Wholesale Markets Quarterly

Q2 2021

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AUSTRALIAN ENERGY REGULATOR

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Summary

This report highlights wholesale electricity and gas market outcomes for the financial year 2020–21 and for Q2 2021.

Electricity markets

Average financial year spot prices in all National Electricity Market (NEM) regions were low in 2020–21. Volume weighted average (VWA) prices ranged from $45 per megawatt hour (MWh) in Tasmania to $72/MWh in NSW.[1] Only in Queensland were prices higher in 2020–21 than in 2019–20. Across the NEM as a whole, 2020–21 marked the first time since 2014–15 financial year prices were below $75/MWh in all regions. This was driven by low prices in Q3 and Q4 2020 and Q1 2021, where quarterly prices across all regions were generally far lower than in the same period last financial year.

There was, however, a significant increase in quarterly prices in Q2 2021 from levels the previous year, particularly in Queensland and NSW. Prices in Queensland reached their highest Q2 level ever and prices in NSW reached their highest Q2 level since 2007. In Q2 2021, spot prices exceeded $5,000/MWh 22 times, across 6 separate days, mostly in Queensland and NSW.

These high prices were largely driven by a high number of planned and unplanned coal generator outages, as well as network (line) outages that limited Queensland and NSW's ability to import cheaper generation from other regions. In Queensland and NSW, 80% of high prices occurred in the 3 weeks following the failure of the Callide C power station on 25 May which further tightened supply-demand conditions.[2] Over this period, more expensive gas and hydro generation was needed to meet demand, which had increased with the onset of winter, and some very cold days.

Frequency control ancillary services (FCAS) costs were also high in Q2 2021 totalling $142 million, the second highest quarterly FCAS costs on record. These included local FCAS costs in Queensland which reached a record $74 million as a result of energy price volatility and line outages.

1 The AER reports the volume-weighted average (VWA) price, which is weighted against native demand in each 30 minute trading interval. AEMO uses the time-weighted average, which is the average of spot prices in the quarter.

2 We used prices above $2,000/MWh for this calculation but it is also true that around 80% of prices above $300/MWh in Queensland and NSW occurred in these 3 weeks.

Gas markets

Average financial year spot prices in all east coast gas markets were low in 2020–21, continuing the trend after significant price falls in 2019–20. Prices ranged from $5.60/GJ in the Wallumbilla Gas Supply Hub to $6.54/GJ in Brisbane, which was the only market where prices had increased from the previous financial year. For all other markets, prices were at their lowest levels since 2015–16.

Despite reaching long term lows on average, across the financial year prices slowly trended up, aligning with rising prices in international LNG markets. However, in Q2 2021 prices increased significantly from the previous quarter with prices ranging from $7.30/GJ in Victoria to $9.17/GJ as average prices increased across all markets by 39%.

There were 2 main contributing factors to higher prices. The first was unseasonably high international gas prices, with prices not flattening or decreasing over Q2 2021 as they have in previous years. The second was outages and constraints across the NEM and Gas markets in May and June. Our focus story highlights that gas generators were called upon to boost electricity generation and this coincided with rising heating demand resulting in daily prices fluctuating between $5/GJ and $15/GJ.

As gas demand increased, there was near record trade at Wallumbilla and record trade on the Day Ahead Auction as participants moved gas between northern and southern markets. Trade through the downstream markets was also at record levels, led by large increases in producer sales. Industrial users have increased their spot purchases over time through these markets and faced significantly higher prices after a number of quarters of relatively low prices.

Electricity markets at a glance

Q2 2021

Spot prices

FY 2020–21 prices fell in all regions except Qld, despite higher than expected prices in Q2 2021.

Demand

Demand increased with colder temps. Demand in NSW reached near Q2 record on coldest June day in 100 years.

Generator outages

Large numbers of black coal outages in Qld and NSW reduced capacity priced <$50/MWh.

Interconnectors

Network outages reduced Qld and NSW's ability to import cheaper generation.

FCAS

50 Hz

Record FCAS costs in Qld of $74m contributed to high FCAS costs in the NEM of $142 million.

Outlook

Price expectations for future quarters increased in all regions.

Gas markets at a glance

Q2 2021

Spot prices

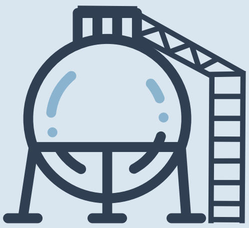
FY prices declined 7%, $5.60-$6.54/GJ across markets

Daily Q2 prices rising and volatile, ranging $5–$15/GJ

Spot trade downstream

Producers drove record levels of spot trade 28.6 PJ in Q2

Gas storage



Storage critical to supply Q2 peak demand

International markets

FY: Record QLD LNG exports as Asian LNG prices increased above domestic prices

Rising Q2 gas spot prices in European and Asian LNG markets

Gas production and flows

Gas production near record levels 5,478 TJ/day in Q2

Day Ahead Auction

Auction reduces transport costs to supply generators in Q2

About this report

This report highlights wholesale electricity and gas market outcomes in Q2 2021 and in the financial year 2020–21.

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.

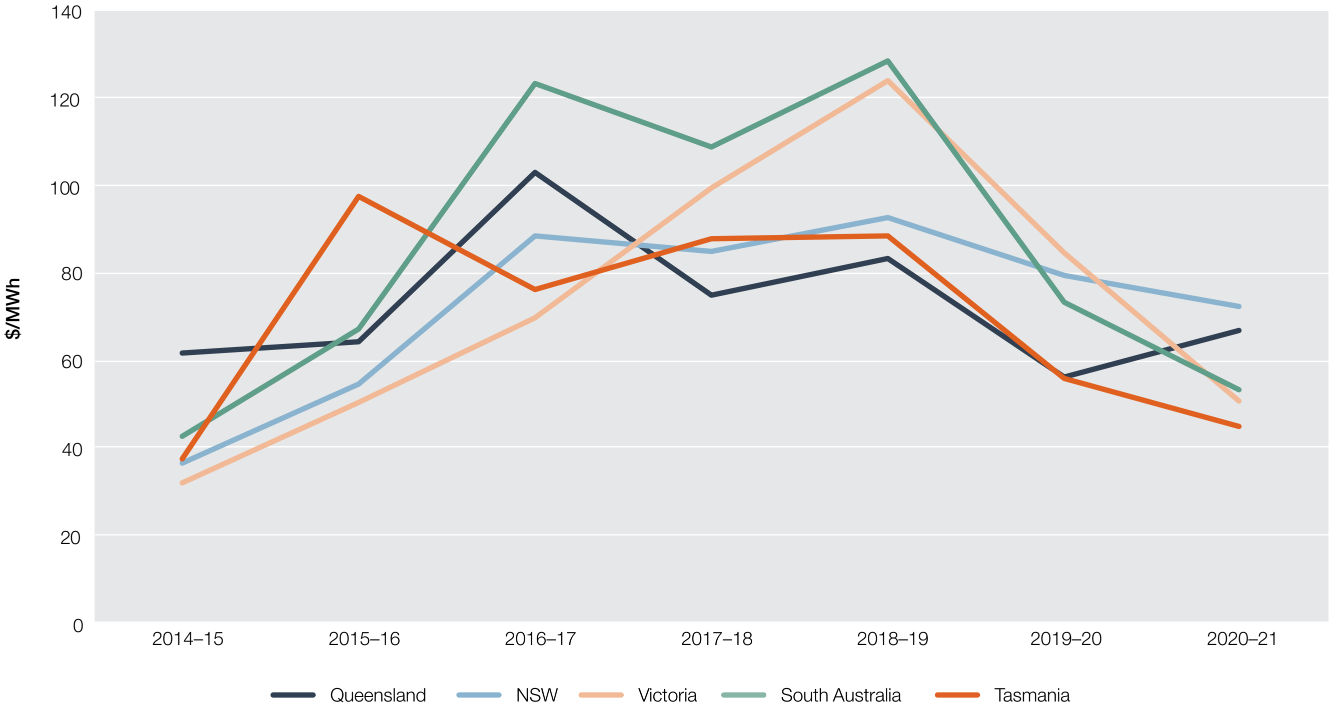
We also have obligations to report quarterly on outcomes in the frequency control ancillary services (FCAS) markets and report on prices over $5,000/MW in ancillary services markets. We fulfil both of these obligations in this report.

1. Electricity

1.1 Financial year prices low across the NEM despite recent price increases

VWA spot prices in all NEM regions were low in 2020–21. Prices ranged from $45/MWh in Tasmania to $72/MWh in NSW (Figure 1.1). These prices were the lowest financial year prices observed since 2014–15 in Tasmania, 2015–16 in South Australia and NSW, and 2016–17 in Victoria. Only in Queensland were 2020–21 prices higher than levels in 2019–20. Across the NEM as a whole, 2020–21 marked the first time since 2014–15 financial year prices were below $75/MWh in all regions.

Figure 1.1 Average financial year spot prices (VWA)



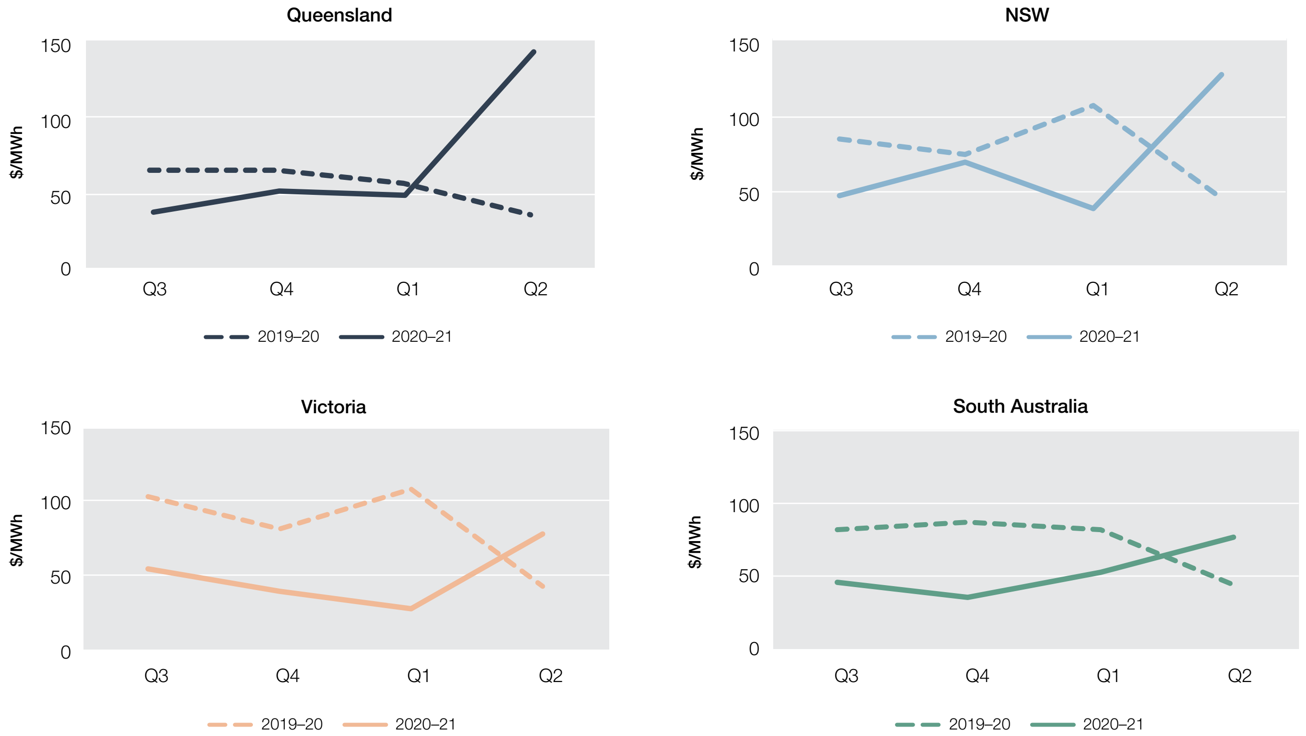
Source: AER analysis using NEM data.

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.

These overall price outcomes for 2020–21 were driven by low prices in Q3 and Q4 2020 and Q1 2021, when quarterly prices across all regions were generally far lower than in the same period last financial year (Figure 1.2).

There was, however, a significant increase in quarterly prices in Q2 2021 from levels the previous year, particularly in Queensland and NSW. Quarterly prices in Queensland reached their highest Q2 level ever and prices in NSW reached their highest Q2 level since 2007. Q2 2020 average prices ranged from $47/MWh in Tasmania to $141/MWh in Queensland.

Figure 1.2 Average quarterly spot prices across 2020–21, compared to 2019–20 (VWA)



Source: AER analysis using NEM data.

Note: Comparison of quarterly prices in financial year 2020–21 (Q3 2020, Q4 2020, Q1 2021 and Q2 2021) with quarterly prices in financial year 2019–20 (Q3 2019, Q4 2019, Q1 2020 and Q2 2020). 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.

Price outcomes in Queensland and NSW were driven by volatile prices in the second half of the quarter, which were due to:

- planned and unplanned generator outages (section 1.4)
- line outages, which reduced the ability of Queensland and NSW to import cheaper generation from other regions (section 1.7)
- high demand (section 1.10)
- increased gas and hydro generation (section 1.4).

Average weekly prices in Queensland peaked at $347/MWh in the week commencing 23 May and $367/MWh in the week commencing 30 May (Figure 1.3).

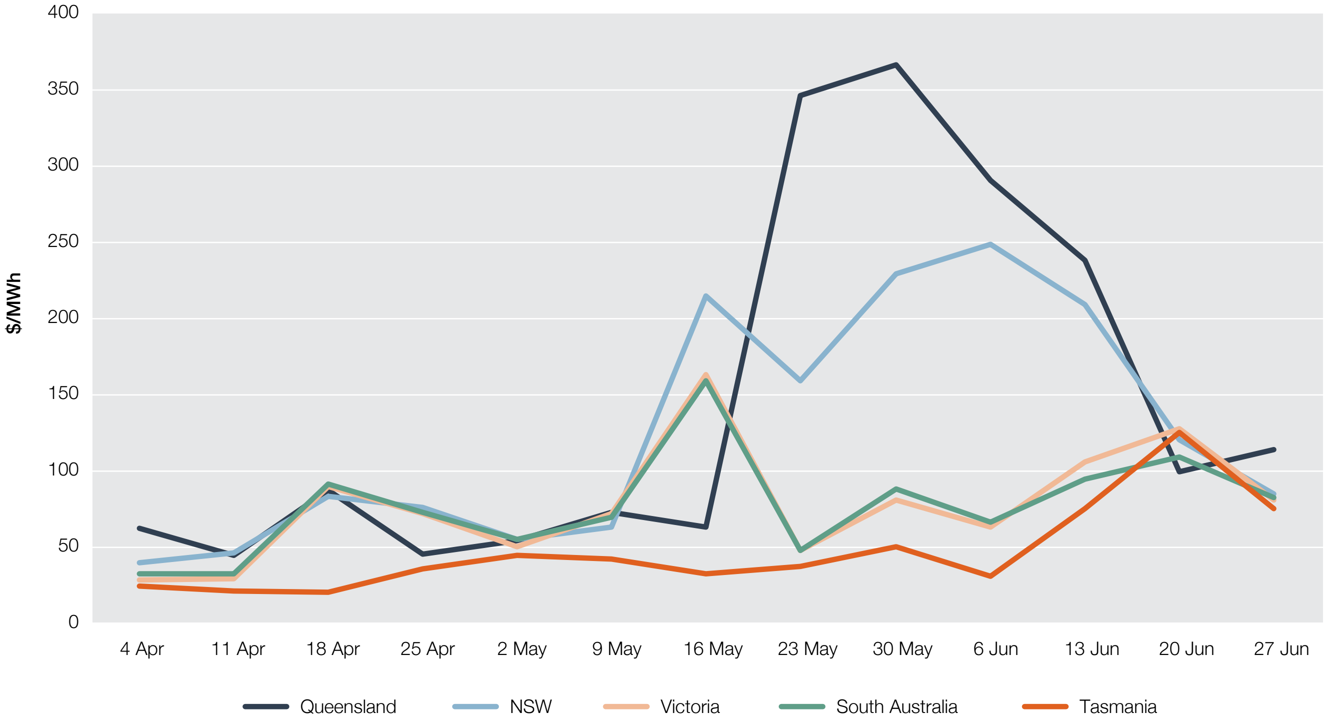
High prices in Victoria and South Australia were driven by outages, high demand and periods of low wind generation.

Spot prices exceeded $5,000/MWh 22 times across the quarter (Figure 1.4). This is the highest number of $5,000/MWh prices ever in Q2 and the first time since 2010 that any spot price was over $5,000/MWh in Q2. These occurred in the second half of the quarter and mostly in Queensland and NSW.

We have already released detailed reports into these half hour prices over $5,000/MWh, a requirement under the National Electricity Rules.[3]

3 The AER publishes $5,000/MWh reports which analyse the drivers of these high prices in more details. AER $5,000/MWh reports.

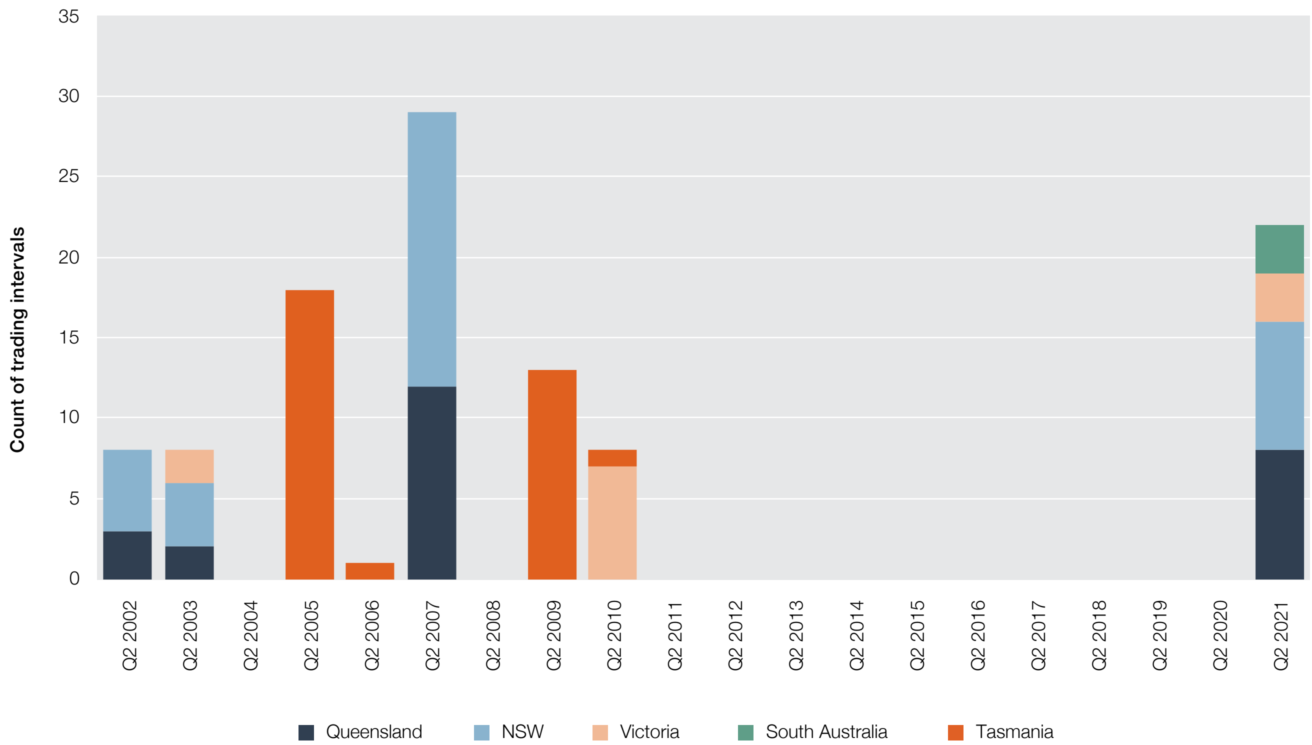
Figure 1.3 Average weekly spot prices, Q2 2021 (VWA)



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.

Figure 1.4 Count of prices above $5,000/MWh, Q2 comparisons



Source: AER analysis using NEM data.

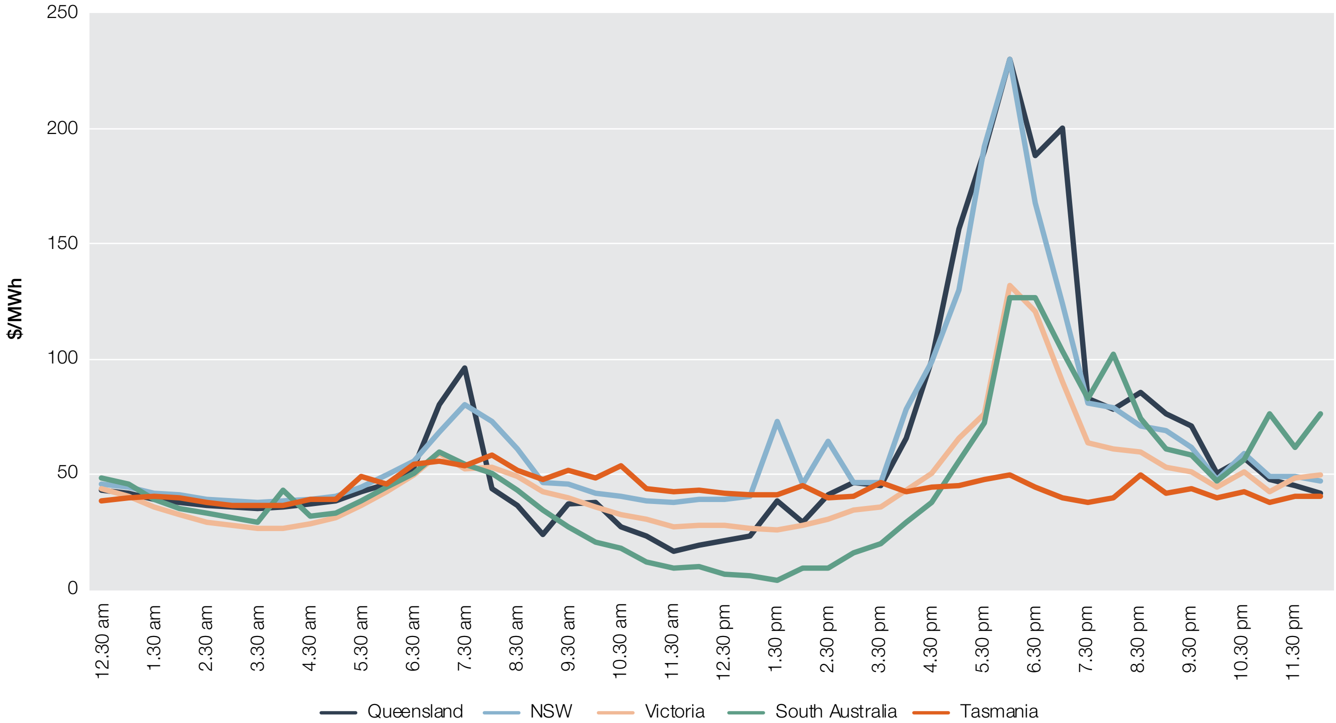
Note: Count of spot prices above $5,000/MWh in each Q2, from Q2 2002 to Q2 2021.

1.2 Wholesale prices lower during the middle of the day

An in-depth look at prices across the NEM in 2020–21 highlights the continuation of some of the intraday dynamics we reported on for 2019–20. While wholesale prices are generally becoming lower during the day before increasing during the evening peak in 2020–21, the trends are not uniform across the NEM regions (Figure 1.5):

- South Australia had significantly lower average prices during the middle of the day than the other regions, driven by high rooftop solar output.
- Average prices on the mainland trended up from 2 pm before peaking in the early evening, as demand increased and solar generation was not available. The high average prices in the evening peak in NSW and Queensland were largely driven by the price spikes in Q2 2021.
- Average prices in Tasmania were relatively flat through the day. At times of high mainland prices in the evening, Tasmanian generation is often offered at lower prices to ensure it is dispatched to take advantage of higher mainland prices.[4]

Figure 1.5 Average spot prices by time of day, 2020–21



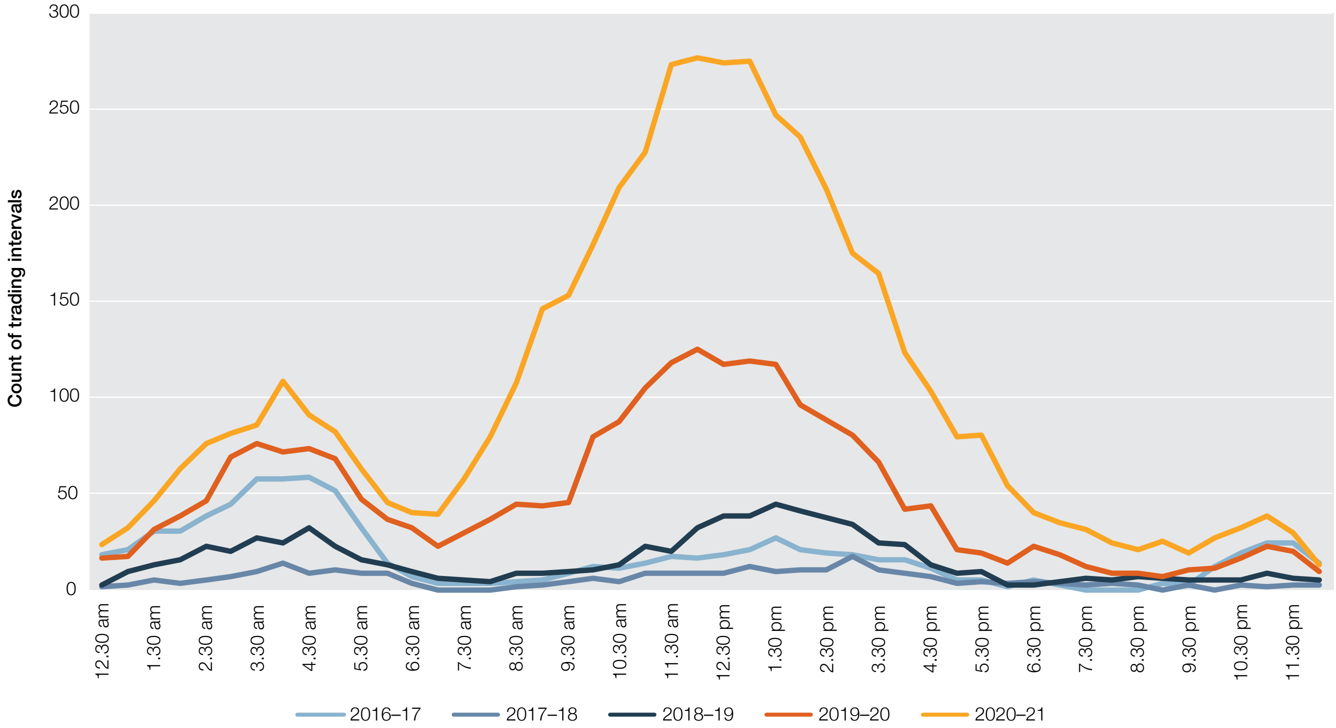
Source: AER analysis using NEM data.

Note: Average prices by trading interval in 2020–21, not volume weighted.

The lower prices during the middle of the day across the NEM, in part, reflected the increased incidence of negative prices. While there were more negative priced trading intervals across all hours than had occurred in previous years, the number of negative prices was particularly high during daylight hours (Figure 1.6).

4 We have previously commented on this trend in our *Wholesale Markets Quarterly Q1 2020*.

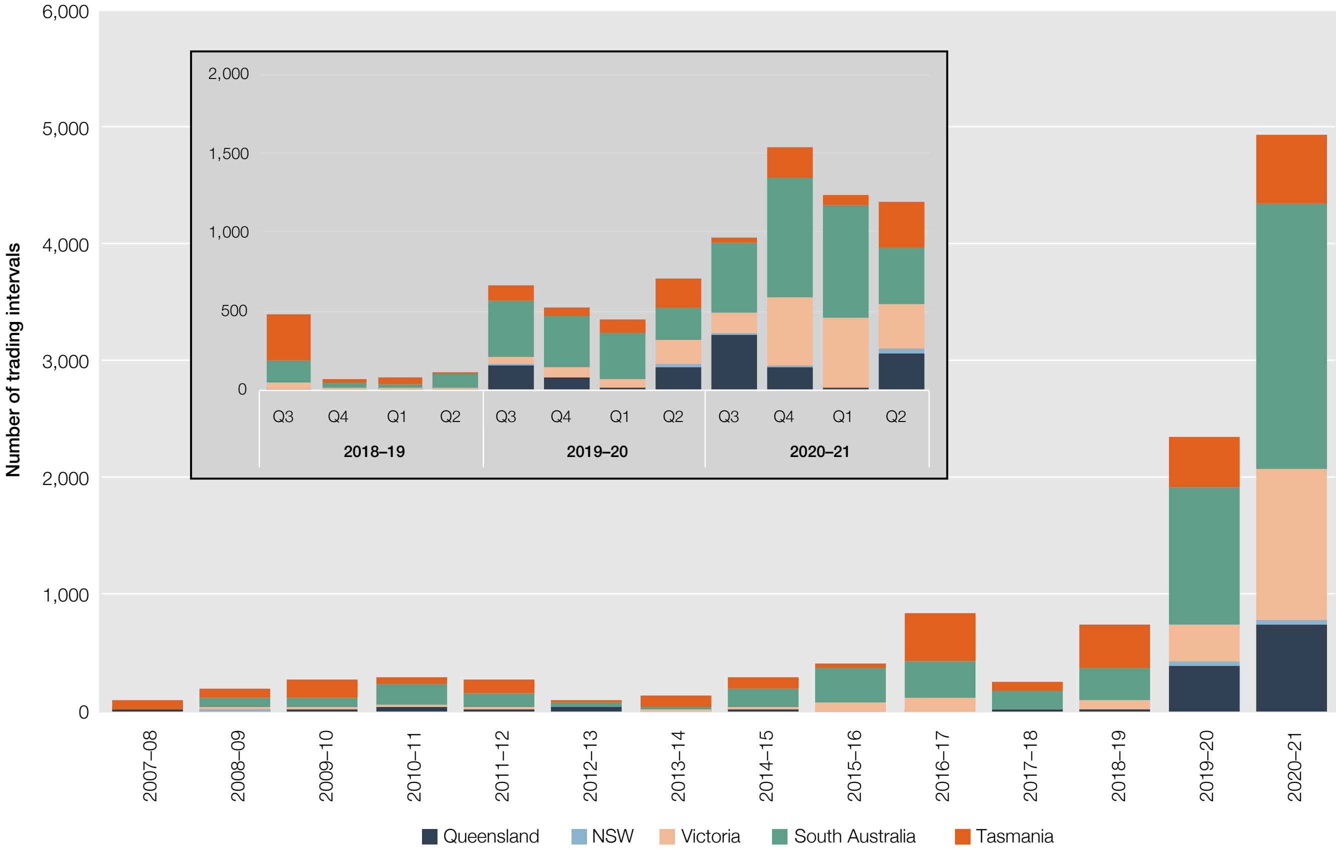
Figure 1.6 Count of negative prices by time of day, financial year



Source: AER analysis using NEM data.
Note: Count of spot prices below $0/MWh by time of day, in each financial year.

There was a record number of negative prices in 2020–21. The 4,931 negatively priced trading intervals in 2020–21 were over double the previous high of 2,338 in 2019–20. While the number of negative prices peaked in Q3 2020, there were record numbers of negative prices in each quarter compared to comparable quarters in previous years (Figure 1.7). While there were more negative prices in South Australia, there were increases in instances of negative prices in every region, especially in Victoria.

Figure 1.7 Count of negative spot prices, financial year and quarterly



Source: AER analysis using NEM data.

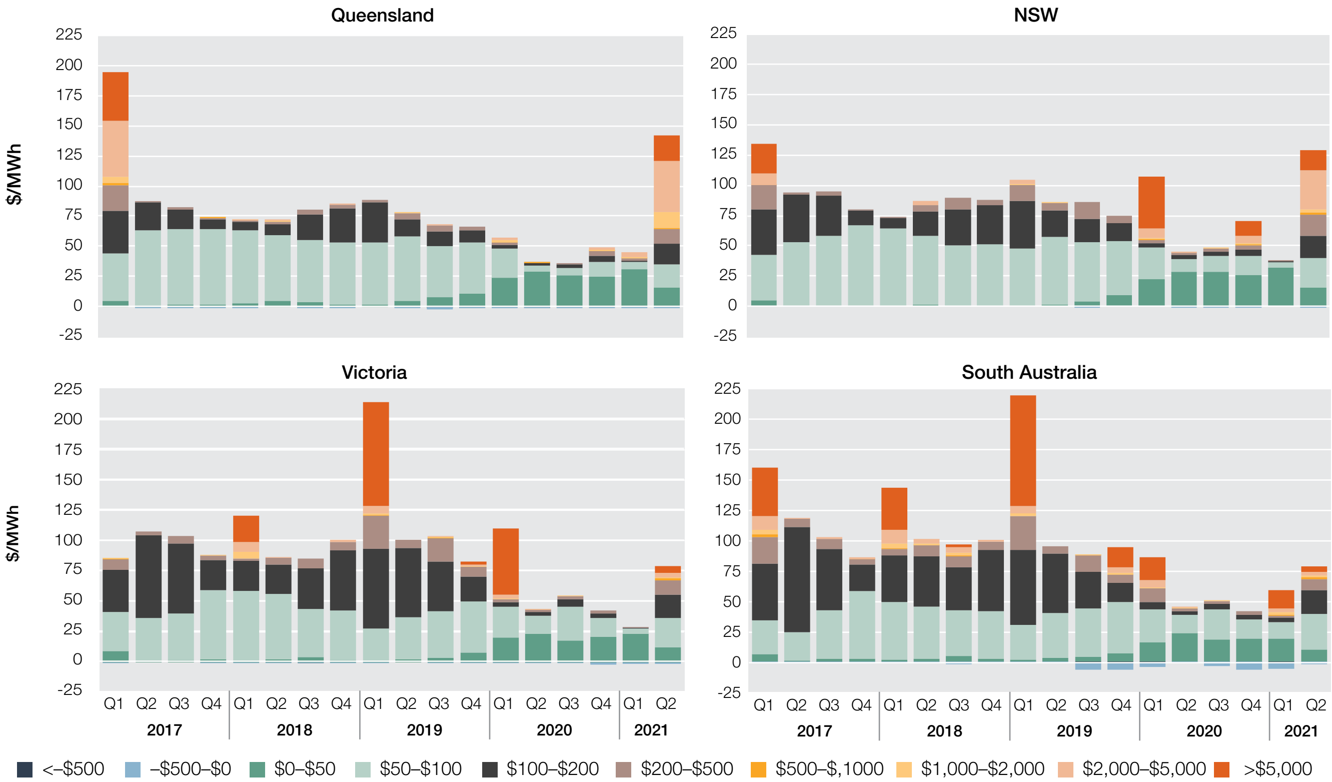
Note: Count of spot prices below $0/MWh in each financial year. Insert: Count of spot prices below $0/MWh in each quarter.

The change in prices was not confined to the emergence of negative prices. Until Q2 2021, there were many more lower priced trading intervals ($0–$50/MWh) and these were playing a far more significant role driving lower average prices (Figure 1.8). Across all regions until Q2 2021, there was a greater contribution from prices in the $0–$50/MWh band and a fall in the contribution of prices over $50/MWh (particularly in the $50–$100/MWh bands).

This trend reversed in Q2 2021, with a fall in the contribution from prices in the $0–$50/MWh band and an increase in the contribution of prices in the $50–$100/MWh band in all regions.

High prices made a large contribution to average Q2 2021 prices in Queensland and NSW. Prices above $2,000/MWh contributed 45% to the overall Queensland Q2 average, with prices above $5,000/MWh contributing 15% to that average. In NSW, prices above $2,000/MWh contributed 26% to the overall Q2 average, with prices above $5,000/MWh contributing 12% to that average.

