater amount and share of capacity over 2021 on the MSP and SWQP. The capacity won on the MSP was largely delivered to the Victorian gas market (Culcairn South delivery point) or the Sydney spot market (Wilton delivery point).

On the MSP and SWQP, participants often submit linked bids, called paired bids, to move gas either from the south to Wallumbilla or from Wallumbilla to the south across multiple auction "legs". Initially, most of the pipeline capacity won on the MSP and SWQP was to move gas southwards on the MSP, however this changed in Q4 2020 when the auction also began to move gas north to Moomba (Figure 2.23).[25]

Figure 2.23 Auction quantities won on the Moomba to Sydney pipeline by route



Source: AER analysis using DAA auction results data.

Note: Quantities shown are the sum of auction products allocated and grouped for different auction routes based on the direction of that auction route and does not necessarily represent the physical volumes of gas that actually flowed for each gas day.

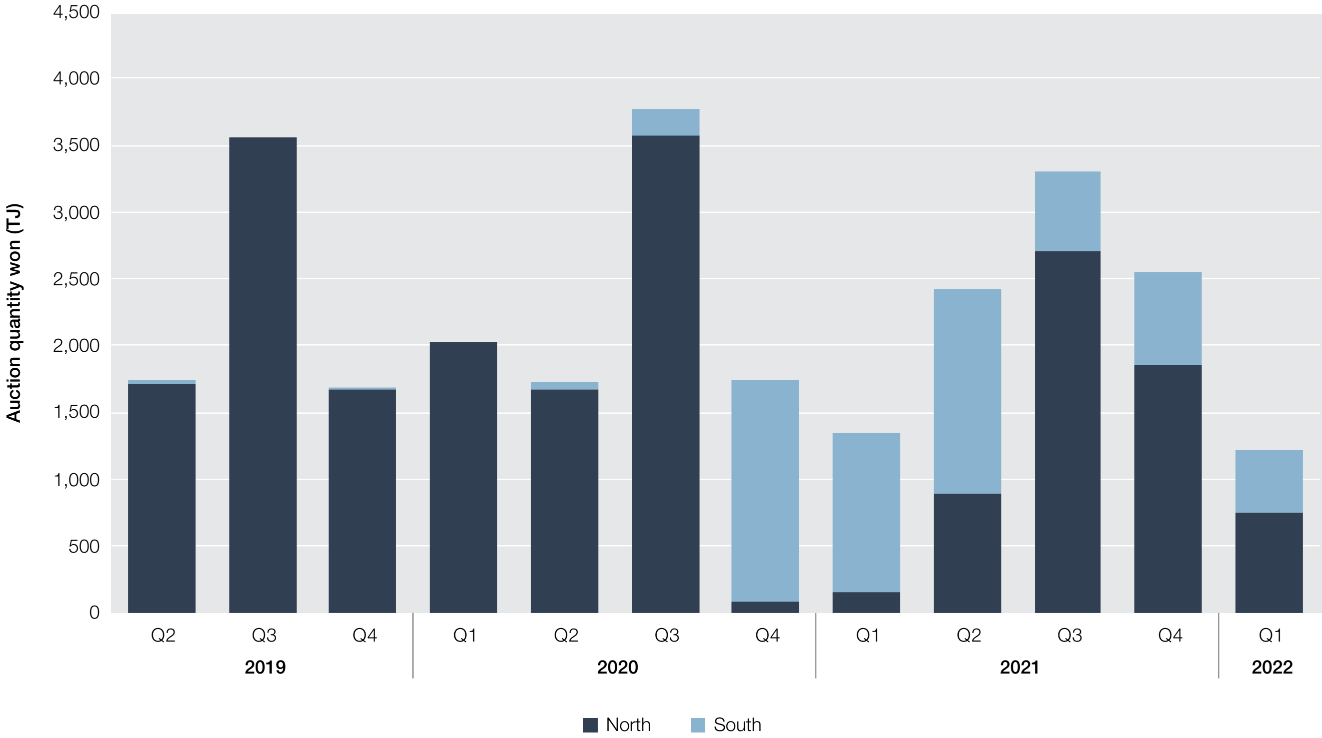
Within NSW flowing west – This service reflects auction capacity won between the Victorian market (Culcairn North) and the adjacent Culcairn Trade Point which is a gateway point to park gas to move gas 3 ways – back to Victoria, to Sydney or Moomba. This service peaked in Q4 2021 when a third of all auction capacity won on the MSP was on this route reflecting the ability of participants to procure gas in the Victorian market and trade or swap this gas at the Culcairn trading point.

Within NSW flows East can reflect price arbitrage opportunities between the Victorian DWGM and Sydney STTM.

On the SWQP, auction capacity is predominantly won on auction routes from Wallumbilla flowing south to Moomba. However, from Q3 2020, participants also started winning capacity flowing north as on the MSP (Figure 2.24). This is because Wallumbilla is a transit point for pipelines connecting to LNG exports at Gladstone. Use of the north auction routes occurred around the same time global gas prices increased.

