Wholesale Markets Quarterly

Q3 2021

July – September

November 2021

AUSTRALIAN ENERGY REGULATOR

Australian Government

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Summary

Electricity markets

Q3 2021 highlighted significant shifts in wholesale electricity market outcomes, driven by the ongoing transition from a market dominated by large coal-fired generators to one that incorporates an increasing volume of dispersed renewable generators.

For the first time in a Q3, average quarterly black coal generation supplied less than 50% of grid demand. Brown coal and gas generation also fell from Q3 2020 levels. This generation was displaced by increased output from renewable generators, with wind generation at record levels.

Prices on the mainland were high in July, particularly in Queensland and NSW, before falling to more moderate levels in August and September. Generation and network outages, coupled with high winter heating demand, played a significant role in causing high prices early in the quarter.

Lower demand later in the quarter played a key role in reducing prices, with South Australia experiencing its lowest ever minimum demand and Victoria its lowest Q3 demand. That South Australia experienced both record Q3 demand and record ever minimum demand in a single quarter shows the extent of demand volatility this quarter.

Record minimum demand from the grid was driven by record rooftop solar output in every region as more homes and businesses generated their own electricity. The growth of solar drove the increase in negative prices. Wholesale prices in South Australia were negative almost a quarter of the time in Q3 2020, a record level. In response to the increase in negative prices in the middle of the day, some participants are changing their offer behaviour, particularly black coal generators in Queensland and NSW.

Volume weighted average (VWA) prices in all regions were lower in Q3 2021 than in Q2 2021 but were generally up from levels in the same quarter last year. Frequency control ancillary services (FCAS) costs were at a record high for a Q3 this quarter, totalling $130 million. Similar to Q2 2021, local FCAS costs in Queensland (which reached a near record of $71 million) were a key driver of this overall outcome.

This report also includes a focus story on the introduction of 5 minute settlement (5MS), highlighting how peaking generators have prepared for 5MS and early market observations.

Gas markets

Q3 2021 saw the emergence of the largest, most sustained price separation between domestic spot market prices and LNG spot netback price assessments since LNG exports commenced in 2015. These assessments, calculated at Wallumbilla in Queensland, increased through the quarter to average $22.18/GJ over Q3 2021. However, domestic spot market prices decreased through the quarter and fell to under $10/GJ in August and September including in Queensland. Accordingly, by the end of the quarter, domestic spot traded gas was priced at less than half the assessed price at which gas could be exported into Asia.

Through August and September, the domestic market remained well supplied despite LNG export production running near nameplate capacity, adjusted for maintenance days. There were significant increases in production at Longford (Victoria) and in Roma (Queensland) with east coast production reaching record levels for Q3 2021, matching record Q3 LNG exports. In August and September prices ranged between $6.70/GJ to $10.00/GJ across domestic spot markets during a period of relatively low demand compared to July.

The quarter was split with July price outcomes differing to those in August and September. In July, domestic spot market prices reflected international LNG spot netback prices more closely. There were 16 instances of prices above $20/GJ in July in southern markets as supply reductions occurred at the Victorian Longford production facility and as southern storage levels diminished. High periods of gas demand occurred through July, which drew gas south from northern suppliers including from gas exporters.

High spot prices in July 2021 did not appear to significantly reduce purchases of spot market gas by industrial users across Q3 2021. Trade through spot markets reached record levels over Q3 2021. Our focus story highlights participation across east coast gas markets in 2021, focusing on which participant groups are buyers and sellers of gas.

Off the back of high July prices, there were record average quarterly prices across all 4 downstream spot markets with prices ranging from $10.10/GJ in Victoria to $11.50/GJ in Adelaide in Q3 2021.

Electricity markets at a glance

Q3 2021

Spot prices

Prices were high in July before easing in August and September.

Negative prices

Record number of negative prices in every region.

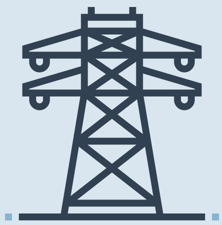
Demand

Demand was high in July driven by cold weather but low in September. Record minimum demand ever in SA.

Generation

Record low Q3 black coal generation. Record high wind generation.

Interconnectors



Interconnector limits reduced Queensland and NSW's access to cheaper generation.

FCAS

50 Hz

Cost of maintaining system frequency was high.

Gas markets at a glance
Q3 2021

Spot prices

Prices rise 28% from Q2, ranging from $10.10-$11.50/GJ in downstream markets.

Spot Trade Downstream

Producers drove a record 19.4 PJ of spot trade in Q3.

Gas storage

Storage played critical role in supplying Q3 peak demand.

International markets

LNG spot netback prices rise across the quarter as European and Asian LNG prices tripled.

Gas production and flows

Gas production reaches record levels 5,650 TJ/day in Q3.

Day Ahead Auction

Auction usage changed to support south and north flows across Q3.

About this report

This report highlights wholesale electricity and gas market outcomes in Q3 2021.

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 of these obligations in this report.

1. Electricity

1.1 Wholesale prices were high in July before easing in August and September

Volume weighted average (VWA) spot prices in all NEM regions decreased from the higher prices experienced in Q2 2021. Prices ranged from $27/MWh in Tasmania to $90/MWh in Queensland. The quarterly price recorded in Tasmania is the lowest quarterly price in any region since Q1 2012 (Figure 1.1).

Figure 1.1 Average quarterly spot 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.

However, quarterly prices were higher in all mainland regions compared to the low prices experienced in Q3 2020, particularly in Queensland and NSW. The average quarterly price in Queensland was its highest Q3 price on record. In contrast, Tasmania's quarterly price was its lowest Q3 price since 2009.

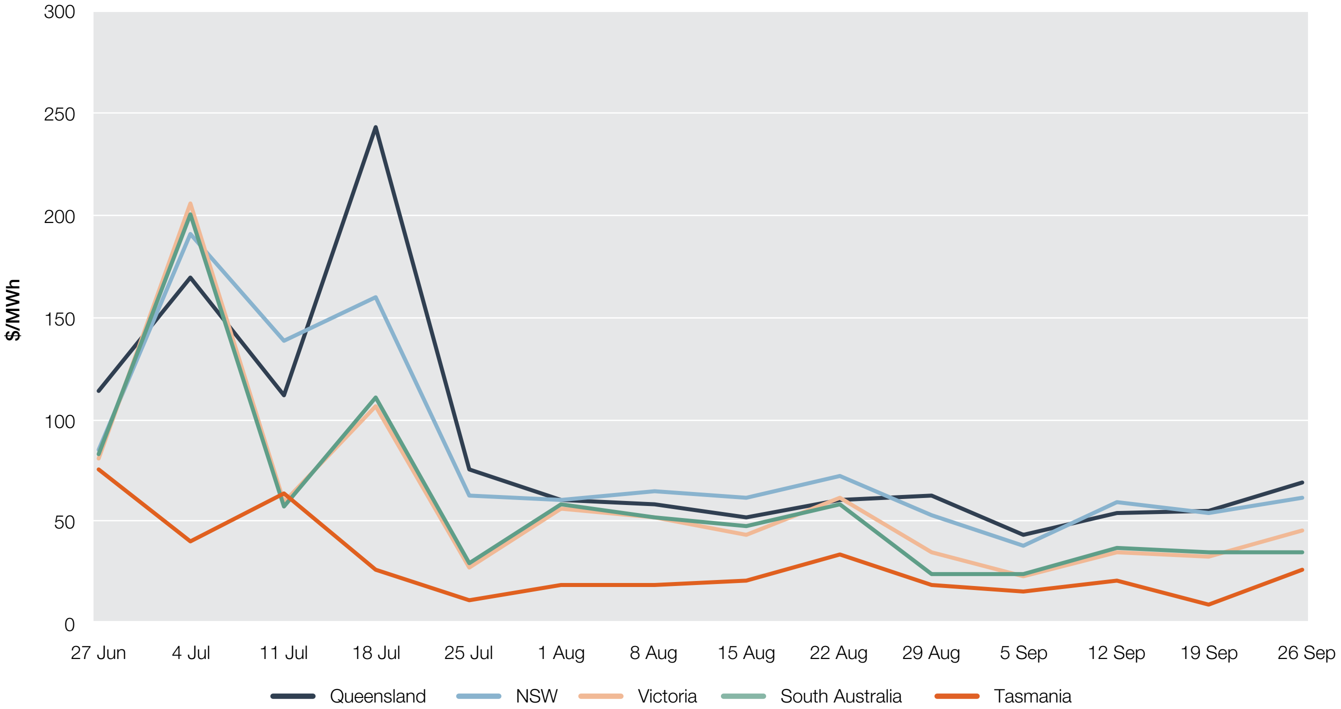
Price outcomes in Queensland and NSW were largely driven by volatile prices in the first 4 weeks of the quarter. These were caused by:

- high demand (section 1.4)
- planned and unplanned generator outages (section 1.6)
- line outages and interconnector limits, which reduced the ability of Queensland and NSW to import cheaper generation from other regions (section 1.12)
- increased offer prices from coal generators (section 1.7).

High prices in Victoria and South Australia in July were driven by similar variables, including generator outages and high demand.

Average weekly prices in Queensland peaked at $243/MWh in the week commencing 18 July and NSW prices peaked at $191/MWh in the week commencing 4 July (Figure 1.2). Prices in Victoria and South Australia also peaked in the week commencing 4 July at $206/MWh and $201/MWh respectively but remained lower than Queensland and NSW for the remainder of the quarter.

Figure 1.2 Average weekly prices, Q3 2021 (VWA)



Source: AER analysis using NEM data.

Note: Volume weighted average weekly prices, weighted against native demand in each region. AER defines native demand as the sum of initial supply and total intermittent generation in a region. Weeks start on Sunday.

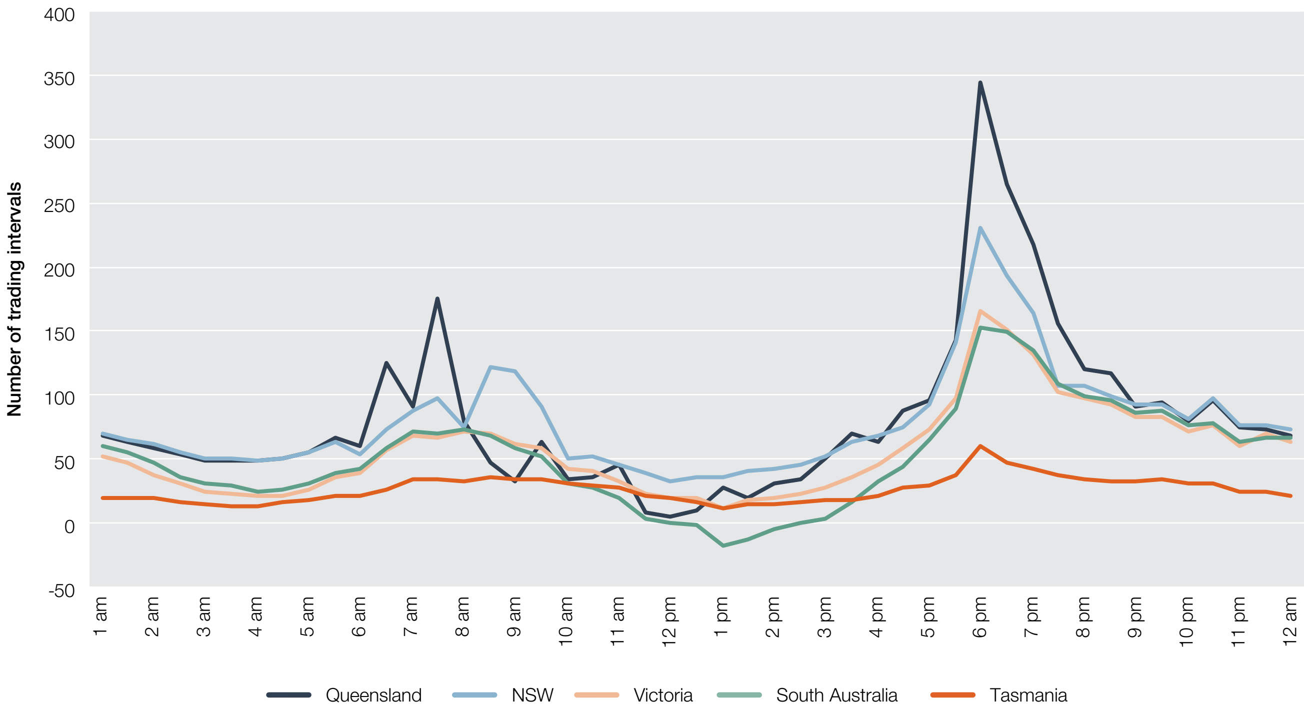
1.2 Wholesale prices were lower during the middle of the day

We have seen a continuation of the intraday dynamics we reported in FY 2020–21. Across all regions, average prices trend up from 6am before peaking early in the morning. During the middle of the day, prices are lower but rise again from around 1.30pm, peaking in the early evening. These morning and evening peaks are driven by a lack of solar generation and higher demand.

This dynamic resulted in some interesting outcomes this quarter (Figure 1.3):

- South Australia recorded negative average prices during the middle of the day, driven by high rooftop solar output. This is the first time negative average prices have been recorded in Q3.
- High evening peak prices in July contributed to high average peak prices for the quarter.
- Average prices in Tasmania were relatively flat through the day, with softer peaks and troughs than mainland regions. However, average prices were less flat than reported in FY 2020–21, which did not have discernible evening peaks.

Figure 1.3 Average spot prices by time of day, Q3 2021

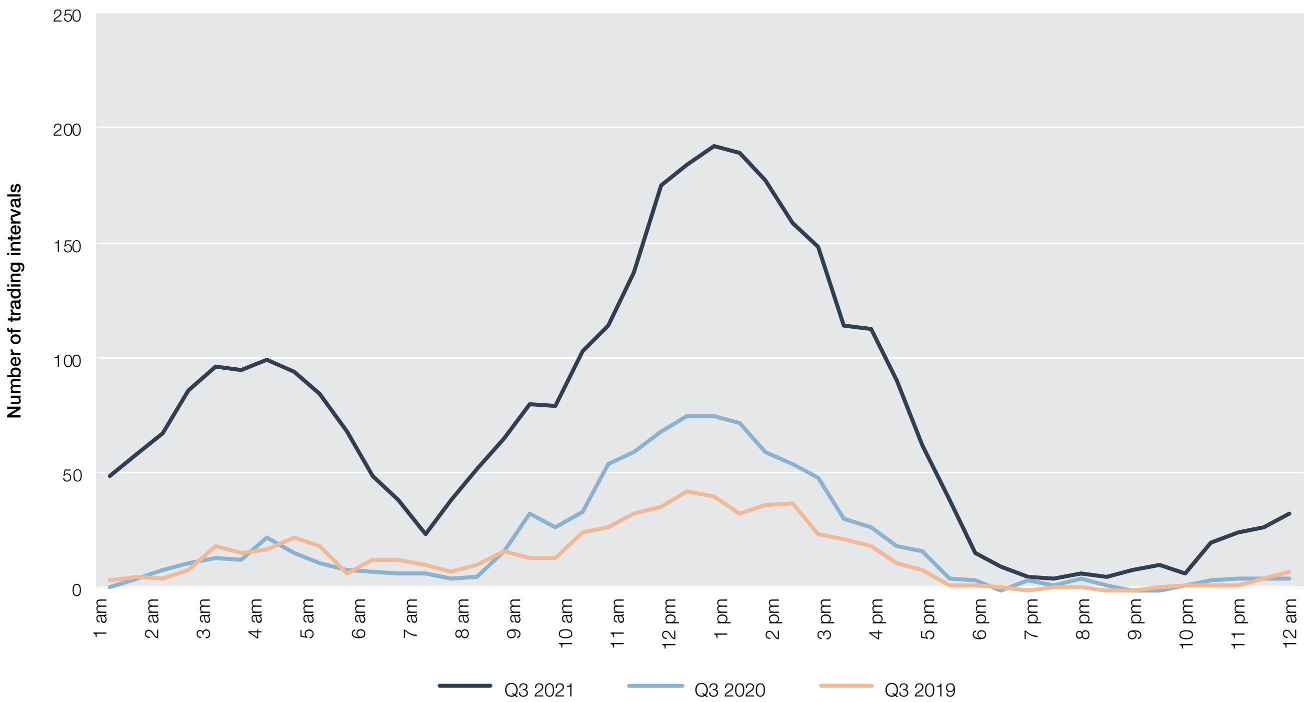


Source: AER analysis using NEM data.

Note: Average prices by trading interval in Q3 2021, not volume weighted.

The lower prices during the middle of the day across the NEM, in part, reflects the increased incidence of negative prices. While there were significantly more negative priced trading intervals in Q3 2021 across all hours than had occurred in previous years, the number of negative prices was particularly higher during the day and overnight (Figure 1.4).

Figure 1.4 Count of negative spot prices by time of day, Q3 comparisons

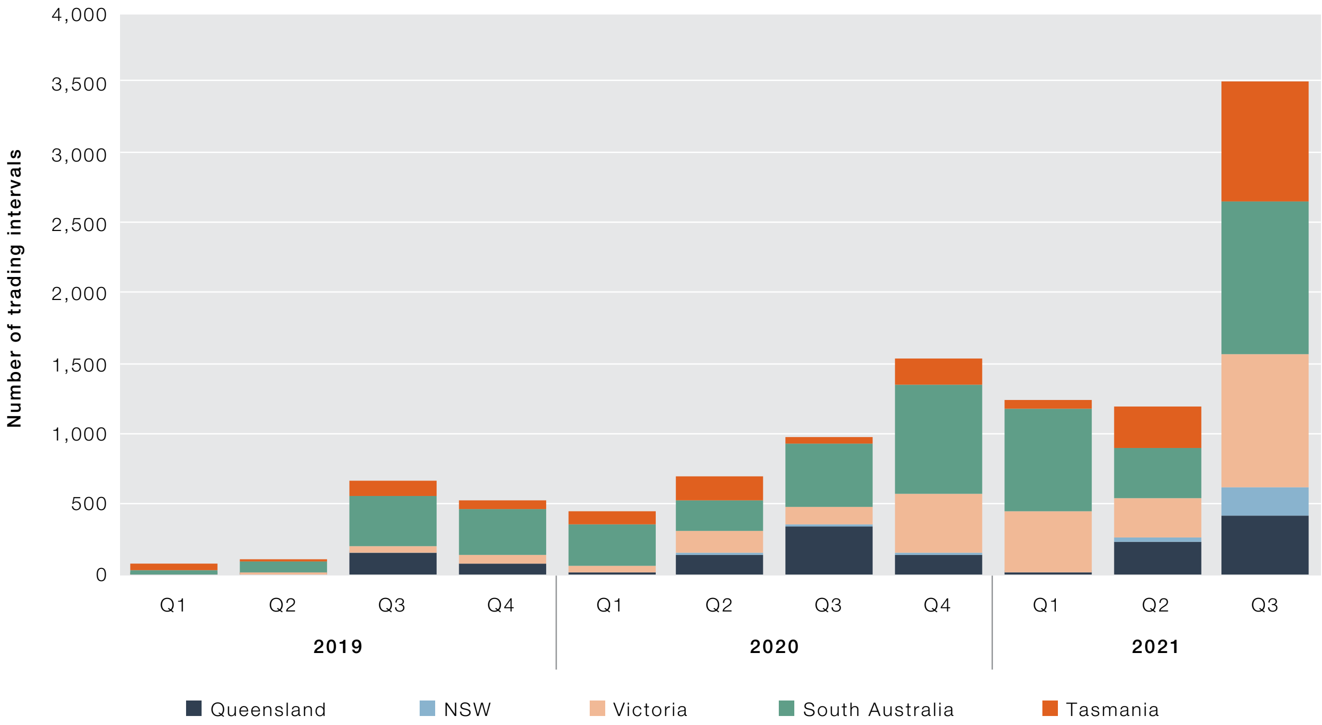


Source: AER analysis using NEM data.

Note: Count of spot prices below $0/MWh by time of day, in quarter 3 of each year.

There were 3,499 negatively priced trading intervals in Q3 2021, a record number. This was almost 3 times the number of negatively priced trading intervals in Q2 2021 and nearly 4 times the amount in Q3 2020. While most negative prices were in South Australia, there were increased instances of negative prices in every region, especially in NSW and Victoria. As a result, almost a quarter of all trading intervals in South Australia, and almost 20% of all trading intervals in Victoria, had negative prices in the quarter.

Figure 1.5 Count of negative prices, quarterly



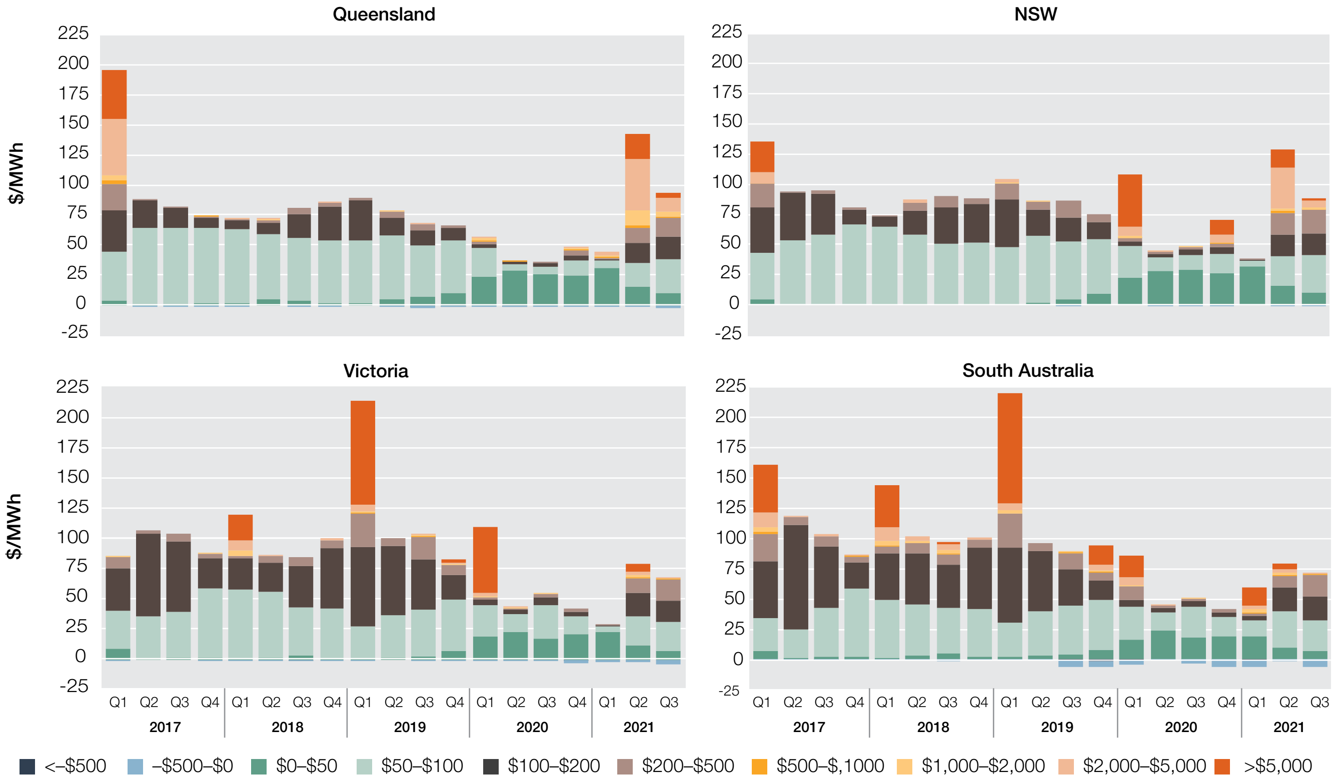
Source: AER analysis using NEM data.
Note: Count of spot prices below $0/MWh in each quarter.

Although the quantity of negative prices increased this quarter, the magnitude of these have decreased. In Q3 2019, only 55% of all negative prices recorded across NEM were above -$50/MWh, but in Q3 2021 this increased to 91%.

However, this change was not confined to negative prices. In Q3 2021, we saw a limited contribution to average prices from the lower priced trading intervals ($0/MWh to $50/MWh) across all mainland regions, continuing the trend from last quarter. In Queensland and NSW, we have observed a corresponding increase in the contribution of prices in the $50/MWh to $100/MWh band (Figure 1.6).

With fewer low prices, higher prices made a large contribution to average Q3 2021 prices in Queensland and NSW. Prices between $50/MWh and $500/MWh contributed almost 70% and 80% to the Queensland and NSW average price, respectively. This contrasts to contributions of 29% and 39% in these regions in Q3 2020.

Figure 1.6 Contribution of different price bands to average quarterly wholesale 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.

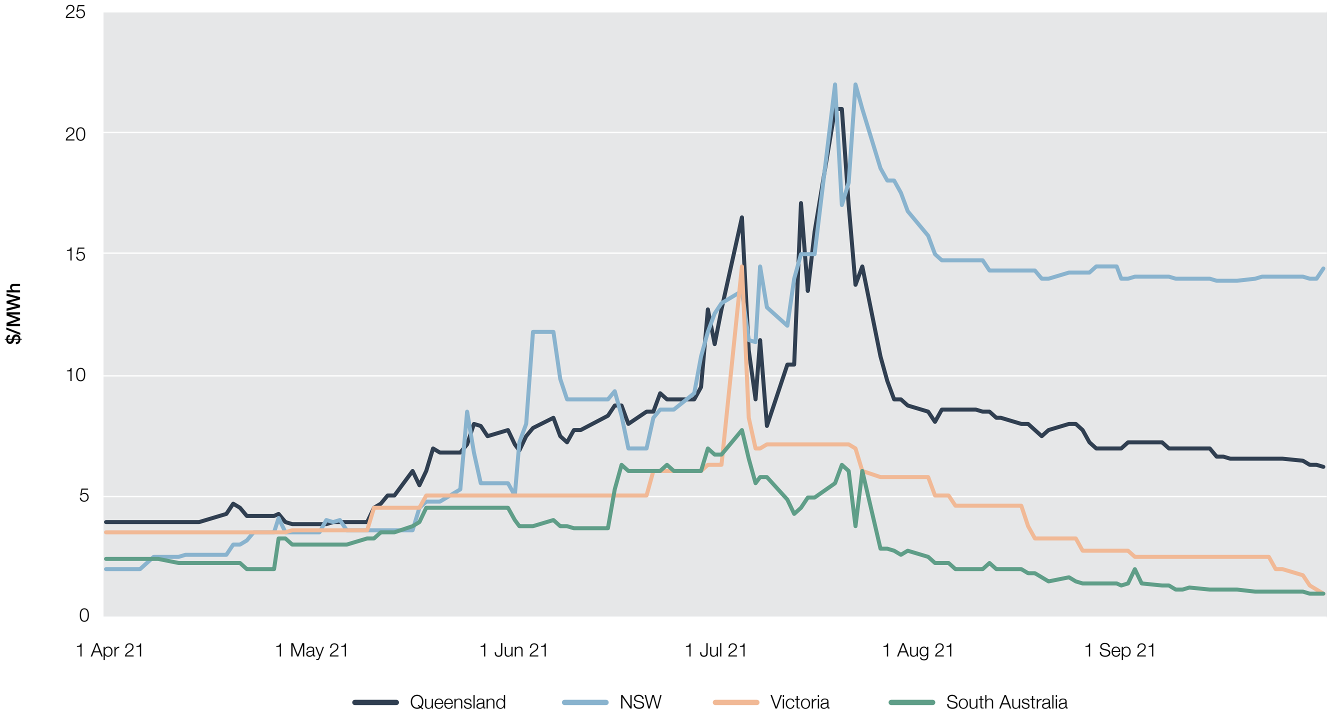
1.3 Summer price expected to be below $80/MWh in all regions

Contract market outcomes at the end of Q3 2021 indicated that market participants expect average prices this summer will be below $80/MWh in all regions. Participants now expect summer prices to be highest in Queensland, reflecting the high spot prices in the region over the past 6 months, and lowest in Victoria.

Q3 2021 base future and cap prices increased in July before falling back in August and September in line with spot prices.

Cap contract prices are a representation of participant's expectations of market volatility. The final cap prices in Queensland ($14.47/MWh) and NSW ($6.14/MWh) were the highest quarter end cap prices ever recorded in these regions in a Q3, exceeding the record set in Q3 2015 where the final cap prices in both regions was just under $4.50/MWh (Figure 1.7). Final cap prices in Victoria and South Australia were both less than $1/MWh.

Figure 1.7 Daily settlement price for Q3 2021 quarterly cap contracts



Source: AER analysis using ASX Energy data.

Note: Daily settlement price for Q3 2021 quarterly caps.

A high volume of spot prices greater than the cap strike price of $300/MWh, like we saw in Queensland, is unusual for Q3. Since 2005, two-thirds of the final Q3 cap prices across the NEM were below $1/MWh.

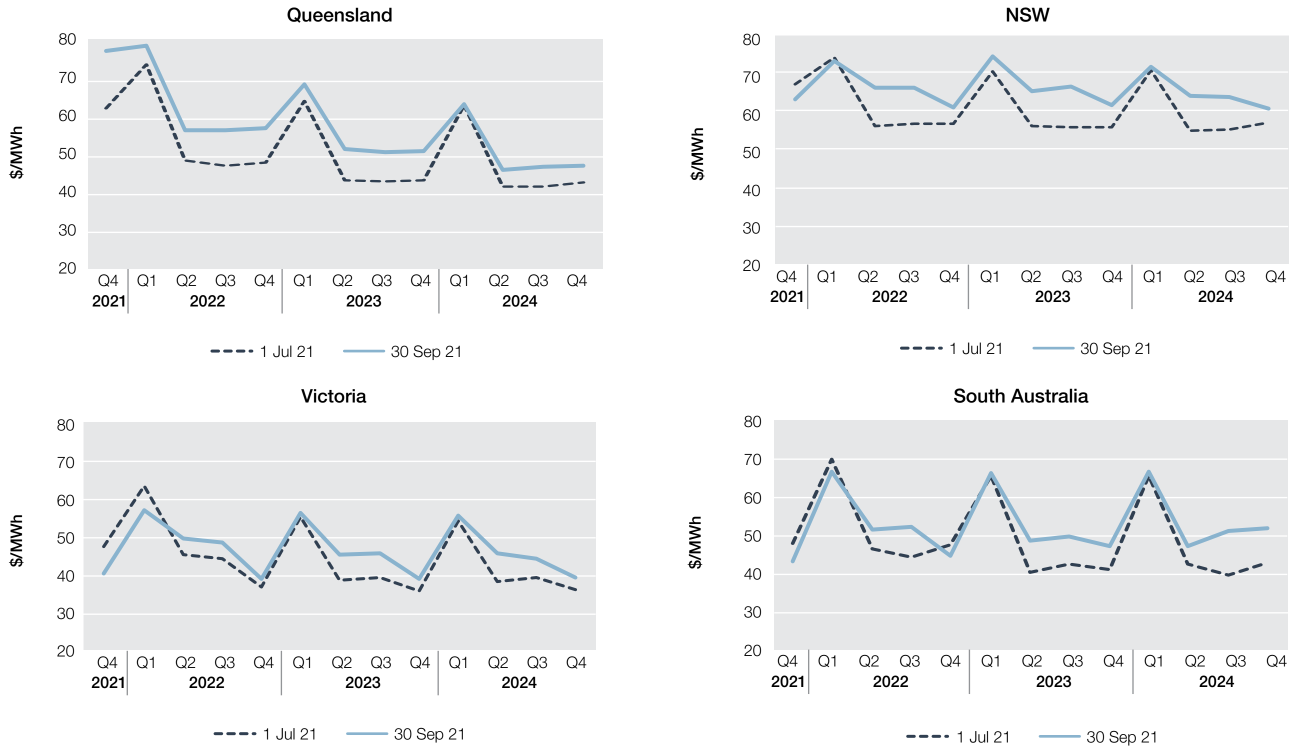
Price expectations for the 3-year horizon reflected regional spot price outcomes in Q3 2021, generally increasing in Queensland and NSW (Figure 1.8):

› Prices for this summer shifted up in Queensland and down in all other regions but are expected to remain below $80/MWh.

› Prices for future summers remained fairly stable, increasing slightly in Queensland and NSW.

› Prices for the shoulder quarters, Q2 and Q3, increased 10% to 20% across all regions.

Figure 1.8 Forward base future prices



Source: AER analysis using ASX Energy data.

Note: Closing price of base futures contracts for Q4 2021 to Q4 2024 on the first trading day (1 July 2021) and last trading day (30 September 2021) of Q3 2021.

1.4 Demand was high in July and low in September

Demand was the primary driver of price outcomes in Q3 2021, swinging from higher than average levels in July, to record low levels in September (Figure 1.9).

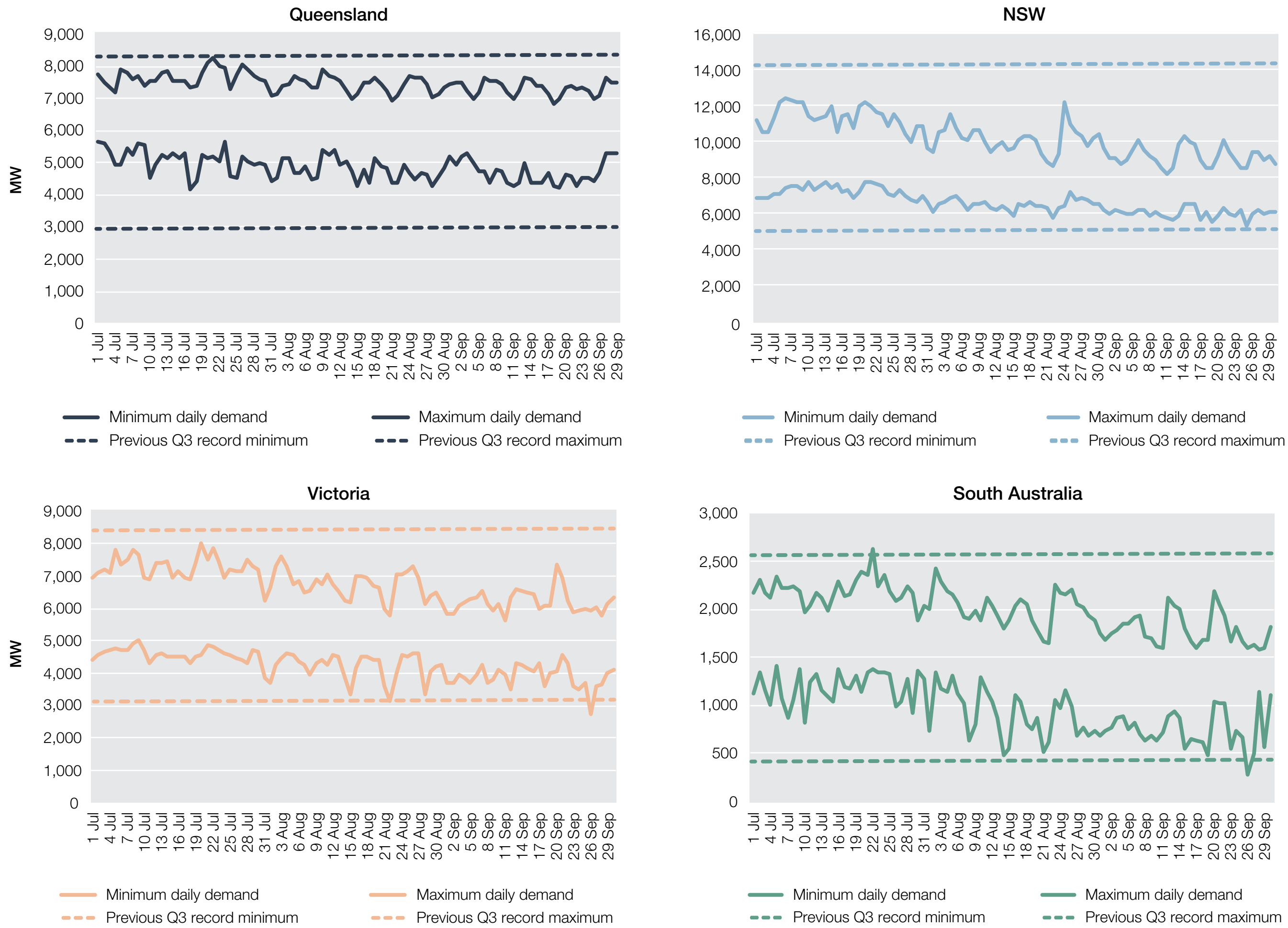
Demand was high in July due to colder than average weather. Demand hit daily maximums for a Q3 in both Queensland and South Australia. On 21 July, Queensland experienced its highest winter demand on record, exceeding the previous record set in 2008. On that day, prices in Queensland rose to over $5,000/MWh.[1] Demand in Queensland remained high throughout the quarter, with average monthly demand in July, August and September higher than the same time last year. AEMO attributed this elevated Queensland demand to a high industrial load driven by increased LNG production and mining.[2]

As the quarter unfolded, demand fell with warmer spring temperatures and record rooftop solar output, particularly in NSW, Victoria and South Australia. This lower demand played a key role in reducing prices. Minimum demand fell below previous Q3 minimum levels in both Victoria and South Australia and close to record Q3 levels in NSW. South Australia experienced its lowest demand on record (265 MW) on 26 September, a record quickly broken in October. That South Australia experienced both record high Q3 demand, followed by record low demand in a single quarter illustrates how much demand varies with the weather in that region.