Figure 1.8 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.

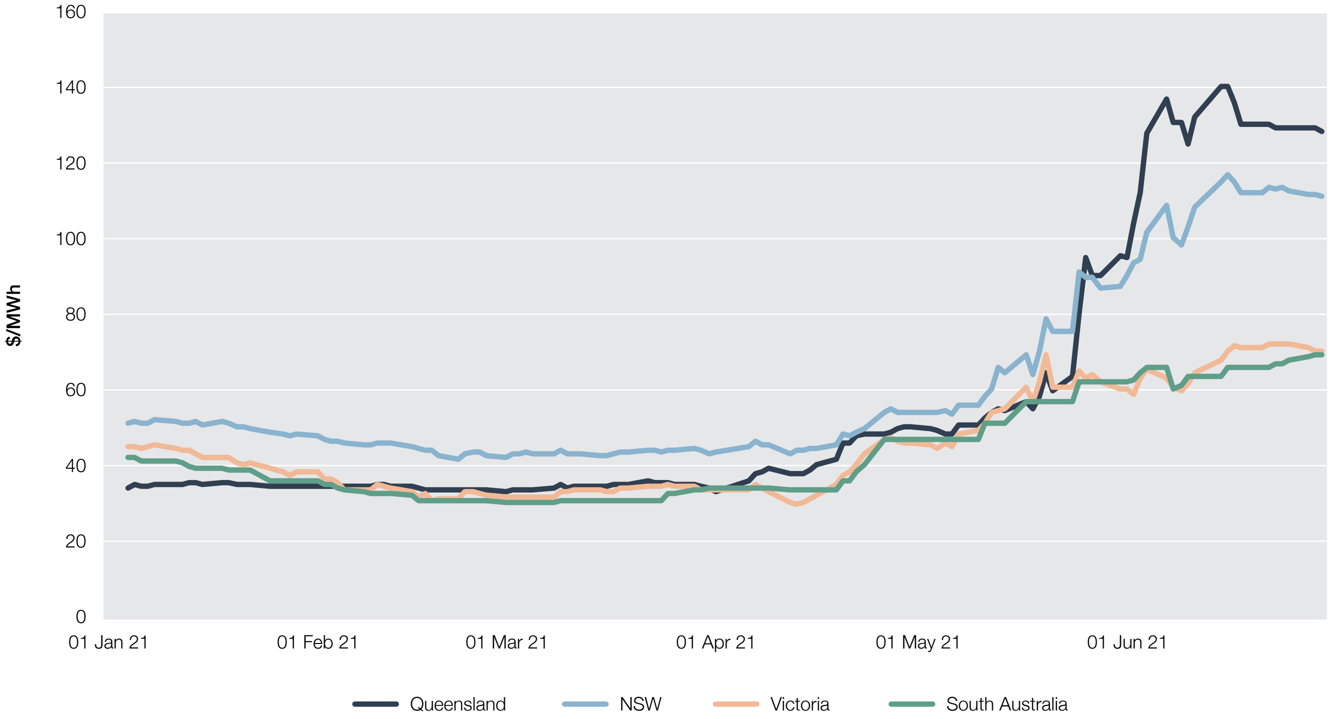
1.3 Future price expectations shift up

Base future prices increased in all regions across Q2 2021, as spot prices were much higher than anticipated as a result of Callide C power station's unexpected outage in May (Figure 1.9). Initial expectations were that low spot prices would continue from Q1 2021 into Q2 2021. However, contract prices rose significantly, particularly in Queensland and NSW where contract prices were 287% and 156% higher respectively.[5]

At the end of the quarter, the final base future price in Queensland was $129/MWh. This is the highest final contract price for any region in Q2 since the NEM began.

5 Futures contracts are settled against the average quarterly spot price in the relevant region.

Figure 1.9 Base future prices, Q2 2021



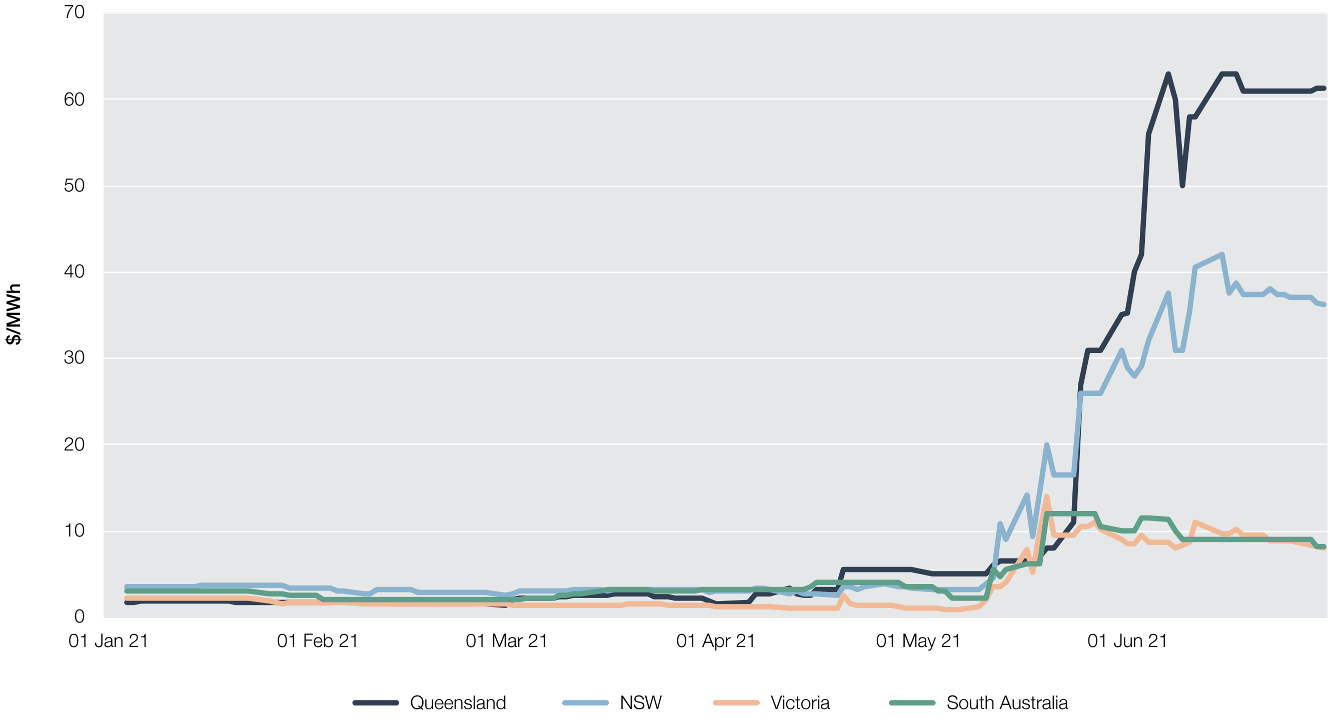
Source: AER analysis using ASX Energy data.
Note: Daily settlement price for Q2 2021 quarterly base futures.

Cap prices began to increase in early May as all regions observed a number of spot prices greater than $300/MWh.[6] They then rose dramatically in the second half of this quarter in Queensland and NSW, with the largest increases in late May and early June, as a result of high prices following Callide's outage (Figure 1.10). This resulted in cap prices finishing the quarter at $61/MWh in Queensland and $36/MWh in NSW.

At the start of the quarter cap prices for Q2 2021 ranged from $1.15/MWh in Victoria to $3.25/MWh in South Australia. As cap contracts are used to provide a hedge against spot prices greater than $300/MWh, these low prices indicate that there was no expectation of sustained high spot prices as the quarter commenced.

6 Caps are contracts setting an upper limit on the price that a holder will pay for electricity in the future. Cap contracts on the ASX have a strike price of $300/MWh.

Figure 1.10 Cap prices, Q2 2021

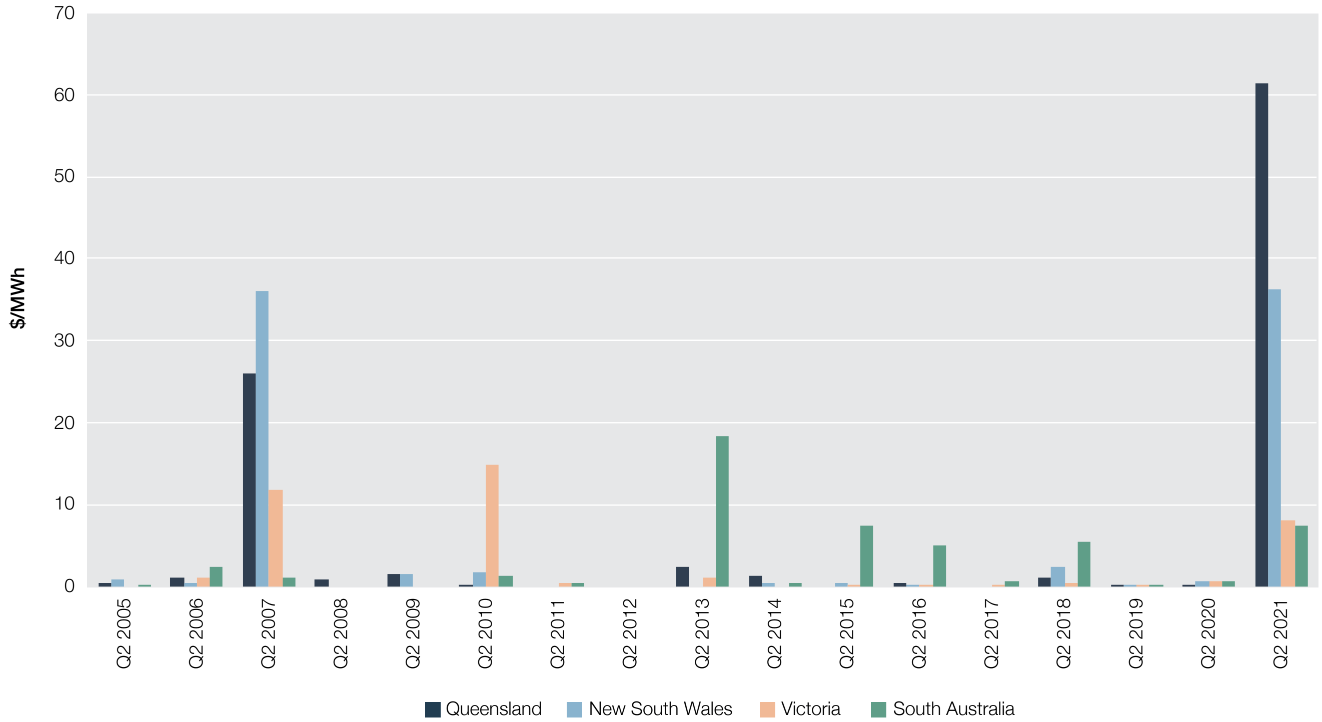


Source: AER analysis using ASX Energy data.

Note: Daily settlement price for Q2 2021 quarterly caps.

Cap prices in Queensland and NSW reached Q2 record levels, reflecting the high number of times prices exceeded \$300/MWh in Q2 2021 (Figure 1.11). The final Queensland cap price was nearly double the previous Q2 record of \$31/MWh, set by NSW in 2007. This is only the second time a final Q2 cap price in Queensland has exceeded \$3/MWh since caps were introduced. High cap prices are not common in Q2 as spot prices are typically not volatile.

Figure 1.11 Final cap prices, Q2 comparisons since 2005



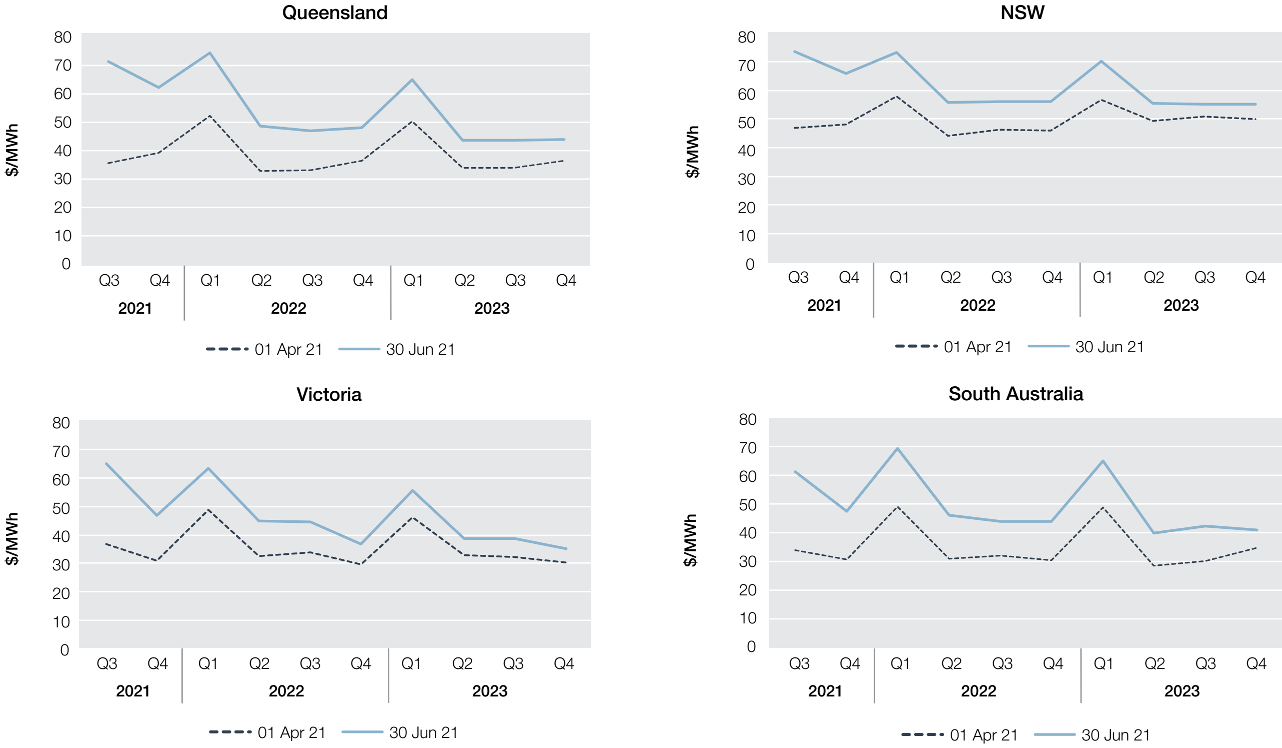
Source: AER analysis using ASX Energy and NEM data.

Note: Final cap prices calculated using NEM spot prices.

Looking ahead, price expectations for future quarters have increased significantly over the past 3 months (Figure 1.12). The higher spot prices observed in Q2 have pushed up price expectations for all upcoming quarters across all 4 regions.

As we entered Q3, the base future prices for Q3 2021 ranged from $61/MWh to $74/MWh with NSW and Queensland the highest priced regions. This is an increase of between 60% and 100% in expected Q3 base future prices from 3 months earlier.

Figure 1.12 Forward base future prices, as at 1 April 2021 and 30 June 2021



Source: AER analysis using ASX Energy data.

Note: Closing price of base futures contracts for Q3 2021 to Q4 2023 on the first trading day (01 April 2021) and last trading day (30 June 2021) of Q2 2021.

Liquidity in the contracts markets remained strong in Q2 2021. Compared to Q2 2020, volumes traded on the ASX increased by 37%.

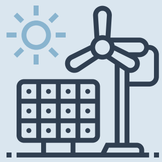
1.4 Thermal generation output continues to fall

A mild summer and increased rooftop solar generation caused average NEM generation in 2020–21 to fall by 370 MW compared to 2019–20 (Figure 1.13).

Average wind and large scale solar generation in 2020–21 increased by 550 MW as new wind and solar farms continued to enter the market. This increase saw wind and large scale solar generation in 2020–21 account for a record 15% of total generation in the NEM – up from 10% just 2 years earlier.

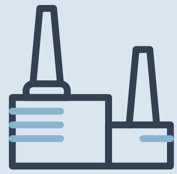
The combination of lower demand and increased wind and solar generation displaced thermal generation. As a result, average black coal generation fell by 540 MW and average gas generation fell by 430 MW. Thermal generation in 2020–21 accounted for a record low 76% of total generation in the NEM – down from 82% just 2 years earlier.

The changing generation mix in 2020–21



15%

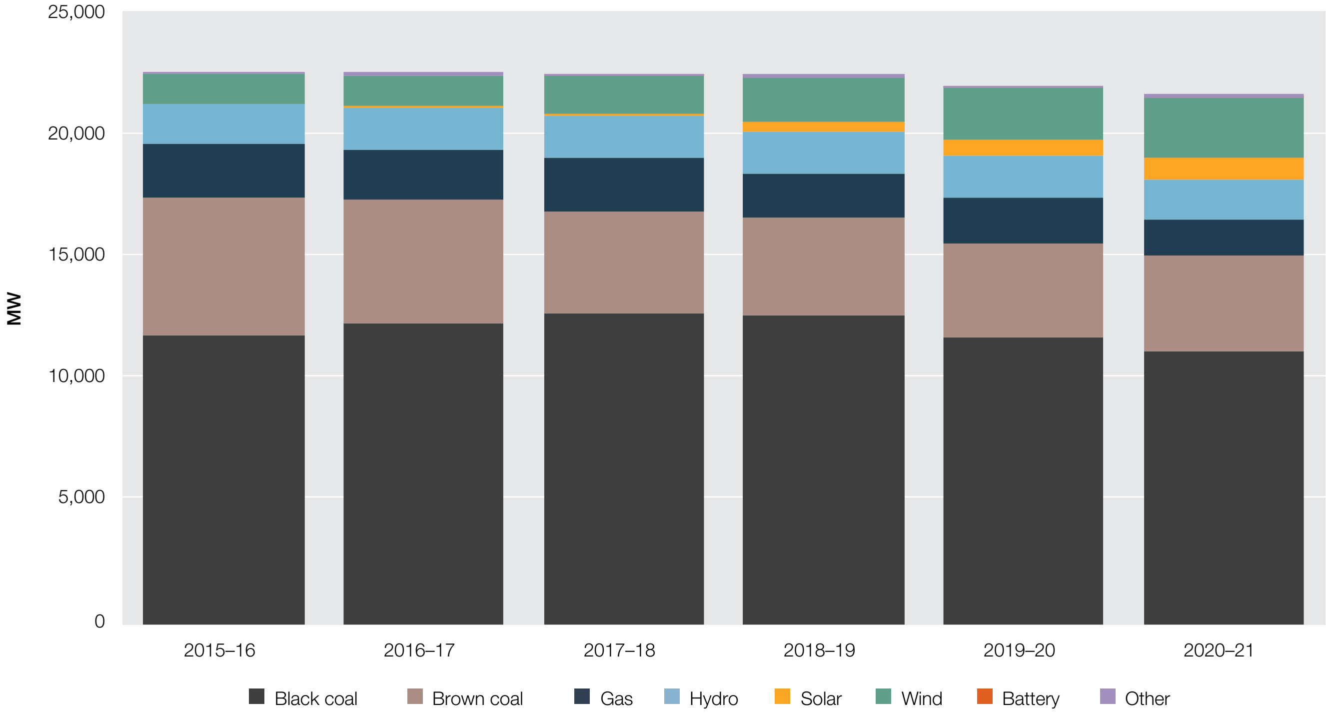
Wind and large scale solar share of annual generation (up from 10% in 2018–19)



76%

Thermal share of annual generation (down from 82% in 2018–19)

Figure 1.13 NEM generation, financial year comparisons

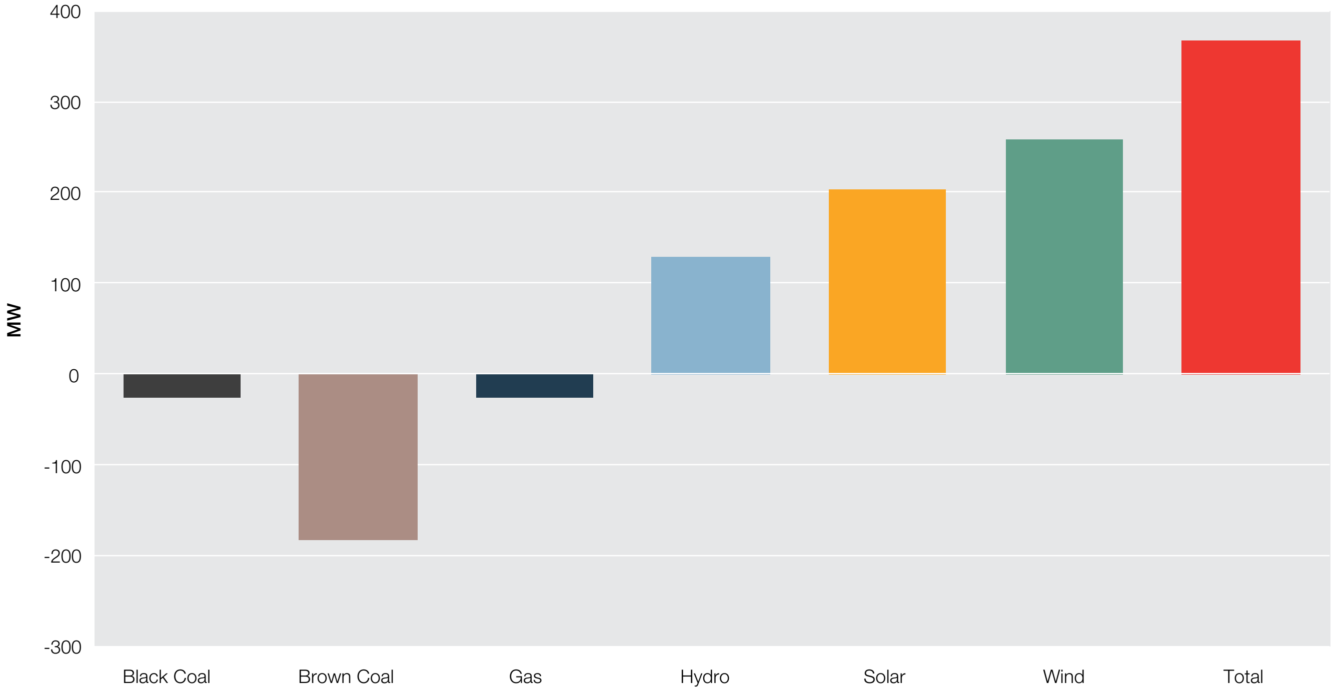


Source: AER analysis using NEM data.

Note: Average (over the financial year) metered generation output in the NEM by fuel type.

Despite lower average generation over the financial year, average generation increased in Q2 2021 to meet increased demand. Average generation over the quarter was 370 MW higher than in Q2 2020 (Figure 1.14). This increase was made up of more wind (260 MW), grid scale solar (200 MW) and hydro generation (130 MW), partly offset by falls in brown coal (180 MW), black coal (25 MW) and gas generation (25 MW).

Figure 1.14 Change in average output, Q2 2021 compared to Q2 2020



Source: AER analysis using NEM data.

Note: Change in average quarterly metered generation output by fuel type from Q2 2020 to Q2 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.

1.5 Q2 2021 hit by a high number of planned and unplanned outages

Even though the fall in average quarterly black coal generation was modest, Q2 2021 was hit by a large number of planned and unplanned black and brown coal generator outages. For example, in Queensland, NSW and Victoria, there were almost 1,000 days of cumulative baseload outages in Q2 2021 compared to 690 in Q2 2020.

It is common for planned outages to be scheduled in autumn when demand is typically lower than in the summer and winter peaks. However, the number of cumulative days lost to planned outages in Q2 2021 was higher than last year, particularly in Queensland and NSW where the numbers of days lost were respectively double and triple those lost in Q2 2020. This increase was from a low base which might have reflected delayed maintenance in Q2 2020 due to COVID-19 lockdowns. Planned outages in Q2 2021 were spread across the quarter. Some units in NSW, such as those at Bayswater and Vales Point power stations, were offline for nearly all of the quarter, while units at Gladstone, Stanwell and Tarong power stations in Queensland were off for over half of the quarter.

In addition to planned outages, there were more unplanned coal outages in Q2 2021 than in Q2 2020, particularly in Queensland and Victoria. The most dramatic black coal outage was the failure of Callide C power station on 25 May. In the lead up to the Callide event there was already 5,000 MW of baseload capacity unavailable in Queensland and NSW due to other outages. When Callide C power station failed it tripped the other 2 operating units at Callide. This took the amount of unavailable capacity across both regions to over 6,000 MW (Table 1.1). Except for a Bayswater unit, most of this capacity remained offline until at least 16 June, when Callide B1 and then Kogan Creek power station returned to service.[7]

7 Bayswater unit 3 (660 MW) came back on line on 2 June, reducing the amount of lost capacity to 5,338 MW.

Table 1.1 Unavailable capacity over 25 May to 16 June due to outages

REGION	UNAVAILABLE CAPACITY (MW)	OUTAGE TYPE	UNIT
Queensland	1,140	Planned	Tarong 1, Stanwell 2, Millmerran 2
	2,380	Unplanned	Kogan (running at 180), Callide B1 and B2, Callide C3 and C4, Gladstone 2
Total	**3,520**		
NSW	1,820	Planned	Bayswater 2, Liddell 1, Vales Point 6
	660	Unplanned	Bayswater 3 (back on 2 June)
Total	**2,480**		Until 2 June, then down to 1,820

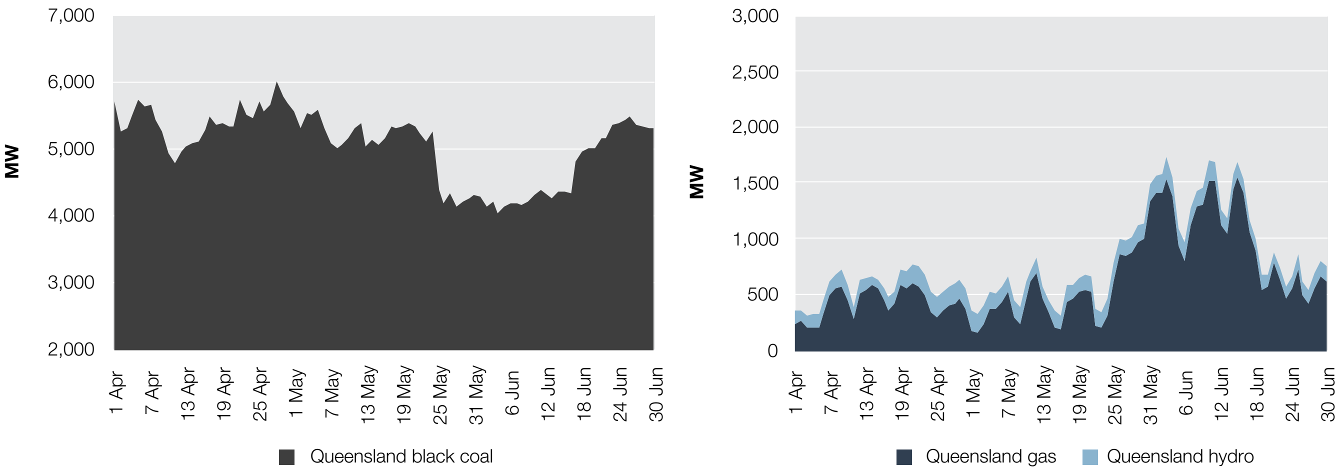
Source: AER using NEM data.

Note: Unavailable capacity is approximate throughout the period.

There were also brown coal outages in Victoria in Q2 2021. In the third week of April, planned and unplanned outages at Loy Yang A and Loy Yang B power stations, and technical issues at Yallourn power station reduced brown coal capacity by 1,400 MW. On 12 June, EnergyAustralia cut output at Yallourn again because of coal supply issues caused by flooding. This reduced the amount of available brown coal capacity by over 1,000 MW for much of the remainder of the month. A full list of baseload outages can be found in Appendix A.

The reduction in coal generation in Queensland and NSW between 25 May to 16 June, and in Victoria in June, meant more expensive gas and hydro generation was dispatched during those weeks (Figure 1.15 and Figure 1.16). In early June, for example, Queensland gas powered generation reached its highest weekly levels since Q1 2017. In Victoria, having started the quarter at very low levels, gas powered generation increased from late May, driven by both cooler winter temperatures and the coal supply issues at Yallourn. Increased demand for gas to generate electricity was one factor that drove significant price increases in domestic gas markets this quarter (section 2.1).

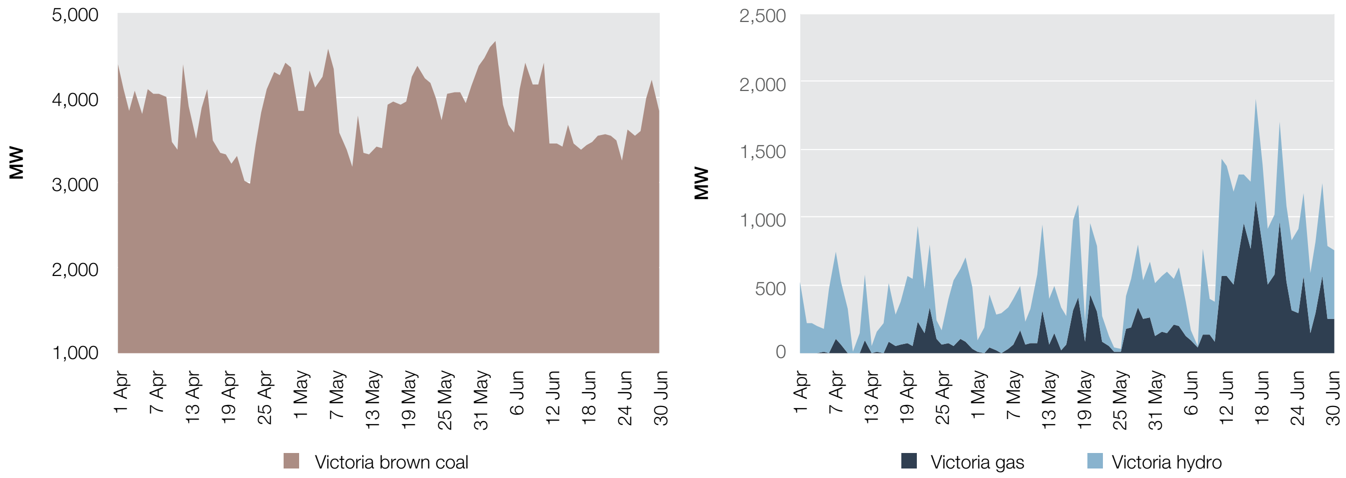
Figure 1.15 Queensland, black coal, gas and hydro generation



Source: AER analysis using NEM data.

Note: Average daily metered generation output of Queensland black coal, gas and hydro generation.

Figure 1.16 Victoria, brown coal, gas and hydro generation



Source: AER analysis using NEM data.

Note: Average daily metered generation output of Victoria brown coal, gas and hydro generation.

Despite several weeks of elevated gas generation in May and June, average quarterly gas generation in the NEM fell to its lowest Q2 level in 2021 since at least 2015. At a regional level, however, gas powered generation output varied compared to Q2 2020:

- It fell in Queensland, with drops in production at Darling Downs, Swanbank E and Condamine power stations in Queensland.
- It was at similar levels in South Australia, despite the retirement of Torrens Island units since Q3 2021.
- It increased in Victoria and NSW, driven by coal outages and winter demand, with increases at Newport and Jeeralang power stations in Victoria, and Uranquinty in NSW.

Hydro generation played an increasing role in the fuel mix in Q2 2021 compared to Q2 2020, particularly in NSW and Queensland. Hydro generation in NSW increased noticeably for a month from the week starting 16 May, with average weekly generation in NSW increasing around 200 MW compared to earlier weeks. In Queensland hydro generation increased from mid-April, and in Victoria it increased towards the end of the quarter driven by increased winter demand. Hydro generation in Tasmania, the largest hydro generating region in the NEM, fell compared to Q2 2020. This fall was from high levels in Q2 2020 which experienced above average rainfall.

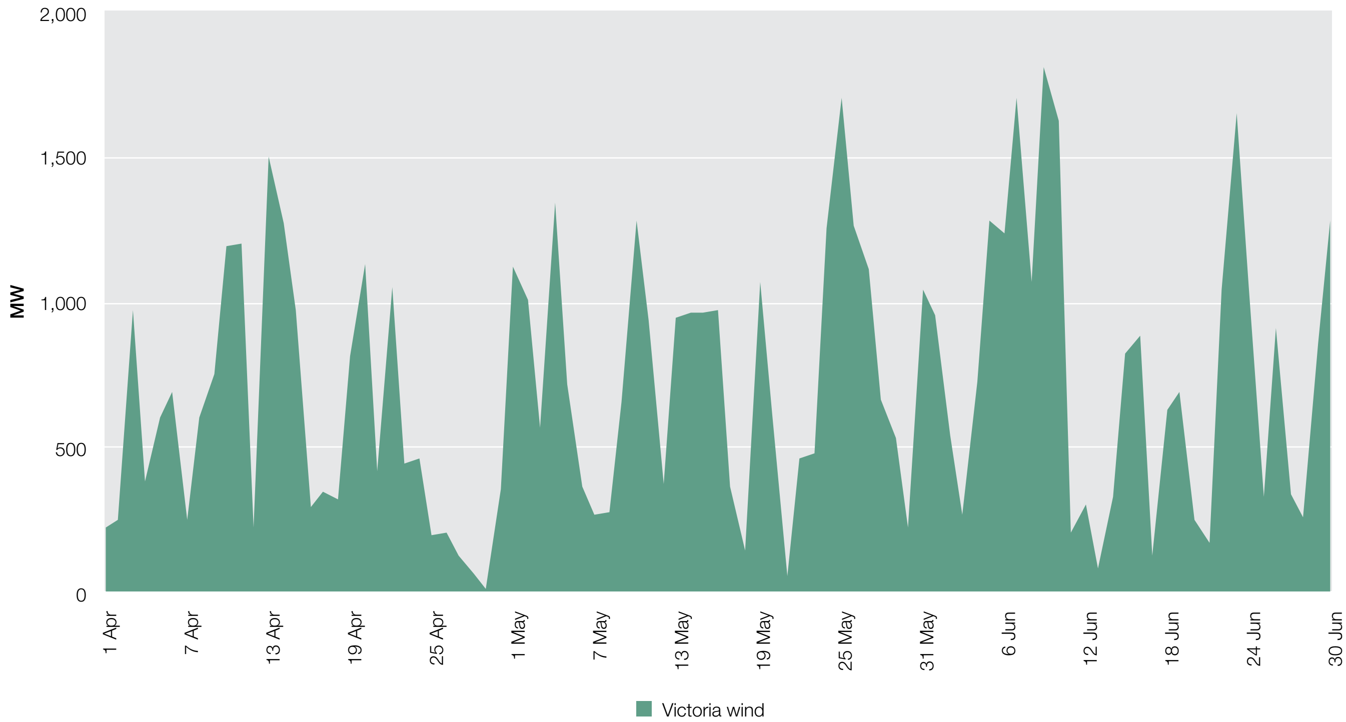
Of all fuel types, wind generation increased the most in Q2 2021 compared to Q2 2020 with the majority of that increase coming from Victoria. In Victoria, average wind generation increased by 30% compared to Q2 2020. Wind generation increased in every other region, except South Australia which experienced mild conditions at the start of the quarter.[8] Record average daily wind generation in the NEM occurred on 25 May.[9] However wind generation output can vary significantly from day to day (Figure 1.17). An example of this variability occurred on 11 June in Victoria, when average wind generation fell around 1,400 MW compared to the amount of wind generation the day before.

Wind conditions across South Australia and Victoria are often similar but it is less common for the same wind conditions to cover NSW as well. However on 17 and 18 May, calm conditions saw wind generation fall across all 3 regions at the same time. At its lowest point only 320 MW was generated out of a possible 6,500 MW of capacity. The lack of low priced wind capacity was one of several factors that contributed to prices rising above $5,000/MWh in the 3 regions. The other factors included unavailable baseload generation due to outages and high demand.