25 AER, *Wholesale markets quarterly Q4 2020*, February 2021.

Figure 2.24 Auction quantities won on the Southwest Queensland pipeline by route



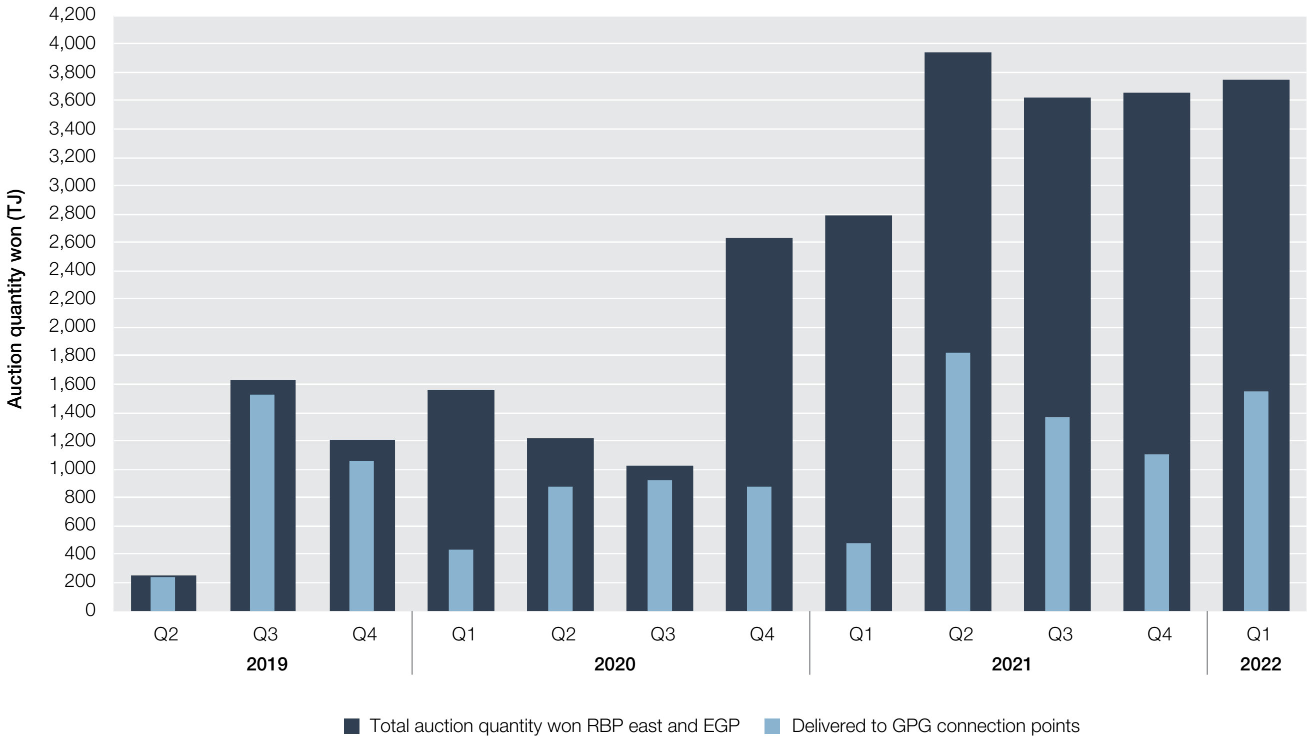
Source: AER analysis using DAA auction results data.

Note: Quantities shown are the sum of auction products allocated and grouped for different auction routes based on the direction of that auction route and does not necessarily represent the physical volumes of gas that actually flowed for each gas day.

RBP and EGP – Facilitating strong flows to gas powered generators

A strong percentage of auction capacity won on the RBP and on the EGP has been for deliveries to gas powered generators.

Figure 2.25 Auction capacity won on the RBP East and EGP (GPG deliveries highlighted)



Source: AER analysis using DAA auction results data.

Note: Quantities shown are the sum of auction products allocated and grouped for auction routes on the EGP and the RBP flowing east for delivery to connection points linked to gas powered generators.