1 AER, $5,000 report – Queensland 21 July 2021.

2 AEMO, Quarterly energy dynamics, Q3 2021, p. 7.

Figure 1.9 Daily maximum/minimum demand Q3 2021



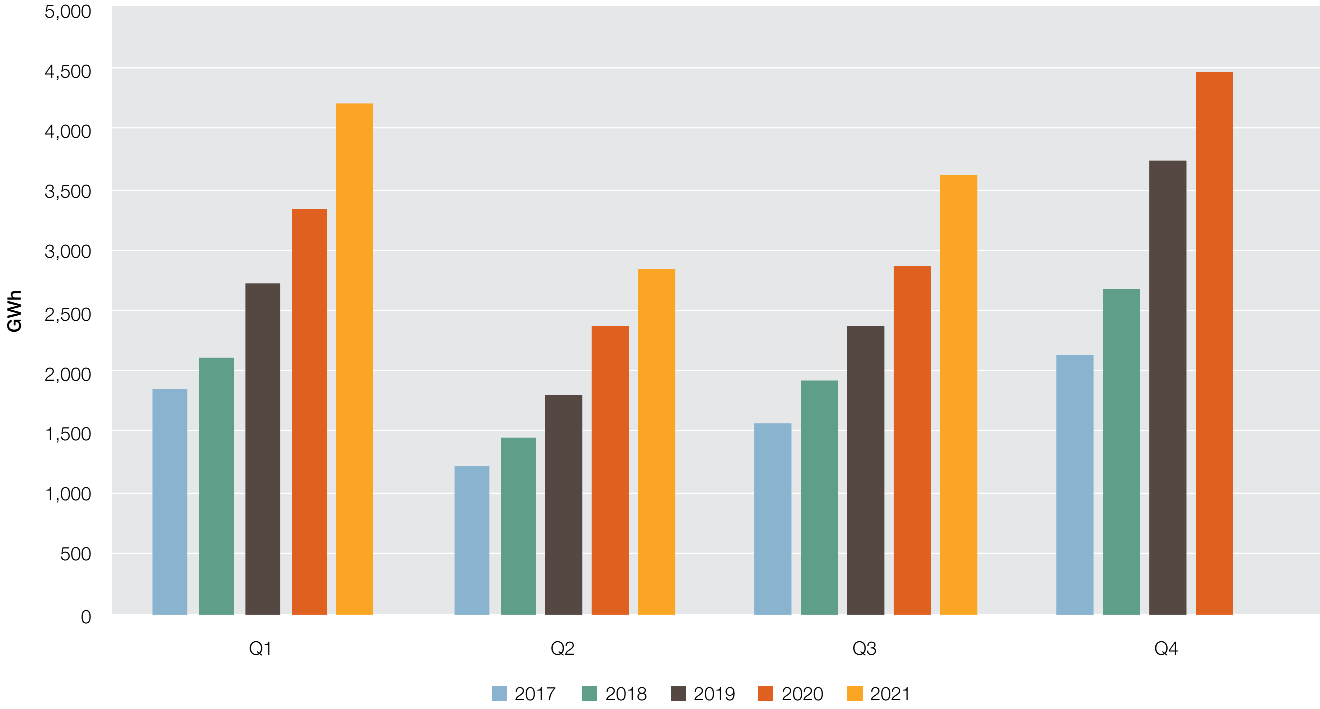
Source: AER analysis using NEM data.

Note: Uses daily minimum and maximum native demand.

Record minimum demand from the grid was driven by record rooftop solar output in every region as more homes and businesses generate their own electricity. In Q3 2021, rooftop solar generation in the NEM increased 26% compared to Q3 2020 with the biggest increase in NSW (up 36%) and Victoria (up 25%).

As rooftop solar generation is typically highest in Q4, it is likely these records will be broken again in the coming months (Figure 1.10).

Figure 1.10 Rooftop solar generation in the NEM, quarterly comparisons



Source: AER analysis using Clean Energy Regulator data.

1.5 Record high wind output and near record low black coal output

Highlighting the growing impact of renewables on the fuel mix, Q3 2021 recorded both the highest quarterly wind output in the NEM and near record low quarterly black coal output.

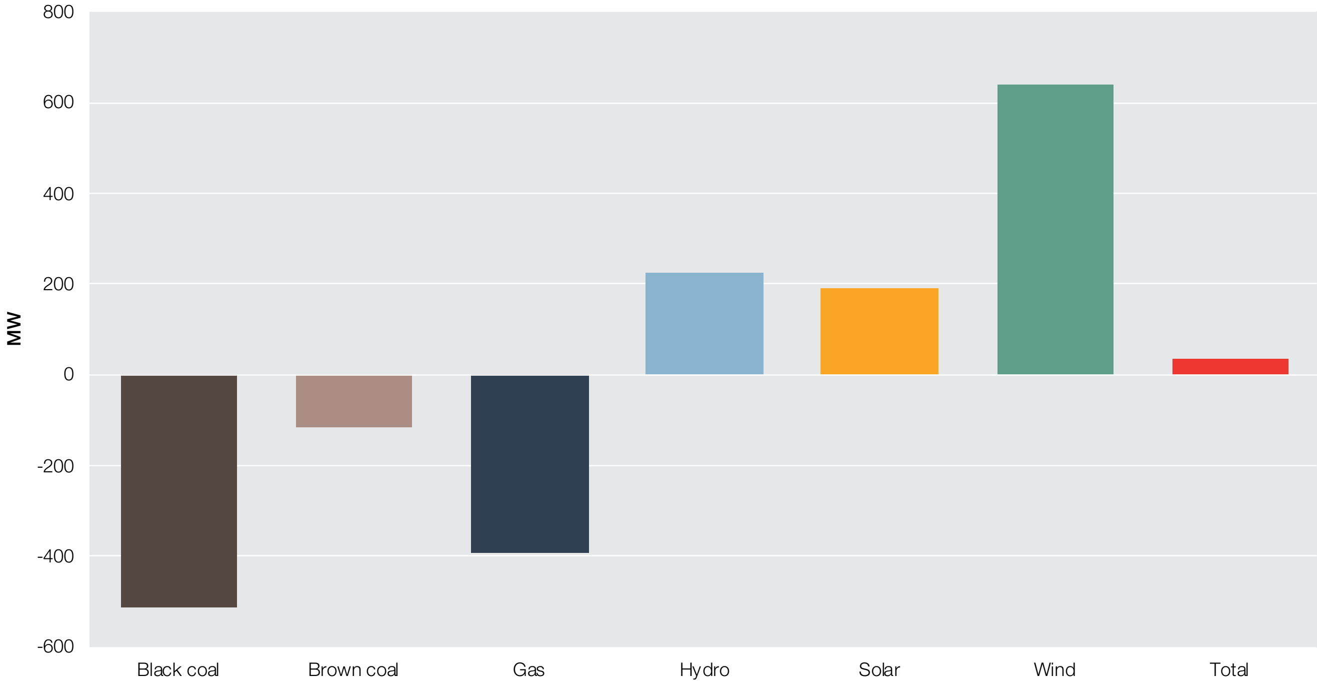
Average renewable generation increased by around 1,000 MW in Q3 2021 compared to Q3 2020. This increase was chiefly made up of 640 MW more wind, 220 MW more hydro and 190 MW more solar output (Figure 1.11).

As total output was relatively unchanged from Q3 2020, the increase in renewable output was met by an equal fall in thermal output of around 1,000 MW. This fall was made up of 510 MW less black coal, 390 MW less gas and 120 MW less brown coal output. Notably, Q3 2021 marked the first time the contribution of black coal to total NEM output fell below 50% since 2015.

The fall in black coal output this quarter continues a 4 year trend of declining black coal generation in the NEM that has been driven by a combination of factors, including:

- lower demand in the middle of the day due to increased rooftop solar (section 1.4)
- increased output from large scale wind and solar generation (section 1.5)
- black coal offering more of their capacity at higher prices in the middle of the day to avoid being dispatched when prices are low (section 1.8)
- black coal outages (section 1.6).

Figure 1.11 Change in average output, Q3 2021 compared to Q3 2020



Source: AER analysis using NEM data.

Note: Change in average quarterly metered generation output by fuel type from Q3 2020 to Q3 2021. 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.

At a regional level, output increased in Victoria and Tasmania compared to Q3 2020, but fell in Queensland, NSW and South Australia (Figure 1.12).

The increase in Victorian output was driven by a 42% increase in wind output compared to Q3 2020, cementing its position as the largest wind generating region in the NEM. Over 1,600 MW of new wind generation capacity has entered the market over the last 12 months. Of that, 970 MW was in Victoria, including the NEM's largest wind farm at Stockyard Hill (531 MW).[3] Increased wind output reduced prices in Victoria relative to NSW, increasing exports into NSW. With Q3 being the windiest quarter of the year, average quarterly wind generation in the NEM exceeded 3 GW for the first time and met 14% of NEM demand (up from 11% in Q3 2020).

In Tasmania, there was a 25% increase in hydro output compared to Q3 2020. Following winter rainfall, Tasmania's hydro storage levels were healthy.[4] Hydro generators in Tasmania offered more capacity at lower prices, offering 40% more capacity priced below $50/MWh than they did in Q3 2020. On average over the quarter, they offered more than 1,000 MW of capacity at negative prices. This resulted in very low prices in Tasmania and increased exports into Victoria.

Total output fell in NSW, comprised mostly of a 487 MW fall in black coal output compared to Q3 2020. NSW demand was lower in August and September, and imports from Victoria were higher. Increased wind and grid scale solar displaced black coal in the middle of the day, with grid scale solar output increasing in all mainland regions and particularly in NSW.

Output in Queensland fell slightly compared to Q3 2020 with average gas generation falling 145 MW. For most of July 2021, Swanbank E power station was on a planned outage, whereas in July 2020 it had an average generation of 230 MW. Despite continuing outages, black coal output in Queensland remained unchanged compared to Q3 2020.

In South Australia, gas output fell with low demand and increased imports from Victoria. Wind output increased slightly. Operation of the synchronous condensers installed by ElectraNet to provide more system strength began in August and September. Once fully tested, these 'SynCons' will allow more wind and solar generation to be dispatched in the region.[5]

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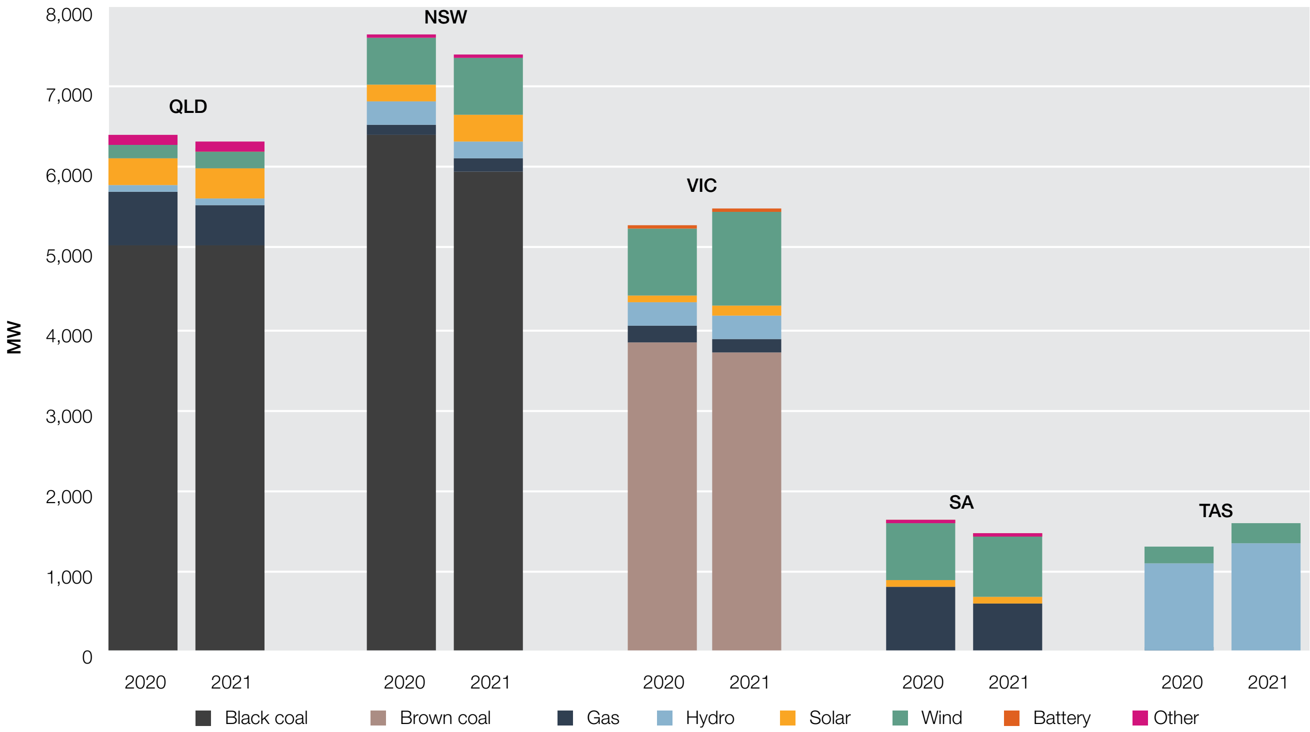
3 Stockyard Hill is currently listed as having a maximum capacity of 286MW on AEMO's registration page.

4 Media release, Premier of Tasmania, 1 September 2021.

5 Following the installation of the SynCons, AEMO has begun transitioning to new limits for variable (non-synchronous) generation in the region. Where they were previously between 1,300 MW to 1,700 MW, they will eventually increase up to 2,500 MW.

Figure 1.12 Regional generation, Q3 comparisons



Source: AER analysis using NEM data.

Note: Average quarterly metered generation output in the NEM by fuel type.

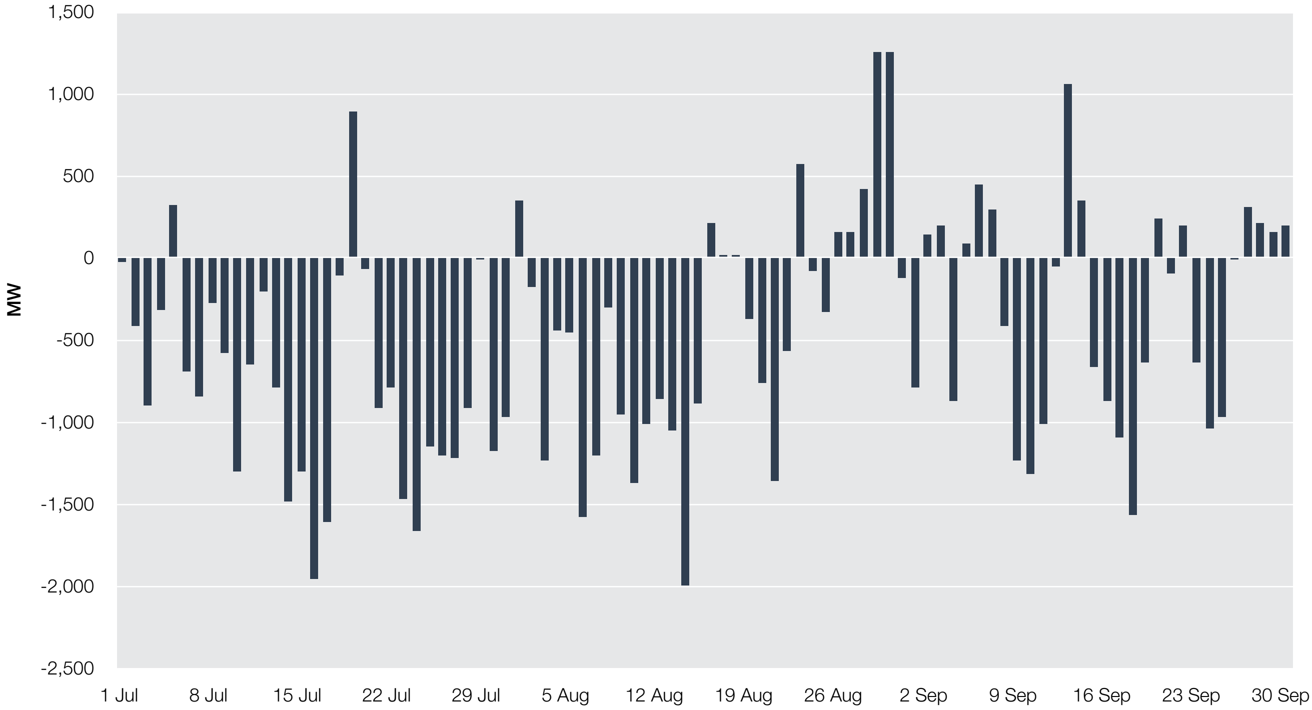
1.6 Black coal outages coincided with high demand in July

Another driver of higher prices in NSW and Queensland was that in July, when demand was higher than average, there were significant black coal outages in both regions.

In NSW, the level of black coal outages in July in Q3 2021 was twice that in Q3 2020. At times this reduced black coal output by up to 2,000 MW (Figure 1.13). There were unplanned outages at Bayswater power station (2 units totalling 1,260 MW) and Eraring power station (1 unit at 720 MW). Coupled with high demand, these outages contributed to volatile prices for the first 3 weeks of the quarter. When these units returned to service and demand started falling, prices fell significantly and remained stable for the remainder of the quarter.

While outages also occurred later in the quarter these had less of an effect on price because demand was low. These included additional unplanned outages at Bayswater (660 MW), Mt Piper (675 MW) and Eraring power stations (720 MW), and planned outages at Liddell (450 MW), and Vales Point power stations (660 MW). Outage details are listed in Appendix A.

Figure 1.13 Difference in daily NSW black coal output in Q3 2021 compared to Q3 2020



Source: AER analysis using NEM data.

Note: Difference in daily metered NSW black coal output in Q3 2021 compared to Q3 2020.

In Queensland, black coal outages also coincided with high demand in July:

- Outages due to the explosion at Callide C power station in May continued through Q3 2021, with unit 3 (350 MW) returning to service on 25 July and unit 4 (350 MW) expected to remain out of service until April 2023.[6]
- There were also continuing outages from Q2 2021 at 2 Gladstone power station units (560 MW total) and a Stanwell power station unit (365 MW).
- In mid-July these outages were joined by a third unit at Gladstone power station (280 MW) and a unit at Tarong power station (350 MW). In the end, Gladstone unit 6 was out for the whole quarter and unit 1 for most of the quarter.

While black coal availability was lower, high demand meant the total amount of black coal dispatched in Q3 2021 was at a similar level to that in Q3 2020, but at higher prices. This is evidenced by price setter outcomes which show black coal in Queensland set an average price of $51/MWh compared to $34/MWh in Q3 2020 (Figure 1.18).

Other outages in Queensland included Swanbank E power station (gas) and Wivenhoe power station (pumped hydro). A major overhaul of a Wivenhoe unit commenced mid-July and returned to service in early November. Because Wivenhoe ran hard in the first 3 weeks in July, average hydro generation in Queensland in Q3 2021 was similar to Q3 2020.

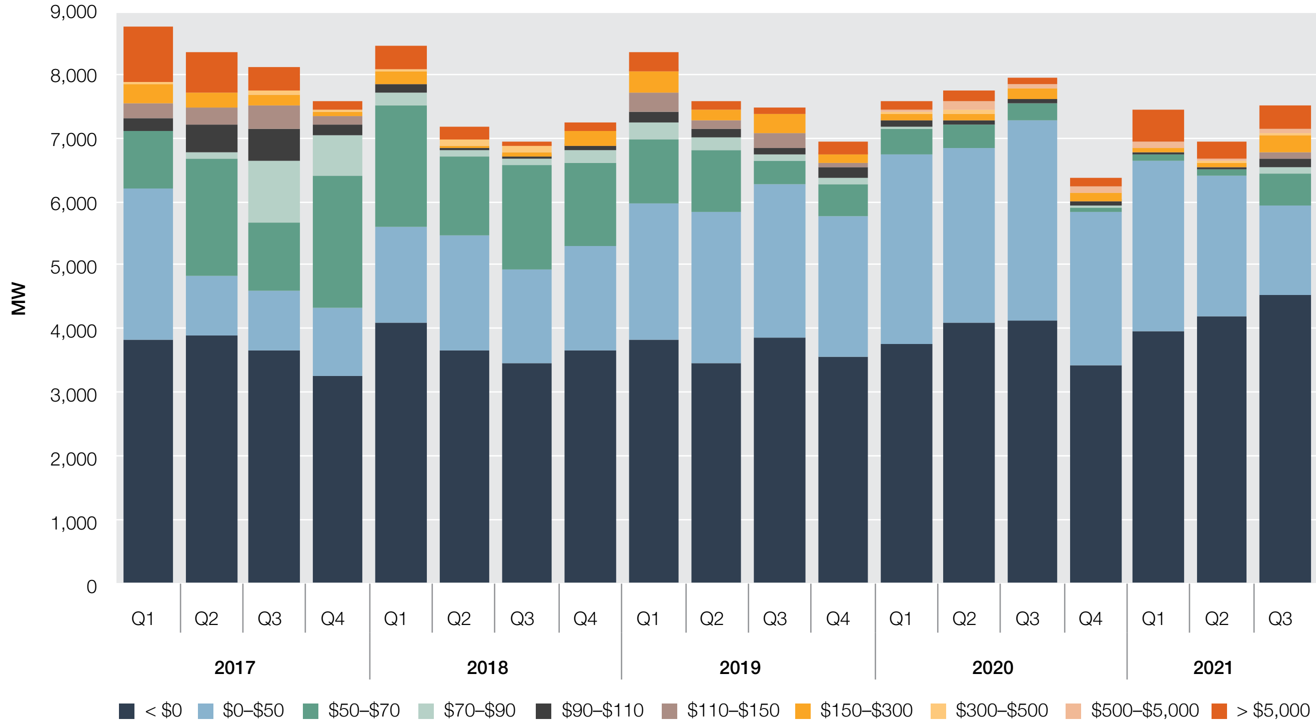
1.7 Black coal generators offered less capacity priced below $50/MWh than in Q3 2020

NSW and Queensland black coal generators offered an average of 1,345 MW and 530 MW less capacity priced below $50/MWh in Q3 2021 than in Q3 2020 (Figure 1.14 and Figure 1.15). The drop in the availability of low-priced black coal capacity was driven by:

- black coal outages (section 1.6)
- black coal generators shifting capacity into higher price bands across the quarter (Figure 1.16).

6 Based on MTPASA as at 5 November 2021.

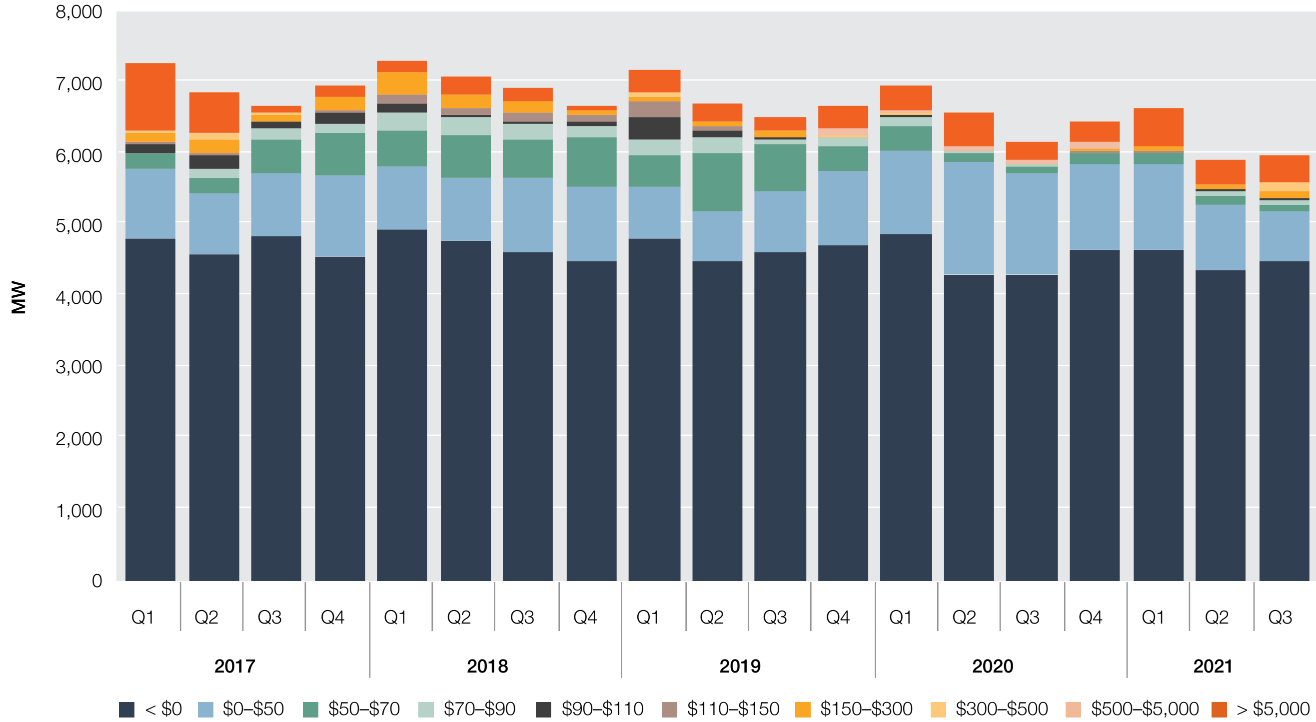
Figure 1.14 NSW black coal offers by price band



Source: AER analysis using NEM data.

Note: Average quarterly offered capacity by NSW black coal generators within price bands.

Figure 1.15 Queensland black coal offers by price band



Source: AER analysis using NEM data.

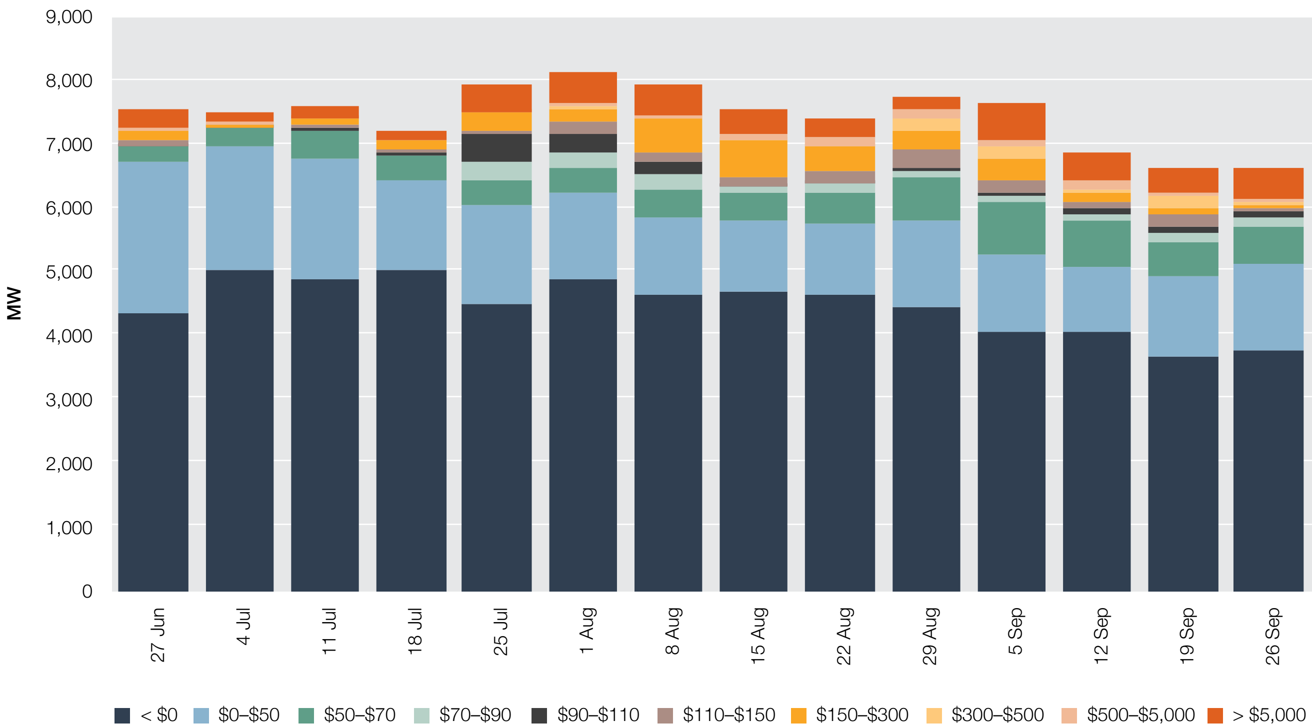
Note: Average quarterly offered capacity by Queensland black coal generators within price bands.

As demand fell in NSW from the last week in July onward, black coal generators offered less capacity into the market priced below $0/MWh (Figure 1.16). At the same time, they shifted capacity into higher price bands. Part of this is explained by how generators are responding to negative prices in the middle of the day, which we consider below (section 1.8). However, this may not fully account for all the increase in offer prices.

In July in Queensland, some generators offered some capacity at the price cap to ensure they could provide raise frequency control ancillary services (FCAS). Limits on the Queensland-NSW Interconnector (QNI) during the quarter meant that, at times, only Queensland generators could provide the region's FCAS requirements.[7] This put upward pressure on FCAS prices, particularly for raise 6 and raise 60 second services. At these times, Queensland generators could potentially earn more revenue providing FCAS to meet these local requirements. However, if a generator is already running at its maximum output it cannot provide raise services. Queensland generator offers reflected this trade-off. Even on 21 July when Queensland spot prices exceeded $5,000/MWh, some generators left capacity priced high perhaps to reduce the chance of being dispatched, and so to be available to provide FCAS.

High-priced offers by black coal generators in Queensland and NSW may have also reflected reduced fuel stockpiles, coal supply issues and high coal prices. Some generators ran harder than expected during the Callide (and other) outages in May and June, which lowered reserves. Other participants reported they had been impacted by coal supply issues and high international coal prices. Faced with these issues, some participants offered some capacity at higher prices to ration coal supplies, in the expectation of higher prices this summer.

Figure 1.16 NSW black coal offers by price band, weekly



Source: AER analysis using NEM data.

Note: Average weekly offered capacity by NSW black coal generators within price bands.

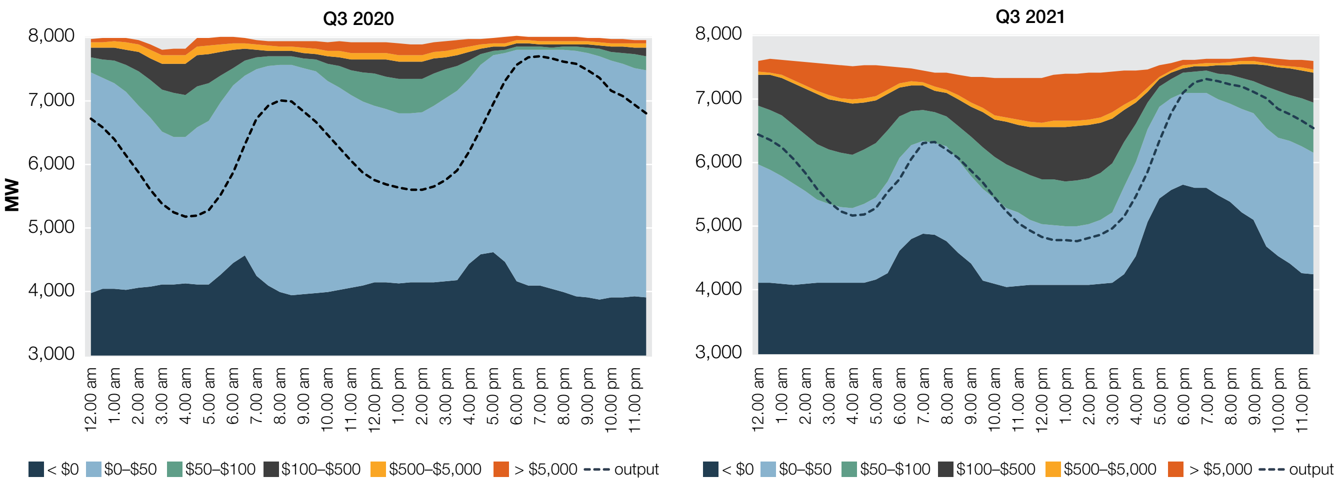
7 The local requirement for raise services was at times up to 250 MW.

1.8 Black coal generators changed the way they offered their capacity during the day

Black coal generators changed the way they offered their capacity into the market, particularly during the middle of the day. For example, comparing offers by time of day in NSW in Q3 2021 with Q3 2020 we observed the following changes (Figure 1.17):

- Across the whole day black coal generators in NSW:
  - offered significantly less capacity between $0/MWh and $50/MWh
  - offered less total capacity.
- In the middle of the day, and between 3am to 5am:
  - generators shifted capacity previously offered below $50/MWh to higher prices (including to above $5,000/MWh) to reduce the chance of being dispatched more at negative or low prices
  - offers below $0/MWh didn't change much as generators need to maintain minimum operating requirements.
- During the morning and evening peaks:
  - generators offered more capacity below $0/MWh to increase the chances of being dispatched at higher prices.
  - demand was met by black coal offered between $50/MWh and $100/MWh on average, whereas in Q3 2020 it was met by black coal offered below $50/MWh.

Figure 1.17 NSW black coal offers by price band, time of day



Source: AER analysis using NEM data.
Note: Average NSW black coal offers in Q3 2021 by various price bands compared to Q3 2020.

Queensland generators offered a lot less in capacity between $0/MWh and $50/MWh in the first 3 weeks of Q3 2021 due to outages.

We will continue to monitor trends in generator offers, and the drivers of these offers, as part of our performance and competition reporting.

1.9 Gas generators responded to high winter prices in July

Gas generators in NSW and Queensland responded to high winter prices by offering more capacity in total and shifting some of that capacity to lower prices.

NSW gas output increased by 55% compared to gas output in Q3 2020 but was still only 2% of total output in the region.

With high prices in July, NSW gas generators offered more total capacity and more capacity priced below $50/MWh than in the same month last year. Uranquinty and Tallawarra power stations shifted around 20% of their collective capacity (or 250 MW) to below $0/MWh leaving around 70% of their capacity priced above $5,000/MWh. In the week starting 25 July, as spot prices fell in NSW, gas generators shifted nearly all their capacity back to above $5,000/MWh. Colongra power station offered nearly all its capacity above $5,000/MWh all quarter.

Queensland gas powered generators offered 30% of their capacity priced below $0/MWh in July when spot prices were high. This mostly included offers from Darling Downs and Braemar A power stations with Swanbank E on an outage. By the end of the quarter, however Queensland gas powered generators offered less total capacity and half the amount of capacity priced below $0/MWh than they offered in July.

We include regional offers by fuel type for all regions in the data spreadsheet published with this report.

1.10 Nearly all fuels set higher prices

Black coal, gas and hydro set much higher prices in Q3 2021 than they did in Q3 2020 in NSW and Queensland. This contributed to higher average quarterly price in both regions.

In NSW, for example,

- black coal set an average price of $53/MWh (up from $38/MWh)
- gas set an average price of $116/MWh (up from $51/MWh)
- hydro set an average price of $103/MWh (up from $66/MWh).