8 AEMO, *Quarterly Energy Dynamics Q2 2021*, July 2021, p. 24.

9 AEMO, *Quarterly Energy Dynamics Q2 2021*, July 2021, p. 23.

Figure 1.17 Victoria, wind generation variability



Source: AER analysis using NEM data.

Note: Average daily metered generation output of Victoria wind generation.

Solar generation almost doubled in NSW in Q2 2021 compared to Q2 2020, making it one of the largest solar generating states in the NEM. Solar generation also doubled in Victoria and increased by 50% in South Australia. This helped contribute to lower prices in the middle of the day (section 1.2).

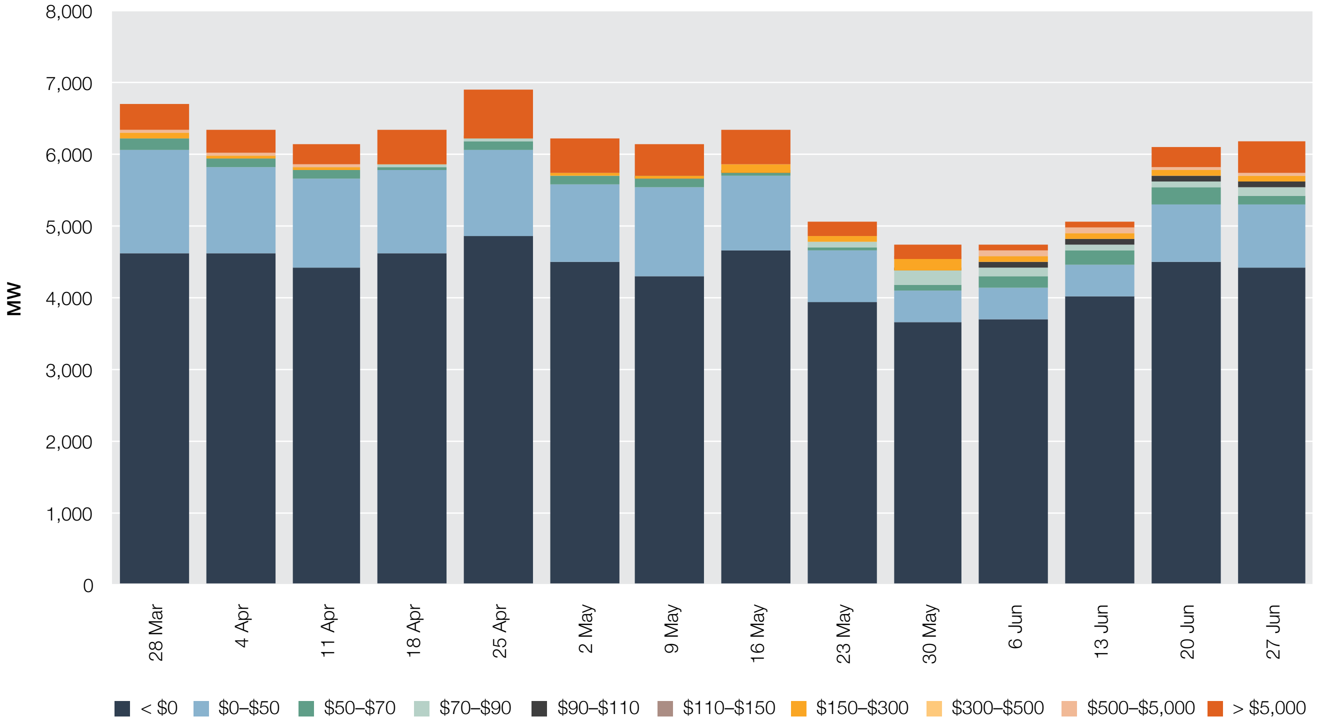
1.6 Low levels of black coal generation offered into the NEM

Due to the large number of planned and unplanned outages in Q2 2021, black coal generators offered less low priced capacity into the NEM.

On average, black coal generators offered 1,440 MW less total capacity in Q2 2021 than they offered in Q2 2020, taking total black coal offers down to their lowest level in any Q2. Of this fall, around 1,000 MW was priced below \$50/MWh. Generally, black coal generators offer the majority of their capacity below \$0/MWh, and in 2020–21 they offered around 90% of their capacity below \$50/MWh.

In Queensland, black coal offers dropped dramatically in the week starting 23 May, when the concurrent outages at Callide C, Callide B and Kogan Creek power stations effectively removed over 1,500 MW of capacity priced below \$50/MWh from the market (Figure 1.18). This was a major driver of price increases in Queensland and NSW at the time.

Figure 1.18 Queensland black coal offers by price band, weekly



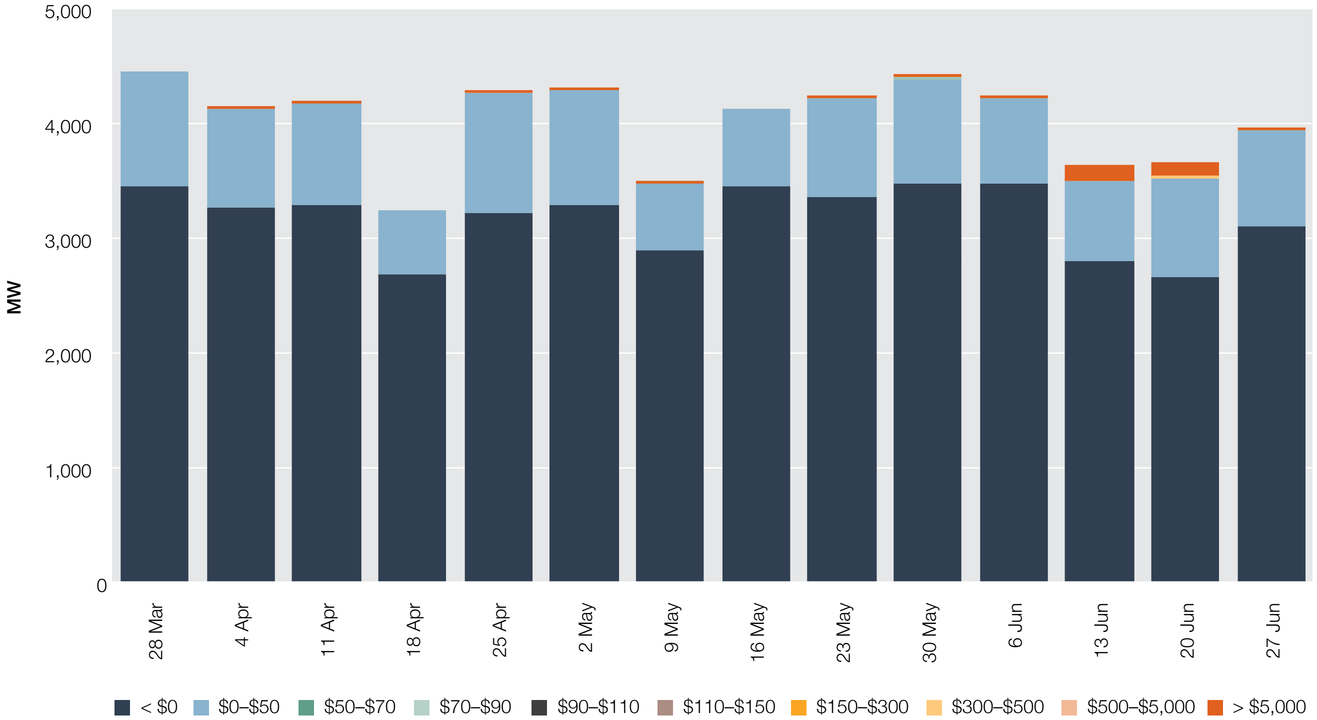
Source: AER analysis using NEM data.

Note: Average weekly offered capacity by Queensland black coal generators within price bands. Weeks start on Sunday. The first and last weeks are partial weeks.

Even though Queensland black coal generators offered around 90% of their capacity priced below $50/MWh over the quarter, they also offered 6% of their capacity priced above $5,000/MWh. In the weeks Queensland prices were at their highest, black coal generators shifted some of this high priced capacity into lower price bands. NSW black coal generators' offers followed similar patterns but with a smaller percentage priced above $5,000/MWh.

Brown coal availability fell in the week starting 18 April due to outages at Loy Yang A and Yallourn power stations (Figure 1.19). Flooding at the Yallourn mine meant that in the week starting 13 June, EnergyAustralia managed its reduced coal supplies by offering less total capacity at Yallourn and shifting some of its remaining capacity into the highest price band.

Figure 1.19 Victoria brown coal offers by price band, weekly



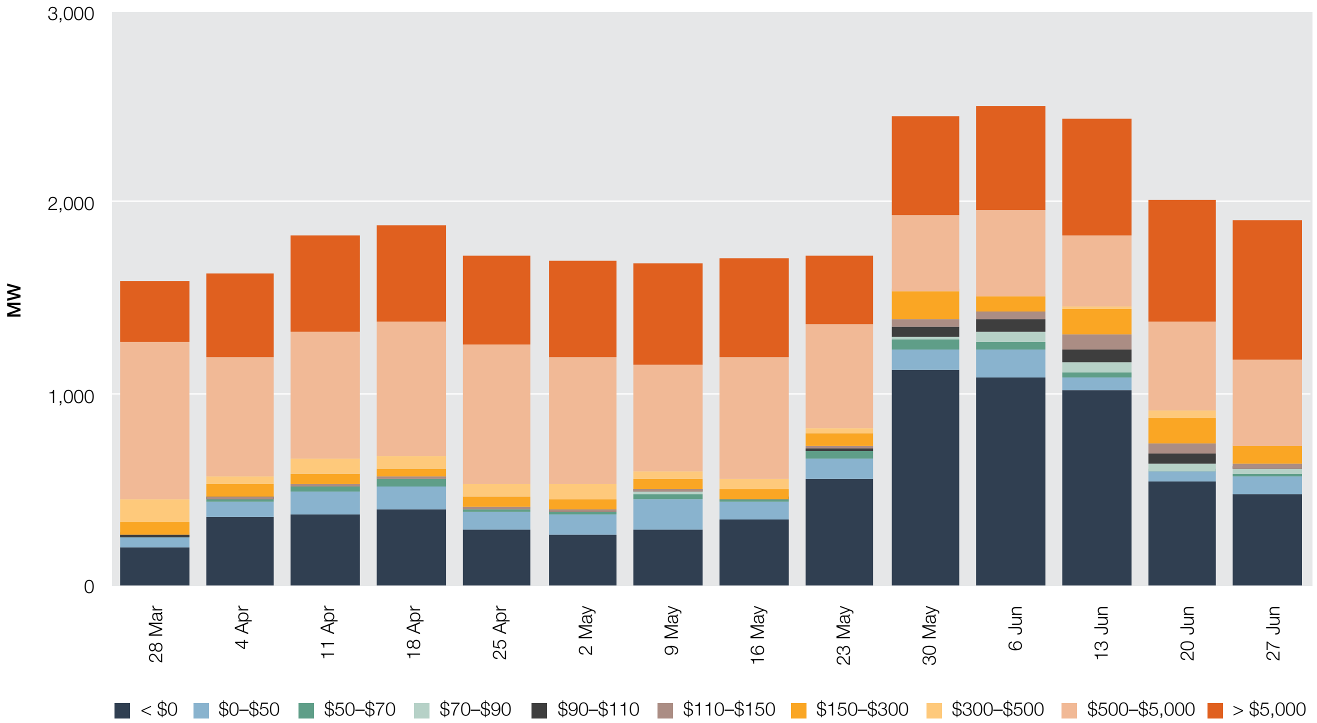
Source: AER analysis using NEM data.

Note: Average weekly offered capacity by Victoria brown coal generators within price bands. Weeks start on Sunday. The first and last weeks are partial weeks.

In response to the black coal outages in Queensland and brown coal outages in Victoria, gas generators increased their availability.

In Queensland after the Callide incident, gas generators increased their average weekly availability by over 700 MW, with 500 MW of this priced below $50/MWh (Figure 1.20).

Figure 1.20 Queensland gas powered generators offers by price band, weekly

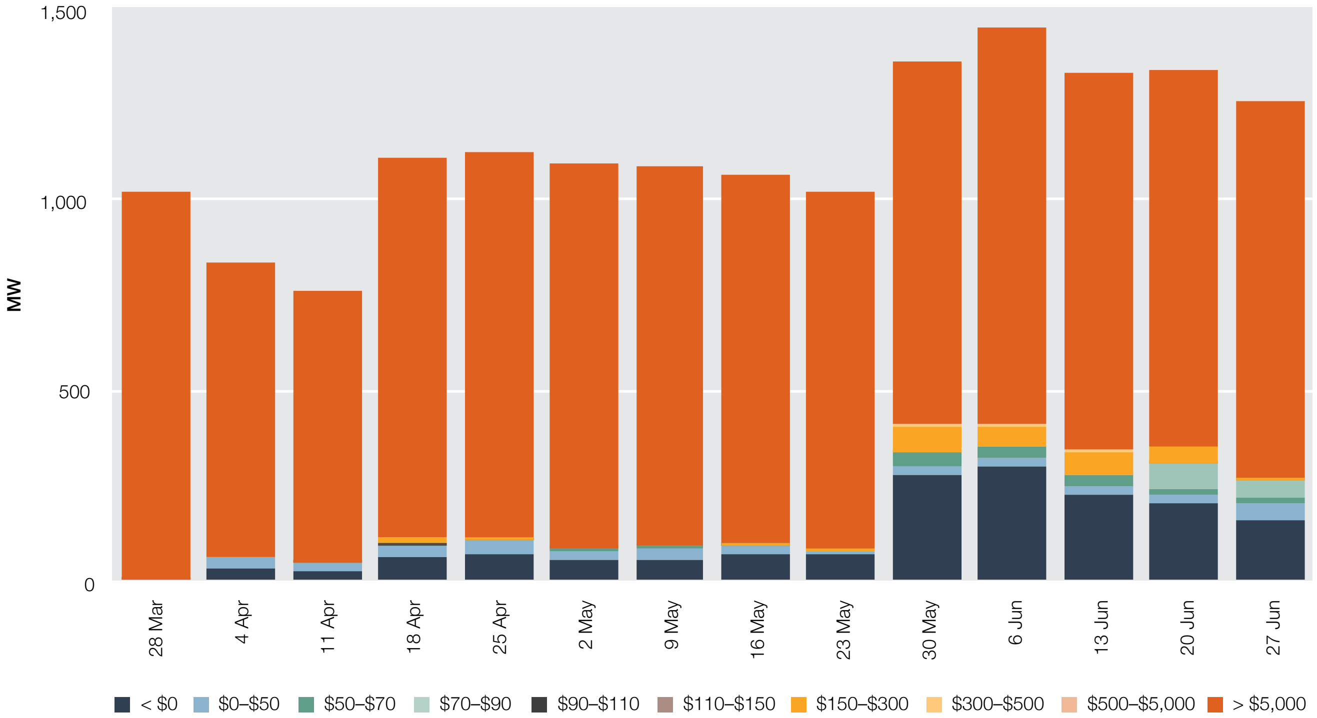


Source: AER analysis using NEM data.

Note: Average weekly offered capacity by Queensland gas powered generators within price bands. Weeks start on Sunday. The first and last weeks are partial weeks.

In NSW, the average weekly amount of gas offered increased in the first 3 weeks of June by around 360 MW compared to offers in April and May, with most of the additional capacity offered below $50/MWh. However, gas generators in NSW still offered at least 70% of their available capacity at prices above $5,000/MWh (Figure 1.21).

Figure 1.21 New South Wales gas powered generators offers by price band, weekly



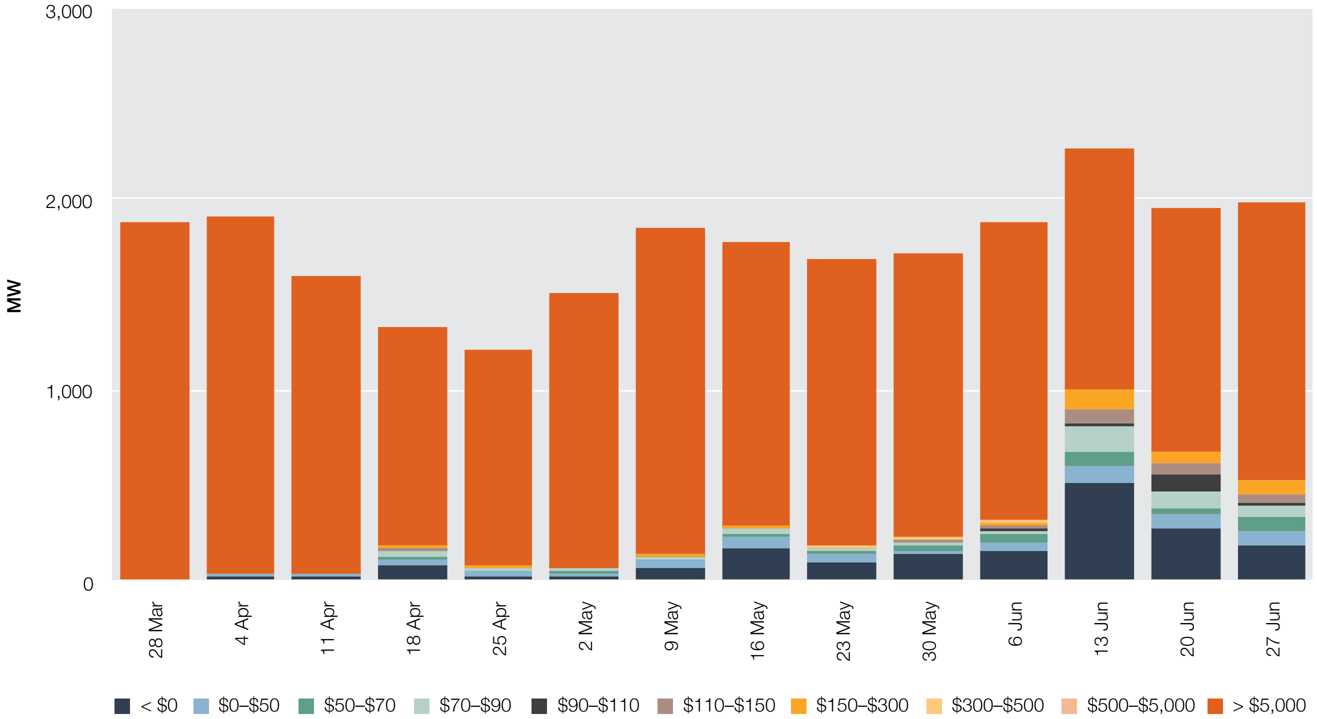
Source: AER analysis using NEM data.

Note: Average weekly offered capacity by NSW gas powered generators within price bands. Weeks start on Sunday. The first and last weeks are partial weeks.

In Victoria, the average weekly amount of gas offered rose gradually as winter demand increased, with a notable increase in the week starting 13 June when Yallourn was facing coal supply issues.[10] Gas generators in Victoria, including EnergyAustralia's Newport and Jeeralang offered more capacity and shifted some capacity into lower price bands at that time (Figure 1.22).

10 Flooding at the Yallourn coal mine commenced 12 June 2021.

Figure 1.22 Victoria gas powered generators offers by price band, weekly



Source: AER analysis using NEM data.

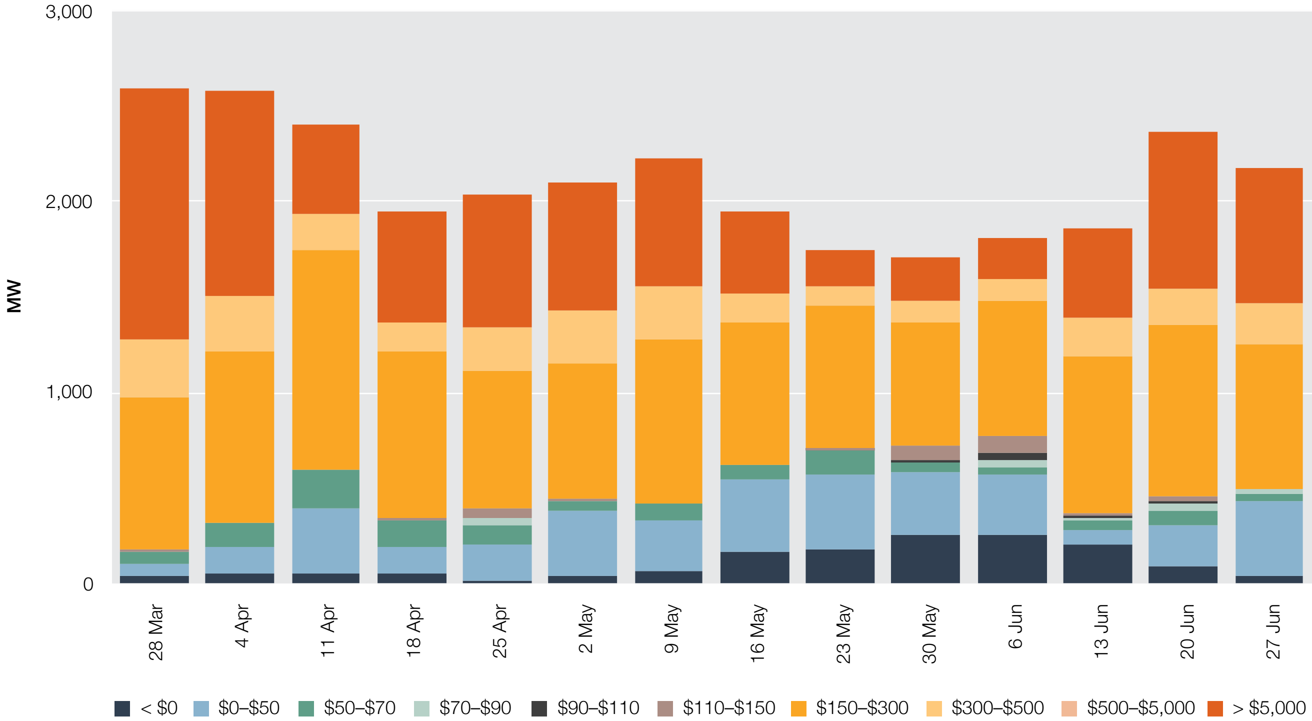
Note: Average weekly offered capacity by Victoria gas powered generators within price bands. Weeks start on Sunday. The first and last weeks are partial weeks.

Even though gas offers increased during the coal outages, Queensland gas generators offered 480 MW less capacity on average over the whole quarter than they did in Q2 2020. Of this reduction, 200 MW was priced below $50/MWh. They also offered 27% of their capacity at prices above $5,000/MWh in Q2 2021 compared to 5% in Q2 2020. There was a big drop in total gas offers in South Australia where gas generators offered almost 300 MW less than in Q2 2020, which was the last quarter when all Torrens A units were operational. Over two thirds of the reduction in Q2 2021 was in offers priced below $50/MWh. In Victoria, total gas generator offers dropped by 100 MW but most of the reduction was from offers priced above $5,000/MWh.

Average quarterly gas offers in NSW in Q2 2021 were similar to offers in Q2 2020. In contrast to Queensland gas offers, 84% of NSW gas capacity was offered at prices above $5,000/MWh.

Hydro generators, like gas generators, offered more capacity priced below $50/MWh during the 3 weeks of the Callide and Kogan Creek events, however they offered less total capacity (Figure 1.23). In Q2 2021, compared to Q2 2020, hydro generators offered almost 750 MW less capacity across the NEM, with over half of this fall in NSW. Almost all the drop in capacity in NSW came from price bands above $5,000/MWh. This was partly offset by a 184 MW increase in capacity offered below $50/MWh.

Figure 1.23 New South Wales hydro offers by price band, weekly



Source: AER analysis using NEM data.

Note: Average weekly offered capacity by NSW hydro generators within price bands. Weeks start on Sunday. The first and last weeks are partial weeks.

Wind capacity offered into the NEM in Q2 2021 increased by around 200 MW compared to Q2 2020. Wind generators in the NEM offered 99% of their capacity at prices below $50/MWh, with nearly all that offered below $0/MWh. Victorian offers increased by an average of 213 MW. This was partly offset by a decrease in offers from South Australia. As wind generators offer nearly all of their capacity at low prices, increased wind output helps put downward pressure on wholesale prices.

Solar offers across the NEM increased by 250 MW in Q2 2021 compared to Q2 2020, with most of the increase coming from NSW. As solar generators typically offer over 95% of capacity priced below $0/MWh, the increase in solar output contributed to lower wholesale prices in the middle of the day (section 1.2) and the increase in the number of negative prices in Q2 2021 compared to Q2 2020 (Figure 1.7). For the first time, while still small, we saw an increase in the amount of capacity Queensland solar generators offered above $5,000/MWh. This could have been to limit their output in order to reduce their exposure to high FCAS costs.[11]

1.7 Interconnector limits reduce Queensland and NSW's ability to import cheaper generation

Line outages and interconnector limits reduced Queensland and NSW's ability to import cheaper generation from other regions when needed, and this also contributed to the higher prices in those regions.

- The ongoing planned outages associated with the upgrade of the Queensland to NSW interconnector (QNI) limited Queensland's ability to import cheaper generation from NSW.
- An increase in line outages around the Vic-NSW interconnector limited NSW's access to cheaper generation from Victoria.

During the outages at Callide B, Callide C and Kogan Creek power stations, upgrades on the QNI meant Queensland was unable to import more generation from NSW when needed. This led to price separation between the 2 regions with the price in Queensland rising above that in NSW. FCAS constraints relating to the QNI upgrades also put upward pressure on Queensland prices.

11 Some FCAS costs are allocated between generators on a causer pay basis. This is determined by the number of times and amount they are away from their target and thus contribute to frequency deviations.

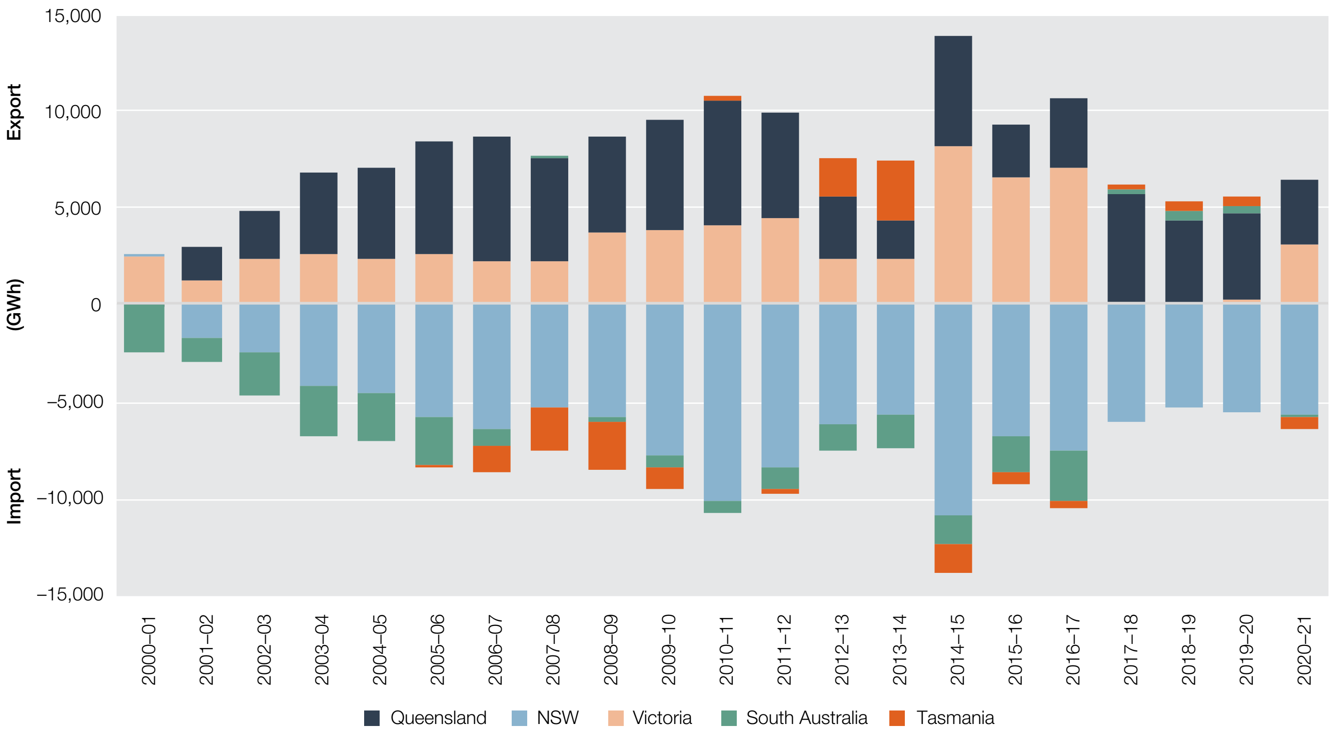
In May 2020, an upgrade to the QNI commenced. This work will allow an additional 460 MW of electricity to flow from NSW to Queensland, and an extra 190 MW from Queensland to NSW. The upgrade is expected to be complete by December 2021 and will help ease capacity concerns ahead of the closure of the Liddell power station in NSW starting in 2022.

NSW's access to cheaper generation from Victoria on the Vic-NSW interconnector was also limited in Q2 2021 which contributed to higher prices in both NSW and Queensland. When NSW was importing from Victoria, flows were constrained 40% of the time in Q2 2021 compared to 25% of the time in Q2 2020, with line outages accounting for two thirds of those constraints. On average, imports into NSW from Victoria were limited to around 520 MW during the evening peak due to planned outages around Canberra and South Morang in Victoria.[12] Without line outages, the normal limit on the Vic-NSW interconnector is around 1,300 MW.

Financial year 2020–21 observations of regional flows were (Figure 1.24):

- 2020–21 was the first time Victoria was a significant net exporter since 2016–17, mostly driven by low demand and excess brown coal, wind and solar generation in Victoria in Q1 2021.
- In 2020–21 exports from Queensland and imports from NSW fell.
- Tasmania and South Australia switched from being net exporters in the previous 3 financial years to become importers in 2020–21.

Figure 1.24 Financial year net flows between regions (exports – imports)



Source: AER analysis using NEM data.

Note: Total amount of energy either imported or exported each quarter.

1.8 Demand increased with the onset of winter

Demand increased over the quarter as temperatures fell and there were some particularly cold days.[13 14] On June 10, Sydney had its coldest June day in 100 years and NSW experienced its highest Q2 daily demand since 2010 (Figure 1.25). Increased demand at a time that supply was reduced due to generator outages lead to more volatile prices (section 1.1). For example on 10 June, prices in NSW rose to above $5,000/MWh.[15]

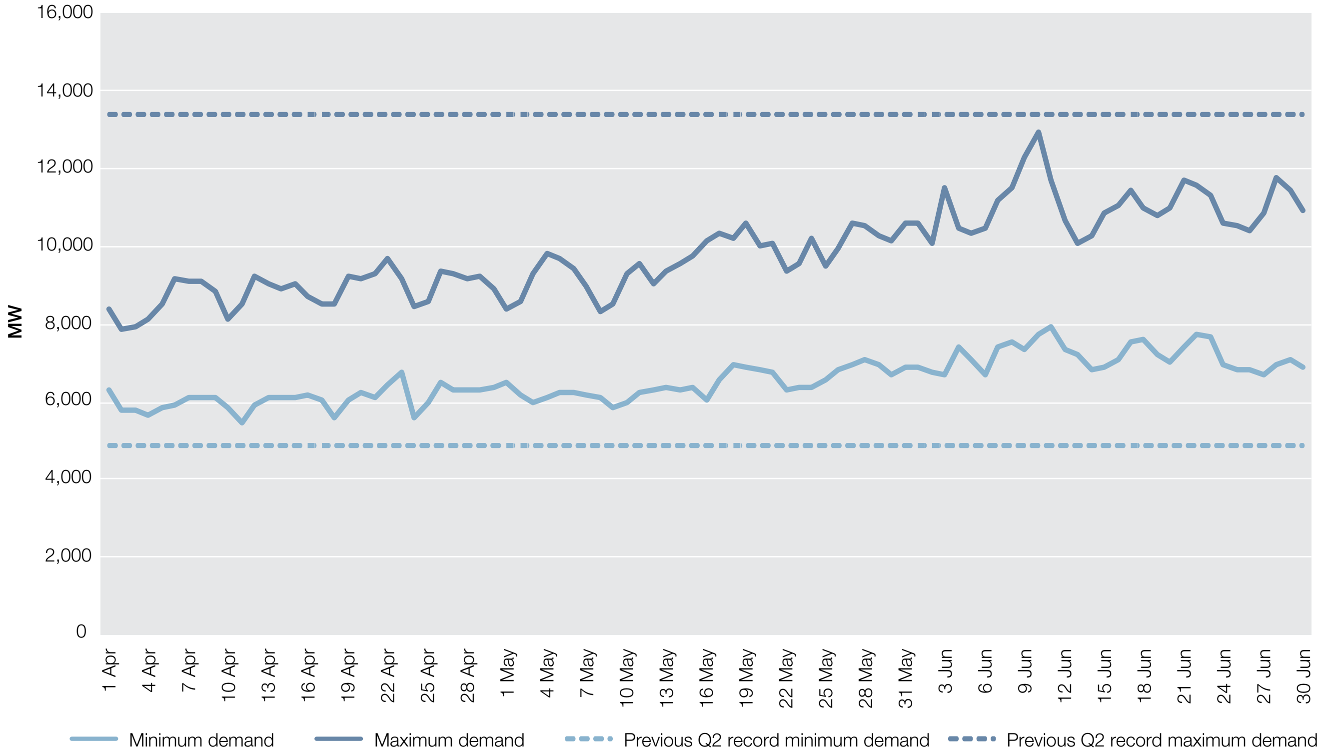
12 The average limit when flows into NSW from Victoria were constrained.

13 In Sydney: April was warmer than average in the day, cooler at night; May was close to average, and June slightly cooler. In Brisbane, April was cooler than usual; May was close to average in the day and cooler at night; and June temperatures were close to average. The Bureau of Meteorology.

14 AEMO analyses demand in more detail in its *Quarterly Energy Dynamics Q2 2021*.

15 The AER publishes $5,000/MWh reports which analyse the drivers of these high prices in more detail. AER $5,000/MWh reports.

Figure 1.25 Daily maximum demand Q2 2021, New South Wales



Source: AER analysis using NEM data.

Note: Uses daily minimum and maximum native demand.

1.9 Nearly all fuel types set higher prices, and more expensive fuels set the price more often

Driven by the generator and line outages described above, and high demand, average quarterly prices in Q2 2021 were higher than in Q2 2020 because (Figure 1.26):

- more expensive fuels such as gas and hydro set the price more often
- gas and hydro generators set higher average prices than they did in Q2 2020, especially in Queensland and NSW.