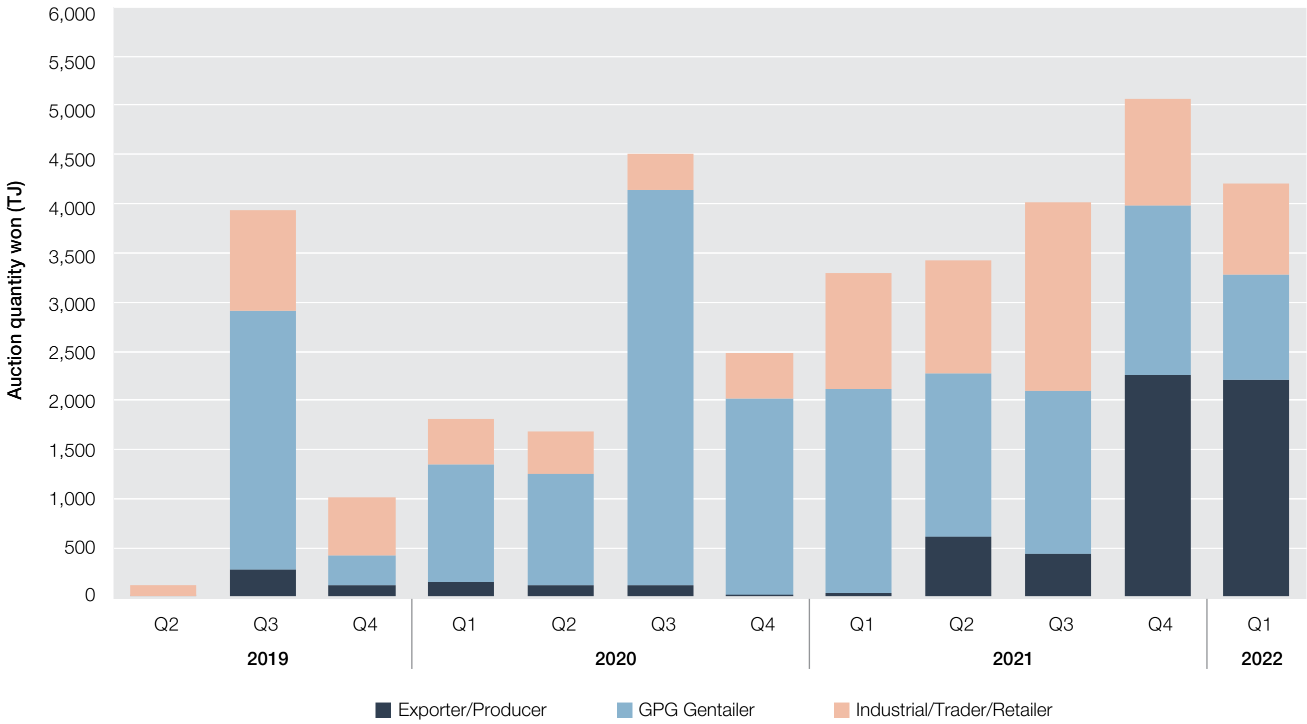
Since Q2 2021, between 30% and 50% of all auction capacity won on these routes has been to gas powered generator connection points. This underscores the importance of the DAA in providing access to cheap transportation, especially at times of high demand from gas powered generators. The highest month of GPG auction deliveries to date was in June 2021. In this month, significant unplanned electricity generator outages in Queensland drove increased gas powered generation.[26]

More recently, other participants have won more capacity on these routes to move gas to downstream markets, alongside gas powered generation trade. As a result, these 2 routes now serve dual purposes.

DAA facilitating trade in downstream markets

Since Q4 2020, the amount of auction capacity won to delivery points connecting to downstream spot markets in Adelaide, Brisbane, Sydney and Victoria has increased, peaking at 5.1 PJ in Q4 2021 (Figure 2.26).

Figure 2.26 Auction quantities won to connection points to downstream spot markets



Source: AER analysis using DAA auction results data.

Note: The downstream spot market connection points are connection points that provide access to the DWGM and the STTM spot gas markets.

The diversity of participants using the auction to bring gas to downstream spot markets has also increased (Figure 2.26). In our November 2021 *Significant Price Variation Report* we noted how traders were able to use the DAA over winter 2021 to offer gas into the market at favourable prices, taking advantage of price arbitrage opportunities.[27] This group won almost 2 PJ in Q3 2021 or 60% of all the total auction capacity won. However, in Q4 2021 and Q1 2022 Exporters and Producers overtook traders, winning most of the auction capacity delivered to downstream spot markets.

Although not major routes, participants won small auction quantities on MAPS and the SEAGas pipelines into Adelaide, winning 0.9 PJ between Q2 2021 and Q1 2022. Over the same period, participants also won 0.87 PJ of auction compression capacity at the Iona storage facility, which is used for deliveries directly into the Victorian gas market or Adelaide.[28]

The DAA continues to provide access to inexpensive pipeline capacity

Across all the auction facilities, auction results have cleared at the reserve price of $0/GJ around 80% of the time (Table 2.2).

26 https://www.aer.gov.au/system/files/Wholesale%20markets%20quarterly%20Q2%202021_1.pdf.

27 AER, *Significant price variation report*, November 2021.

28 Compression services are used to facilitate gas deliveries in a non-linear relationship.

Table 2.2 DAA, weighted average prices and number of days of zero prices

	WEIGHTED AVERAGE CLEARING PRICE IN AUCTION ON PRICE DAYS (NUMBER OF DAYS OF ZERO PRICES)			
	Q2 2021 $/GJ	Q3 2021 $/GJ	Q4 2021 $/GJ	Q1 2022 $/GJ
SWQP	0.17 (67 days)	0.13 (65 days)	0.18 (67 days)	0.22 (55 days)
MSP	0.10 (77 days)	0.45 (64 days)	0.09 (75 days)	0.10 (61 days)
RBP	0.25 (66 days)	0.31 (68 days)	0.12 (68 days)	0.18 (76 days)
EGP	0.62 (47 days)	0.40 (68 days)	0.18 (35 days)	0.40 (34 days)

Winning capacity on the DAA can be cheaper than buying the same services from a pipeline operator. For example, at 1 January 2022, buying equivalent services form APA on the SWQP (western haul) would cost either $1.93/GJ or $0.97/GJ, depending on the service (Table 2.3). But both are more expensive than the DAA average cleared price on the SWQP of $0.03/GJ.