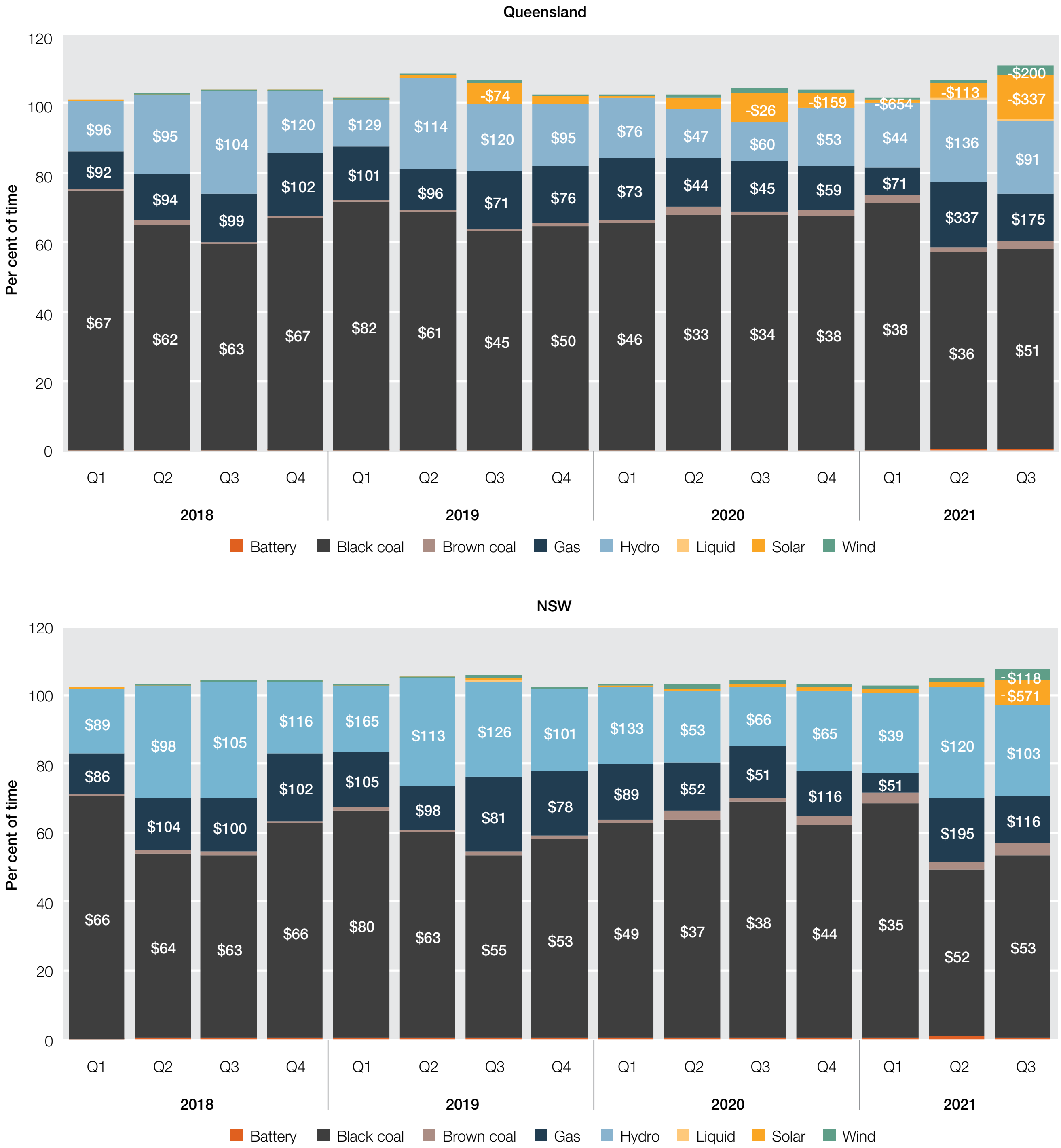
An increase in the price set by black coal is significant because it sets the price over half of the time. The increase in the price set by gas, particularly in Queensland reflects the impact of the high priced events when very expensive gas generation was needed to peak high demand.

These increases were partly offset by wind and solar setting lower average prices than a year ago. In NSW, for example, solar set an average price of -$571/MWh and wind set an average price of -$118/MWh. The offset was only partial because wind and solar set the price a lot less frequently than the other fuel types.

That said, wind and solar generators set the price a record amount of time in Queensland and NSW. For example, in Queensland, solar set the price 13% of the time and wind 3% of the time.

Hydro also set the price more of the time in Q3 2021 than in Q3 2020 in NSW and Queensland while black coal set the price less of the time. When hydro generation, which is generally more expensive than coal, sets the price more often it increases the average quarterly price.

Figure 1.18 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).

1.11 Increased fuel costs contributed to higher prices

Wholesale electricity price movements may reflect changes in underlying costs. Spot prices for both coal and gas commodities have increased significantly since the start of the year, and this may have contributed to black coal and gas generators offering their capacity into the wholesale market at higher prices (section 1.7).

In Q3 2021, generators that may have run harder than expected this quarter and last quarter, due to outages at other power stations, may have had to source some additional coal at higher prices. Black 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. Generally, generators are not fully exposed to the international price of coal but can become exposed if long term contract negotiations coincide with fluctuating coal prices or if they buy a portion of their coal at spot prices.

For this reason, the price of coal at the Newcastle port can be used as a reference point for maximum coal fuel costs, and this has been increasing since December 2020. In Q3 2021, the price for Newcastle coal rose materially, increasing from around $135/tonne at the start of the quarter to around $250/tonne by the close. We have also received reports that it has been difficult to source coal domestically, regardless of the price. Fuel supply issues have caused some black coal generators to conserve coal in the lead up to summer.

Gas powered generators source their gas from a variety of sources. When deciding whether to use gas for electricity generation, market participants will often value their gas at the price they could sell it on the spot market. Domestic gas prices increased in Q3 2021 compared to Q3 2020 with unprecedented daily price spikes in July (section 2.1). High domestic gas prices were driven by:

- colder than average temperatures that increased peak winter demand for gas, and gas powered generation
- very high international prices, although we have noted a recent delinking of domestic and international gas prices (section 2.1).

We discuss domestic gas prices in much more detail in the gas chapter of this report (Chapter 2).

1.12 Interconnector limits contributed to higher prices in NSW and Queensland

Changes in relative prices between regions impacted interconnector flows compared to Q3 2020 (Figure 1.20):

- Lower prices in Victoria relative to NSW and Queensland since Q4 2020 moved it from being a net importer in Q3 2020 to a net exporter. This trend continued in Q3 2021.
- Higher prices in Queensland meant it exported less into NSW, instead, NSW imported more from Victoria.
- Lower prices in Tasmania resulted in increased exports into Victoria.

Prices separated between Queensland and NSW this quarter, and even more so between NSW and Victoria. Price separation occurs when flows between regions are restricted.

At times, network limits reduced Queensland's access to cheaper generation from NSW which contributed to high energy and FCAS prices in Queensland (section 1.1 and section 1.14). Network outages due to the ongoing work on QNI continued and imports into Queensland were constrained 17% of the time during Q3 2021. From late August, the number of constrained intervals per day increased. Constraints to manage the QNI network outages sometimes forced exports out of Queensland into NSW to maintain local FCAS requirements in the region (section 1.14). Work on the QNI is expected to be completed by the end of the year in readiness for summer.

Network limits also restricted NSW's access to cheaper generation from Victoria. While NSW was importing cheaper generation from Victoria much of the time, network limits meant that it couldn't import everything it needed, and so NSW demand had to be met by more expensive NSW generation (Figure 1.19). This quarter:

- flows from Victoria into NSW were constrained 37% of the time, compared to 9% in Q3 2020
- the most NSW could import from Victoria reduced significantly from 800 MW last year, to as low as 150 MW on average this quarter[8]
- increased output from Tumut power station, compared to Q3 2020 contributed to lower NSW import limits[9]
- AEMO invoked constraints to manage network outages in NSW.[10]

8 The nominal limit is usually between 700 MW and 1,600 MW depending on what generators around Murry and Lower and Upper Tumut are running.

9 The nominal capacity of the Vic-NSW interconnector is highly dependent on the output of Murray generators (for NSW to Victoria) and Lower/Upper Tumut generators (for Victoria to NSW). AEMO, Interconnector capabilities for the NEM, November 2017, p. 5.
This did not contribute to price separation between NSW and Victoria unless Tumut power station was dispatched out of merit order.

10 These NSW outages included outages of lines from Canberra to Upper Tumut, and Dederang to South Morang.

Figure 1.19 NSW import limits from Victoria

Source: AER analysis using NEM data.

Note: Average import limit by time of day in Q3 2020 compared with Q3 2021.

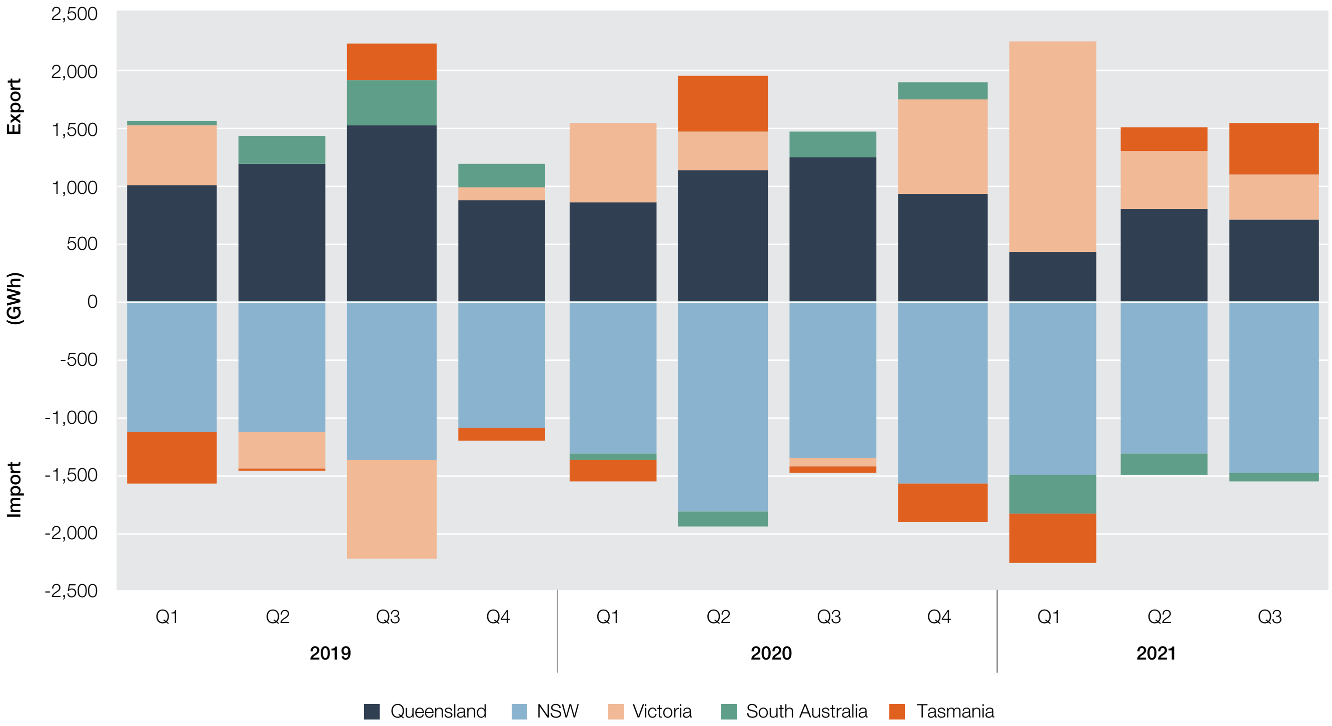
At times, network outages in NSW reduced flows over the Victoria to NSW (Vic-NSW) interconnector. For example, planned network outages of the Capital to Kangaroo Valley line contributed to prices exceeding $5,000/MWh in NSW on 14 July 2021.[11] There is a significant amount of generation in the area and, with the outages, the main transmission pathway for generation to get through to load centres in Sydney was through the Yass to Marulan line. To avoid overloading the line, AEMO invoked constraints affecting generation in southern NSW and flows on the Vic-NSW interconnector. When the constraint bound (the interconnector reached the capacity set by the constraint), output from Upper Tumut power station effectively replaced imports on the Vic-NSW interconnector and caused counter price flows from NSW into Victoria.[12]

11 AER, $5,000 report – NSW 14 July 2021.

12 Counter flows occur when energy is exported from the more expensive region to the cheaper region.

Transgrid is currently upgrading the Vic-NSW interconnector, which should allow more energy to be transferred between Victoria and NSW.[13] Because demand has been low since the electrical work began in August, weekly flows over the VIC-NSW interconnector haven't been particularly impacted. This upgrade is also expected to complete by the end of the year.

Figure 1.20 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.

Separately, flows from South Australia to Victoria are still limited to 420 MW due to the ongoing outage of significant network equipment at the Para substation. It will likely take a few months before significant changes to flows over the Heywood interconnector from South Australia to Victoria are observed.

1.13 Over 1GW of new wind, battery and solar capacity entered the market

Almost 1200 MW of wind, battery and solar capacity entered the market in Q3 2021 (Figure 1.21). This was mostly located in Victoria, including the NEM's largest windfarm at Stockyard Hill (478 MW) and the Victorian Big Battery (360 MW – Table 1.1).[14] Stockyard Hill experienced long delays in its commissioning process.

The third unit at Torrens Island A power station closed in September, with the last unit expected to close in September 2022. Also expected to close next year is the first Liddell unit (500 MW) in NSW on 1 April 2022.[15]

13 https://www.transgrid.com.au/projects-innovation/victoria-to-nsw-interconnector.

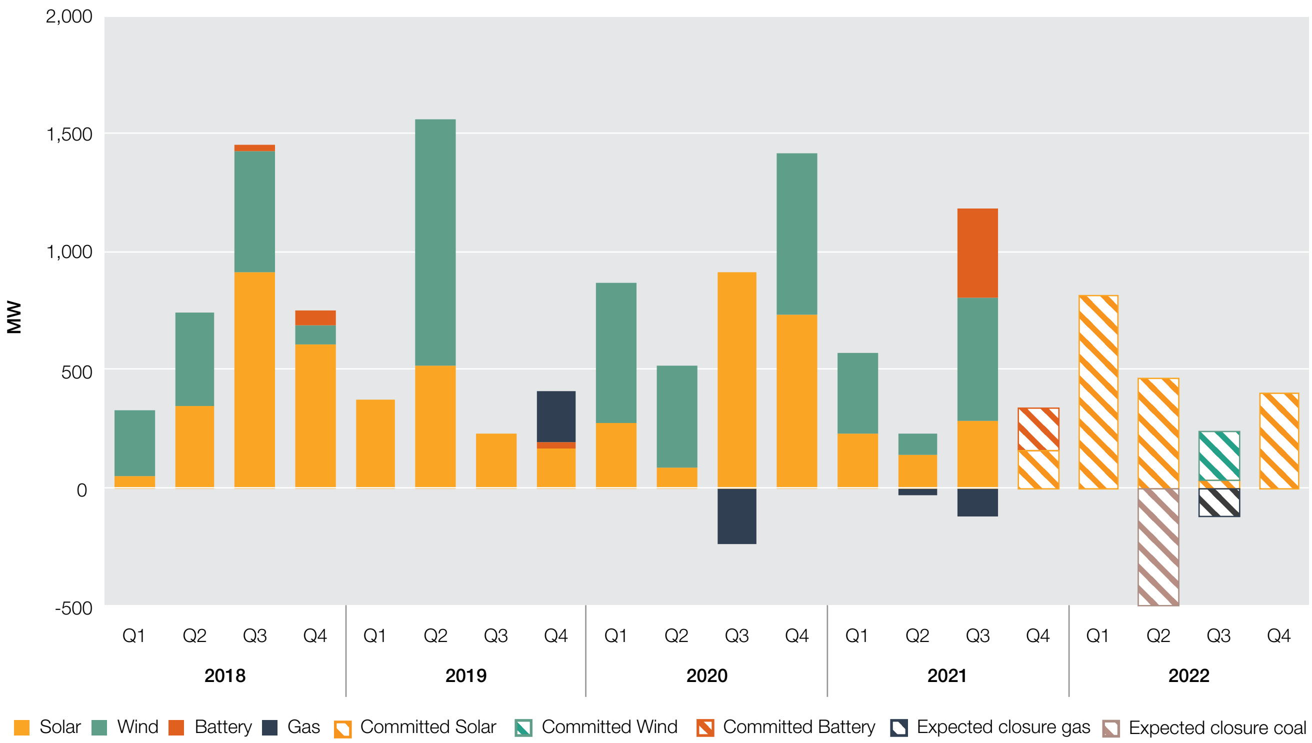
14 Stockyard Hill is currently listed as having a maximum capacity of 286MW on AEMO's registration page.

15 The AER is currently considering an application for exemption from notice of closure requirements from AGL Energy to close the Hunter Valley Gas Turbines on 1 January 2022. We expect to deliver a decision in December 2021.

Table 1.1 New entry and exit, by fuel type and region

REGION	STATION	FUEL TYPE	HIGHEST CAPACITY OFFERED IN Q3 2021 (MW)	REGISTERED CAPACITY (MW)
Queensland	Kennedy Energy Park – Phase 1	Solar	8.4	16
Queensland	Kennedy Energy Park – Phase 2	Wind	11	43
NSW	Junee Solar Farm	Solar	0.1	36
NSW	Wagga North Solar Farm	Solar	0.7	55
NSW	Suntop Solar Farm	Solar	4.8	175
Victoria	Bulgana Green Power Hub – BESS	Battery	20	24
Victoria	Stockyard Hill Wind Farm	Wind	202	478
Victoria	Victorian Big Battery	Battery	30	360
Total				**1187**
Less exits				
South Australia	Torrens Island A	Gas		-120

Figure 1.21 Quarterly new entry and exits



Source: AER analysis using AEMO generator information (July 2021) and NEM data.

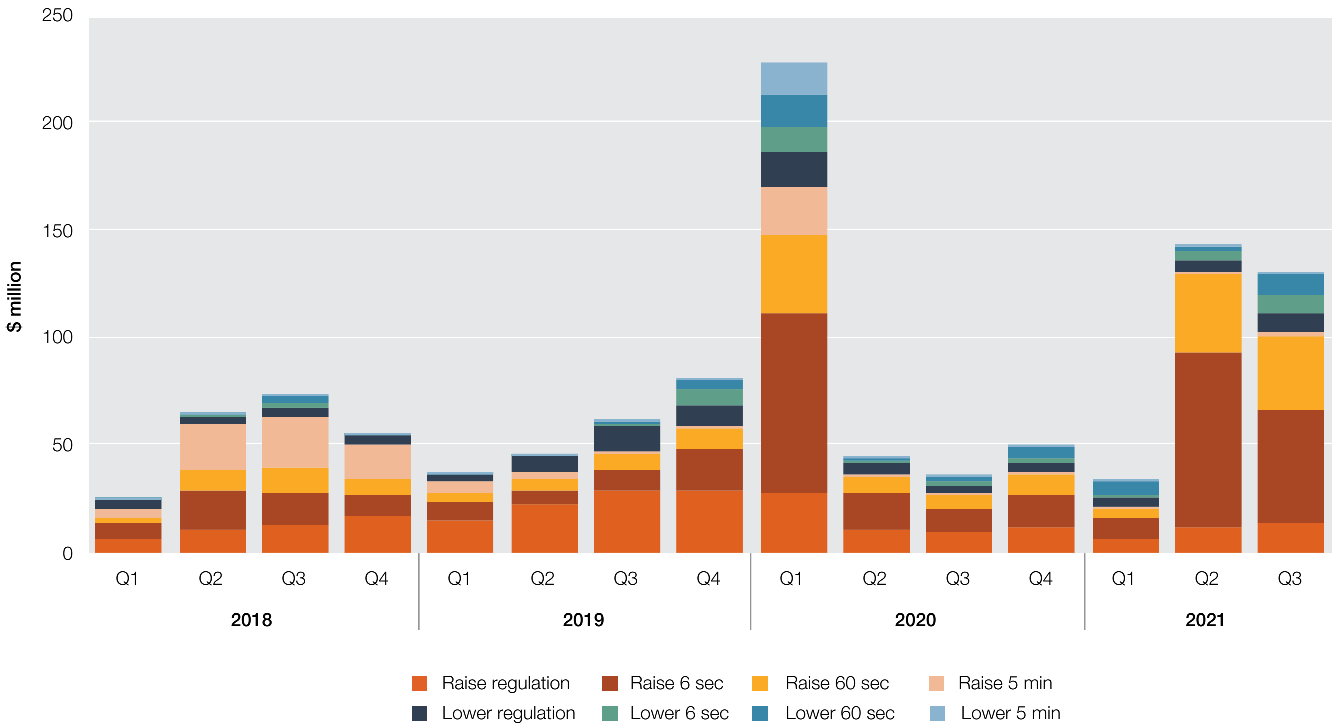
Note: New entry is recorded using registered capacity of scheduled and semi-scheduled generators. Hashed areas reflect committed new entry and planned generator retirements according to the classification in AEMO Generator Information. The new entry date is taken as the first day the station produces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

1.14 FCAS costs high, particularly in Queensland

Frequency control ancillary services (FCAS) costs were also high in Q3 2021 totalling $130 million, a record for Q3 (Figure 1.22). Like Q2 2021, local FCAS costs in Queensland (which reached a near record of $71 million) were a key driver of this overall outcome. Local FCAS costs in Tasmania were $5 million, which is relatively high.

Global FCAS costs were $54 million. Costs were greatest for raise 6 second and raise 60 second services, which are needed to increase frequency when generators fail, or load suddenly increases.

Figure 1.22 Total FCAS costs by ancillary service



Source: AER analysis using NEM data.

Note: Average quarterly FCAS costs in the NEM.

High local FCAS costs in Queensland were due to a combination of factors, including:

- the ongoing QNI upgrade
- reduced FCAS availability due to the interaction between energy and FCAS markets
- outages of some FCAS providers.

Upgrades to the QNI required Queensland to provide its own FCAS 43% of the time over Q3 2021. There were planned line outages in northern NSW as part of the upgrade that meant Queensland was at risk of becoming electrically isolated from the rest of the NEM.

To manage this possibility, AEMO required Queensland to supply its own FCAS. At times, the constraints to manage the line outage also forced exports out of Queensland into NSW to maintain local FCAS requirements in Queensland. This contributed to both high energy and FCAS prices.

The interactions of the energy and FCAS markets means there is a trade-off between providing energy and FCAS. For example, a generator that is operating at its maximum capacity cannot provide raise services, so their 'effective' available capacity for raise services would be zero. In Q3 2021 high winter demand for energy and high FCAS requirements were competing against each other.

Outages at Callide, Stanwell, Gladstone and Tarong power stations meant those units were also not available to provide FCAS. Due to the high demand for energy during some evening peaks and generator outages, the remaining units that could provide FCAS had reduced capacity to provide raise services.

FCAS prices reached the price cap of $15,100/MW for 6 of the 8 FCAS services this quarter. Prices for raise 6 second services exceeded $5,000/MW for a total of 95 trading intervals and raise 60 second for a total of 71 trading intervals. AEMO's *Quarterly energy dynamics* explains how QNI upgrades increased local FCAS costs in Queensland.

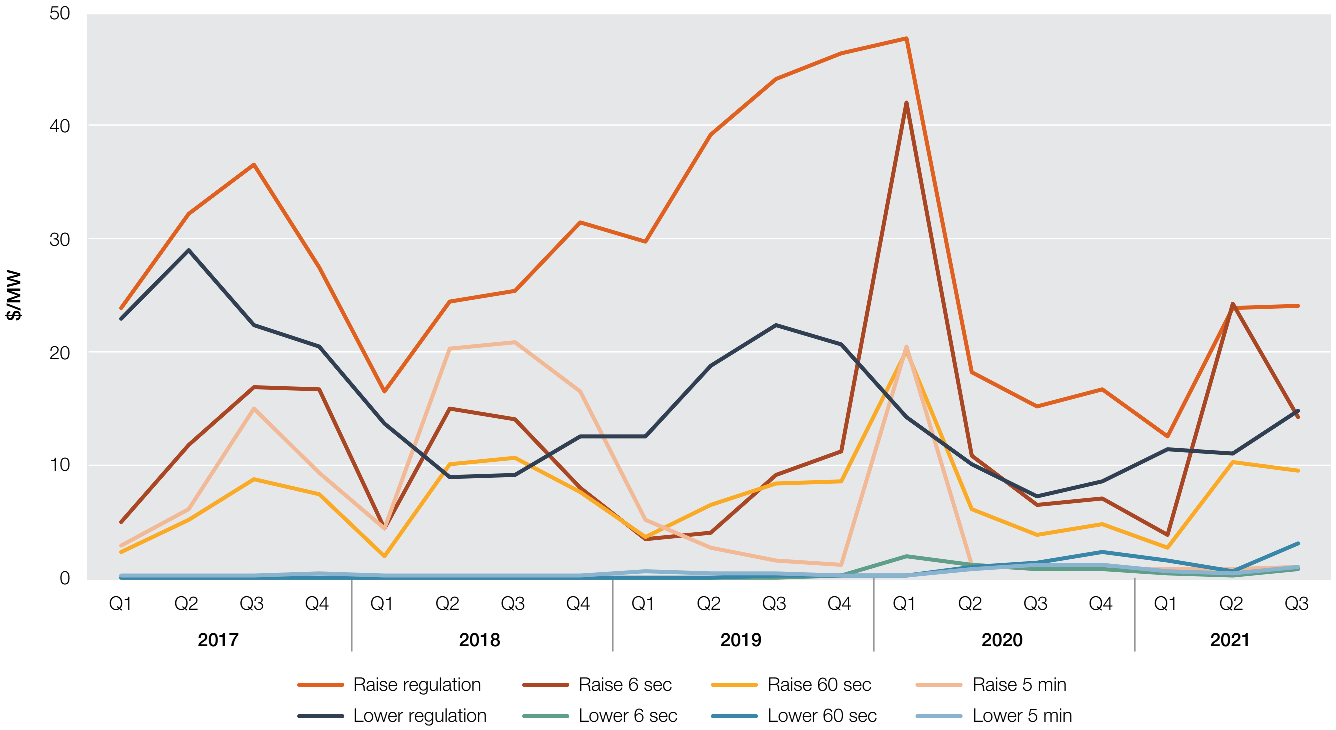
Table 1.2 Queensland FCAS prices when there was a local requirement, Q3 2021

	AVERAGE PRICE $/MW	MAXIMUM PRICE $/MW	MINIMUM PRICE $/MW	COUNT OF PRICES > $5,000/MW
Lower 5 minute	135	14,686	0	3
Lower 60 second	118	15,100	1	17
Lower 6 second	109	15,100	0	18
Lower regulation	82	14,694	5	3
Raise 5 minute	1,251	15,100	1	12
Raise 60 second	2,053	15,100	0	71
Raise 6 second	3,286	15,100	0	95
Raise regulation	1,280	15,100	9	0

Source: AER analysis using NEM data.

Global FCAS prices were highest for raise and lower regulation services followed by prices for raise 6 and 60 second services. Other than this, prices for the remaining services remained relatively low. However, prices for local FCAS in Queensland were very volatile. The amount of FCAS enabled did not significantly increase this quarter so was not a key driver of increased FCAS costs in Q3 2021.

Figure 1.23 FCAS prices by service, quarterly



Source: AER analysis using NEM data.

Note: Average quarterly global FCAS prices, by service.

Focus – How peaking generators have prepared for 5 minute settlement and early market observations

Five minute settlement (5MS) came into effect in the NEM on 1 October 2021. This reduced the time interval for financial settlement from 30 minutes to 5 minutes, aligning the timelines for dispatch and financial settlement.[16]

The goal of 5MS is to facilitate more efficient operational decisions, investment, and bidding. As our energy system transitions, flexible fast response technologies are becoming more important in firming fluctuations in intermittent renewable generation.[17] In this analysis we have explored how generators have prepared for 5MS through investment and operational strategies, as well as some initial observations in rebidding and prices.

Preparing for 5 minute settlement

While 5MS aims to provide better price signals for investment in fast response technologies, participants with existing assets will need to adapt to the new market.

Operational challenges

While fast start technologies like batteries and demand response aggregators are already suited to this market change, the existing peaking fleet faces more challenges. Peaking generators that rely on generating at high prices will need to adjust their operations to be dispatched at those prices. Technologies like combined cycle gas turbines (CCGT) can take around 10–20 minutes from start up to full load, and open cycle gas turbines (OCGT) can take 20–40 minutes.[18]

Previously, the settlement price was the average of the 6 dispatch prices that occurred during any given half-hour trading interval. This meant that if a dispatch price was high early in the trading interval, as long as generators were dispatched within that interval, they would receive a high average price. However, 5MS means that generators who are not already generating and cannot start up in time may miss out on those prices.

Peaking generators have also traditionally been the providers of cap contracts. This means when the price goes above $300/MWh they have to generate to cover that contract. If these generators cannot start in time to cover these contracts, they don't receive the higher income from generating at the time of high prices and are also potentially exposed through the contracts they've sold.

Generators also have to balance potential (missed) revenue with the costs of starting up and longer term maintenance, as well as technical requirements. These generators will often have limited start-ups or running hours before scheduled maintenance.

We have observed that generators have responded to the demands of 5MS in various ways.

Building new plants with fast capability

Participants have built new generators with fast start technologies to be more responsive to price spikes. AGL's Barker Inlet power station in South Australia was the NEM's first material addition of fossil fuel capacity since an upgrade to Eraring power station in 2012. The 211 MW gas-fired generator was commissioned to replace capacity lost by the retirement of Torrens Island A power station and uses reciprocating engine technology, which enables it to start up within 5 minutes.

There has also been significant investment in batteries across the NEM, from existing participants and new entrants. These can respond quickly and so are well suited to 5MS. Since the rule change was announced in 2017, 8 battery projects have come online.

Upgrading existing generation assets

Participants have upgraded their existing assets to take advantage of established infrastructure while also enabling them to respond more quickly to the market.

16 AEMC, Five Minute Settlement, rule change, 28 November 2017.

17 AER, Wholesale electricity market performance report 2020, December 2020, p. 1.

18 B Skinner, 'Barker Inlet: A new technology responding to the market', *Australian Energy Council*, 12 March 2020.

Two significant South Australian generators recently upgraded their gas turbines in preparation for the start of 5MS. With these upgrades Origin Energy's Quarantine power station and EnergyAustralia's Hallett power station are now able to start up and generate within 5 minutes of receiving a target from AEMO.[19]

Origin Energy tested Quarantine's modifications in June this year. This involved offering a unit to start and be dispatched within 5 minutes for 1,679 dispatch intervals that month. Rebid reasons attributed these to 'Plant testing – 5min start mod test'. However, Quarantine has not operated in this way since the start of 5MS, perhaps due to technical issues and the lack of high prices.

Changing operational strategies

Even where peaking generators have not upgraded or built new assets, they will have reviewed how they're operating their assets. These may include:

- Operating 'harder', starting as quickly as possible and taking on the risks of increased maintenance or replacement costs. Generators may adjust their technical specifications like ramp rates or fast start inflexibility profiles to do this. This enables them to better respond to high prices, but they may still not be able to be sufficiently flexible.
- Warming up their units, so they are ready to generate, but not dispatching any output into the grid. This enables the generator to respond immediately and run when there are high prices, but this strategy still consumes fuel. Generators would have to balance the chance the price would be high with the costs of fuel and maintenance.

We have explored how a generator may adapt its operating strategies through adjusting its fast start inflexibility profiles in our case study below.

Generators may also adjust their contracts to suit the new market. Alinta Energy has reported that its open cycle gas-fired generator Braemar A power station was sometimes not able to respond in time to 5 minute price spikes, and they may change the terms of their contracts to better reflect their plant characteristics.[20] There may be a greater uptake of bespoke over-the-counter contracts to accommodate this.

Potential future investment

There is also a range of new generation slated to be built that will be responsive to 5MS. However, it is important to note that not all of this investment may come to fruition as the market and investment environment evolves.

Generators are looking at new investments in batteries on existing generation sites. As with upgrading existing assets, this enables participants to leverage off established infrastructure. Batteries can immediately respond to a 5MS market while other generation comes online or adjusts output. Examples of investment in batteries include:

- Origin Energy has announced a 700 MW battery to be built at its Eraring power station in NSW, as well as plans to build batteries at Mortlake (Victoria), Uranquinty (NSW), and Darling Downs (Queensland).
- AGL Energy has also announced 200 MW battery at Loy Yang A power station (Victoria), and a 250 MW unit at Torrens Island power station (South Australia).
- Neoen is also looking to expand into NSW.

Other participants have planned investment in pumped hydro, which is also able to respond quickly to changes in the market. For example, Alinta Energy plans to build a 600 MW power station at Ovens Mountains in NSW, while Genex Power is planning a 250 MW station at Kidston in Queensland. Pumped hydro also forms the basis of the 'Snowy 2.0' (2,000 MW), 'Battery of the Nation' (2,500 MW) and Borumba Dam proposals in NSW, Tasmania and Queensland respectively.

Case study – Oakey Power Station

As peaking generators now operate under different market conditions, we looked to see if there have been any immediate changes in the way they are offered. We have observed that some participants have changed how they bid their fast start inflexibility profiles (FSIP) since the start of 5MS (Box 1). For example, Shell Energy has changed the way it offered its FSIP at Oakey Power Station from 1 October.

19 M Griffin, 'Fast start, clean finish: repowering Australia', *General Electric*, 4 June 2020.

20 G Parkinson, '"We've been caught out:" Switch to 5-minute settlement traps market turtles', *Renew Economy*, 8 October 2021.

Box 1: What is a Fast Start Inflexibility Profile?

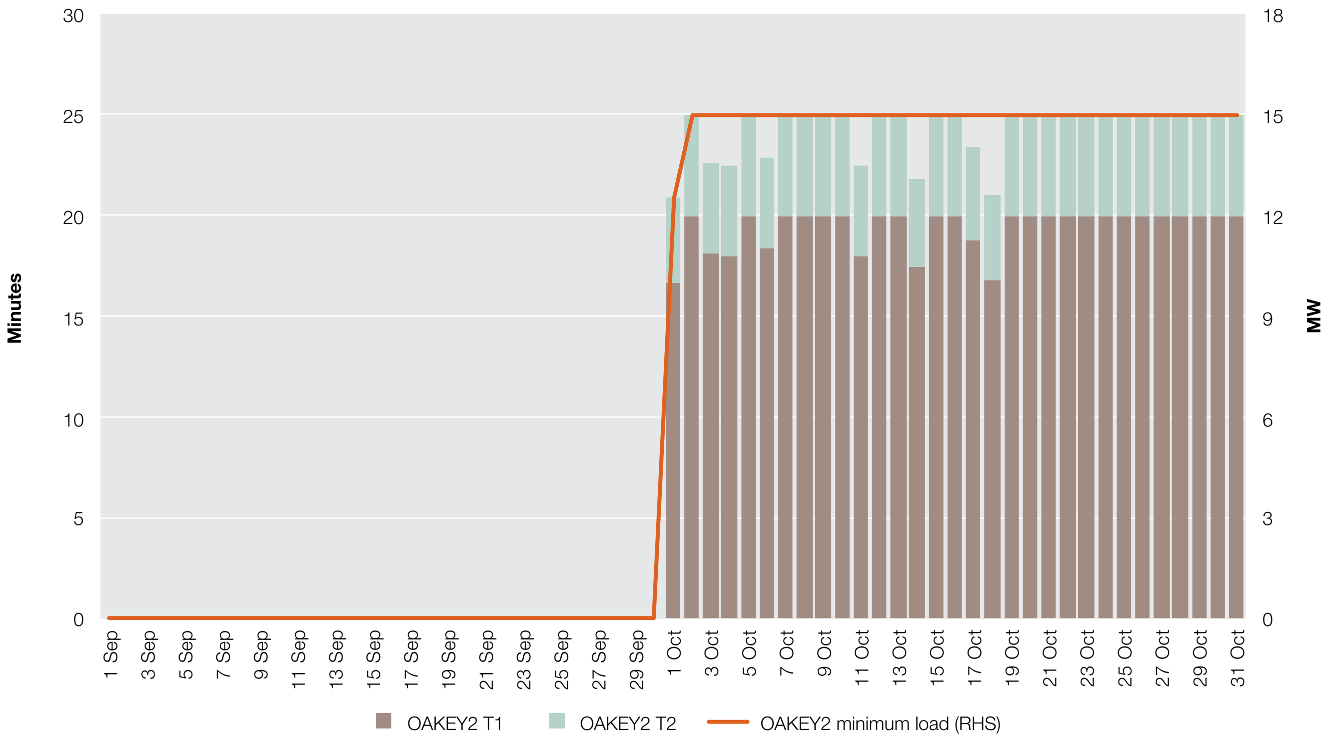
Generators that can come on and reach minimum loading within 30 minutes are referred to as fast start units. A generator offers in a unit's Fast Start Inflexibility Profile (FSIP), which defines its start-up and shut-down performance and is used to determine whether the unit should be dispatched. A FSIP must contain the following parameters:

- T1: the time in minutes, following the issue of a dispatch instruction by AEMO to increase its loading from 0 MW, which is required for the generator to begin to vary its dispatch level from 0 MW in accordance with the instruction.
- T2: the time in minutes that the generator requires after T1 to reach a specified minimum MW loading level.
- T3: the time in minutes that the generator requires to be operated at or above its minimum loading level before it can be reduced below that level.
- T4: the time in minutes, following the issue of a dispatch instruction by AEMO to reduce loading from the minimum loading level to zero, that the generator requires to completely comply with that instruction.

