Wholesale Markets Quarterly

Q4 2020

October – December

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AUSTRALIAN ENERGY REGULATOR

Australian Government

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Summary

Electricity markets

Average annual National Electricity Market (NEM) spot prices fell between 23% and 58% in 2020 compared to 2019, and were below $70/MWh in all regions for the first time since 2015. Volume weighted average (VWA) annual prices ranged from $43/MWh in Tasmania to $68/MWh in NSW. Historically one of the cheaper regions, this is the first time annual prices in NSW have been the highest in the NEM since 2007.

Quarterly price outcomes displayed similar overall trends. Q4 2020 prices were between 6% and 60% lower than prices in Q4 last year with average Q4 2020 prices ranging from $35/MWh in South Australia to $71/MWh in NSW. This was the first time since Q1 2012 that South Australia had the lowest quarterly price in the NEM.

In December, demand was particularly low in South Australia and Victoria with lower than average temperatures and record rooftop solar output. As a result, both regions experienced their lowest daily demand ever. At the same time, wind and large scale solar generation was high, with record wind and solar generation in Victoria, and record solar generation in South Australia. The combination of low demand and cheap renewable generation led to a record number of negative prices and average weekly prices as low as $3/MWh in South Australia and $14/MWh in Victoria.

While lower than the same time last year, Q4 2020 prices increased in NSW and Queensland compared to Q3 2020, with average quarterly prices in NSW $20/MWh higher than in other regions. This quarter on quarter price increase was a function of warmer than average temperatures, as well as network and generator outages. There were 3 high priced events in NSW driven by various factors, including black coal generator and network outages. These black coal generator outages, which were mainly planned, also resulted in a significant reduction in black coal generation this quarter. Q4 2020 saw the lowest black coal generation across the NEM since 2014, with record low black coal generation in NSW.

Q4 2020 also highlighted significant changes in the NEM's generation fuel mix.

More wind and large scale solar generation was recorded in Q4 2020 than ever before, assisted by a record 3,700 MW of renewable capacity entering the market in 2020. As a result of significant new entry, wind and solar generators provided a record 17% of NEM output this quarter.

High wind and large scale solar generation combined with lower levels of demand in Q4 2020 saw gas generation fall to its lowest Q4 level since 2005.

Gas markets

Average annual east coast spot market prices fell by 41% in the 2020 calendar year to $5.12/GJ. Individually, annual average prices ranged between $4.83/GJ at the Wallumbilla Gas Supply Hub (GSH), to $5.70/GJ in the Adelaide Short Term Trading Market (STTM). This is the first time since 2015 that calendar prices have been below $6/GJ across all markets. This reduction in prices was linked to a 31% fall in average Asian LNG spot prices over the year.

However, prices rose in Q4 2020 across all domestic markets, with a minimum increase from Q3 2020 of $0.59/GJ in the Adelaide STTM to a maximum increase of $2.11/GJ in the Brisbane STTM. Despite these increases, average east coast spot market prices were $5.92/GJ this quarter, similar to prices levels in Q1 2020. Brisbane prices were the highest at $6.28/GJ, with prices there higher than all southern market prices for the first time since Q3 2018.

At the same time, Asian LNG price assessments increased over Q4 2020, rising from around $6/GJ at the start of Q4 2020 to reach $10/GJ by 1 December 2020. This was then followed by a volatile 6 week period, where prices rose by 370%.

Highlighting the interaction between global and domestic supply, demand and pricing, as Asian LNG spot prices rose, Queensland production rose to record levels in December to facilitate a record 34 LNG export cargoes from Gladstone. However, this increased export activity did not encourage large domestic price rises, as in part this activity occurred during a lower demand period for the east coast domestic gas markets. Notably, in Q4 2020, gas used for gas powered generation reduced 10.5 PJ from Q4 2019. This offset some of the extra demand from LNG exporters who shipped around 25 PJ more gas than in Q4 2019.

Increased demand for LNG exports was also evident as Exporter and Producer participants sold less gas into domestic markets this quarter. In the Sydney STTM, Exporters and Producers scheduled less gas, accounting for only 9% of total supply. However, this did not have large price impacts. Similarly, trade at the GSH was down this quarter as Exporters and Producers sold the least amount of gas in 4 years.

Participants were able to use the Day Ahead Auction this quarter to support additional demand for gas in the north. In Q4 2020, 95% of capacity won on the South West Queensland Pipeline was on the route to send gas north, from Moomba into Queensland. Participants also won significant capacity on the Moomba to Sydney Pipeline on routes to ship gas north. More generally, gas flows from south to north were at their highest levels since Q4 2017.

Electricity markets at a glance

Q4 2020

Spot prices

Average 2020 prices fall by 23% to 58% compared to 2019, but Q4 prices rise in NSW and Queensland.

Demand

Record low demand in South Australia and Victoria due to record rooftop solar and mild start to summer.

Outages

Black coal outages and network outages in Q4 reduce availability of low priced generation in NSW.

Generation

Fuel mix continues to move from thermal to renewables. Wind and solar provide 17% of NEM output in Q4.

FCAS

50 Hz

More units (nearly all demand response) register to provide FCAS.

Outlook

Base future prices fall in all regions in 2020, but fall more significantly in the southern regions.

Gas markets at a glance

Q4 2020

Spot prices

Slight increase in all markets. Northern prices more expensive than southern prices

Spot trade downstream

Net trade quantities reduced, but proportions of total demand increased to record levels

Wallumbilla trade

Exchange trade still down on record 2019 levels

International prices and LNG exports

Significant short term rises in export prices and record LNG demand

Gas production and flows

Flows reversed to send gas north. Record Roma production in Queensland

Day Ahead Auction

Auction capacity won assists gas flows north into Queensland

About this report

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 market performance report*.

Importantly, this 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 FCAS prices over $5,000/MW. We fulfil both of these obligations in this report.

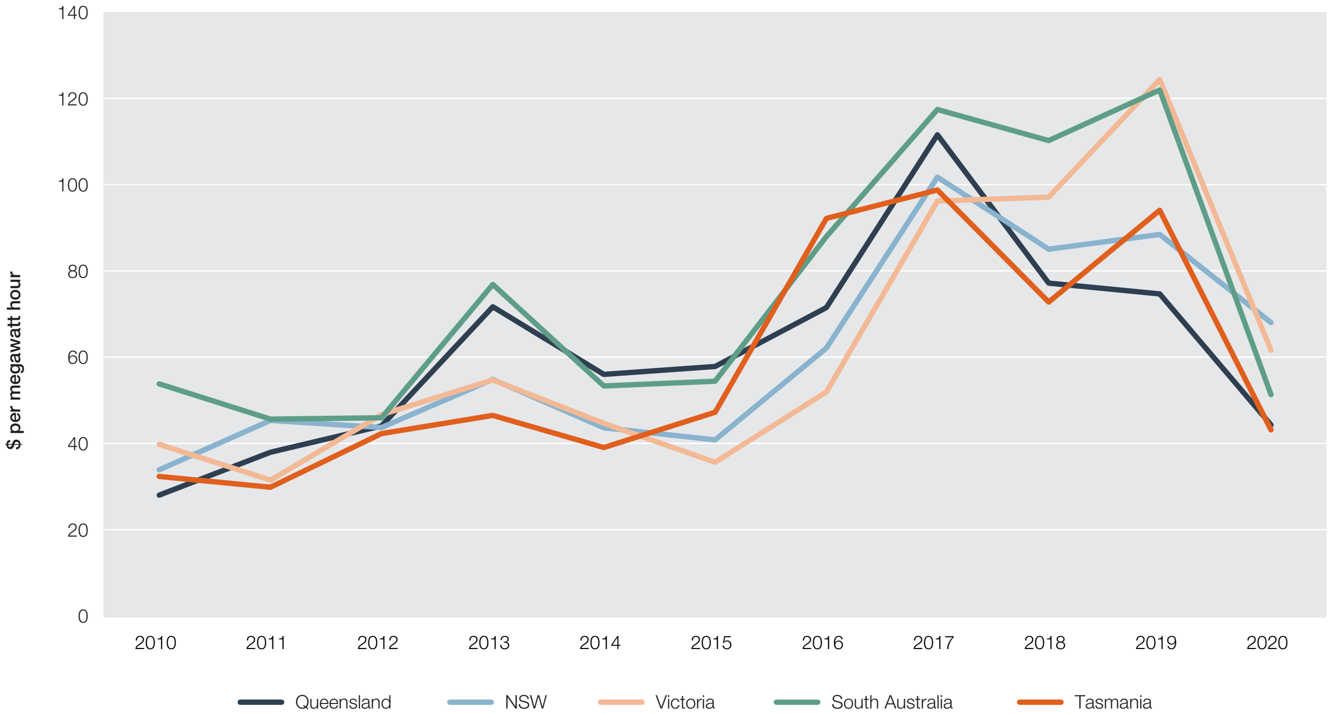
1. Electricity

1.1 Spot prices remain low but have increased in NSW and Queensland recently

In 2020 average annual spot prices fell between 23% and 58% compared to 2019, and were below $70/MWh in all regions for the first time since 2015 (Figure 1.1).[1] Annual volume weighted average (VWA) prices ranged from $43/MWh in Tasmania to $68/MWh in NSW.

Historically one of the cheaper regions, this is the first time annual prices in NSW have been the highest in the National Electricity Market (NEM) since 2007. In NSW, average prices were impacted by price spikes in January, November and December.

Figure 1.1 Average annual prices (VWA)



Source: AER analysis using NEM data.

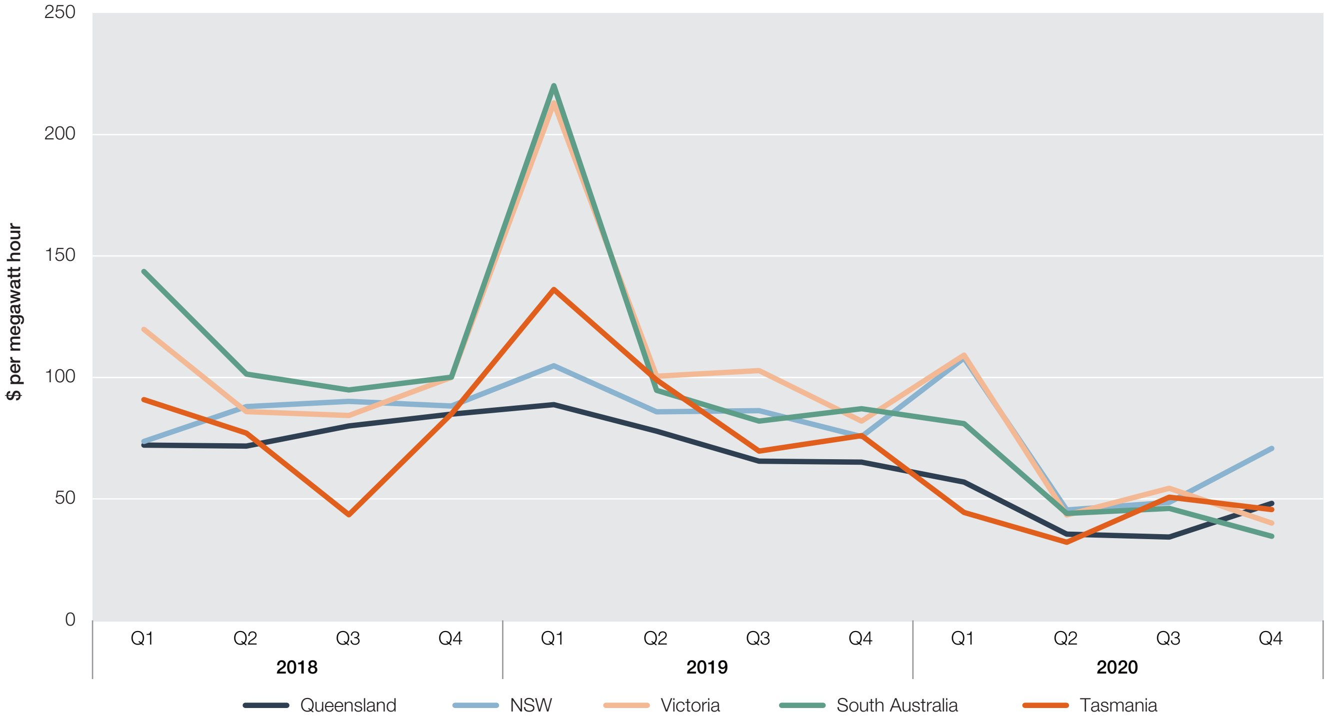
Note: Volume weighted average price is weighted against native demand in each region. AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Quarterly prices displayed similar trends to annual prices. In Q4 2020, prices were between 6% and 60% lower than average prices a year previously (Figure 1.2). Average quarterly prices ranged between $35/MWh in South Australia and $71/MWh in NSW. South Australia had the lowest quarterly price in the NEM for the first time since Q1 2012.

Compared to Q3 2020, prices in Q4 2020 increased in NSW (46%) and Queensland (40%), but fell in South Australia, Victoria and Tasmania.

1 Key drivers of the fall in average prices in 2020 are analysed in previous quarterly reports. They were:
- increased offers of low priced coal capacity in line with falling fuel costs (which then picked up in Q4 2020)
- the new entry of solar and wind
- lower summer demand due to mild conditions at the start and the end of the year (notwithstanding some extreme events).

Figure 1.2 Average quarterly prices (VWA)



Source: AER analysis using NEM data.

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

The increase in average prices in NSW in Q4 2020 compared to Q3 2020 was partly driven by 3 high price spikes that occurred in the quarter. During these events, the spot price exceeded $5,000/MWh for a total of five 30 minute trading intervals and this alone contributed over $12/MWh to the average quarterly price. These events were largely driven by:

- black coal generator outages (planned and unplanned), which reduced supply in NSW
- network outages in southern NSW and outages due to the Queensland-NSW interconnector upgrade, which restricted the amount of energy that could be imported to help meet demand.

At times, tight supply was exacerbated by higher than forecast demand and rebidding. We published a detailed analysis of these high priced events on our website.[2]

Smaller price spikes (exceeding $2,000/MWh) contributed a further $7/MWh to the NSW quarterly average price. Most of these smaller spikes were related to NSW black coal outages which we discuss further in a coal focus story. Other factors that contributed to higher prices in NSW included days of high demand, network outages limiting regional flows, and to a lesser extent rising fuel costs.

There were periods in the quarter where reserves were particularly tight in NSW. On 17 December 2020, when prices exceeded $5,000/MWh, there were insufficient short-term reserves in NSW. To ensure reliability of supply, AEMO issued actual Lack of Reserve notices prompting market participants to increase supply or reduce demand.[3] AEMO also activated the Reliability and Emergency Reserve Trader (RERT). AEMO use the RERT to maintain power system reliability and security by contracting with non-market participants to increase supply or reduce demand at times of reserve shortfalls.

The increase in average prices in Queensland in Q4 2020 from Q3 2020 was largely due to the higher Q4 temperatures. Queensland experienced its second warmest November on record, and in December 2020, most of the state reported several days or more of heatwave conditions. With more air conditioning, demand for energy increased pushing up prices. The increase in prices in Queensland was also due to higher prices in neighbouring NSW. As energy flows from a cheaper region to a more expensive region, prices tend to align.

2 The 3 high priced events occurred on 16 November, 20 November and 17 December.

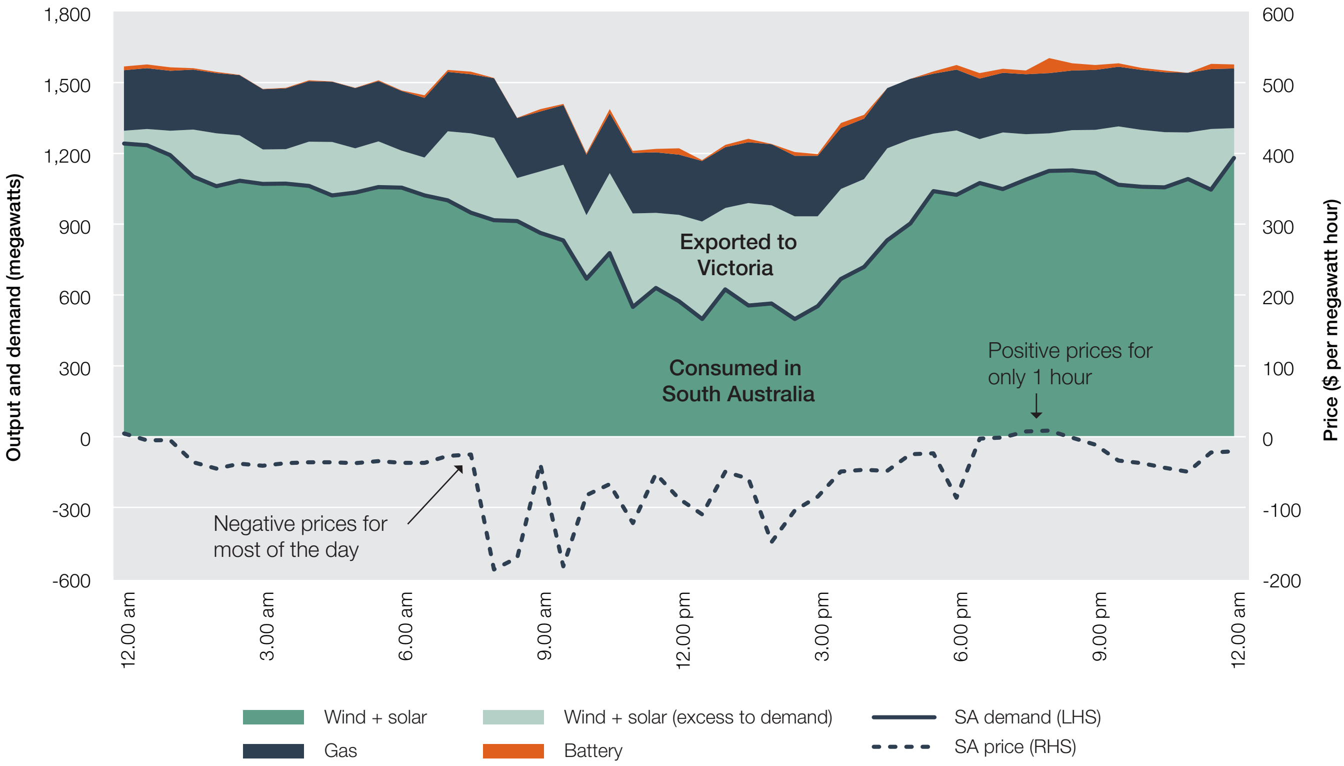
3 An actual Lack of Reserve (LOR) 1 in NSW was declared from 2.35 pm to 8.35 pm, and an actual LOR 2 was declared from 5.10 pm to 6.05 pm. Due to this, Reliability and Emergency Reserve Trader was dispatched / activated from 5.20 pm to 6.30 pm and intervention pricing applied for the 5.30 pm and 6 pm trading intervals.

In contrast with the north, the fall in prices in the southern regions was driven by mild weather and low demand, as well as record high renewable generation.

Victoria and South Australia recorded their coolest December on record since 2010, as well as their highest ever output from rooftop solar. These factors combined to significantly reduce demand from the grid. With high wind and large scale solar generation, average weekly prices in Victoria, South Australia and Tasmania dropped dramatically in the week starting 6 December 2020. In this week, prices fell to just $3/MWh in South Australia, $14/MWh in Victoria and $18/MWh in Tasmania – the lowest average weekly price on record in South Australia and second lowest in Victoria.

On Sunday 6 December, prices reached a record low daily average of -$30/MWh in Victoria, and even lower prices of -$46/MWh in South Australia and -$35/MWh in Tasmania. Never before have there been so many negatively priced trading intervals in one day. Of the 48 trading intervals during the day, only 2 were priced greater than $0/MWh in South Australia and Victoria, and in Tasmania no intervals were priced greater than $0/MWh. On this day, wind generation was high in Victoria and South Australia. In South Australia, for example, wind and solar generation, which offer most of their capacity at negative prices, exceeded regional demand for the entire day (Figure 1.3). AEMO directed gas generation on to keep the system secure, and excess low priced generation was exported to Victoria.

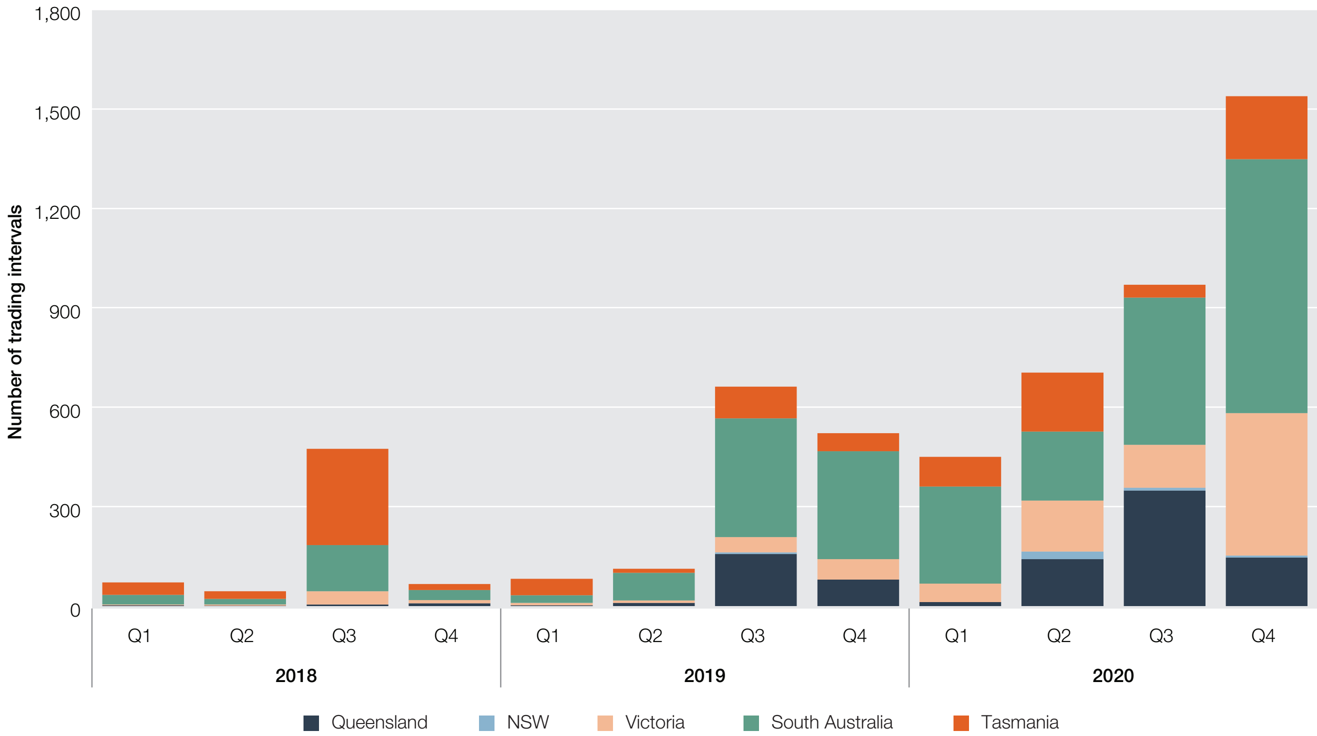
Figure 1.3 Generation, demand and negative prices in South Australia, 6 December 2020



Source: AER analysis using NEM data.

In Q4 2020 there were almost three times as many negative prices than there were in Q4 2019 (Figure 1.4). While almost half of the negative prices occurred in South Australia, there was also a significant increase in the number of negative prices in Victoria.

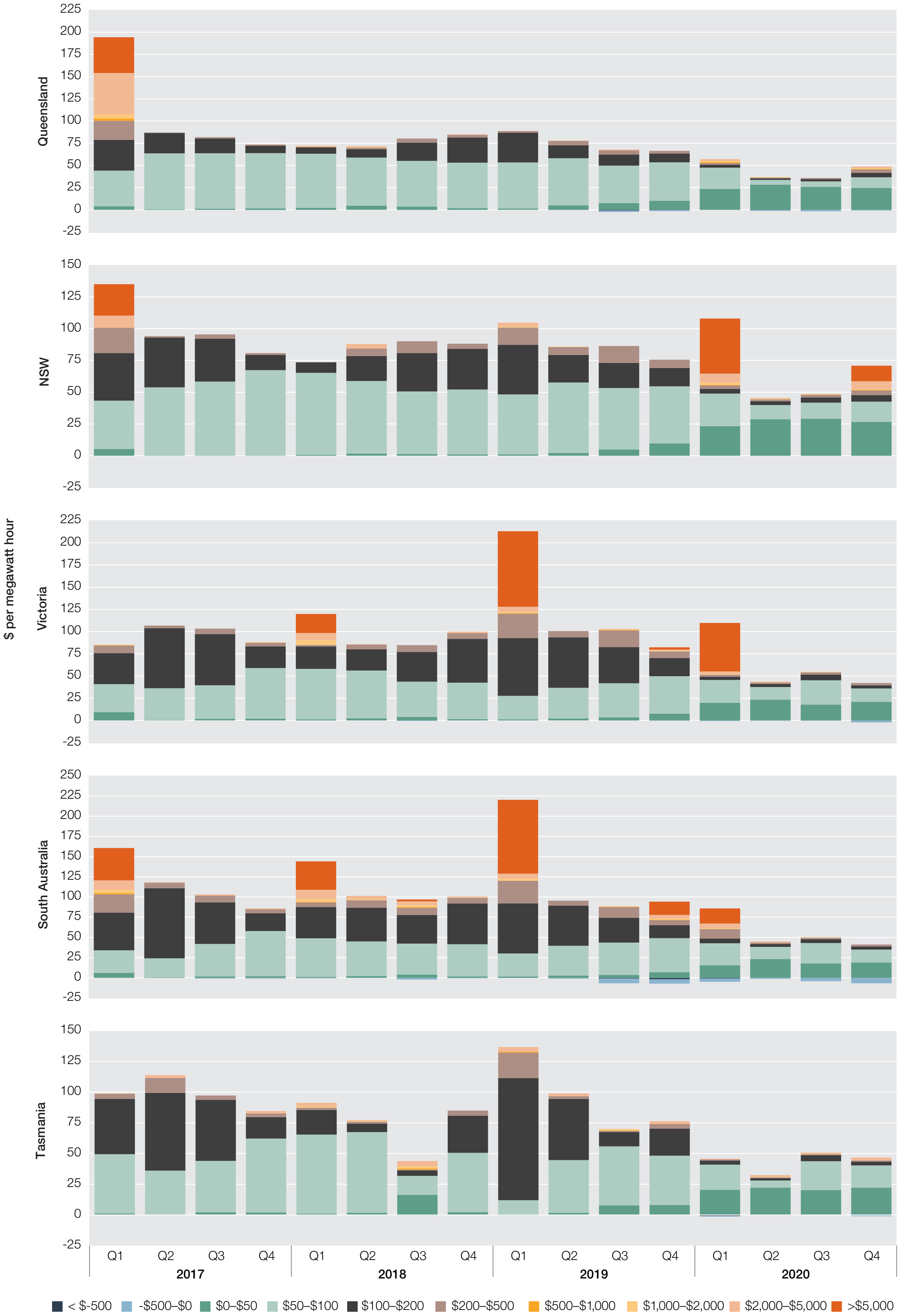
Figure 1.4 Quarterly count of negative prices



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

The contribution of different price bands to average quarterly prices highlights the impact the high priced events had on NSW price in Q4 2020 (Figure 1.5). Without the prices over $5,000/MWh, the quarterly price in NSW would have been $59/MWh, closer to prices in the other regions. In contrast, negative prices reduced the average price in South Australia by almost $7/MWh, and to a lesser extent in Victoria. While there were also negative prices in Queensland and Tasmania, they had less impact on average quarterly prices.

Figure 1.5 Contribution of different price bands to average quarterly wholesale prices



Source: AER analysis using NEM data.

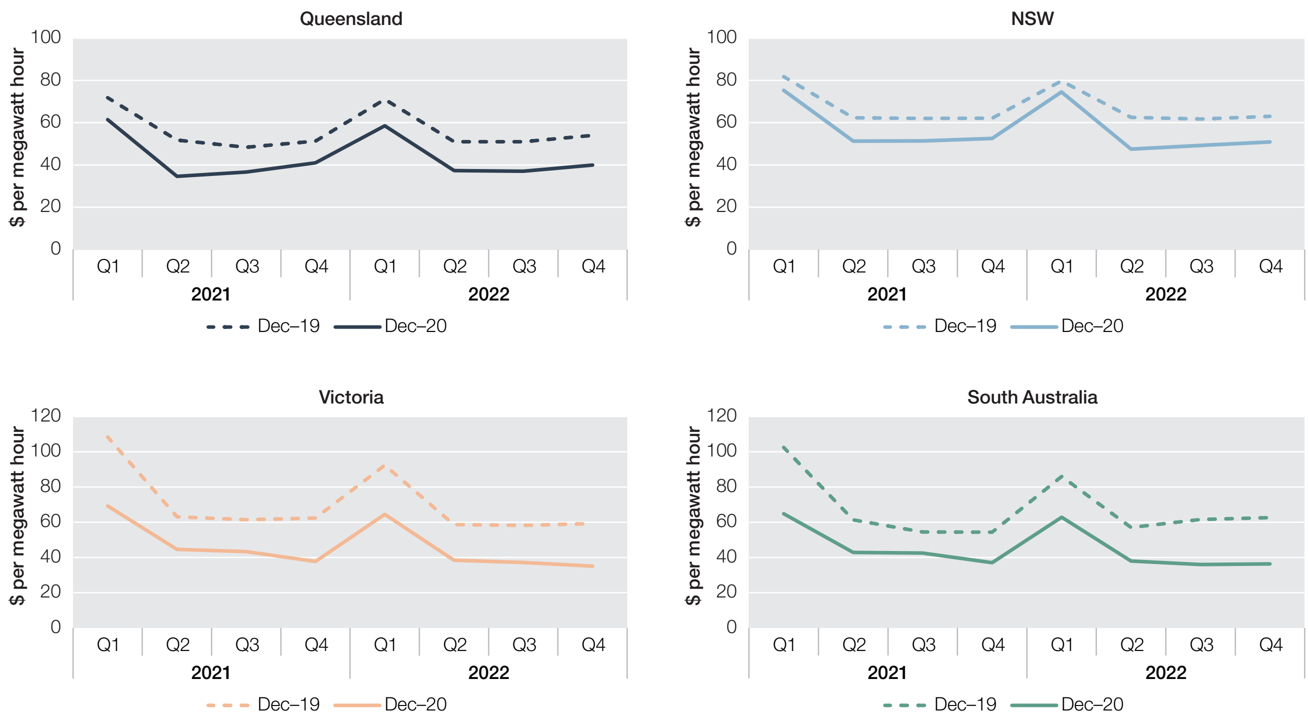
Note: Shows extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in each region.