Table 2.3 Comparison of DAA prices, and day ahead tariffs

	DAY AHEAD FIRM CAPACITY STANDING PRICE ($/GJ)*	DAY AHEAD INTERRUPTIBLE/AS AVAILABLE STANDING PRICE ($/GJ)**	DAA AVERAGE CLEARED PRICE ($/GJ)
SWQP (Western haul)	1.93	0.97	0.03
MSP (Moomba to Sydney)	1.77	0.89	0.10

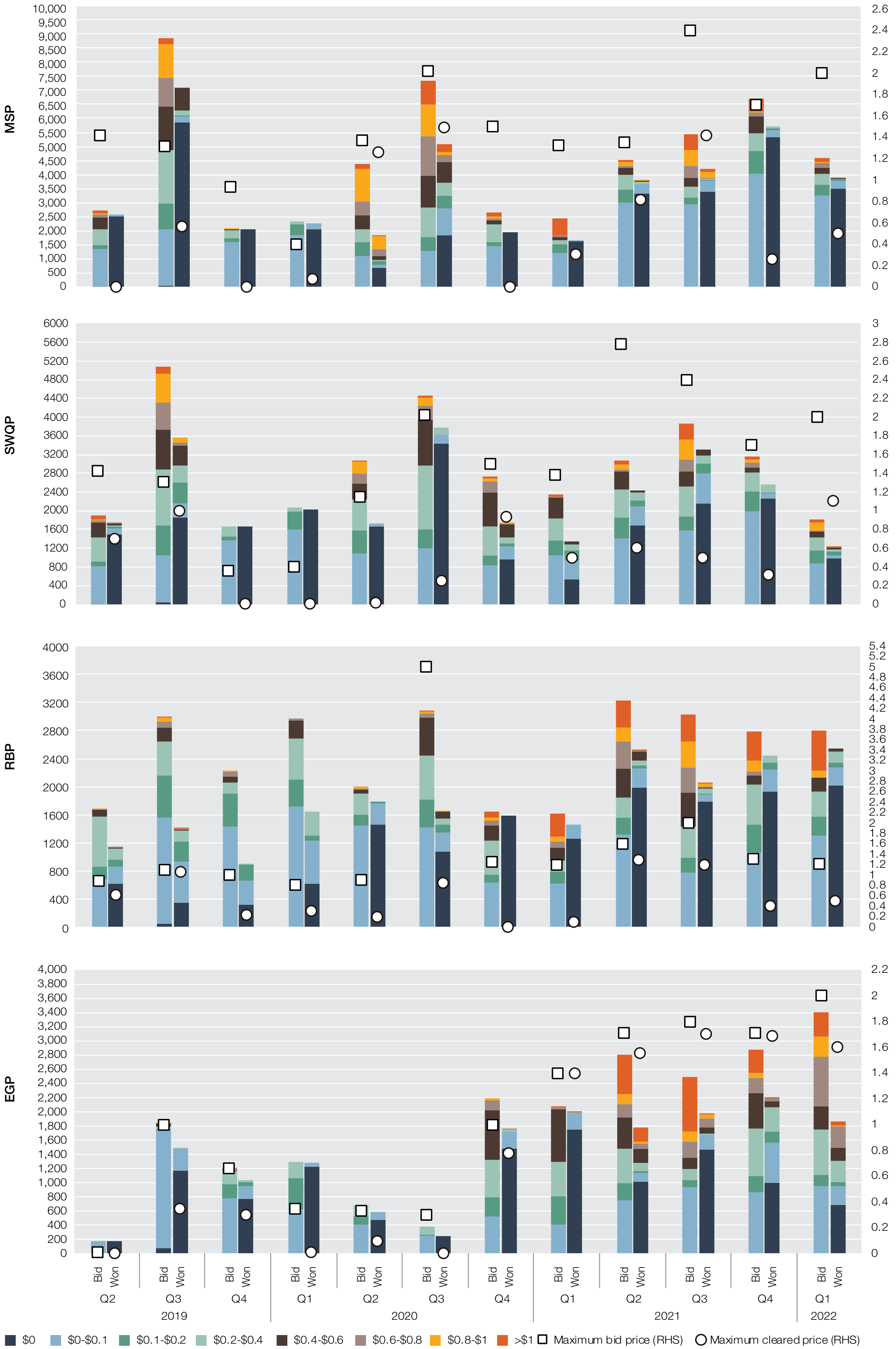
Source: APA, Tariffs and Terms, January 2022.

Notes: Firm services are scheduled as priority over transportation services. Interruptible /as available services are lower priority services which may be curtailed in favour of firm services.
* day ahead firm service tariff = (long term firm tariff) * (1+0.5).
** day ahead interruptible/as available service tariff = (long term firm tariff) * (1-0.25).

However, there are signs of increased prices on some routes

While in many quarters the maximum price on the most traded routes, MSP, SWQP, RBP and EGP, has been zero, bidding at higher prices has steadily increased, particularly during the winter months (Figure 2.27). Where bid volumes are higher than auction volumes, auction prices are more likely to clear above $0/GJ.

Figure 2.27 Auction bidding and clearing on the MSP, SWQP, RBP and EGP



Source: AER analysis using DAA auction results data.

Note: The auction bid stack volumes calculated for the facilities includes paired bids that could include multiple other auction facilities.