While some elements of a participant's offer are required to reflect the technical characteristics of a generator, such as those related to ancillary service parameters, the rules are currently silent on other technical elements like the FSIP. This is despite the dispatch process treating these parameters as if they do reflect the technical characteristics of generators.

The T1 and T2 times together represent the minimum time a unit needs to warm up and reach their minimum output. Prior to the start of 5MS, Shell Energy consistently bid in both T1 and T2 at 0 minutes for both units at Oakey power station in Queensland. This meant that the units could respond almost immediately to changing conditions and did not have to wait a minimum time before receiving a generation target. However, from 1 October Shell Energy began to bid both units with an average T1 of around 20 minutes and a T2 of around 5 minutes (Figure 1.24).[21] This meant the units would not receive a generation target until after around 25 minutes.

Figure 1.24 Oakey power station unit 2 daily average T1 and T2 times



Note: AER analysis using AEMO data. Minutes and MW are averages for that day. Lower averages indicate dispatch intervals on that day where T1 and T2 times were reduced.

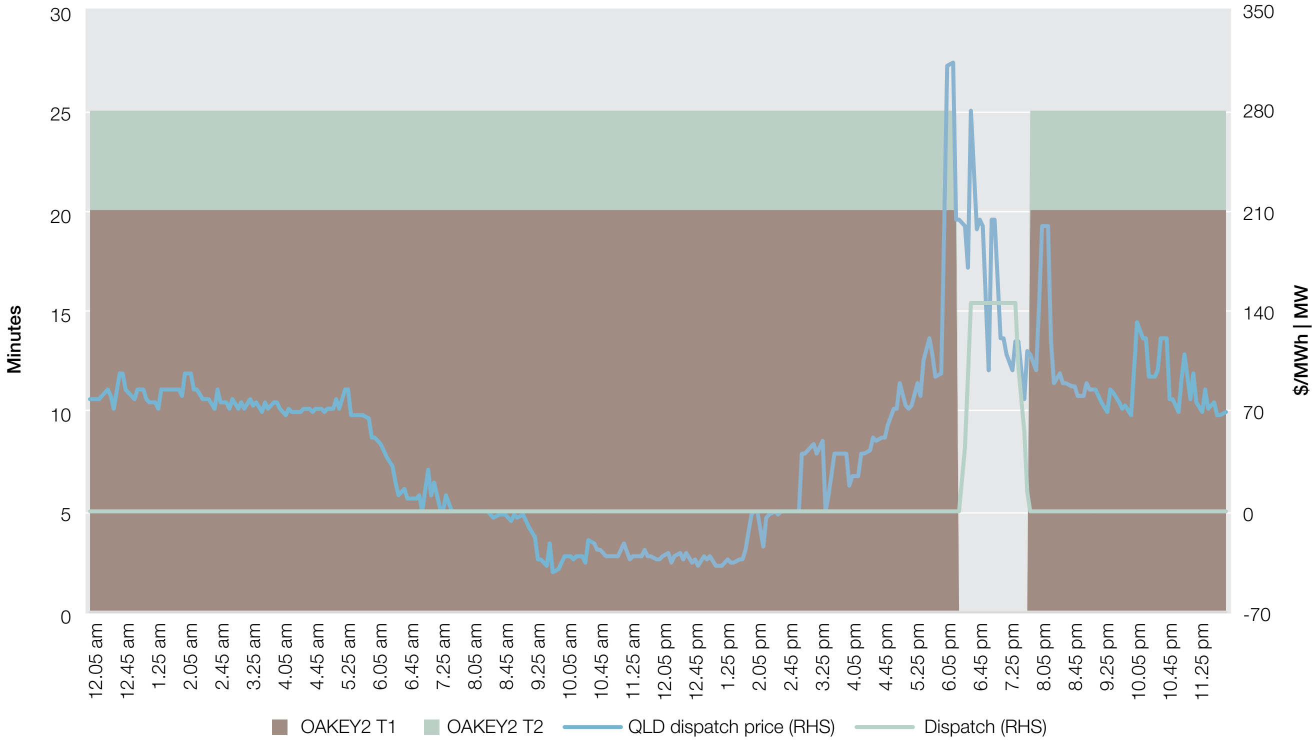
Although on average Oakey power station unit 2's (OAKEY2) T1 and T2 times were bid in higher, there were 7 days in October when Shell Energy reduced these times in response to high prices. These included 17 and 18 October, when OAKEY2's T1 and T2 times were changed in response to dispatch prices above $300/MWh during the evening peak.

21 Unit 1 had similar trends, but we focus on unit 2 in this analysis.

During the day on 17 October, Shell Energy offered OAKEY2's T1 and T2 times at 20 minutes and 5 minutes respectively (Figure 1.25). During this period, it did not receive a target to generate, as its available capacity was priced above $14,000/MWh.

However, at 6.10 pm and 6.15 pm, prices increased to around $310/MWh. In response, Shell Energy rebid most of OAKEY2's capacity to below $1/MWh and reduced both the T1 and T2 times to 0 minutes. The reason given for the rebid was 'Amended contract position'. This resulted in OAKEY2 receiving a dispatch target and generating from 6.30 pm until the rebid was reversed just before 8 pm.

Figure 1.25 Oakey power station unit 2 T1 and T2 times, dispatch and price, 17 October

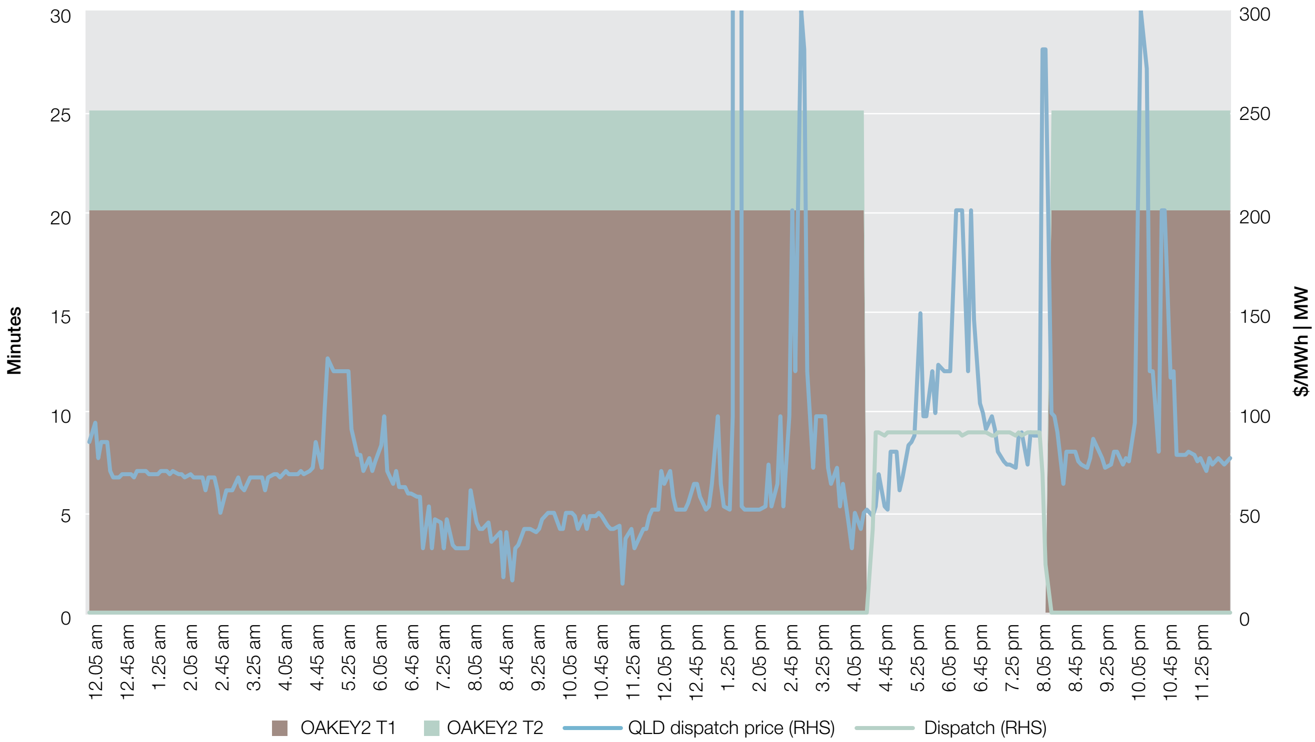


Note: AER analysis using AEMO data.

The next day, Shell Energy again responded to high prices by rebidding its energy and FSIP (Figure 1.26). During the day there were several high prices, including a dispatch price of $15,096/MWh at 1.40 pm, as well as a couple of other dispatch prices around $300/MWh during the afternoon.

Just before 4 pm, over half of OAKEY2's capacity was rebid from the cap to below $0/MWh in response to an amended contract position. However, OAKEY2 did not receive a target to generate until its T1 and T2 times were both rebid to 0 minutes effective from 4.25 pm. These rebids were reversed by 8.15 pm and OAKEY2 no longer received a target.

Figure 1.26 Oakey power station unit 2 T1 and T2 times, dispatch and prices, 18 October



Note: AER analysis using AEMO data. Right-hand axis capped at $300 per MWh/MW for illustrative purposes.

These events highlighted how in a 5MS market, a generator's FSIP can determine if and when they are dispatched.

Early market observations – Offers and price outcomes

One of the expected benefits of 5MS is to resolve inefficiencies associated with late rebidding and to provide more efficient wholesale price outcomes. While it is still very early in the implementation of 5MS and difficult to draw any conclusions about its impacts, we have observed some initial changes in bidding behaviour and price outcomes. October is typically a shoulder period in the NEM, so we are still to see how the market will operates when under pressure from sustained peak demand periods.

There have been a significant number of new generators come online since October 2020. Therefore, to observe the early impacts of 5MS against current market conditions we have compared October 2021 with both October 2020 and September 2021.

Changes in number of offers

5MS has changed participants' rebidding incentives. As they no longer receive an average 30 minute price, under 5MS they now have to be ready to capture a 5 minute price spike.

In October, we found the total number of energy offers (initial offers and subsequent rebidding) increased by 30%, while FCAS offers increased by 40%, compared to September (Figure 1.27). The increase of offers in October 2021 was primarily driven by battery, solar, gas and hydro generators. The number of offers from wind have increased steadily since May and the number of coal offers has remained largely unchanged. Given there is only a month's worth of data during a traditional shoulder period it is difficult to draw any firm conclusions. However possible reasons for this increase in offers are:

- the use of automated bidding software
- participant rebidding to avoid negative prices
- new generating units participating in the market.

In September 2021, ARENA estimated over 35% of solar and wind farms in the NEM had introduced automated bidding software in the last 2 years.[22] The number of rebids by wind and solar generators in Q3 2021 was four and

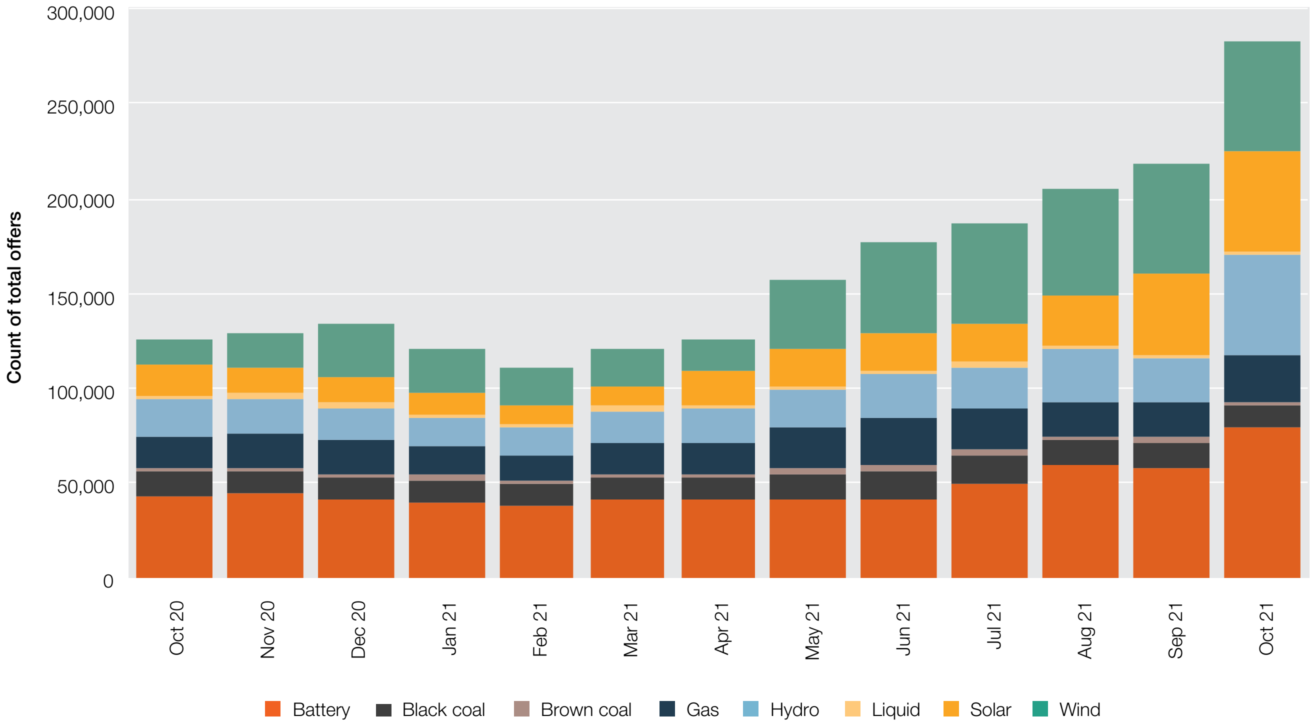
22 ARENA, Generation Operations Three: Negative Pricing and Bidding Behaviour on the NEM, September 2021, p. 3.

a half times higher than the same time last year, as participants increased offer prices to avoid being dispatched at negative prices.[23]

Negative prices increased a little in October 2021 compared to 2020, but it is too early to conclude whether increased rebids are due to increases in negative prices.

The increase in hydro offers appears to be Hydro Tasmania doubling the amount of offers.

Figure 1.27 Total energy offers

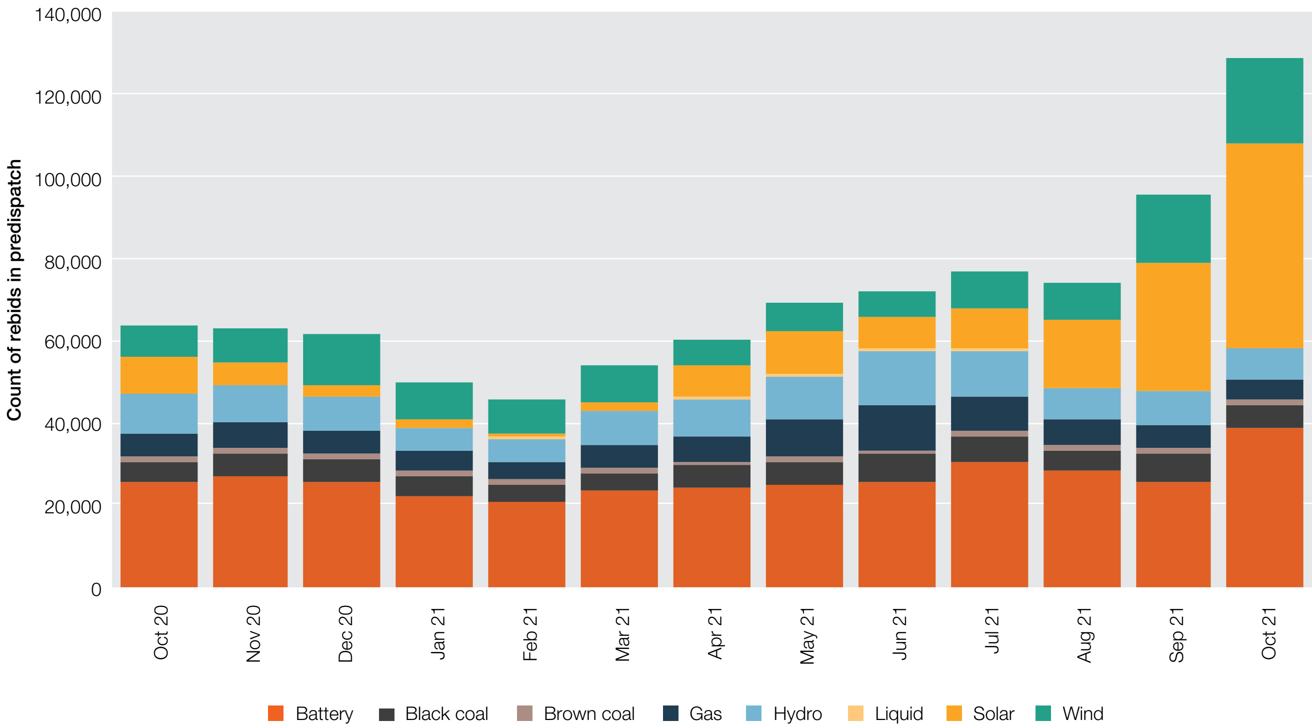


Note: AER analysis using AEMO data.

Looking at predispatch energy offers, generators submitted 33,400 more bids in October than in September (Figure 1.28). The predispatch period starts at 12.30 pm the day before the relevant trading period and is when AEMO publishes detailed forecasts including pricing for the following trading day. Battery, wind and solar increased their rebidding during these time frames, likely due to automated rebidding. While hydro total offers increased, their rebids did not significantly change during predispatch, indicating the increase in total offers noted above, occurred before price forecasts were published.

23 AEMO, Quarterly Energy Dynamics – Q3 2021, 22 October 2021, p. 17.

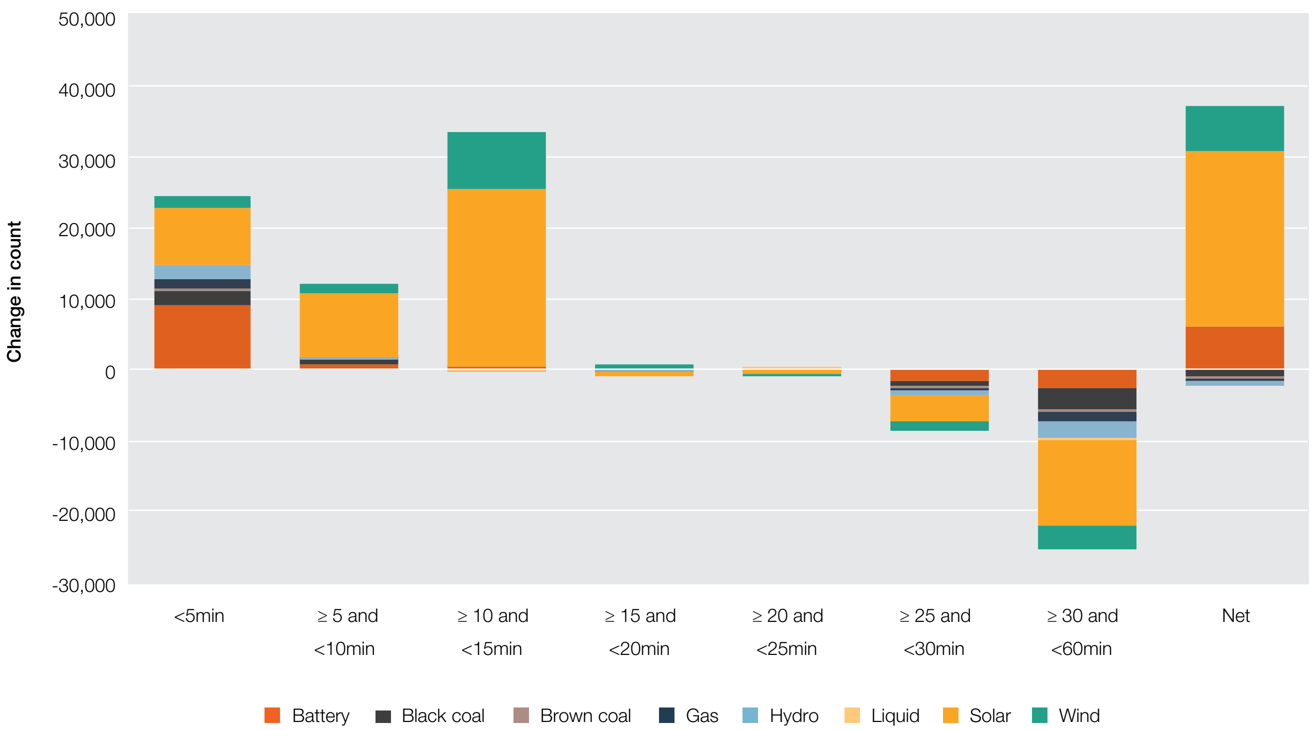
Figure 1.28 Rebids in the predispatch period



Note: AER analysis using AEMO data.

Focusing on rebids up to an hour before dispatch, we analysed how close to dispatch the rebids were received in October compared to September (Figure 1.29). While more rebids were submitted overall, solar, wind and battery generators submitted less rebids during the 25 to 60 minute window before dispatch, instead concentrating their rebids in the 0 to 15 minute window. This may reflect their ability to react faster than other fuel types to actual or forecast prices, which is what 5MS was designed to incentivise. There was not any significant change in the number of rebids beyond an hour out.

Figure 1.29 Rebids within 60 minutes of dispatch, October and September comparisons



Note: AER analysis using AEMO data.

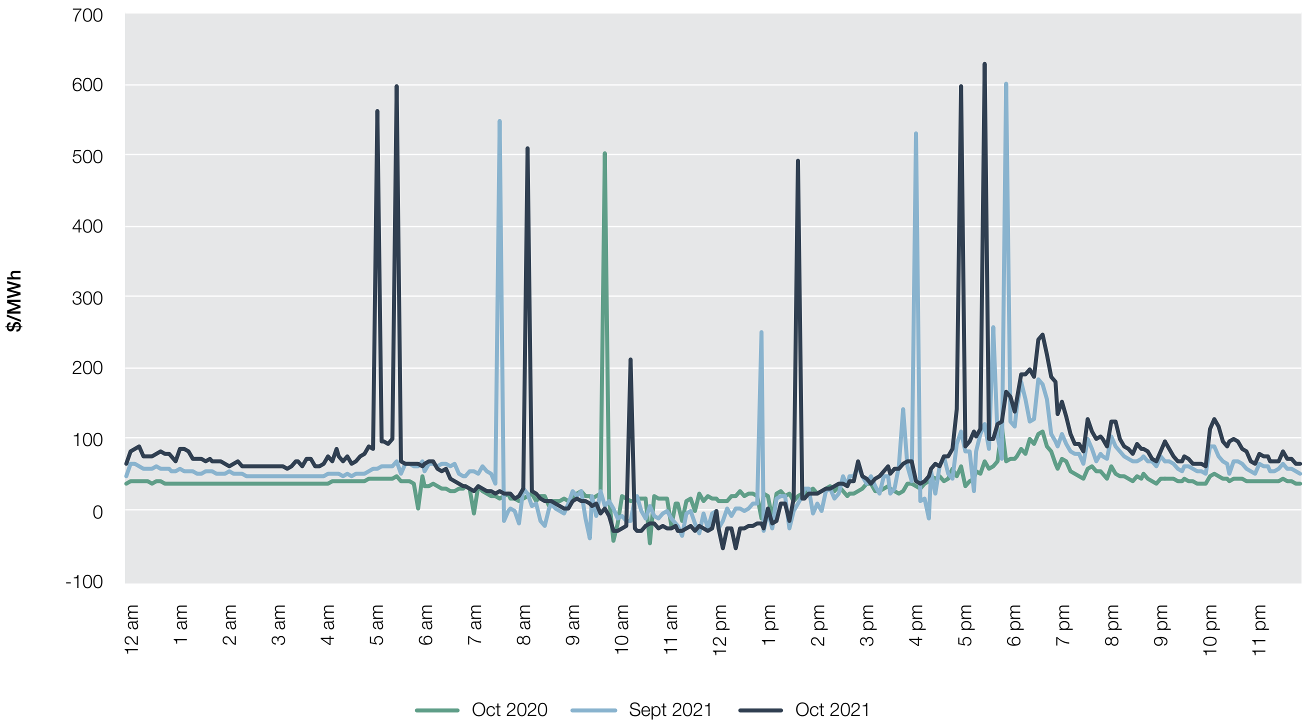
Dispatch price outcomes

We compared the dispatch price by time of day, and the distribution of dispatch prices in October 2020, September 2021 and October 2021. The two regions of interest so far are Queensland and Victoria, which follows from our findings in this report. This quarter Queensland experienced supply pressures with generator outages, increased fuel costs, constrained interconnectors and local FCAS demand, while Victoria had a significant increase of low-priced supply with almost 1,200 MW of renewable generation coming online (section 1.13).

Queensland

Dispatch price outcomes for Queensland in October 2021 were more volatile than October 2020. However, it appears this volatility has continued from September 2021 and reflects the market drivers such as ongoing outages, network upgrades, FCAS and rising fuel costs (section 1.1) rather than purely a change to 5MS (Figure 1.30).

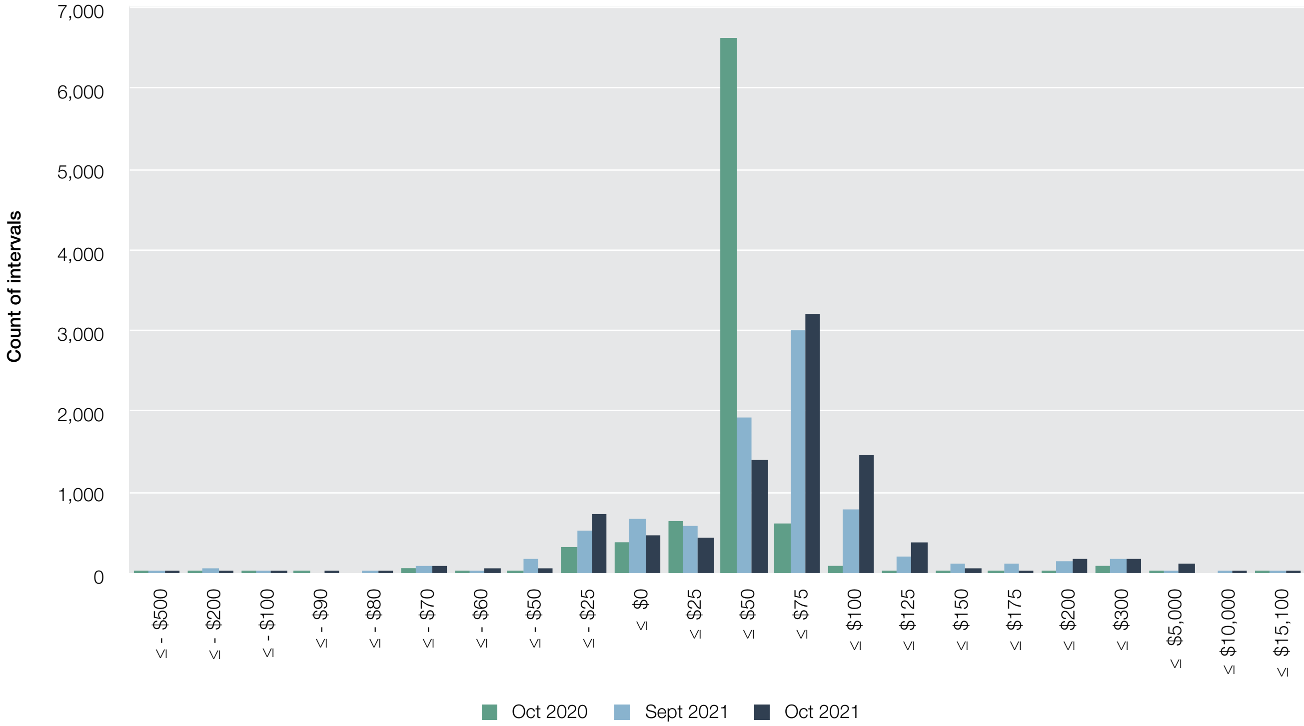
Figure 1.30 Queensland dispatch price time of day comparison



Note: AER analysis using AEMO data.

The distribution of prices in Queensland has spread into higher price bands and some negative bands compared to October 2020. Last year dispatch prices occurred most often between $25/MWh and $50/MWh, but this year prices are settling between $50/MWh to $100/MWh more often (Figure 1.31). Again, this is to be expected if Q3 price outcomes continue into Q4 (section 1.3).

Figure 1.31 Queensland dispatch price distribution



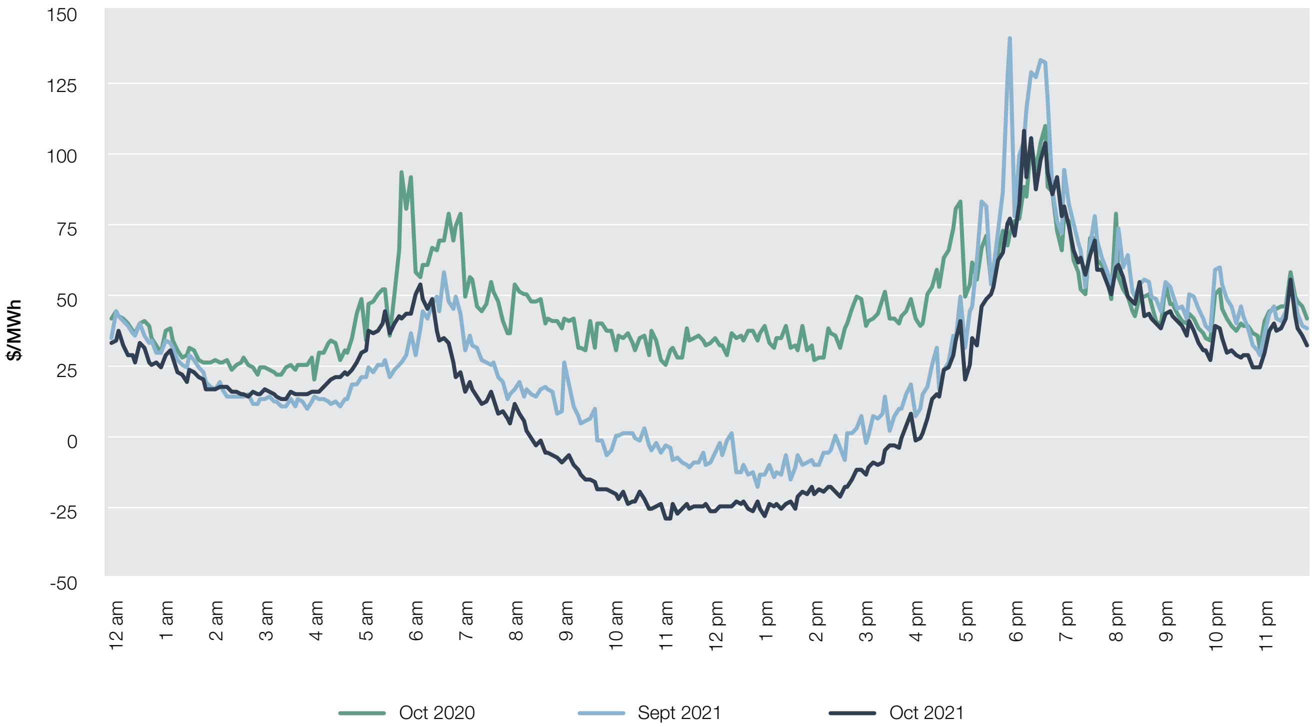
Note: AER analysis using AEMO data.

Victoria

In Victoria, the increased count of negative prices continues to get more pronounced during the middle of the day, which is an expected outcome due to the increase of installed renewable generation. Typically, renewable generation supplies more low priced capacity into the market and installations of rooftop solar reduces grid demand. The combination of these drivers leads to more negative prices, especially in the middle of the day.

However, between 6 pm and 7 pm (during evening peak demand), price outcomes are settling around $40/MWh lower than in September, but to similar levels as last year. These prices may reflect that 5MS is driving more efficient outcomes when demand is higher, and the sun is not shining. We will continue to monitor these trends as supply and demand conditions tighten over summer.

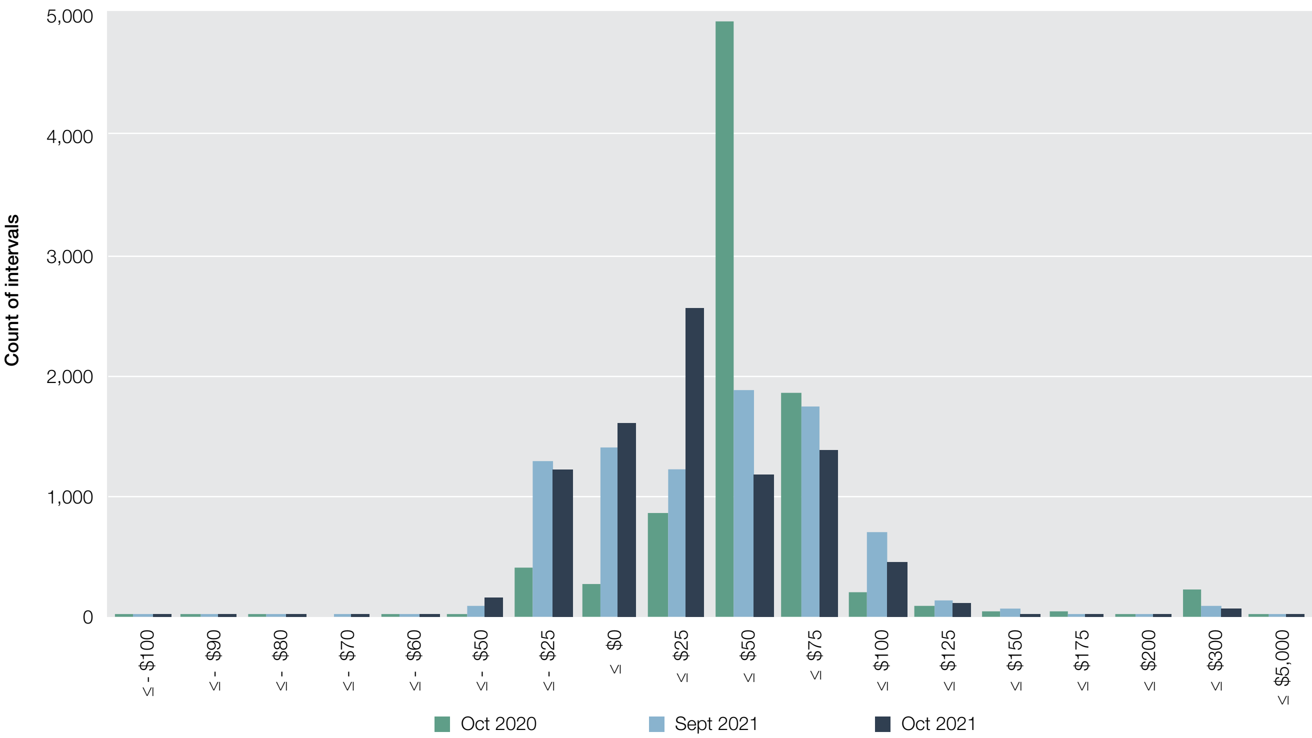
Figure 1.32 Victoria dispatch price time of day comparison



Note: AER analysis using AEMO data.

Looking at the distribution of dispatch prices, October 2020 was dominated by dispatch prices between $25/MWh and $50/MWh, while the distribution of prices in September and October 2021 were spread out across more price bands. September prices settled most often between $25/MWh and $75/MWh while October 2021 prices settled more between -$25/MWh and $25/MWh.