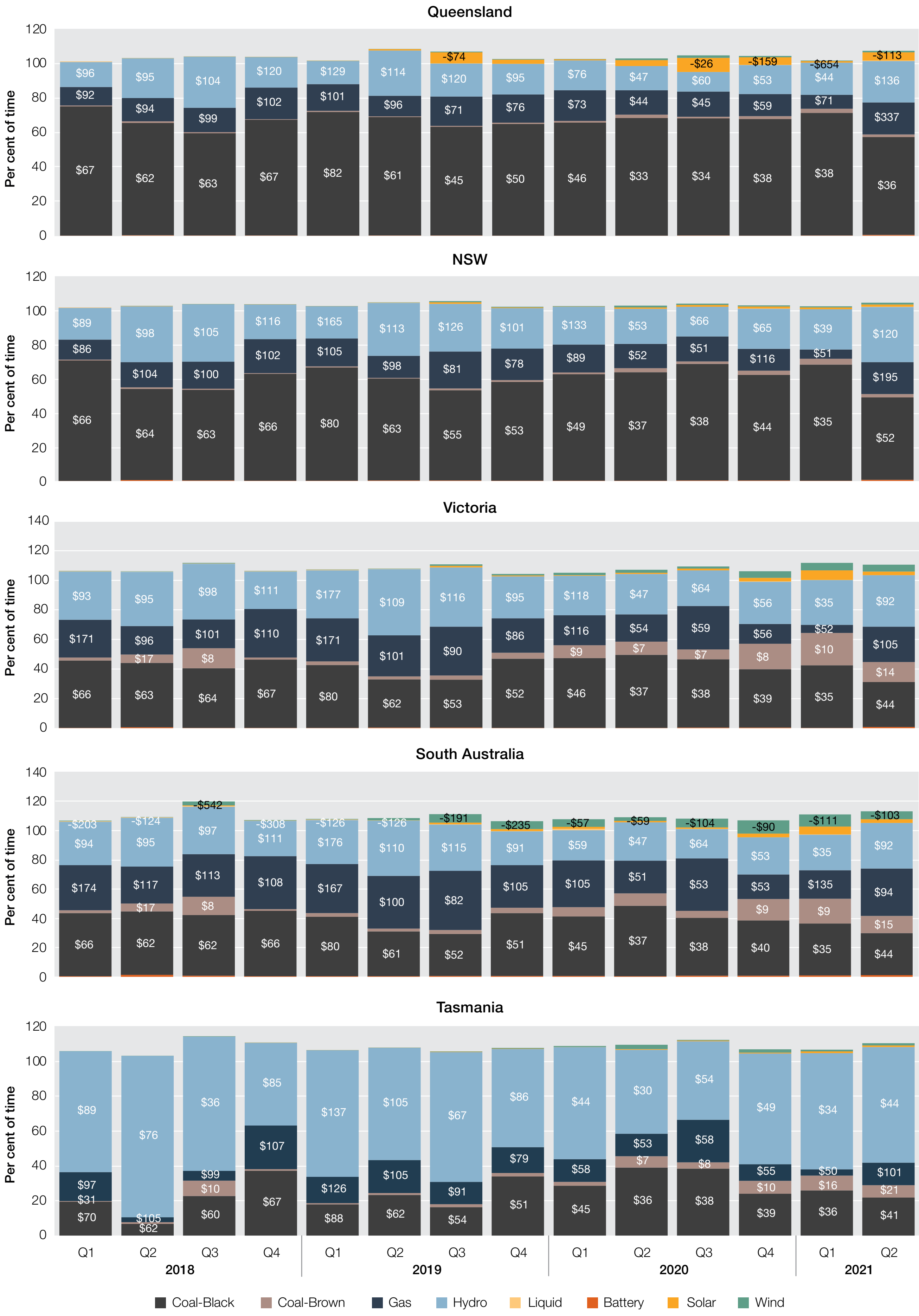
More expensive gas and hydro generation was needed, particularly in Queensland and NSW, to replace the large amount of baseload capacity that was removed by outages, and to meet the higher levels of demand. This a reversal of the conditions experienced in the previous 2 quarters when gas and hydro generation was generally not needed to meet demand.

In Queensland, combined gas and hydro set the price over 40% of the time compared to 28% of the time in Q2 2020 and they set much higher prices. Gas generators set an average price of $337/MWh, and hydro generators set an average price of $136/MWh this quarter, compared to $44/MWh and $47/MWh respectively in Q2 2020. These average increases were driven by some particularly high priced intervals when peaking gas and hydro typically set the price. Because of outages and higher demand (section 1.8), black coal set the price 12% less often.

In NSW, combined gas and hydro set the price more often in Q2 2021 than in any other quarter in at least the last 6 years, setting the price over half of the time. Gas generators set an average price of $195/MWh and hydro generators set an average price of $120/MWh, which, while lower than in Queensland, is still quadruple and double the prices they set in Q2 2020. Black coal set progressively higher prices each month. So while it set an average quarterly price of $52/MWh in Q2 2021, in June it set an average monthly price of $82/MWh.

In Victoria, black coal set the price only 30% of the time, which is less than in any quarter since at least Q1 2005, and gas and hydro set the price almost 60% of the time. Gas and hydro set average prices that were nearly double the prices they set in Victoria in Q2 2020, however, they set much lower prices in Victoria than in NSW and Queensland. Price setting outcomes in South Australia were closely aligned with those in Victoria.

Figure 1.26 Price setter by region



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).

1.10 Fuel costs rise

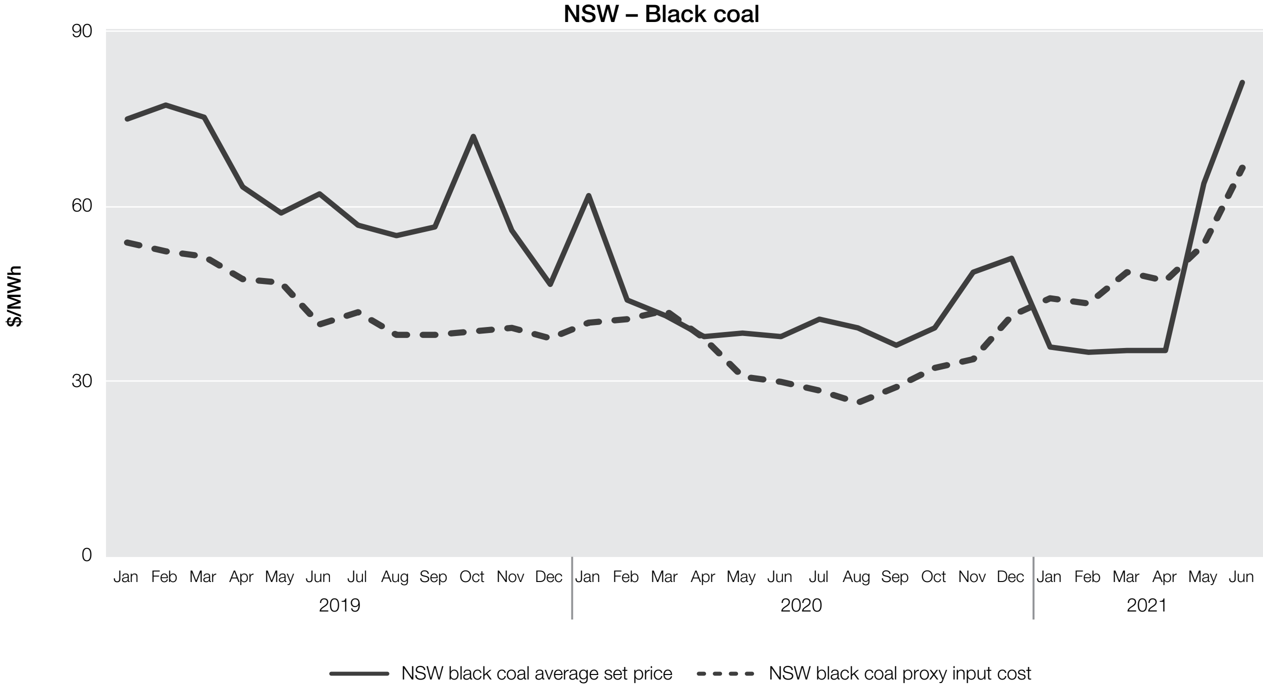
International and domestic gas prices rose over the quarter as did the Newcastle coal index (Figure 1.27).

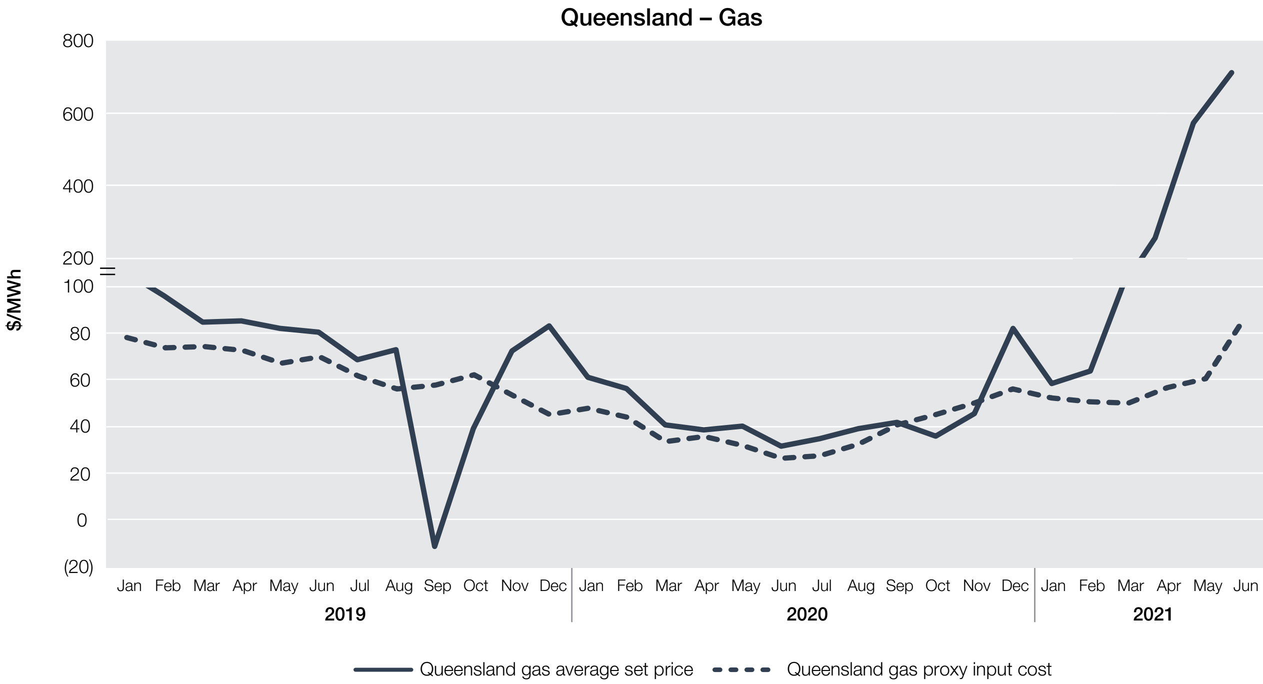
Gas input costs increased over the quarter in every region. For example, the Queensland gas proxy input cost rose from below $51/MWh in March to above $87/MWh in June 2021, the highest level we have observed since July 2016.[16] The drivers of rising gas spot prices in June included unexpectedly high domestic demand for gas powered generation and rising international gas prices (section 2.1).

The price set by gas generators in Queensland increased as the quarter progressed and exceeded the proxy input costs by over $510/MWh in May and June, driven by numerous high priced events in the region when the most expensive peaking gas was needed to meet demand.

16 Proxy price based on Brisbane STTM prices, converted using a standard heat rate for gas generators.

Figure 1.27 Proxy input costs and the average price set by NSW black coal and Queensland gas





Source: AER analysis using the GlobalCOAL Newcastle coal index, the STTM price and NEM data.

Note: Black coal proxy input cost is derived from the Newcastle coal index (USD$/tonne) sourced from globalCOAL, converted to AUD$/MWh with RBA exchange rate, and average heat rate for coal generators. The gas proxy input cost is derived from the STTM (AUD$/GJ) of a respective region, converted to AUD$/MWh with average heat rate for gas generators.

International coal prices rose for the fourth consecutive quarter driven by rising seasonal demand and international supply problems.[17] This caused the coal proxy to increase by 130% between April and June to the highest level we have seen in at least 6 years.[18]

The price set by NSW coal generators remained below the rising coal proxy cost in April, but then soared to rise above it in May and June. In April, black coal generators set an average price of $35/MWh, in line with the low prices they set in Q1 2021, but in May that price jumped to $64 MWh, and in June it jumped again to $81/MWh. NSW coal generators last set a monthly price that high in September 2017. In contrast, where the monthly price set by Queensland black coal generators is generally similar to that set in NSW, in Q2 2021 it remained around half the price set by black coal generators in NSW.

The gap between the proxy fuel input costs we use and the price at which gas generators in particular set the price was very large in Q2 2021. As highlighted above, this was largely driven by the times these fuel types were setting prices – times of short supply and particularly high prices. We will continue to monitor the prices set by generators, including looking at this information at a participant level.

1.11 More solar capacity in NSW and more wind capacity in Victoria

Over 3,000 MW of new wind and solar farms entered the market in 2020–21. Most of the new capacity entered in the first half of the financial year, slowing noticeably in the second half (Table 1.2). Geographically, around two thirds of the new capacity was located in NSW and the remaining third in Victoria.

New entry in 2020–21 took total large scale solar capacity in the NEM to over 5 GW and total wind capacity to over 8 GW. The largest share of solar capacity is now located in NSW and the largest share of wind capacity is located in Victoria. Combined, NSW and Victoria account for around two thirds of total wind and large scale solar capacity in the NEM. In 2020–21, 270 MW of gas capacity also left the market. AGL Energy closed the first 2 units of Torrens Island Power Station in South Australia and Stanwell closed the Mackay Gas Turbine, a small, remotely controlled peaker in Queensland.

Table 1.2 Financial year 2020–21 new entry and exit, by fuel type and region

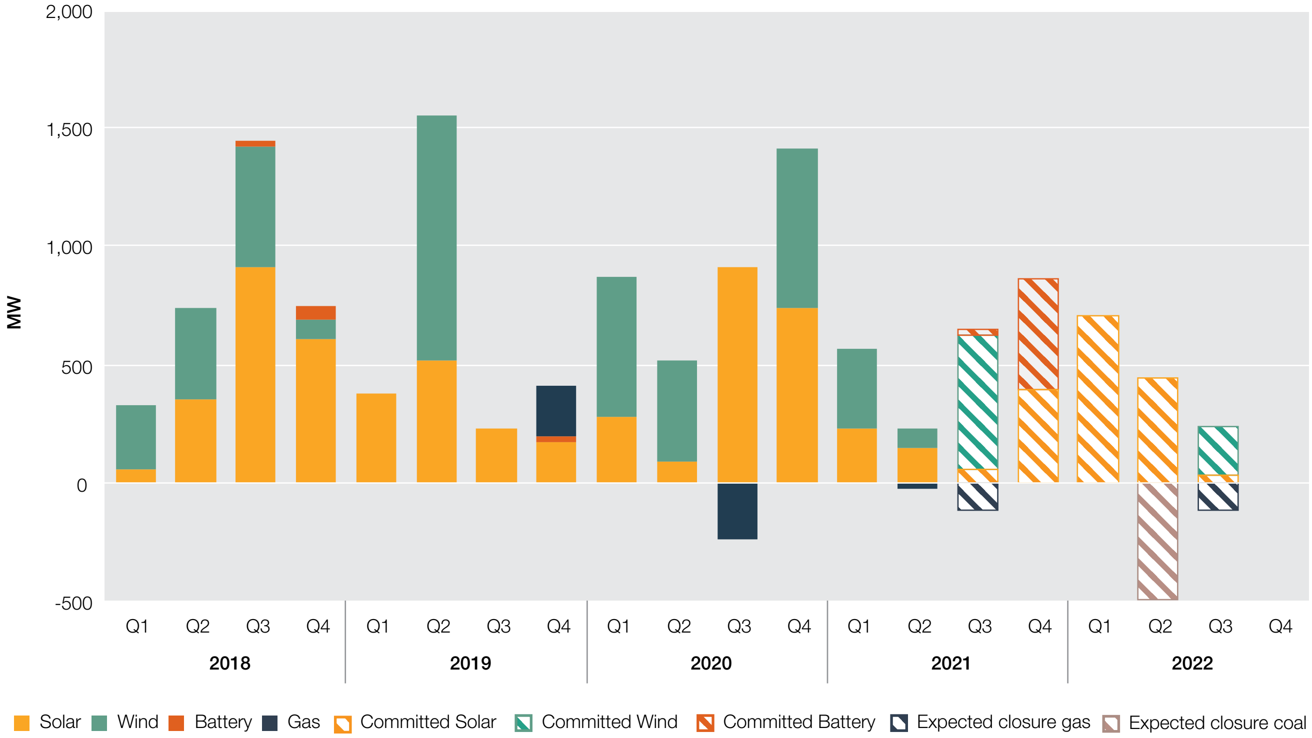
REGION	SOLAR	WIND	TOTAL NEW ENTRY	GAS EXIT
Queensland	108	0	108	-30
NSW	1,314	610	1,924	
Victoria	603	492	1,095	
SA	0	0	0	-240
Tasmania	0	0	0	
NEM	2,025	1,102	3,127	-270

In Q2 2021 only one solar farm, Gunnedah (144 MW), and one wind farm, Bango 999 (84 MW), entered the market, both located in NSW (Figure 1.28). Mackay gas turbine (30 MW) in Queensland left the market.

17 On 1 June, spot prices for high quality thermal coal in the port of Newcastle were reported to have risen to the highest price since 2011.

18 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 obtain coal from further afield. Because short term supply contracts and renegotiated long term contracts are often shaped by international coal prices, we use the price of coal at the Newcastle port as a reference point for NSW coal fuel costs. However, the Newcastle coal price reflects a generator's theoretical maximum cost of some of its coal.

Figure 1.28 Quarterly new entry and exits



Source: AER analysis using AEMO generator information (May 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.

1.12 FCAS costs high

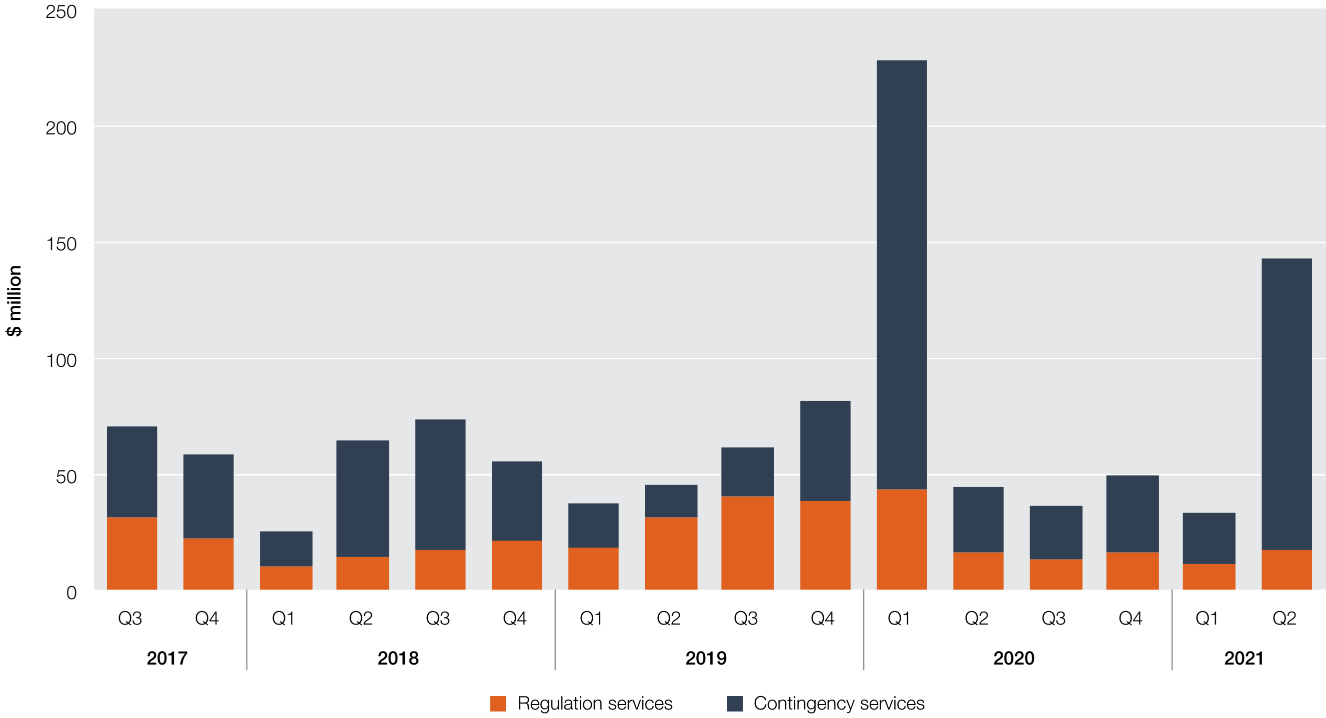
FCAS costs in 2020–21 were the second highest on record, after record FCAS costs in 2019–20. These high financial year costs were mostly the result of high FCAS costs in Q2 2021.

Total FCAS costs in Q2 2021 were $142 million, including record local FCAS costs in Queensland of $74 million. This was the second highest quarterly FCAS costs in the NEM, after record costs in Q1 2020 (Figure 1.29).

Upgrades on QNI and plant outages were the main drivers behind FCAS costs in Queensland in Q2 2021. When upgrades on QNI were underway the region had to provide its own FCAS, in the event it became islanded from the rest of the NEM. Also local plant outages and limited imports from NSW reduced the supply available to meet the requirement for FCAS and demand for energy. As a result, higher priced capacity for contingency services was frequently needed across the quarter, ultimately leading to the cumulative price threshold being breached. Our focus story explains the drivers of the high local Queensland FCAS costs in more detail.

Total FCAS costs were mostly driven by contingency costs of $126 million, mostly in Queensland. The cost of raise 6 second services made up greatest portion ($81 million) followed by the cost for raise 60 second services ($36 million). Compared to Q2 2020 there was almost no change in the cost of regulation services.

Figure 1.29 Total FCAS costs

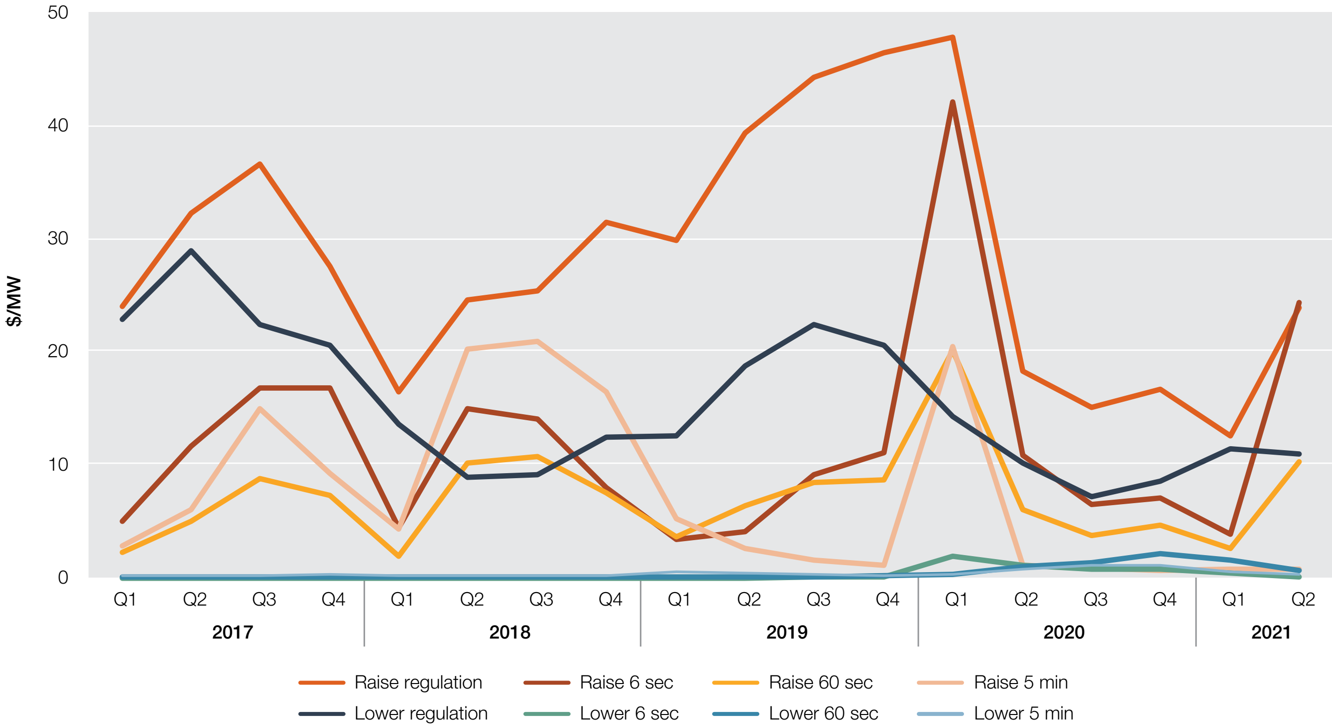


Source: AER analysis using NEM data.
Note: Average quarterly FCAS costs in the NEM.

The increase in global costs in Q2 2021 compared to Q2 2020 was mainly due to an increase in global FCAS prices rather than in increase in global enablement. Average quarterly global prices for raise 6 second services rose 124% compared to Q2 2020, for raise 60 second services they rose 70% and for raise regulation services they rose 31% (Figure 1.30).

There was very little change in the quarterly average prices for lower services or raise 5 minute services.

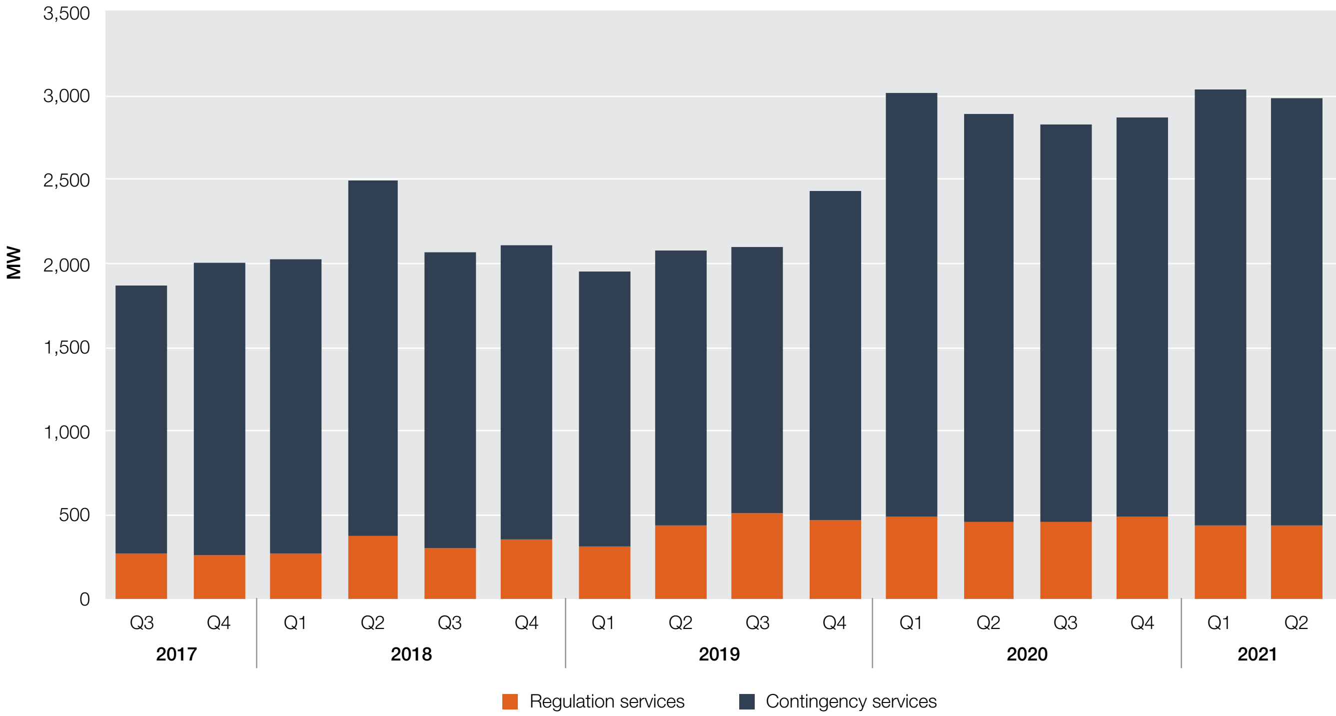
Figure 1.30 FCAS prices by service, quarterly



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

There was little change in average enablement in Q2 2021 compared to Q2 2020 (Figure 1.31).

Figure 1.31 FCAS enablement



Source: AER analysis using NEM data.
Note: Average quarterly FCAS enablement.

Focus – Drivers of high FCAS costs in Queensland

In Queensland in Q2 2021, average frequency control ancillary services (FCAS) prices exceeded $5,000/MW in raise 6 second (R6), raise 60 second (R60) and lower 6 second (L6) services for a total of 37 trading intervals. The principal drivers of these high FCAS prices were:

- network outages as part of the Queensland–NSW Interconnector (QNI) upgrade, increased Queensland's risk of becoming electrically islanded and triggered local FCAS requirements in Queensland
- insufficient capacity was offered below $5,000/MW in Queensland to meet high local requirements
- the interaction of energy and FCAS markets reduced the amount of FCAS available
- the co-optimisation of high energy and FCAS prices.

Rebidding of capacity by participants from low to high prices did not contribute to the high prices.

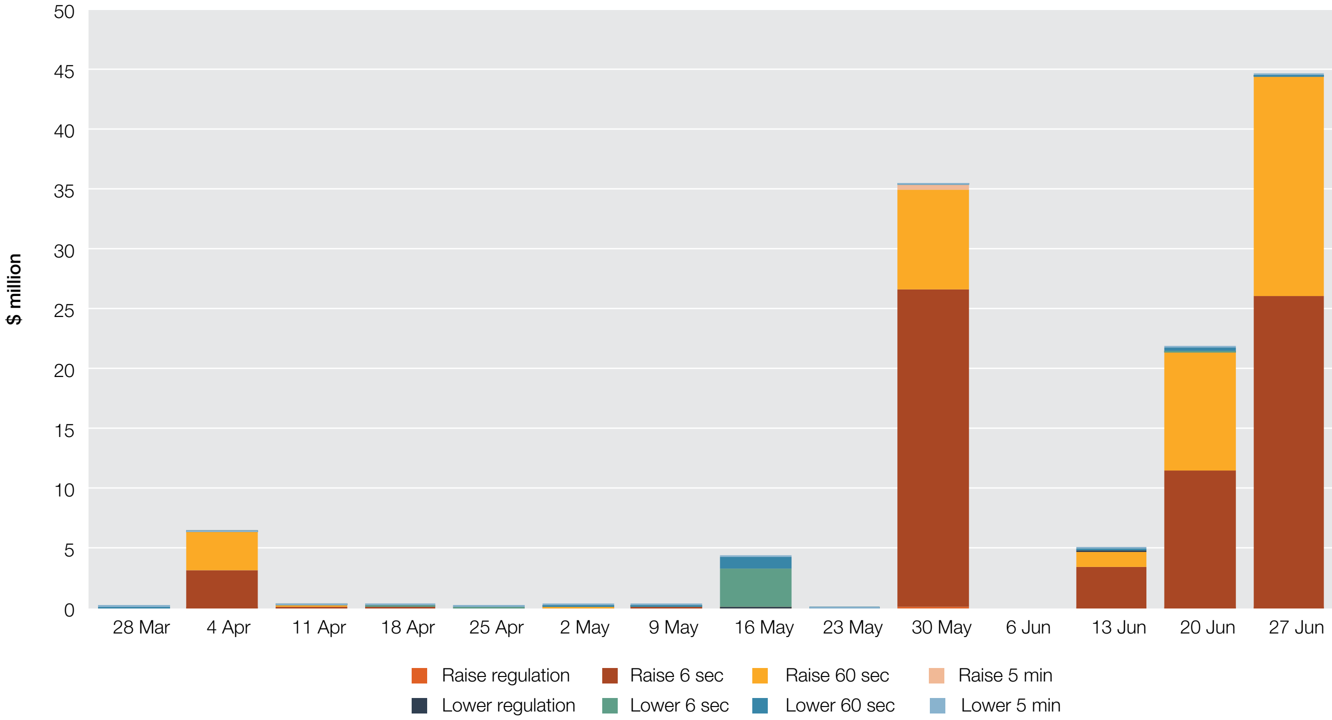
High FCAS prices in Queensland during Q2 2021

Over the quarter, there were 37 trading intervals where FCAS prices exceeded $5,000/MW: 34 occasions for R6, 12 occasions for R60 and 3 occasions for L6.[19] A complete table of all the trading intervals where FCAS prices were above $5,000/MW is in Appendix B.

As a result of high prices and local requirements, Queensland FCAS costs reached their highest level ever. Most of these costs occurred late in the quarter (Figure 1.32).

19 Some trading intervals had more than one high priced service exceed $5,000/MW.

Figure 1.32 Weekly local Queensland FCAS costs



Source: AER analysis using NEM data.

Note: Weeks start on Sundays. The first and last weeks are whole weeks. The week starting 27 June includes local FCAS costs on 3 July.

The high costs that occurred for the week beginning 27 June were due to FCAS prices on 3 July exceeding $5,000/MW. Although not part of Q2 2021, we include those prices in our analysis as they were caused by the same drivers.

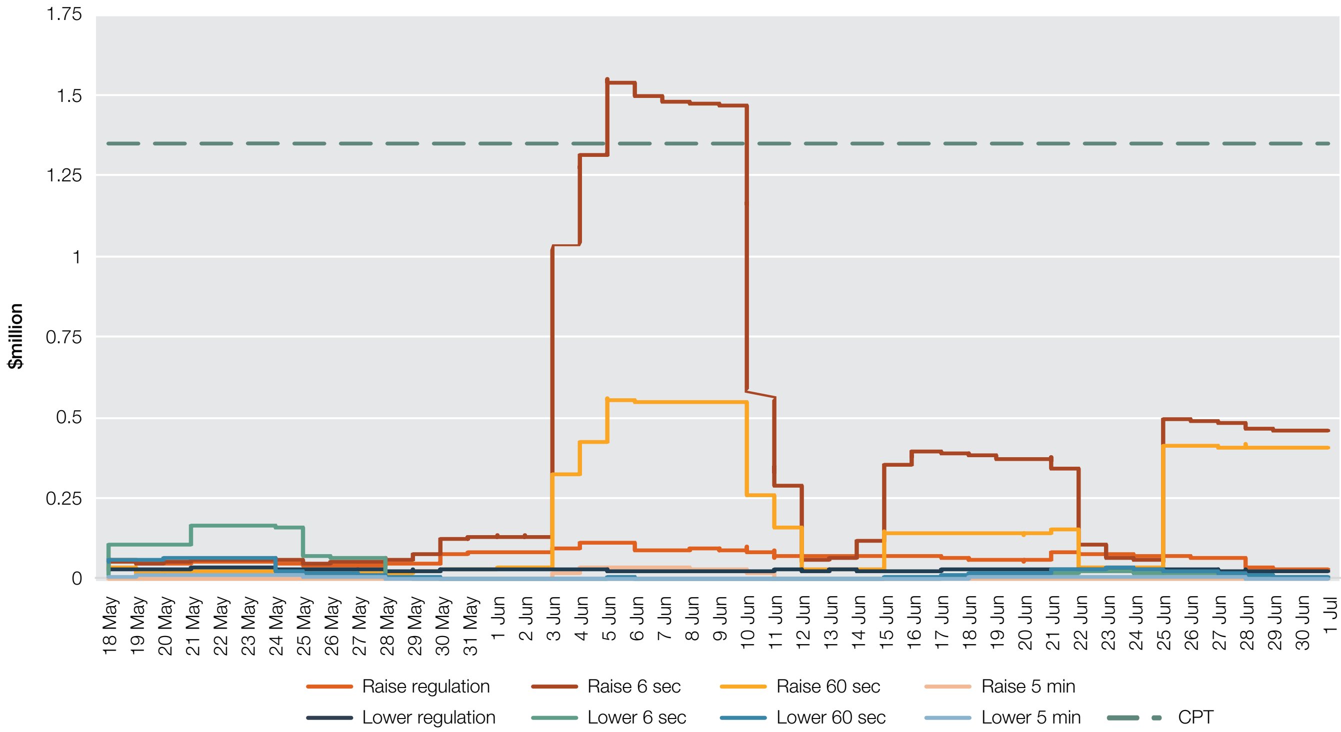
Cumulative price threshold

On 3, 4 and 5 June, prices for R6 services in Queensland were sustained at sufficiently high levels to exceed 6 times the cumulative price threshold (CPT – Figure 1.33). The Australian Energy Market Operator (AEMO) immediately capped prices for all FCAS to $300/MW until the cumulative price fell below the CPT on 10 June.