Every year, the MSP and SWQP are in high demand when gas is moved from north to south for the winter (Figure 2.27) increasing prices. In Q3 2021, auction bid volumes significantly exceeded auction quantities won on all facilities, and more than 22% of all auction bids were priced above $0.80/GJ. Interestingly, over 2021 and Q1 2022, demand outstripped supply on all major auction facilities, and participants missed out more often.

The EGP was the most over-subscribed auction facility in 2021. Strong competition for auction capacity contributed to the highest auction clearing prices, which ranged between $1.40/GJ and $1.70/GJ. The EGP is also the only facility, of the 4 key auction facilities, where the share of auction results clearing at $0/GJ has continued to decrease, falling from 100% in Q3 2020 to a record low of 36% in Q1 2022. This contrasts to MSP where bidding for northern routes to take gas towards Wallumbilla accelerated in 2021. However, as the northern route was still largely under subscribed this led to an increase in the number of zero dollar auction clearing prices.

Capacity Trading Platform – the first 3 years

To date, participants have only conducted one test trade of 1 TJ on the CTP. This occurred in February 2020. The high likelihood of securing pipeline capacity through the DAA at favourable prices appears to have provided little incentive for shippers to seek capacity on the CTP.

In November 2021, the Department of Industry, Science, Energy and Resources (DISER) reported that participants are reluctant to trade on the CTP for several reasons.[29]

For buyers, as noted above, over the first 3 years of the DAA, over 80 per cent of auction capacity has been won for zero dollars. And, at the same time there has been very little curtailment of auction quantities once won by firm shippers. As a result, buyers have not needed to purchase short-term firm secondary capacity products on the CTP. They can bid into spot markets or service gas powered generators with certainty the auction capacity will be there.

For sellers, they have been unlikely to get a higher price on the CTP as buyers see the prevailing cheap DAA prices. And, although ‘bumping’ has been rare, sellers under the DAA rules, retain the ability to reclaim relinquished firm capacity, should gas or electricity market conditions change. Lastly, participants expressed a desire to retain firm capacity to manage short-term demand peaks.

Outlook for the CTP

If auction clearing prices increase or participants are consistently outbid, they may start bidding for short term capacity through the CTP. It could also motivate sellers to offer capacity they are unlikely to need.

It is unclear what level of prices might motivate trades on the CTP. As the AER commences receiving over-the-counter short term trade information in 2022[30], it will indicate what prices auction participants have been willing to pay *off market* for short-term capacity, or for gas swaps. This will help us understand whether there are potential trades happening off market which could instead be conducted through the CTP.

If shippers negotiate long term contracts that better match seasonal demand, it will reduce the amount of unnominated capacity for sale on the DAA. For example, historical firm contracts may create seasonal uncontracted capacity if shippers have flat contracts for a year, but their end demand is seasonal. The AER will continue to monitor changes in auction capacity over time to understand if available unnominated capacity is changing, which might reflect participants contracting less annual firm capacity.

The AER will continue to actively participate in reform discussions and monitor participation in the CTP and DAA to inform the evolution of these markets. Our recent submission to the consultation paper on *Options to advance the east coast gas market*, drew on our analysis of DAA and Gas Supply Hub (GSH) outcomes as well as market participant feedback. Participants had indicated a preference for off market bilateral trades to avoid paying GSH fees, and a preference for negotiating and executing transactions over the phone rather than through the GSH trading platform. We expect they may hold the same concerns in relation to the capacity trading platform which has associated set up fees.[31] We also highlighted that the auction is not being used on some regional pipelines in South Australia (Figure 2.20), that are not connected to spot markets and where there are only 2 shippers, to indicate where the DAA has added less value.

In 2022–23 we will draw on data from our new contract market monitoring powers to further examine the DAA and CTP and to better understand short-term capacity trade activity.

29 DISER, Options to advance the east coast gas market – Consultation on the Wallumbilla Gas Supply Hub and the pipeline capacity trading framework, Stakeholder information forum, 30 November 2021.

30 Proposed changes to National Gas Legislation previously tabled for first reading to the 54th South Australian Parliament second session on 9 September 2021, expected to be reintroduced in the current sitting of SA Parliament.

31 https://www.aer.gov.au/system/files/AER%20Letter%20to%20Senior%20Energy%20Officials%20encl.%20Submissions%2813468454.1%29_0_1.pdf.