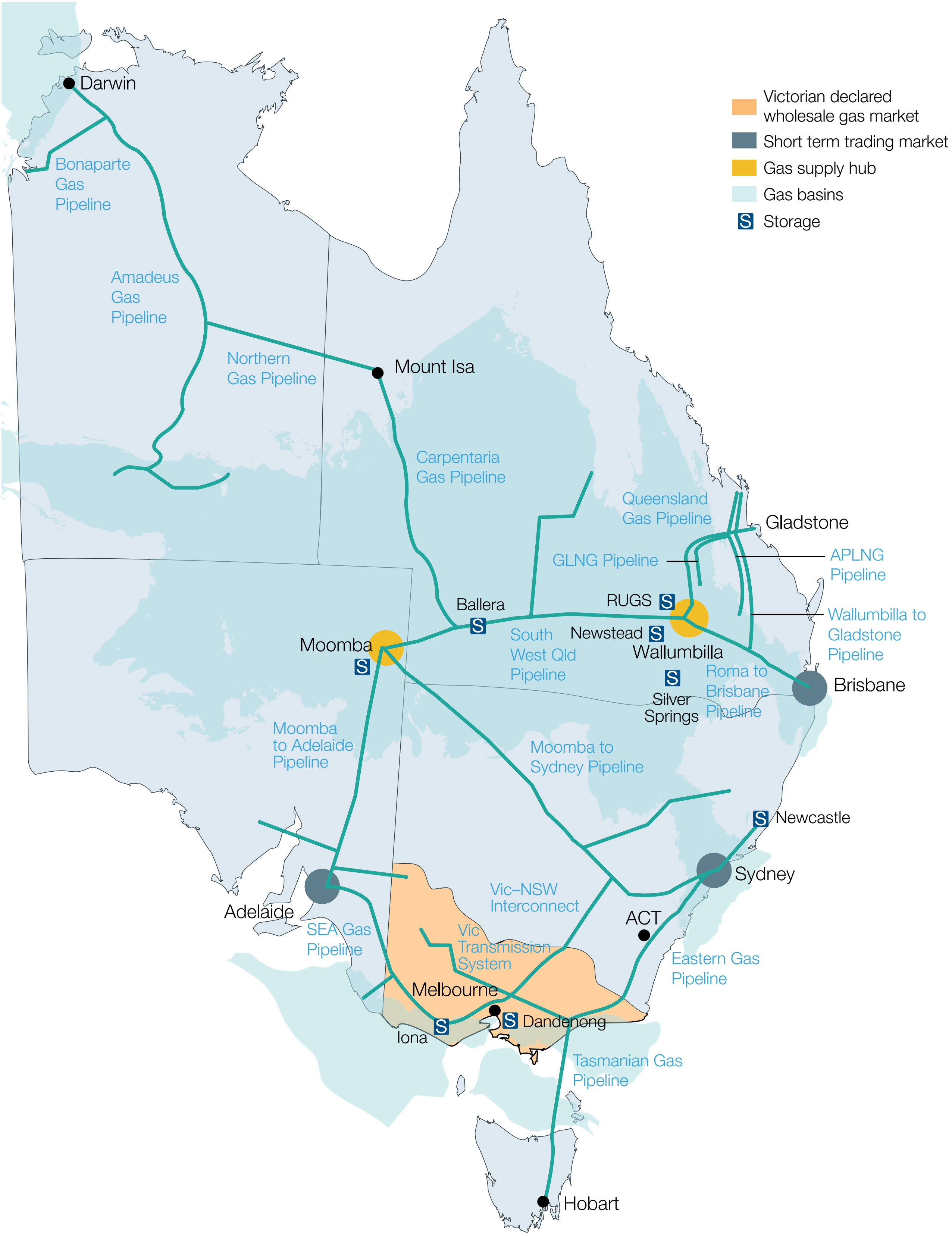
Figure 1.33 Victoria dispatch price distribution



Note: AER analysis using AEMO data.

While we are seeing a shift in dispatch prices across the NEM, it is too early to isolate the effect of the new settlement rules, especially given the other market factors that continue to influence wholesale prices. We will continue to monitor and report on participant behaviour and the effect of 5MS especially during the upcoming summer where we expect a tighter demand and supply balance.

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
Wallumbilla to Gladstone Pipeline
Ballera
RUGS
Newstead
Wallumbilla
Moomba
South West Qld Pipeline
Roma to Brisbane Pipeline
Silver Springs
Brisbane
Moomba to Adelaide Pipeline
Moomba to Sydney Pipeline
Newcastle
Sydney
Adelaide
SEA Gas Pipeline
Vic–NSW Interconnect
ACT
Vic Transmission System
Eastern Gas Pipeline
Melbourne
Dandenong
Iona
Tasmanian Gas Pipeline
Hobart

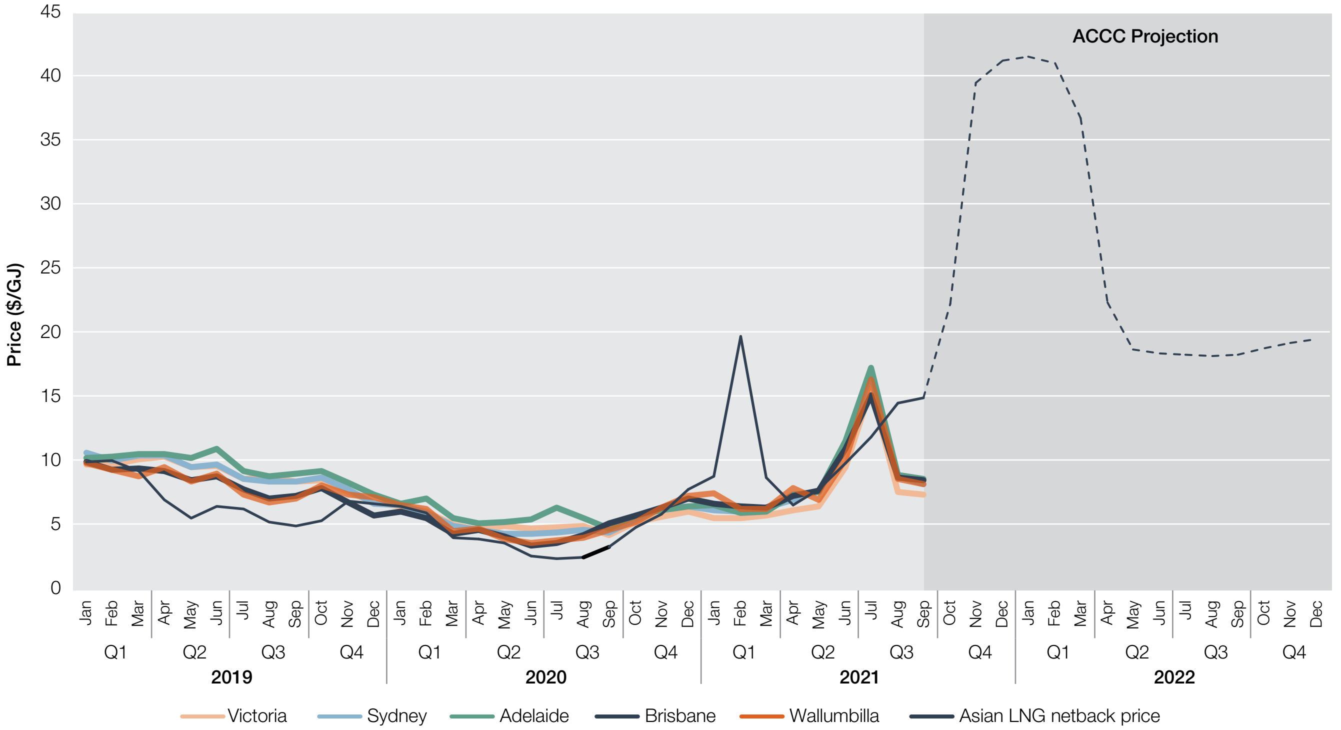
2.1 Prices rising and volatile

Domestic prices increased by 28% on average since last quarter. Across all markets, prices ranged from $10.10/GJ in Victoria to $13.42/GJ at the Wallumbilla Gas Supply Hub.[24]

Average domestic and international prices de-linked across Q3, particularly in September, due to a range of factors affecting international markets (Figure 2.1). Typically, the Wallumbilla Gas supply Hub has the closest link to international prices as Queensland LNG exporters trade more actively there than in other spot markets. The price at Wallumbilla was close to the Asian LNG netback price of $13.66/GJ for Q3 2021 deliveries, however, was significantly less than the Asian LNG netback price based on assessments for future deliveries occurring in Q3 ($22.18/GJ).

Assessments over Q3 include assessments for future deliveries to Asia in October and November, reflecting that gas deliveries can take 6 to 12 weeks because of LNG transportation logistics (liquefaction, shipping). Previous AER analysis has indicated a strong correlation between LNG netback assessment prices (for future deliveries) and the Wallumbilla day ahead on screen price.[25]

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.

Note: Wallumbilla hub is the on screen, day ahead price. Victoria is daily imbalance price at 6:00am. Sydney, Adelaide and Brisbane are ex ante prices. The Moomba hub has not been included, given it sees very few trades. The Asian LNG netback price is shown on a delivered basis.

Domestic prices have more than doubled since the economic impacts of the COVID-19 pandemic pushed global and domestic prices down in mid-2020. In July in particular, domestic prices were extremely volatile and daily prices reached records in excess of $20/GJ for weeks across markets. In July, prices increased as residential heating requirements rose during a period of colder than average temperatures. At the same time, demand from gas powered generators (GPG) increased and supply from the Longford production facility in Victoria reduced, which tightened the supply-demand balance. Pipeline constraints also limited deliveries of gas from the north to southern markets on some days in July. Additionally, the Iona storage facility increased its offer prices reflecting scarcity pricing as storage levels diminished putting further upward pressure on prices across markets.[26]

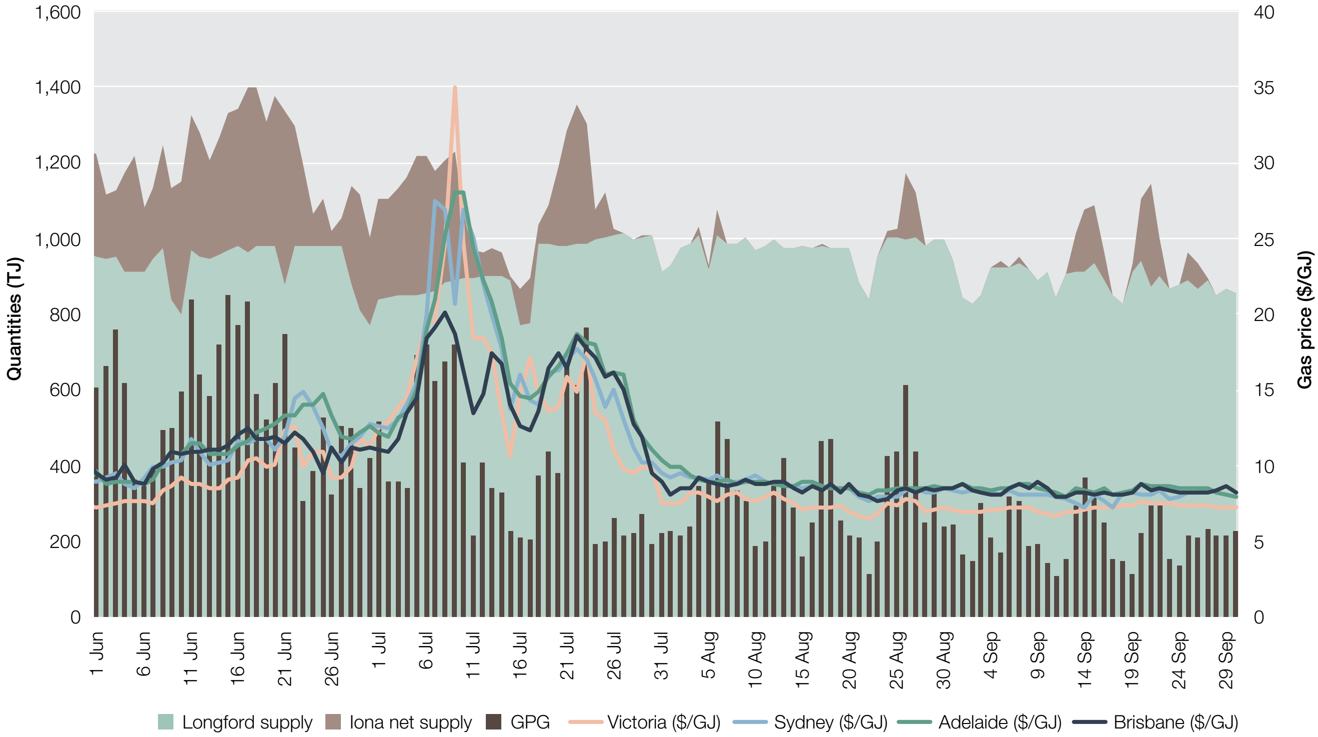
Prices stabilised at lower levels in August and September as the Longford facility increased gas supply after an outage from 3 to 17 July. Also, demand from GPG reduced as coal powered electricity generators returned to service from maintenance outages, contributing to lower gas prices (Figure 2.2).

24 The Wallumbilla price is the day ahead on screen price at the WAL location.

25 AER, Wholesale markets quarterly Q1 2020, p. 57.

26 AER, *Significant price variation report*, July 2021.

Figure 2.2 Gas supply, GPG and Spot prices



Source: AER analysis using NEM, Victorian DWGM and STTM and Natural Gas Services Bulletin Board data.
Note: Gas use estimates are conversion of electricity generation output using average heat rates (GJ/MWh).

Internationally, gas prices rose to unprecedented levels, ranging from $20/GJ to $40/GJ throughout the quarter as buyers from Asia, Europe and South America competed to purchase LNG cargoes. By the end of the quarter, domestic prices and Asian LNG prices diverged significantly. For example, for September deliveries, the Asian LNG netback price rose to $14.9/GJ whereas average east coast market domestic prices were $8.05/GJ in September.[27] This is an atypical price trend for this time of year. Usually, international prices are lower during the Northern Hemisphere summer in Q3, as compared to northern winter months over Q1 and Q4. A mix of factors drove higher gas prices in Asia, Europe and the Americas during Q3 2021, including:[28]

- economic activity recovering from COVID-19 impacts and higher associated energy demand
- higher demand to replenish gas storage volumes in Europe ahead of winter
- higher gas demand for electricity generation due to:
  - more cooling load required in Asia during a hot summer
  - the need to replace lost of hydro generation capacity due to drought conditions in South America
  - low renewable generation output
  - South Korea and China limiting coal generator output to meet environmental policies
- lower global supply because of outages at production facilities in Europe, USA and Western Australia
- constrained supplies from Russia.

International gas prices are anticipated by futures markets to remain at elevated levels for the remainder of 2021 and into 2022, particularly over the November to February months during the Northern Hemisphere winter (Figure 2.1). Logistical constraints and high demand for shipping may be adding to the cost of transporting gas, as freight rates increased significantly toward the end of Q3. Beyond threats to energy security, the rise in international gas prices has widespread implications for global economies. They have the potential to affect the economics of running electricity generators and the availability of gas as a feedstock supporting food supply chains and industrial processes. So far, the volatility in energy markets globally has led to retailer failures, electricity supply rationing and reductions in fertilizer production across a number of countries.[29] In Australia, high gas prices similarly have the

27 The Asian LNG netback price for LNG netback price assessments over September for deliveries in October–November was $22.18/GJ

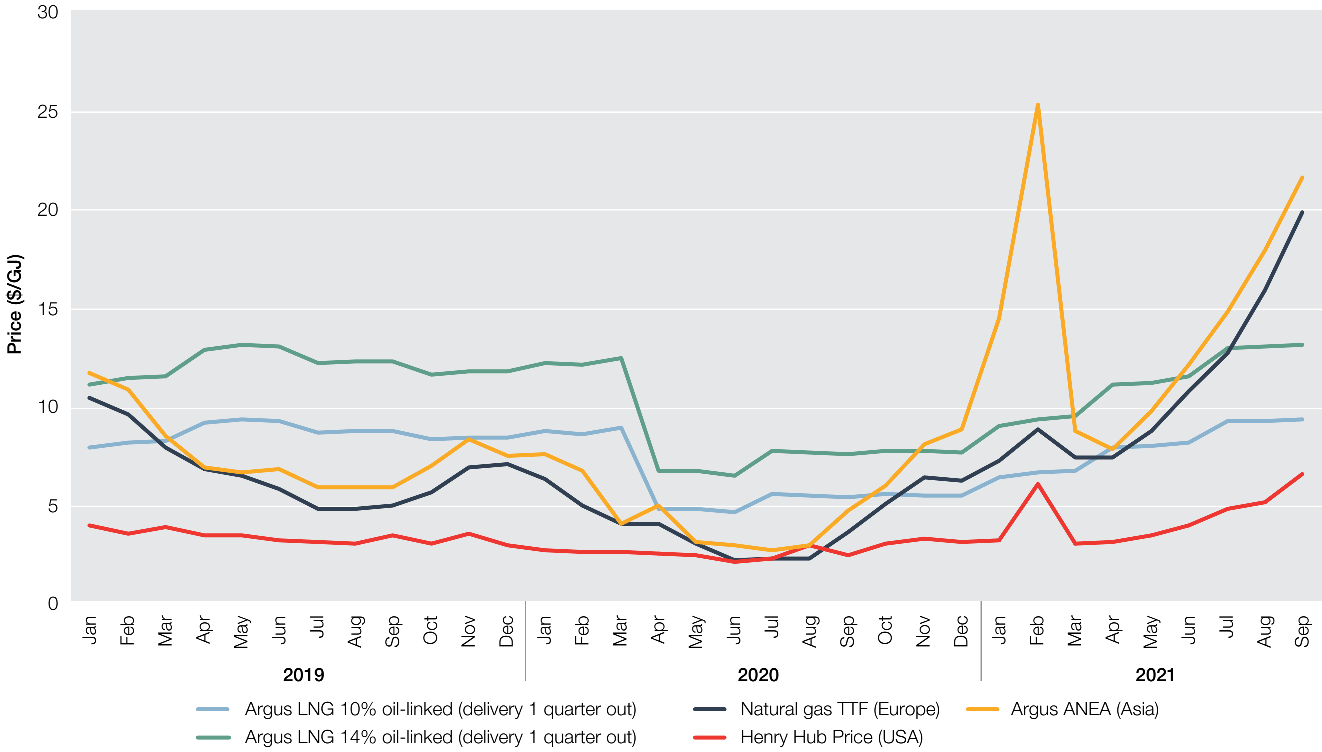
28 Department of Industry, Science, Energy and Resources, *Resources and energy quarterly*, September 2021, pp. 70–77.

29 AFR, What's behind China's regional power outages?, accessed 28 October 2021;
AFR, Europe faces energy price shock with gas and power at records, accessed 28 October 2021.

potential to raise the wholesale cost of electricity when gas is needed to supply electricity generators, particularly when other generators are constrained.

Oil prices have also increased over the past year to now be greater than USD$100/barrel, up from lows of around USD$50/barrel to USD$60/barrel during 2020. This also bears on the cost of gas sold under contracts, which is typically linked to a percentage of the prevailing oil price (Figure 2.3).

Figure 2.3 International gas prices



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

Notes: The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4–12 weeks before the date of delivery.

The Argus LNG 14% oil linked contract prices are indicative of a 14% 3-month average Ice Brent crude futures slope.

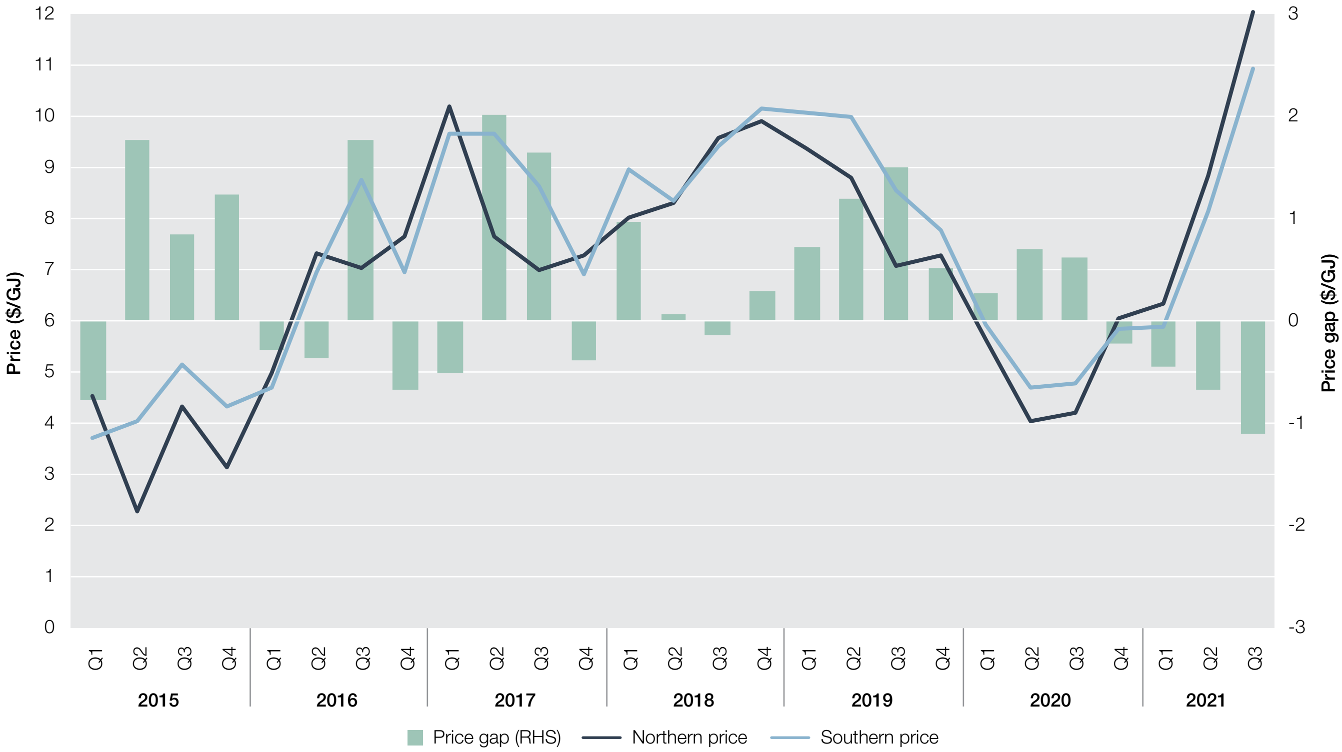
The Argus Natural gas TTF price is a month ahead delivered spot price calculated at the Title Transfer Facility (TTF) in the Netherlands.

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

Domestic prices in the northern markets remained above southern markets by $1.11/GJ (Figure 2.4). This was driven by some extremely high prices at Wallumbilla ($13.42/GJ) and a lower average Victorian price ($10.10/GJ).

Figure 2.4 Price difference between northern and southern domestic markets



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

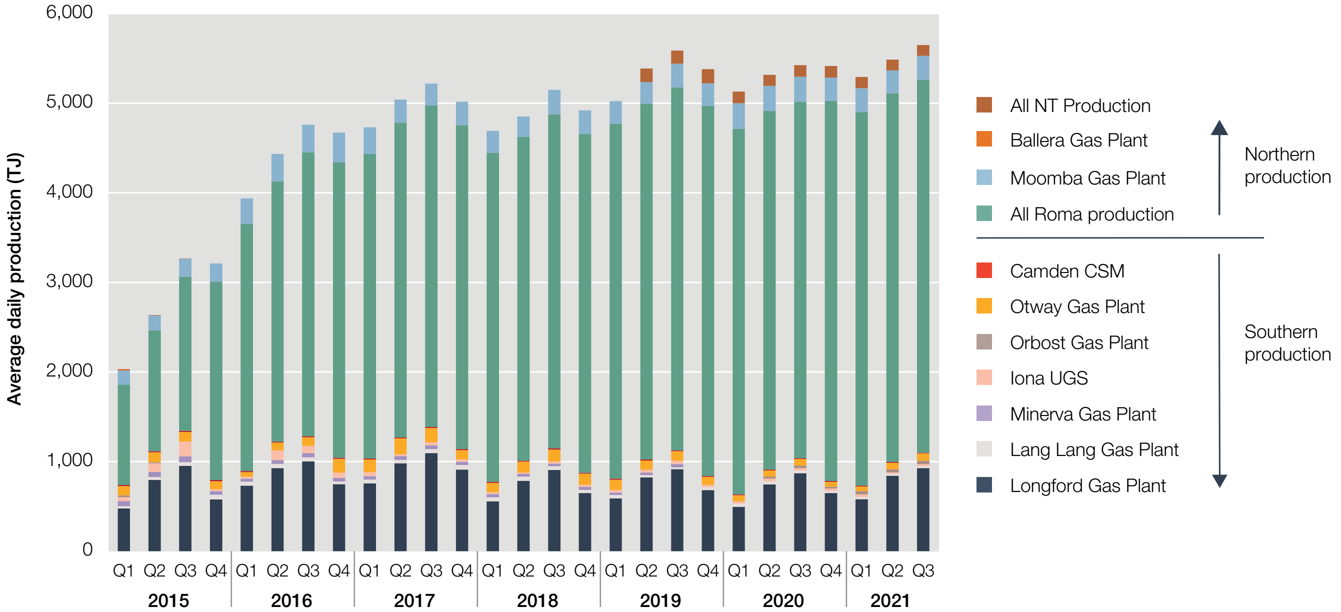
Note: If the price gap is positive the southern price is higher than the northern price. If the price gap is negative the southern price is lower than the northern price.

2.2 East coast production reaches record levels

Gas production levels continued to rise, reaching a record average daily level of 5,649 TJ/day in Q3 2021, increasing from 5,487 TJ/day in Q2 2021 and 5,424 TJ/day in Q3 2020 (Figure 2.5). Gas production typically peaks in Q3 every year to meet peak demand for domestic winter heating. This year, east coast demand over Q3 2021 was 5% higher than in Q3 2020 as a result of higher LNG exports, driving the new production record.[30] The increase in production was largely met by higher production volumes at the Longford gas production plant in Victoria of 928 TJ/day and elevated gas production at Roma in Queensland of 4,162 TJ/day.

30 AEMO, *Quarterly Energy Dynamics Q3 2021*, October 2021, p. 35.

Figure 2.5 East coast production (including Northern Territory)



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

The Longford gas plant has not reached this level of production since its record in 2017, despite an outage from 3 to 17 July.

The Longford outage coincided with high prices across all markets, as it reduced the availability of contracted gas that otherwise might be priced into markets cheaply. A number of large production facilities associated with LNG exporters in Queensland (APLNG and QGC) also undertook maintenance, although only the Jordan outage coincided with the Longford outage. The east coast market benefitted from the staggering of outages over Q3 2021 (Table 2.1).

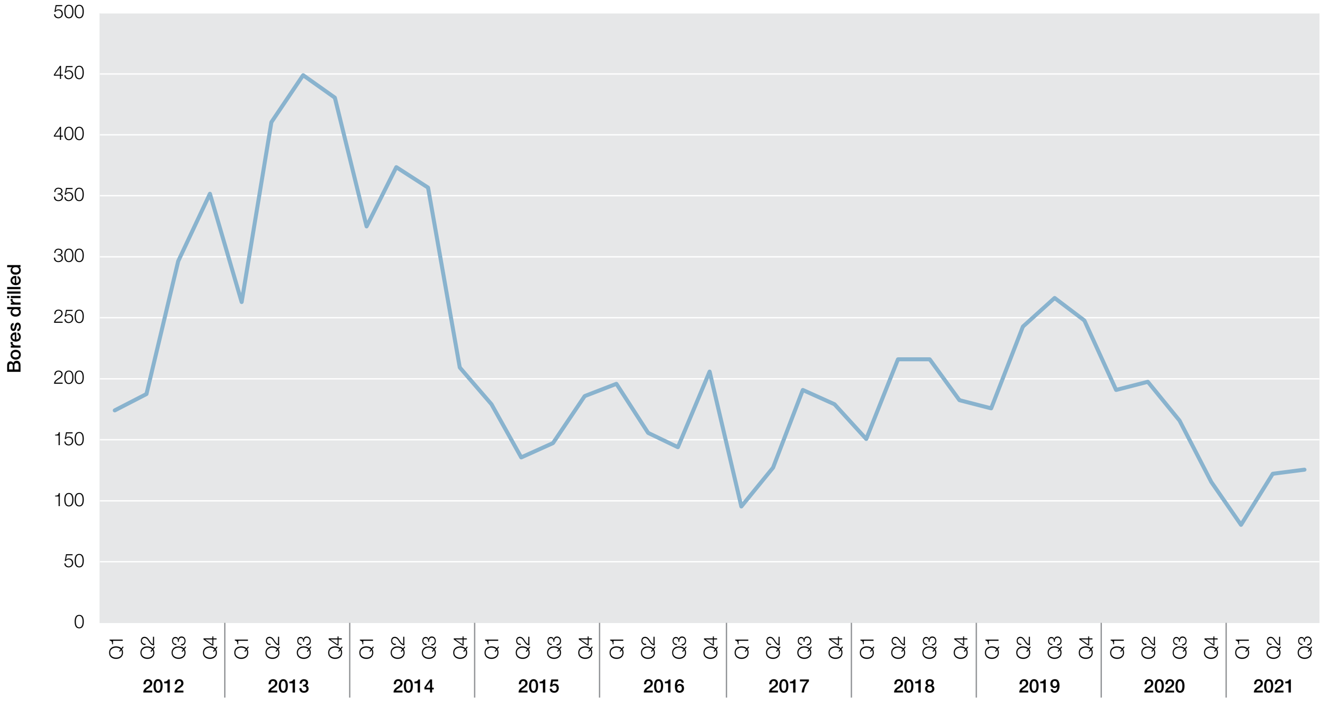
Table 2.1 Gas production facility outages

DATE	FACILITY	OPERATOR	NAMEPLATE CAPACITY (TJ/DAY)	MAXIMUM CAPACITY DURING MAINTENANCE (TJ/DAY)
29 Jul–7 Aug	Eurombah Creek	APLNG	186	85
1–8 Jul	Jordan	QGC	497	10–264
8–24 Aug	Combabula	APLNG	285	200
26–30 Aug	Kenya	QGC	180	0
28 Jul–10 Aug	Talinga	APLNG	125	0–58
3–17 Jul	Longford	Esso	1,115	850–900

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

There was a slight increase in the number of new coal seam wells drilled in Queensland, increasing to 126 wells in Q3 2021 compared to 123 wells in Q2 2021. This marks a reversal of the downward trend in gas exploration that began in 2020, which coincided with the onset of the COVID-19 pandemic. Drilling numbers can be indicative of planned supply changes, as a continuous procession of new wells is required to support ongoing production from coal seam gas resources such as those in Roma, Queensland.

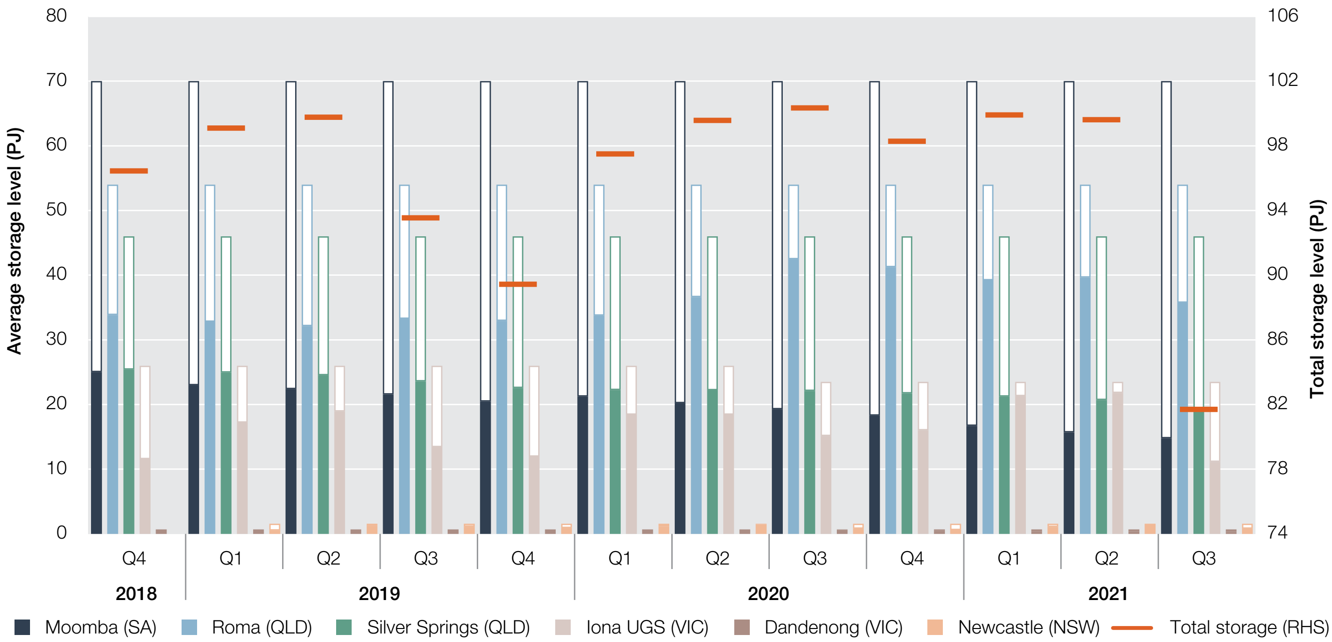
Figure 2.6 Queensland coal seam gas bores drilled



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

Gas storage played an important role to meet high demand in southern states, supplying high volumes of gas to southern markets over July. Notably, the Iona storage facility in Victoria proved to be a key supply source, injecting 200–300 TJ/day in July, while the Longford gas plant underwent a maintenance outage. Reflecting this, average gas storage volumes declined materially from 99.6 PJ in Q2 2021 to 81.6 PJ in Q3 2021. Additionally, there was limited ability for Iona to refill in July due to a constraint, which lasted from 1 to 31 July.

Figure 2.7 Storage levels



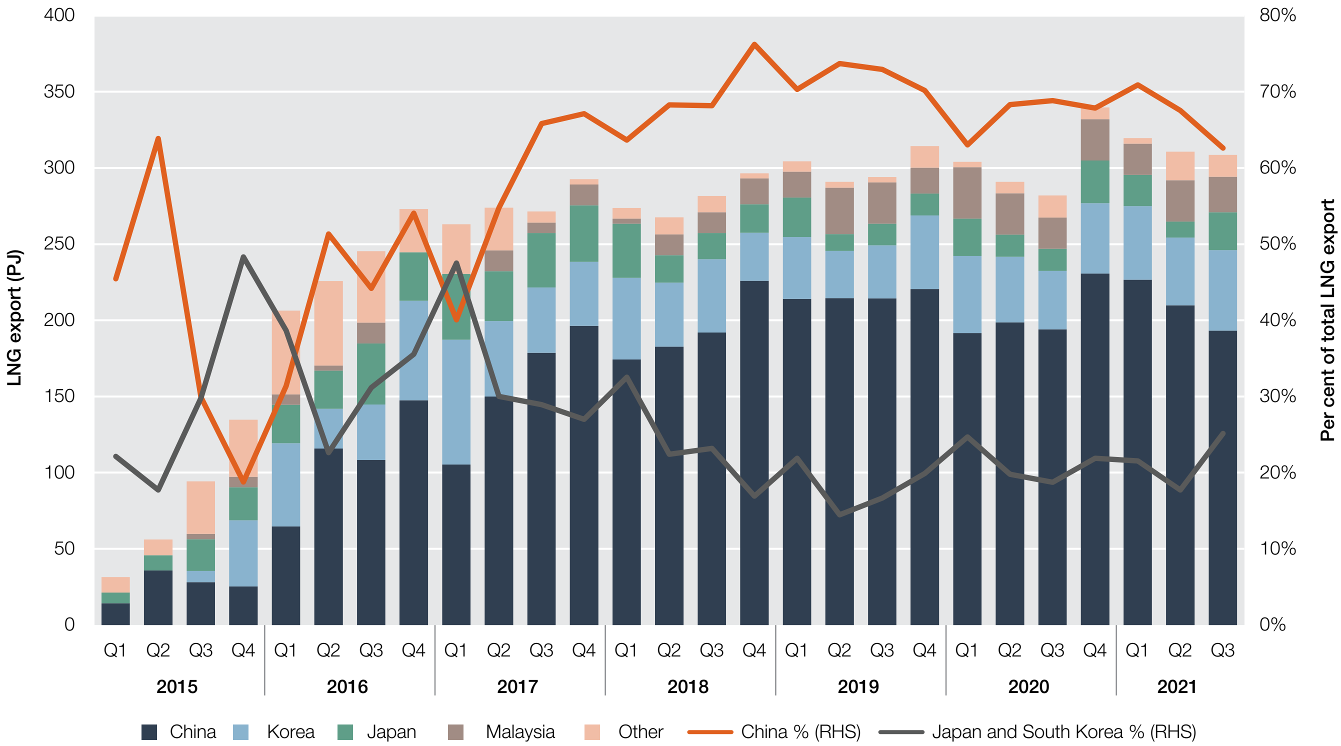
Source: AER analysis using Natural Gas Services Bulletin Board data.