With lower prices and lower output, NEM turnover (price times output) in 2020 fell 40%, down to its lowest level since 2015. Turnover fell most in Victoria, South Australia and Tasmania where spot prices and demand fell.

Looking forward, base future prices fell over 2020, reflecting an expectation that falls in spot prices will continue into the future.

Between December 2019 and December 2020, all regions saw a fall in prices for 2021 and 2022 base futures (Figure 1.6). Base future prices in December 2020 indicated contract market participants expected spot prices for Q1 2021 to be around $60/MWh to $75/MWh, falling to around $34/MWh to $50/MWh for the remainder of 2021. Participants also expect spot prices in NSW to remain higher than in other regions.

Figure 1.6 Forward base future prices, as at December 2019 and December 2020



Source: AER analysis using ASX Energy data.

Note: Closing price of base futures contracts for Q1 2021 to Q4 2022 on the last trading day of Q4 2019 (31 December 2019) and Q4 2020 (31 December 2020).

In line with broader price trends, prices of Q1 2021 cap contracts fell in Victoria and South Australia while rising in NSW and Queensland. Despite this, by the end of December the highest cap prices were still in Victoria and South Australia, but the gap between prices in these regions and NSW reduced. Meanwhile, Queensland prices remained significantly lower than the other regions. At the end of 2020, the price of Q1 2021 caps in Victoria, South Australia and NSW were around $25/MWh, compared to $10/MWh in Queensland.

The cap prices in South Australia and Victoria suggest market participants are still anticipating possible price spikes in Q1 2021, however low base prices indicate they expect average prices to remain low.

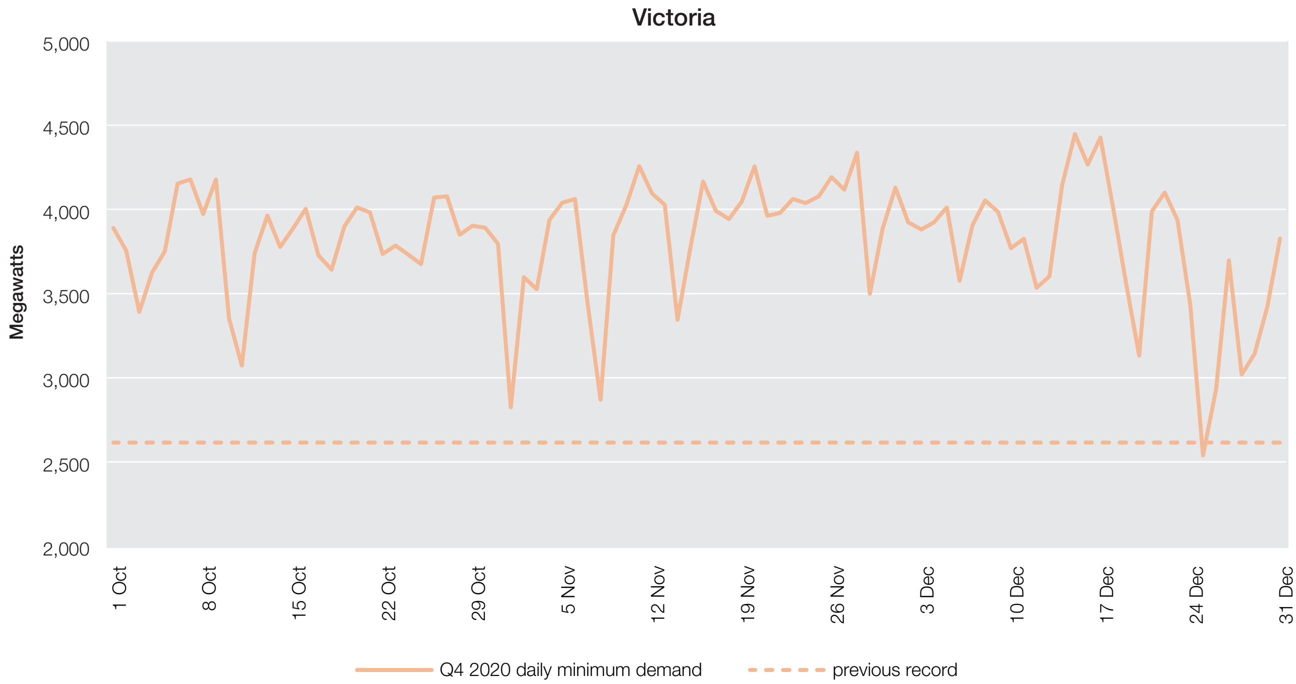
The traded volumes for base futures on the ASX in Q4 2020 were the highest in a decade, increasing significantly in all regions except South Australia. Victoria was the highest traded region, followed closely by NSW and Queensland.

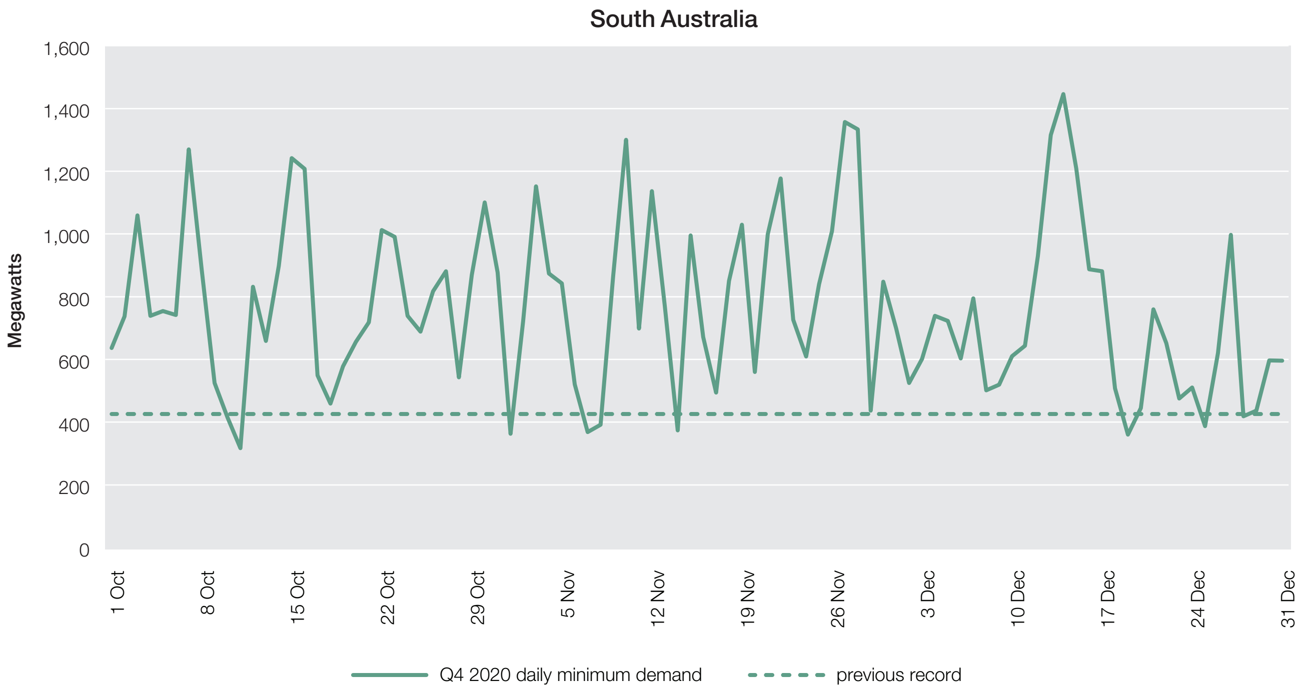
The liquidity of a future product generally refers to how easily it can be bought and sold, and the more it is traded, the easier it is for a market participant to buy or sell. The liquidity ratio is the ratio of total traded volume to native demand in that region. It allows us to compare liquidity in regions with very different demand levels. Liquidity of base futures has improved in all regions except South Australia. Victoria had the highest liquidity ratio in Q4 2020 reaching its highest ever level. For every 1 MWh of demand in Q4 2020, there were almost 3 MWh of base contracts traded in Victoria for that quarter. Liquidity in South Australia remains very low and was the only region where liquidity dropped this quarter.

1.2 Demand fell to record low levels in the south but remained high in NSW and Queensland

Demand fell to record lows in Q4 2020 in both South Australia and Victoria. In South Australia daily minimum demand fell below the previous record 9 times during Q4 2020, and on 11 October 2020 it fell to its lowest level ever of just 318 MW (Figure 1.7). In Victoria demand fell to its lowest level ever of 2,539 MW on Christmas day.

Figure 1.7 Minimum daily demand



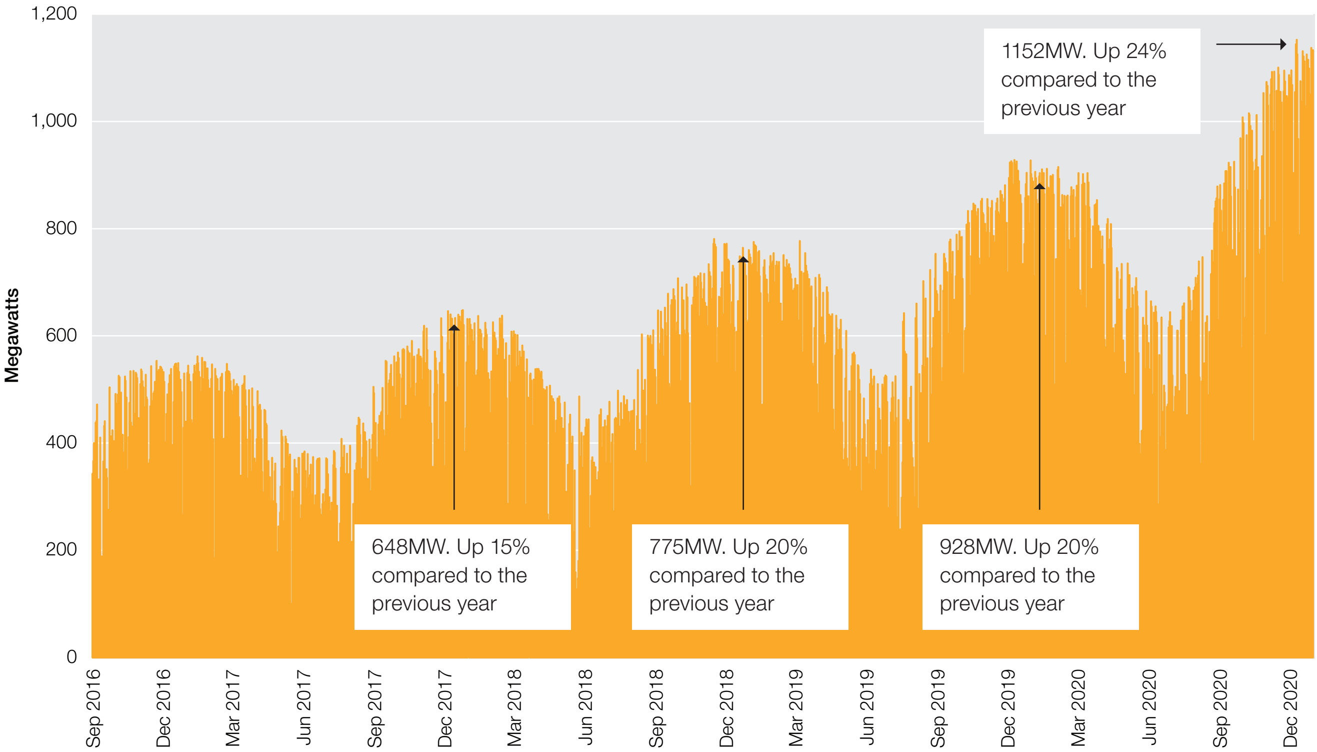


Source: AER analysis using NEM data.

Note: Uses daily minimum native demand. Record refers to the lowest record native demand that has occurred in the region since market start.

Lower demand in the southern regions was driven by mild temperatures and higher than ever rooftop solar generation. Generation from rooftop solar continues to grow each year, setting new records every summer. In South Australia over the past 4 years, generation from rooftop solar has increased between 15% and 24% each year (Figure 1.8). On 10 December 2020 both South Australia and Victoria set new records, generating 1,152 MW and 1,865 MW respectively in the middle of the day.[4]

Figure 1.8 Daily maximum rooftop solar generation, South Australia



Source: AER analysis using NEOmobile rooftop solar data, Intelligent Energy Systems.
Note: Uses daily maximum generation.

By contrast, demand was high in the north due to warmer than average temperatures. Queensland experienced its second warmest November on record and saw heatwave conditions in December. Increased air conditioning usage resulted in multiple days of very high demand, rising to 9,465 MW on 2 December 2020, just short of the record of 10,179 MW set on 13 February 2019.

This quarter, NSW also experienced days of high demand due to hot weather. November temperatures were the warmest since 2014. The month ended with much of the state, including Sydney, experiencing severe heatwave conditions. Demand reached 12,535 MW on 28 November compared to the overall Q4 record demand of 13,627 MW.

1.3 Record new wind and large scale solar capacity enter in 2020

On the supply side, there has been a rapid increase in the amount of wind and large-scale solar capacity in the NEM. Over the past 3 years over 9,000 MW of new wind and solar entered the market with 3,700 MW of that entering in 2020 (Table 1.1). Of the 3,700 MW, around 2,000 MW was solar (mostly located in NSW) and 1,700 MW was wind (mostly located in Victoria).

4 AEMO forecasts rooftop solar for every 30 minute interval but is not able to directly measure it. NSW also set a new record. It was forecast to generate 2,504 MW during the half hour ending 12:30 on 9 December.

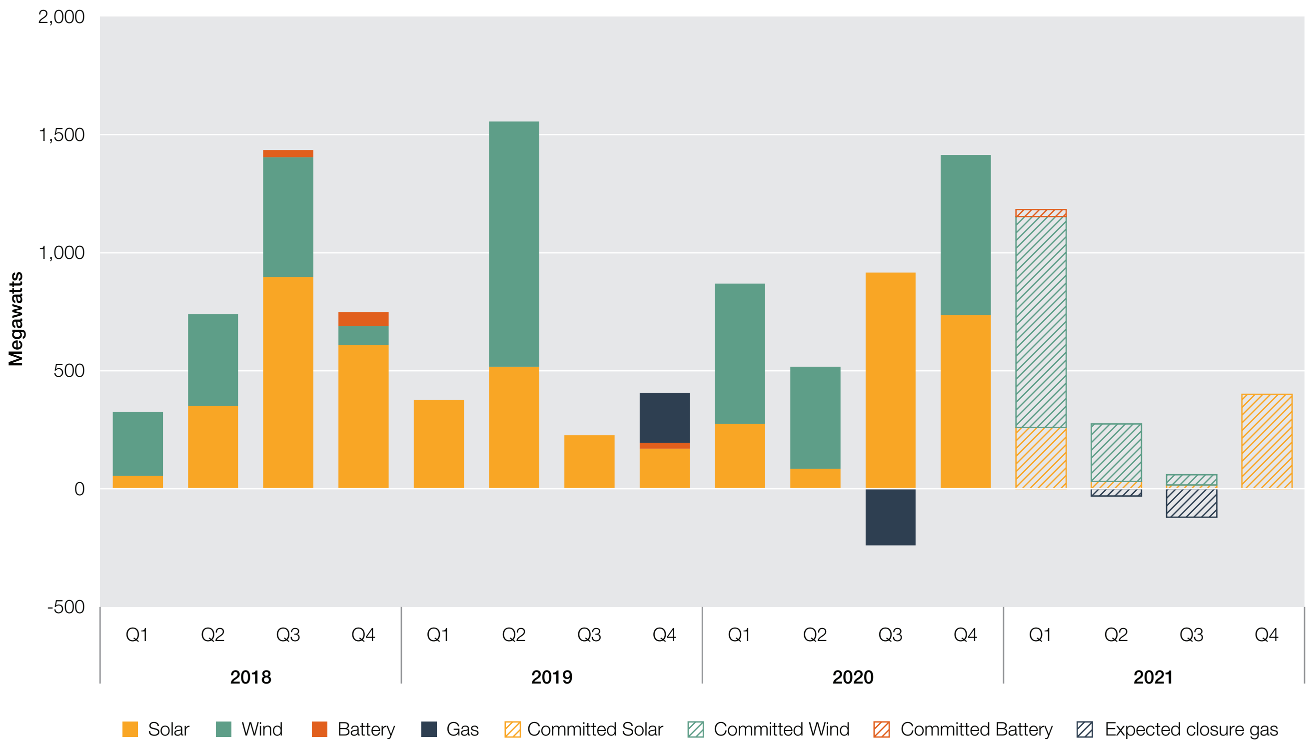
Table 1.1 New entry in 2020

REGION	SOLAR (MW)	WIND (MW)	TOTAL (MW)
Queensland	262	0	262
NSW	1,285	477	1,762
Victoria	465	969	1,434
South Australia	0	0	0
Tasmania	0	259	259
Total	**2,012**	**1,705**	**3,717**

Note: Uses megawatts of registered capacity.

In Q4 2020, 3 new wind and 6 new solar farms entered the market, totalling around 1,400 MW (Figure 1.9). Of these, the largest was Moorabool Wind Farm (312 MW) in Victoria (Table 1.2). Stockyard Hill Wind Farm (511 MW), soon to be the largest wind farm in the NEM, is also located in Victoria but is currently experiencing connection delays. We note the size of new wind and solar farms has been increasing over time.[5]

Figure 1.9 New entry and exit



Source: AER analysis using NEM data.

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

5 The average size of a wind or solar farm installed in Victoria and NSW is approaching 200 MW.

Table 1.2 New entry during Q4 2020

REGION	STATION	FUEL TYPE	HIGHEST CAPACITY OFFERED Q4 2020 (MW)	REGISTERED CAPACITY (MW)	COMMENCE DATE
NSW	Sunraysia Solar Farm	Solar	4	228	Nov–20
NSW	Molong Solar Farm	Solar	30	36	Nov–20
NSW	Wellington Solar Farm	Solar	6	216	Nov–20
NSW	Collector Wind Farm	Wind	73	226	Nov–20
NSW	Crudine Ridge Wind Farm	Wind	7	141	Dec–20
Victoria	Moorabool Wind Farm	Wind	30	312	Nov–20
Victoria	Yatpool Solar Farm	Solar	25	94	Dec–20
Victoria	Glenrowan West Solar Farm	Solar	2	132	Dec–20
Queensland	Middlemount Sun Farm	Solar	2	30	Dec–20

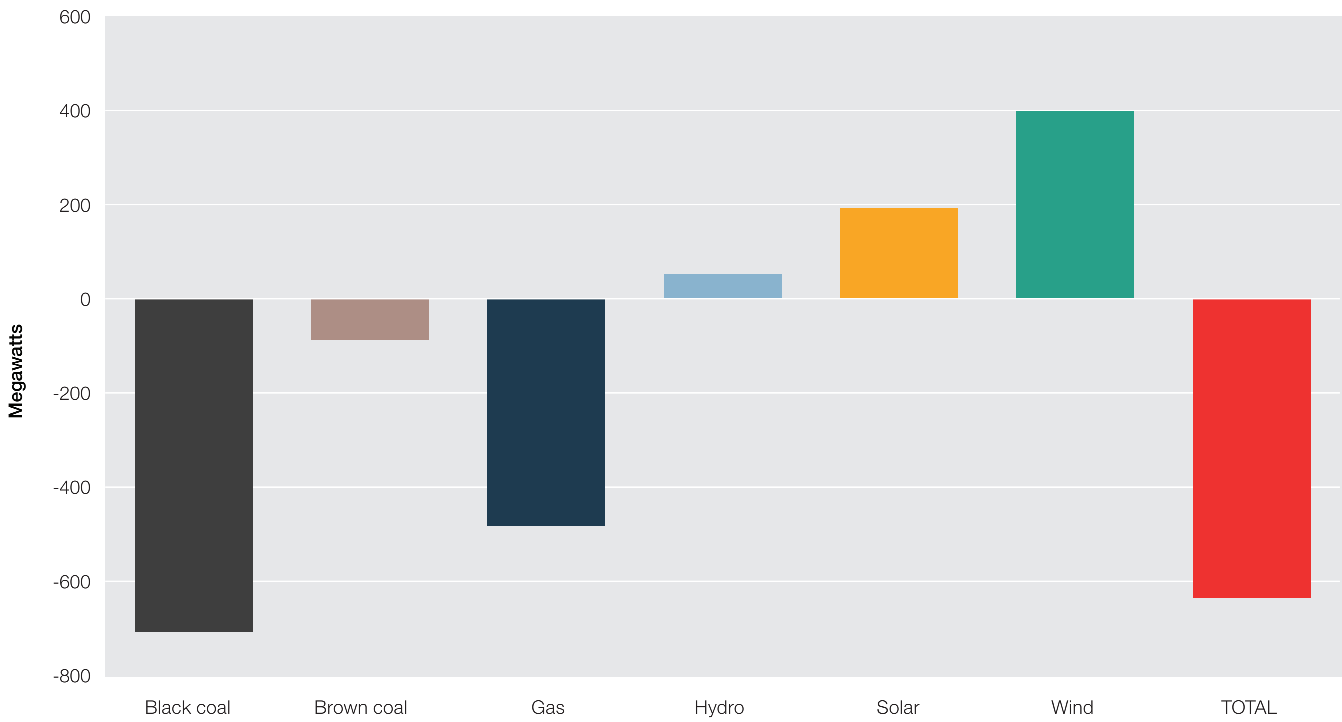
Note: Registered capacity of solar farms is typically between 15% and 25% higher than maximum capacity due to the conversion of energy from DC to AC.

1.4 Record high renewable generation and low coal and gas generation

Q4 2020 highlighted significant changes in the NEM's generation fuel mix. Comparing average quarterly generation output in Q4 2020 with the same time last year (Figure 1.10):

- total output fell by around 600 MW, reflecting lower NEM demand
- wind and large scale solar generation increased by around 600 MW
- coal and gas generation decreased by around 1,200 MW.

Figure 1.10 Change in average quarterly NEM generation, Q4 2019 to Q4 2020



Source: AER analysis using NEM data.

Note: Change in average quarterly metered generation output by fuel type from Q4 2019 to Q4 2020. Solar generation includes large scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.

Generation from wind and large scale solar rose to contribute 17% of total output in the NEM in Q4 2020, up from 14% in Q4 2019.

Average quarterly wind output in the NEM increased by 400 MW compared to a year earlier. Both Victoria and South Australia saw record wind generation – the most ever in Victoria and the most in a Q4 in South Australia. Wind generation exceeded gas generation in the NEM for the fifth quarter in a row. When demand is low, as it was in Q4 2020, cheaper fuel types, like wind generators, tend to increase their share of total output at the cost of more expensive fuel types, such as gas.

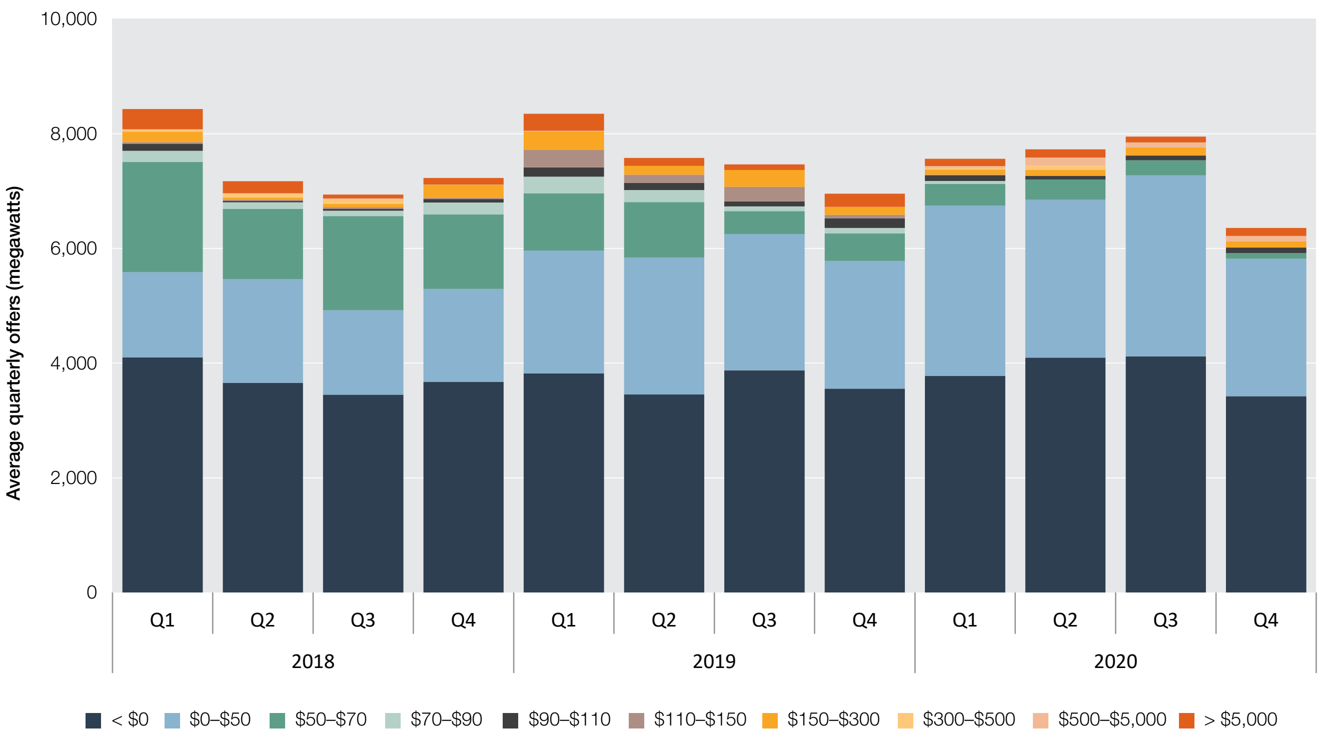
Large scale solar output has also continued to increase, with average generation increasing by almost 200 MW in Q4 2020 compared to Q4 2019, and record large scale solar generation in every mainland region this quarter.

While coal remains the dominant fuel source in the NEM, Q4 2020 saw the lowest level of black coal output across the NEM since 2014 and lowest ever in NSW. Key drivers of this included black coal generator outages and cheaper priced renewables displacing coal during the middle of the day. We analyse the drivers for low coal generation output in more detail in the coal focus.

Black coal generators in NSW experienced a high number of outages in Q4 2020, with more than 60% of these for planned maintenance or upgrades (Table 1.4). The main outages were at Bayswater, Liddell and Mt Piper power stations. Meanwhile, Queensland black coal generators also had significant outages in Q4 2020, with planned outages at Tarong North and Kogan Creek power stations.[6]

Outages substantially decreased the amount of capacity NSW black coal offered into the market in Q4 2020, reducing the amount of low priced capacity available in the region (Figure 1.11).

Figure 1.11 NSW black coal offers, by price band



Source: AER analysis using NEM data.

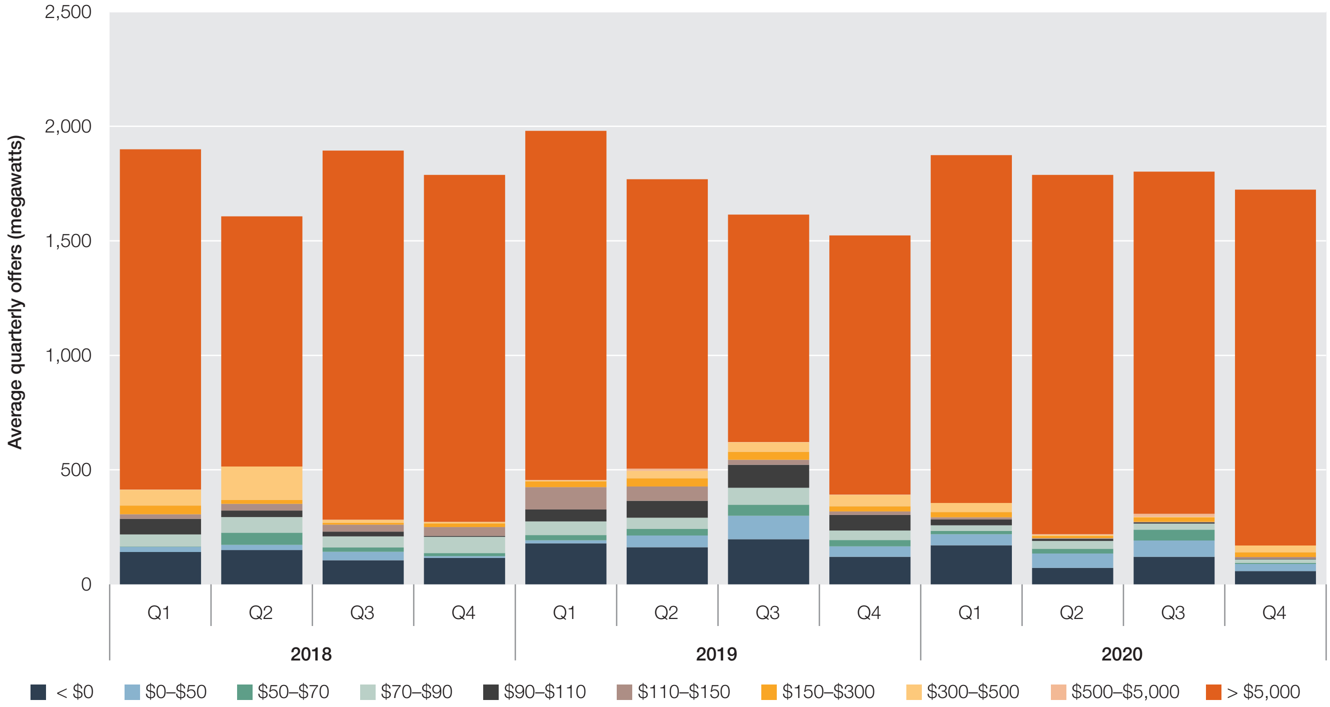
Note: Average quarterly offered capacity by NSW black coal generators within price bands.