Appendix A Baseload Outages

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q1 2022	REASON FOR OUTAGE	RETURNED TO SERVICE
Queensland		**292**		
Callide C, Callide Power Trading	Black coal, 2 units, 420 MW each	Unit 3: 11 days	Unplanned (4 days) – Technical issues – spray control valve steam leak repairs	24/02/2022
			Planned (7 days)	Unknown
		Unit 4: 90 days	Expected (90 days) – significant failure on 25 May 2021	Unknown
Callide B, CS Energy	Black coal, 2 units, 350 MW each	Unit 1: 10 days	Unplanned (10 days) – Technical issues – tube leak	15/01/2022
		Unit 2: 35 days	Planned (20 days)	15/02/2022
			Unplanned (15 days) – Unit trip	Unknown
Gladstone, CS Energy	Black coal, 5 units, 280 MW each	Unit 1: 55 days	Unplanned (24 days) – Unit trip	25/01/2022
			Unplanned (5 days) – Unit trip	23/02/2022
			Unplanned (15 days) – Technical issues – Tube leak	11/03/2022
			Unplanned (11 days) – Technical issues – Tube leak	Unknown
		Unit 2: 15 days	Unplanned (3 days) – Technical issues – Turbine vibration	4/01/2022
			Planned (12 days) – Technical issues – FD fan issues	24/03/2022
		Unit 3: 1 day	Unplanned (1 day) – Unit trip	Unknown
		Unit 4: 25 days	Planned (24 days)	22/03/2022
			Unplanned (1 day) – Unit trip	Unknown
		Unit 5: 24 days	Unplanned (16 days) – Steam leak	22/01/2022
			Planned (8 days)	25/02/2022
Kogan Creek, CS Energy	Black coal, 1 unit, 713 MW	Unit 1: 26 days	Unplanned (26 days) – Technical issues	18/02/2022
NSW		**271**		
Bayswater, AGL Energy	Black coal, 3 units, 630 MW – 655 MW	Unit 2: 11 days	Planned (11 days)	12/01/2022
		Unit 3: 28 days	Planned (28 days)	Unknown
		Unit 4: 8 days	Unplanned (7 days) – Tube leak	22/02/2022
			Planned (1 day)	Unknown

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q1 2022	REASON FOR OUTAGE	RETURNED TO SERVICE
Liddell, AGL Energy	Black coal, 4 units, 450 MW each	Unit 1: 34 days	Planned (12 days)	9/02/2022
			Unplanned (22 days) – Tube leak	7/03/2022
		Unit 2: 9 days	Planned (9 days)	31/03/2022
		Unit 3: 25 days	Unplanned (15 days) – Plant failure	26/02/2022
			Unplanned (10 days) – Plant failure	15/03/2022
		Unit 4: 22 days	Unplanned (11 days) – Tube leak	28/02/2022
			Unplanned (11 days) – Unit trip	20/03/2022
Vales Point, Delta Electricity	Black coal, 1 unit, 660 MW	Unit 5: 1 day	Planned (1 day)	2/01/2022
Eraring, Origin Energy	Black coal, 4 units, 680 MW each	Unit 1: 16 days	Unplanned (16 days) – Oil cooler repair	Unknown
		Unit 2: 21 days	Unplanned (21 days) – Station trip	14/03/2022
		Unit 3: 33 days	Unplanned (33 days) – Tube leak repairs	1/03/2022
		Unit 4: 21 days	Unplanned (21 days) – Avoid short mill movement	22/01/2022
Mount Piper, Energy Australia	Black coal, 2 units, 675 MW each	Unit 1: 6 days	Unplanned (4 days) – Grease line repair	23/01/2022
			Unplanned (2 days) – Unit trip	13/02/2022
		Unit 2: 36 days	Planned (3 days)	4/01/2022
			Unplanned (1 day) – Unit trip	9/01/2022
			Planned (32 days)	Unknown
Victoria		**98**		
Loy Yang A, AGL Energy	Brown coal, 3 units, 500 MW – 525 MW	Unit 1: 7 days	Planned (7 days)	23/03/2022
		Unit 2: 5 days	Unplanned (5 days) – Unplanned plant limits/ Tube leak	7/02/2022
		Unit 4: 2 days	Planned (2 days)	28/03/2022
Yallourn, Energy Australia	Brown coal, 4 units, 355 MW each	Unit 1: 25 days	Planned (11 days)	10/02/2022
,			Unplanned (6 days) – Tube leak	21/02/2022
			Unplanned (2 days) – Condensate outage	27/02/2022
			Unplanned (6 days) – Tube leak	13/03/2022
		Unit 2: 30 days	Unplanned (5 days) – Plant trip	6/01/2022
			Unplanned (8 days) – Tube leak	2/02/2022

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q1 2022	REASON FOR OUTAGE	RETURNED TO SERVICE
			Unplanned (11 days) – Tube leak	18/02/2022
			Unplanned (6 days) – Water wall repairs	11/03/2022
		Unit 3: 6 days	Unplanned (4 days) – Tube leak	25/01/2022
			Unplanned (2 days) – Unit trip	Unknown
		Unit 4: 23 days	Unplanned (21 days) – Ash hopper failure	25/02/2022
			Unplanned (2 days) – Coal supply issues	Unknown