Note: Storage levels are averages across a quarter.

2.3 Record Queensland LNG exports in Q3 with plants running hard

Total Queensland LNG exports reached a record high for a Q3. Queensland LNG exports declined only slightly to 309 PJ in Q3 2021 from 311 PJ in Q2 2021, with reductions in LNG exported to China offset by increased volumes exported to South Korea and Japan (Figure 2.8). Asian GPG demand increased over summer with a hotter than average summer driving higher electricity consumption for cooling requirements. The increase in demand for gas, rising LNG and oil prices are forecast to translate into increased export earnings for Australia, rising from $30 billion in 2020–21 to $56 billion in 2021–22.[31]

Figure 2.8 LNG shipped from Gladstone Port by destination



Source: AER analysis using Gladstone Port Corporation data.

As Asian LNG prices have surged to unprecedented levels, total Queensland LNG exports remained above 300 PJ, a record high for a Q3. This was impressive, considering a number of maintenance outages took place at LNG export plants over 44 days in Q3 2021 (Table 2.2).[32] Accounting for maintenance outages, Queensland LNG plants were approximately 98% utilised over Q3 2021 when comparing their production to nameplate capacity.[33] LNG exports increased in higher volumes as the quarter progressed, reaching 31 cargoes in September – a level as high as during the peak demand Northern Hemisphere winter months (Dec–Feb).

Table 2.2 LNG plant outages

FACILITY	PERIOD	CAPACITY	NAMEPLATE CAPACITY (PJ/ QUARTER)	NAMEPLATE CAPACITY ADJUSTED FOR MAINTENANCE (PJ/QUARTER)
QCLNG	15 June – 13 July	0.5–1 train	115.6	107.4
APLNG	28 July – 24 August	1 train	122.4	103.8
GLNG	4 – 6 September	0.5 train	106.1	105.2

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

31 Department of Industry, Science, Energy and Resources, *Resources and energy quarterly*, September 2021, p. 70.

32 QCLNG forecast a June/July outage of between 0.5 and 1 train. Pipeline flows to the QCLNG facility indicate that the maintenance outage was at a capacity of 1 train.

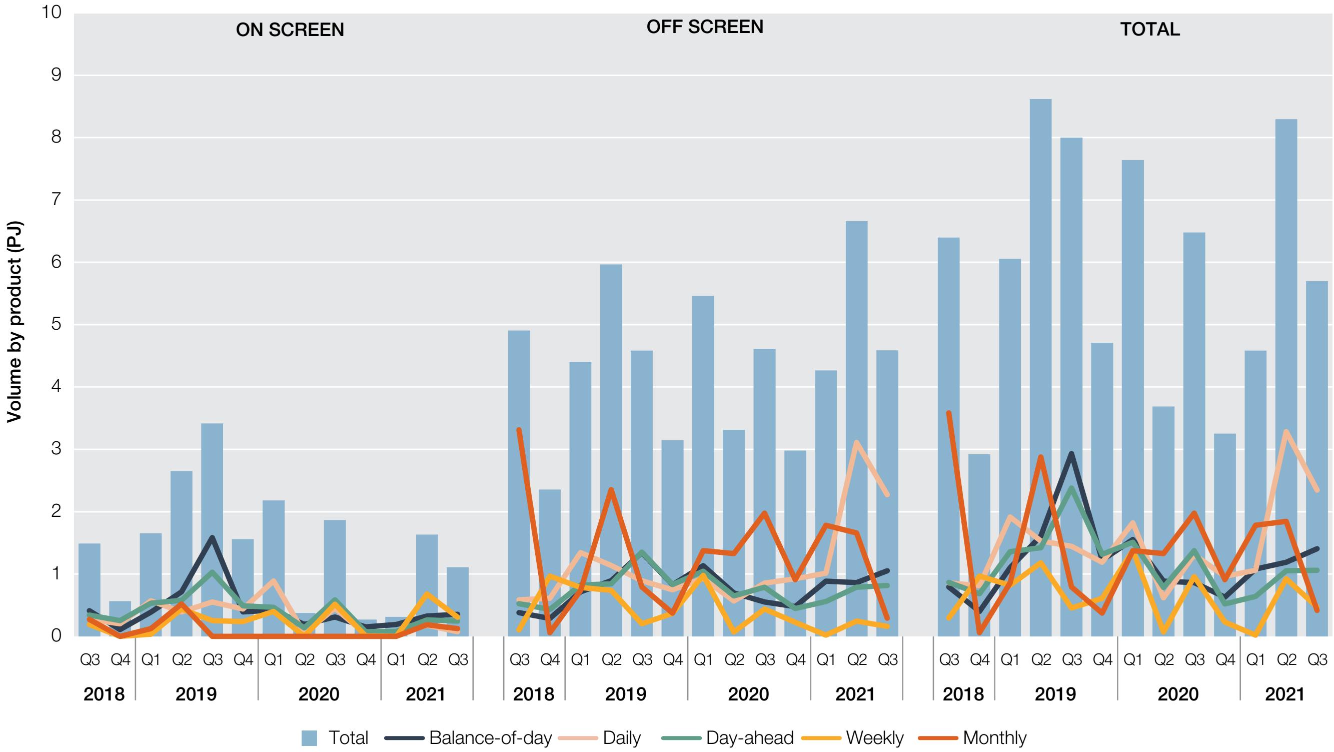
33 The LNG facilities have some capability to surge production capacity above the stated nameplate capacity of each individual facility. The LNG facilities have not demonstrated the ability to sustain continual production at surge capacity levels on an ongoing basis.

Strong interest in LNG from Asian buyers is expected to continue to drive growth in Australia's LNG exports, as economies recover post-COVID-19 and environmental policies favour gas use for electricity generation over higher emitting fuel sources. China has announced gas will play a pivotal role in its transition to be carbon neutral by 2060 and is set to overtake Japan as the largest importer of LNG by the end of 2021. Additionally, South Korea has pledged to pursue net zero emissions by 2050 by using more gas, and less coal and nuclear powered generation. Similarly, Taiwan will target gas powered generation of 50% for its total electricity mix, with plans to construct an additional 3 new LNG import terminals.[34]

2.4 Trade at Wallumbilla declines as international prices peak

Gas traded through the Gas Supply Hubs declined by 31% from 8.3 PJ in Q2 2021 to 5.7 PJ in Q3 2021. Trade declined most significantly for monthly products whereas shorter term day-ahead and balance of day products increased in volume in Q3 2021 (Figure 2.9).[35] Despite a fall in the volume of gas traded, more gas was delivered this quarter than in Q2 2021, as large volumes of gas traded in Q2 2021 were for delivery this quarter.

Figure 2.9 Gas Supply Hub – On screen, off screen and total trade volumes by product



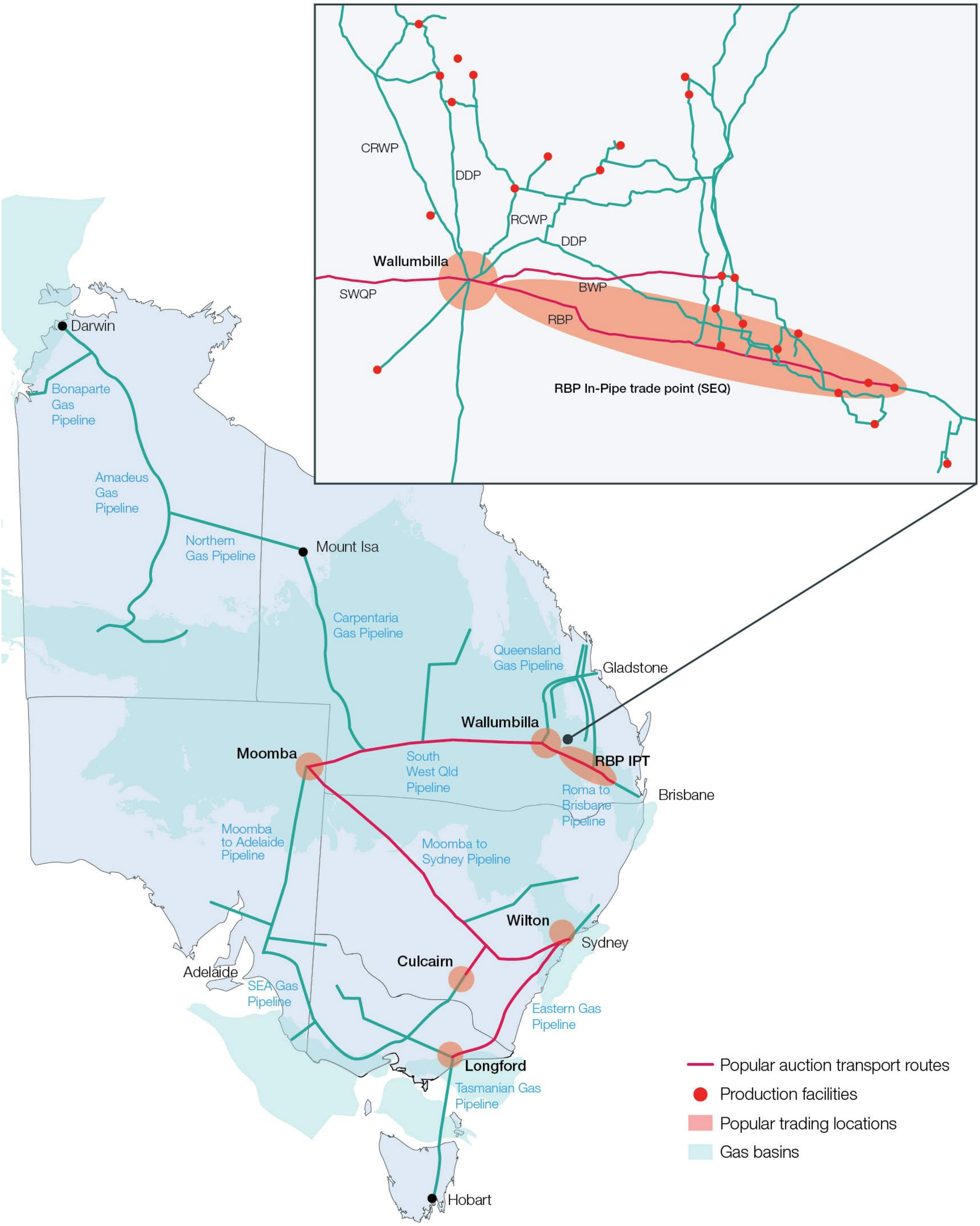
Source: AER analysis using Gas Supply Hub trades data.

Most of the trade recorded at the Gas Supply Hubs took place at the Wallumbilla (4.3 PJ) and South East Queensland (1.3 PJ) locations, with minimal trade recorded at newly available delivery points in Victoria (0 PJ) and Sydney (0.08 PJ – Figure 2.10).

34 Department of Industry, Science, Energy and Resources, *Resources and energy quarterly*, September 2021, p. 72.

35 There are 5 standard product lengths that participants can use when trading at the Gas Supply Hub: balance of day, daily, day ahead, weekly and monthly.

Figure 2.10 Major gas trading locations



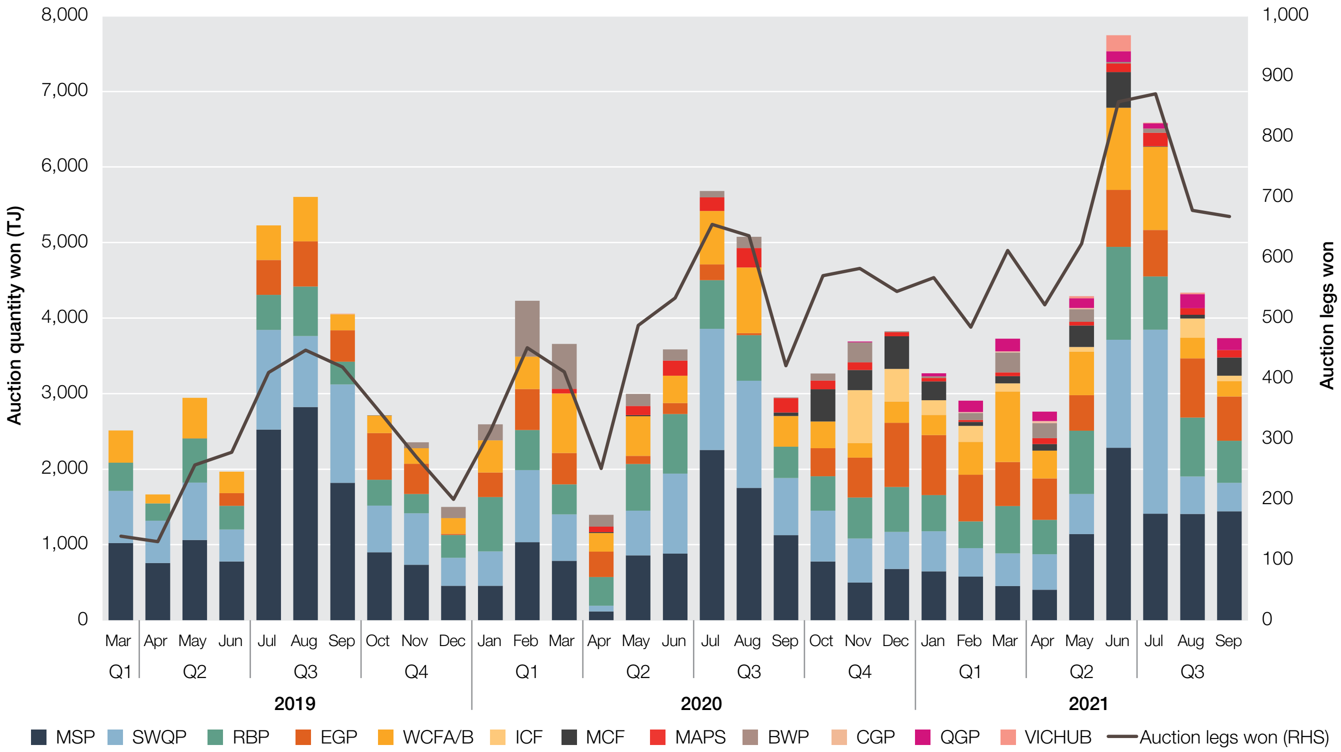
Source: AER analysis using Gas Supply Hub, DWGM and STTM data, GEOScience Australia.

Trading volumes declined amid extremely volatile prices at the Gas Supply Hubs, ranging from $7.40/GJ to $27.49/GJ. Prices at the Gas Supply Hub peaked in July, coinciding with elevated trading volumes at this time (section 2.1). As international prices increased substantially over August and September, trading volumes at the Gas Supply Hub declined and conversely LNG exports increased. Our focus story discusses the competitive dynamics between trading participants at the Gas Supply Hub.

2.5 Trade through the Day Ahead Auction maintains at Q2 levels

Trade remained high on the Day Ahead Auction (DAA) for pipeline capacity, recording only slightly lower volumes of 14.7 PJ for Q3 2021 compared to 14.8 PJ in Q2 2021. The highest month of trade this quarter was in July when 6.6 PJ was traded and there was strong usage of the Moomba to Sydney pipeline (MSP) and South West Queensland pipeline (SWQP) (Figure 2.11).

Figure 2.11 Pipeline capacity won on the Day Ahead Auction

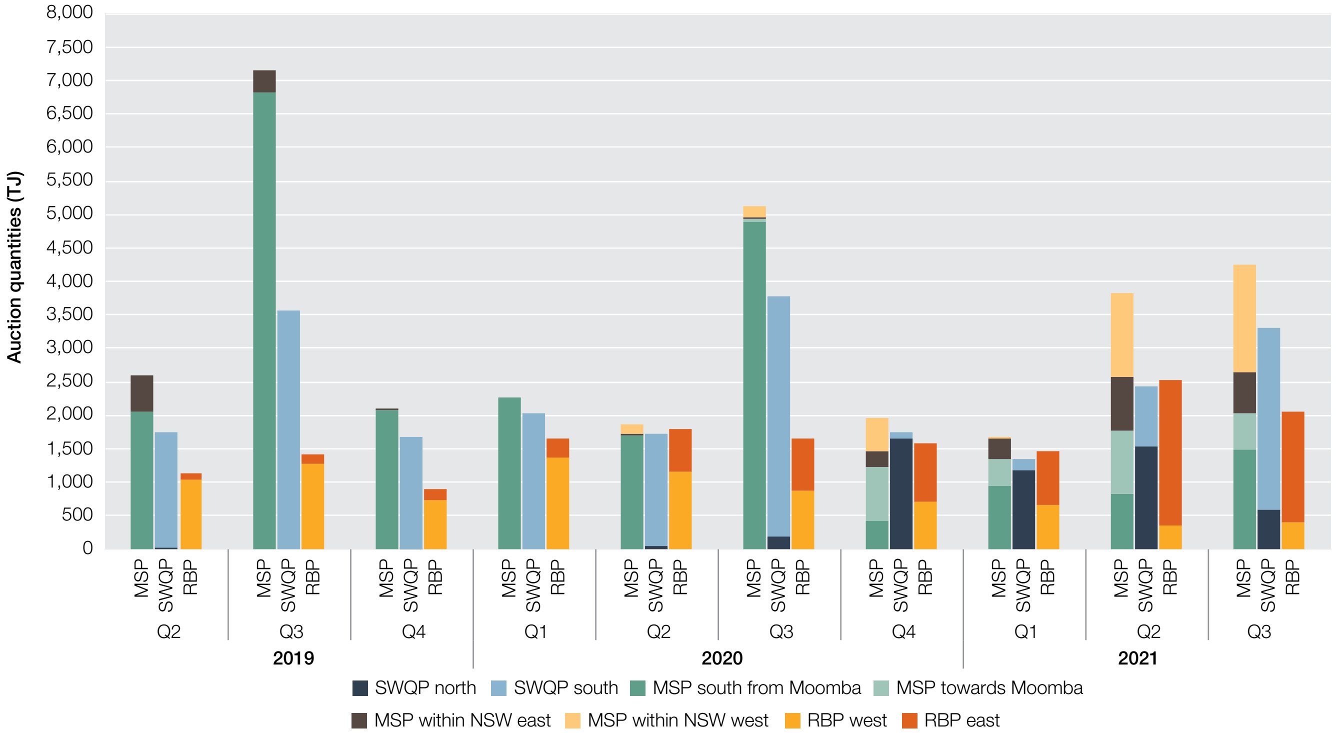


Source: AER analysis using DAA auction results data.

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.

DAA use varied during the quarter, facilitating gas moving either north or south as volatile prices changed opportunities to arbitrage across markets (Figure 2.12). Early in the quarter, gas moved from Queensland toward southern markets on the SWQP and MSP during a period of colder than average temperatures, when gas demand was high for heating. Conversely, in September auction capacity on these pipelines was used to transport gas north from southern markets, coinciding with higher international prices and rising LNG exports.

Figure 2.12 Day Ahead Auction quantities won on the MSP, SWQP and RBP, by route



Source: AER analysis using DAA auction results data.

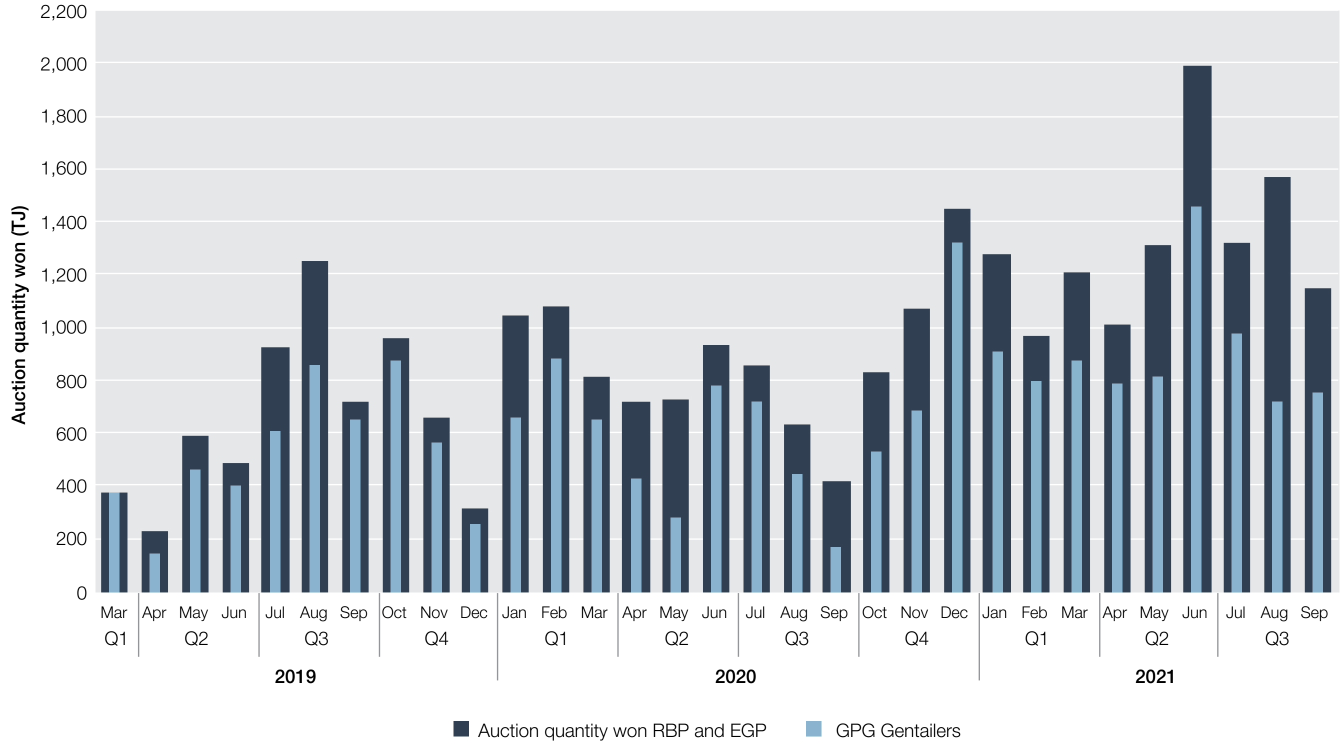
Note: Quantities shown are the sum of auction products allocated and grouped for different auction routes based on the direction of that auction route and does not necessarily represent the physical volumes of gas that actually flowed for each gas day.

Overall, the DAA continued to facilitate the relatively cheap transportation of gas at an average cost of between $0/GJ to $0.25/GJ, compared to the short-term cost of transport which can exceed $1/GJ per pipeline across the east coast.[36]

Auctioned pipeline capacity was also used to supply GPG, which experienced individual days of high use during July, particularly on the Roma to Brisbane pipeline (RBP) and Eastern Gas pipeline (EGP). In July, a greater volume of auctioned pipeline capacity was used to supply generators, compared to other months in Q3 2021 (Figure 2.13). High prices paid for auctioned pipeline capacity were recorded on the EGP ($1.7/GJ) and RBP ($1.2/GJ). This demonstrates a willingness by GPG participants to pay more for gas to enable extra output at their generators during times of high NEM prices.

36 ACCC, *Gas inquiry 2017–25 interim report*, July 2021, p. 79.

Figure 2.13 Auctioned pipeline capacity supplying electricity generators



Source: AER analysis using DAA auction results data.

The supply of auctioned pipeline capacity was constrained most during July, when gas demand reached elevated levels. Importantly, constraints did not significantly hinder the volume of auctioned pipeline capacity that facilitated the flow of gas from Queensland to southern markets during July. The SWQP, which is the main transport bottleneck for importing or exporting gas from Queensland, has become less constrained since 2019, coinciding with higher gas production in southern states. This allows for greater access to cheap gas transportation, facilitating more liquid trade across the east coast.

Figure 2.14 Frequency of Day Ahead Auction constraints quarter on quarter comparison

Pipeline	Direction	Q3 2019			Q3 2020			Q3 2021		
		Jul	Aug	Sep	Jul	Aug	Sep	Jul	Aug	Sep
BWP					63%	19%		63%		
EGP		10%	26%	17%					13%	67%
MSP	South from Moomba				7%					
	Towards Moomba		52%		67%	94%		77%	10%	
	Within NSW East								3%	3%
	Within NSW West		10%							3%
QGP					3%				3%	3%
RBP	East							13%	100%	7%
	West				13%	36%	7%	7%	10%	
SWQP	North SWQP	83%	81%	83%	70%	65%	17%	67%	13%	
	South SWQP							7%	10%	37%

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

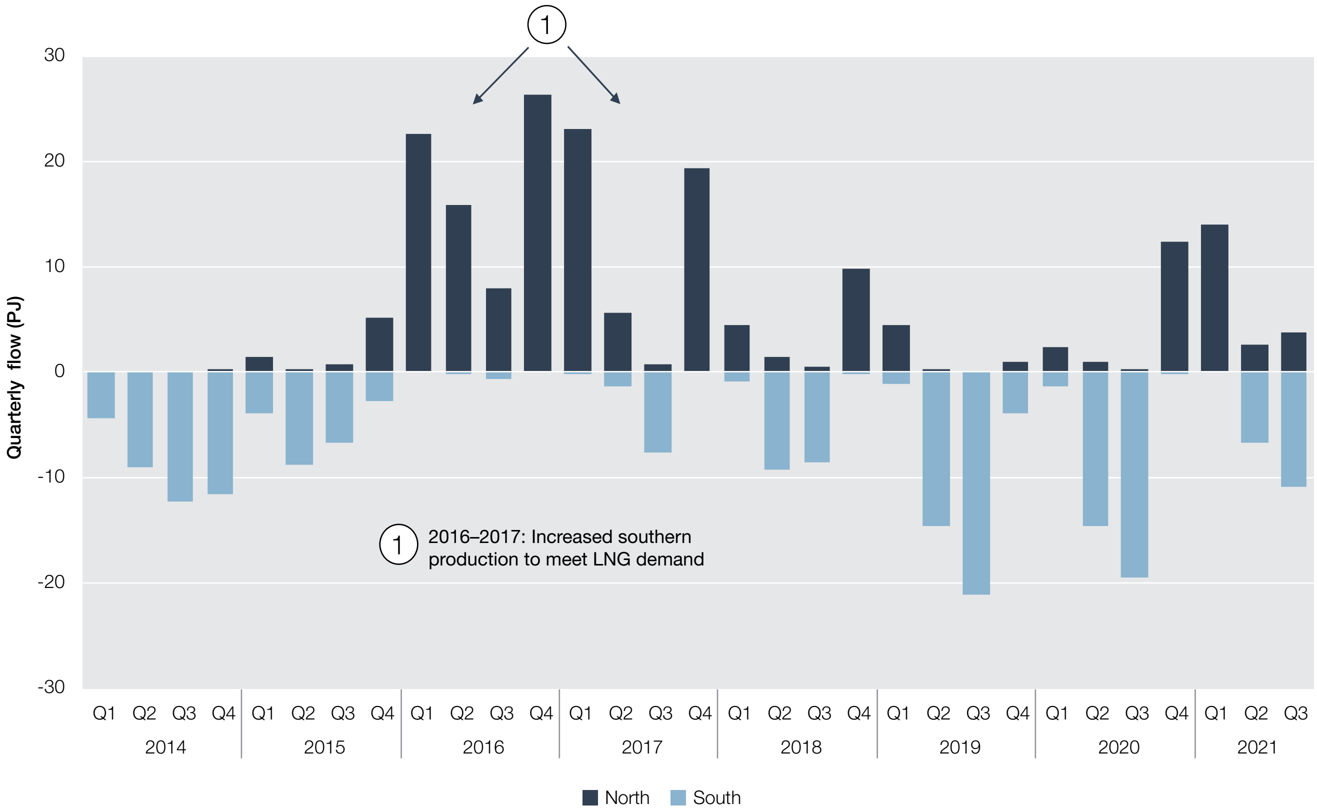
Source: AER analysis using DAA auction results data.

Notes: 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 south and north over the quarter

In Q3 2021, 10.99 PJ of gas flowed from northern markets toward southern markets, a reduction from greater flows south in Q3 2020 and Q3 2019 (Figure 2.15). At various times throughout the quarter, gas flow changed directions toward its greatest value use with some flows north.

Figure 2.15 North-South gas flows

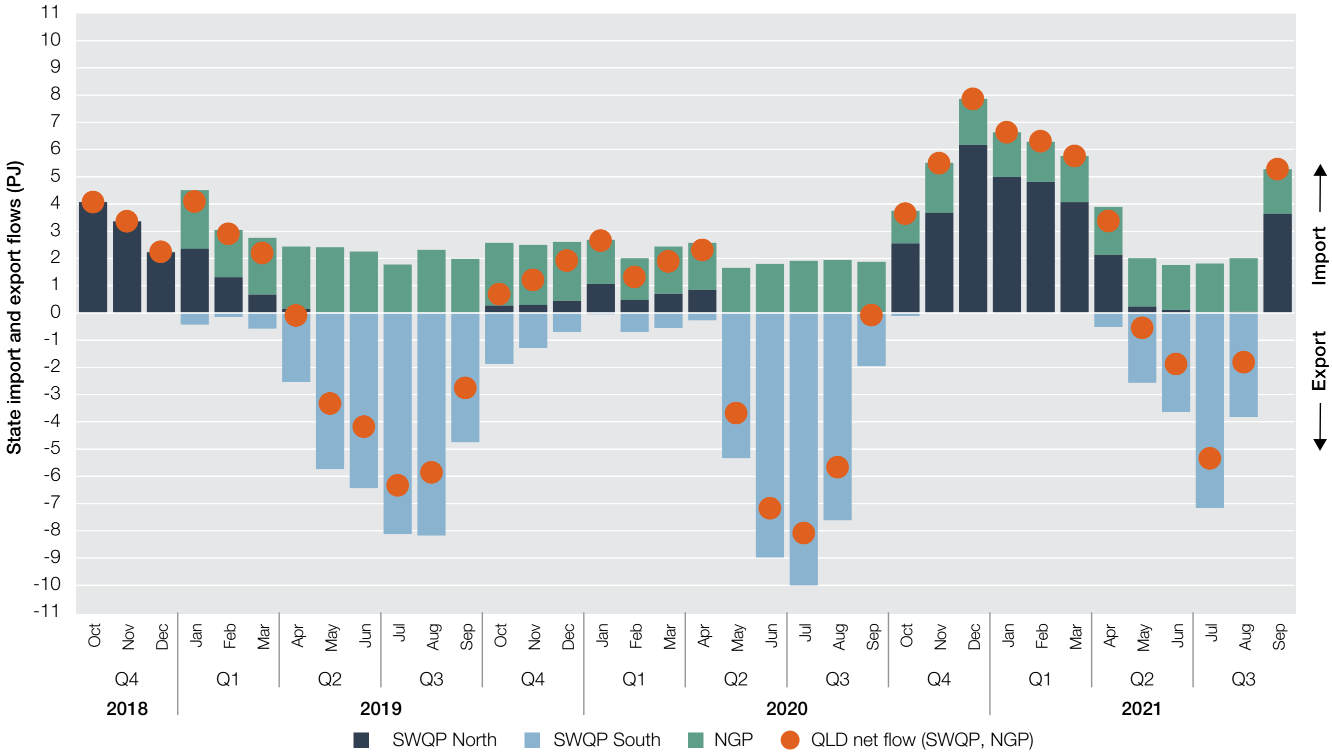


Source: AER analysis using the Natural Gas Services Bulletin Board.

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

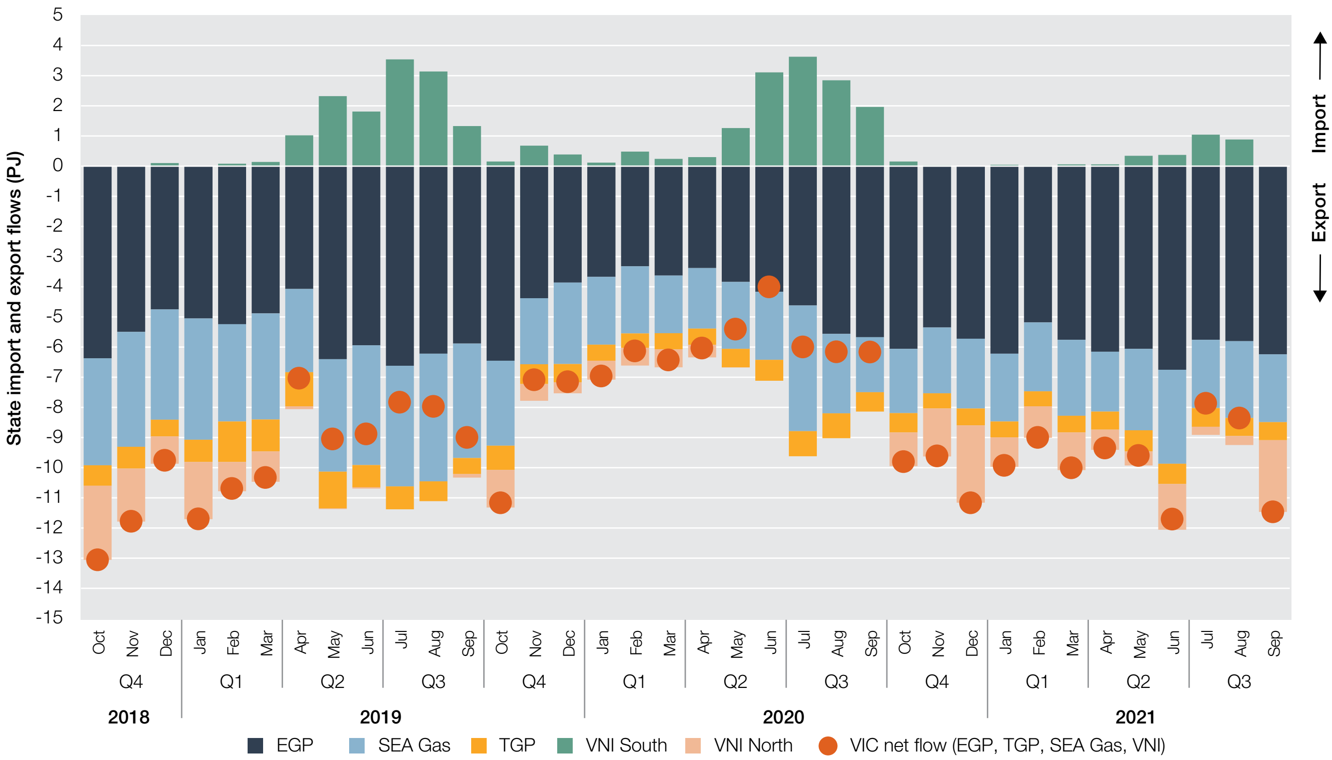
In July, colder than average temperatures drove higher use of gas in southern markets necessitating increased flows of gas from Queensland toward southern markets. GPG demand was also elevated at this time due to a number of coal-fired generator and electricity network outages. In September, Queensland became a net importer of gas (5.3 PJ) from other states and territories, coinciding with rising international prices and high LNG export demand, as Victoria exported large volumes of gas (Figure 2.16 and Figure 2.17).