Average gas generation in the NEM fell to its lowest Q4 level since 2005, with average output in Q4 2020 down by 480 MW compared to Q4 2019, falling in NSW, Victoria and South Australia. In Victoria, for example, average quarterly gas generation fell 65% to just 84 MW, and in South Australia, where gas made up 48% of regional output in Q4 2019, it made up 38% in Q4 2020.

6 Across NSW and Queensland, significant outages occurred for black coal generators throughout the quarter with the majority for planned maintenance. NSW experienced a cumulative total of 447 days of outages, 271 planned and 176 unplanned. Queensland experienced a cumulative total of 383 days of outages, 315 planned and 68 unplanned.

While Victorian gas generators offered more total capacity into the market in Q4 2020 than in Q4 2019, they reduced the amount of capacity priced below $50/MWh and increased the amount of capacity priced above $5,000/MWh (Figure 1.12). As a result, 90% of Victorian gas offers were priced above $5,000/MWh and 5% were priced below $50/MWh. As these generators are dispatched less often, they need to receive higher prices to recover costs when they do run.

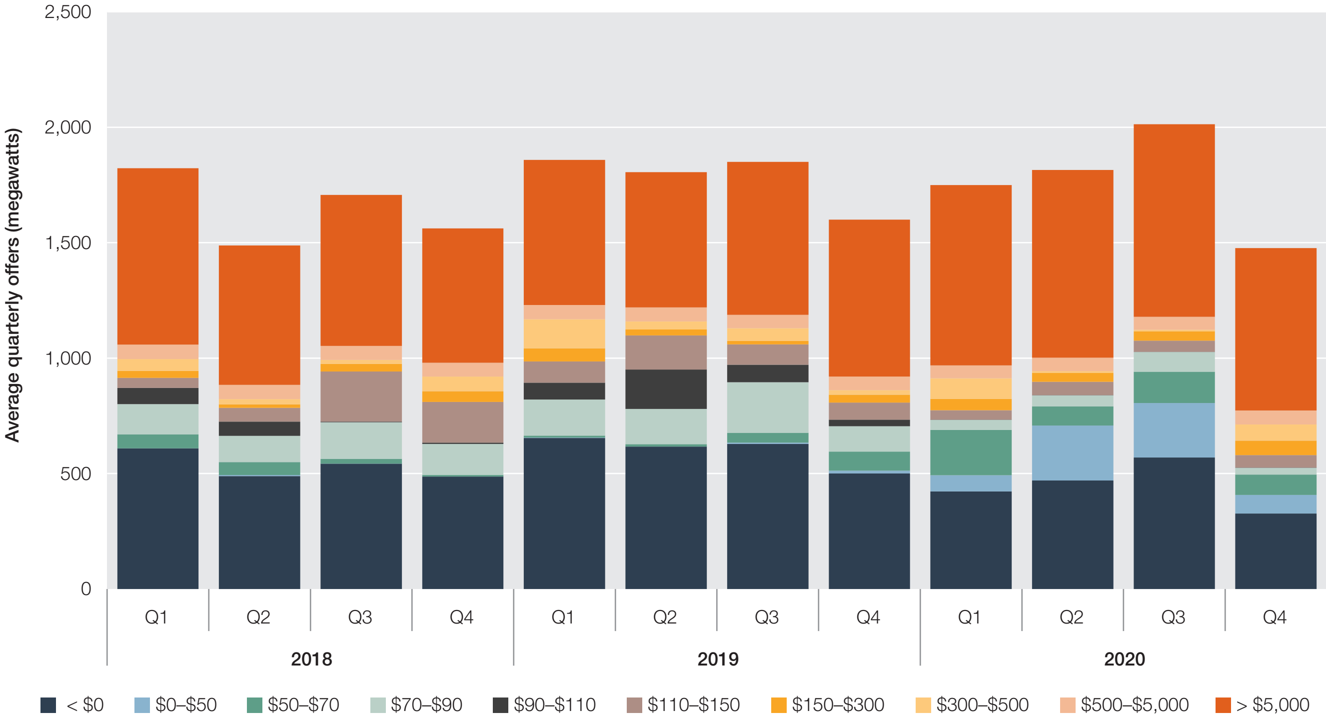
Figure 1.12 Victoria gas offers, by price band



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

In South Australia, gas generators offered less total capacity into the market and half the amount of capacity priced below $50/MWh than in Q3 2020 (Figure 1.13). This was largely due to the closure of the 2 units at Torrens Island A power station in September 2020.

Figure 1.13 South Australia gas offers, by price band



Source: AER analysis using NEM data.

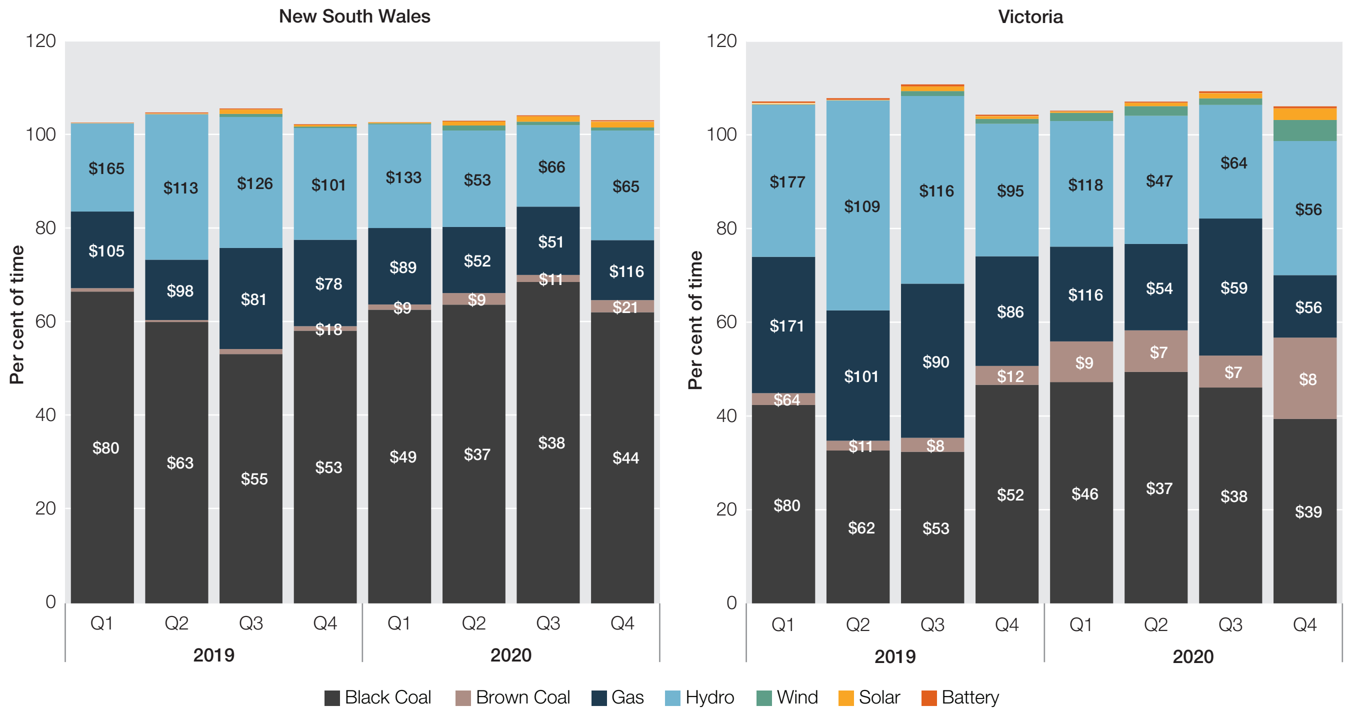
Note: Average quarterly offered capacity by South Australia gas generators within price bands.

Hydro generation increased mostly in NSW and Victoria but fell significantly in Tasmania in Q4 2020 compared to Q4 2019. The increase in hydro generation on the mainland contributed to the displacement of gas in Victoria and NSW. The decrease of hydro generation in Tasmania was due to low prices in Victoria and low water levels in Tasmania.

1.5 Cheaper fuel types set the price more often in the south

Cheaper fuels, such as brown coal, wind and solar, set the price in Victoria and South Australia more often in Q4 2020 than in previous quarters and this contributed to lower average quarterly prices (Figure 1.14).

Figure 1.14 Comparison of price setters between NSW and Victoria



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 numbers within each bar is the average price set by that fuel type when it is marginal (i.e. setting the price).

Brown coal set the price 17% of the time in Victoria at an average price of only $8/MWh. For brown coal to set the price, demand and prices need to be low. Low demand in Victoria and South Australia also meant wind set the price more often. Wind set the price in South Australia over 9% of the time, at an average price of -$90/MWh. And in Victoria, wind set the price almost 5% of the time, at an average price of -$71/MWh.

In contrast, gas generation set the price a lot less often in Victoria, South Australia and Tasmania than in previous quarters. In South Australia, for example, gas generation set the price only half as often in Q4 2020 than it usually would in a Q4. This also contributed to lower average quarterly prices.

In NSW, while the amount of time coal and gas set the price didn't significantly change, the price they set was higher in Q4 2020 than in Q3 2020. This is significant because in NSW and Queensland, coal and gas set the price around 75% of the time.

The average price set by gas generation in NSW doubled compared to Q3 2020, increasing from $51/MWh to $116/MWh. The large jump was driven by the 3 high price events in NSW when expensive gas peakers were needed to meet demand. Without these events, NSW gas generators would have set a price closer to the price it set in other regions. In Queensland, the average price set by gas generation also increased but to a lesser extent, rising by $14/MWh compared to Q3 2020.

The average price set by black coal was $44/MWh in NSW, which was $6/MWh higher than in Q3 2020 but still around $10/MWh lower than a year ago.

Hydro generation set the price more often in every region, particularly in Tasmania, and at lower prices than in Q3 2020. On average, hydro set prices lower than or equal to those set by gas, with average prices set by hydro ranging from $65/MWh in NSW down to $49/MWh in Tasmania.

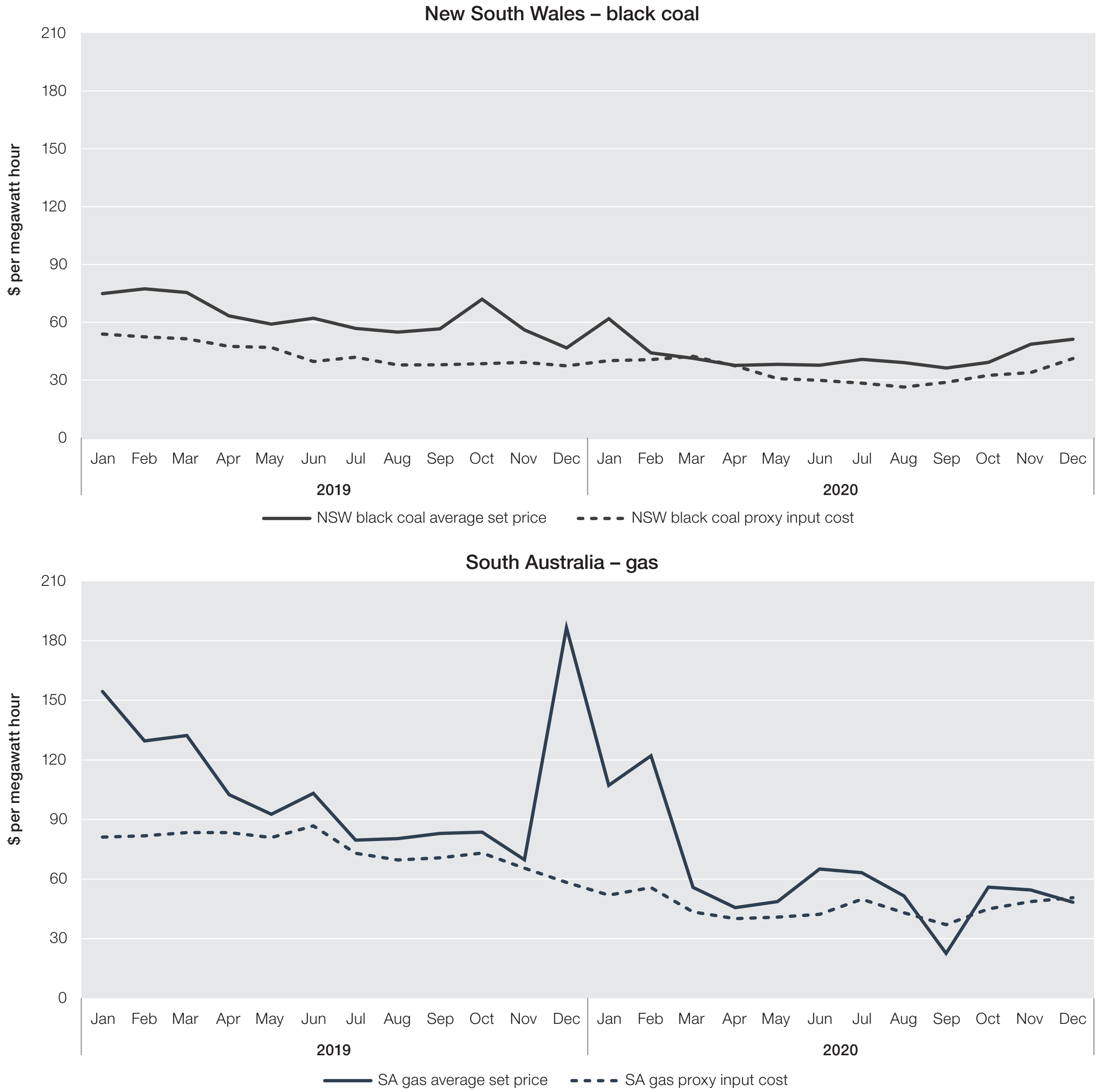
1.6 Fuel costs increase

In the absence of detailed generator cost data, commodity prices can be used as a reasonable proxy for fuel costs. This proxy lets us assess whether changes in the average prices set by coal and gas generators reflected changes in input costs. We found the increases in the average prices set by coal and gas generators in Q4 2020 were in line with increasing commodity prices (Figure 1.15). The exception was gas generators in South Australia in December.

The price set by NSW black coal generators continued to track the NSW black coal proxy input cost which rose from $29/MWh in September to $41/MWh in December. Our coal proxy input cost is based on the Newcastle thermal coal index which has since continued to increase in 2021. Forward prices for Newcastle coal indicate input costs will stay at this higher level for the next few months before easing in May.[7]

After falling to low prices at the end of Q3 2020, the South Australian gas proxy input cost increased in Q4 2020. A significant short term increase in export prices and record LNG demand put upward pressure on domestic gas prices (section 2.1). The rise in input costs directly impacted the price set by South Australian gas generators in October 2020. However, low demand for gas generation in South Australia, particularly in December 2020 led to gas generators in that region setting lower prices. When demand is low, more expensive peaking gas is not needed, and less expensive baseload gas generators are more likely to set the price. In NSW however, where demand was higher, the price set by gas doubled. During the 3 high price events in NSW, the more expensive peaking gas was needed.

Figure 1.15 Proxy input costs and the average price set by NSW black coal and South Australia gas



Source: AER analysis using 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 price (AUD$/GJ) of a respective region, converted to AUD$/MWh with average heat rate for gas generators.

7 Source: globalCOAL market report, 29 January 2021.

1.7 Regional flows impacted by increased exports from Victoria and interconnector limits

Upgrades to the Queensland-NSW interconnector (QNI), and associated network outages, reduced exports from Queensland into NSW in Q4 2020 (Figure 1.16). This limited the amount of cheaper priced capacity that could get to NSW and was another factor contributing to the higher prices in NSW.

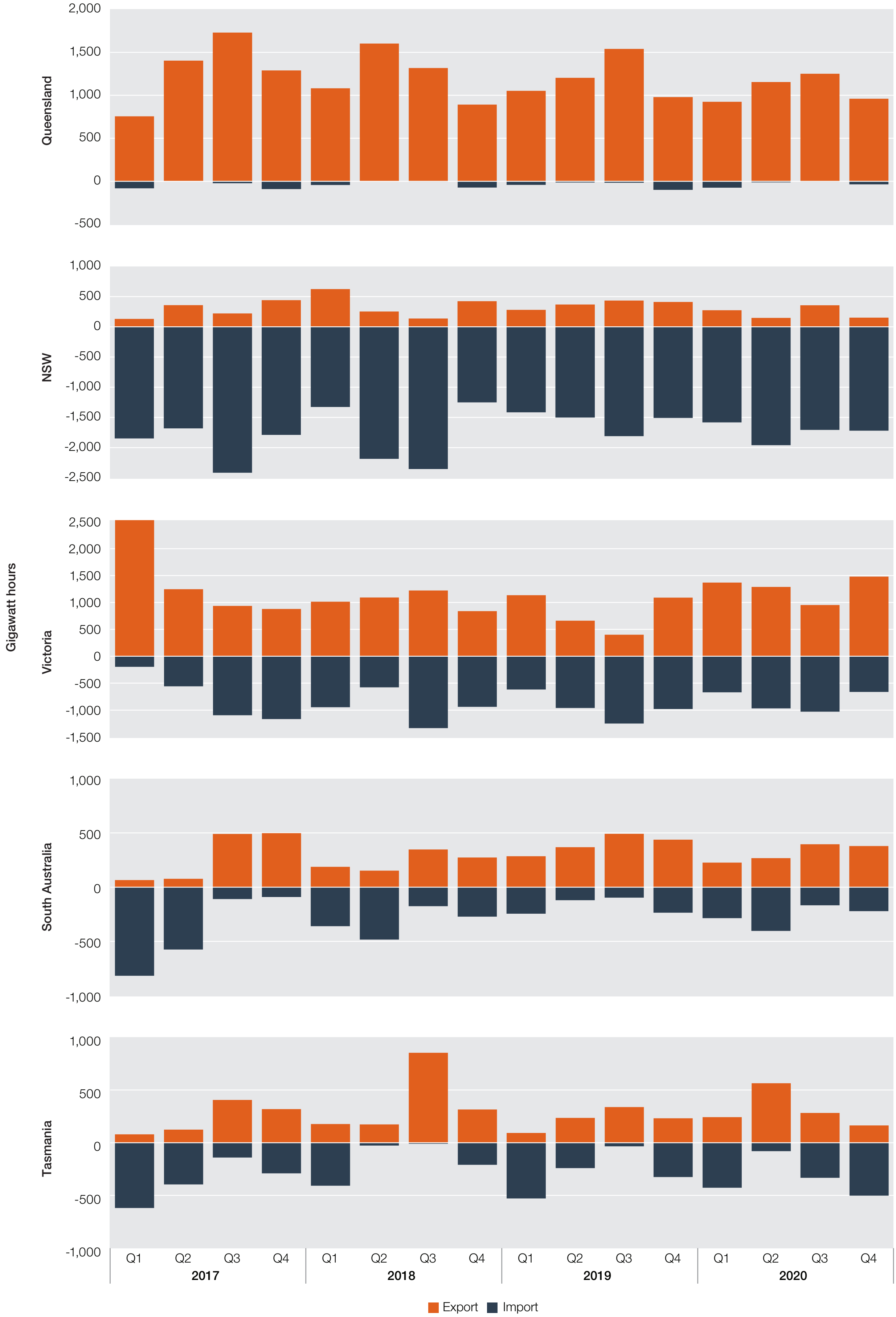
The upgrade to QNI will allow a further 190 MW of energy to be transferred from Queensland into NSW.[8] The increased transfer capacity is intended to help avoid construction of new generation and storage capacity ahead of the impending closure of Liddell power station in NSW from 2022. The project is expected to be completed in November 2021.

As flows generally go from a lower to a higher priced region, lower prices in Victoria in Q4 2020 led to higher exports. With less imports from Queensland, NSW imported more from Victoria. Lower hydro generation in Tasmania also required it to import from Victoria.

An ongoing outage of key network equipment in South Australia continued to limit exports from South Australia across the Heywood interconnector. This contributed to the record number of negative prices in South Australia as cheaper priced wind generation was limited from getting into Victoria.

8 The QNI upgrade will also allow an additional 460 MW of energy to flow from NSW into Queensland.

Figure 1.16 Regional interconnector flows



Source: AER analysis using NEM data.

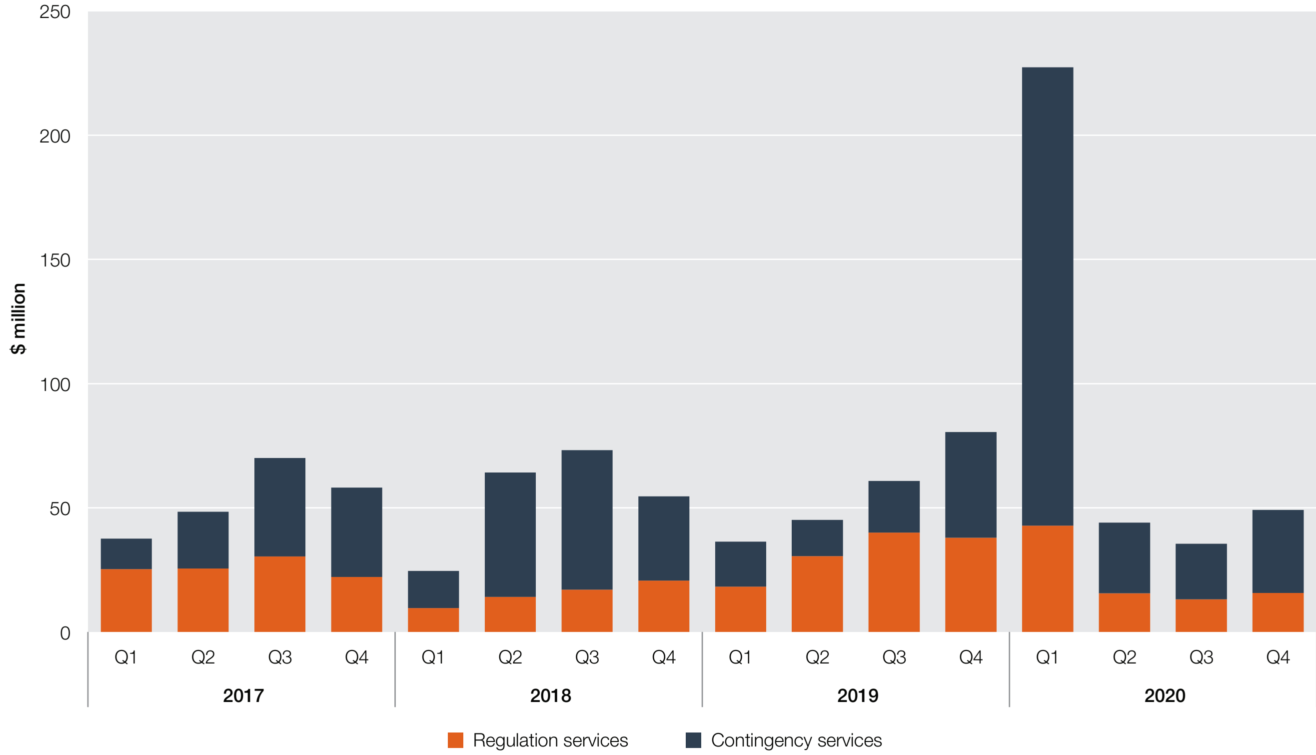
Note: Total amount of energy either imported or exported each quarter. In Q1 2017, Victorian exports were 2,530 MW.

1.8 FCAS costs lower than a year ago

Total FCAS costs in Q4 2020 were lower than a year ago but higher than in Q3 2020 (Figure 1.17). The increase in total costs in Q4 2020 was due to local FCAS costs in Queensland.

Local FCAS costs in Queensland were largely driven by a high price event in Q4 2020. Local costs in Queensland on 17 November 2020 alone were $4.3 million. These local costs were caused by high prices in raise contingency services. This and other instances of prices above $2,000/MW during the quarter were related to the ongoing upgrade of the QNI. We report on the causes of the 17 November 2020 event in our Focus.

Figure 1.17 Total NEM FCAS costs



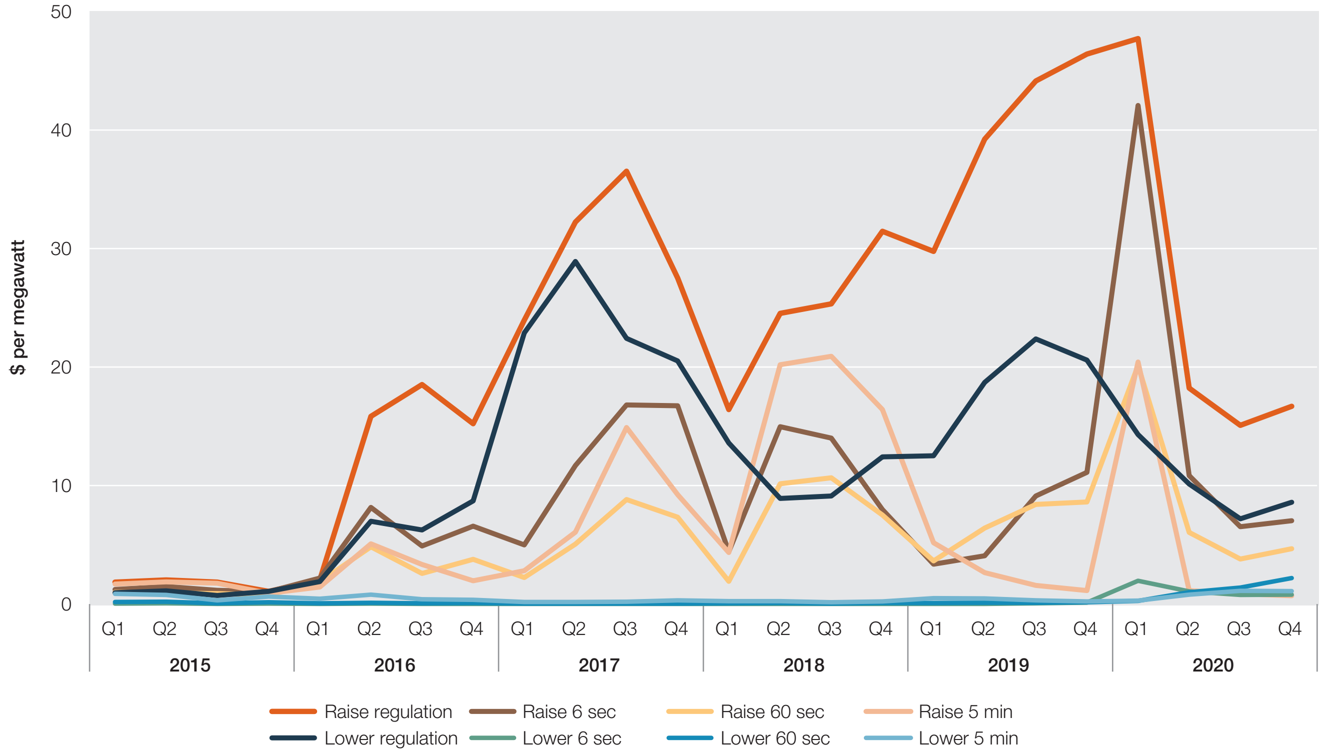
Source: AER analysis using NEM data.

In Q4 2020, 8 new units registered to provide FCAS. They were all demand response participants and virtual power plants, who only participate in FCAS markets and do not provide energy. In addition, 2 existing thermal generators have also registered to provide additional FCAS services.[9]

After generally falling for 2 quarters, prices rose slightly in most FCAS markets in Q4 2020 (Figure 1.18). These included prices for regulation services and for raise 60 second and 6 second contingency services.

9 Quarantine and Darling Downs gas generators in Queensland were already registered to provide some FCAS services and are now registered to provide more services.