Appendix B Day Ahead Auction routes grouped by direction

FACILITY	DIRECTION	DAA ROUTE RECEIPT POINT NAME TO DELIVERY POINT NAME	RECEIPT POINT ID TO DELIVERY POINT ID
MSP	South from Moomba	MSP Inlet >>> Bathurst	1502045–1202022
		MSP Inlet >>> Canberra	1502045-1202027
		MSP Inlet >>> Dubbo	1502045–1202062
		MSP Inlet >>> MAPS Exit	1502045–1502039
		MSP Inlet >>> Uranquinty Power Station	1502045–1202047
		MSP Inlet >>> Culcairn South	1502045–1202026
		MSP Inlet >>> Culcairn Trade Point	1502045–1290016
		MSP Inlet >>> Griffith	1502045–1202063
		MSP Inlet >>> Wilton	1502045–1202052
		MSP Inlet >>> Wilton Trade Point	1502045–1290019
	Towards Moomba	Culcairn North >>> MAPS Exit	1202025–1502039
		Culcairn North >>> SWQP Exit	1202025–1502057
		Culcairn Trade Point >>> MAPS Exit	1290015–1502039
		Culcairn Trade Point >>> SWQP Exit	1290015–1502057
		Culcairn Trade Point >>> MGP Exit	1290015–1502040
		Culcairn North >>> MGP Exit	1202025–1502040
		EGP Entry >>> MAPS Exit	1202038–1502039
		EGP Entry >>> SWQP Exit	1202038–1502057
		EGP Entry >>> MGP Exit	1202038–1502040
		MSP Inlet >>> SWQP Exit	1502045–1502057
		Wilton Trade Point >>> MAPS Exit	1290018–1502039
		Wilton Trade Point >>> MGP Exit	1290018–1502040
		Wilton Trade Point >>> SWQP Exit	1290018–1502057
	Within NSW East	Culcairn North >>> Wilton	1202025–1202052
		Culcairn North >>> Wilton Trade Point	1202025–1290019
		Culcairn Trade Point >>> Culcairn South	1290015–1202026
		Culcairn Trade Point >>> Culcairn Trade Point	1290015–1290016
		Culcairn Trade Point >>> Wilton	1290015–1202052
		Culcairn Trade Point >>> Wilton Trade Point	1290015–1290019
		Wilton Trade Point >>> Wilton Trade Point	1290018–1290019
		Wilton Trade Point >>> Wilton	1290018–1202052
	Within NSW West	Culcairn North >>> Culcairn Trade Point	1202025–1290016
		EGP Entry >>> Culcairn Trade Point	1202038–1290016
		Wilton Trade Point >>> Culcairn South	1290018–1202026
		Wilton Trade Point >>> Culcairn Trade Point	1290018–1290016

RBP	East	Condamine >>> Ellen Grove	1404086–1404089
		RBP Trade Point (IPT) >>> Condamine	1490022–1404085
		RBP Trade Point (IPT) >>> Ellen Grove	1490022–1404089
		RBP Trade Point (IPT) >>> Murarrie	1490022–1404093
		RBP Trade Point (IPT) >>> Oakey PS	1490022–1404095
		RBP Trade Point (IPT) >>> RBP Trade Point (IPT)	1490022–1490021
		RBP Trade Point (IPT) >>> Swanbank PS	1490022–1404104
		RBP Trade Point (IPT) >>> Tingalpa	1490022–1404105
		RBP Trade Point (IPT) >>> Wambo	1490022–1404261
		Scotia >>> RBP Trade Point (IPT)	1404102–1490021
		Wallumbilla Run 3 >>> Condamine	1404109–1404085
		Wallumbilla Run 3 >>> Ellen Grove	1404109–1404089
		Wallumbilla Run 3 >>> Murarrie	1404109–1404093
		Wallumbilla Run 3 >>> RBP Trade Point (IPT)	1404109–1490021
		Wallumbilla Run 7 >>> Tingalpa	1404111–1404105
	West	Argyle >>> Wallumbilla delivery	1404082–1404097
		Condamine >>> Wallumbilla delivery	1404086–1404097
		RBP Trade Point (IPT) >>> Wallumbilla delivery	1490022–1404097
		Scotia >>> Wallumbilla delivery	1404102–1404097
		Wallumbilla Run 2 >>> Wallumbilla delivery	1404108–1404097
		Woodroyd >>> Wallumbilla delivery	1404112–1404097
SWQP	North	Ballera Entry >>> Wallumbilla LP Trade Point	1404114–1490026
		SWQP Entry from MCF >>> GLNG Delivery Stream	1590026–1404129
		SWQP Entry from MCF >>> Wallumbilla LP Trade Point	1590026–1490026
		SWQP MSP Entry >>> Ballera Exit	1590027–1404115
		SWQP MSP Entry >>> SWQP to MCF Exit	1590027–1590025
		SWQP MSP Entry >>> Wallumbilla LP Trade Point	1590027–1490026
		Wallumbilla HP Trade Point >>> GLNG Delivery Stream	1490025–1404129
		Wallumbilla HP Trade Point >>> Wallumbilla LP Trade Point	1490025–1490026
	South	Ballera Entry >>> SWQP to MCF Exit	1404114–1590025
		Wallumbilla HP Trade Point >>> Cheepie	1490025–1404116
		Wallumbilla HP Trade Point >>> Ballera Exit	1490025–1404115
		Wallumbilla HP Trade Point >>> SWQP to MCF Exit	1490025–1590025