Prolonged exposure to sustained high wholesale market prices has the potential to materially impact the financial viability of market participants. The CPT exists to limit the financial exposure of market participants to sustained price risk.[20] In FCAS markets, once the sum of the previous 2,016 dispatch prices exceeds 6 times the CPT for energy (at the time $1,347,600 for FCAS) prices are capped at $300/MW for all FCAS markets until the cumulative price falls below the CPT.

20 The CPT is set each financial year by the AEMC as part of the NEM's reliability settings in accordance with the Rules. In 2020–21, the energy CPT is $224,600/MWh.

Figure 1.33 Cumulative price threshold



Source: AER analysis using NEM data.

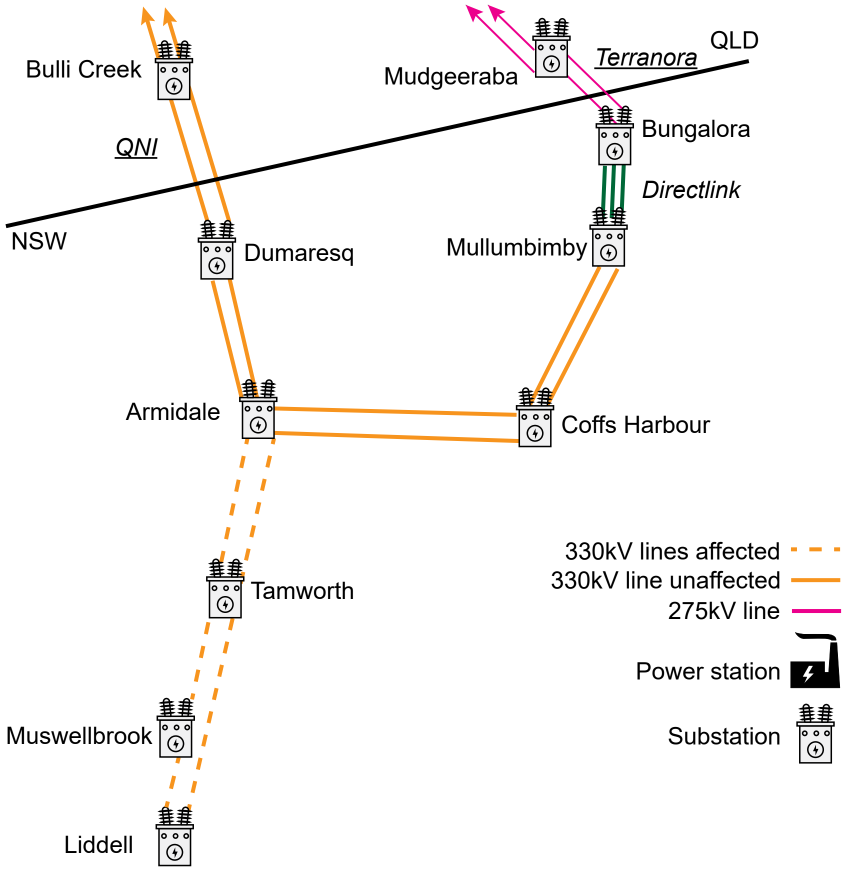
QNI upgrade meant local FCAS was required

The upgrade to QNI required a series of transmission line outages that reduced interregional transfer capability and increased the credible risk of Queensland electrically separating from the rest of the NEM (Table 1.3 and Figure 1.34). This required AEMO to invoke constraints that set the requirement for FCAS that had to be sourced locally in Queensland and was the main driver of high prices. The local requirement was as high as 328 MW for R6, which is over half the normal global requirement.

Table 1.3 Line outages and affected FCAS

DATE	LINE OUTAGE	FCAS WHERE PRICES >$5,000/MW
10 April	Liddell to Tamworth	R6, R60
18 May	Muswellbrook to Tamworth	L6
3 and 4 June	Liddell to Muswellbrook	R6, R60
15 June	Armidale to Tamworth	R6, R60
25 June	Liddell to Tamworth	R6, R60
3 July	Liddell to Tamworth	R6, R60

Figure 1.34 Simplified network diagram of affected lines



Source: AER

Note: Directlink is a direct current interconnector that cannot provide FCAS.

FCAS-Energy interaction reduces FCAS availability

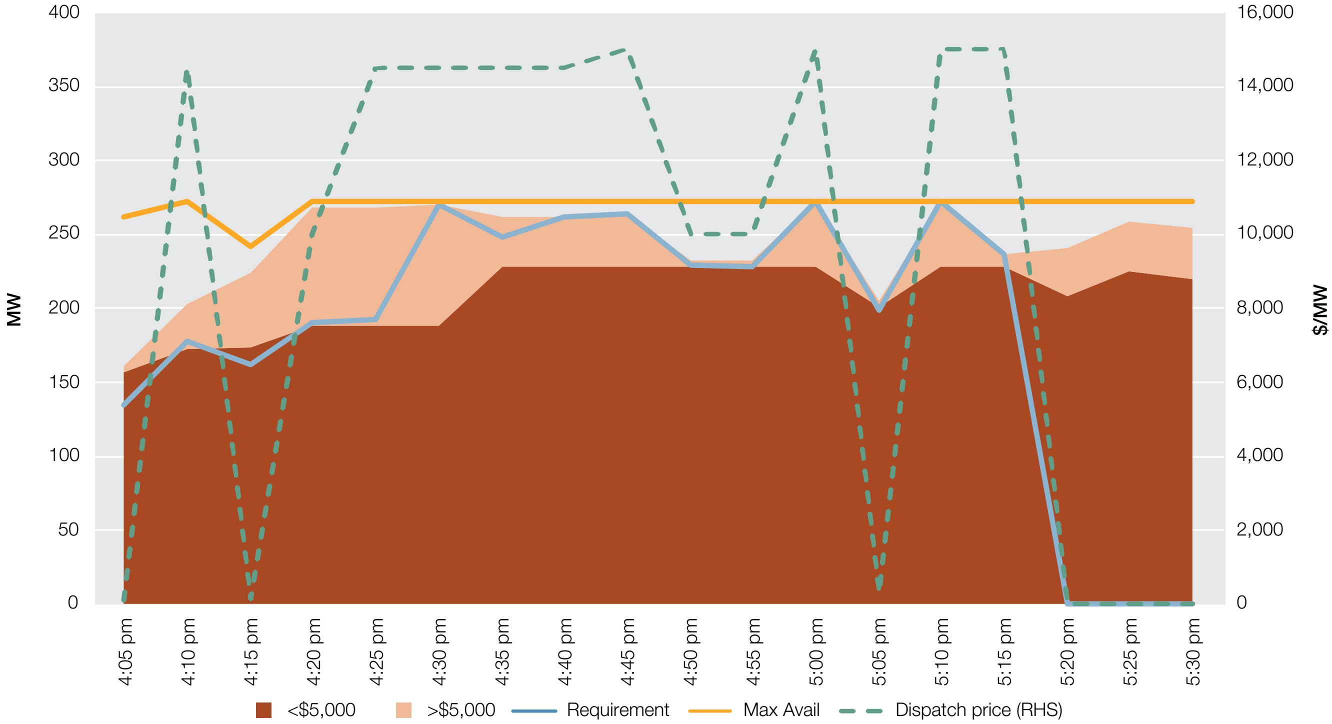
While a generator can simultaneously provide energy and FCAS, its output in energy influences its ability to provide FCAS and vice versa. Participants registered for both markets will offer their maximum capacity for FCAS and energy across 10 price bands for a trading day. This sets a theoretical maximum availability of FCAS for a generator. However, the trade-off between energy and FCAS determines the 'effective' availability of FCAS for a generator.

For example, a generator that is operating at its maximum capacity in energy cannot increase its output any further to provide raise services, so its effective available capacity for raise services would be 0 MW. To provide additional raise services a generator would need its energy target reduced to provide it the headroom necessary for it to provide raise services.

During the generator outages in Q2 2021 (Appendix A) the remaining generators needed to make up for the loss in the energy market. Where these generators also offered FCAS, this left them less headroom to provide raise services. This trade-off was seen in more than half of the high-priced trading intervals in the quarter and reduced the maximum availability during a trading interval by up to 45%.

On 10 April the effective availability for R6 services was lower than the maximum availability in most trading intervals, showing how the trade-off between the energy and FCAS markets can reduce FCAS availability (Figure 1.35). On this occasion, the FCAS price was set by a co-optimisation between energy and FCAS during 5 of the high-priced trading intervals.

Figure 1.35 Effective availability of raise 6 second services, 10 April



Source: AER analysis using NEM data.
Note: Prices are 5 minute prices.

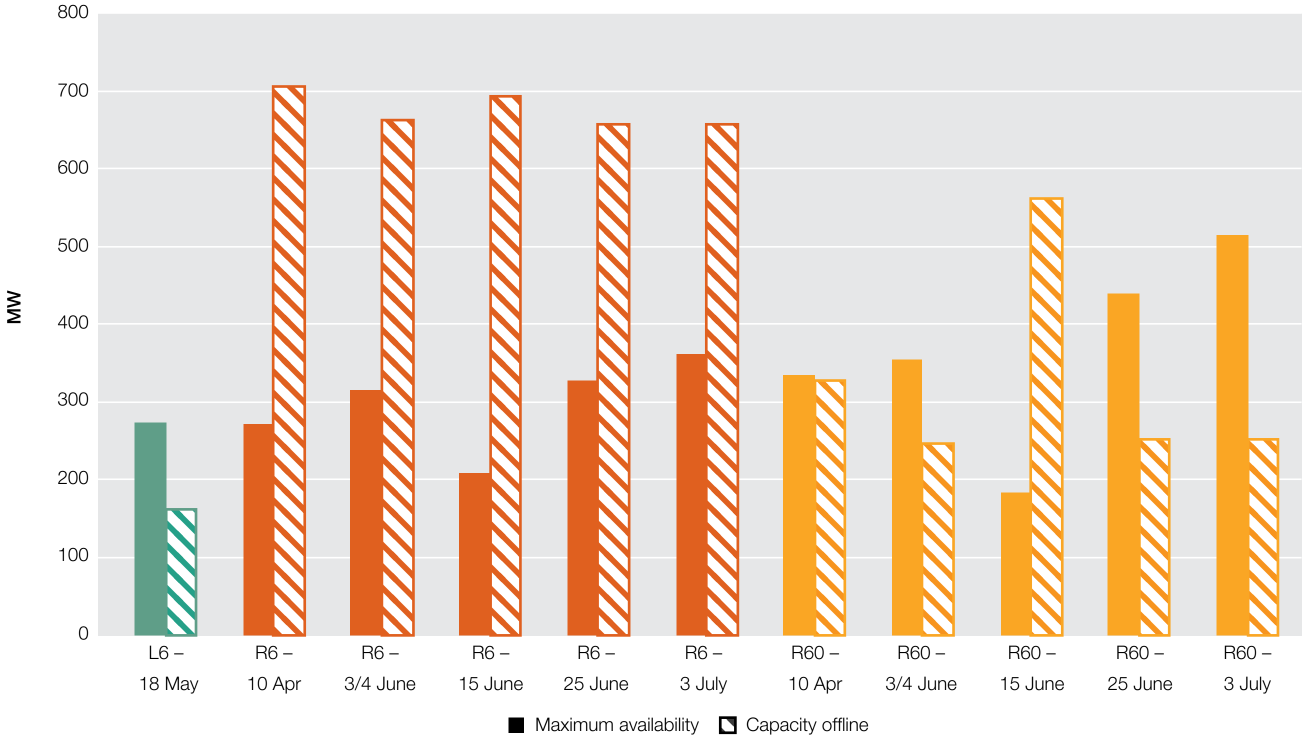
Generator outages reduced the amount of FCAS offered

When FCAS exceeded $5,000/MW there were significant generator outages that reduced the amount of R6, R60 and L6 services offered. The most significant include:

- CS Energy – Stanwell unit 2, Callide B units 1 and 2, and at least one Gladstone unit
- Alinta Energy – Braemar unit 3
- CleanCo – Swanbank E unit for R6 services.

These outages saw up to 693 MW of R6 services, 562 MW of R60 services and 162 MW of L60 services of registered capacity unable to be offered (Figure 1.36). For R6 services this was more than was actually offered into the market.

Figure 1.36: Maximum availability of units online and registered capacity of units offline



Source: AER analysis using NEM data.

Price setter and co-optimisation

During the 37 trading intervals where FCAS prices exceeded $5,000/MW, there were 218 FCAS dispatch (5 minute) prices that exceeded $5,000/MW. Of these, 88 (40%) were a result of co-optimised prices with energy, and 130 (60%) were set by a marginal generating unit in Queensland. Of the 218 high FCAS prices, 30 (14%) coincided with energy prices in Queensland above $5,000/MWh.

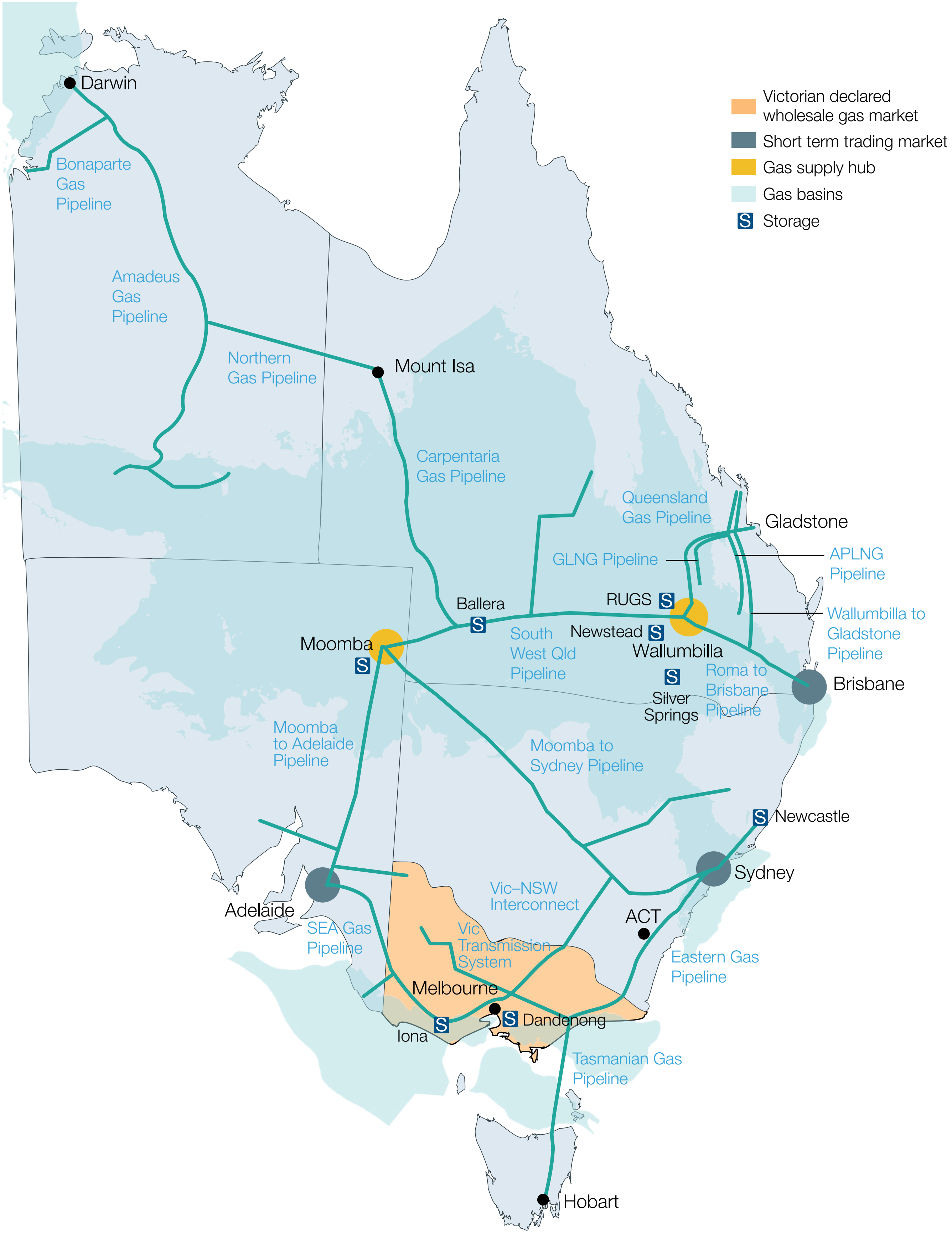
FCAS prices set by generating units in Queensland:

- Stanwell (Tarong and Stanwell) – 61 (28% of high prices)
- CS Energy (Gladstone) – 51 (23%)
- Origin Energy (Mt Stuart, Darling Downs) – 10 (5%)
- Shell (Oakey) – 6 (3%)
- CleanCo (Swanbank) – 2 (1%).

Rebidding

Rebidding of capacity from low to high prices did not contribute to the high FCAS prices. Throughout the high-priced events, the majority of generators provided an additional 10 to 50 MW of capacity for one or more service, with many also moving capacity from high price bands to lower price bands. Demand response aggregators also made additional FCAS capacity available.

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

2.1 Prices rising and volatile

		SPOT PRICE OUTCOMES				
		FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21
Price, $/GJ	VIC	8.58	8.03	9.67	6.58	5.71
	ADL	8.83	8.06	10.1	7.13	6.54
	BRI	8.21	7.46	9.41	5.77	6.32
	SYD	8.81	8.5	9.92	6.49	6.21
	WAL	7.84	7.79	9.19	6.76	5.6
	Asian LNG Netback price at Wallumbilla	7.16	8.66	9.84	5.01	7.21

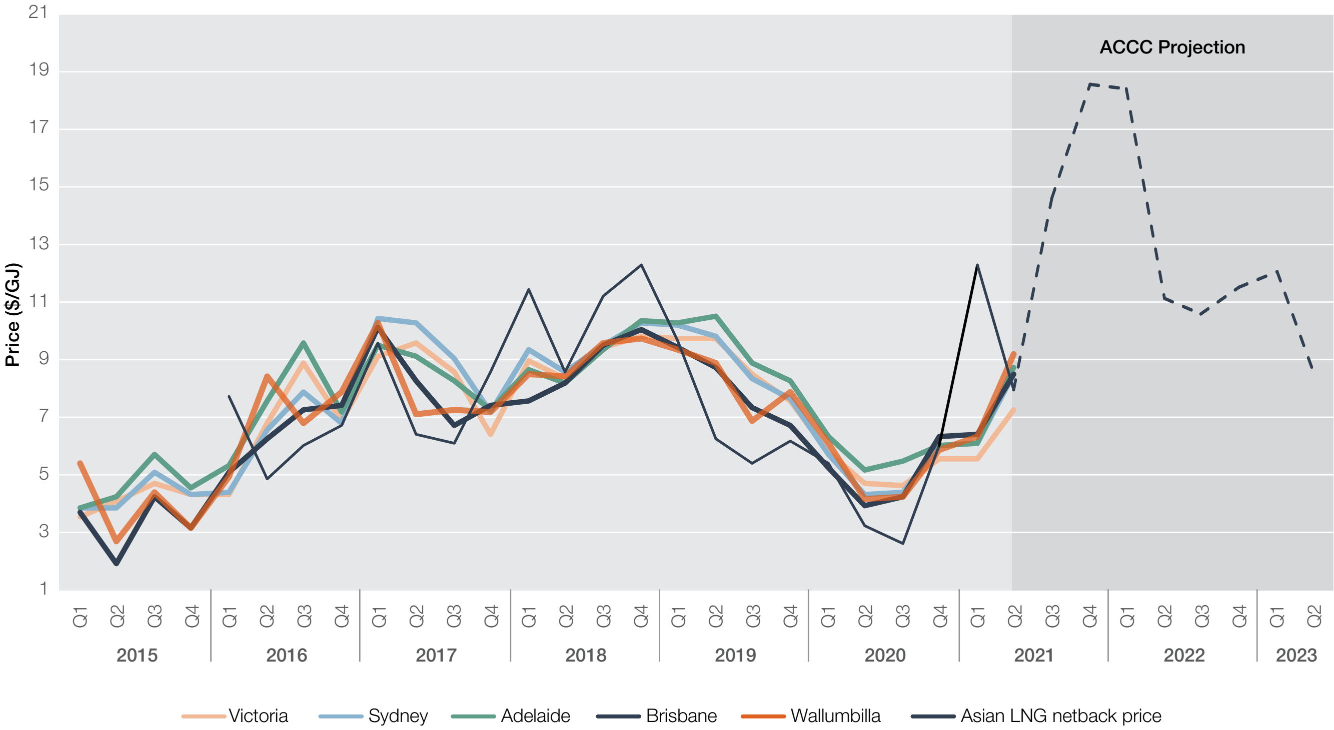
Source: AER analysis using Argus media, DWGM, STTM, GSH data and ACCC netback price series

Financial year prices declined on average by 7% across east coast domestic markets, while international prices netback to Wallumbilla increased by 44% from 2019–20 to 2020–21.

Asian LNG netback prices increased sharply following tight conditions in the Asian LNG market in Q1 2021 and more recently have gone up because of global gas price rises.

Although domestic prices fell on a financial year basis, quarterly prices have been rising since Q2 2020 (Figure 2.1).

Figure 2.1 Domestic spot prices and Asian LNG spot netback price



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

Note: Wallumbilla hub is the exchange traded day ahead price. Victoria is daily imbalance price at 6:00am. Sydney, Adelaide and Brisbane are ex ante prices. The Moomba gas supply hub has not been included, given it sees very few trades.

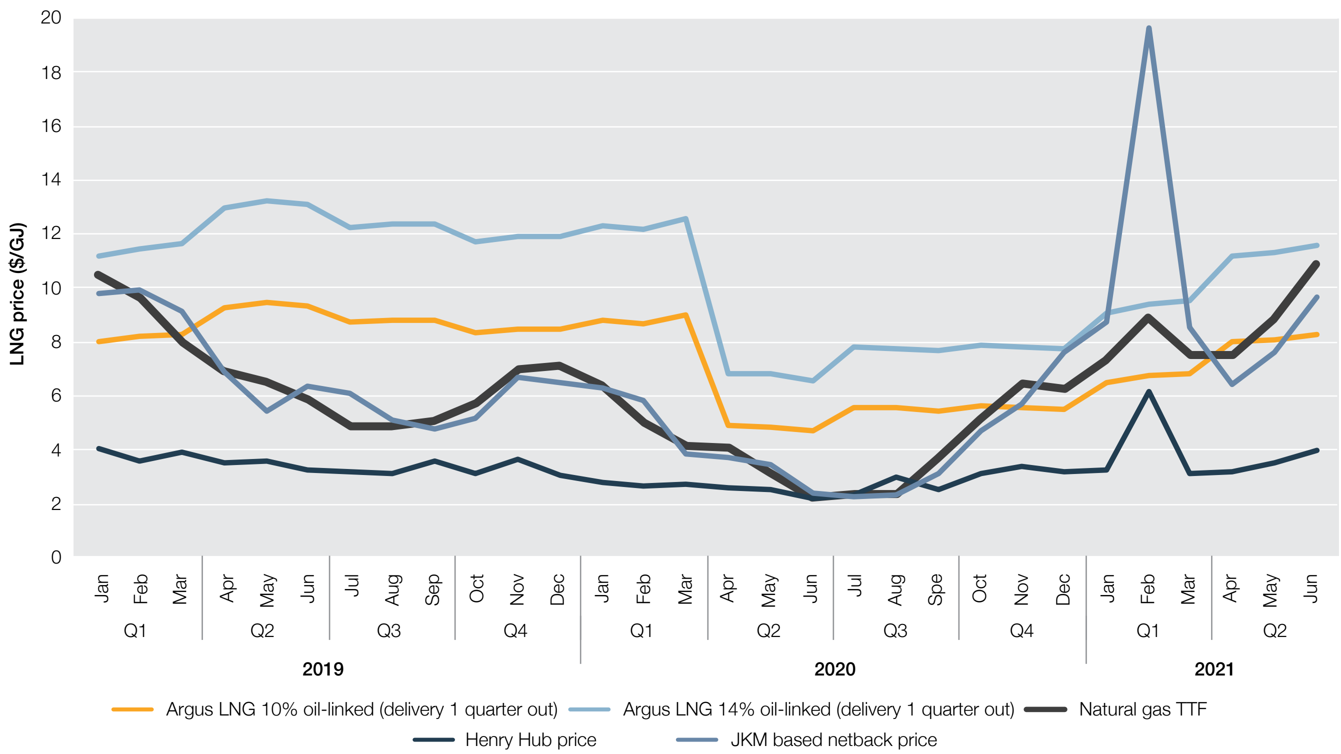
Domestic prices increased materially since last quarter, on average ranging from $7.26/GJ to $9.17/GJ in Q2 2021, compared to $5.50/GJ to $6.40/GJ in Q1 2021 across markets.

Prices were extremely volatile across all markets during Q2 2021, and on single days ranged between $5/GJ and $15/GJ. Gas price volatility increased over May and June, as more gas was required to supply electricity generation during a high number of planned and unplanned baseload generator outages. A number of factors drove gas market volatility and higher prices during Q2 2021 which we discuss further in our focus story:

- Unplanned outages at coal fired electricity generators in Queensland and Victoria
- Planned outages at coal fired electricity generators in Queensland, Victoria and NSW
- Competitive bidding for gas by gentailers to supply electricity, incentivised by high NEM prices
- Supply constraints at Iona storage and Longford production facilities in Victoria
- Periods of low wind generation in Victoria, NSW and South Australia, requiring gas powered electricity generation
- Higher international prices in Asian LNG markets.

Key international prices have been trending upwards influencing domestic price increases. Asian LNG netback prices continue to rise since the lows of 2020, averaging $7.92/GJ in Q2 2021. This is significantly lower than the Q1 2021 quarterly price of $12.30/GJ, which reflected an abnormally acute price spike in January (Figure 2.2). The consistent rise of global gas prices over Q2 2021 follows strong demand in Europe including for storage refill, impacting the Dutch title transfer facility (TTF) price. Strong buying activity from Asian countries ahead of the northern hemisphere summer to meet peak cooling loads for electricity generation, and increases in industrial activity also impacted the Asian LNG price.[21] In contrast, in Q2 2019 and Q2 2020 the Dutch TTF and Asian LNG netback prices trended down and were much lower (Figure 2.2). International LNG prices have also been supported by a rise in oil prices which has also been buoyed by an increase in industrial activity in the Asia region. Asian and European prices have trended on a similar path since 2019, as international markets have become increasingly linked through global trade.

Figure 2.2 International gas prices



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

Notes: The ACCC Netback price is used as a proxy for the Japan Korea Marker (JKM) physical spot price assessment representing cargoes delivered ex-ship (des) to Asia, trading in the month before the date of delivery.

The Argus LNG 14% and 10% oil linked contract prices are indicative of a 14% and 10% 3-month average Ice Brent crude futures slope.

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

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

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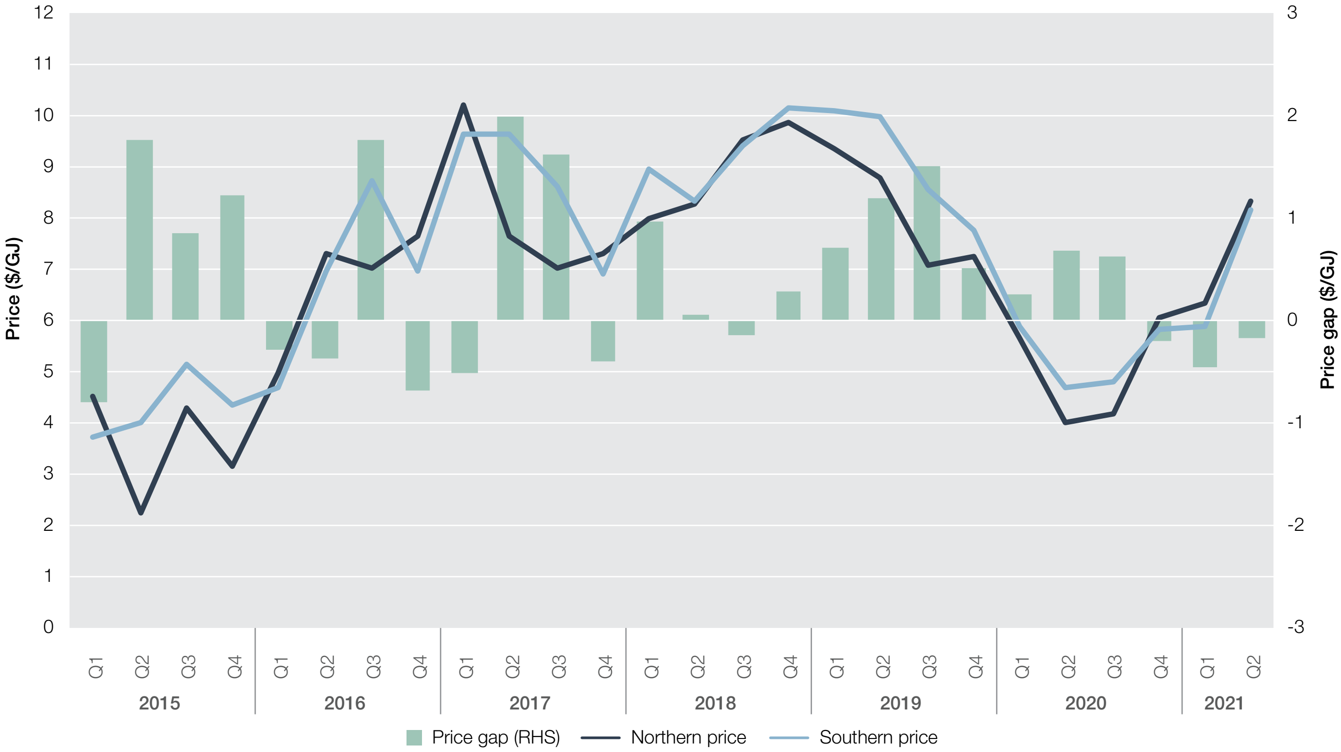
21 Reuters, Global gas prices rally on hot summer, storage demand, 2 July 2021, accessed 9 August 2021.

In our last quarterly report, we analysed the developments in pricing structures in relation to the Asian LNG market and the increasing use of European and American price benchmarks to price LNG trades. This quarter saw this trend continue with the rise in the use of the Dutch TTF price series linked to spot LNG cargoes sold to Asia.[22] Domestically, Origin bought 91 PJ from APLNG to supply gas to southern markets over 4 years at an Asian JKM-linked price to begin supply from January 2022.[23] Increasingly, gas markets are becoming more integrated globally with changes in international pricing structures bearing on pricing dynamics within countries. We will continue to monitor these developments and explain the implications for the Australian markets.

In Q2 2021, northern market prices remained higher than southern market prices, a trend that has been sustained since Q3 2020 (Figure 2.3). Historically, over the winter period (June to August) it has been a consistent trend for prices to be higher in the south as northern gas flows south.

Figure 2.3 Price difference between northern and southern domestic markets



Source: AER analysis using DWGM, STTM and GSH 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.

22 Independent Commodity Intelligence Service, China's Sinopec imports ICIS TTF-Linked LNG cargo, 29 July 2021, accessed 9 August, 2021.

23 Origin Energy, Origin boosts gas supply to southern markets, accessed 27 July 2021.

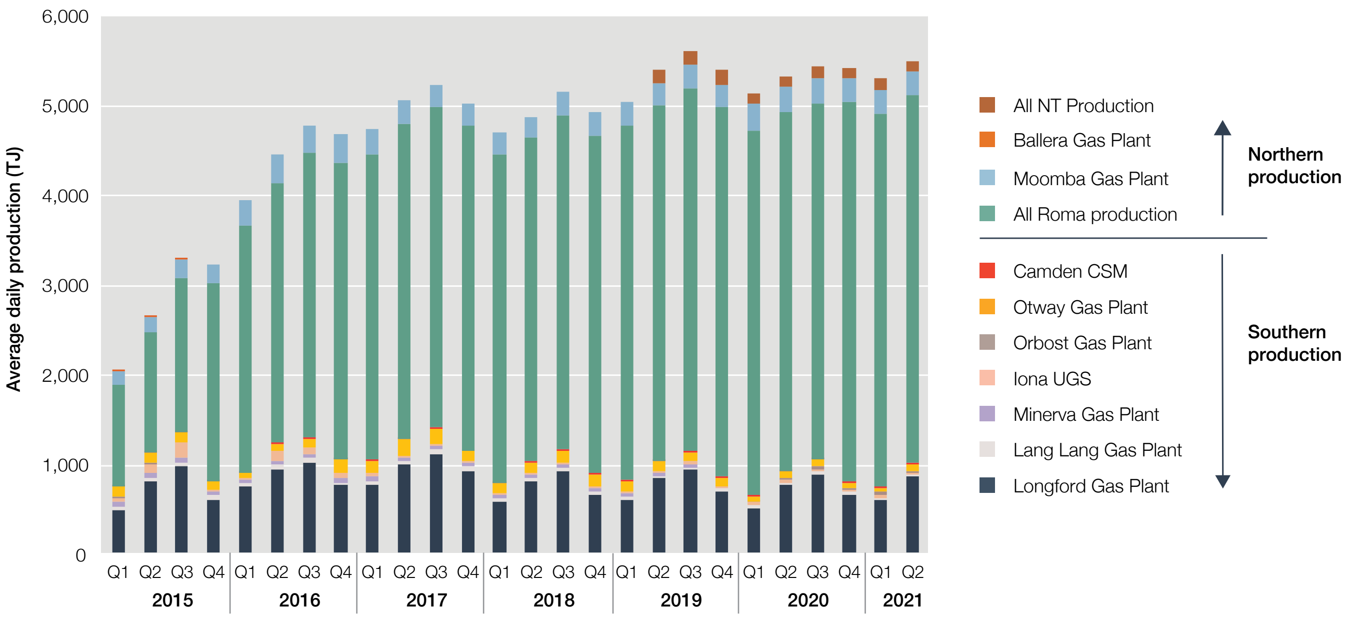
2.2 Production robust, storage key to meeting demand peaks

		PRODUCTION AND STORAGE OUTCOMES				
		FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21
Production, PJ	Northern	1,329	1,411	1,502	1,638	1,649
	Southern	422	394	352	322	324
	Total	1,751	1,805	1,868	1,959	1,973
Average gas storage level, PJ		N/A	N/A	98.6	95.0	99.5

Gas production levels continue to rise and over the last financial year increased slightly from 1,959 PJ in 2019–20 to a record level of 1,973 PJ in 2020–21. Gas production rises follow increased levels of LNG exports from Queensland.

Production on the east coast remained robust, reaching, on average, 5,487 TJ/day in Q2 2021, an increase from 5,294 TJ/day in Q1 2021 (Figure 2.4). The quarterly increase in gas production largely reflects the rise in the Longford gas plant in Victoria from 580 TJ/day in Q1 2021, to 841 TJ/day in Q2 2021 to meet stronger residential demand during winter in southern states. This level of Longford's production has not been seen since Q2 2017, at a time when the facility achieved the highest yearly production result. In its latest *Victorian gas planning report*, AEMO flagged the short term future depletion of gas fields that supply Longford will reduce the peak capacity of supply to meet peak demand.[24] During Q2 2021, the Longford plant operated at reduced capacity of 922 TJ/day, below its nameplate rating of 1,115 TJ/day. On individual days in April and June, when Longford's production was constrained, a number of domestic price spikes occurred. Price and availability of gas on the east coast is very sensitive to Longford's operational capacity, which declined in a number of instances across June and April as discussed in our focus story.