Figure 2.16 Queensland import and export gas flows



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

Figure 2.17 Victoria import and export gas flows

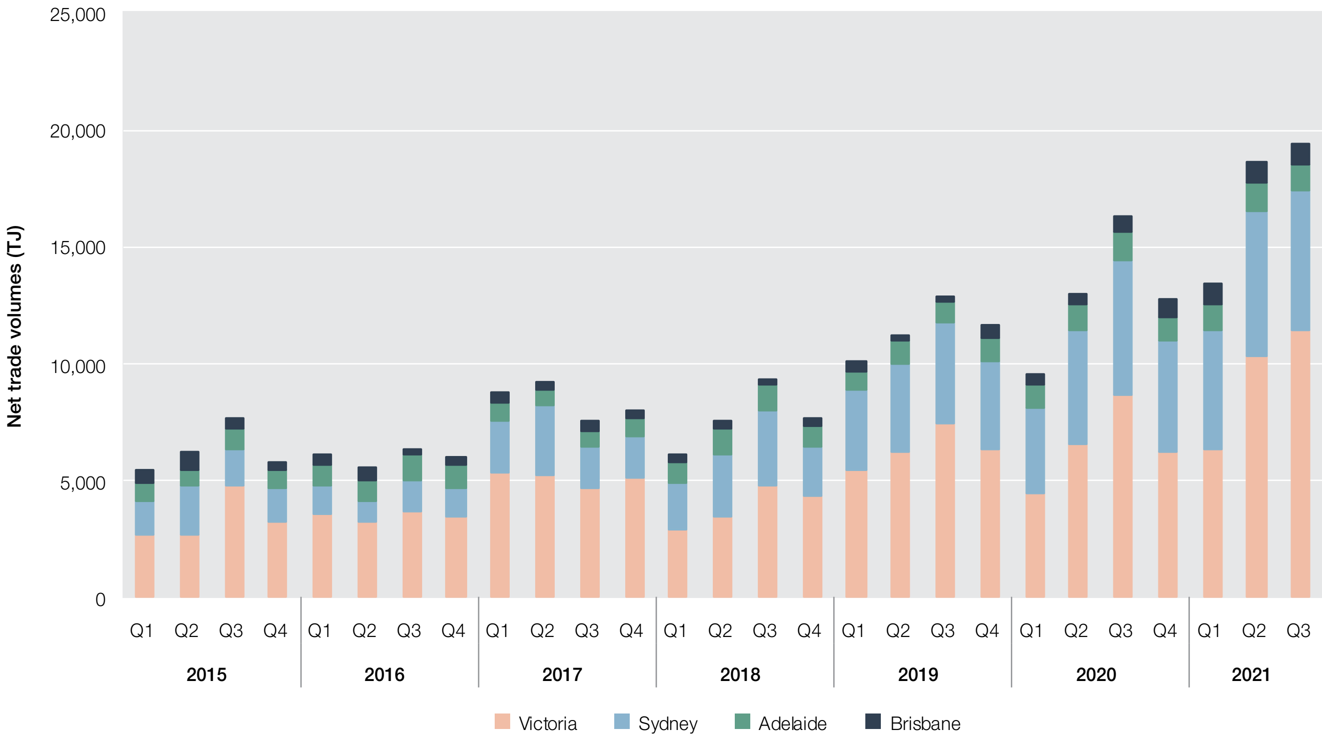


Source: AER analysis using the Natural Gas Services Bulletin Board.

2.7 Spot market trade maintains near 24% of demand in Sydney

Spot market trade increased slightly to 19.4 PJ in Q3 2021, up from 18.7 PJ in Q2 2021. This was driven by larger trading volumes in Victoria, offsetting a reduction in trading volumes in all other markets (Figure 2.18).

Figure 2.18 Spot trade liquidity



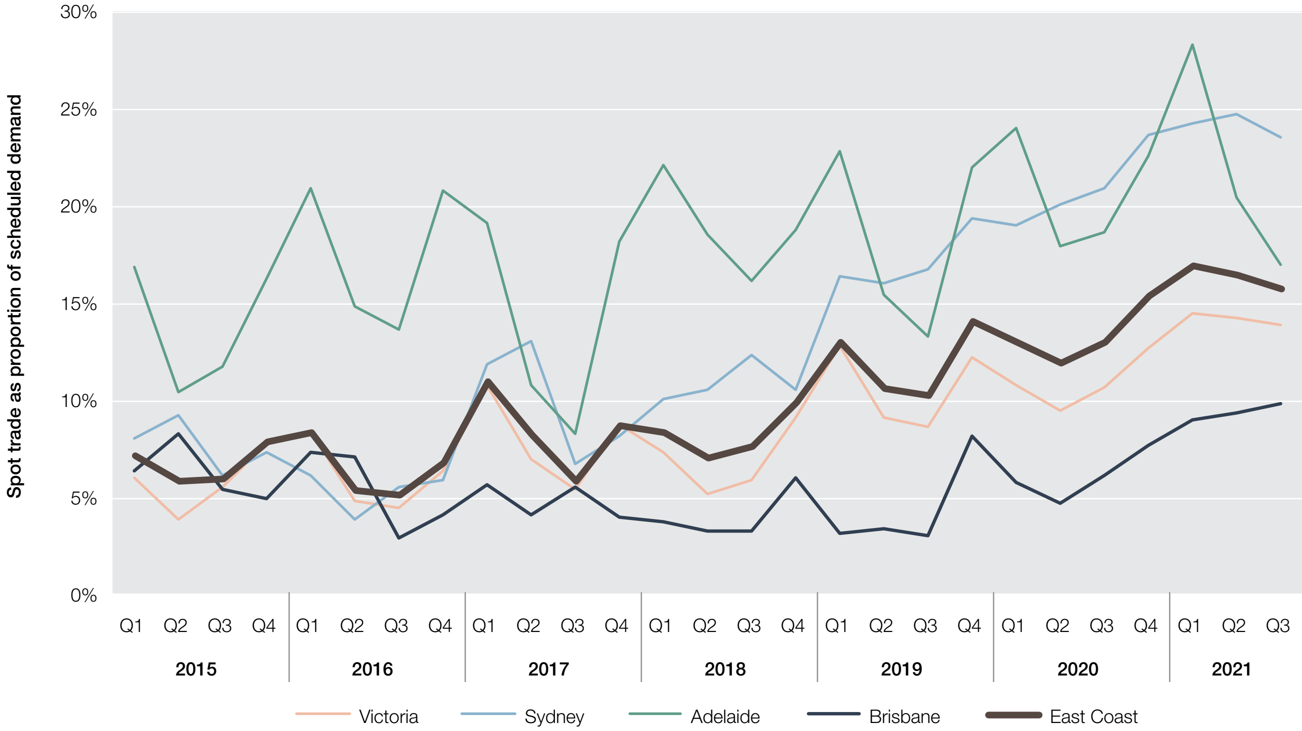
Source: AER analysis using DWGM and STTM data.

As prices have risen during Q3 2021, exporter and producer participants have increased their selling activity in the spot markets, while industrial customers reduced their purchases, as discussed in our focus story. In recent quarters, industrial customers have benefitted from this, sourcing cheaper gas supply at low spot prices instead of through relatively higher contract price offers. Several buying models have emerged recently where aggregators negotiate collectively for industrial customers, linking offers to wholesale prices.

Conversely, GPG gentailers increased their purchases on the spot markets over Q3, particularly in August and September when prices reduced from their peak in July.

Spot trade as a proportion of demand declined slightly in Q3 from Q2 2021 (Figure 2.19). This was particularly the case in the Adelaide and Victorian markets. Spot trade in Sydney continues to be highest across all markets at around 24% of demand over 2021.

Figure 2.19 Spot trade as a proportion of demand



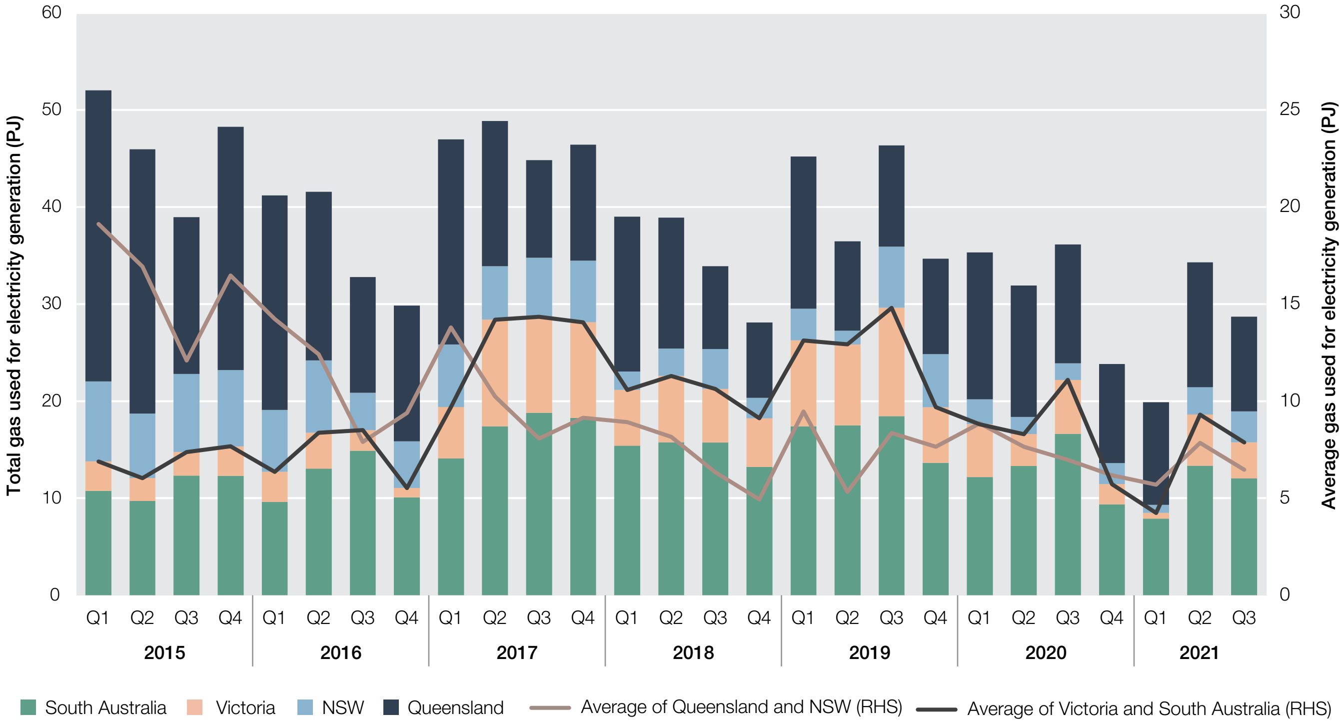
Source: AER analysis using DWGM and STTM data.

2.8 Gas needed to support the NEM in July

Gas used for electricity generation declined from 36.1 PJ in Q2 2021 to 28.7 PJ in Q3 2021 as average renewable generation increased by around 1,000 MW from Q3 2021 replacing thermal output (section 1.5) (Figure 2.20). Gas usage by electricity generators has been trending down since 2017, however GPG is required during times where other generators are constrained or on outage. At times in July, peak demand for GPG coincided with high price periods of over $20/GJ as discussed in our *Significant price variation report, July 2021*.[37]

37 AER, *Significant price variation report, July 2021*.

Figure 2.20 Gas used for electricity generation



Source: AER analysis using NEM data.

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

2.9 Gas futures trading recovers

The volume of gas trade in Victorian gas futures contracts rose substantially from 842 TJ in Q2 2021 to 2,839 TJ Q3 2021 (Table 2.3). Trade in the Victorian gas futures declined during the periods of persistently low east coast gas prices. This increase in trade reflects the recovery in prices during Q3 2021.

Table 2.3 Victorian gas futures trade summary

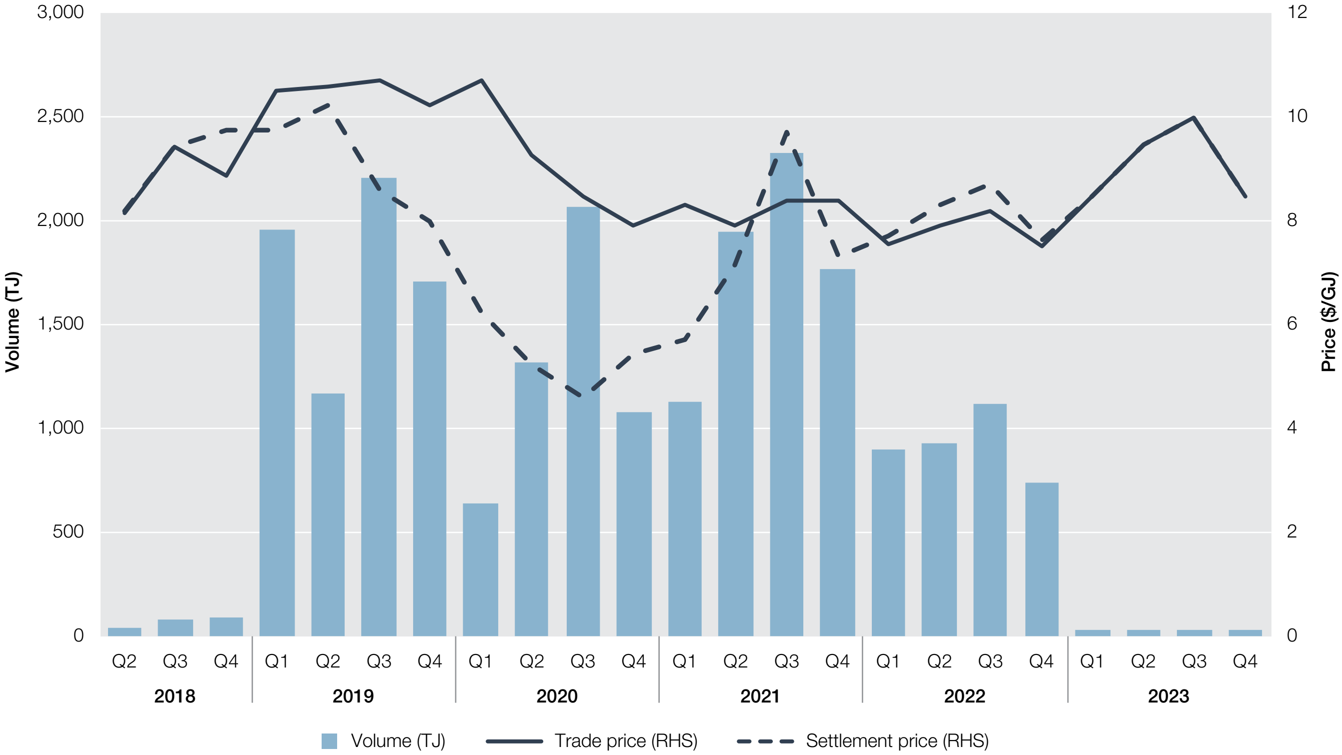
TRADE DATE	QUANTITY (TJ)	NUMBER OF CONTRACTS
Q2 2013	92	10
Q3 2016	92	10
Q4 2016	46	5
Q2 2018	777	85
Q3 2018	1303	143
Q4 2018	3294	361
Q1 2019	1661	182
Q2 2019	2528	276
Q3 2019	989	108
Q4 2019	2058	225
Q1 2020	2051	224
Q2 2020	2842	310
Q3 2020	743	81
Q4 2020	741	81
Q1 2021	668	73
Q2 2021	842	92
Q3 2021	2839	310

Source: ASX Energy.

Note: Trade date reflects of transaction not contract expiry date.

Settlement prices indicate expected gas prices of approximately $7.3/GJ for the remainder of 2021 and within a range of $7.3/GJ to $8.7/GJ over 2022 (Figure 2.21). Futures contracts for 2023 delivery traded for the first time this quarter in small volumes, providing a price signal 2 years into the future. The volume of trade is relatively low compared to electricity financial contracts and represents around 5% of physical gas trade in the Victorian market. Nonetheless, this trend toward greater volumes of trade is a positive development for market liquidity, which has traditionally lacked a forward price signal.

Figure 2.21 ASX Victorian futures trade



Source: ASX Energy.

Note: Trading volumes are organised by contract expiry date.

Focus – Competition in the wholesale spot gas markets

We examined competition in spot markets in a focus story in our *Wholesale markets quarterly Q3 2020* report which focused on how the spot markets have evolved since 2016. In our *Wholesale markets quarterly Q4 2020* report we commented on how the bidding behaviour of exporters and producers in the Sydney Short Term Trading Market (STTM) has changed over time. In our *Wholesale markets quarterly Q2 2021* we noted how exporters and producers have continued to increase their participation in the spot markets, driving higher spot trades across the east coast. This focus story continues to expand our analysis of competition in the spot markets focussing on participation in the Victorian Declared Wholesale Gas Market (DWGM), the Sydney, Adelaide and Brisbane STTMs and the Gas Supply Hub (GSH), as well as assessing how competition has evolved in the DAA since the introduction of capacity trading reforms in March 2019. Our analysis indicates progress towards the COAG Energy Council's Australian Gas Market 2014 Vision:

> 'The establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities.'

This focus story details our key findings for 2021:

Increased trade in downstream markets:

- There is increased diversity of participation across different groups of participants.[38]
- Exporters and producers, and traders have increased gas trade, with exporters and producers selling larger quantities of gas on spot markets.
- Industrials, retailers and GPG gentailers are strong buyers off the spot markets.
- The volume of gas traded is increasing, most notably in Victoria and Sydney.
- Competition to set marginal prices, particularly in Victoria and Sydney, has increased.

Trade through the GSH remains moderate although somewhat higher recently:

- Trade through the GSH has recently returned to levels seen in 2019 after a low in 2020, with exporters and producers both buying and selling through the GSH in Q3 2021.
- Trades extending out to longer trading windows of up to 10 months in the GSH this year.

The DAA continues to increase in popularity as competition for auction capacity grows:

- Participation in the DAA has continued to increase peaking at 18 participants bidding in the auction over 13 auction facilities on 49 different auction routes in 2021.
- Stronger competition for auction capacity, especially during high demand periods and on popular auction routes, have seen participants bidding for capacity at higher prices.
- The DAA is facilitating arbitrage opportunities, and price differences across markets appear to be narrowing as more arbitrage occurs.

Competition in the downstream spot markets continues to rise

Trade in Victoria and the Sydney, Adelaide and Brisbane STTMs continues to increase each year. Record trade levels occurred across the 4 markets from May to September 2021, with 7.3 PJ of gas traded in the spot markets in September alone, setting a new monthly record high (Figure 2.22). Our analysis in this section discusses net buy and net sell positions in the various markets (Box 2.1).

Box 2.1 Evaluating trade in the DWGM and Sydney, Adelaide, Brisbane STTMs

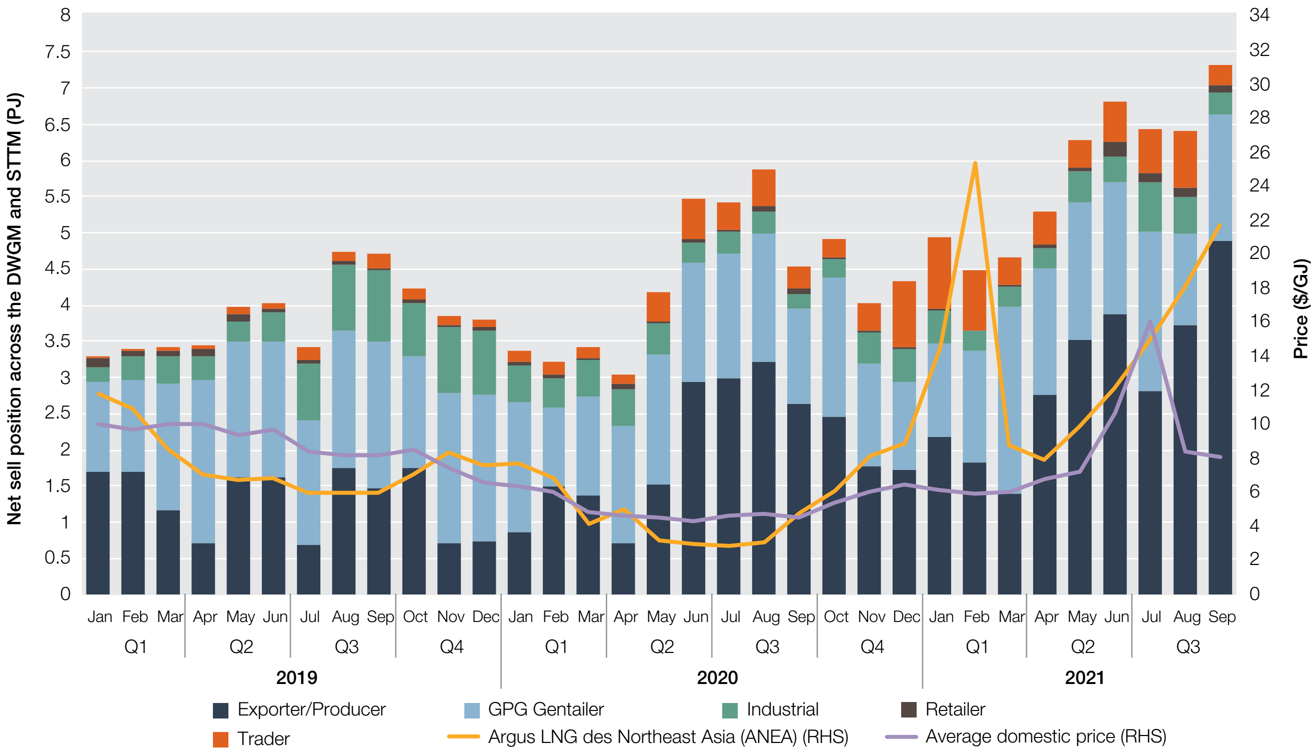
Our calculations find the daily net trade position in each market for a participant, and sum these across the quarter. Participants who are net sellers in a market one day and net buyers the next will show as having both a net buy and net sell position in the period assessed. Where participants have a more dominant net sell or buy position, this reflects the predominance of this as their daily position across the period.

For example, on a day where a participant buys 10 TJ from the Victorian market and sells 10 TJ into the Sydney STTM, its position will show as net sell for Sydney and net buy for Victoria. This example is typical of a Trader who arbitrages prices between markets. Traders appear as both net sellers and net buyers depending on the market or month. Exporters and producers typically sell gas, and so appear as strong net sellers but occasionally withdraw gas from markets (potentially for export) and show up as net buyers. Oppositely, industrials and retailers (which includes Weston Energy and Eastern Energy) typically appear as strong net buyers, but also sometimes sell gas.

GPG gentailers (which include AGL, Origin and EnergyAustralia) net trade positions often reflect surplus or deficits between their sales into markets and own customer demand. Although overall they sell more gas into markets at a gross level, on a net basis they can often offer less traded gas (surplus/deficits to own use) than exporters and producers.

38 We have classified participants into 5 groupings for our analysis – GPG gentailer, retailer, industrial, trader or exporter and producer (Appendix B).

Figure 2.22 Net sell position in the downstream spot markets



Source: AER analysis using DWGM, STTM and Argus Media data.

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

The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4–12 weeks before the date of delivery.[39]

The average domestic price was calculated as a simple average between the Victoria daily imbalance price at 6:00am and the Sydney, Adelaide and Brisbane ex ante prices.

The continued rise of trade in the domestic spot markets is in large part due to exporters and producers continuing to sell more gas in these markets. Until September this year, exporter and producer net sell positions into the downstream markets totalled 27 PJ, compared to 23.7 PJ and 15.6 PJ for the whole of 2020 and 2019 respectively. This upward trend in domestic trade by exporters and producers over 2021 continued despite rising international gas prices. Notably, producers sold gas domestically at prices below the international spot Asian LNG netback prices in Q3 2021 (section 2.1).

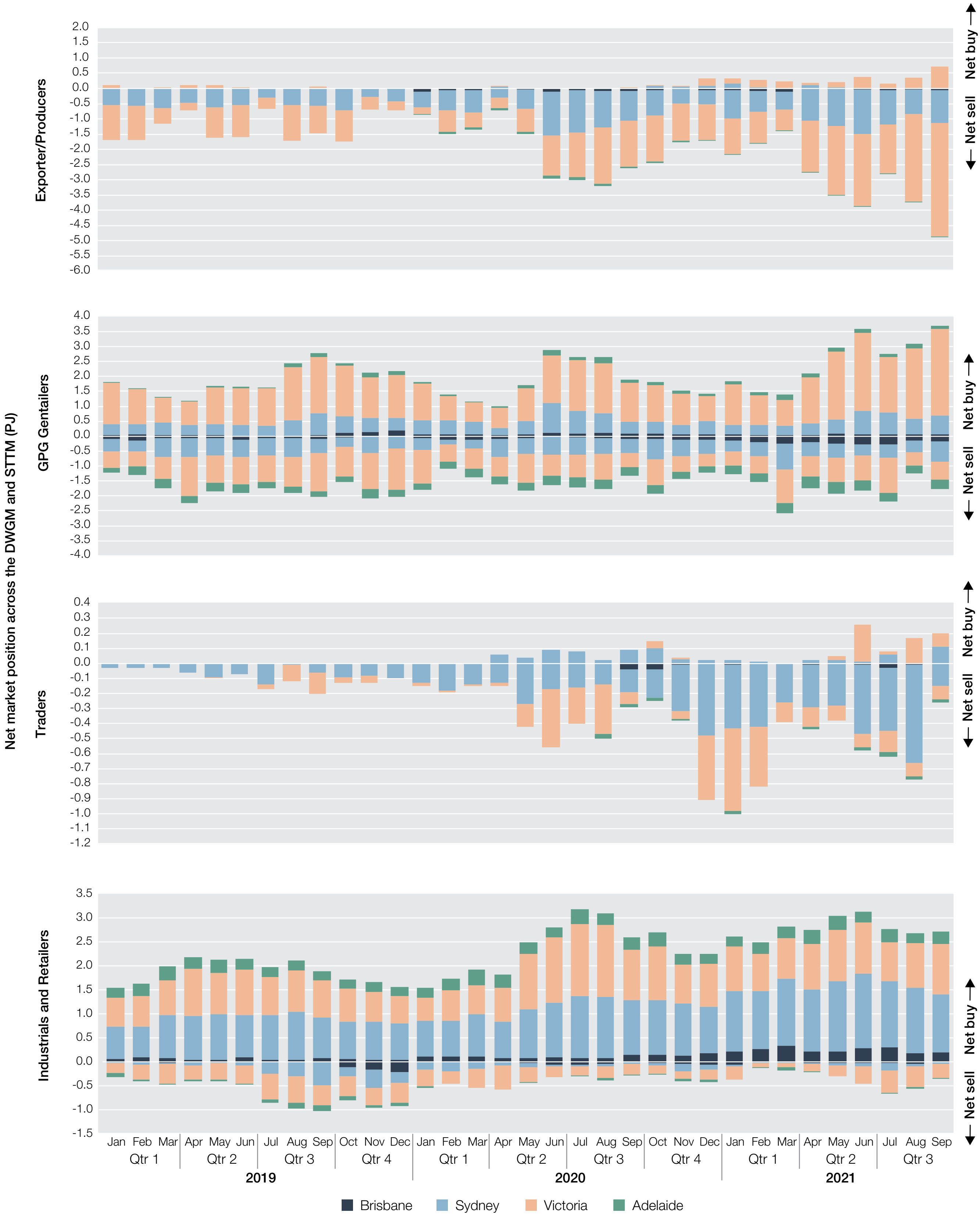
Trader participation in the spot markets, although small compared to exporters and producers and GPG gentailers, is also increasing as these participants continue to grow their presence in the market. In 2019, traders only made up 2.4% of the overall net sell position in the spot markets. By comparison, in 2021 this has grown to 10.5% on average, supporting competition in the spot markets.

Victoria and Sydney are the most traded spot markets

Across all participant groups, trade in the downstream markets has increased since 2019 with Victoria and Sydney standing out as the most traded markets on the east coast (Figure 2.23).

39 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.

Figure 2.23 Net buy and sell positions by participant type in the downstream spot markets



Source: AER analysis using DWGM and STTM data.

Note: Trade in the Victorian DWGM and Sydney, Adelaide and Brisbane STTMs were estimated netting scheduled sell quantities for each trading participant.

Exporters and producers have been increasing their net sell positions year on year in Victoria and Sydney where they are most actively trading. They were particularly active in Victoria since April 2021, ultimately reaching a record net sell position of 3.7 PJ in September 2021. Most of this was traded by BHP Billiton and Esso on the back of robust production levels at Longford (section 2.2). Compared to 2019 and 2020, where most gas sold into the Victorian market by exporters and producers was by Santos and BHP Billiton. Since December last year, Santos has switched from being a net seller to a net buyer of gas from Victoria, while over the same period Santos was mostly a net seller of gas in the Sydney STTM. BHP Billiton and Esso have also continued to increase their net sell positions in the Sydney market since 2019.

GPG gentailers have increased their net buy positions in Victoria from 4.7 PJ in Q3 2020 to 7.1 PJ PJ in Q3 2021, while there has almost no change in their net buying positions in the other markets.

Within the trader participant group only Macquarie Bank and Strategic Gas Market Trading (SGMT) were actively participating in Victoria and Sydney at the beginning of 2019. This contrasts with Q3 2021 where Eastern Energy and PetroChina are now also participating in the market and traders are actively trading across all 4 downstream spot markets more broadly. Notably, traders have been the most active in the Sydney STTM, setting a record net sell position of 646 TJ in August 2021. This is consistent with some trader participants arbitraging prices between the lower priced Victorian market, where they were net buyers ($7.50/GJ in August), and a higher priced Sydney market ($8.67/GJ in August). The AER will report more on arbitrage between markets in future *Wholesale markets quarterly* reports.

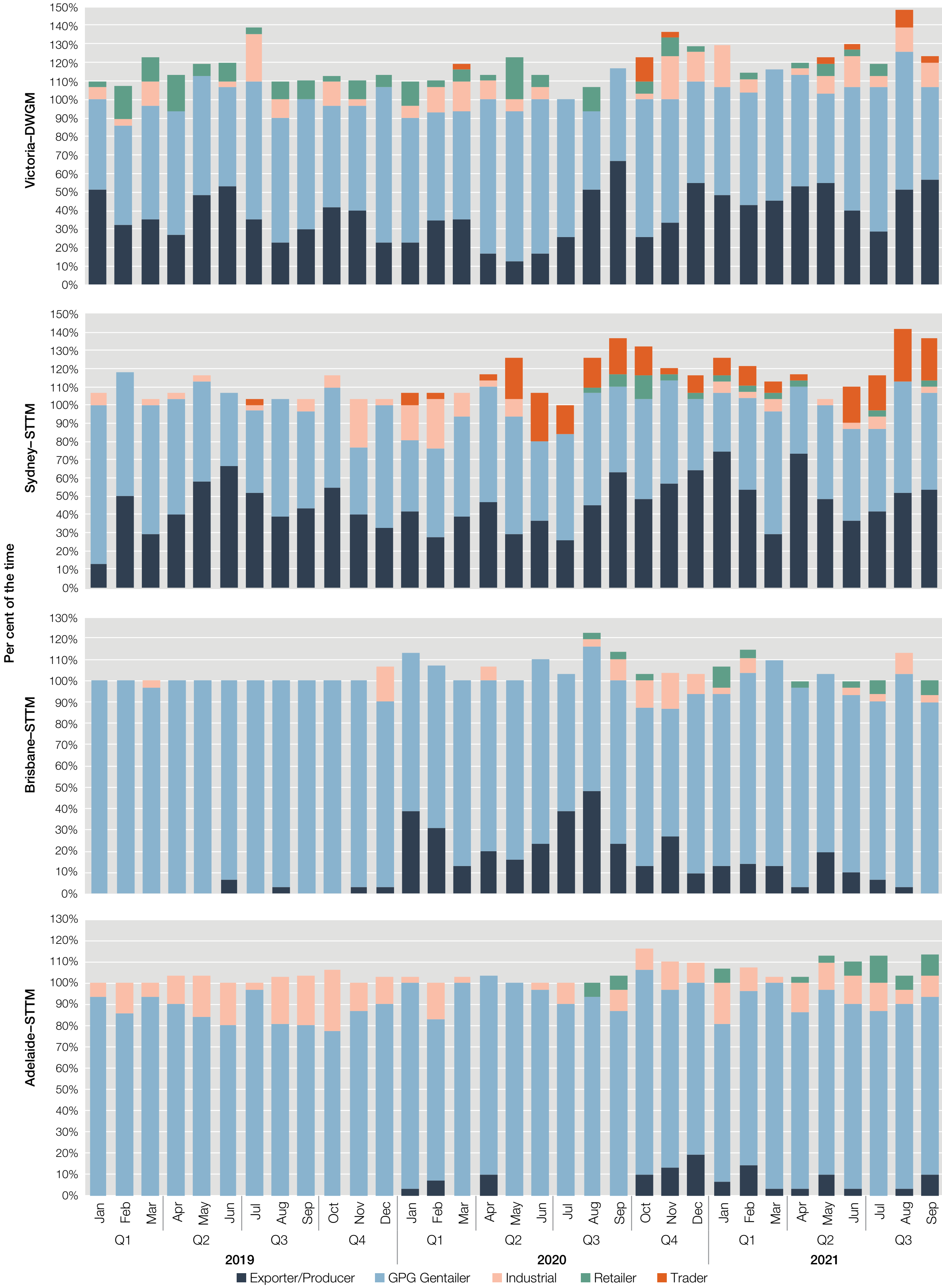
Industrials and retailers are also net buying more gas in the spot markets, especially the Sydney STTM. As a result of domestic prices increasing from record lows in 2020, these participants are now more exposed to rising wholesale domestic prices. However, similar to GPG gentailers, the high price period in July 2021 has not led to a large change to this group's buying levels.

Increasingly exporters and producers and traders are setting prices

As noted in our previous focus on competition in the spot markets, prices are set more frequently by exporters and producers, and traders in Victoria and Sydney, whereas GPG gentailers are more active in price setting in Adelaide and Brisbane (Figure 2.24).[40]

40 AER, *Wholesale markets quarterly Q3 2020*, November 2020.

Figure 2.24 Price setter by participant type



Source: AER analysis using DWGM and STTM data.

Notes: The DWGM price setter was calculated for the 6 am market schedule. The STTM price setter was calculated for the D-1 schedule. The price can be set by more than one participant grouping on a given gas day.

Often more than one participant can set the price in a market at the same time through equally priced offers or bids, as shown by totals above 100% in the above figure. This was particularly pronounced in Victoria and Sydney in in August 2021, with BHP Billiton and Visy in Victoria, and Santos and Eastern Energy in Sydney frequently having the same price setting bids as other participants. This highlights increased competition with several participants having price offers close to (or at) the market clearing price. In 2021, exporters and producers set the price almost 40% of the time on average in Victoria and Sydney.

In the Brisbane and Adelaide STTMs, GPG gentailers still dominate overall market trade, for both net sell or buy positions, and often they set the market clearing price. During 2021, GPG gentailers accounted for 70% and 86% of the net sell positions in Brisbane and Adelaide respectively. They also set the price most of the time in these markets.

Trade at the Wallumbilla Gas Supply Hub has returned to 2019 levels recently

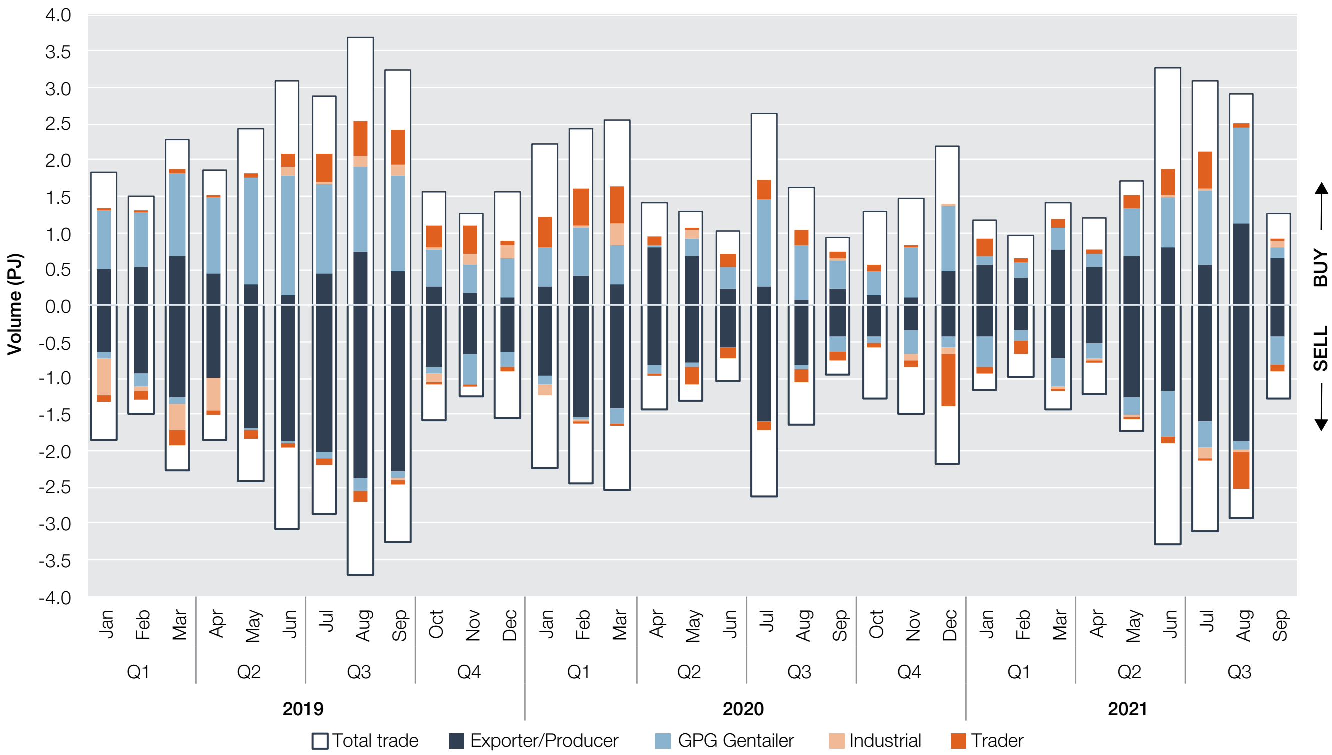
To assess participation in the GSH, we netted buy and sell quantities for each trading participant on a daily delivered basis for all product types and all trade locations (Box 2.2 – Figure 2.25).