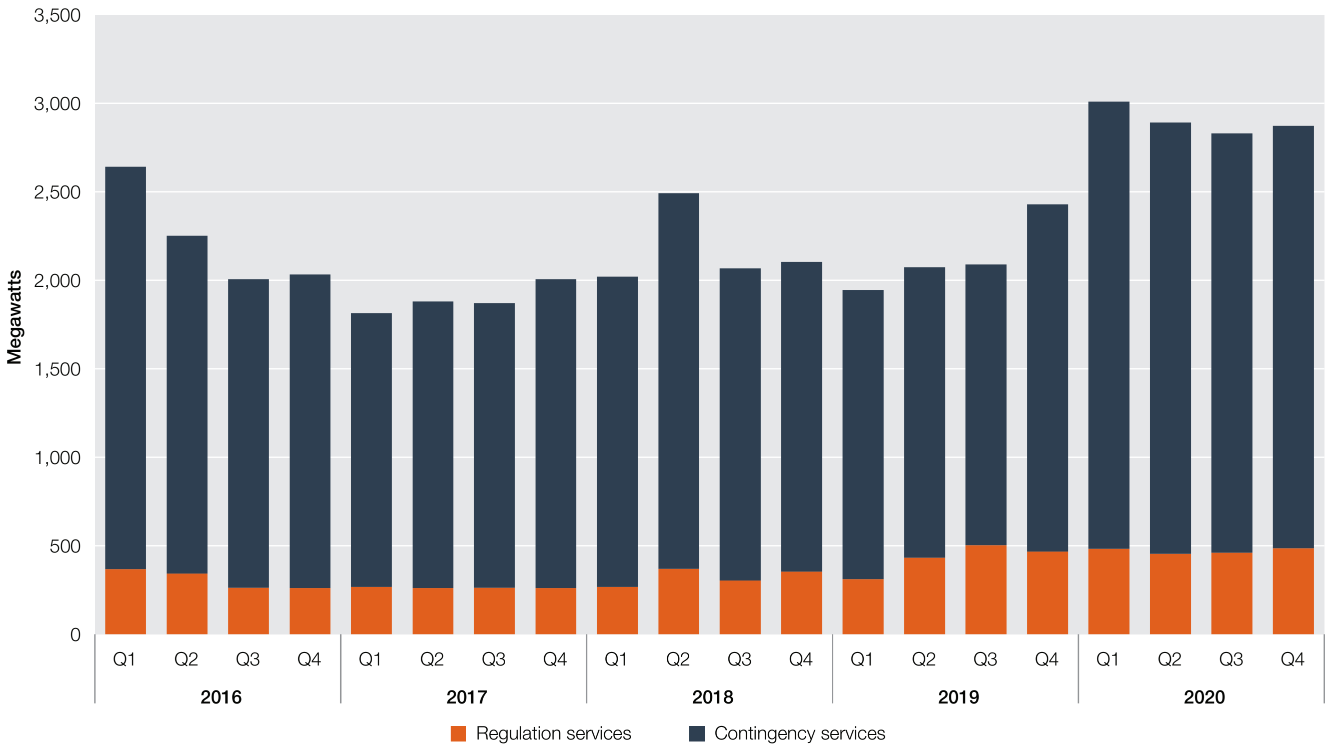
Figure 1.18 Quarterly FCAS prices, global



Source: AER analysis using NEM data.

The amount of FCAS enabled has remained steady over the past 3 quarters following a step increase in contingency FCAS enabled in Q1 2020 (Figure 1.19). This increase followed changes AEMO made to an assumption it uses to calculate how much FCAS is required.

Figure 1.19 Quarterly FCAS enabled



Source: AER analysis using NEM data.

From 9 December 2020, AEMO started slowly reducing the assumed load relief in Tasmania, from 1% to 0%. The reduction is scheduled to be completed by mid-2021 and will increase the requirement for all Tasmanian contingency FCAS.[10] This follows similar changes on the mainland in 2019.

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

In Queensland on 17 November 2020, average prices for raise 60 second (R60) FCAS exceeded $5,000/MW for 3 trading intervals. This resulted in high local FCAS costs in Queensland. The main drivers of these high FCAS prices were:

- a line outage as part of the Queensland-NSW Interconnector (QNI) upgrade, which left Queensland at risk of becoming electrically islanded and needing to provide its own FCAS
- the interaction of energy and FCAS markets, which reduced the amount of FCAS available to the market
- at times there was not enough capacity offered below $5,000/MW to meet high local requirements
- high energy prices coincided with high FCAS prices.

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

High prices on 17 November 2020

Dispatch prices for R60 and R6 services exceeded $5,000/MW collectively on 18 occasions between 1.10 pm and 3.10 pm, including R60 prices reaching the price cap of $15,000/MW on 10 occasions. For 3 consecutive trading intervals, average prices for R60 exceeded $5,000/MW.

Table 1.3 30 minute average prices for Queensland local FCAS

TRADING INTERVAL	RAISE 60 SEC ($/MW)	RAISE 6 SEC ($/MW)
1.30 pm	10,017	2,521
2.00 pm	14,367	950
2.30 pm	6,479	2,497
3.00 pm	575	4,360
3.30 pm	452	2,296

QNI upgrade

In May 2020, an upgrade to QNI commenced to increase the transfer capacity between Queensland and NSW. The increase will allow a further 460 MW of energy to be transferred into Queensland and 190 MW more into NSW. The increased transfer capacity is intended to help avoid construction of new generation and storage capacity ahead of the impending closure of Liddell power station in NSW in 2022 and 2023. The project is expected to be completed in November 2021.

Effects of the planned outage on QNI

The upgrade to QNI saw a planned outage on the 88 Muswellbrook to Tamworth 330 kV line on 17 November 2020. Due to the planned line outage, there was a credible risk of Queensland separating from the NEM. To account for this risk, AEMO required Queensland to provide FCAS locally.

Interaction between energy and FCAS

Interactions between the energy and FCAS markets can effectively reduce the capacity of FCAS that is available to the market or can lead to pricing outcomes, which differ from offers. There are trade-offs between the provision of FCAS and energy, which determines the effective availability of FCAS. For example, a generator that is operating at its maximum capacity in energy cannot generate any more to provide raise services so their effective available capacity for raise services would be 0 MW.

10 AEMO fact sheet, Changes to load relief value and contingency FCAS volumes in Tasmania.

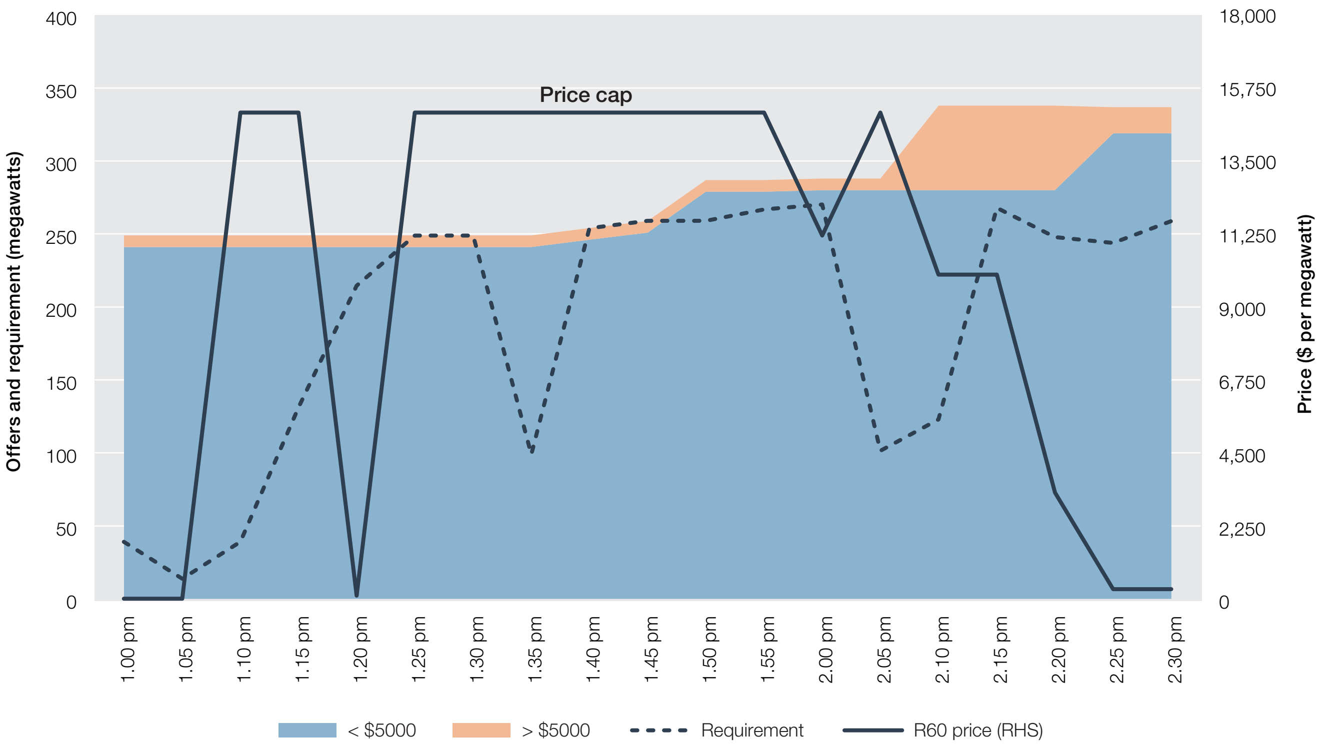
At 1.10 pm, a sudden increase in the local requirement for raise services coincided with energy prices reaching the price cap of $15,000/MW for 5 minutes. The increase in energy prices was driven by an increase in demand and constraints limiting generation to maintain system security. The increase in demand was mainly met by Gladstone power station, a provider of FCAS. Due to the interaction between energy and FCAS, the additional capacity dispatched by Gladstone meant it had less capacity available to meet FCAS requirements.

From 1.10 pm, the local requirement increased to 249 MW within 15 minutes. Between 1.10 pm and 3.10 pm, requirement for R60 services reached as high as 277 MW. Throughout the majority of this period, there was either:

- insufficient R60 capacity offered below $5,000/MW (Figure 1.20), or
- insufficient effective capacity available below $5,000/MW due to the interaction between energy and FCAS (Figure 1.21).

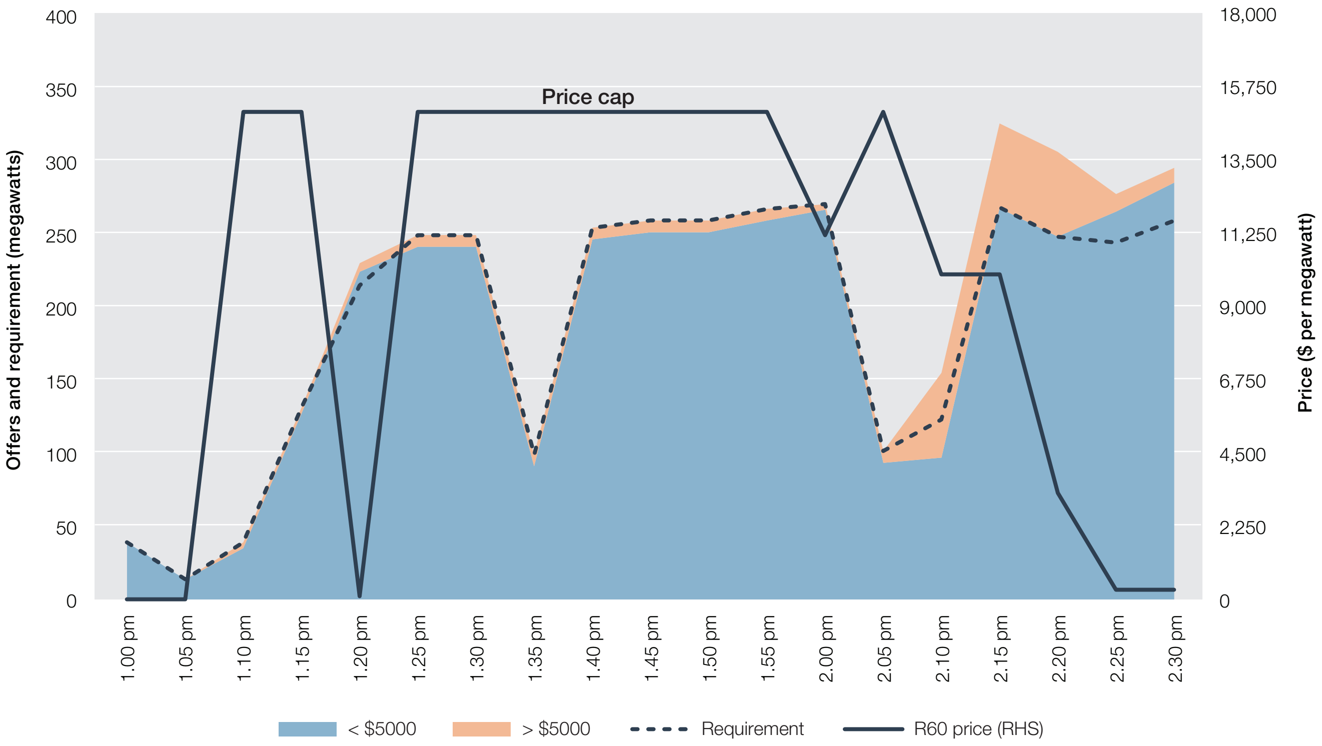
This resulted in capacity above $5,000/MW needing to be dispatched to meet the local requirement.

Figure 1.20 Queensland local raise 60 second maximum offers



Source: AER analysis using NEM data.
Note: Maximum availability refers to the amount offered into the market by participants.

Figure 1.21 Queensland local raise 60 second effective offers



Source: AER analysis using NEM data.

Note: Effective availability refers to the amount FCAS on offer that can be dispatched, accounting for trade-offs between FCAS supply and electricity generation.

Rebidding

Rebidding of capacity did not contribute to high R60 prices on 17 November 2020. Between 1.30 pm and 2.30 pm, participants offered almost a further 100 MW of capacity for the R60 service.

To meet the high requirement in Queensland, thermal and demand response aggregators made additional FCAS capacity available throughout the high-priced intervals. Throughout the 2 pm trading interval, CS Energy's Callide B power station added 28 MW below $1/MW due to co-optimisation between energy and FCAS. Also throughout the 2 pm trading interval, Enel X Australia, a demand response aggregator, made up to 20 MW available below $2/MW in response to high prices. At 2.03 pm, ERM Power's Oakey power station added 50 MW at $10,000/MW due to FCAS and energy co-optimisation. Despite ERM Power making its additional capacity available above $5,000/MW, R60 prices were already exceeding $5,000/MW when the rebid came into effect at 2.10 pm.

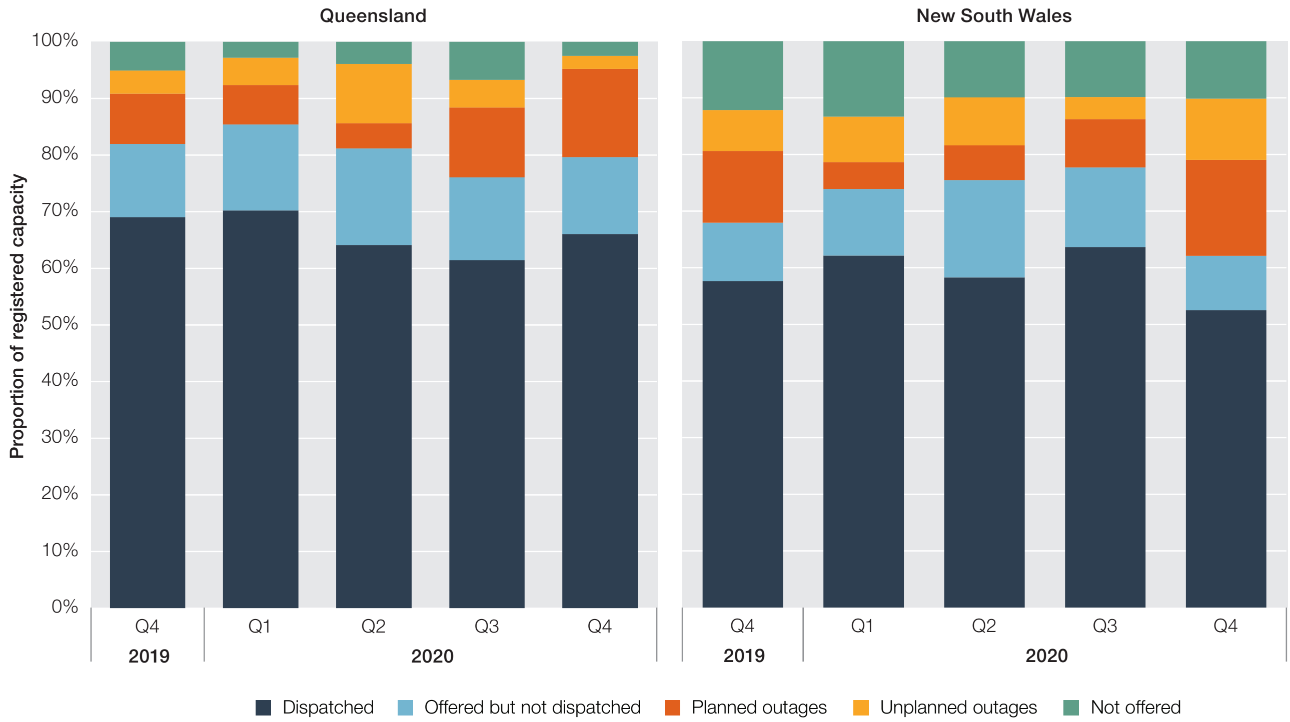
The 88 Muswellbrook to Tamworth 330 kV line returned to service at 4 pm on 5 December 2020 following early completion of the planned outage.

Focus – What were the drivers behind low black coal generation in Q4 2020?

In Q4 2020 black coal generation output was at its lowest level across the NEM since 2014, with record low black coal generation output in NSW. In this focus, we investigate how much of the reduction in black coal generation in Q4 2020 was due to outages or generators offering less than registered capacity, and how much was due to offered capacity not being dispatched.

Our analysis indicates the primary driver of low black coal generation output was the fall in generation capacity offered into the market, mostly due to planned outages. In Q4 2020, planned outages resulted in 15% to 20% of registered capacity being unavailable across Queensland and NSW (Figure 1.22). Generation that was offered but not dispatched, was at a similar level to previous quarters so did not significantly drive low generation output in Q4 2020.

Figure 1.22 Black coal capacity allocation



Source: AER analysis using NEM data.

Note: Chart shows how black coal registered capacity was used on average in each quarter. Not offered for other indicates when the generating plant may be online but not offering all its registered capacity for plant or economic reasons.

While generators have a maximum level of capacity they can provide (registered capacity), they will rarely run at this level all of the time. Total output in a given quarter will depend on the amount of capacity generators offer into the market and how much of that capacity is then dispatched. A capacity factor is a measure of the amount of energy produced by a generator expressed as a proportion of its maximum possible production.

Our analysis uses 2 types of capacity factors to explore how generator outages and the changing demand profile drove record low black coal generation output in Q4 2020:

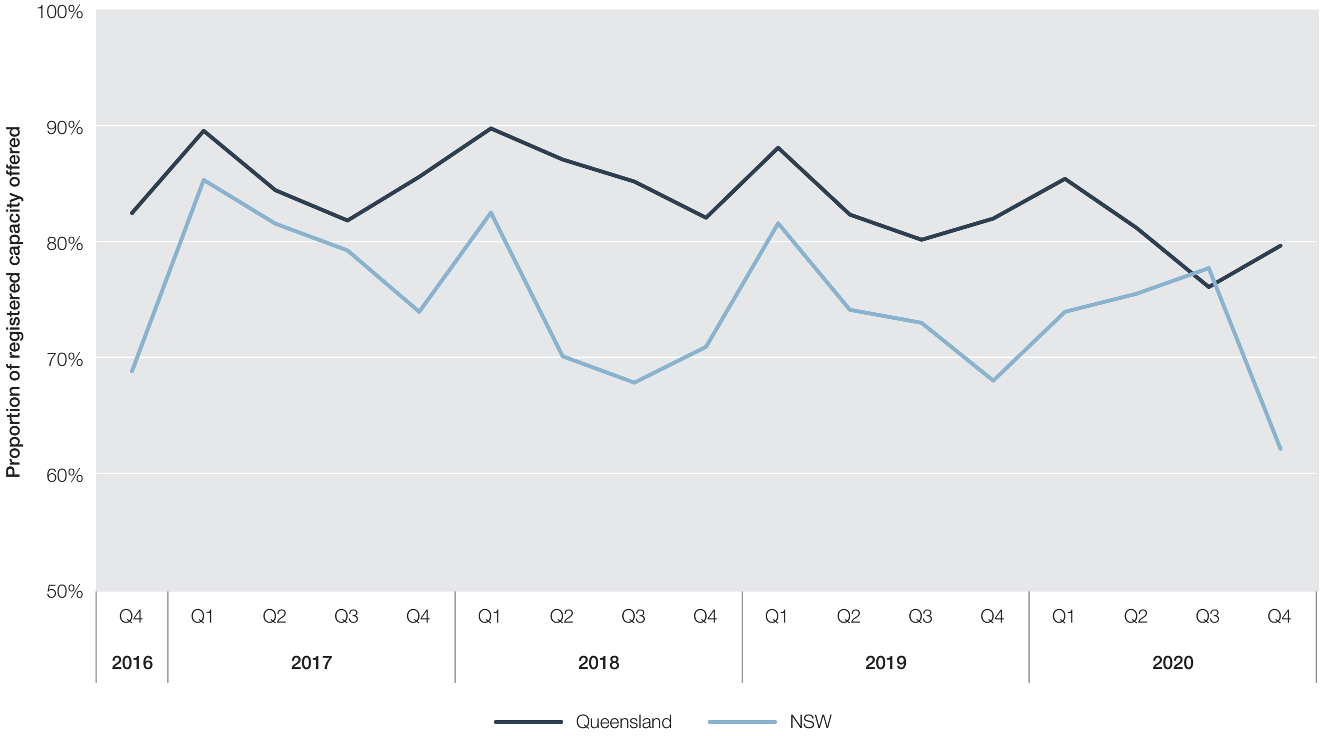
- *Availability capacity factor (ACF)* shows how much capacity was offered compared to registered capacity. This measure shows the impact of maintenance, unplanned outages or a generator's ability to offer into the market.
- *Output capacity factor (OCF)* shows how much capacity was dispatched compared to what was offered. This measure indicates whether changes in black coal output were due to changes in their offer prices, demand, or the output of other lower priced capacity.

Outages drove lower availability capacity factors in Q4 2020

Coal generators tend to operate continuously, at stable levels of output. They typically only shut down for maintenance or unplanned outages, because the costs to restart are high and can increase wear and tear on the plant. Generally, participants take the opportunity to undertake maintenance during the 'shoulder season' outside of the summer and winter peak demand periods. As a result, average black coal generation availability, and therefore ACF tends to be highest in Q1.

Across both regions, significant outages drove low ACF outcomes in Q4 2020 (Figure 1.23). In NSW, outages accounted for around 3,000 MW of the 3,900 MW reduction, while in Queensland the ratio was slightly higher at 1,440 MW of the 1,600 MW reduction.

Figure 1.23 Availability capacity factors



Source: AER analysis using NEM data

Note: Average quarterly availability capacity calculated using 30 minute max-avail for black coal in each region, divided by the total registered capacity for black coal in that region.

The vast majority of outages were due to planned maintenance rather than unplanned outages. Planned maintenance accounted for 87% of outages in Queensland and 61% in NSW and was the primary driver of the low ACF outcomes for black coal in Queensland and NSW in Q4 2020 (Table 1.4).

- In NSW, planned outages included the upgrades by AGL Energy at Bayswater power station, maintenance by Origin Energy on most units at Eraring power station and EnergyAustralia on one unit at Mt Piper power station. The remaining outages were shorter and unplanned, mostly occurring across Bayswater, Vales Point and Liddell power stations.
- In Queensland, major upgrades and maintenance over the last 3 quarters has resulted in lower availability capacity factors since Q1 2020. In particular, CS Energy undertook planned maintenance at Kogan Creek power station and all 6 units at Gladstone power station, and completed a major overhaul at Callide B power station that had commenced in June 2020. Also, Stanwell undertook planned maintenance at Tarong North power station.

Table 1.4 Black coal generator outages, Q4 2020

STATION NAME, COMPANY	STATION CAPACITY (SUMMER RATING MW)	NUMBER OF DAYS OFFLINE IN Q4 2020	PLANNED MAINTENANCE OR UPGRADES	UNPLANNED OUTAGES	NOTES
Queensland			**310**	**50**	
Callide B, CS Energy	2 units, 350 MW each	Unit 1: 49 days	40	8	Planned for completing major overhaul that commenced in June Unplanned for 'unit trip'
Callide C, Callide Power Trading	2 units, 420 MW each	Unit 3: 6 days	6	-	Planned outage
		Unit 4: 3 days	-	3	'Unit trip'
Gladstone, CS Energy	6 units, 280 MW each	Unit 1: 22 days	15	8	Planned outage Unplanned outage for 'unit trip' on 24 Dec and remained offline after the end of Q4 2020.
		Unit 2: 18 days	18	-	Planned outage
		Unit 3: 15 days	15	-	Planned outage
		Unit 4: 39 days	39	-	Planned outage
		Unit 5: 23 days	23	-	Planned outage
		Unit 6: 17 days	17	-	Planned outage
Kogan Creek, CS Energy	713 MW	30 days	30	-	Planned outage
Millmerran, InterGen	2 units, 306 MW each	Unit 2: 10 days	-	10	'Mill or feeder limitation'
Stanwell, Stanwell Corporation	4 units, 365 MW each	Unit 2: 11 days	-	11	'Unit trip'
		Unit 4: 13 days	13	-	Planned outage
Tarong, Stanwell Corporation	4 units, 350 MW each	Unit 1: 9 days	-	9	Continued unplanned outage from Q3 2020 for 'tube leak'
		Unit 2: 29 days	29	-	Planned outage
Tarong North, Stanwell Corporation	443 MW	63 days	63	-	Planned outage
New South Wales			**272**	**176**	
Bayswater, AGL Energy	4 units, 630 MW - 655MW	Unit 1: 20 days	-	20	'Plant failure'
		Unit 2: 16 days	-	16	'Plant failure'
		Unit 3: 20 days	-	20	'Unit trip'
		Unit 4: 58 days	58	-	Major systems upgrade[11]
Eraring, Origin Energy	4 units, 680 MW each	Unit 1: 23 days	23	-	Planned outage
		Unit 3: 12 days	12	-	Planned outage
		Unit 4: 22 days	-	22	'Tube leak'
Liddell, AGL Energy	4 units, 450 MW each	Unit 1: 31 days	15	16	Continued planned outage from Q3 2020 Unplanned outage for 'unit trip'
		Unit 2: 83 days	83	-	Significant maintenance works[12]
		Unit 3: 34 days	-	34	'Unit trip'
		Unit 4: 13 days	-	13	'Tube leak', 'plant failure'

11 AGL Energy on Bayswater systems upgrade
12 AGL Energy on significant maintenance works at Liddell

STATION NAME, COMPANY	STATION CAPACITY (SUMMER RATING MW)	NUMBER OF DAYS OFFLINE IN Q4 2020	PLANNED MAINTENANCE OR UPGRADES	UNPLANNED OUTAGES	NOTES
Mt Piper, EnergyAustralia	2 units, 675 MW each	Unit 1: 87 days	81	6	Major maintenance program[13]
		Unit 2: 9 days	-	9	'Tube leak'
Vales Point, Sunset Power (trading as Delta Electricity)	2 units, 660 MW each	Unit 5	-	14	'Plant failure', 'tube leak'
		Unit 6	-	7	'Tube leak'

Source: AER analysis using NEM data

Note: Table includes all outages of black coal generating units in the NEM that occurred for one day or more. The count of 'planned' and 'unplanned' outage days is cumulative for the whole quarter and may refer to one or more outages.

Generators offering less than registered capacity drove the remainder of low average quarterly ACF results. In NSW, this accounted for around 900 MW of the 3,900 MW reduction, while in Queensland it accounted for 160 MW of 1,600 MW. Generators may offer less than their registered capacity for a range of reasons including:

- Technical issues that aren't severe enough to cause an unplanned outage.
- Ambient temperatures – on hot days, cooling the plant can be harder and limit how much energy the generator can produce.
- Economic reasons.

Older generators that are approaching closure may also offer less than their registered capacity. The black coal generation fleet is older in NSW than in Queensland. In Queensland, all stations but Gladstone were commissioned after 1983, while in NSW, all but Mt Piper were commissioned before 1983. As a result, some generating units in NSW are scheduled to close in the near future and on average, are offering less than their registered capacity on a regular basis compared to the newer generating units in Queensland.

In particular, Liddell (2,000 MW power station in NSW's Hunter Valley) is the next black coal power station expected to close, starting in Q4 2022. This station has generally had the lowest ACF of all black coal power stations in NSW since Q4 2016. Liddell's quarterly ACF has been declining from 70% in Q3 2019 to 43% in Q4 2020. In part, this has been driven by outages but also because generators are offering less than their registered capacity.

Output capacity factors indicate black coal offers remain competitive

While outages have played a significant role in reducing the overall black coal generation capacity offered into the market, this next section assesses how changes in offers, demand, and generation from cheaper sources has impacted black coal generation output.