Figure 2.4 East coast production (including Northern Territory)



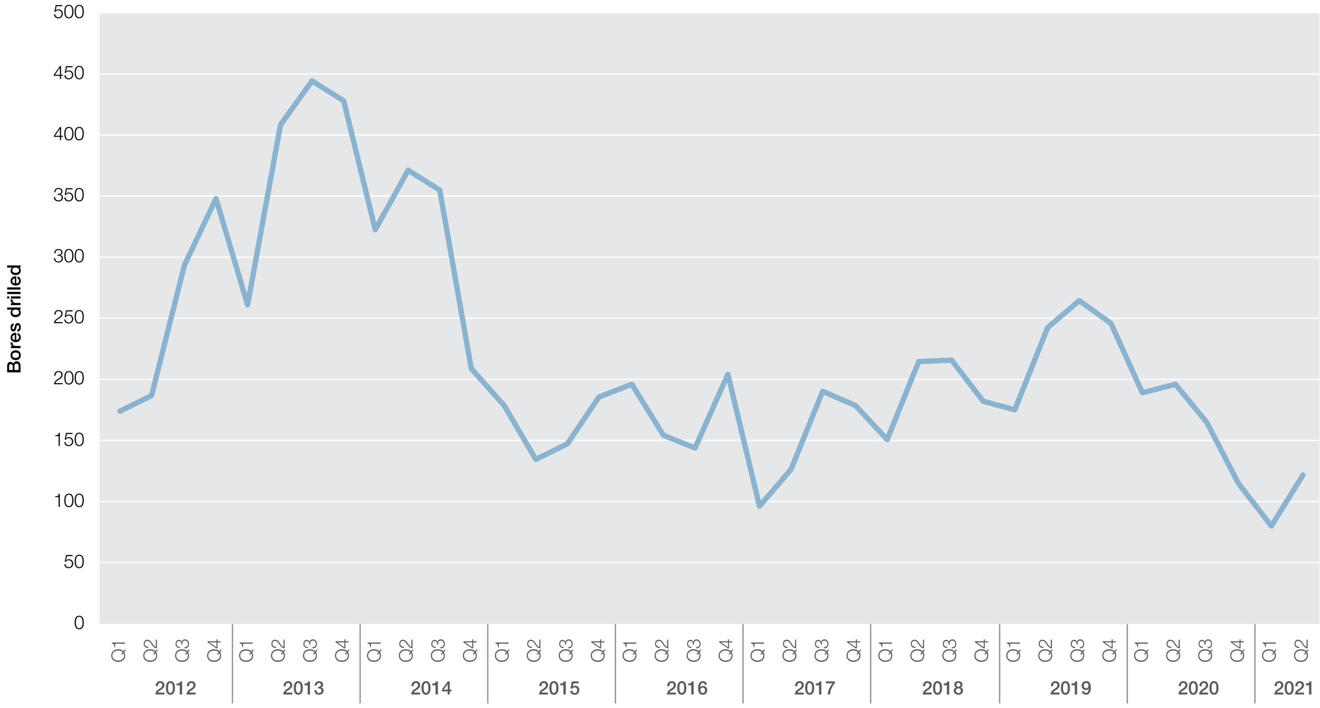
Source: AER analysis using Natural Gas Services Bulletin Board data.

Production in Queensland remained high, reaching, on average, 4,116 TJ/day in Q2 2021, coinciding with elevated LNG export volumes and high trading volumes at the Wallumbilla gas supply hub (section 2.4). Queensland remains the most significant source of gas on the east coast, and production each year grows alongside the amount of gas exported as LNG to Asia.

There was an increase in the number of new coal seam gas wells drilled in Queensland, reaching 123 in Q2 2021, increasing from 81 in Q1 2021, amid rising gas production volumes (Figure 2.5). This marks a reversal in the downward trend in gas exploration that began in 2020, that coincided with the onset of the COVID-19 pandemic. Drilling numbers can be indicative of planned supply changes, as a procession of new wells is required to support ongoing production from coal seam gas resources such as those in Roma.

24 AEMO, Victorian gas planning report, March 2021, pp. 3–4.

Figure 2.5 Queensland coal seam gas bores drilled

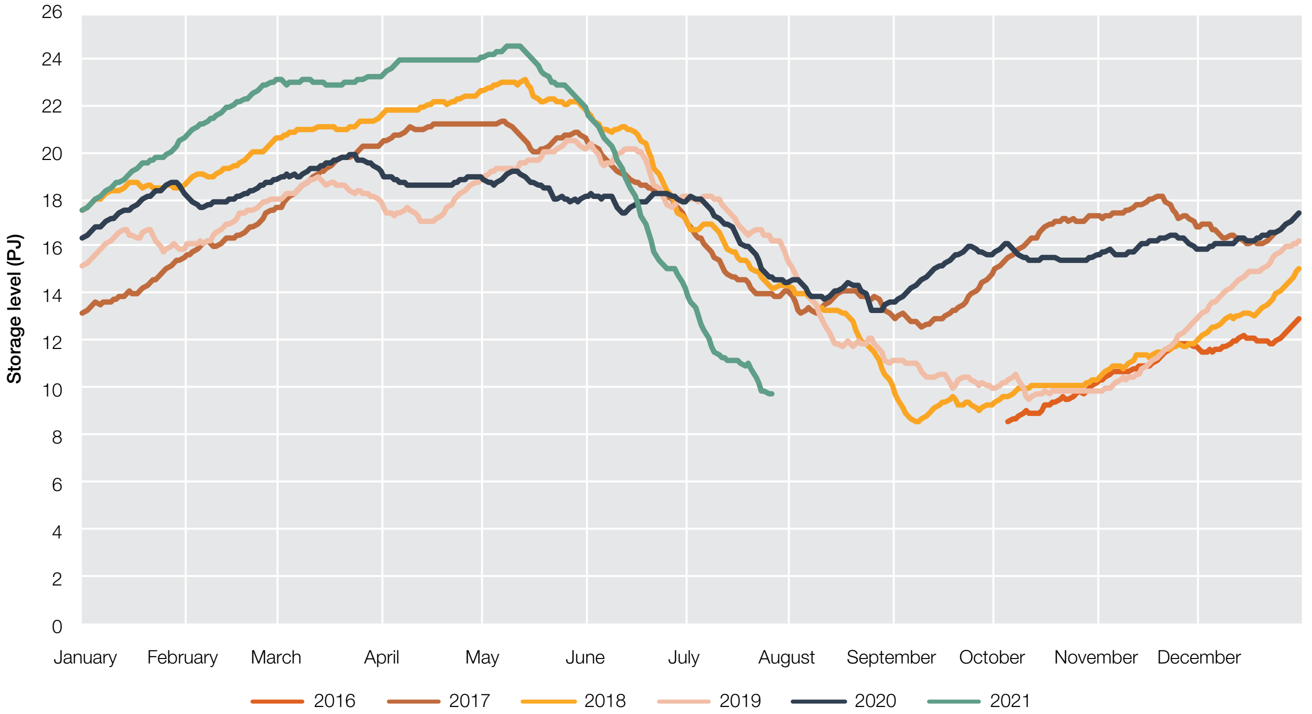


Source: AER analysis using Queensland Department of Natural Resources, Mines and Energy data.

Gas storage played an important role to meet high demand in southern states with storage levels reaching a record peak before the quarter, and a record trough at quarter end (Figure 2.6). In particular, the Iona storage facility in Victoria has proved to be a key supply source, injecting 200–300 TJ/day, sometimes in excess of 400 TJ/day throughout June. The Australian Government's *National gas infrastructure plan* has flagged expansion of the Iona storage facility and surrounding pipelines, as well as the development of the Golden Beach storage facility as key gas supply projects to meet peak gas demand shortages originally forecast for 2024. These developments could result in at least 820 TJ/day of storage being available from Victoria in coming years, to offset declines in supply from the Longford production facility.[25]

25 Department of Industry, Science, Energy and Resources, *National gas infrastructure plan interim report*, May 2021, p. 7.

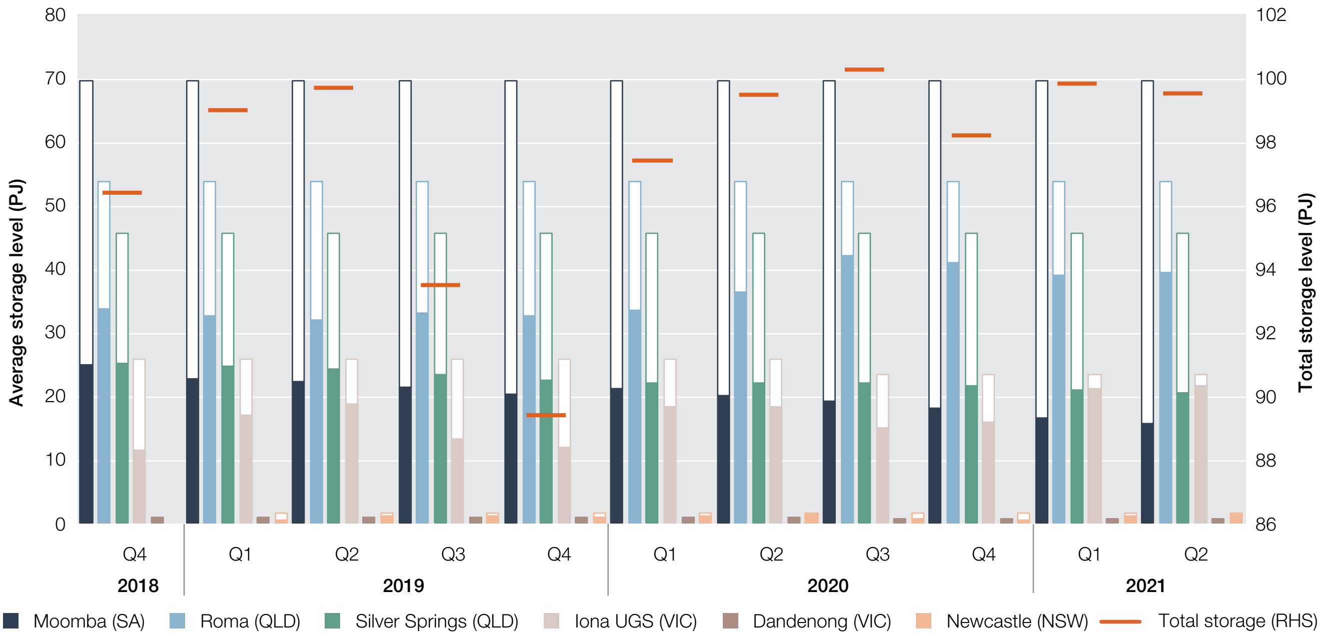
Figure 2.6 Change in Iona storage facility volumes year-on-year



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

Average storage levels did not change materially over the quarter, reaching 99.6 PJ in Q2 2021, compared to 99.9 PJ in Q1 2021 (Figure 2.7). The slight decline reflects the gradual decline in Moomba and Roma storage volumes, offset by higher average storage volumes at Iona which can cycle faster in larger quantities compared to other facilities.

Figure 2.7 Storage levels



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

Note: Storage levels are averages across a quarter.

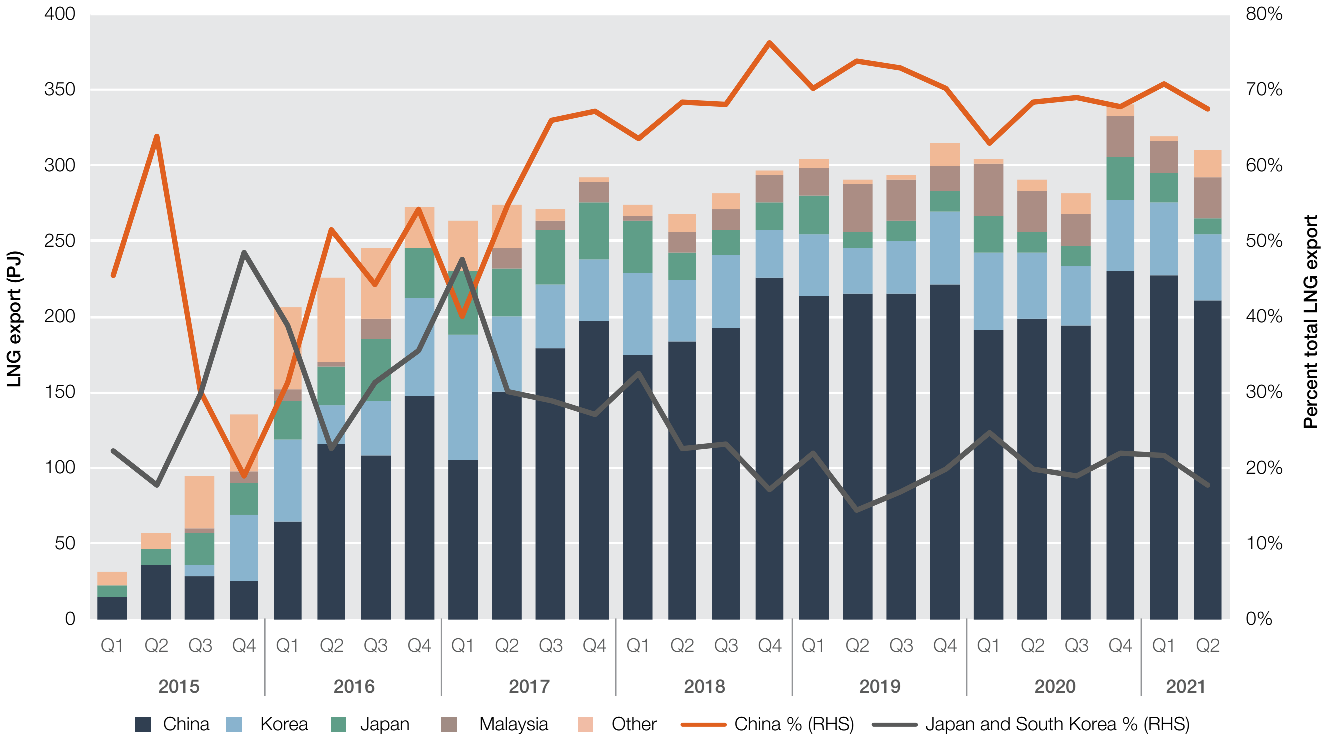
2.3 Queensland LNG exports still strong

LNG EXPORT OUTCOMES		FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21
Exports, PJ	Total	1,055	1,105	1,173	1,203	1,252
Exports by country, PJ	China	511	732	846	825	861
	Korea	233	181	151	177	177
	Japan	148	126	73	68	74
	Malaysia	27	38	78	105	95
	Other	136	29	25	29	45

Queensland LNG exports increased to a record high of 1,252 PJ in 2020–21, a rise of 4.1% on 2019–20 export volumes, amid rising international prices and recovery of industrial activity in Asia since the COVID-19 outbreak. Most of the increase in LNG exports can be attributed to higher buying volumes from China.

Total Queensland LNG exports remained high at around 311 PJ in Q2 2021, down from a record volume of 340 PJ in Q4 2020, and 320 PJ in Q1 2021 (Figure 2.8). LNG exports reached their highest level in April during Q2, which coincided with Queensland importing gas at this time. Exports remained robust despite a number of maintenance outages at export facilities (Table 2.1).

Figure 2.8 LNG shipped from Gladstone Port by destination



Source: AER analysis using Gladstone Port Corporation data.

Table 2.1 LNG plant outages

FACILITY	PERIOD	CAPACITY
APLNG	5–8 May	1 train
GLNG	9 May–7 June	1 train
QCLNG	15 June–13 July	0.5–1 train

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

Strong interest in LNG from Asian buyers continues, particularly ahead of the Northern hemisphere summer for electricity generation to meet cooling requirements, and ongoing recovery in industrial activity. China is the largest buyer of Queensland LNG exports, and is forecast to surpass Japan as the largest LNG importer in 2022. A number of key structural factors appear to be supporting gas use in Asia, including switching from coal and nuclear generation to gas for electricity generation. Also, government policies promoting gas as a relatively lower emitting fuel in countries such as China, South Korea, Japan and Taiwan.[26] In particular, China has announced gas will play a key role in meeting their pledge to achieve carbon neutrality by 2060. The Qatar Government recently announced plans to significantly expand its LNG export capacity by 33 million tonnes per annum by 2025, this would be approximately double the export capacity of the Queensland LNG export projects.[27]

2.4 Trade at Wallumbilla soars in Q2 2021

GAS SUPPLY HUB OUTCOMES		
	FY 19/20	FY 20/21
Volume Traded	24 PJ	22.6 PJ
Off screen	16.5 PJ	18.5 PJ
On screen	7.5 PJ	4.1 PJ
Average price	$5.93/GJ	$5.98/GJ
Active participants	18	18

Source: AER analysis using GSH data.

Note: Total of all products traded at all locations. We consider a participant “active” in the GSH on a yearly basis if it makes at least 12 trades in the year.

Gas traded through the gas supply hubs in 2020–21 was slightly down from the previous financial year, however gas traded on screen almost halved (Figure 2.9).[28] Oppositely, trades settled bilaterally off screen increased, with industry commenting they have been using brokers to find counterparties to overcome inactive bidding on screen. Both forms of trades assist with liquidity, however only on screen trading is designed to bring multiple sellers and buyers together in real time to ‘outbid’ each other.

Against the longer term trend, traded volume at the GSH increased to the second highest ever level this quarter, with around 8.3 PJ traded in Q2 2021 – 0.3 PJ short of the record. This near record occurred in a large part due to significant growth in traded daily and weekly products which together accounted for 50% of all traded volume.[29]

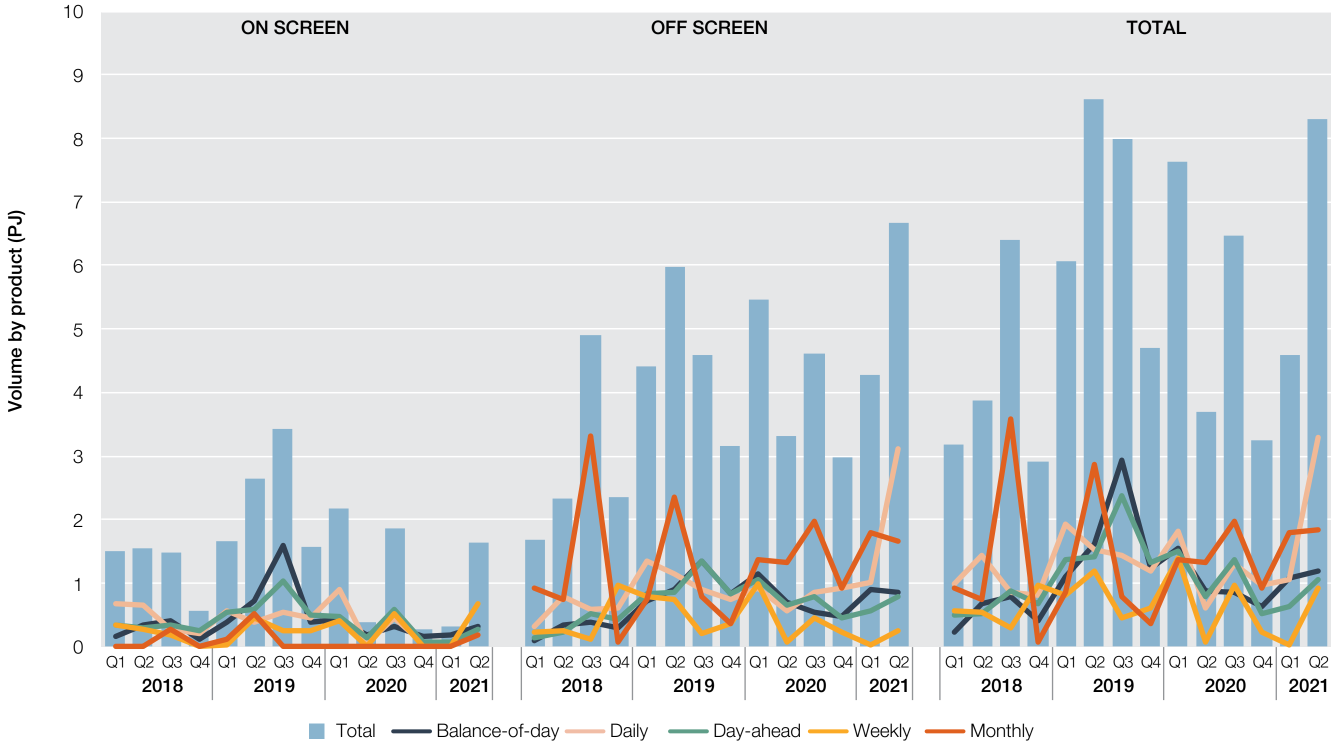
26 Department of Industry, Science, Energy and Resources, *Resources and Energy Quarterly*, June 2021, pp. 65–66.

27 Department of Industry, Science, Energy and Resources, *Resources and Energy Quarterly*, June 2021, p. 68.

28 Participants using the Gas Supply Hubs can lodge trades either ‘on screen’ or ‘off screen’. On screen trades are matched anonymously through the Gas Supply Hub trading platform. Off screen trades are agreed to by participants separately and then lodged through the hub for settlement. ‘Off market’ trades do not use the Gas Supply Hub platform at all.

29 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 2.9 Gas Supply Hub – On screen, off screen and total trade volumes by product



Source: AER analysis using Gas Supply Hub trades data.

Promisingly, on screen trades increased markedly this quarter. However, this has happened before without long term effect, with trade increasing in Q3 2020 before reducing significantly the next quarter. Early signs in Q3 2021 are that on screen trading has been sustained, albeit along with high prices. On screen trade volumes increased for every product this quarter, including weekly trades, which were not traded on screen in Q1 2021, and monthly trades, which were traded on screen for the first time in 2 years.

The average quantity per trade this quarter increased despite a reduction in monthly products, which by nature of their longer duration have the highest quantity per trade. This can be explained in part by higher volumes in daily transactions. The average daily trade in Q1 2021 was 9.4 TJ, however this increased to 20.3 TJ per trade this quarter with off screen trades driving the higher average at 27 TJ per trade. Daily products were the most traded this quarter, with 3 times as many trades as the previous quarter (and 5 times that of Q2 2020).

Overall, the churn rate at Wallumbilla exceeded 10%, which is the only time other than Q3 2019 that this has happened.[30]

Exporters and Producers increased their trades this quarter, making 63% of all sales, while gas powered generators and gentailers (GPG Gentailers) increased their positions buying off the exchange. This participation upstream is consistent with the increase in capacity purchased through the Day Ahead Auction by GPG Gentailers (section 1.5).

As noted last quarter, on 28 January 2021 AEMO expanded the boundary of the Gas Supply Hub to include new trade locations at Wilton (NSW) and Culcairn (NSW–Victoria). Participants now have an ability to trade from Queensland to NSW and Victoria using the Gas Supply Hub. Activity at these new locations has declined since their introduction, with 2 TJ being delivered to Sydney this quarter compared to 67 TJ in Q1 2021, and 0 TJ being delivered to Victoria this quarter compared to 70 TJ in Q1 2021.

30 The churn rate refers to the total trade through the gas supply hubs as a proportion of total regional bulletin board gas flows.

2.5 Use of the Day Ahead Auction continues to grow

DAY AHEAD AUCTION OUTCOMES	FY 19/20	FY 20/21
Capacity won, PJ	39.9	49.2
Total auction volume bid, PJ	56.5	64.9
Auction legs won	4538	7075
Won at $0/GJ clearing price, %	78	81
Active participants	15	18
Number of auction facilities traded	10	13

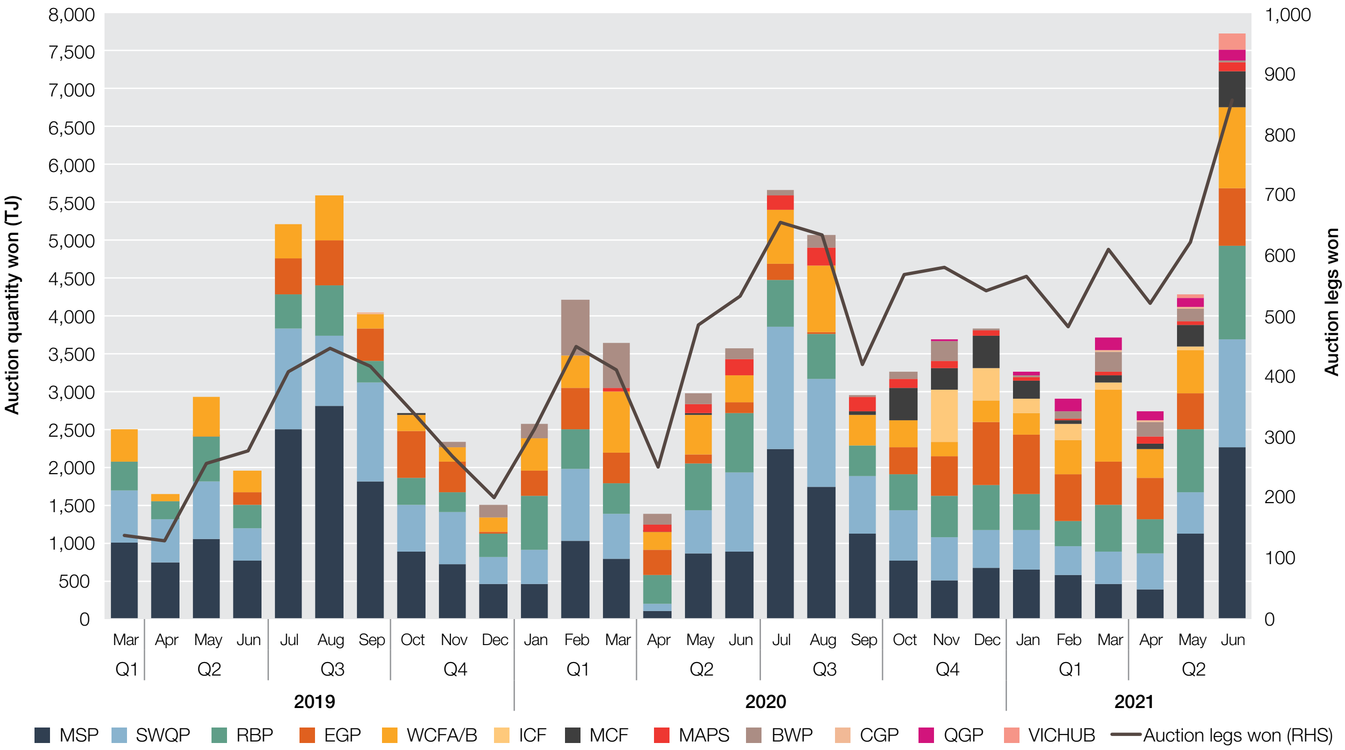
Source: AER analysis using DAA auction results data.

Note: Results shown for all auction facilities excluding capacity trades.
We consider a participant 'active' in the DAA on a yearly basis if it won capacity in the auction at least 3 times in any quarter over the year.

Since the introduction of reforms in March 2019 to improve access to pipeline capacity, the Day Ahead Auction (DAA) has been particularly successful with use of the DAA increasing across all metrics. Most notably, auction capacity won increased by 9.3 PJ over 2020–21 with more active participants in the market and more auction facilities traded on. Since market start, 98.2 PJ of auction capacity has been won with 78.7 PJ clearing at the reserve price of $0/GJ.

In Q2 2021, 14,975 TJ (15 PJ) of auction capacity was won, an increase of 86% compared to last quarter. June stands out as a record auction month with 7,745 TJ of auction capacity won across 10 auction facilities by 15 active participants (Figure 2.10).

Figure 2.10 Pipeline capacity won on the Day Ahead Auction



Source: AER analysis using DAA auction results data.

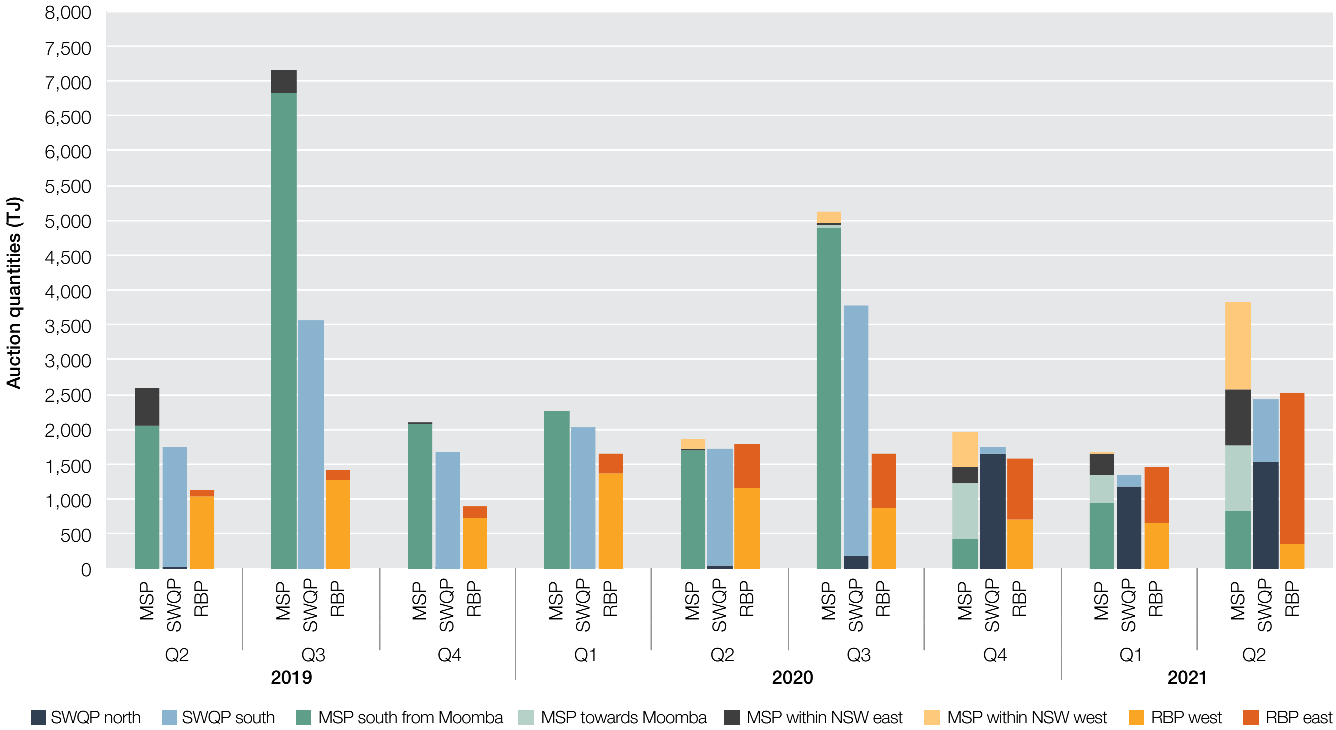
Note: Quantities shown are the monthly sum of auction products allocated on each pipeline and do not necessarily represent the physical volumes of gas that actually flowed for each gas day.

For the first time this quarter 240 TJ of auction capacity was won on the VICHUB auction facility located at Longford, linking the Declared Wholesale Gas Market (DWGM) and the Eastern Gas Pipeline (EGP). Participants also won record auction quantities this quarter of 2,525 TJ on the Roma to Brisbane Pipeline (RBP), 2,017 TJ on the Wallumbilla Compression Facility B (WCFB), 394 TJ on the Queensland Gas Pipeline (QGP) and 47 TJ on the Carpentaria Gas Pipeline (CGP).

As gas powered generation increased this quarter the auction provided a cost effective means for GPG Gentailers to secure pipeline capacity. GPG Gentailers dominated in the auction with 7,476 TJ of auction capacity won by this participant grouping this quarter, a 100% increase from Q2 2020. Exporters and Producers also continue to increase their utilisation of the auction winning a record 4,010 TJ of auction capacity in Q2. The majority of this capacity was won on the Moomba to Sydney Pipeline (MSP), WCFB, and the South West Queensland Pipeline (SWQP).

The DAA continued to provide flexibility for participants to deliver gas in response to fluctuating demand and prices, especially between northern and southern markets. On the SWQP and MSP the predominant routes that auction capacity was won on during the quarter was from south to north driven by price arbitrage opportunities between the northern and southern markets and gas demand. Capacity was also won on routes from north to south in response to higher prices and demand in the southern states during the quarter (Figure 2.11).

Figure 2.11 Day Ahead Auction quantities won on the MSP, SWQP and RBP, by route



Source: AER analysis using DAA auction results data.

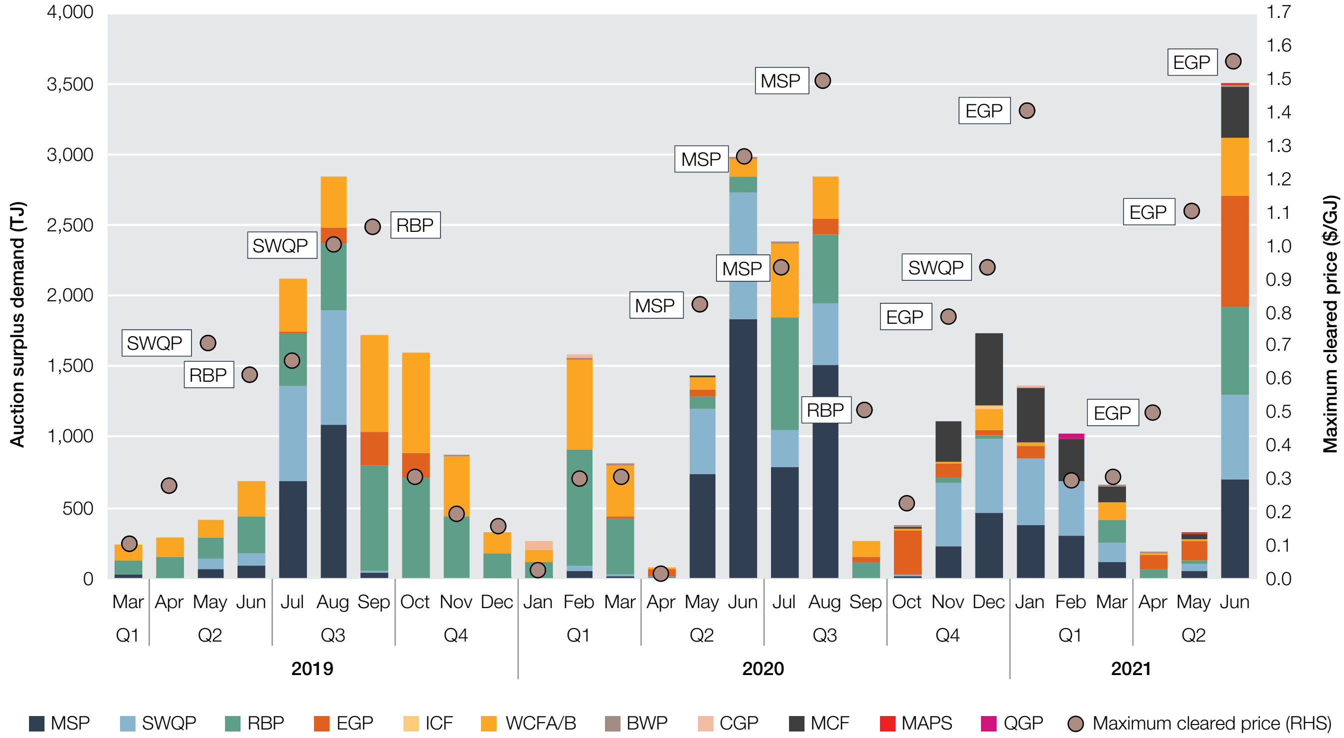
Note: Quantities shown are the sum of auction products allocated and grouped for different auction routes based on the direction of that auction route and do not necessarily represent the physical volumes of gas that actually flowed for each gas day.

More than one third of all auction capacity on the MSP was won from Culcairn North and the Culcairn Trading Point on routes flowing to Sydney and Moomba.[31] On the SWQP around 60% of all auction quantities won this quarter was on routes north towards Wallumbilla with the majority of those won by GPG Gentailers. A record auction quantity of 2,164 TJ was won this quarter on routes flowing east on the RBP, with two thirds of the auction capacity won to delivery points supplying gas generators increasing after the Callide and Kogan Creek unplanned outages in Queensland (section 1.5). GPG Gentailers also accounted for almost 80% of all the auction capacity won on the RBP compared to only 50% on average across all the other auction facilities.