Box 2.2 Net sell and net buy positions in the GSH

There are 5 standard product lengths that participants can use when trading at the GSH: balance of day, daily, day ahead, weekly and monthly. Trade is voluntary, and participants can trade gas on the day or for days in the future, combining buy and sell orders of various length. As the GSH spans multiple delivery and receipt points, it is also possible to buy gas at one location and sell at another. This is different to the downstream markets, which are mandatory, day ahead markets at one fixed location.

Our analysis calculates a net position for a participant as the net of all trades scheduled for delivery each gas day. For example, a participant could buy a monthly product of 20 TJ for delivery at Wallumbilla 6 months in advance, which includes the chosen gas day. On the gas day the participant also sells 10 TJ through a daily product at the SEQ trading location. Our analysis would indicate that on this gas day the participant was a net buyer of 10 TJ through the GSH.

Figure 2.25 Net trade by participant type based on delivered dates



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

Note: Net trade in the GSH was calculated netting buy and sell quantities for each trading participant on a daily delivered basis for all product types and all trade locations.

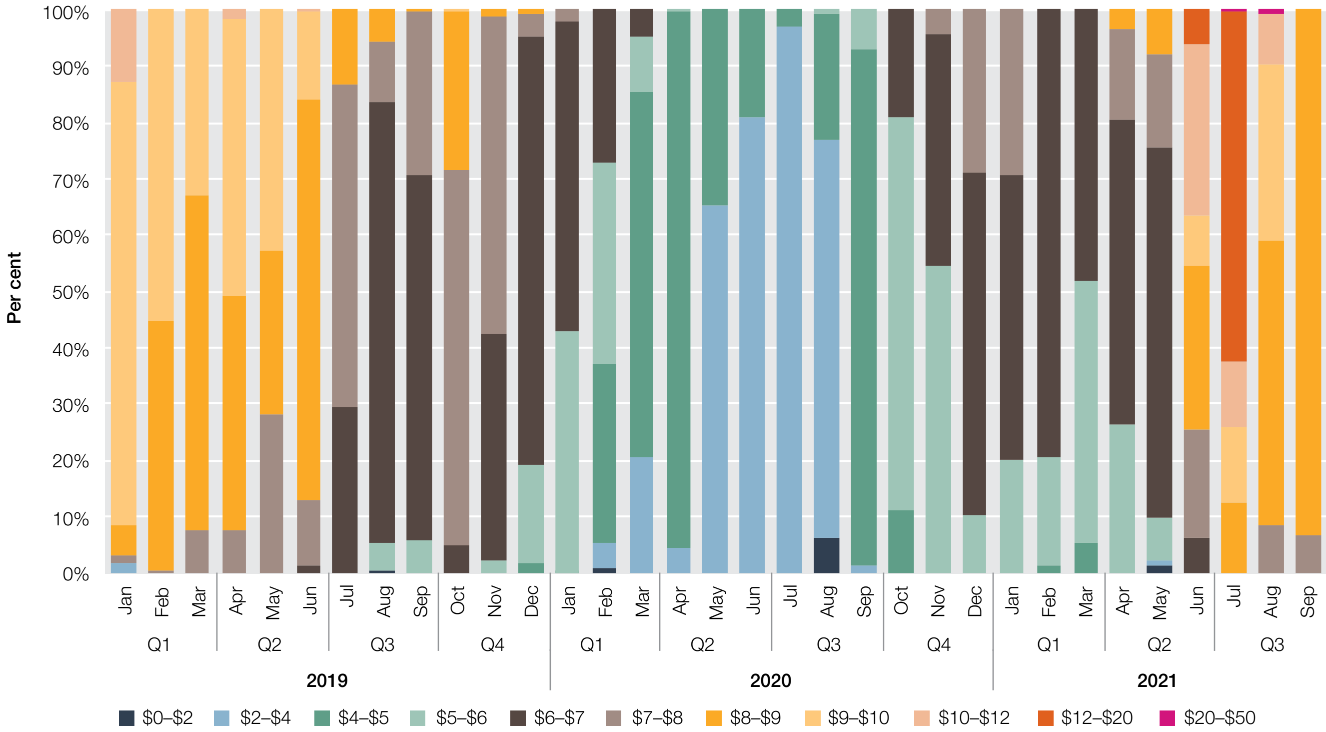
The total trade in the GSH was calculated on a delivered basis for all product types and all trade locations.

Net trade in the GSH has steadily increased from May this year, peaking in August at levels we have not seen since Q3 2019. This followed subdued trading at the GSH for most of 2020 as prices kept falling, decreasing the opportunity to arbitrage gas prices between northern and southern markets, causing participants to divert more gas into storage.[41] In 2021, net trade as a proportion of total trade varied between a low of 58% in June to a high of 88% in May. This reflects that in June 2021 there was more trading and re-trading by participants for the same gas deliveries.[42]

There were 7 exporter and producer participants actively trading at the GSH over the period. More than 60% of net sales on the GSH by exporters and producers in 2021 could be attributed to two participants with LNG export interests. Traders and GPG gentailers have fluctuated between being net buyers and net sellers on the GSH but on balance are buying more often.

Similar to what has been observed in the downstream spot markets, GSH prices decreased across 2020 and have risen more recently (Figure 2.26).

Figure 2.26 GSH price bands



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

In line with falling domestic and international prices in 2020, most GSH trades were priced between $2 and $4/GJ, peaking in July 2020 when 97% of the trade through the GSH fell within this range. As gas prices started to increase in September 2020 so did the traded price bands, with most trade shifting above $5/GJ. In July 2021 when domestic gas prices peaked, 62% of the trades through the were priced between $12 and $20/GJ.

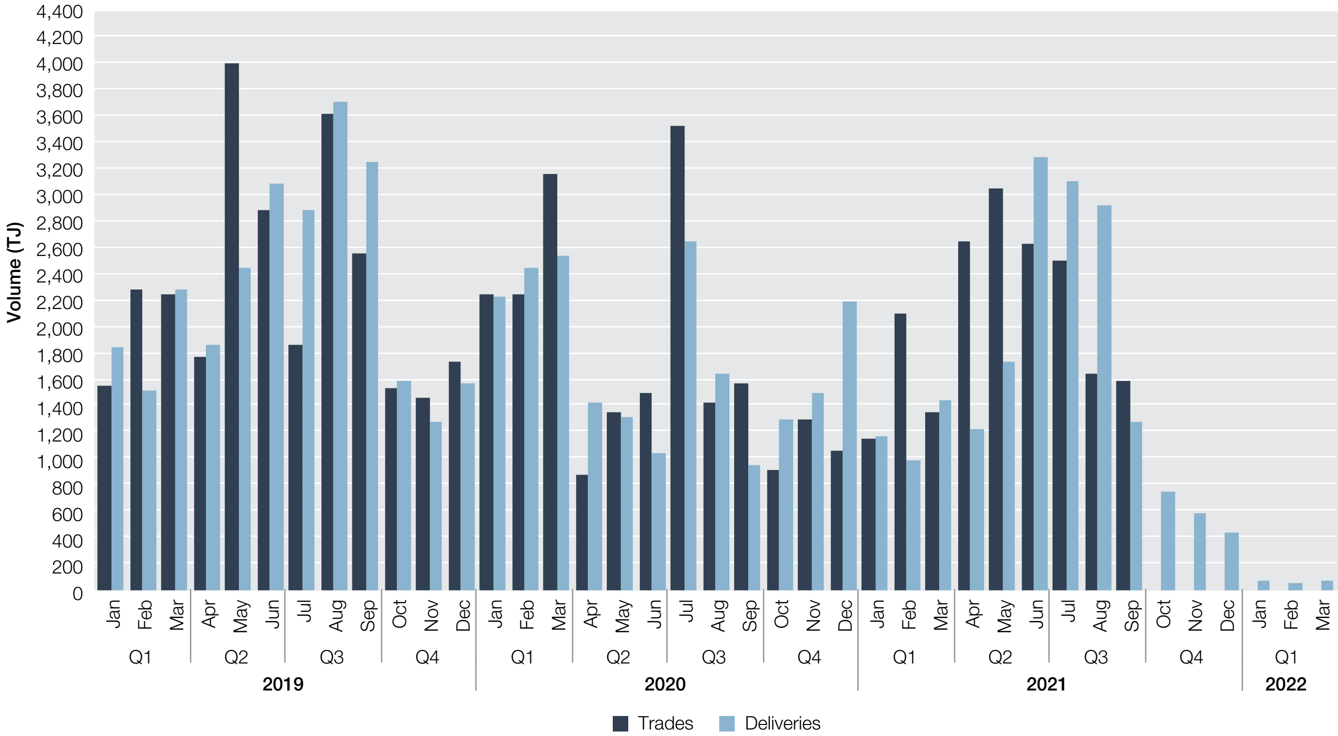
Participants are buying increasingly future dated products

In April and May this year, participants at the GSH started to purchase more gas for deliveries over June to August, when gas demand was expected to peak in the east coast (Figure 2.27). By getting in early, these trades were executed at lower prices than if they were made on the day. Most trades on the GSH in April and May were priced below $7/GJ, compared to June onwards when prices shifted above $8/GJ.

41 AER, *Wholesale markets quarterly Q2 2020,* August 2020.

42 An example of how a participant's trading positions will be netted for a given gas day in June. In this example the participant has bought 10 TJ as a monthly product in March for delivery at the WAL trading location, 10 TJ of a weekly product and 10 TJ bought as a daily product for delivery at the SEQ trading location. On the sell side the participant is selling a weekly product of 5 TJ at the WAL trading location and a balance-of-day product of 10 TJ at the SEQ trading location. Overall the participant is buying 30 TJ and selling 15 TJ for a net buy position of 15 TJ on the day through the GSH.

Figure 2.27 GSH trades versus deliveries



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

Note: Traded refers to the day that the gas trade was made, while delivered refers to the day the gas will be delivered as per the trade product and conditions.

Where broker participants acted as an intermediate between two trading participants, we have not included those trades but merely reflected the net trade between the end buyer and seller.

On 22 September 2020, AEMO extended the trading window for non-netted monthly products to 12 months. Although monthly products are traded mostly 1 to 3 months ahead of the delivery date, we have observed some trades extending out to longer trading windows of up to 10 months.

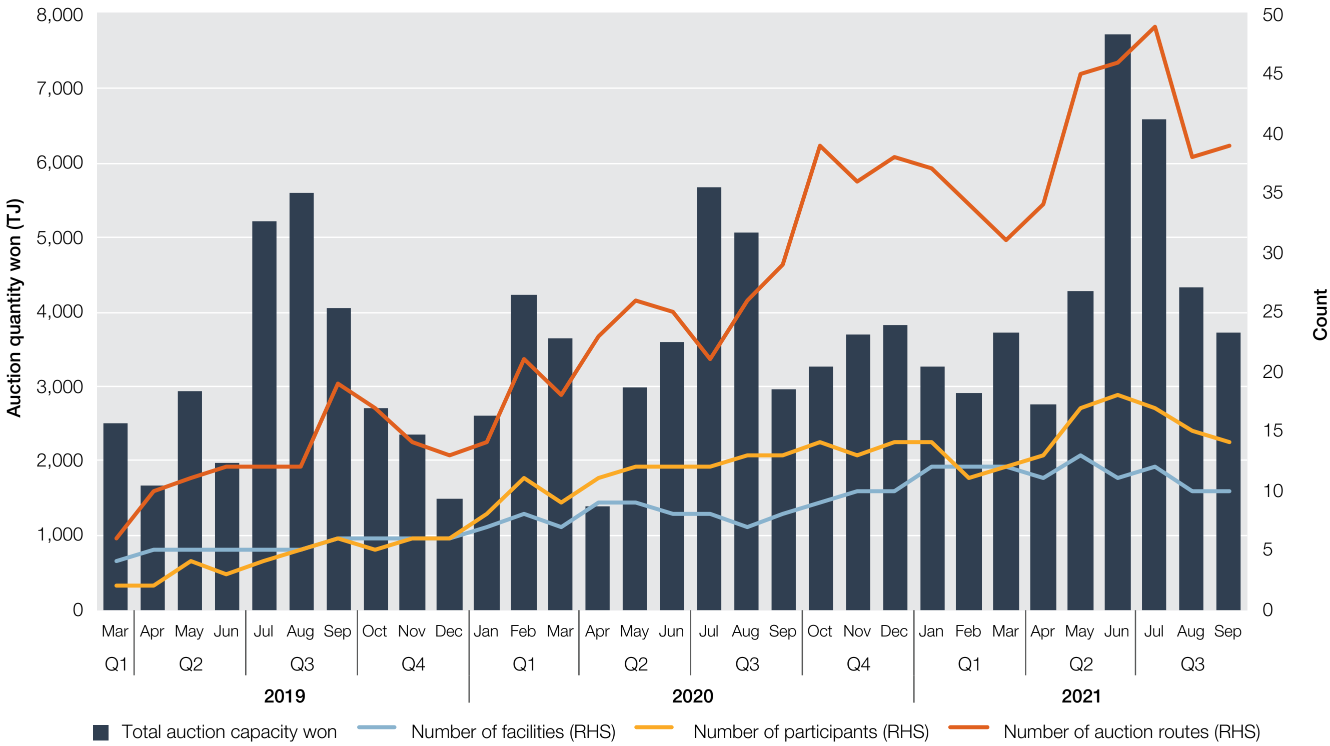
Competition for DAA capacity continues to increase

In our *Pipeline Capacity Trading 2 Year Review*, which covered the period from March 2019 to December 2020, we discussed the functioning and success of the capacity trading reforms, focussing on the DAA (Box 2.3).[43] Over the course of 2021, we have continued to see participation in the DAA increase with 112.8 PJ of auction capacity won since the market started, of which 90.5 PJ cleared at the reserve price of $0/GJ (Figure 2.28).[44]

43 AER, Pipeline Capacity Trading 2 Year Review.

44 Median for 2019: number of participants – 5; number of auction facilities – 5; number of auction routes traded on – 12
Median for 2020: number of participants – 12; number of auction facilities – 8; number of auction routes traded on – 24
Median for 2021: number of participants – 14; number of auction facilities – 12; number of auction routes traded on – 38.

Figure 2.28 DAA auction capacity won and participation



Source: AER analysis using DAA auction results data.

Note: Total auction quantity won is 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 number of auction facilities, participants and auction routes is based on bidding data into the DAA.

As competition in the DAA has increased over time, participants are bidding in the auction at higher prices to secure auction capacity, especially on the most popular auction routes (Figure 2.29). The higher prices are particularly evident during the winter months when demand for auction capacity is the highest, as participants seek capacity to transport gas to where the demand is highest, typically Victoria and Sydney. In recent quarters, we have observed the dynamic nature of the auction, especially on the MSP, SWQP and RBP where the auction direction changes to accommodate gas flows in both directions on these bi-directional pipelines (section 2.5). The DAA has also been used successfully by participants to transport gas particularly to the Sydney market from the north through the SWQP and MSP, or from the south using the EGP or the MSP, through Culcairn.

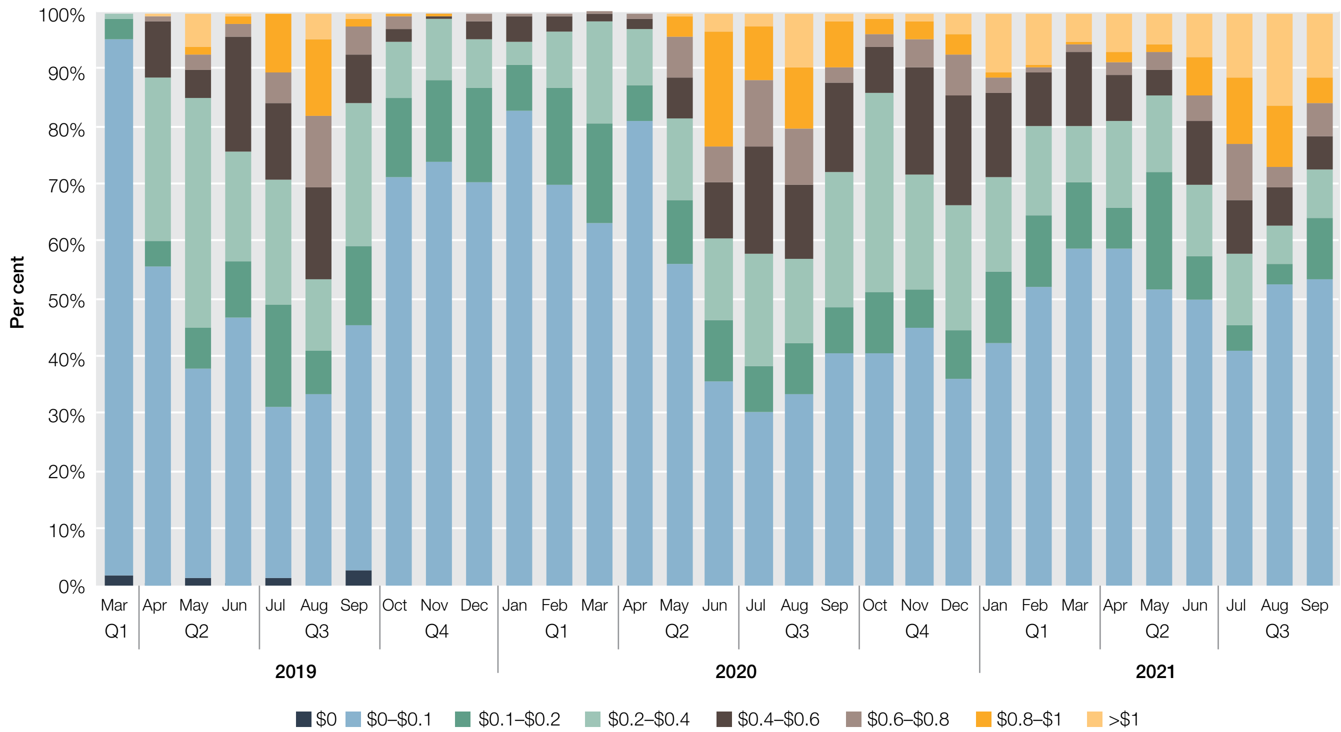
Box 2.3 How the DAA works

The Day Ahead Auction is a mandatory auction on non-exempt pipelines of any contracted, but unnominated pipeline capacity determined the day prior to the gas day.

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.

The lowest accepted bid price in the auction determines the clearing price on days when demand exceeds available capacity. When there is more capacity available than participant demand, the auction is cleared at the reserve price of $0/GJ. All proceeds go to the facility operator. While participants can win auction capacity for $0/GJ, additional charges and fees make the real cost slightly higher.

Figure 2.29 DAA bid stack price bands

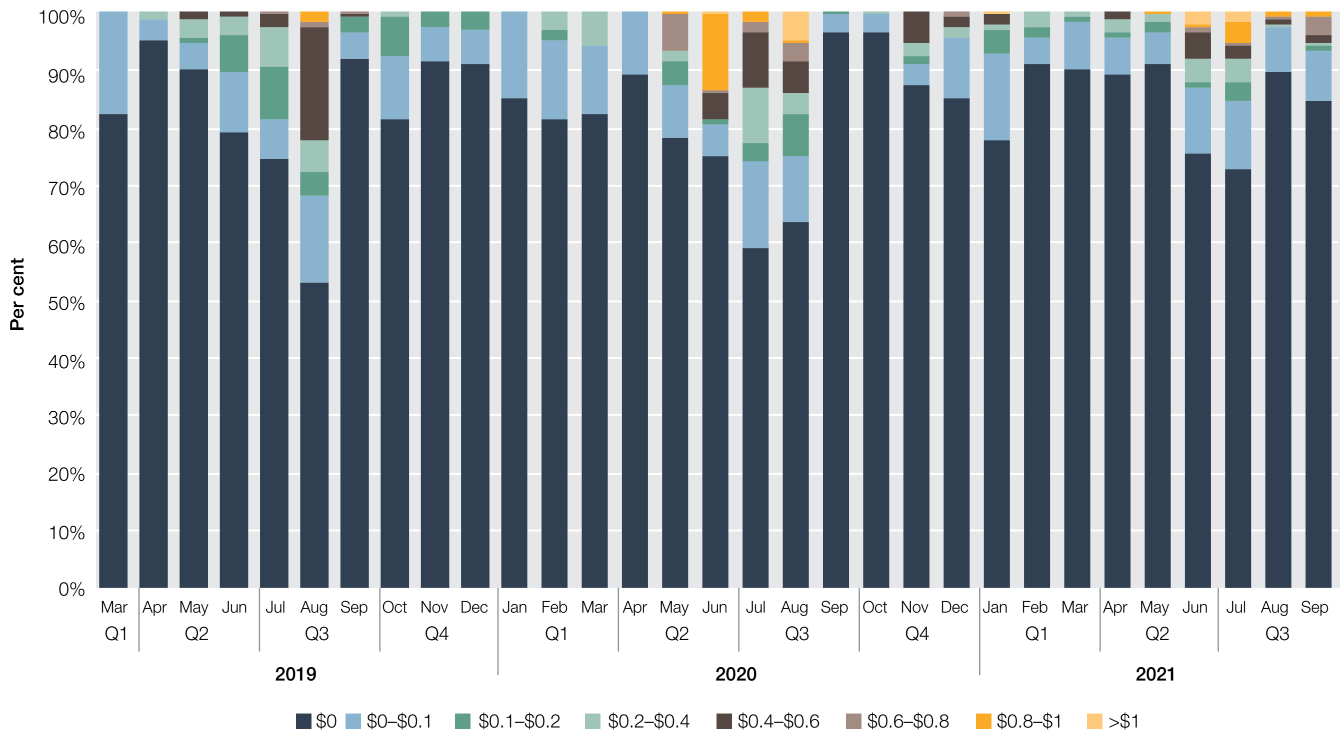


Source: AER analysis using DAA auction results data.

Note: The auction bid stack volumes are calculated across all facilities and includes paired bids that could include multiple auction facilities.

Even though participants are bidding in the market at higher prices, the DAA still clears on most of the auction routes at the reserve price of $0/GJ (Figure 2.30). This is because participant bids are only used to determine the merit order when auction demand exceeds available capacity. Where demand for auction capacity is high, particularly on the MSP, EGP, RBP and SWQP we have frequently observed auction clearing prices above $1/GJ.

Figure 2.30 DAA cleared auction results price bands



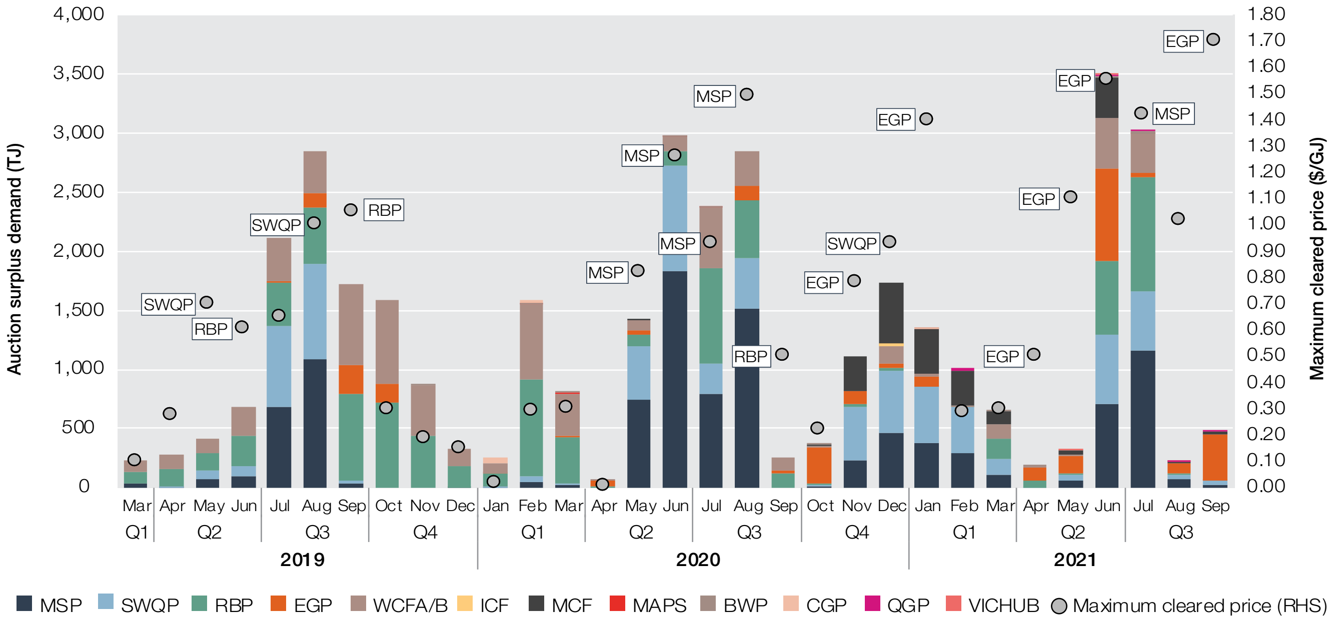
Source: AER analysis using DAA auction results data.

Note: The auction cleared stack volumes are calculated across all facilities and includes paired bids that could include multiple auction facilities.

The maximum clearing price has also been increasing each year. In 2019 the maximum clearing price was $1.05/GJ on the RBP, in 2020 it was $1.49/GJ on the MSP and in 2021 it was $1.70/GJ on the EGP, recorded in Q3 2021.

Surplus demand indicates the volume of auction bids that 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 auction facility.[45] As competition in the DAA has increased, the surplus demand on these auction facilities has continued to increase over time, with June and July this year recording the highest total surplus demand since the market started (Figure 2.31). The total surplus demand across all auction facilities since the market started is 37.6 PJ.

Figure 2.31 DAA surplus demand and maximum clearing prices



Source: AER analysis using DAA auction results data.

Note: Surplus demand is calculated on auction routes where auction capacity was bid on.

Looking forward

As the gas market continues to evolve it is important that these markets are competitive and liquid to secure the best possible outcome for all participants. We will continue analysing and reporting on the state of competition in these markets, especially following the implementation of the Gas Market Transparency Reforms next year.

Through these reforms, participants will be required to report short term over the counter (OTC) commodity trades of a contract period of less than one year, as well as gas swap arrangements. Reporting on short term OTC trades will allow us to better understand how the market is working and how flexibly participants can adjust trading portfolios. We would expect participants to use both OTC and AEMO markets in response to outage events, which might create surplus supply or, if they win new customers, require additional purchases to meet demand.

We understand swaps of gas between locations to be widespread, but it is unclear how much is traded in comparison to visible substitutes, such as volumes won through the DAA. Analysing trends in both swaps and short term transportation arrangements, such as through the DAA, will assist us to understand if gas is moving efficiently between locations across the east coast.

45 A participant can pair bids over multiple auction facilities requiring it to win auction capacity on all the paired auction facilities before it will be successful in winning capacity overall. For example, when a participant pairs a bid of 10 TJ to move gas from Wallumbilla to Sydney it would have a paired bid on the MSP and SWQP auction facilities. If the MSP is constrained resulting in the bid not being successful, the bid on the SWQP will also be unsuccessful even though the SWQP might not be constrained, because the bid was paired with the MSP.

Appendix A Electricity generator outages

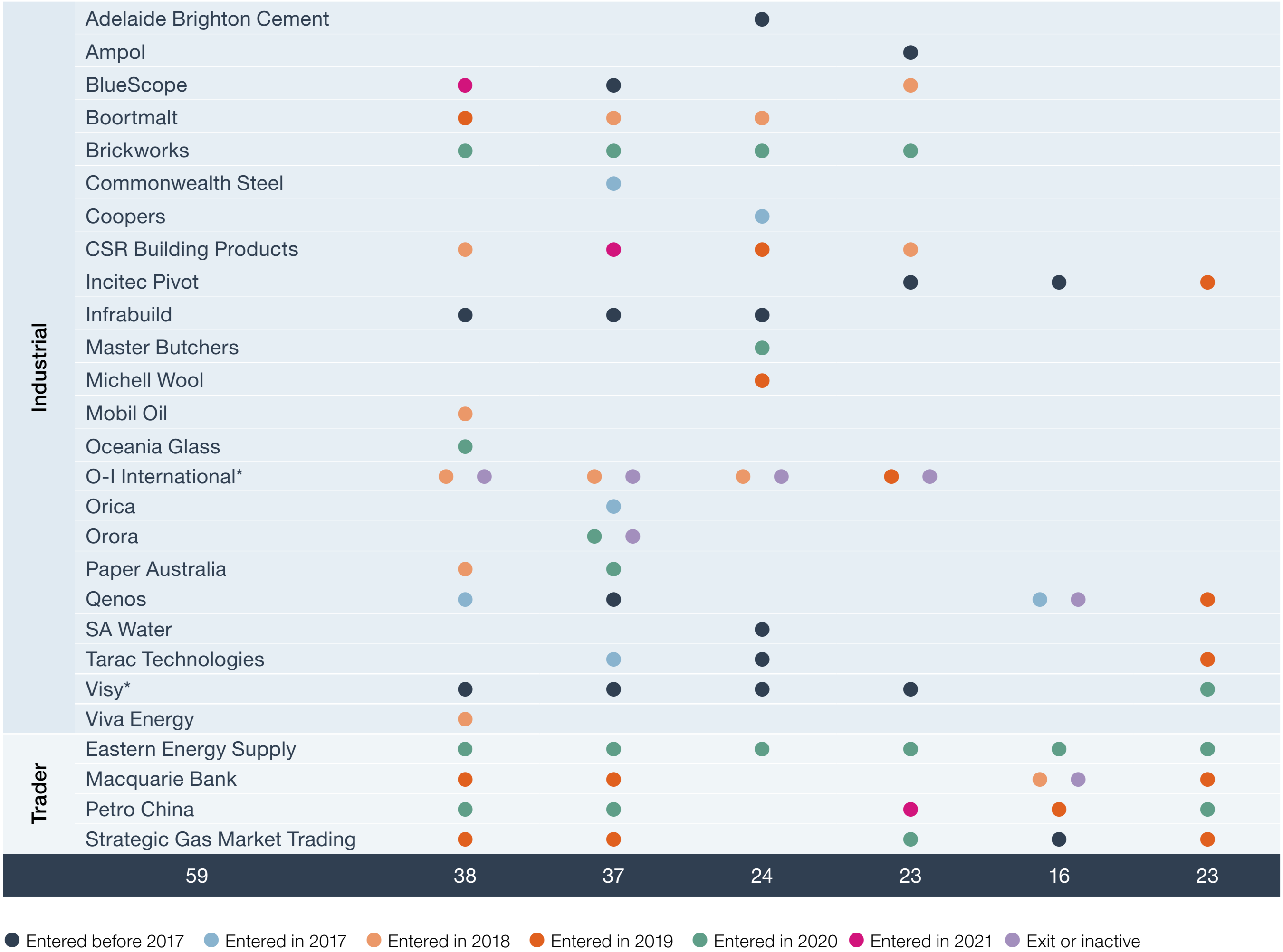
STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q3 2021	REASON FOR OUTAGE	RETURNED TO SERVICE
Queensland				
Callide C, Callide Power Trading	Black coal, 2 units, 420 MW each	Unit 3: 24 days	Unplanned – tripped following significant failure of Callide C unit 4 on 25 May	26/07/2021
		Unit 4: 92 days	Unplanned – significant failure on 25 May	Unknown
Gladstone, CS Energy	Black coal, 6 units, 280 MW each	Unit 1: 78 days	Unplanned – unit trip	Unknown
		Unit 2: 21 days	Planned (20 days)	28/09/2021
			Planned (1 day)	1/10/2021
		Unit 4: 20 days	Planned	7/09/2021
		Unit 5: 47 days	Planned	17/08/2021
		Unit 6: 92 days	Planned	Unknown
Stanwell, Stanwell Corporation	Black coal, 2 units, 365 MW each	Unit 2: 21 days	Planned – outage started in Q2 2021	22/07/2021
		Unit 3: 41 days	Planned	Unknown
Tarong, Stanwell Corporation	Black coal, 4 units, 350 MW each	Unit 1: 25 days	Unplanned (17 days) – unit trip	3/08/2021
			Planned (8 days)	11/09/2021
Tarong North, Stanwell Corporation	Black coal, 1 unit, 443 MW each	39 days	Planned	31/08/2021
NSW				
Bayswater, AGL Energy	Black coal, 4 units, 630 MW – 655 MW	Unit 1: 10 days	Unplanned – technical issues	29/07/2021
		Unit 2: 25 days	Planned (11 days) – outage started Q1 2021	12/07/2021
			Unplanned (14 days) – tube leak	28/07/2021
		Unit 3: 24 days	Unplanned (11 days) – technical issues	21/08/2021
			Unplanned (5 days) – plant failure	27/08/2021
			Unplanned (8 days) – technical issues	21/09/2021
Liddell, AGL Energy	Black coal, 4 units, 450 MW each	Unit 1: 23 days	Planned (1 day)	2/07/2021
			Unplanned (12 days) – tube leak	14/09/2021
			Unplanned (10 days) – plant failure	30/09/2021
		Unit 3: 16 days	Planned	6/09/2021
		Unit 4: 23 days	Unplanned (14 days) – technical issues	Unknown
			Unplanned (9 days) – plant failure	20/08/2021
Eraring, Origin Energy	Black coal, 2 units, 680 MW each	Unit 2: 18 days	Unplanned – technical issues	26/07/2021
		Unit 4: 43 days	Unplanned – technical issues	Unknown
Vales Point, Delta	Black coal, 2 units, 660 MW each	Unit 6: 10 days	Planned	26/09/2021
Mt Piper, EnergyAustralia	Black coal, 2 units, 675 MW each	Unit 2: 20 days	Unplanned (13 days)	20/09/2021
			Planned (7 days)	Unknown

Victoria				
Loy Yang A, AGL Energy	Brown coal, 4 units, 520 MW – 540 MW	Unit 1: 12 days	Unplanned (6 days) – plant failure	28/07/2021
			Unplanned (6 days) – plant failure	7/09/2021
		Unit 3: 62 days	Planned	30/09/2021
Yallourn, EnergyAustralia	Brown coal, 4 units, 355 MW each	Unit 1: 15 days	Unplanned (12 days) – oil leak	11/08/2021
			Unplanned (3 days) – tube leak	29/08/2021
		Unit 2: 15 days	Unplanned (2 days) – soot blower issue	11/07/2021
			Planned (13 days) – technical issues	Unknown
		Unit 4: 15 days	Unplanned (6 days) – unit trip	30/09/2021
			Unplanned (1 day) – unit trip	2/07/2021
			Planned (8 days)	5/09/2021

Appendix B Gas participant list

PARTICIPANT LIST IN EASTERN GAS MARKET

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



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 aquired by AGL, ERM was aquired by Shell (Shell Retail), O-I International was aquired by Visy.
* Arrow also operates the Braemar 2 power station.
* ICAP Brokers is also active in the GSH, but does not trade gas commodities (trade facilitior).

Appendix C 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
		EGP Entry >>> MAPS Exit	1202038–1502039
		EGP Entry >>> SWQP Exit	1202038–1502057
		Wilton Trade Point >>> MAPS Exit	1290018–1502039
		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	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	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
		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

Common measurements and abbreviations

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

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