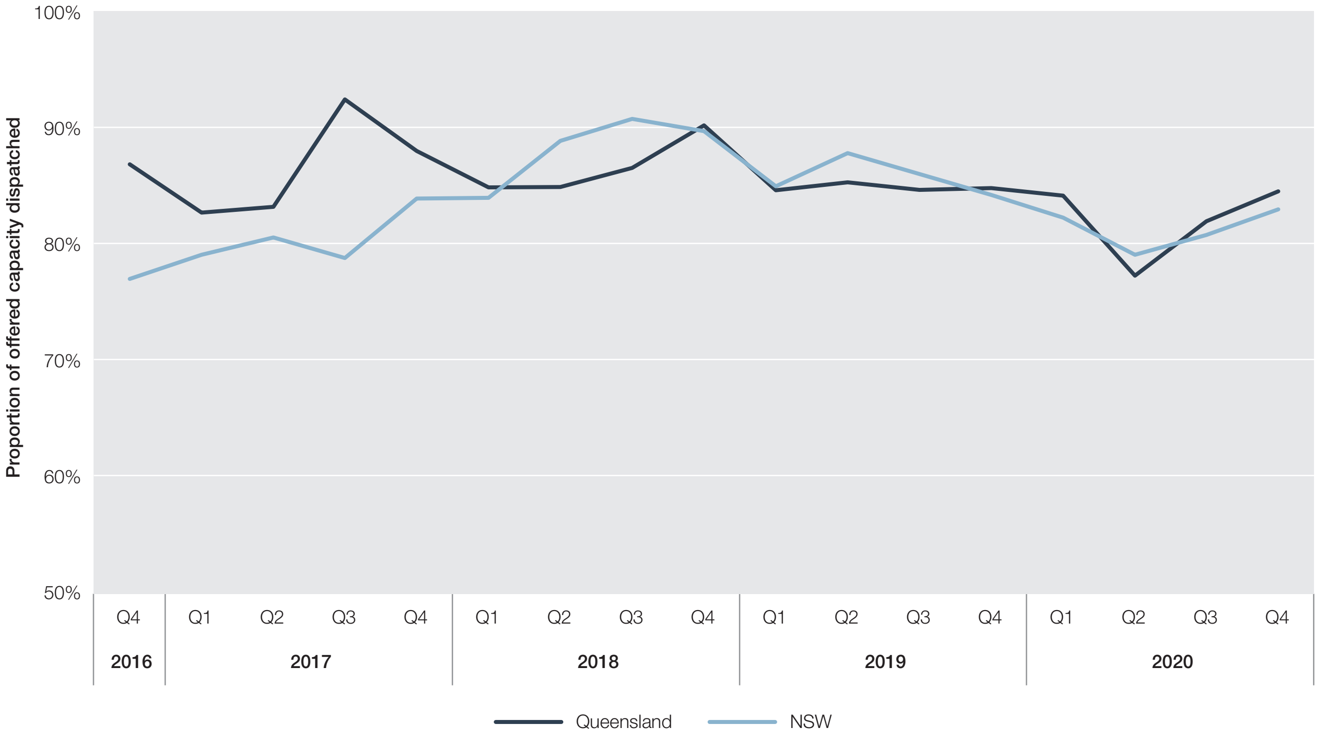
From the summer following the closure of Hazelwood power station in Victoria, OCF increased for NSW black coal generators. Hazelwood was a 1,600 MW brown coal power station whose exit in Q2 2017 shifted Victoria from being a large net exporter of electricity to a net importer.[14] From Q1 2018, NSW black coal has been operating at an OCF that aligns more closely with those seen in Queensland. Since then, quarterly OCF for black coal has been fairly stable with around 80% to 90% of black coal offers getting dispatched in NSW and Queensland.

Across both Queensland and NSW, OCF dipped in Q2 and Q3 2020 and then picked up in Q4 2020 to around 85% – similar to most of 2019 (Figure 1.24). A similar proportion of coal offers continued to be dispatched compared to the capacity offered to the market. This suggests that black coal offers continued to be competitive and did not contribute to low black coal generation output in Q4 2020.

13 EnergyAustralia on Mt Piper major maintenance program

14 AER Hazelwood advice, March 2018.

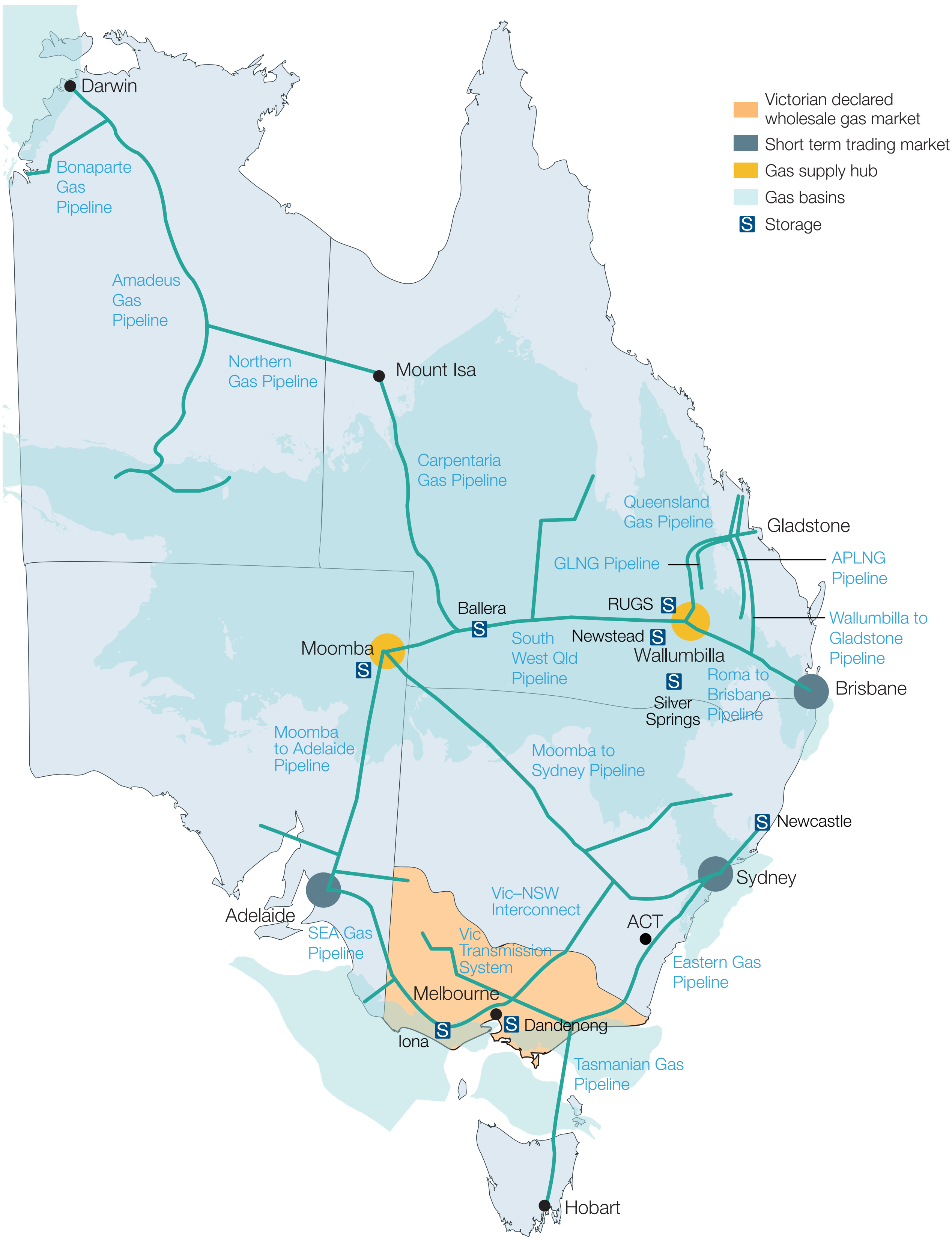
Figure 1.24 Generation output capacity factors



Source: AER analysis using NEM data

Note: Average quarterly output capacity calculated using 30 minute metered output for black coal in each region, divided by 30 minute max-avail for black coal that region.

2. Gas



Victorian declared wholesale gas market
Short term trading market
Gas supply hub
Gas basins
Storage
Darwin
Bonaparte Gas Pipeline
Amadeus Gas Pipeline
Northern Gas Pipeline
Mount Isa
Carpentaria Gas Pipeline
Queensland Gas Pipeline
Gladstone
GLNG Pipeline
APLNG Pipeline
Ballera
RUGS
Newstead
Wallumbilla
Wallumbilla to Gladstone Pipeline
Moomba
South West Qld 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
Eastern Gas Pipeline
Melbourne
Iona
Dandenong
Tasmanian Gas Pipeline
Hobart

2.1 International and domestic prices fell in 2020, despite late increases

INTERNATIONAL AND DOMESTIC PRICES ($/GJ)					
		2017	2018	2019	2020
Argus LNG des Northeast Asian spot price[15]		8.83	12.55	7.70	5.33
	VIC	8.39	9.12	8.84	5.11
	SYD	9.20	9.40	8.97	5.08
East coast spot market prices[16]	ADL	8.50	9.13	9.44	5.70
	BRI	8.09	8.81	8.02	4.89
	WAL	8.52	8.96	7.84	4.83
LNG Netback price at Wallumbilla[17]		7.65	10.88	6.83	4.29

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

In 2020, average prices fell from 2019 levels by around $4/GJ in southern markets and $3/GJ in northern markets (Figure 2.1). This reduction was primarily due to Asian LNG spot price falls across most of 2020. For the past 4 years, average domestic spot prices have correlated broadly with Asian spot prices and the LNG netback price.

As a result of lower international spot prices and declining oil-linked contract prices, LNG exporters received less revenue in 2020, despite increases in the volume of exports (section 2.3).[18] Lower prices in the east coast spot markets were favourable for industrial buyers who increased purchases through these markets over 2020 (section 2.7).

However as the year ended, Asian LNG spot prices increased sharply over Q4 2020 and into Q1 2021.

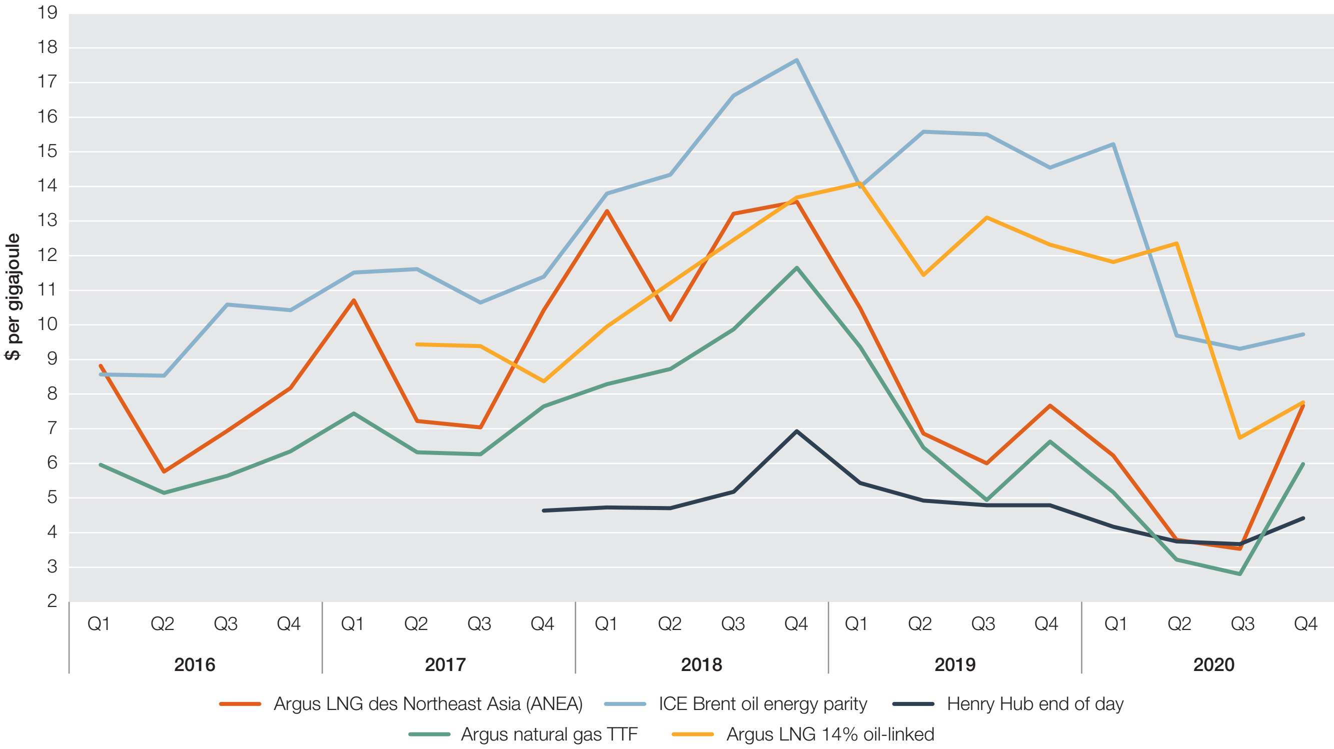
15 The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4-12 weeks before the date of delivery.

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

17 The ACCC calculate the Asian LNG netback price to measure the price that a gas supplier could expect to receive for exporting gas.

18 LNG sales take 12.6bn hit despite record exports, https://www.afr.com/companies/energy/lng-sales-take-12-6b-hit-despite-record-exports-20210118-p56uum, 16 January 2021, accessed 10 February 2021

Figure 2.1 Delivered Asian LNG spot price and Brent oil price



Source: AER analysis using Argus media data and Bloomberg data

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

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

The ICE Brent oil energy parity price is a month ahead settled price/barrel expressed/GJ where one barrel of oil is taken to be 6.1178623 GJ.

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 Scoville via Bloomberg.

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Argus Media Northeast Asia (ANEA) price assessments for cargoes to be delivered in December 2020 averaged $8.88/GJ. However, price assessments for cargoes to be delivered in January and February 2021 were much higher at $14.50/GJ and $25.36/GJ.[19]

Starting around the beginning of December prices increased sharply to a record high in early January 2021. ANEA spot price assessments rose by 370% between 1 December 2020 and 15 January 2021. Over this time, oil prices were relatively stable, which meant oil-linked contract prices and Brent oil energy parity prices did not increase to the same degree. There are a number of factors which contributed to the sudden spot price spike, including:

- There was unexpectedly strong demand in Asia from the largest consumer nations, such as China, Japan and South Korea, due to a northern winter cold snap.[20] Demand for gas in China may have been driven higher by coal generation fuel supply issues.
- Higher shipping costs over late 2020 indicate that price increases were driven by higher demand, rather than lower supply.
- Ongoing congestion at the Panama Canal caused delays in cargoes reaching Asia, which likely prevented some additional supply being delivered to market to address the demand spike.
- An inability to direct LNG cargoes away from European and other global destinations in sufficient quantities to satisfy quickly rising demand in Asian markets.

19 December delivery price assessment are captured in Figure 2.1 for Q4, January and February delivered cargo price assessments are not shown.

20 Bloomberg, Bitter Cold Means Chaos as Global Energy Systems Show Strain, https://www.bloomberg.com/news/articles/2021-01-15/bitter-cold-brings-chaos-as-global-energy-systems-show-strain, 15 January 2021, accessed 1 February 2021.

However, these high prices were only temporary, as ‘prompt’ prices fell to below $11/GJ by the start of February. Current futures pricing indicates that these high Asian LNG spot prices are unlikely to return over the next year. Some additional factors are likely to have contributed to this:

- As spot gas prices were well above long-term gas contract pricing, buyers were incentivised to take more gas through arrangements under long-term contracts.
- Spot gas prices were well above Brent oil energy parity prices and coal price equivalents (not shown), which encouraged customers to substitute other fuel sources for gas.[21]
- The difference between Asian and European spot prices reached as high as USD$26/mnBtu on 13 January 2021, which incentivised redirections of cargoes to Asia.[22 23]

As Asian LNG spot prices increased sharply, they diverged from European Title Transfer Facility (TTF) prices, which did not rise. This supports the conclusion that the price increase in Asia was driven by local demand factors and limitations on immediate supply from other regular sources.

European gas prices are linked to global LNG prices because European domestic gas markets rely on LNG imports to supplement pipeline gas imports and domestic production. The TTF is the most liquid gas hub in Europe and prices at the TTF tend to track Asian LNG spot prices. Differences between the TTF and Asian LNG prices reflect regional conditions.

Large regional price differences also allow participants to arbitrage prices, diverting LNG shipments away from lower priced regions for delivery to higher priced destinations. That European gas prices remained moderate while Asian LNG prices were at record highs indicates that the change in the Asian LNG market was not large enough to severely impact the global LNG market.

Oil prices have also been volatile over the 2020 calendar year. Daily Brent oil prices have varied from a high in Q1 2020 of over $99/barrel to a low in Q2 2020 of just above $30. Brent oil prices can influence global LNG prices to the extent that contracts are struck with reference to oil prices, but oil can also been seen as a substitute for gas. Comparing oil and LNG prices over time shows that oil is typically a more expensive form of energy than LNG and that oil prices may represent a ceiling on gas prices.

In Q1 2020, average Brent oil prices were $15.22/GJ, which was more than twice the ANEA price of $6.23/GJ. In Q2 2020, oil and LNG prices fell to below $10/GJ and $4/GJ respectively, whilst maintaining around the same relative price differential. In Q4 2020, the oil price remained under $10/GJ, while Asian LNG prices rose sharply to $7.67/GJ. This reduced the difference between the 2 prices to the lowest level in 2 years.

Over Q4 2020 and into early Q1 2021, LNG netback price increases outpaced more moderate domestic price rises (Figure 2.2).[24]

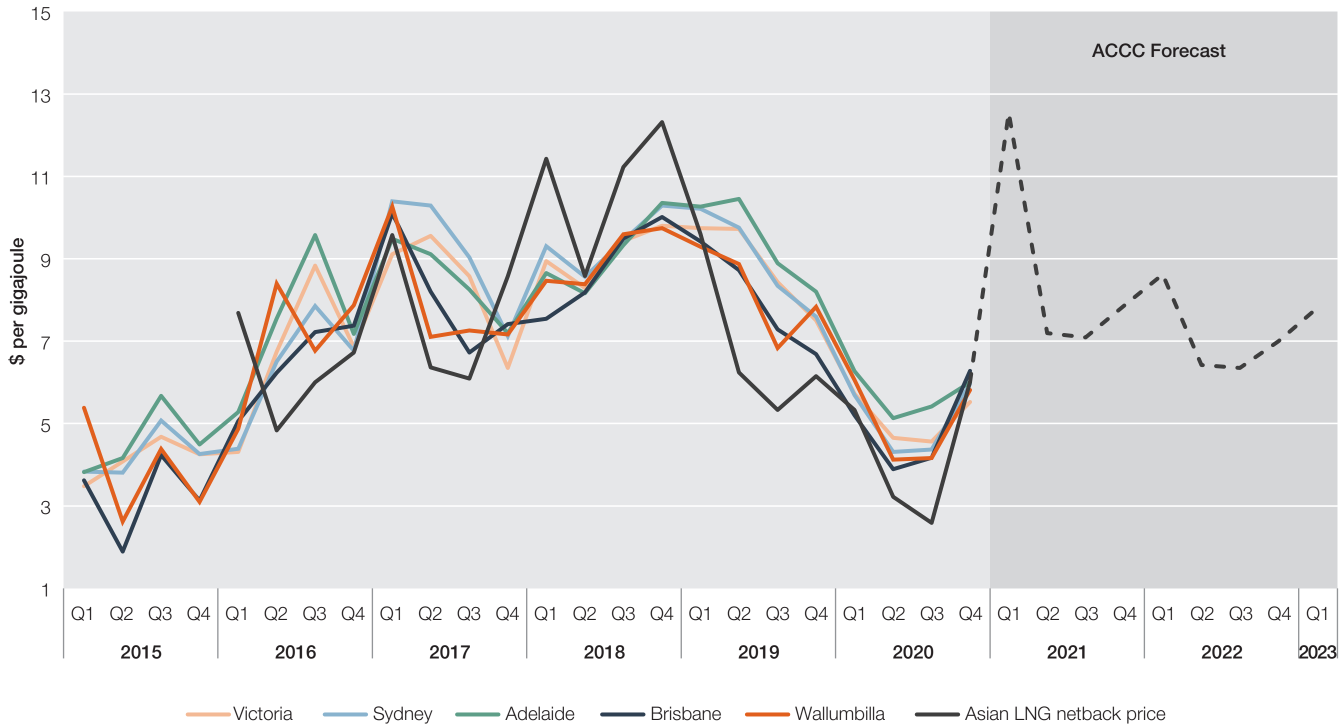
21 The Brent oil price is a trading classification of crude oil, which serves as a global benchmark price for the purchase of oil.

22 Argus Media, Asian spot LNG prices at record high on ‘perfect storm’, https://www.argusmedia.com/en/news/2174803-asian-spot-lng-prices-at-record-high-on-perfect-storm, 7 January 2021, accessed 9 February 2021.

23 USD$/million British thermal units (mnBtu or mmBtu) is the international price standard for LNG.

24 Three separate types of markets for gas operate in eastern Australia. The Gas Supply Hubs (GSH) at Wallumbilla and Moomba are “upstream” exchanges for the wholesale trading of natural gas. The Short Term Trading Markets (STTM) in Brisbane, Sydney and Adelaide, and the Declared Wholesale Gas Market (DWGM) in Victoria as “downstream” markets for managing the imbalance of gas consumption and demand.

Figure 2.2 Domestic spot prices and Asian LNG spot netback price



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

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

Downstream, the Brisbane Short Term Trading Market (STTM) was the highest priced market, increasing by 34% from Q3 2020 prices. Adelaide and Sydney STTM prices also rose more modestly this quarter. In Victoria, prices increased for the first time since Q1 2019.

Across all downstream markets, the maximum daily price was $7.98/GJ on 30 November 2020 in Sydney. On this day, prices reached maximum levels in Adelaide and Victoria as well. There was high electricity demand in NSW across late November and this is likely to have influenced the maximum prices in the gas markets (Section 1.2).

Over December to February, domestic spot prices separated from Argus Media's ANEA price (Table 2.1).

Table 2.1 Domestic spot prices and Asian LNG spot price comparison

YEAR	MONTH	ANEA LNG SPOT PRICE ($/GJ)	AVERAGE EAST COAST SPOT PRICE ($/GJ)
2020	December	8.88	6.55
2021	January	14.50	6.37
2021	February	25.36	6.13*

Source: AER analysis using Argus media data (ANEA), DWGM, STTM, WGSH data (East coast spot price)

Note: Prices shown are prices or price assessments for deliveries made in the month with the February price being calculated for the east coast until 10 February.

This is the first time domestic prices have separated significantly from Asian LNG spot prices since late 2018 (Figure 2.2). At that time, the separation occurred as domestic prices flattened after increasing over the previous year. Similar to this quarter however, in Q4 2018 gas used for gas powered generation decreased and more gas flowed from south to north (section 2.6).

A number of factors in the domestic market meant price rises domestically were moderate in comparison to ANEA price increases:

- Domestic demand dropped in Q4 2020 as gas used for gas powered generation declined (section 2.9)
- The southern market was less reliant on northern production this quarter, in fact excess gas flowed north (section 2.6)
- LNG exporters increased production to record levels (section 2.2) to meet record exports (section 2.3).

In general, wholesale spot price decreases or increases may not result in immediate corresponding rises in retail market offers. Gas trade through wholesale spot markets, although rising, only accounted for up to 20% of total gas market consumption in 2020 (section 2.7). Larger volumes of gas continue to be bought or sold through longer term bilateral contracts.

Interestingly, northern market prices exceeded southern market prices for the first time since Q3 2018 (Figure 2.3). This drove high movements of gas from southern markets to the north this quarter (section 2.6).

Figure 2.3 North-South price gap

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

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

2.2 Higher production over Q4 2020 in the north

		PRODUCTION AND STORAGE			
		2017	2018	2019	2020
Production, PJ	Northern	1,385	1,441	1,578	1639
	Southern	441	348	347	309
	Total	1,826	1,788	1,925	1,947
Average gas storage level, PJ		N/A	N/A	95.4	98.9

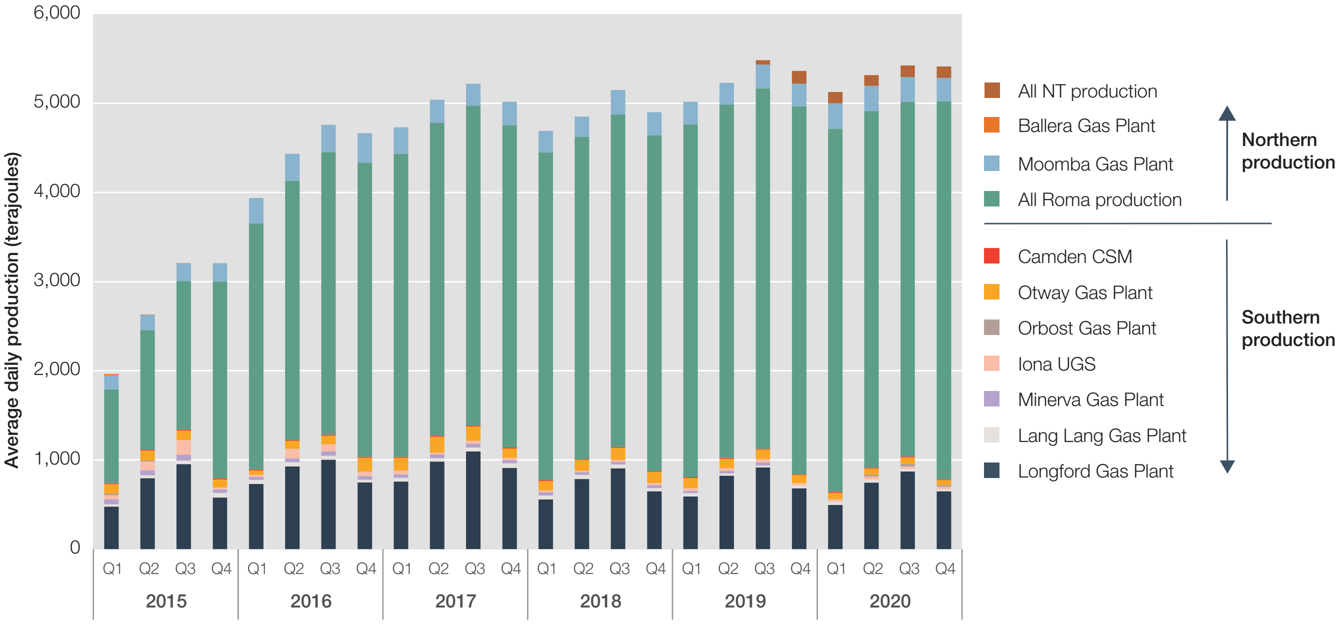
Source: AER analysis using Natural Gas Services Bulletin Board data

Note: Data for storage is not continuous, as new storage facilities have been added since 2016/17

Total production levels reported through the Natural Gas Services Bulletin Board increased slightly over 2020 although only due to new reporting of long-standing fields. Within reported northern production, Northern Territory production increased from 17.7 PJ to 46.4 PJ – however this was a result of the Yelcherr production facility only commencing reporting on 14 October 2019 despite producing since around 2009. It produces around 90 TJ/day of gas production for Northern Territory usage. Excluding Yelcherr indicates total production slightly decreased from 2019 to 2020.

Reductions in production of 38 PJ occurred across southern production fields (Figure 2.4). The Australian Energy Market Operator (AEMO) and the Australian Competition and Consumer Commission (ACCC) have identified the ongoing depletion of Victorian gas fields as a risk to gas power generation availability in 2023–24.[25] Orbost is a new facility, which commenced operation in March 2020 near the Gippsland Basin. It is comparatively smaller, with a nameplate rating of 68 TJ/day compared to the neighbouring Longford facility's rating of 1,115 TJ/day. However, Orbost has not been able to meet this production potential, as its output fell over Q4 2020.[26]

Figure 2.4 East coast production (including Northern Territory)



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

East coast production typically falls in the last quarter of the year, however production remained high over the last quarter of 2020. Daily average production levels only reduced slightly from the previous quarter to 5,414 TJ/day.

The Roma gas fields, located in close proximity to the 3 east coast export projects, recorded new record average daily production of above 4,240 TJ/day. This is significantly higher than the previous record of 4,126 TJ/day recorded in Q4 2019. Comparing the 2 quarters, daily production in the region peaked at 4,377 TJ/day and exceeded 4,300 TJ across 29 days from late October 2020, whereas flows only exceeded 4,300 TJ/day twice during Q4 2019. This reflects the record LNG exports demand this quarter (section 2.3).

In the South, gas production reduced as southern demand declined, reflecting reduced gas heating requirements. Despite this, there was excess southern supply this quarter as less gas was needed for gas powered generation. In the National Electricity Market, this quarter was the lowest Q4 of GPG demand since 2005 (section 2.9). Participants sent this excess supply north, resulting in the highest northern flows on the SWAP since Q4 2017 (section 2.6).

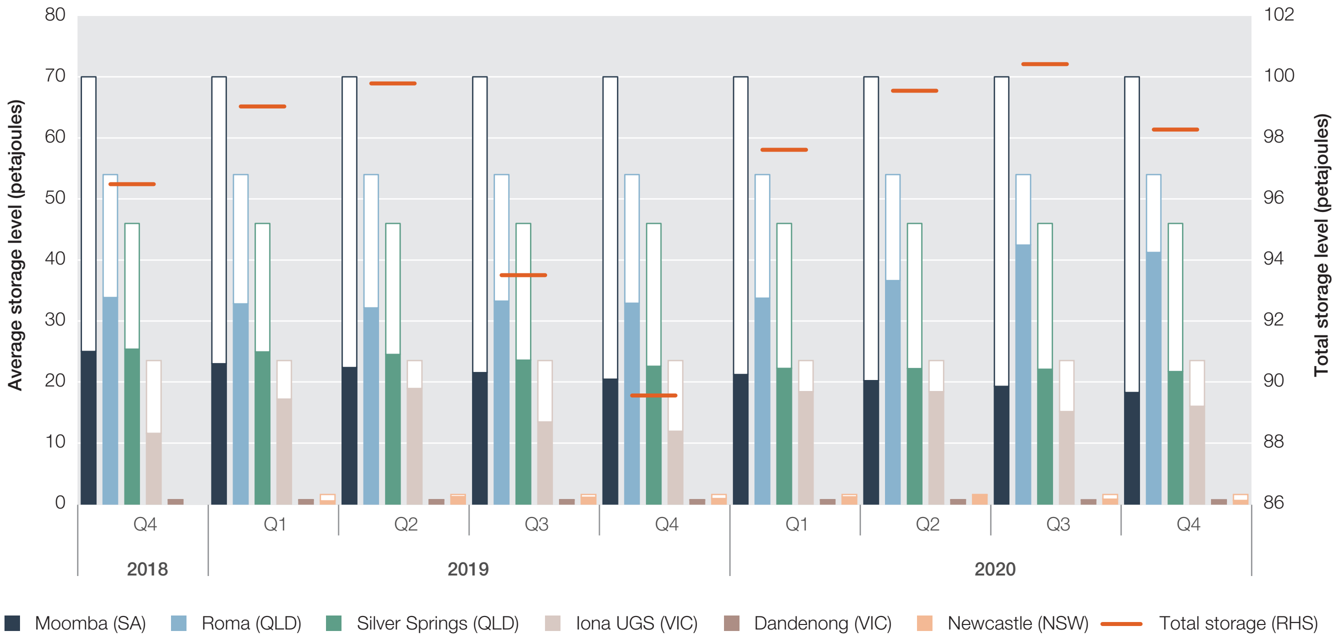
Average storage levels in 2020 were higher than in 2019 (Figure 2.5). This was due to higher storage levels at Iona and a significant increase at Gladstone LNG's Roma storage facility, which was filled in the middle of the year when prices were low. The actual storage level at Iona, which is a critical resource for southern gas demand balancing was at its highest levels for the end of a Q4 since 2017.[27] However in Q4 2020, some storage was depleted to assist in meeting record LNG export demand.