Appendix C Gas participant list

PARTICIPANT LIST IN EASTERN GAS MARKET

	Market participant	Victoria	Sydney	Adelaide	Brisbane	GSHs	DAA
GPG Gentailer	AGL*	● (dark navy)	● (dark navy)	● (dark navy)	● (dark navy)	● (dark navy)	● (orange)
	Alinta Energy	● (dark navy)	● (light blue)	● (dark navy)	● (dark navy)	● (dark navy)	● (orange)
	CleanCo				● (orange)	● (orange)	● (orange)
	EnergyAustralia	● (dark navy)	● (dark navy)	● (dark navy)		● (light blue)	● (orange)
	Engie	● (dark navy)					● (magenta)
	Hydro Tasmania	● (dark navy)	● (dark navy)				
	Origin	● (dark navy)	● (dark navy)	● (dark navy)	● (dark navy)	● (dark navy)	● (orange)
	Shell Retail	● (magenta)	● (magenta)	● (magenta)	● (magenta)	● (magenta)	● (magenta)
	Snowy Hydro	● (dark navy)	● (dark navy)	● (light blue)	● (light orange)		
Exporter/Producer	Arrow*		● (green)		● (orange)	● (dark navy)	● (green)
	APLNG					● (dark navy)	● (magenta)
	BHP Billiton	● (orange)	● (orange)				
	Cooper Energy	● (green)					
	Esso	● (dark navy)	● (dark navy)				● (orange)
	GLNG					● (dark navy)	
	Lochard Energy	● (light blue)					
	Santos	● (dark navy)	● (dark navy)	● (dark navy)	● (dark navy)	● (dark navy)	● (orange)
	Senex	● (red)	● (magenta)		● (magenta)	● (green)	● (magenta)
	Shell*	● (magenta)	● (orange)	● (magenta)	● (magenta)	● (magenta)	● (orange)
	Walloons Coal Seam Gas (QGC)					● (dark navy)	● (orange)
	Westside Corporation					● (green)	● (green)
Retailer	1st Energy	● (green)					
	Agora	● (red)					
	Covau	● (dark navy)	● (dark navy)	● (magenta)	● (green)		
	CPE Mascot		● (dark navy)				
	Delta Electricity		● (dark navy)				
	Discover Energy	● (magenta)	● (green)	● (green)	● (green)		
	Dodo	● (dark navy)	● (dark navy)				
	GloBird Energy	● (light orange)	● (green)	● (green)	● (green)		
	OVO Energy	● (magenta)					
	Powershop	● (light blue)	● (magenta)				
	Simply Energy*		● (light blue)	● (dark navy)			
	Sumo Gas	● (light blue)	● (magenta)				
	TasGas	● (magenta)					
	Tango	● (magenta)					
	Weston Energy	● (light blue)	● (dark navy)	● (light blue)	● (light orange)		● (red)

Industrial	Adelaide Brighton Cement			Entered before 2017			
	Ampol				Entered before 2017		
	BlueScope	Entered in 2021	Entered before 2017		Entered in 2018		
	Boortmalt	Entered in 2019	Entered in 2018	Entered in 2018			
	Brickworks	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020		
	Commonwealth Steel		Entered in 2017				
	Coopers			Entered in 2017			
	CSR Building Products	Entered in 2018	Entered in 2021	Entered in 2019	Entered in 2018		
	Incitec Pivot				Entered before 2017	Entered before 2017	Entered in 2019
	Infrabuild	Entered before 2017	Entered before 2017	Entered before 2017		Entered in 2022	Entered in 2022
	Master Butchers			Entered in 2020			
	Michell Wool			Entered in 2019			
	Mobil Oil	Entered in 2018					
	Oceania Glass	Entered in 2020					
	Orica		Entered in 2017				
	Paper Australia	Entered in 2018	Entered in 2020				
	Qenos	Entered in 2017	Entered before 2017			Entered in 2017, Exit or inactive	Entered in 2019
	SA Water			Entered before 2017			
	Tarac Technologies		Entered in 2017	Entered before 2017			Entered in 2019
	Visy	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017		Entered in 2020
	Viva Energy	Entered in 2018					
Trader	Eastern Energy Supply	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020
	Macquarie Bank	Entered in 2019	Entered in 2019			Entered in 2018	Entered in 2019
	Petro China	Entered in 2020	Entered in 2020		Entered in 2021	Entered in 2019	Entered in 2020
	Strategic Gas Market Trading	Entered in 2019	Entered in 2019	Entered in 2021	Entered in 2020	Entered before 2017	Entered in 2019
	61	42	38	26	22	20	25

● Entered before 2017 ● Entered in 2017 ● Entered in 2018 ● Entered in 2019 ● Entered in 2020 ● Entered in 2021 ● Entered in 2022
● Exit or inactive

Note: For Victoria, Adelaide, Sydney, Brisbane and the GSH the year represents when participants commenced trading. For the DAA the year represents when participants registered.

* Click Energy was acquired by AGL, ERM was acquired by Shell (Shell Retail), O-I International was acquired by Visy.
* Arrow also operates the Braemar 2 power station.
* Simply Energy is the retail arm of Engie, who own and operate gas generation assets in South Australia.

* ICAP Brokers is also active in the GSH, but does not trade gas commodities (trade facilitator).

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
QNI	Queensland New South Wales Interconnector	BWP	Berwyndale to Wallumbilla Pipeline
VNI	Victoria to New South Wales Interconnector	CGP	Carpentaria Gas Pipeline
V-SA	Heywood Interconnector	EGP	Eastern Gas Pipeline
V-S-MNSP1	Murraylink Interconnector	ICF	Iona Compression Facility
T-V-MNSP1	Basslink Interconnector	MAPS	Moomba to Adelaide Pipeline System
N-Q-MNSP1	Terranora Interconnector	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
		WCFA	Wallumbilla Compression Facility A
		WCFB	Wallumbilla Compression Facility B

AUSTRALIAN
ENERGY
REGULATOR