The surplus auction demand across all facilities totalled 4 PJ for the quarter with only the Iona Compression Facility (ICF) and MAPS recording no surplus auction demand (Figure 2.12).

31 See Appendix D for more information on how we grouped and classified different auction routes and directions.

Figure 2.12 Day Ahead Auction surplus demand and maximum clearing prices



Source: AER analysis using DAA auction results data.

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

Surplus auction demand on the EGP was a record 1032 TJ for the quarter linked to strong demand to transport gas from Victoria to Sydney resulting in the EGP being the most constrained auction facility during the quarter with a record auction clearing price of $1.55/GJ (Figure 2.13). Strong auction demand was also observed on the MSP, SWQP, RBP, WCFB and MCF. Although the auction was not constrained on the WCFB and MCF during the quarter the surplus demand was due to paired bids on the SWQP and RBP where the auction was constrained.

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

		Q2 2019			Q2 2020			Q2 2021		
Pipeline	Direction	Apr	May	Jun	Apr	May	Jun	Apr	May	Jun
BWP					7%	3%	3%	10%		30%
EGP					10%	3%		23%	29%	63%
MSP	South from Moomba	3%	3%			36%	97%		3%	33%
	Towards Moomba									10%
	Within NSW East		3%							3%
	Within NSW West									3%
QGP										70%
RBP	East							10%	10%	33%
	West	13%	42%	87%	3%	16%	40%	13%	3%	47%
SWQP	North SWQP							3%	13%	47%
	South SWQP		16%	40%		3%				

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

Source: AER analysis using DAA auction results data.

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

On the SWQP the auction was only constrained on auction routes flowing north, peaking at 47% in June, while on the RBP the auction was constrained in both directions also peaking in June at the time of the Callide outage. Although there was only 3 TJ of surplus demand on the QGP in June, the auction bid volumes matched the auction constraints on a number of days resulting in clearing prices above $0/GJ.[32] The MSP was less constrained this quarter compared to Q2 2020 when the majority of auction demand on the MSP was on routes flowing south.

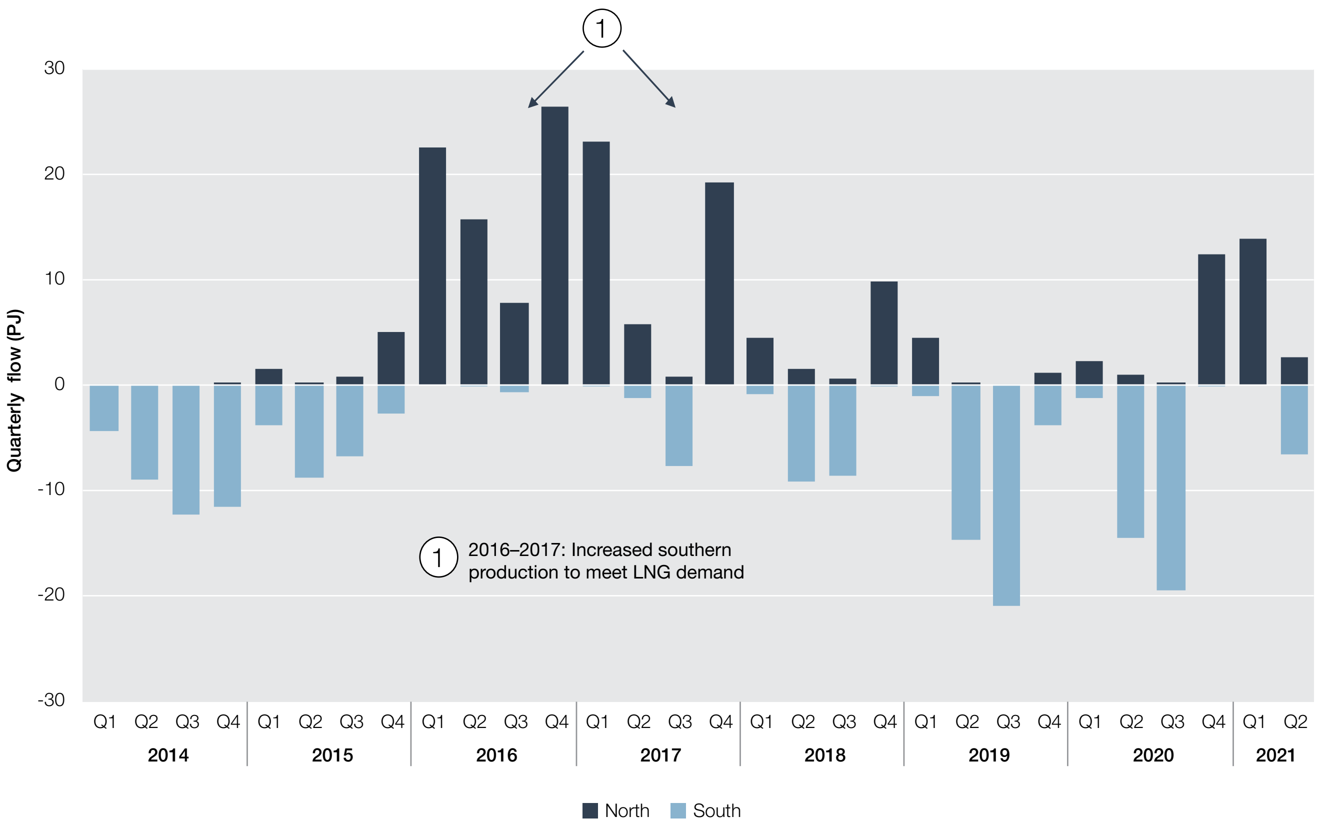
2.6 Gas flows to markets of highest value

		INTERSTATE GAS FLOW OUTCOMES						
		TAS	VIC	NSW	NT	SA	QLD	
		Import	Export	Import	Export	Export	Import	Export
Gas flows, PJ	FY 19/20	7.4	85.2	119.1	22.8	4.53		13.8
	FY 20/21	7.5	108.5	111.5	20.4	12.9	22.8	

A number of trends changed significantly in 2020–21 from the previous financial year. Notably, Queensland has changed its position from being a net exporter of 13.8 PJ of gas in 2019–20 to become a net importer of 22.8 PJ of gas in 2020–21. This coincided with a rise in LNG exports to a record level of 1,252 PJ over 2020–21 and rising international LNG prices above domestic prices. The northern flow of gas to Queensland was strongest during Q4 2020 and Q1 2021. Victoria increased net exports from 85.2 PJ in 2019–20 to 108.5 PJ in 2020–21.

In Q2 2021, gas predominantly flowed from northern markets toward southern markets (Figure 2.14). At various times throughout the quarter, gas flow changed directions toward its greatest valued use.

Figure 2.14 North-South gas flows



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

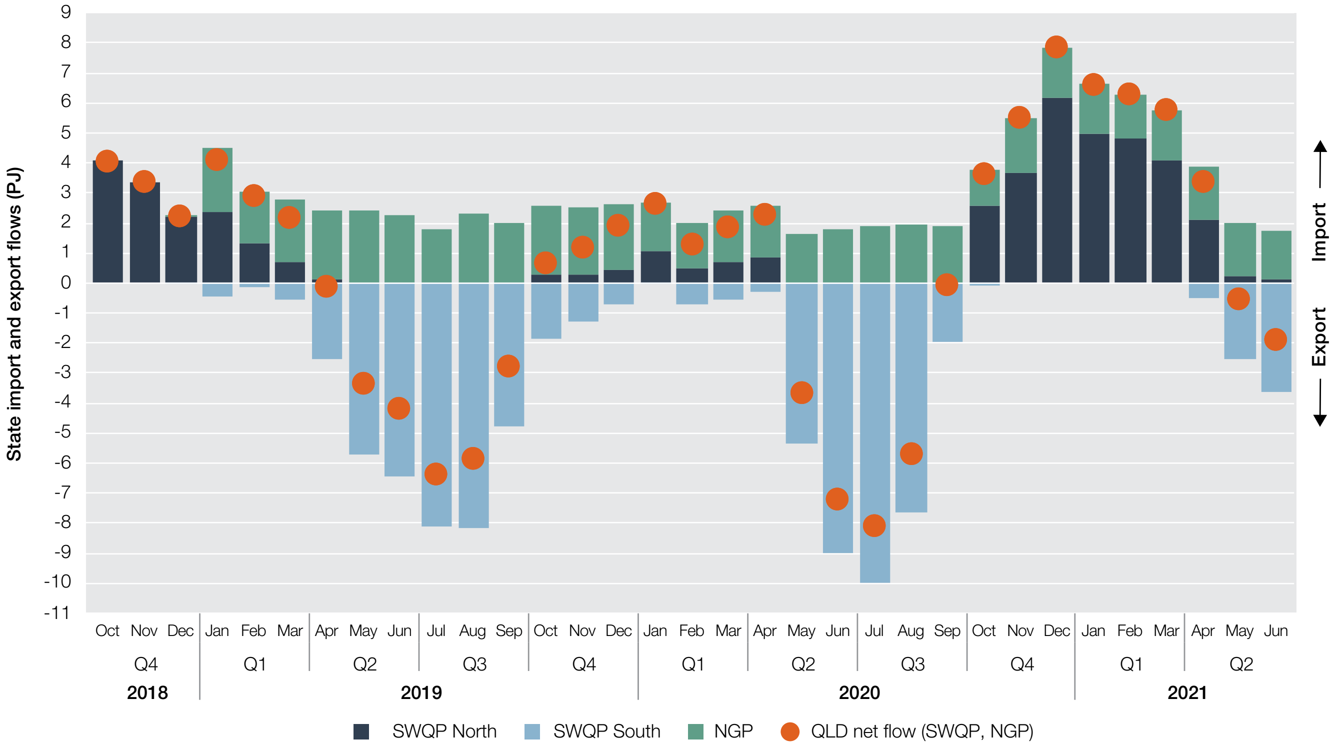
Note: North-South flows depict net physical flows around Moomba – north or south.

Queensland remained a net importer of gas in Q2 2021 although it recorded a significant decline from 18.7 PJ in Q1 2021 to 0.9 PJ this quarter. In April, gas flowed north from southern markets to Queensland, which coincided with

32 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.

high LNG exports from Queensland. During May and June, gas flows reversed flowing from Queensland to southern markets to meet high demand and capitalise on relatively higher southern gas prices (Figure 2.15). A constraint on the Moomba to Sydney Pipeline from 1 April to 13 May reduced southbound gas flow capacity to NSW from 446 TJ/day to 297 TJ/day, contributing to lower flows from Queensland over this time.

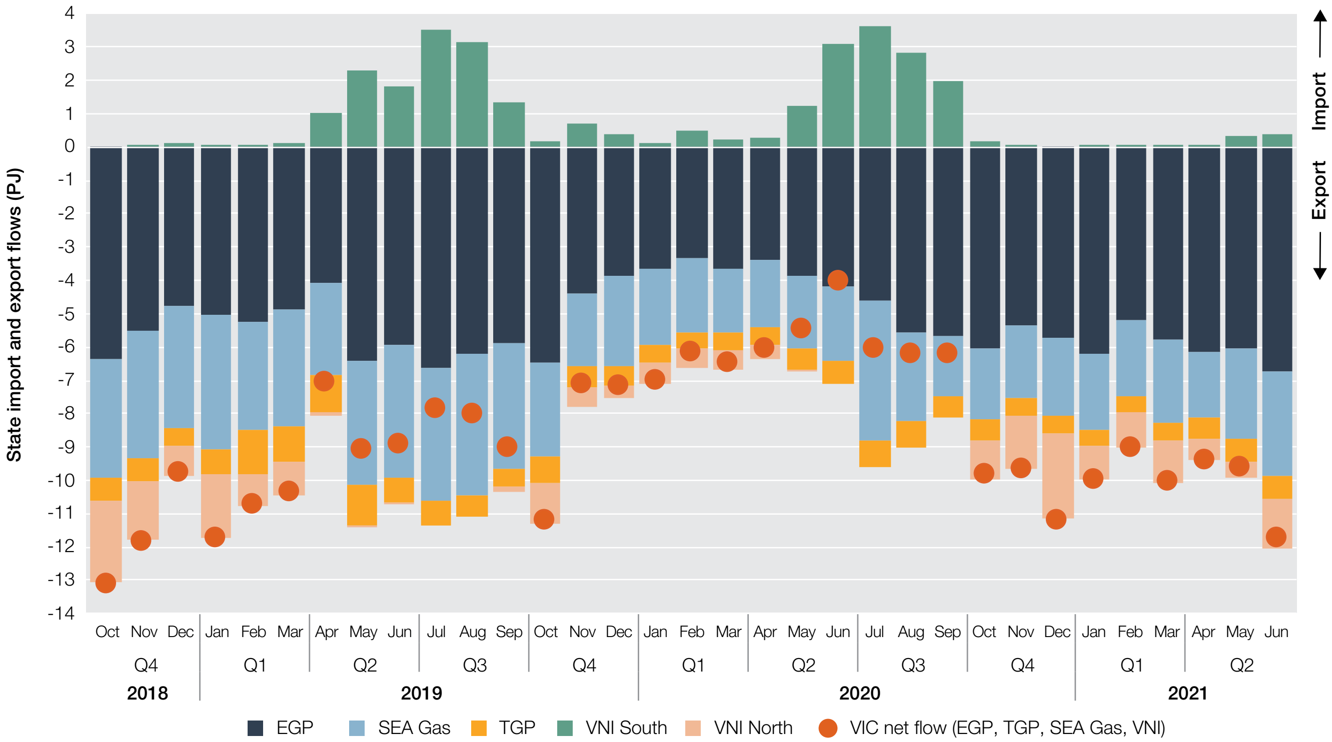
Figure 2.15 Queensland import and export gas flows



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

Net export of gas from Victoria increased to 30.7 PJ of gas in Q2 2021, significantly more than the 15.4 PJ in Q2 2020. Most of the increased exports were via the Eastern Gas Pipeline to NSW (Figure 2.16). This follows a trend of higher exports from Victoria since Q4 2020, coinciding with less gas supplied from Queensland.

Figure 2.16 Victoria import and export gas flows



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

Recently, Origin Energy struck a deal with APLNG to supply 91 PJ to the domestic market over 4 years from January 2022. The arrangement also involves an agreement with APA to expand the southbound flow of gas from Queensland to southern markets commencing 2023. These deals are likely to support periods of greater imports into Victoria.[33]

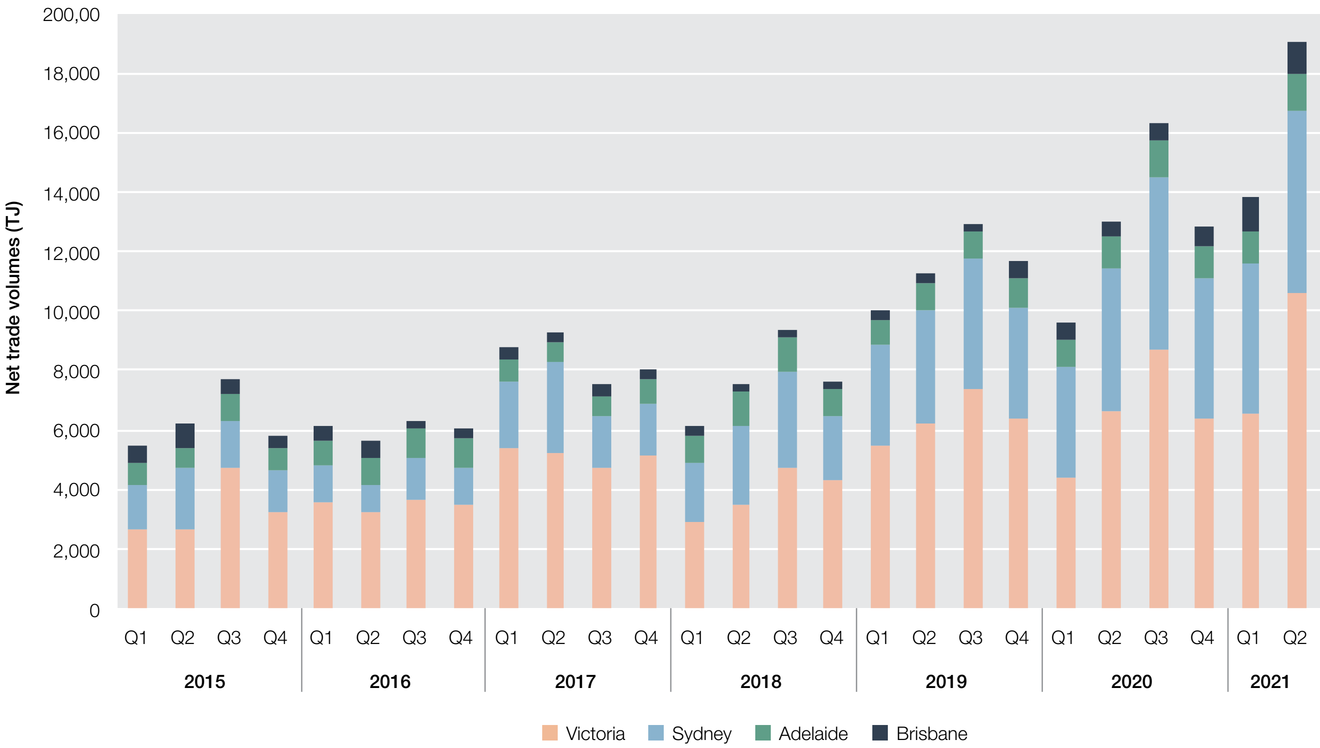
2.7 Producers drive record spot market trade

SPOT MARKET TRADING OUTCOMES						
		FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21
Trade Volumes (PJ)	VIC	17.7	16.2	20.8	24.8	32.2
	SYD	8.0	8.1	12.5	16.7	21.7
	ADL	3.5	3.5	3.8	3.9	4.6
	BRI	1.3	1.4	1.2	1.8	3.5
	TOTAL	30.4	29.3	38.3	47.2	62.0
Trade volume as a proportion of demand (%)	VIC	7%	6%	9%	10%	13%
	SYD	9%	9%	14%	19%	23%
	ADL	15%	16%	18%	18%	22%
	BRI	4%	4%	4%	5%	9%

Financial year outcomes show higher liquidity across spot markets in 2020–21, with a total of 62 PJ traded compared to 47.2 PJ in 2019–20. Victoria and Sydney markets are leading trading volumes, representing around 87% of gas traded across spot markets.

Spot market trade increased significantly across the quarter, rising from 13.8 PJ in Q1 to 19 PJ in Q2 2021, with most trade occurring in Victorian and Sydney markets (Figure 2.17). Trade in the spot markets increased in Q2 2021, as LNG exports have declined since Q4 2020 record levels, while production volumes have risen over the same time period. Trading during Q2 2021 has increased, alongside rising and more volatile prices, with large gas producers BHP, Esso and Santos in particular selling more into Victorian and Sydney markets.

Figure 2.17 Spot trade liquidity

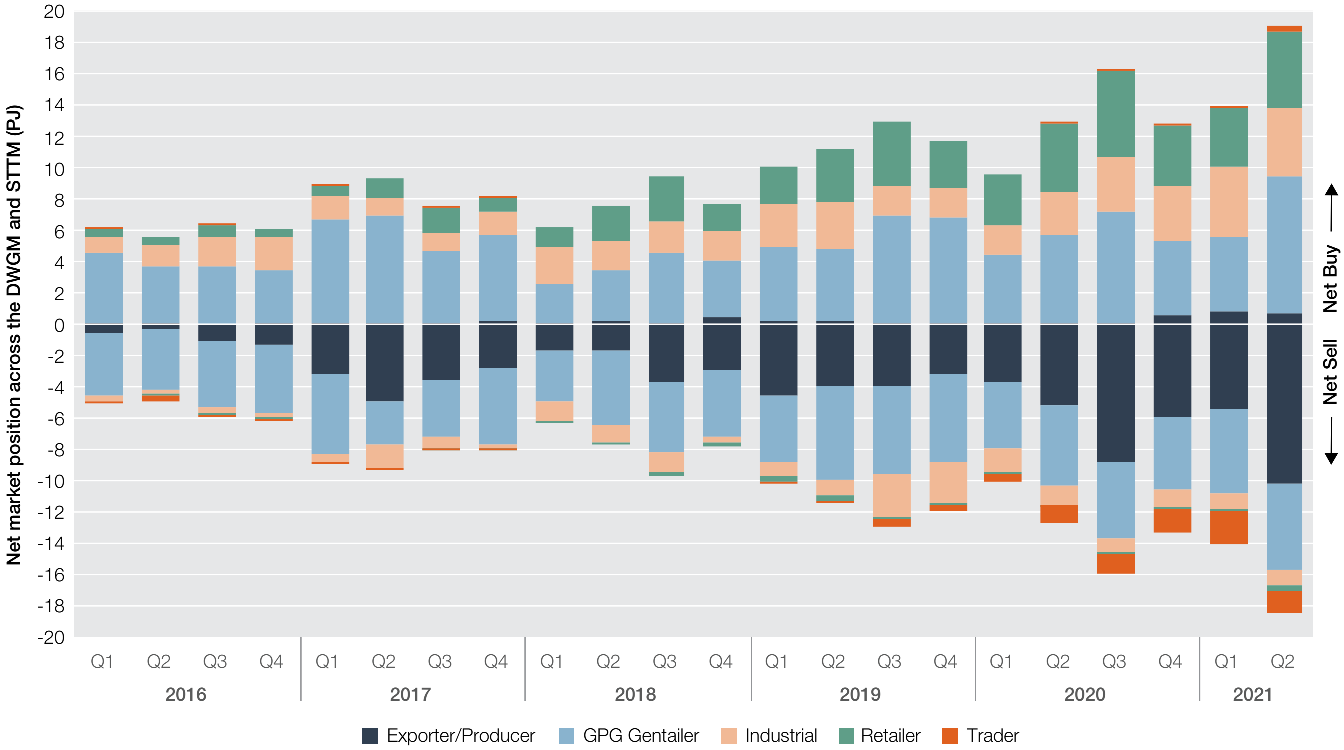


Source: AER analysis using DWGM and STTM data.

33 Origin Energy, Origin boosts gas supply to southern markets, accessed 27 July 2021.

The Exporters and Producers are more actively participating in spot markets, driving higher trading volumes across the east coast markets (Figure 2.18). Exporters and Producers increased gas sales to the spot markets during the quarter, selling 10.1 PJ in Q2 2021, increasing from 5.4 PJ in Q1 2021. Sales by Exporters and Producers increased throughout the quarter, peaking in June, following higher demand in southern markets. Industrial customers and Retailers have increasingly sourced gas from spot markets buying higher quantities since 2020.

Figure 2.18 Spot trade by participant

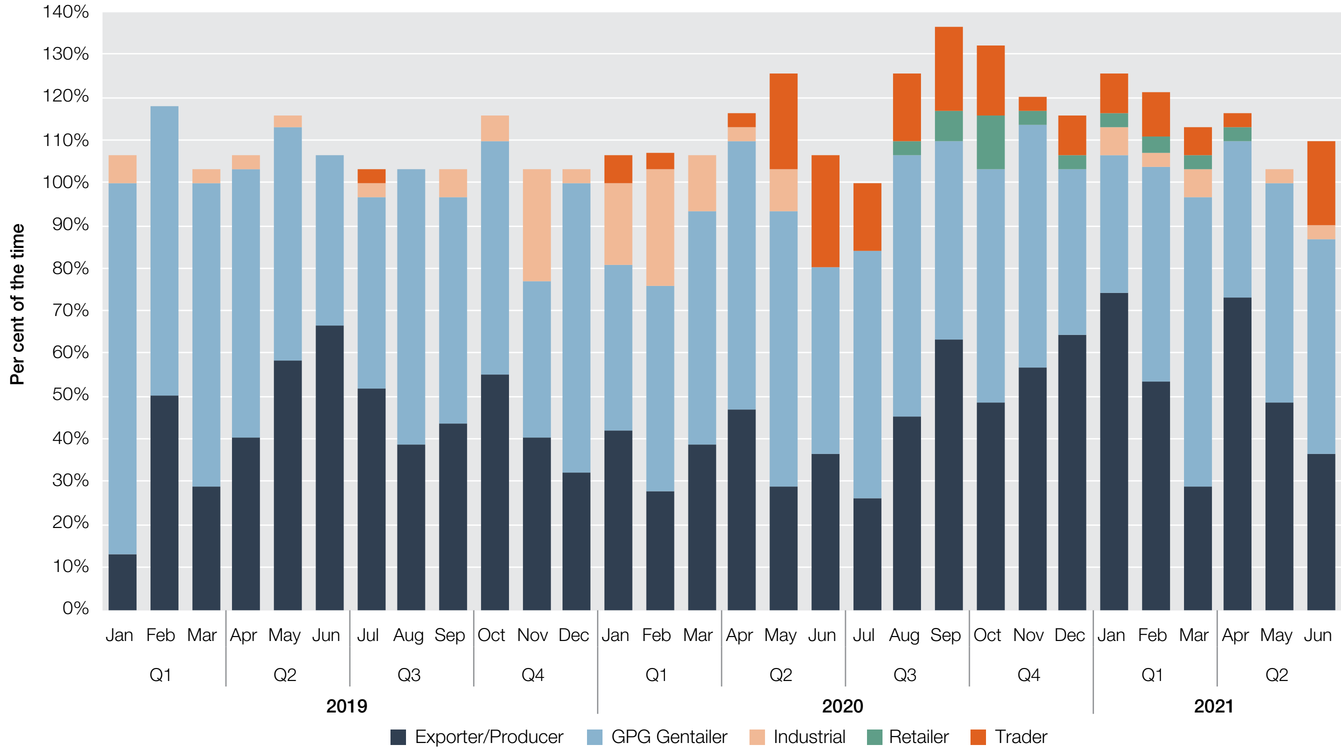


Source: AER analysis using DWGM and STTM data.

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

GPG Gentailers, and Exporter and Producer participants mostly set the marginal price of gas in spot markets in Q2 2020. Interestingly, GPG Gentailers more often set the price of gas in June within Sydney and Victorian markets during periods of high prices and elevated gas use for electricity generation (Figure 2.19 and Figure 2.20). This is significant as the volume of gas trade is highest in Victoria and Sydney. In the Adelaide and Brisbane markets, GPG Gentailers typically set the price at least 80% of the time, being relatively less challenged by other participants than in Victorian and Sydney markets.

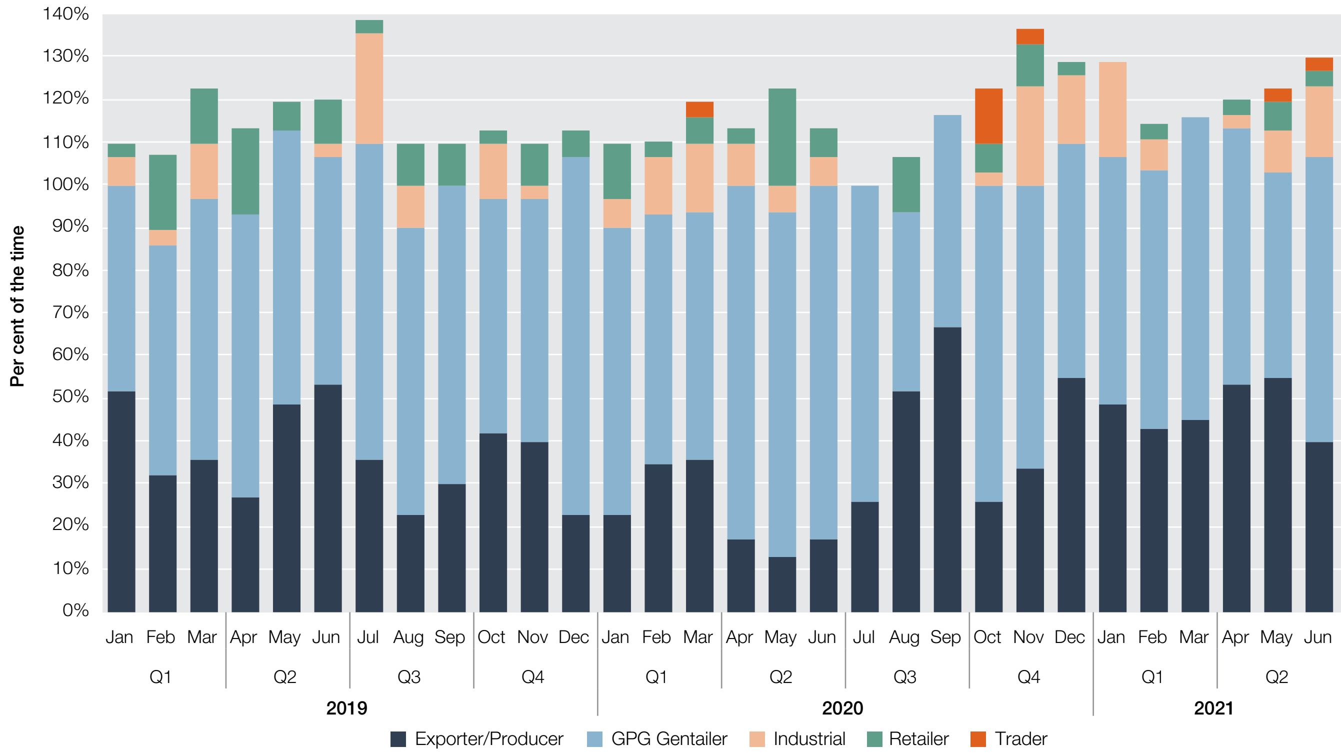
Figure 2.19 Sydney STTM price setter by participant



Source: AER analysis using STTM data.

Note: The Sydney STTM price setter was calculated for the D-1 schedule.

Figure 2.20 Victorian DWGM price setter by participant

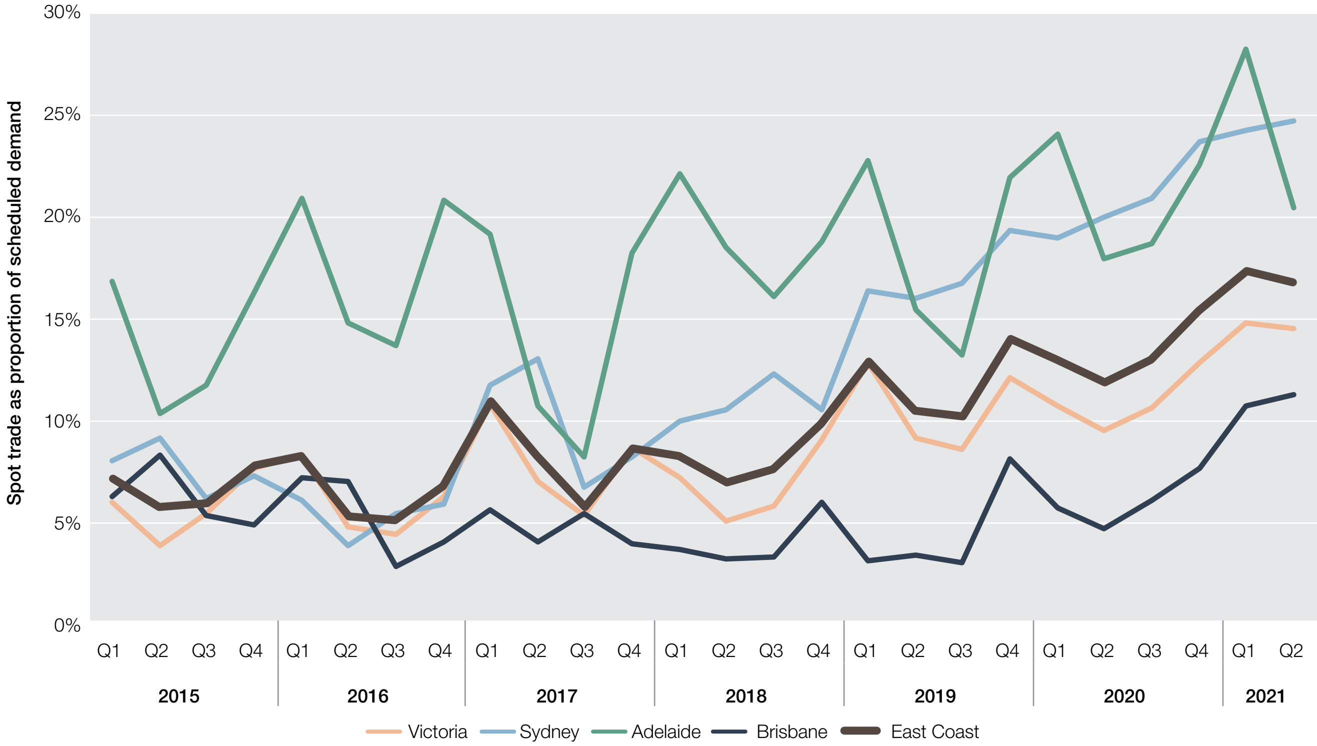


Source: AER analysis using DWGM data.

Note: The DWGM price setter was calculated for the 6 AM market schedule.

The spot trade as a proportion of demand declined in Q2 2021 from Q1 2021, as demand growth outweighed the growth in trade volumes (Figure 2.21). This was particularly the case in the Adelaide and Victorian markets.

Figure 2.21 Spot trade as a proportion of demand



Source: AER analysis using DWGM and STTM data.

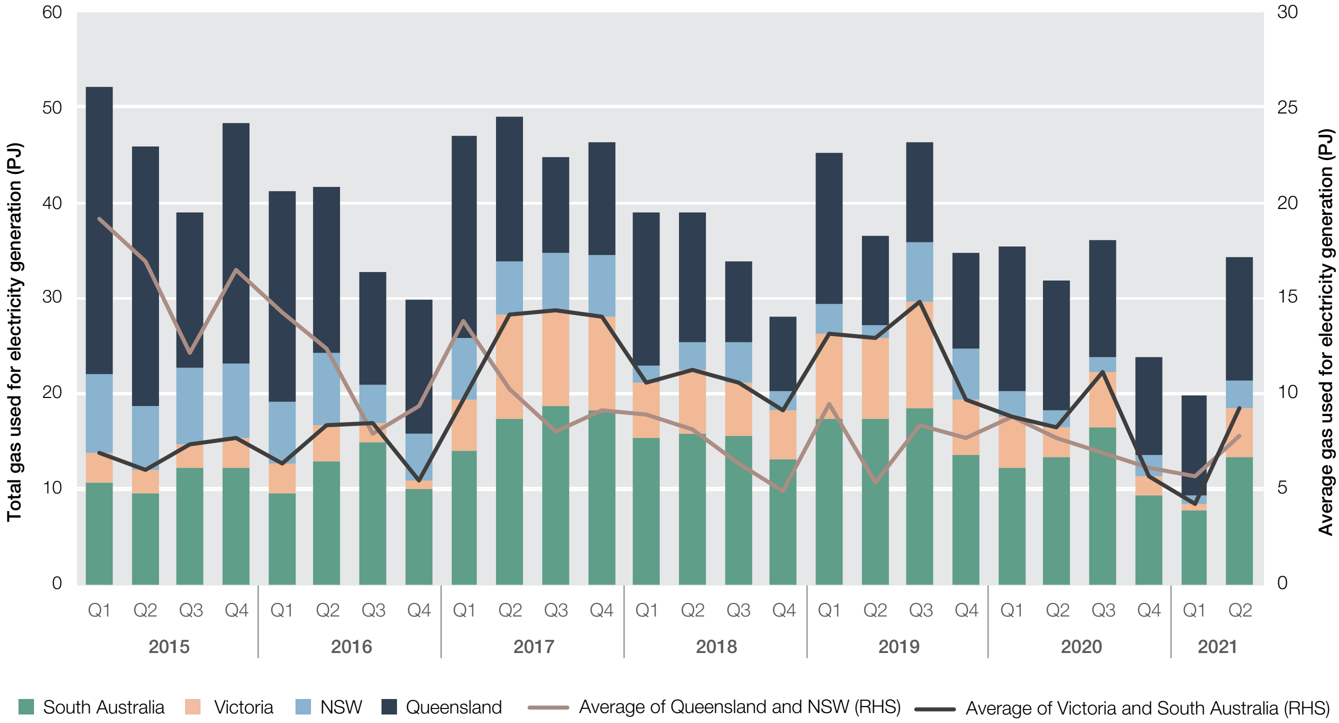
2.8 NEM influencing gas prices in Q2 2021

		GAS POWERED GENERATION OUTCOMES				
		FY 16/17	FY 17/18	FY18/19	FY19/20	FY20/21
Total GPG, PJ	QLD	62	51	41	49	46
	NSW	21	17	11	16	8
	VIC	19	32	28	26	14
	SA	56	68	64	58	47
	TOTAL	159	169	144	148	114

Over the last financial year, gas use by electricity generators has continued to fall from 148 PJ in 2019–20 to 114 PJ in 2020–21. Gas use for electricity generation has been declining since 2016–17, driven by increased low priced wind and solar generation output as well as falling demand.