25 AEMO, Gas Statement of Opportunities, March 2020, pp. 10-11; ACCC, Gas inquiry report, January 2020, p. 12.

26 AEMO, Quarterly Energy Dynamics – Q4 2020, 29 January 2021, p. 30.

27 AEMO, Quarterly Energy Dynamics – Q4 2020, 29 January 2021, p. 31

Figure 2.5 Storage levels



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

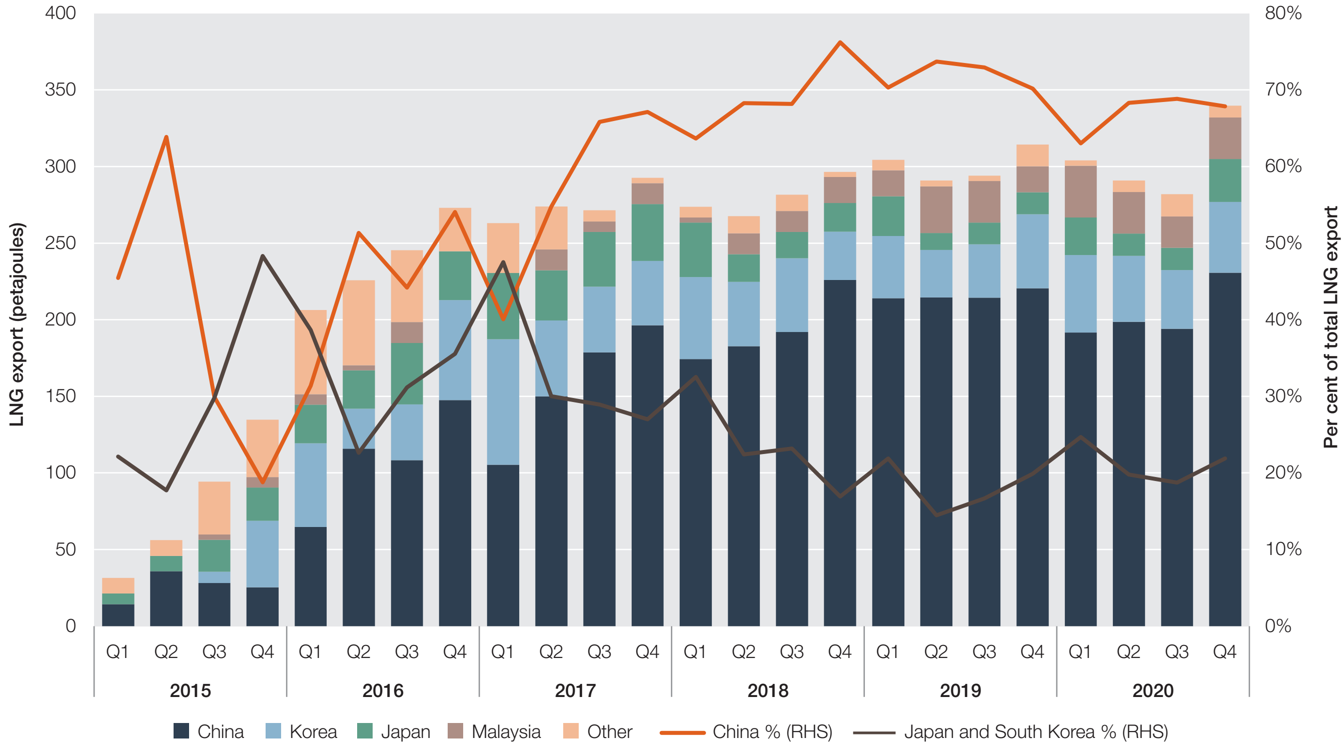
2.3 LNG exports increased to record levels this quarter

LNG EXPORT					
YEAR		2017	2018	2019	2020
LNG export, PJ		1,101	1,119	1,204	1,217
Number of cargoes		313	311	333	340
	China	631	775	863	815
	South Korea	216	175	155	178
Destination breakdown, PJ	Japan	149	89	65	82
	Malaysia	34	48	92	108
	Other	72	32	28	33

Source: AER analysis using Gladstone Port Corporation data.

Total Queensland LNG exports increased to a record high of 1,217 PJ in 2020, an increase of 2.5% on 2019 export volumes (Figure 2.6). This was driven by record levels of LNG exports in Q4 2020 as international prices spiked, despite generally low international spot gas and oil prices across the year.

Figure 2.6 LNG shipped from Gladstone Port by destination

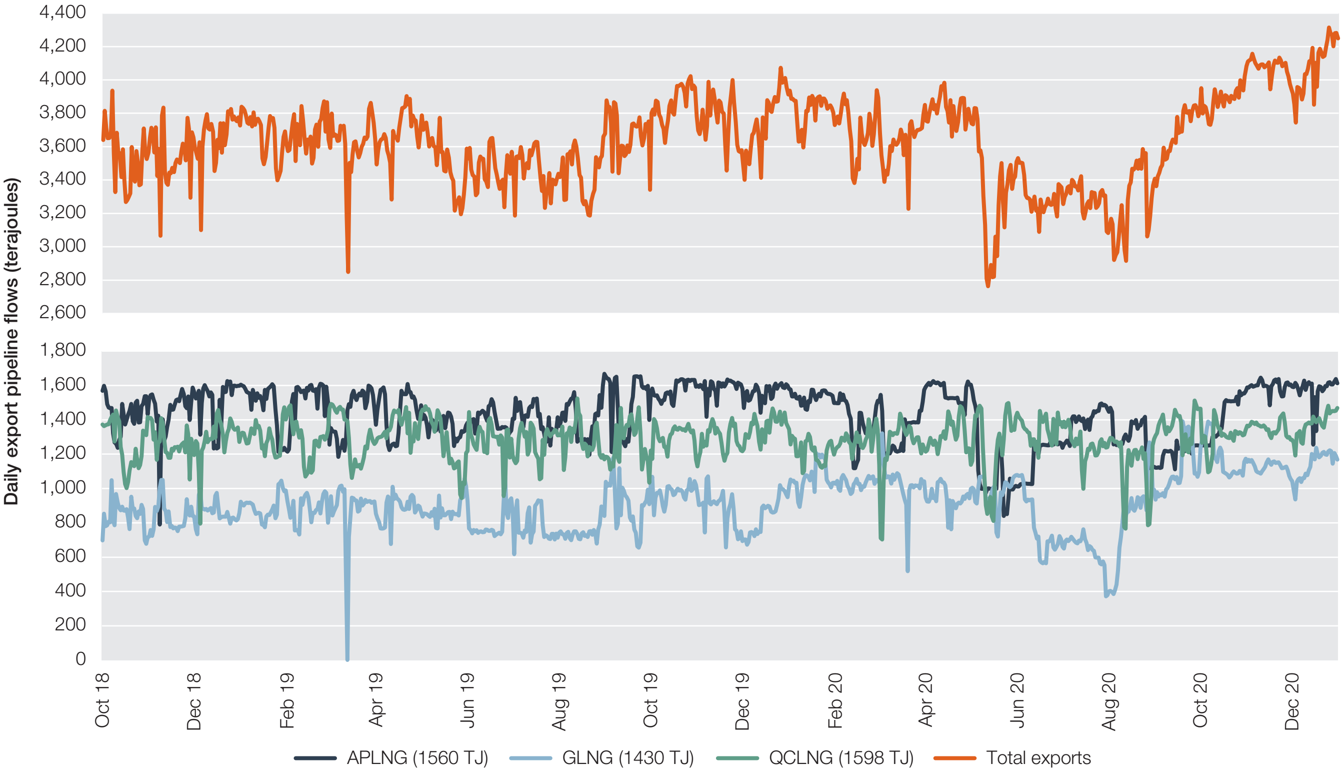


Source: AER analysis using Gladstone Port Corporation data.

Over the calendar year, cargoes marked for export to China reduced, but this was offset by higher exports marked for delivery to South Korea, Malaysia and Japan. The remaining 33 PJ of exports to other countries was dominated by Singapore with 26 PJ in 2020, with only single cargoes marked for delivery to India and Argentina. This is expanded from 2019, where the remaining other cargoes were only marked for delivery to Singapore.

In Q4 2020, a record 230.6 PJ of exports was destined for China, keeping China as the most significant buyer of Queensland LNG. In December in particular, a record 34 cargoes were exported. As Roma production increased, so too did flows on the pipelines connecting Roma to the LNG export trains (Figure 2.7). Over the quarter, flows on those pipelines approached or exceeded nameplate ratings.

Figure 2.7 East coast pipeline flow and LNG exports



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

Queensland LNG exports have been relatively unaffected by the effects of COVID-19, which has reduced demand for LNG globally and led to reduced exports from other major exporting countries such as the United States.

2.4 Gas Supply Hub trade volumes fall over 2020 with significant drops in this quarter

GAS SUPPLY HUBS	2018	2019	2020
Number of trades	1,919	3,635	2,655
Trade volume, PJ	16.4	27.4	21.1
Volume weighted average price, $/GJ	9.02	7.98	4.68

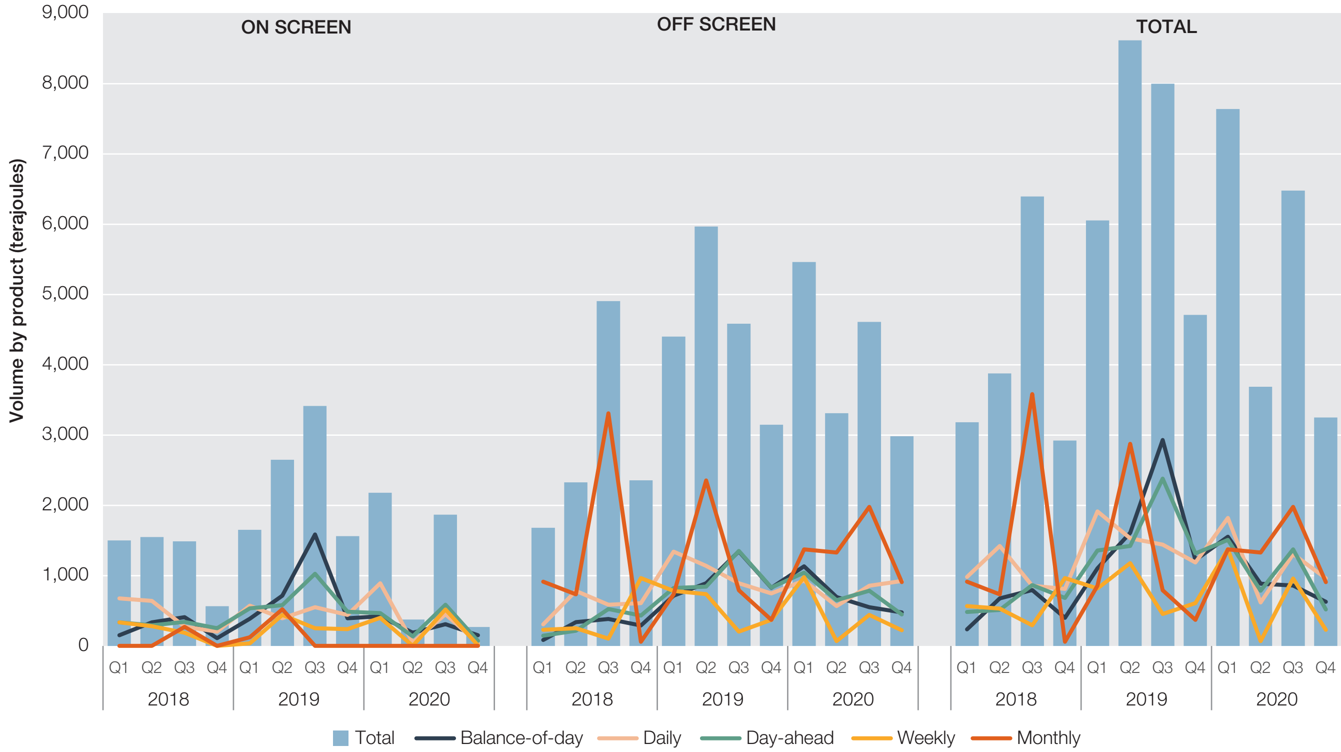
Source: AER analysis using GSH trades data.

Note: Results shown for all locations, products and trade types, excluding capacity trades.

Over the calendar year traded volumes fell to around 21 PJ, down from more than 27 PJ traded in 2019. In particular, low volumes of trade in Q4 2020 contributed to this as participants traded 3.3 PJ at the Gas supply Hubs, the least in 2 years. This reduction in volume was primarily due to a collapse in on screen trading, which at 270 TJ was the lowest volume traded since market start in Q1 2014.[28]

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.

Figure 2.8 Gas Supply Hub – On screen, off screen and total trade volumes by product



Source: AER analysis using Gas Supply Hub data.

Compared to Q4 2019, the volume of gas traded on screen fell by more than 80%, while off screen trades remained relatively steady. The volume for each product traded on screen fell by between 62% and 97%.[29] Participants traded no monthly products on screen for the sixth quarter in a row. By location, trade at both the South East Queensland and Wallumbilla locations were down by more than 80%.

Off screen, there was more gas traded in both daily and monthly products than in Q4 2019, with volume in monthly products more than doubling. However, this increase was offset by falls in volume for other products, which reduced by between 40% and 46%.

In 2020, 19 participants traded at the Gas Supply Hubs, of which 17 were active, an increase from the 16 total participants in 2019.[30] With more participants, there were positive signs for competition. The top 3 buying participants only accounted for 40% of trade volumes in 2020, down from 51% last year. Similarly, the top 3 selling participants comprised less of the market, down to 53% in 2020 from 64% in 2019.

Traders are significantly more involved in the market and were the only participant group to trade more this year than last year, increasing to 20% of total trade in 2020 from 13% in 2019. In Q4 2020, Traders appeared resilient to trade reductions, selling their highest ever volume of gas this quarter, almost triple the volume sold in Q4 2019. This, combined with significant reductions in sales by other participants, resulted in Trader sales accounting for 32% of total gas sold in Q4 2020.

Exporters and producers sold 610 TJ of gas in Q4 2020, the lowest volume in 4 years. More generally, the total gas traded by Exporters and Producers in Q4 2020 was the lowest volume since Q1 2017. This, as a proportion of the market was only 26%, the lowest proportion of trade since Q1 2016. This reduction in trade by these participants is part of a broader trend this quarter (section 2.8).

The churn rate for Q4 2020 fell to 5.9% at Wallumbilla, from 6.1% at the same time last year. Similarly, the churn rate at the Moomba hub declined from 0.4% in Q4 2019 to 0.2% this quarter.

Finally, the volume weighted average price at the Gas Supply Hubs in 2020 fell to $4.68/GJ, more than 40% lower than the 2019 average price. Importantly, no price in 2020 was greater than $7.65/GJ, the lowest annual maximum price since market start in 2014. This quarter, with significantly less on screen trade, prices were higher for all on screen products. As a result, the difference between the volume weighted average price for on screen and off screen products widened out to $0.27/GJ.

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

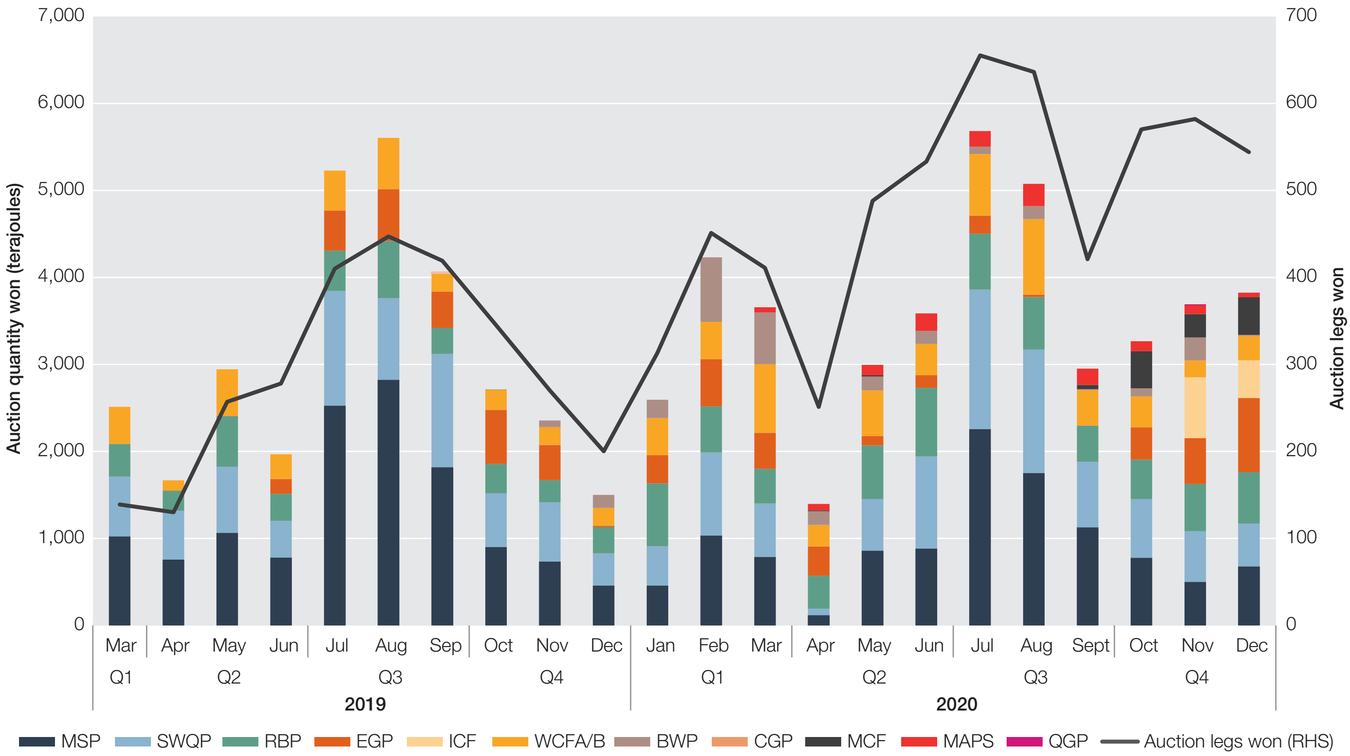
30 We consider a participant "active" if it makes at least a number of trades equal to the number of months in the quarter (3) or year (12).

2.5 Day Ahead Auction used to move gas north

The Day Ahead Auction (DAA) is approaching its two year anniversary of its commencement on 1 March 2019. The AER will be publishing a separate report on the DAA in March 2021 to report on outcomes over the first 2 years.

This quarter, DAA volumes increased 65% compared to Q4 2019 levels. In December alone, participants won 3,825 TJ of capacity, which is more than twice the 1,500 TJ won in December 2019 (Figure 2.9).

Figure 2.9 Pipeline capacity won on the Day Ahead Auction



Source: AER analysis using DAA auction results data.

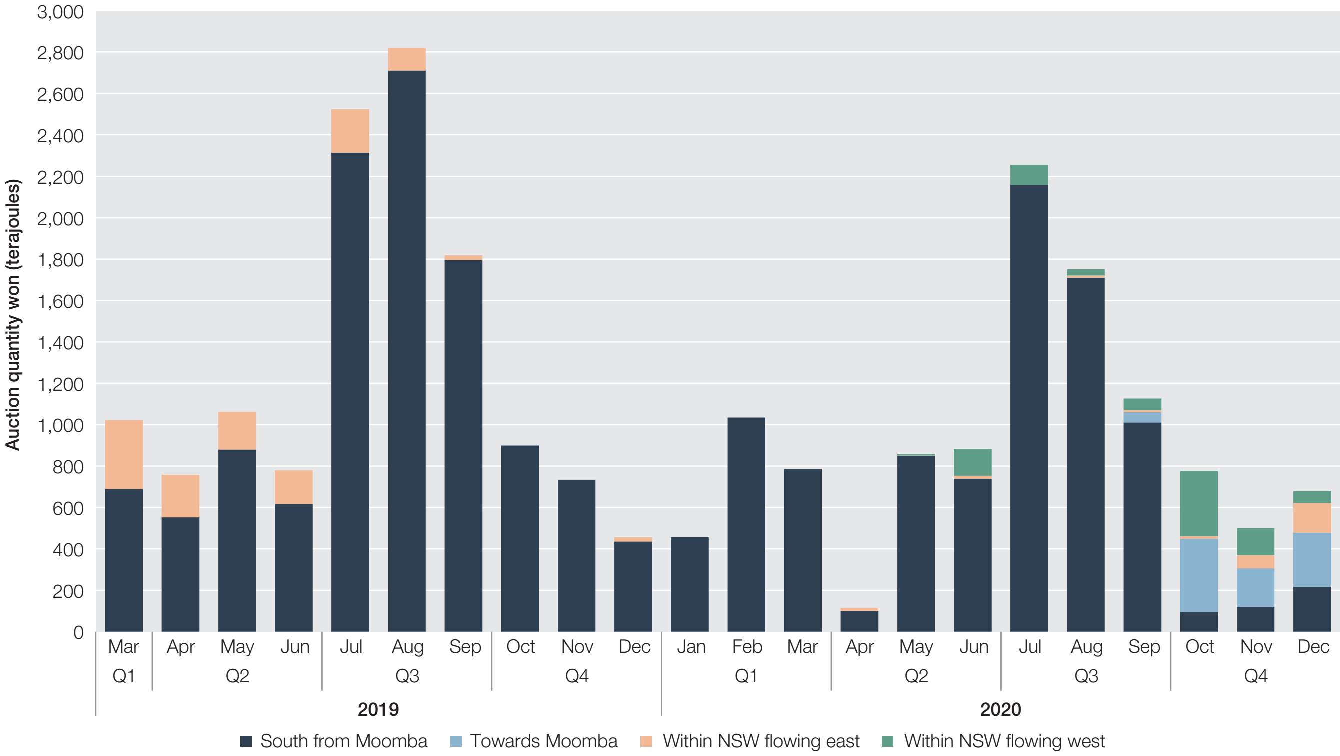
Note: Quantities shown are the monthly sum of auction products allocated on each pipeline and do not necessarily represent the physical volumes of gas that actually flowed for each gas day.

From this quarter reporting on the DAA was on a gas day basis, whereas previously reporting was on an auction day basis.

For the first time, the Iona Compression Facility (ICF) and Queensland Gas Pipeline featured in auction quantity results with auction capacity on the ICF representing 10.5% of total auction capacity sold for the quarter. Participants also won record auction quantities on the Moomba Compression Facility (MCF) used to move gas between the south and north, and the Eastern Gas Pipeline.

Gas flowed from the south to northern markets over Q4 2020, which was reflected in the capacity won by participants (section 2.6). Participants predominantly won capacity for routes towards Moomba (SA) on the MSP and flowing north on the SWQP towards Wallumbilla (Figure 2.10 and Figure 2.11). This is a significant change from previous quarters where participants predominately won gas on routes to send gas south from northern markets.

Figure 2.10 Auction quantities won on the Moomba to Sydney Pipeline by route

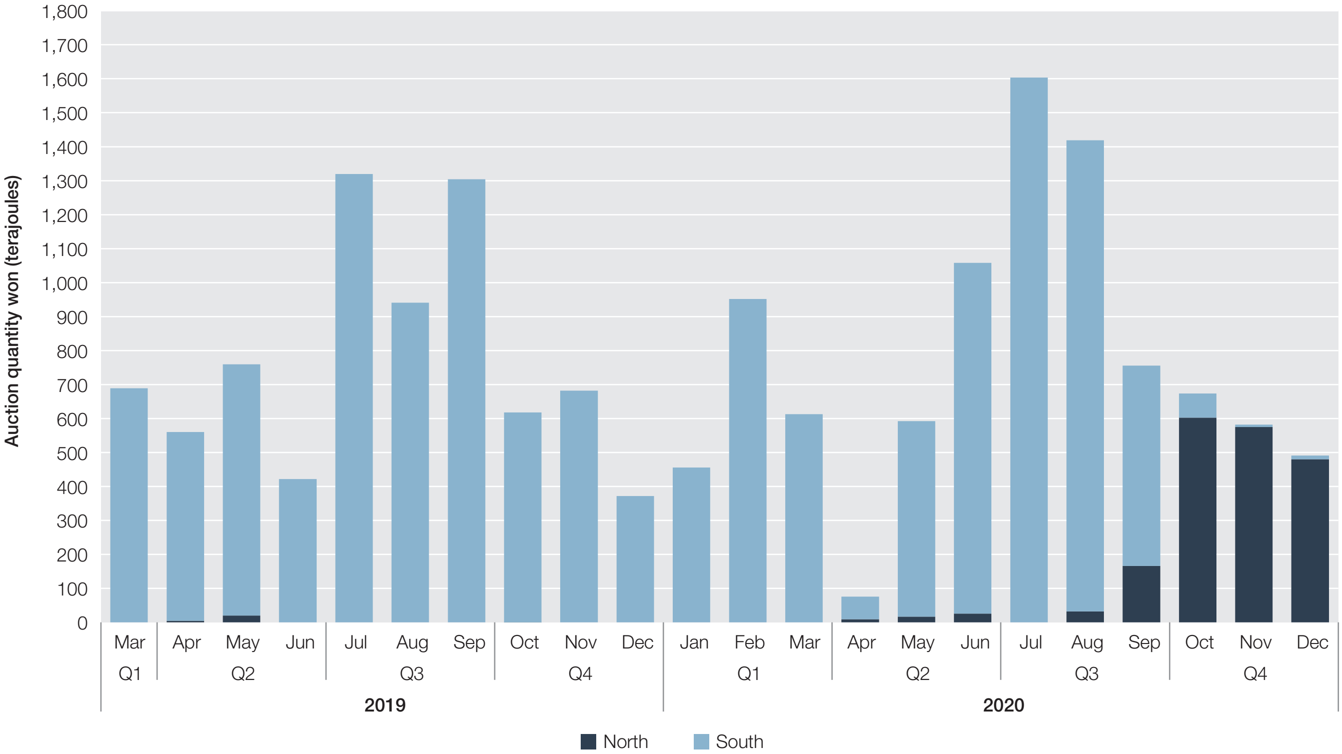


Source: AER analysis using DAA auction results data.

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

The flow north towards Moomba represented 41%/cent of all auction quantities won on the MSP in Q4 2020. A further 26% of auction quantities won on the MSP this quarter were for routes west, but within NSW from receipt points near Sydney. The majority of auction capacity bought on the MSP over Q4 2020 was by Exporters and Producers, and Traders. This contrasts to Q3 2020, where the majority of auction capacity was won by Gentailers for deliveries south from Moomba to Victoria (Culcairn).

Figure 2.11 Auction quantities won on the South West Queensland Pipeline by route



Source: AER analysis using DAA auction results data.

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

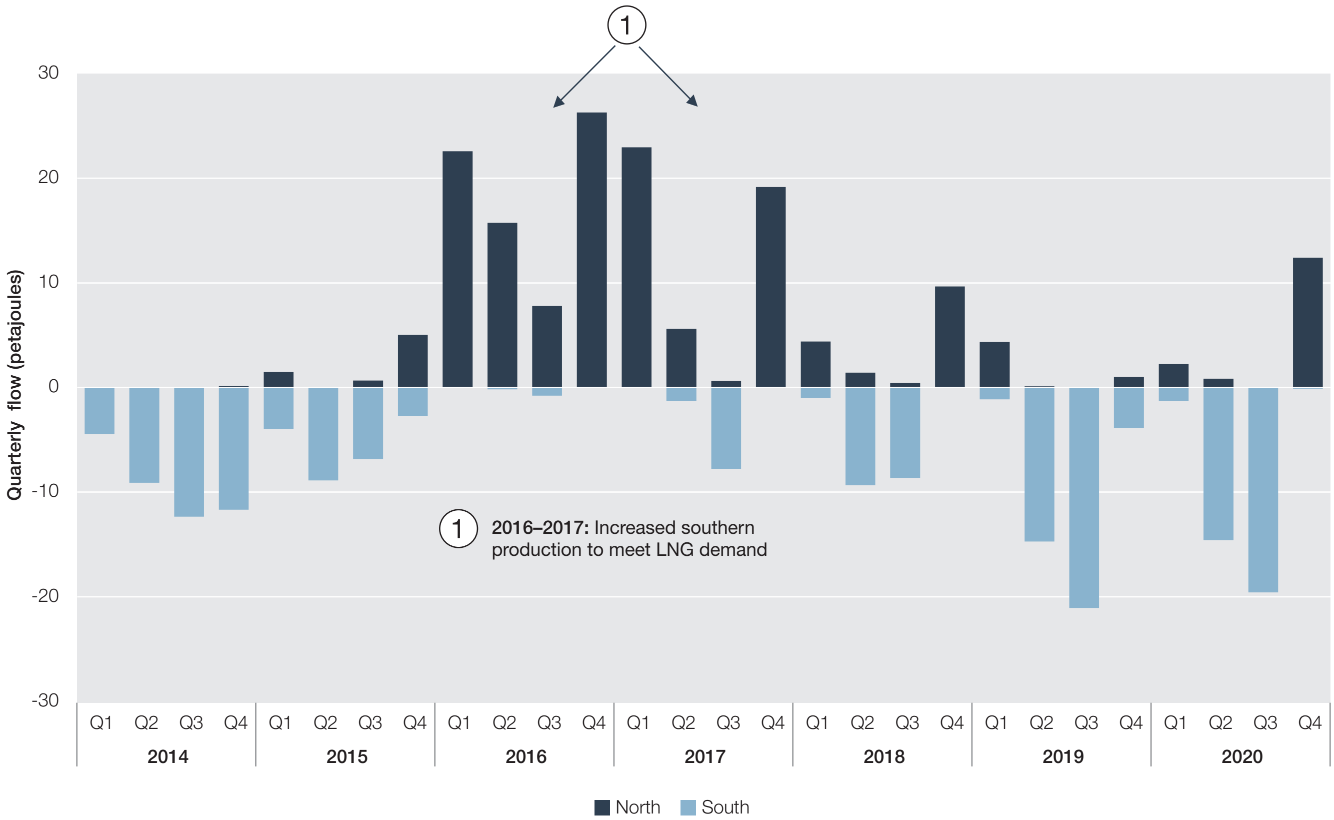
On the SWQP, 95% of all auction quantities won this quarter were predominantly on routes north towards Wallumbilla. This is contrary to the typical direction of auction flows since the start of the DAA. This quarter, 1,657 TJ of capacity was won on routes north, compared to only 275 TJ for all previous quarters combined.

This change in how participants are using the auction this quarter is an example of how participants can use the auction flexibly to adapt to market needs. Participation in the auction over the quarter reflected broader movements of gas north for LNG exports from Gladstone.

2.6 Gas flows change direction to flow north

This quarter saw the highest gas flows into Queensland since Q4 2017 through the SWQP. In total, 12.4 PJ of gas was imported from the southern regions (Figure 2.12).

Figure 2.12 North-South gas flows



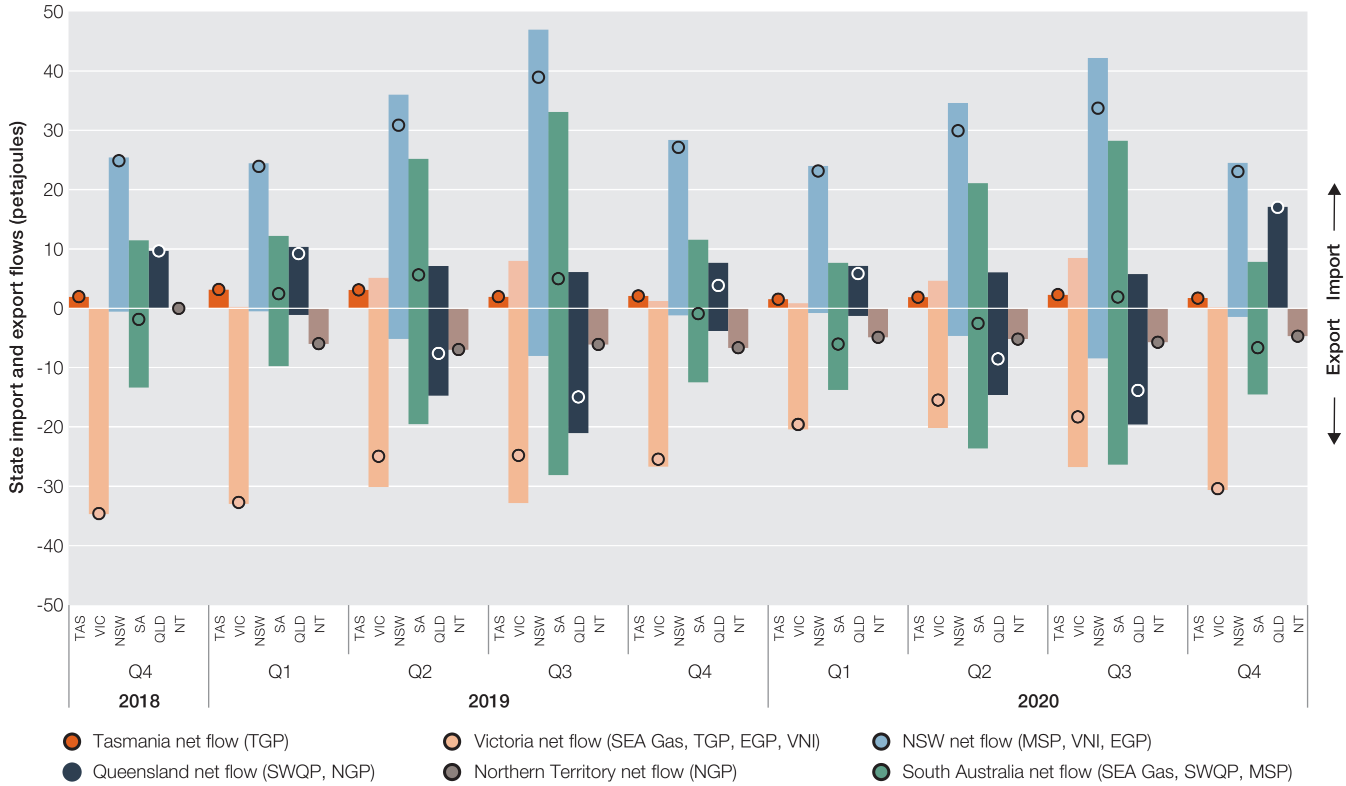
Source: AER analysis using the Natural Gas Services Bulletin Board.
Note: North/South flows depict net physical flows around Moomba – north or south.

These flows were in response to increased LNG export demand as Asian LNG spot prices rose across the quarter. This contrasts with Q4 2017, when additional southern gas was required to meed LNG export commitments as production facilities were still ramping to maximum production. This quarter, daily flows north peaked at 268 TJ on the SWQP.

By state, Victoria and South Australia increased net gas exports from Q4 2019 to Q4 2020 (Figure 2.13). Over the same period Queensland significantly increased net gas imports and NSW reduced net gas imports.[31]

31 The net gas flow rate of a state is the difference between the amount of gas imported into the state and the amount of gas exported from the state. If a state is a net exporter of gas it means it exports more gas than it imports and vice versa when it is a net importer of gas.

Figure 2.13 Interstate gas flows

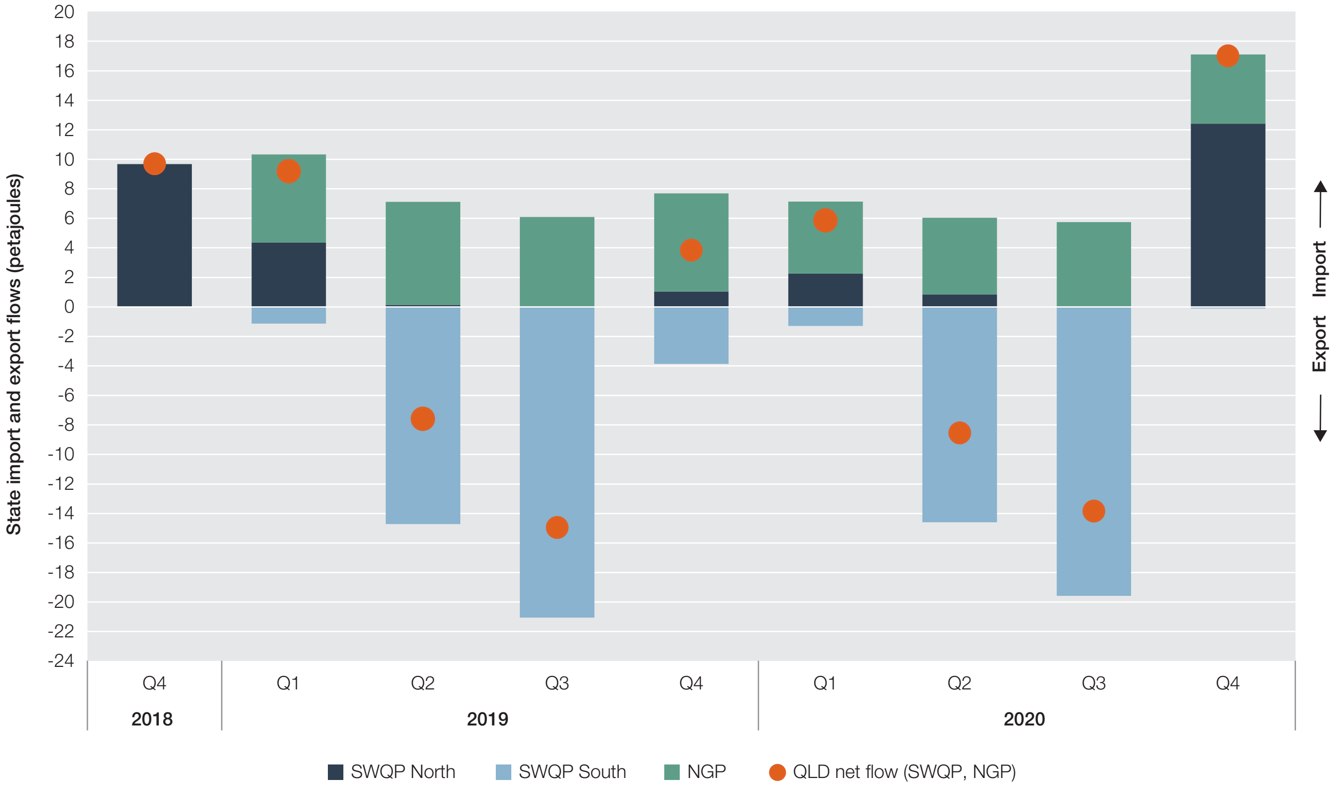


Source: AER analysis using the Natural Gas Services Bulletin Board.

Note: TGP - Tasmania Gas Pipeline; SEA Gas - includes the Port Campbell Iona Pipeline and the Port Campbell Adelaide Pipeline; MSP - Moomba Sydney Pipeline; EGP - Eastern Gas Pipeline; VNI - Victoria-NSW interconnector; SWQP - South-West Queensland Pipeline; NGP - Northern Territory Pipeline.

In total, 17 PJ was imported into Queensland over Q4 2020 (Figure 2.14). This was supported by 4.7 PJ of flows from the Northern Territory on the Northern Gas Pipeline (NGP), which combined with southern flows to make the highest level of imports into Queensland since the NGP was connected in Q4 2018. Since connection in late 2018, NGP flows have been fairly constant, achieving a maximum of 7 PJ in Q2 2019. Generally, the SWQP continues to be the cause of swings in gas flows.

Figure 2.14 Queensland import and export gas flows

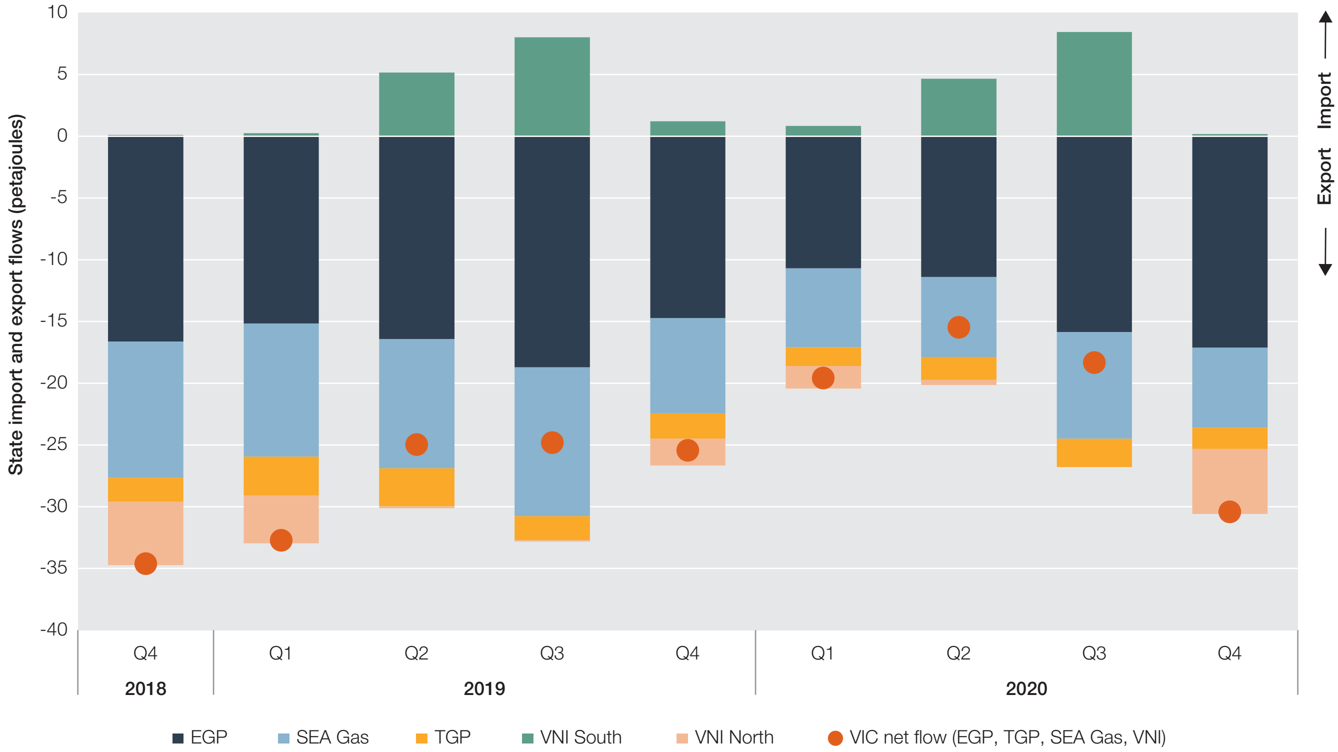


Source: AER analysis using the Natural Gas Services Bulletin Board.

Net flows on the Victoria–New South Wales Interconnector (VNI) were 5.1 PJ north this quarter (Figure 2.15).[32] Unlike the previous 6 quarters, there were negligible VNI flows south in Q4 2020. Victorian net exports this quarter were at the highest levels since Q1 2018, as a result of increased LNG export demand, and lower demand from gas powered generators.

32 The VNI links the Victorian gas market with NSW and the northern markets at Culcairn. The net flow of gas through the VNI is almost entirely north over Q4 meaning that Victoria is exporting gas north.

Figure 2.15 Victoria import and export gas flows



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

In NSW, 17.1 PJ flowed from Victoria on the EGP this quarter, supporting demand. This was an increase from Q3 2020, despite less demand for heating this quarter and a reduction in gas powered generation demand (section 2.9). This increase in flow on the EGP largely compensated for a reduction in flow south from Moomba into NSW, which was only 2.1 PJ this quarter, compared to 11.5 PJ in Q4 2019.

2.7 Spot trade increases on a yearly and quarterly basis

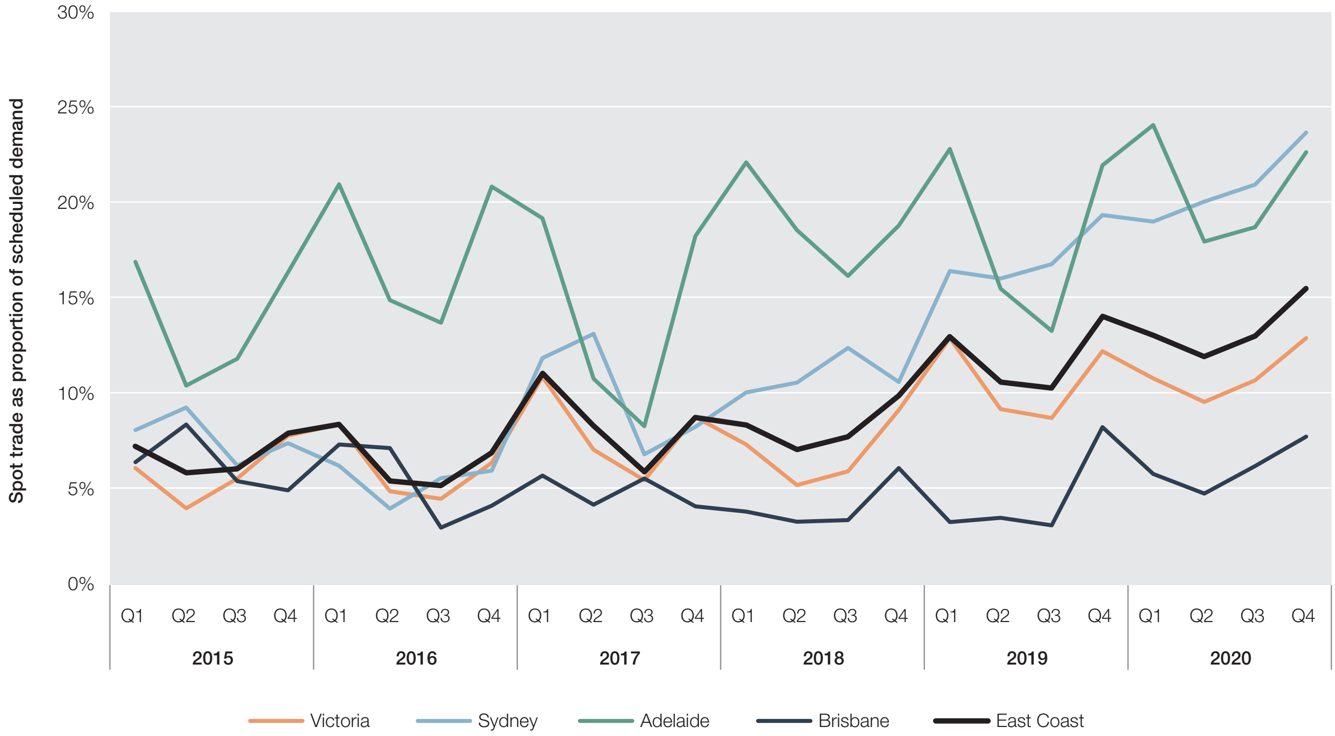
SPOT MARKET OUTCOMES					
		2017	2018	2019	2020
Total net market trade volume, PJ	VIC	20,434	15,485	25,526	26,132
	SYD	8,796	9,952	15,307	19,064
	ADL	2,931	4,046	3,603	4,273
	BRI	1,489	1,254	1,464	2,238
Spot trade as a proportion of scheduled demand (%)	VIC	7.6%	6.6%	10.3%	10.8%
	SYD	9.8%	10.9%	17.0%	20.9%
	ADL	13.0%	18.4%	17.4%	20.3%
	BRI	4.8%	3.9%	4.3%	6.0%

Source: AER analysis using DWGM and STTM data

Spot market liquidity continued an upward trend this quarter. For the first time, the proportion of trade to demand across the whole east coast was greater than 15% (Figure 2.16).[33]

33 While quantities traded were higher, the proportions of total net trades in most markets were lower for Q2 2020, with unusually high demand early in the quarter leading into winter.

Figure 2.16 Spot trade liquidity



Source: AER analysis using DWGM and STTM data

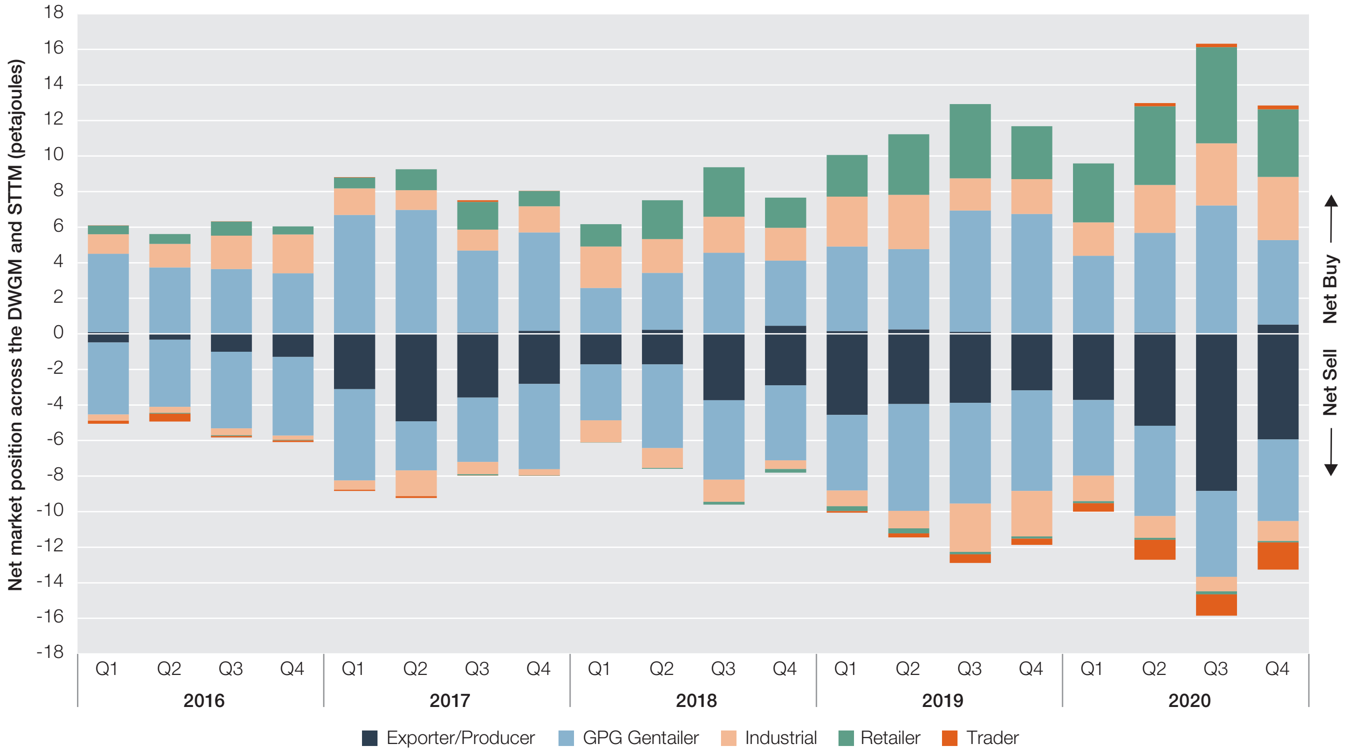
These markets appear to be continuing to transition from balancing markets where retailers and gentailers have traditionally traded small supply-demand imbalances to markets where there are a number of largely seller and buyer only participants on each side of the market.

2.8 Exporter and Producer participants reduced domestic sales significantly

This quarter, Exporter and Producer participants reduced sales as less gas flowed south.[34] At the same time, Trader participants increased sales to 1.5 PJ, despite a fall in net trades overall (Figure 2.17).

34 For our purposes, we classify participants into 5 different groups: Exporters and Producers, Gentailers, Retailers, Industrials or Traders. See Appendix A for a list of these participants and how we group them.

Figure 2.17 Spot trade by participant

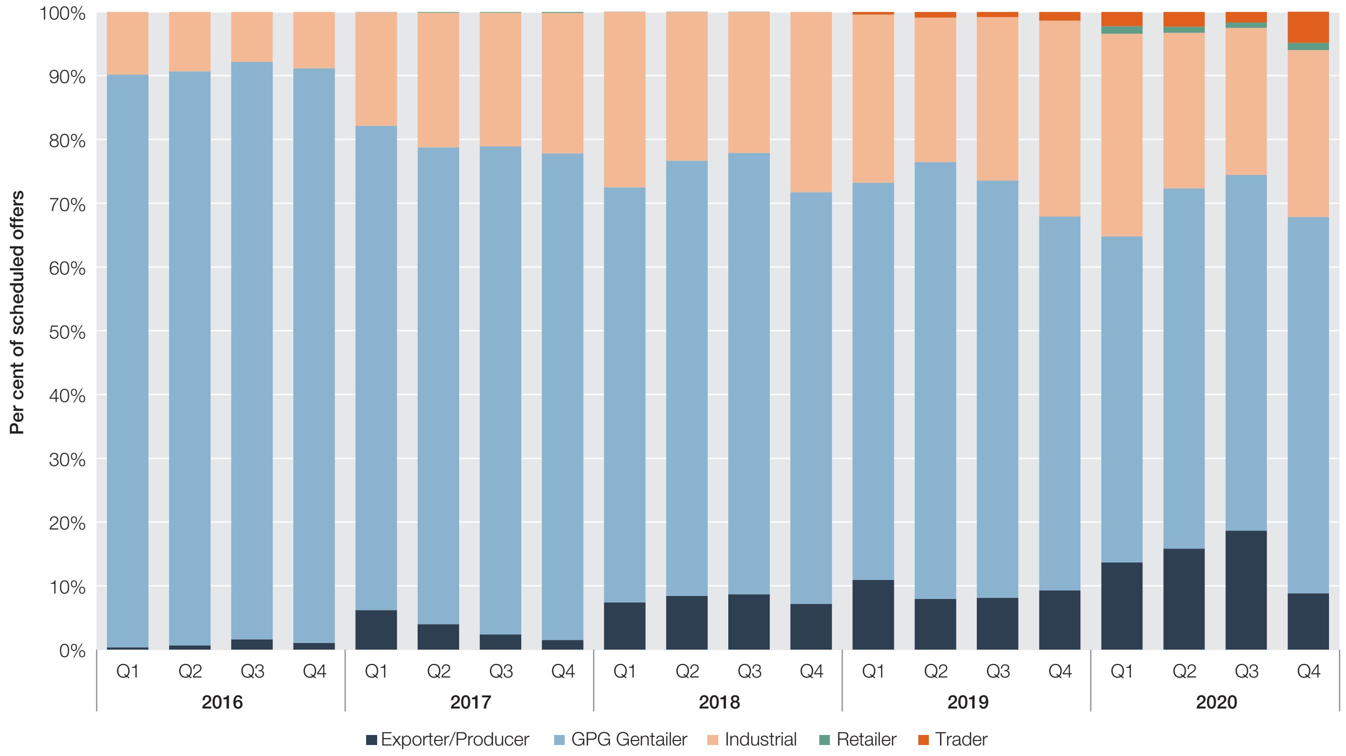


Source: AER analysis using DWGM and STTM data.

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.

In Q4 2020, the share of gas scheduled into the Sydney STTM by Exporters and Producers reduced to 9%. This is the lowest level since Q3 2019 (Figure 2.18). This includes trade by Shell Energy Australia, Santos, Arrow Energy, Esso and BHP. At the same time, Traders increased their share of gas scheduled into the Sydney STTM to record levels. This includes trade by Eastern Energy Supply, Macquarie Bank, PetroChina, and Strategic Gas Market Trading.

Figure 2.18 Scheduled offers by participant group

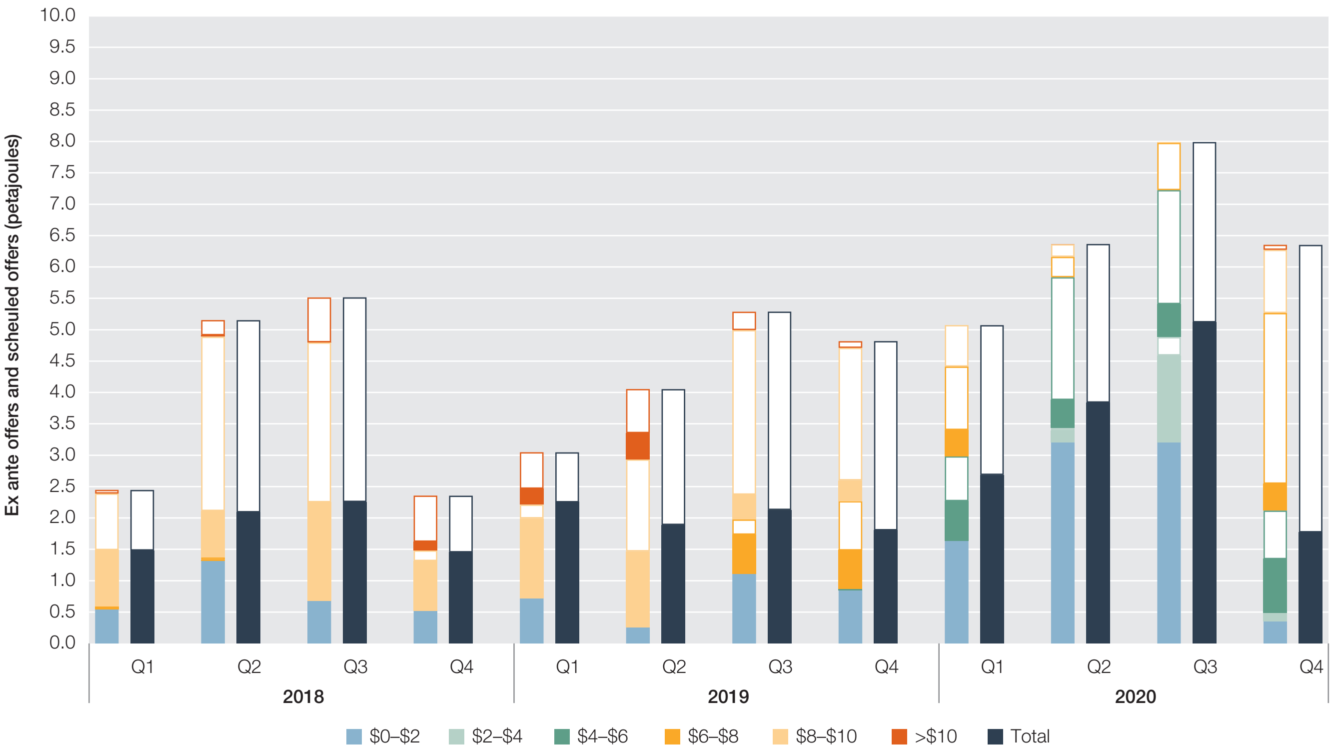


Source: AER analysis using STTM data.

Note: The Sydney STTM offers were calculated for the D-1 schedule.