Gas used for electricity generation grew since last quarter, rising from a very low 20 PJ in Q1 2021, to 34 PJ in Q2 2021, reaching a similar level of gas used in Q2 2020 (Figure 2.22). Gas powered generators increased output in all states from the previous quarter, with most gas used by generators in Queensland (13 PJ) and South Australia (13 PJ), compared to Victoria (5 PJ) and NSW (3 PJ).

Figure 2.22 Gas used for electricity generation



Source: AER analysis using NEM data.

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

Gas generators increased their output and demand for gas in Q2 2021 from the previous quarter in response to significant planned and unplanned generator outages, periods of low wind generation and colder temperatures, particularly late in the quarter (section 1.5). The higher levels of demand by gas powered generators across markets in June coincided with a period of sharp price rises in all markets, as discussed in our focus story.

2.9 Victorian gas futures trading subdued

GAS FUTURES TRADE OUTCOMES			
	FY 18/19	FY 19/20	FY 20/21
Trade (PJ)	8.8	7.9	3.0
Trade (# of contracts)	962	867	327

Over the last financial year, gas futures trade continued to decline from 7.9 PJ in 2019–20 to a low of 3 PJ in 2020–21. The downward trend in gas futures trades began since 2018–19 when trading volumes were at their peak.

The volume of trade in Victorian gas futures contracts remained subdued in Q2 2021 (Table 2.2). Total volume of contracts traded was 842, an increase from 668 contracts during Q1 2021 but significantly lower than the peak of 2,842 contracts traded in Q2 2020.

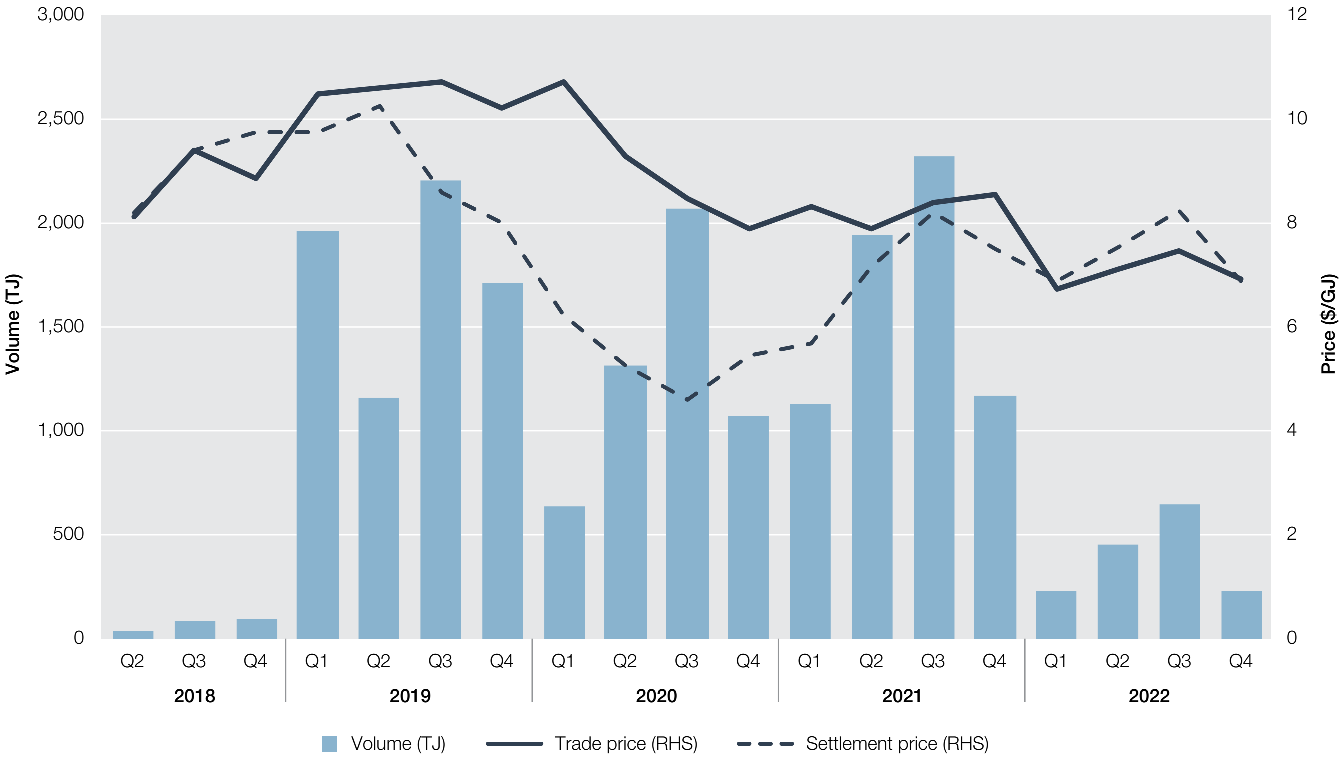
Table 2.2 Victorian gas futures trade summary

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	1,303	143
Q4 2018	3,294	361
Q1 2019	1,661	182
Q2 2019	2528	276
Q3 2019	989	108
Q4 2019	2,058	225
Q1 2020	2,051	224
Q2 2020	2,842	310
Q3 2020	743	81
Q4 2020	741	81
Q1 2021	668	73
Q2 2021	842	92

Source: AER analysis using ASX Energy data.
Note: Trade date reflects of transaction not contract expiry date.

Settlement prices indicate expected gas prices between $7.5/GJ and $8.2/GJ for the remainder of 2021 and between $6.91/GJ and $8.24/GJ throughout 2022 (Figure 2.23). The difference between settlement and traded contract prices shows the divergence between actual prices and expectations from prior years. In Q2 2021, Victorian gas futures prices settled for $7.2/GJ, compared to an average traded price of $7.9/GJ.

Figure 2.23 ASX Victorian futures trade

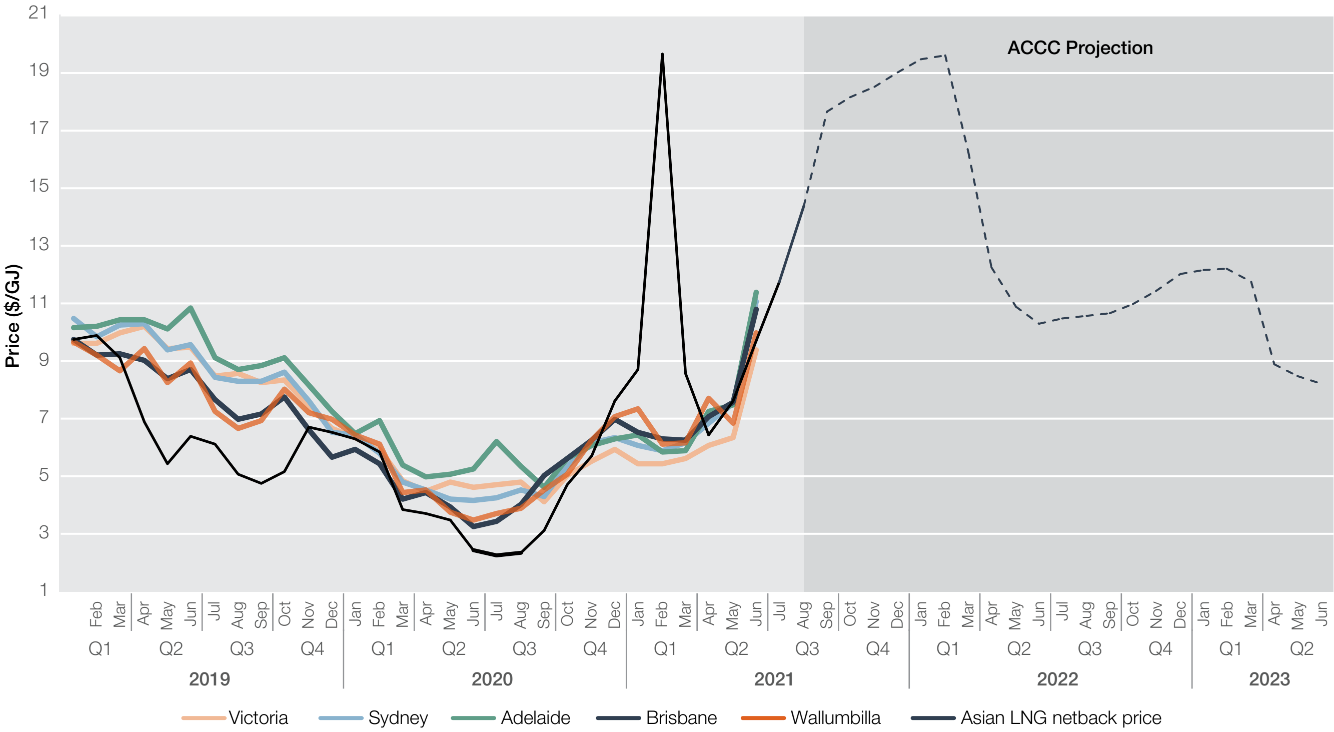


Source: AER analysis using ASX Energy data.
Note: Trading volumes are organised by contract expiry date.

Focus – Gas price volatility

This quarter saw a sharp rise in wholesale gas spot market prices, and heightened levels of price volatility. This occurred alongside rising trading volumes, with buyers exposed to these prices. Increasingly, the spot markets are being used by industrial customers and GPG Gentailers to source gas exclusively, or as a compliment to their gas supplied under contract. This section provides an in depth analysis of the reasons for elevated prices over June 2021, and a number of sporadic price spikes that occurred throughout April and June (Figure 2.24).

Figure 2.24 Monthly domestic and international prices



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

Monthly gas prices throughout Q2 rose sharply by 43% to 53% from May to June across markets, outpacing the rise in international prices of 27% over the same period (Table 2.3).

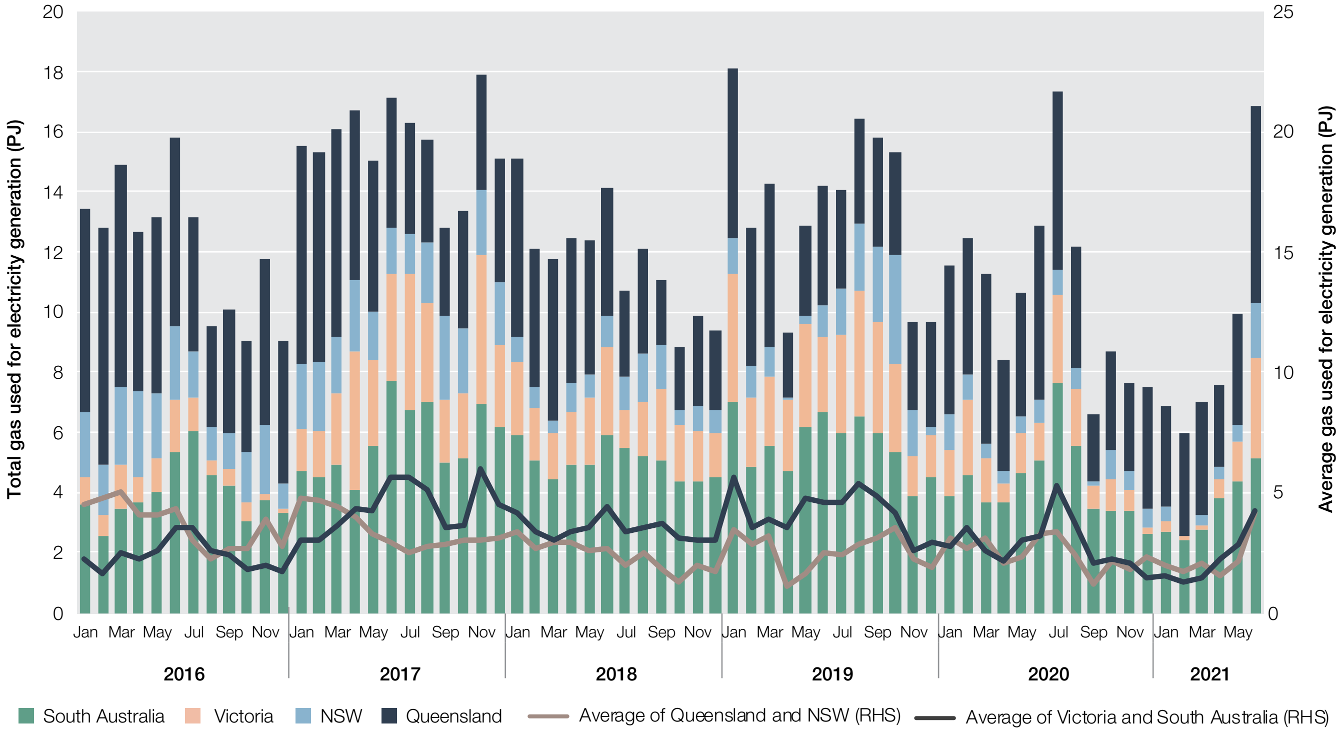
Table 2.3 Monthly average spot prices Q2 2021

		VICTORIA	SYDNEY	ADELAIDE	BRISBANE	WALLUMBILLA	ASIAN NETBACK
Average price, $/GJ	April 21	6.07	6.84	7.24	7.10	7.71	6.44
	May 21	6.34	7.52	7.48	7.56	6.83	7.64
	June 21	9.38	11.06	11.41	10.80	10.00	9.69

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

During Q2 2021, the level of domestic prices rose to be approximately equivalent to higher international netback prices, which have consistently risen since the lows of mid-2020. Another contributing factor to higher prices was the large increase in the gas used for electricity generation during June. This high level of gas powered electricity generation has been seen few times since 2017, at the time the 1,600 MW Hazelwood power station closed and more gas was required to balance the NEM (Figure 2.25). The total gas used in June 2021 exceeded 16 PJ, a level rarely achieved in recent quarters. While generators may not directly source their gas from the spot markets, these prices are a general indicator of gas costs. In general, Q2 includes some winter months which raises average demand levels, as gas demand increases to meet residential heating requirements.

Figure 2.25 Monthly gas use by electricity generators



Source: AER analysis using NEM data.

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

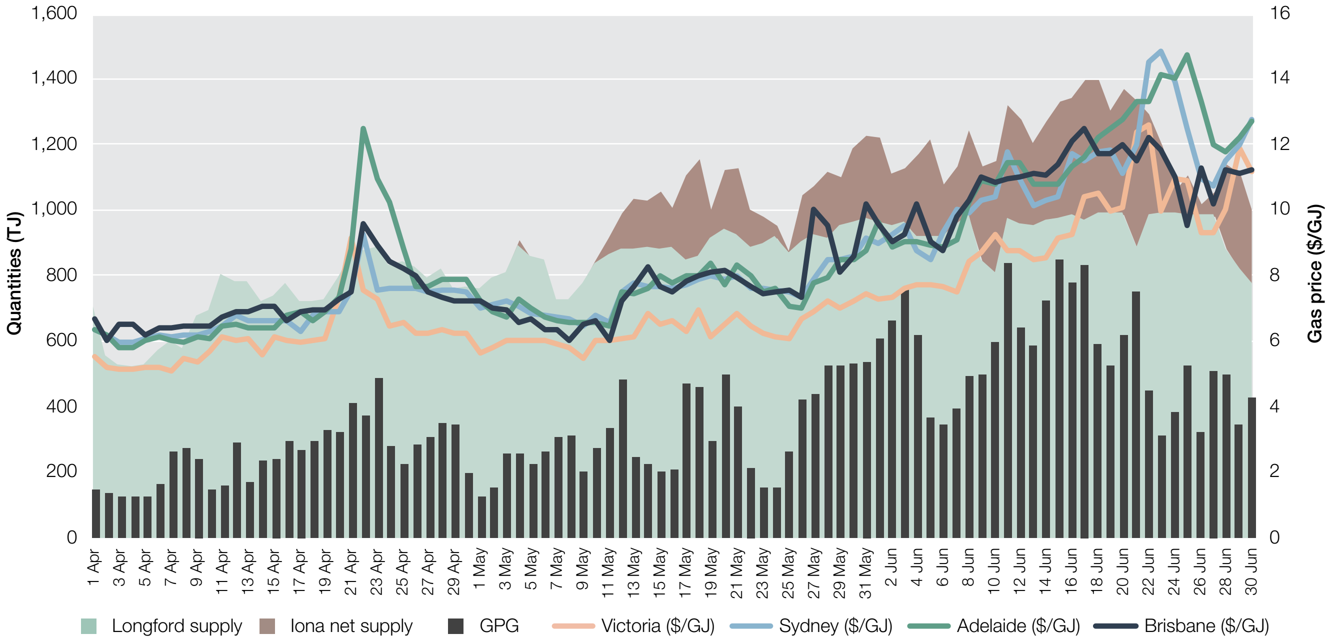
On a number of individual days, gas prices spiked across markets during April and June. During the week commencing 18 April, prices peaked at $12.50/GJ in Adelaide and approximately $21/GJ (20–21 April) in Victoria. Price sensitivity analysis of the Victorian spot market shows that 10% higher demand on 21 June could have resulted in a $169/GJ price in Victoria.[34] Gas prices peaked to a lesser extent in Sydney $9.26/GJ and Brisbane $9.59/GJ (22 April). The cause of these price spikes were a reduction in gas supply due to a disruption at the Moomba production facility leading to a reduction by more than 40 TJ. This was followed by significant rebidding of gas into higher price bands on both the Moomba to Adelaide and Moomba to Sydney pipelines. Additionally, a planned outage at the Iona gas storage facility in Victoria meant that it could not provide any gas supply injections throughout the week (Figure 2.26). The events of 20 and 21 April also coincided with higher gas demand due to cold weather, low wind generator output, and higher NEM demand met by increased levels of gas powered generation. These events serve to show how fine the gas market supply-demand balance can be, particularly at times when more gas powered generation is required in the NEM because of low electricity output from non-gas sources of generation.

During the week commencing 20 June, prices reached even higher levels, ranging from $13/GJ to $15/GJ in Sydney and Adelaide for most of the week and the Victorian price at $17/GJ on 21 June (Figure 2.26). This was caused by a range of factors including an unplanned outage and reduction in supply from the Longford gas plant on 21 June, leading AEMO to issue a threat to system security notice.[35] Additionally, gas use for power generation was relatively high in Victoria (217 TJ), NSW (148 TJ) and South Australia (218 TJ) compared to typical gas powered generation levels. On 17 June, the price in Victoria reached $14/GJ, as a high volume of gas (308 TJ) was used for electricity generation, in response to reduced output by the Yallourn power station in Victoria, after an unforeseen flooding event at the attached coal mine since 12 June.

34 Prices in Victoria are determined by an average of 5 schedule prices throughout the gas day. The weighted daily price is determined by weighting the 6 am ex ante price by scheduled imbalances (differences between participant scheduled gas to and from the market) for the whole gas day. Weighting the subsequent 4 prices by changes to the respective scheduled daily imbalances through the day. Therefore, the 6 am price is significantly more heavily weighted than the other schedule prices during the day.

35 AEMO, *Declared Wholesale Gas Market – Intervention Report*, June 2021, p. 4.

Figure 2.26 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).

This period serves to demonstrate the need for gas to balance the NEM when periods of lower renewable output coincide with baseload generator outages. Currently there is a total installed gas generation capacity of 11,063 MW in the NEM that could serve this purpose. This consists of 2,063 MW in NSW, 3,270 MW in Queensland, 2,576 MW in Victoria, 2,766 MW in South Australia, and 388 MW in Tasmania. Additionally, some of these generators can start generating within 5 minutes, offering capability to respond to price signals at short notice.

Appendix A Electricity generator outages

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q2 2021	REASON FOR OUTAGE	RETURNED TO SERVICE
Queensland		**480**		
Callide C, Callide Power Trading	Black coal, 2 units, 420 MW each	Unit 3: 43 days	Unplanned (6 days) – technical issues	13/05/2021
			Unplanned (37 days) – tripped following significant failure of Callide C unit 4 on 25 May	Unknown
		Unit 4: 49 days	Planned (12 days)	22/04/2021
			Unplanned (37 days) – significant failure on 25 May	Unknown
Callide B, CS Energy	Black coal, 2 units, 350 MW each	Unit 1: 59 days	Unplanned (17 days this quarter) – technical issues during Q1 2021	18/04/2021
			Unplanned (42 days) – technical issues	16/06/2021
		Unit 2: 28 days	Unplanned (28 days) – tripped following significant failure of Callide C unit 4 on 25 May	22/06/2021
Gladstone, CS Energy	Black coal, 6 units, 280 MW each	Unit 1: 50 days	Planned (29 days)	7/05/2021
			Unplanned (21 days) – technical issues	29/05/2021
		Unit 2: 15 days	Unplanned – technical issues	21/06/2021
		Unit 3: 6 days	Unplanned (6 days this quarter) – technical issues during Q1 2021	7/04/2021
		Unit 4: 19 days	Planned	8/05/2021
		Unit 5: 23 days	Planned (9 days)	10/04/2021
			Unplanned (6 days) – technical issues	19/04/2021
			Planned (8 days this quarter)	Unknown
		Unit 6: 6 days	Planned (6 days this quarter)	Unknown
Kogan Creek, CS Energy	Black coal, 1 unit, 713 MW	16 days	Unplanned – technical issues	17/06/2021
Millmerran, InterGen	Black coal, 2 units, 306 MW each	Unit 1: 5 days	Unplanned – technical issues	13/04/2021
		Unit 2: 40 days	Unplanned (4 days) – unit trip	23/04/2021
			Planned (36 days)	5/06/2021
Stanwell, Stanwell Corporation	Black coal, 4 units, 365 MW each	Unit 2: 71 days	Unplanned (28 days this quarter) – technical issues during Q1 2021	29/04/2021
			Planned (43 days)	Unknown
Tarong, Stanwell Corporation	Black coal, 4 units, 350 MW each	Unit 1: 50 days	Planned	19/06/2021
NSW		**357**		
Bayswater, AGL Energy	Black coal, 4 units, 630 MW – 655 MW	Unit 2: 91 days	Planned – outage started in Q1 2021	Unknown
		Unit 3: 17 days	Planned (4 days)	14/04/2021
			Unplanned (13 days) – technical issues	2/06/2021
		Unit 4: 9 days	Unplanned – technical issues	3/05/2021

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q2 2021	REASON FOR OUTAGE	RETURNED TO SERVICE
Liddell, AGL Energy	Black coal, 4 units, 450 MW each	Unit 1: 53 days	Planned (46 days)	21/06/2021
			Unplanned (7 days) – unit trip	Unknown
		Unit 2: 32 days	Unplanned (18 days) – technical issues	13/05/2021
			Unplanned (14 days) – unit trip	27/06/2021
		Unit 3: 34 days	Unplanned (22 days) – significant transformer incident on 17 December 2020	23/04/2021
			Unplanned (7 days) – technical issues	1/05/2021
			Unplanned (5 days) – unit trip	21/05/2021
Vales Point, Delta Electricity	Black coal, 2 units, 660 MW each	Unit 5: 2 days	Planned	19/04/2021
		Unit 6: 83 days	Planned	1/07/2021
Eraring, Origin Energy	Black coal, 4 units, 680 MW each	Unit 1: 17 days	Planned (12 days)	13/04/2021
			Unplanned (5 days) – technical issues	3/06/2021
		Unit 4: 19 days	Planned	4/05/2021
Victoria		**160**		
Loy Yang A, AGL Energy	Brown coal, 4 units, 500 MW – 540 MW	Unit 1: 11 days	Planned	25/04/2021
		Unit 2: 7 days	Unplanned (4 days) – plant failure	7/06/2021
			Planned (3 days)	28/06/2021
		Unit 3: 11 days	Unplanned (6 days) – plant failure	13/05/2021
			Unplanned (5 days) – plant failure	19/05/2021
Loy Yang B, Alinta Energy	Brown coal, 2 units, 520 MW each	Unit 2: 11 days	Planned (7 days)	23/04/2021
			Unplanned (4 days) – technical issues	16/05/2021
Yallourn, Energy Australia	Brown coal, 4 units, 355 MW each	Unit 1: 11 days	Unplanned (11 days this quarter) – plant failure during Q1 2021	12/04/2021
		Unit 2: 49 days	Unplanned (10 days) – technical issues	14/04/2021
			Unplanned (9 days) – technical issues	26/04/2021
			Unplanned (6 days) – technical issues	14/05/2021
			Unplanned (6 days) – technical issues	22/05/2021
			Unplanned (3 days) – technical issues	30/05/2021
			Unplanned (15 days) – coal supply issues, following heavy rains and risk of flooding	27/06/2021
		Unit 3: 25 days	Planned (9 days)	31/05/2021
			Unplanned (2 days) – technical issues	6/06/2021
			Planned (2 days)	10/06/2021
			Unplanned (3 days) – coal supply issues, following heavy rains and risk of flooding	15/06/2021
			Unplanned (9 days) – coal supply issues, following heavy rains and risk of flooding	25/06/2021
		Unit 4: 35 days	Planned (13 days)	5/05/2021
			Planned (3 days)	11/05/2021
			Unplanned (19 days) – coal supply issues, following heavy rains and risk of flooding	Unknown

Appendix B 30 minute FCAS prices greater than $5,000/MW

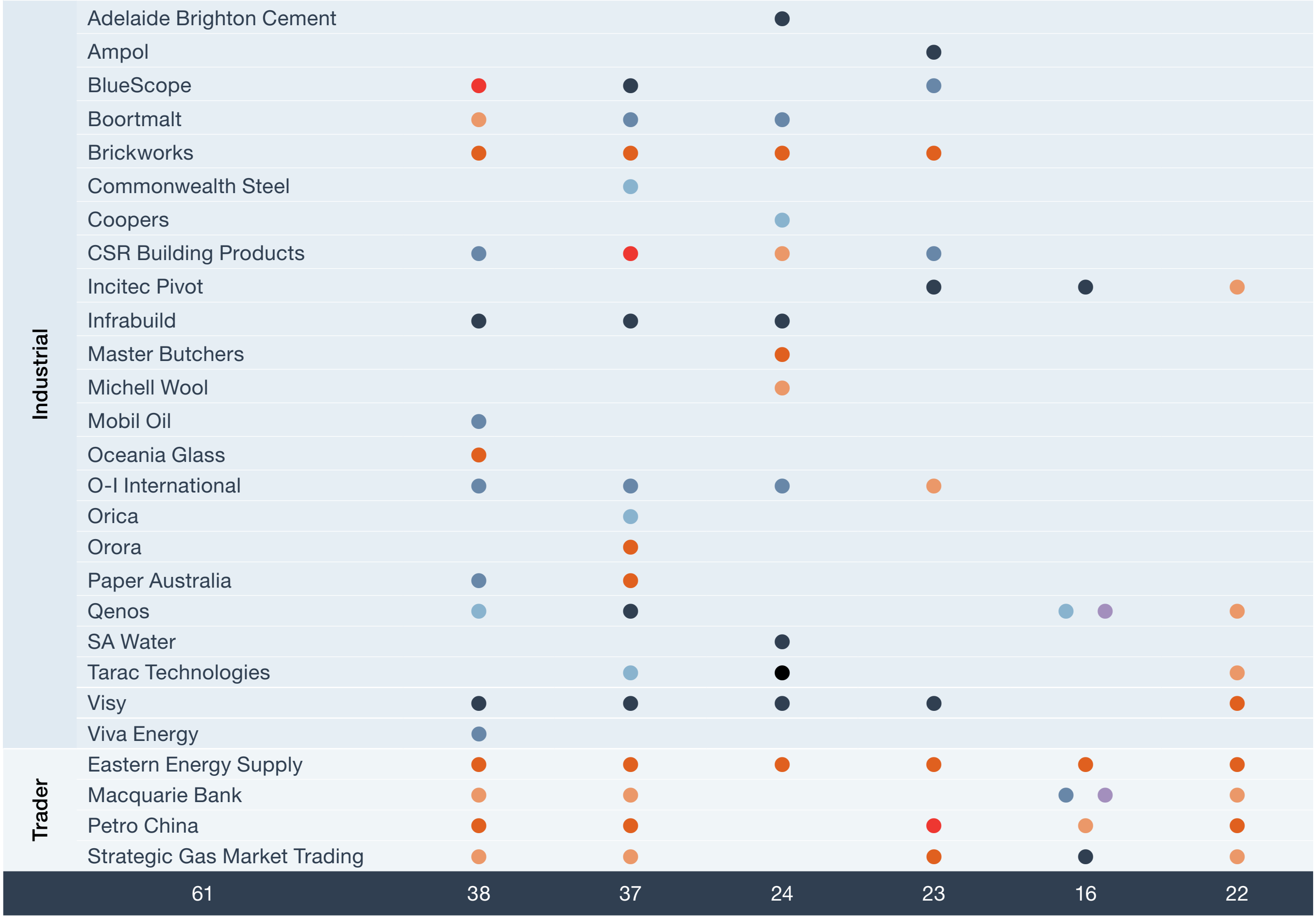
We have obligations to report on prices over $5,000/MW in ancillary services markets.

DATE	TRADING INTERVAL	RAISE 6 SECOND PRICE $/MW	RAISE 60 SECOND PRICE $/MW	LOWER 6 SECOND PRICE $/MW	ENERGY PRICE $/MWH	CO-OPTIMISED WITH ENERGY (# OF D.I.)	MAX AVAIL REDUCED BY MORE THAN 10%
10 April	4.30 pm	8,959	10,676		1,666	R6 (2) R60 (1)	R6 (13%) R60 (17%)
10 April	5 pm	13,167	11,500		180	R6 (2)	R60 (10%)
10 April	5.30 pm	5,050			2,037	R6 (3)	R6 (10%)
18 May	6 pm			5,339	183	L6 (2)	-
18 May	6.30 pm			6,828	49	L6 (3)	-
21 May	5.30 pm			7,063	4	L6 (4)	L6 (10%)
3 June	7.30 am	7,500			2,202	R6 (1)	R6 (15%)
3 June	4 pm	9,708	7,287		1,688	R6 (1)	R6 (12%) R60 (25%)
3 June	4.30 pm	7,550			1,498	R6 (1)	-
3 June	5 pm	10,539			1,498	R6 (1)	-
3 June	5.30 pm	12,140			1,706	R6 (4)	-
3 June	6.30 pm	10,231	8,116		6,310	R6 (4) R60 (2)	R60 (17%)
3 June	7 pm	12,404	7,560		6,878	R6 (6) R60 (3)	R60 (10%)
3 June	7.30 pm	9,262			1,894	R6 (1)	-
3 June	8.30 pm	8,620			1,954	R6 (2)	R6 (11%)
3 June	9 pm	8,386			1,796	R6 (1)	-
3 June	9.30 pm	9,329			1,923	R6 (3)	-
3 June	10 pm	6,680			1,773	R6 (1)	-
3 June	10.30 pm	10,027			143	R6 (4)	-
3 June	11 pm	8,404			209	R6 (5)	-
3 June	11.30 pm	6,888			103	R6 (2)	-
3 June	12 am	6,723			101	R6 (2)	-
4 June	1.30 am	8,358			170	-	-
4 June	2 am	8,358			129	-	-
4 June	7 am	5,726	7,542		1,916	R6 (1) R60 (2)	R6 (12%) R60 (17%)
4 June	7.30 am	9,167			1,981	R6 (1)	-
5 June	5.30 pm	7,516	5,239		2,453	R6 (3) R60 (2)	R6 (48%) R60 (52%)
15 June	7.30 am	8,721	5,012		1,667	R6 (3) R60 (2)	R6 (17%) R60 (27%)
15 June	10.30 am	5,017			2,143	-	-

DATE	TRADING INTERVAL	RAISE 6 SECOND PRICE $/MW	RAISE 60 SECOND PRICE $/MW	LOWER 6 SECOND PRICE $/MW	ENERGY PRICE $/MWH	CO-OPTIMISED WITH ENERGY (# OF D.I.)	MAX AVAIL REDUCED BY MORE THAN 10%
15 June	11 am	10,195			2,037	R6 (1)	R6 (13%)
15 June	5 pm	12,528			1,623	R6 (3)	R6 (14%)
25 June	3.30 pm	14,500	14,500		166	R6 (2)	-
25 June	4 pm	14,500	13,000		191	R6 (1)	-
25 June	4.30 pm	14,500	14,954		2,588	R6 (3)	R60 (13%)
25 June	5 pm	7,357			134	R6 (2)	-
25 June	5.30 pm	14,709	14,500		376	R6 (6)	R60 (19%)
25 June	6 pm	11,665	6,285		147	R6 (3)	R60 (20%)
3 July	9.30 am	5,694	5,791		2,037	R6 (3) R60 (1)	R6 (19%) R60 (20%)
3 July	10 am	11,088	7,310		215	R6 (1)	R6 (12%) R60 (13%)
3 July	10.30 am	12,200	12,136		973	R6 (1)	-
3 July	11 am	14,600	13,033		2,703	R6 (1) R60 (1)	-
3 July	11.30 am	14,500	10,810		200	R60 (3)	-
3 July	12 pm	12,639	9,133		168	R6 (1)	-
3 July	12.30 pm	14,833	10,750		234	-	R6 (13%) R60 (10%)
3 July	1 pm	14,583	10,750		232	-	-
3 July	1.30 pm	14,500	8,912		287	R60(1)	-
3 July	2 pm	10,757	6,767		279	R6 (2)	-
3 July	2.30 pm	12,101	6,080		146	R60 (2)	R60 (10%)
3 July	3 pm	14,711	11,589		198	R6 (3) R60 (3)	R6 (13%) R60 (14%)
3 July	3.30 pm	7,850			232	R6 (2) R60 (1)	R60 (14%)

Appendix C 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	●					●
	ERM*	● ●	● ●	● ●	● ●	● ●	● ●
	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	●					
	Click Energy*	● ●	● ●				
	Covau	●	●		●		
	CPE Mascot		●				
	Delta Electricity		●				
	Discover Energy		●	●	●		
	Dodo	●	●				
	GloBird Energy	●	●	●	●		
	Powershop	●					
	Simply Energy		●	●			
	Sumo Gas	●					
	TasGas	●					
	Tango	●					
	Weston Energy	●	●	●	●		



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

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

* Click Energy was aquired by AGL, ERM was aquired by Shell (Shell Retail).
* Arrow also operates the Braemar 2 power station.
* ICAP Brokers is also active in the GSH, but does not trade gas commodities (trade facilitator).

Appendix D 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 >>> 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 >>> 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

FACILITY	DIRECTION	DAA ROUTE RECEIPT POINT NAME TO DELIVERY POINT NAME	RECEIPT POINT ID TO DELIVERY POINT ID
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
	West	Argyle >>> Wallumbilla delivery	1404082-1404097
		Condamine >>> Wallumbilla delivery	1404086-1404097
		RBP Trade Point (IPT) >>> Wallumbilla delivery	1490022-1404097
		Scotia >>> Wallumbilla delivery	1404102-1404097
SWQP	North	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 >>> Ballera Exit	1490025-1404115
		Wallumbilla HP Trade Point >>> SWQP to MCF Exit	1490025-1590025

Common measurements and abbreviations

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	GSH	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
		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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