The amount of gas offered by Exporters and Producers reduced as they moved offers into higher price bands. The amount of gas offered by these participants into the Sydney STTM at below $6/GJ decreased from 7.2 PJ in Q3 2020 to 2.1 PJ this quarter (Figure 2.19). On the other hand, the amount of gas offered by Exporters and Producers at prices greater than $6/GJ increased from 0.8 PJ in Q3 2020 to 4.2 PJ this quarter. Of this, only 0.4 PJ of the offered gas was scheduled at prices between $6 and $8/GJ.

Figure 2.19 Ex ante offer stack and scheduled quantities by price band for Exporter and Producer participants



Source: AER analysis using STTM data.

Note: The Sydney STTM offers were calculated for the D-1 schedule.

By participant, Shell almost tripled the volume of gas it offered from 209 TJ in Q3 2020 to 605 TJ this quarter, but as most of this was in higher price bands only 15.4 TJ got scheduled. For Shell, this was also the first quarter it offered gas at prices higher than $2/GJ in the Sydney STTM. On the other hand, Santos reduced the volume of gas it offered into the Sydney STTM from 4.8 PJ in Q3 2020 to 1.9 PJ this quarter. But of this, 77% was priced greater than $6/GJ. This contrasts with Q3 2020 where the majority of its offers were for prices less than $6/GJ. As with Shell, Santos shifting offers to higher price bands resulted in less gas being scheduled into the market in Q4 2020.

Demand for LNG exports is likely to have influenced the Exporter and Producer offers into the Sydney STTM. This quarter, there were 96 export cargoes, which reflected increasing Asian LNG spot prices. Comparatively, in Q3 2020 there were only 78 cargoes and participants undertook planned maintenance, while Asian LNG prices were lower.

This change in behaviour from Exporters and Producers contributed to average prices increasing from $4.39/GJ in Q3 2020 to $5.69/GJ this quarter. Further price increases were mitigated by the relative small size of Exporters and Producers in the market. To compensate, other participants increased gas offers, replacing much of the change in offers.

2.9 Less gas used for gas powered generation in 2020 with notable falls this quarter

GAS POWERED GENERATION OUTCOMES		2017	2018	2019	2020
Total GPG, PJ	VIC	36	23	34	16
	NSW	24	11	16	8
	SA	69	60	67	51
	QLD	58	46	45	51
	TOTAL	187	140	163	127

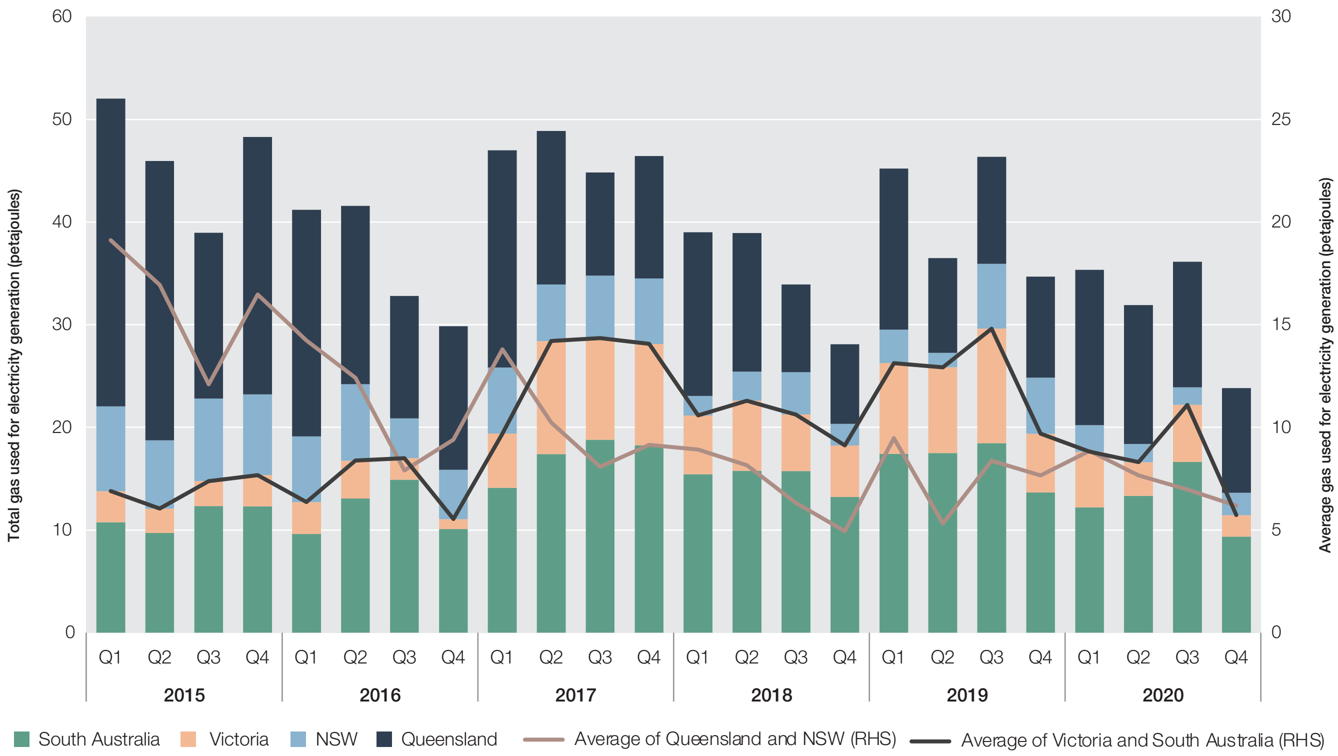
Source: AER analysis using NEM data.

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

Demand for gas used for gas powered generation was down in 2020 by 36 PJ from 2019 levels (Figure 2.20). Across the year, falls occurred over all mainland regions except Queensland. Decreases in Victorian gas powered generation demand were particularly large reducing by over 50%.

Compared to Q4 2019, demand for gas used for gas powered generation in Q4 2020 declined by a total of 10.9 PJ across all regions except Queensland. In Queensland, demand actually increased over the year by 0.4 PJ. The increases in Queensland were driven by greater generation at Swanbank E power station. The decreases in other regions were driven by reduced generation at Tallawarra (NSW), Uranquinty (NSW) and Torrens Island (South Australia) power stations.[35] The reduced generation in South Australia coincided with the closure of two units at the Torrens Island A power station in September 2020 (section 1.3). While there was more capacity offered by gas generators in Victoria, available capacity was priced at higher levels. Electricity generation in Victoria and South Australia was also impacted by lower demand due to milder weather, record levels of rooftop solar generation output and high wind generation (section 1.3).

Figure 2.20 Gas used for gas powered generation



Source: AER analysis using NEM data.

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

35 AEMO, Quarterly Energy Dynamics – Q4 2020, 29 January 2021, p. 17

2.10 ASX gas futures prices rising in 2021

The volume of trade in Victorian gas futures contracts remained subdued in Q4 2020 (Table 2.2). Total volumes were 741 TJ this quarter, reducing dramatically since Q2 2020.

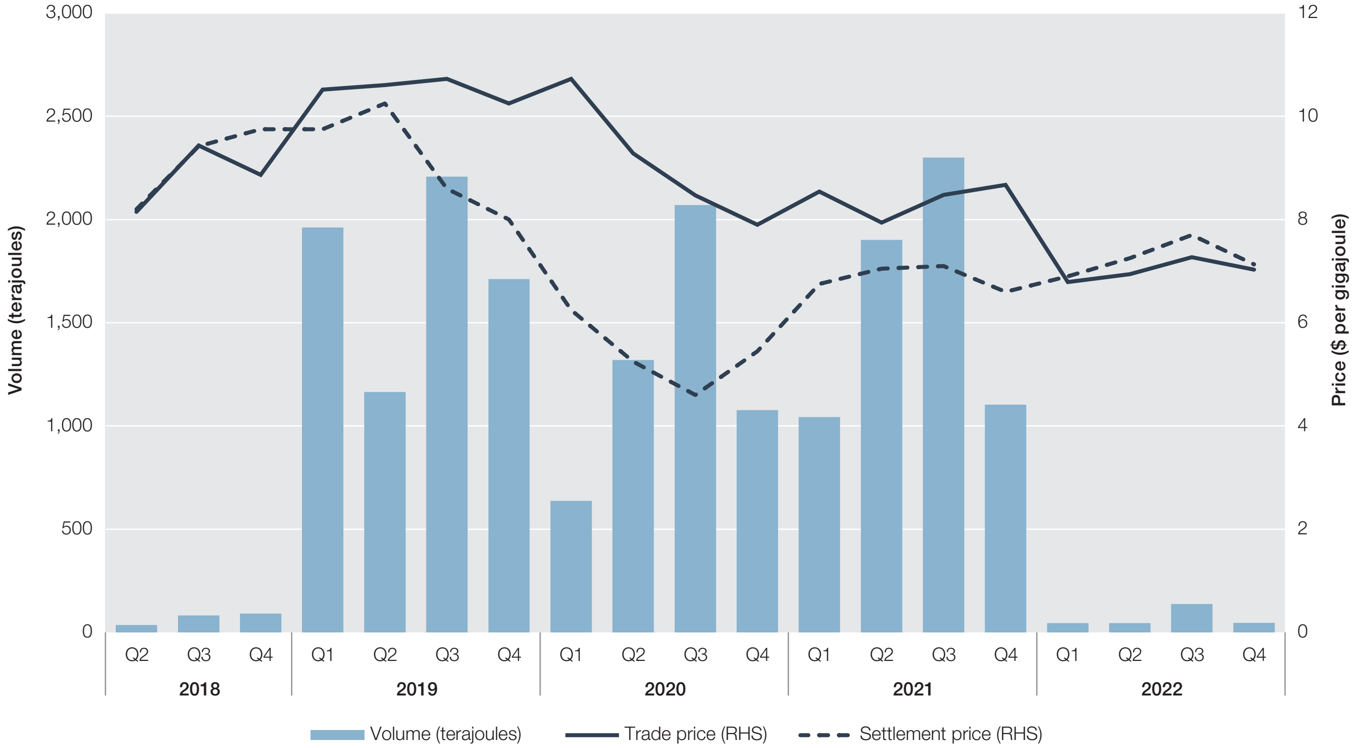
Table 2.2 Victorian gas futures trade summary

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	2,528	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

Source: ASX Energy.
Note: Trade date reflects the date of transaction not contract expiry date.

Settlement prices indicate expected gas prices between \$6.6/GJ and \$7.1/GJ over 2021 (Figure 2.21). The difference between settlement and traded contract prices shows the divergence between actual prices and expectations from prior years. In Q4 2020, futures contract prices settled for \$5.5/GJ, compared to an average traded price of \$7.9/GJ.

Figure 2.21 ASX Victorian futures trade



Source: ASX Energy.

Note: Trade date reflects the date of transactions not contract expiry date.

The term of contracts extends across all quarters, through to Q4 2022, providing a 2 year price signal. However, the quantity of gas traded under contracts still represent less than 5% of physical gas demand in the Victorian market.

Focus – Market Operator Service payments

Recently, we published a report analysing a significant price variation event, which occurred in the Brisbane STTM on 1 October 2020. On this day, 38 TJ less gas was nominated to meet demand in the market, resulting in Market Operator Service (MOS) payments of $916,366.[36] MOS is used to balance daily fluctuations between forecast and actual supply and demand (Box 2.1).

Box 2.1 Market Operator Services

Market Operator Service (MOS) is relevant to the Adelaide, Brisbane and Sydney STTMs. For every gas day, AEMO schedules gas deliveries on pipeline to meet forecast demand. In a simple example, if forecast demand was 120 TJ, AEMO would schedule 120 TJ of pipeline deliveries based on participant ex ante offers to deliver gas.

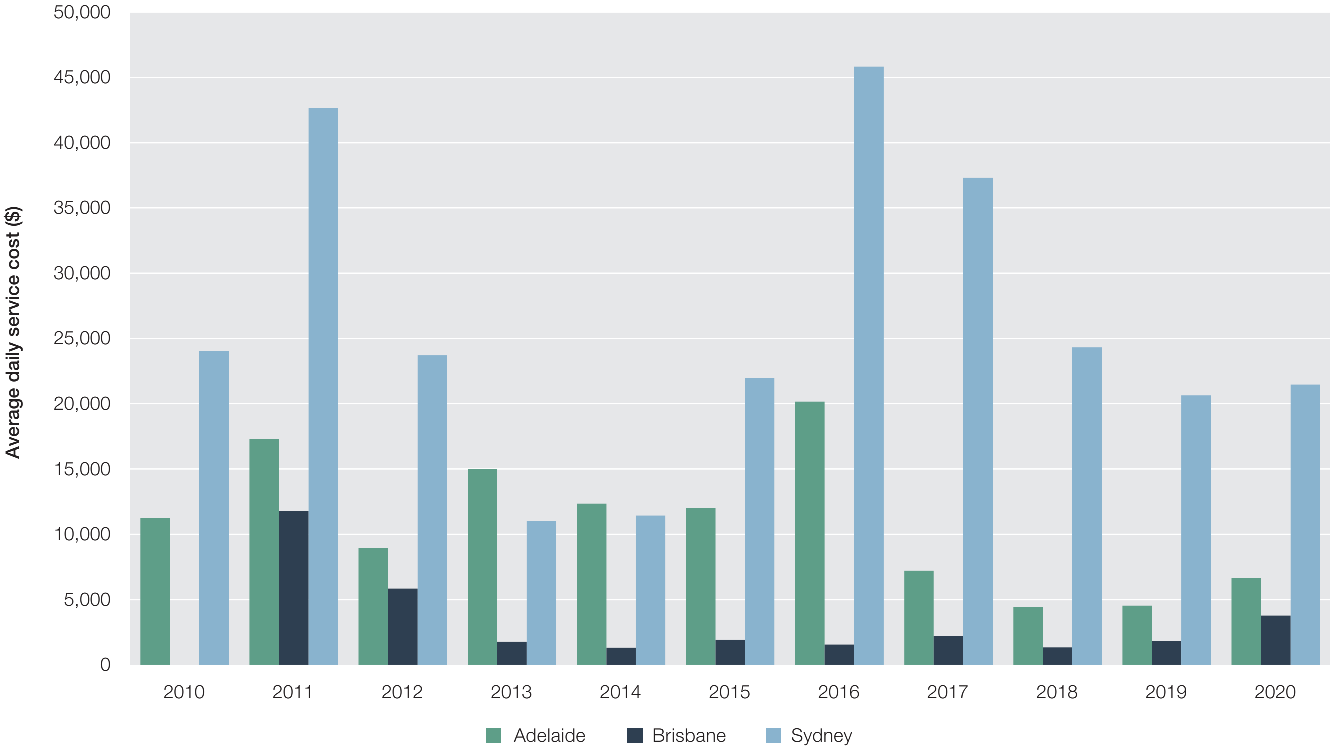
MOS, also known as 'balancing gas' is the difference between what was scheduled on the pipeline and the actual quantities of gas that flowed on a pipeline on the gas day. MOS offers must be based on contracts on pipelines to supply increase MOS (loan gas from the pipeline) or decrease MOS (park gas on the pipeline). Increase MOS and decrease MOS are supplied based on MOS offers which is entirely separate to the STTM's primary offers.

MOS caused by participants failing to nominate scheduled quantities to pipeline operators is not common. However MOS is required daily as hub demand is inevitably under or over forecast to some degree. Large demand forecast inaccuracies can lead to significant MOS requirements.

36 AER, Significant price variation report – MOS service payments, 1 October 2020, p. 5.

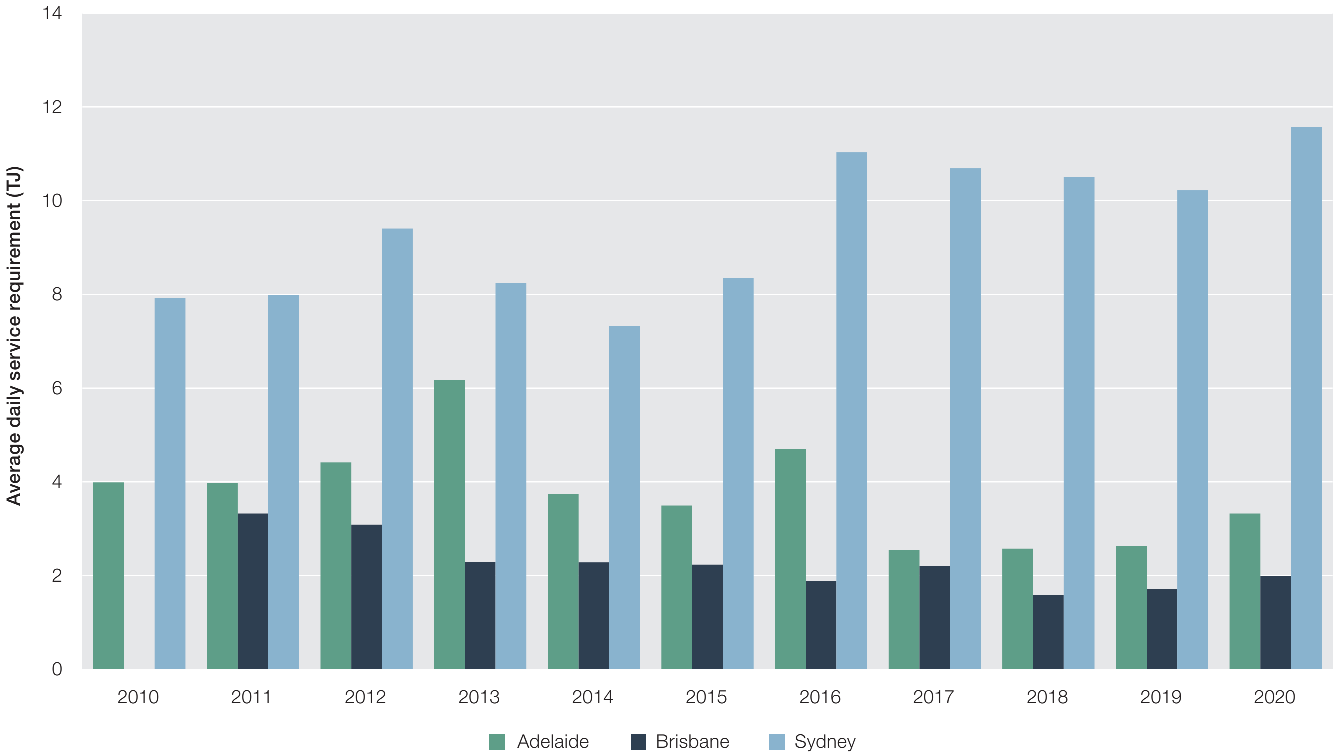
Following this Brisbane event, we have conducted a further review of MOS trends across all STTM hubs to determine patterns in payments the market has had to bear over the years. MOS payments impose additional costs to market participants. MOS typically costs at present levels between 4% and 16% of the value of net gas trades across the 3 STTMs. However, where significant MOS requirements occur more frequently, such as in 2015 and 2016, MOS costs can be more pronounced. For both of those years in Adelaide and Sydney, costs were above 27% of the net ex ante traded value and up to 53% in Sydney for 2016 (Figure 2.22 shows MOS payment trends and Figure 2.23 shows volume trends).

Figure 2.22 Market Operator Service daily service payments



Source: AER analysis using STTM data.

Figure 2.23 Market Operator Service average daily volumes



Source: AER analysis using STTM data.

Whilst there is a financial framework set up to penalise participants' deviations contributing to higher MOS requirements, the AER aims to minimise any unnecessary additional market costs as this may flow onto end consumers, or discourage new entrants.[37] As such, we monitor and report on causes of MOS, such as large demand forecast errors. We also report on instances of counteracting MOS, which imposes a cost for both storage and supply of gas that leads to multiple costs be levied to address a single deviation (Box 2.2).

Box 2.2 Counteracting MOS

When 2 or more pipelines connect to a market, such as in the Adelaide and Sydney STTMs, sometimes increase MOS is provided by one pipeline as similar quantities of decrease MOS are provided by another, connected pipeline. This is known as 'counteracting MOS'.

On days of counteracting MOS, there can be little difference between forecast demand and actual demand, but a significant difference between scheduled receipts and deliveries, and actual receipts and deliveries for each pipeline.

Counteracting MOS leads to participants having to pay to park gas on one pipeline and loan gas from the other pipeline.

Our previous reports include analysis of the causes of MOS in Adelaide and Sydney STTMs, which include:

- In Adelaide – Following the opening of the Elizabeth valve in the Adelaide distribution system in 2014, a constraint on the SEAGas pipeline that hindered supply reaching a section of the system was significantly mitigated. This lead to a noticeable reduction in counteracting MOS volumes being allocated to the SEAGas and Moomba to Adelaide Pipeline (MAP).[38] However, this did not lead to a reduction in MOS payments. In 2016 we published a further report analysing factors that could contribute to counteracting MOS in Adelaide that related to hourly scheduling of gas on SEAGas and volumes on MAP.[39] Following this report, counteracting MOS in Adelaide has reduced (Figure 2.24).

37 MOS costs are largely recouped through deviation charges associated with MOS allocations resulting from differences between ex post allocations and ex ante scheduled quantities, in line with the causer pays mechanism introduced in 2014.

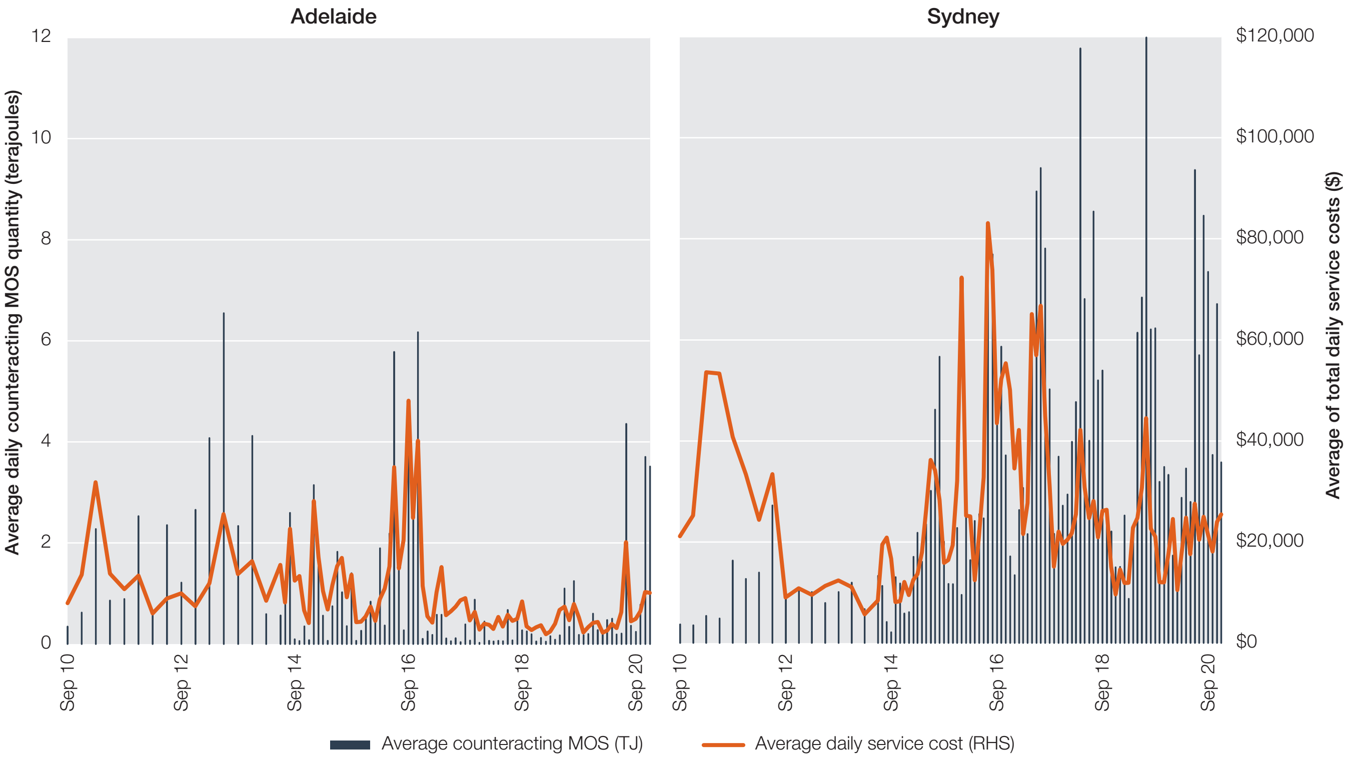
38 AER, Quarterly compliance report April – June 2014, August 2014, pp. 16-17.

39 AER, Significant price variation report 21 November 2016 (ADL STTM), 31 March 2017, pp. 7-8.

- In Sydney – Following high payments for lower MOS from 2016, we engaged with market participants to reduce the size and directional bias of demand forecasting errors.[40] Although overall MOS costs have reduced since then, persistent counteracting MOS volumes in Sydney have occurred between 2016 and 2020 (Figure 2.22). Across 2021 we will conduct enquiries into the underlying causes to ensure participants are not unnecessarily burdened by the costs of these services.

As part of our current work, we are examining how participant nominations into the Wollongong subnetwork of the Sydney STTM are impacting counteracting MOS requirements on the market's two main pipelines. We will also consider reviewing counteracting MOS days in the Adelaide market if recent events persist. We provide updates in future reports.

Figure 2.24 Market Operator Service cost trends



Source: AER analysis using STTM data.

40 AER, Quarterly compliance report July – September 2016, November 2016, pp. 9-10; AER, Quarterly compliance report July – September 2017, pp. 11-12.

Appendix A Gas snapshots

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	●	●	●	●	●	●
	Snowy Hydro	●	●	●	●		
Exporter/Producer	Arrow		●		●	●	●
	APLNG					●	
	BHP Billiton	●	●				
	Cooper Energy	●					
	Esso	●	●				●
	GLNG					●	
	Lochard Energy	●					
	Santos	●	●	●	●	●	●
	Senex					●	
	Shell		●				●
	Walloons (QGC)					●	●
	Westside Corporation					●	●
Retailer	1st Energy	●					
	Click Energy	●	●				
	Covau	●	●		●		
	CPE Mascot		●				
	Delta Electricity		●				
	Discover Energy		●	●	●		
	Dodo	●	●				
	GloBird Energy	●	●	●	●		
	Powershop	●					
	Simply Energy		●	●			
	Sumo Gas	●					
	Weston Energy	●	●	●	●		

Industrial	Adelaide Brighton Cement			Entered before 2017			
	Ampol				Entered before 2017		
	BlueScope		Entered before 2017		Entered in 2018		
	Boortmalt	Entered in 2019	Entered in 2018	Entered in 2018			
	Brickworks	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020		
	Commonwealth Steel		Entered in 2017				
	Coopers			Entered in 2017			
	CSR Building Products	Entered in 2018		Entered in 2019	Entered in 2018		
	Incitec Pivot				Entered before 2017	Entered before 2017	Entered in 2019
	Infrabuild	Entered before 2017	Entered before 2017	Entered before 2017			
	Master Butchers			Entered in 2020			
	Michell Wool			Entered in 2019			
	Mobil Oil	Entered in 2018					
	Norske Skog	Entered in 2018					
	Oceania Glass	Entered in 2020					
	O-I International	Entered in 2018	Entered in 2018	Entered in 2018	Entered in 2019		
	Orica		Entered in 2017				
	Orora		Entered in 2020				
	Paper Australia	Entered in 2018	Entered in 2020				
	Qenos	Entered in 2017	Entered before 2017			Entered in 2017, Exit or inactive	Entered in 2019
	SA Water			Entered before 2017			
	Tarac Technologies		Entered in 2017	Entered before 2017			Entered in 2019
	Visy	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017		
	Viva Energy	Entered in 2018					
Trader	Eastern Energy Supply	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020
	Macquarie Bank	Entered in 2019	Entered in 2019			Entered in 2018	Entered in 2019
	Petro China	Entered in 2020	Entered in 2020			Entered in 2019	Entered in 2020
	Strategic Gas Market Trading	Entered in 2019	Entered in 2019		Entered in 2020	Entered before 2017	Entered in 2019
	61	37	37	24	21	18	19

● Entered before 2017 ● Entered in 2017 ● Entered in 2018 ● Entered in 2019 ● Entered in 2020 ● 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.

* Arrow also operates the Braemar 2 power station

DAY AHEAD AUCTION SNAPSHOT

	2019				2020				
	MAR	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Auction to date
number of active participants	1	4	6	6	11	12	14	15	17*
number of facilities	4	6	6	7	7	9	8	11	12
auction legs won	139	665	1,276	815	1,175	1,272	1,712	1,696	8,750
capacity won, TJ	2,513	6,577	14,891	6,563	10,482	7,976	13,709	10,782	73,492
maximum auction price, $/GJ	0.10	0.70	1.05	0.30	0.30	1.26	1.49	0.93	1.49
% won at $0/GJ	82%	88%	71%	87%	82%	78%	69%	89%	79%
% won at ≥$0.10/GJ	0.4%	8%	20%	5%	4%	14%	23%	5%	12%

GAS SUPPLY HUBS SNAPSHOT	2014	2015	2016	2017	2018	2019	2020
number of trades	481	875	798	1,638	1,919	3,635	2,655
trade volume, PJ *% of trade by top 3 buyers : sellers*	2.4 *67% : 89%*	6.4 *71% : 75%*	7.9 *66% : 56%*	11.6 *51% : 59%*	16.4 *53% : 52%*	27.4 *51% : 64%*	21.1 *40% : 53%*
trade value, $million	5	24	57	89	148	219	98
volume weighted average price, $/GJ	2.01	3.66	7.20	7.68	9.02	7.98	4.68
number of trading participants *number of active participants on-screen vs. off-screen*	8 *7:0*	12 *11:7*	12 *11:11*	13 *12:9*	13 *12:12*	16 *13:16*	19 *15:15*
% traded through exchange (sum bought divided by regional demand)	N/A	N/A	N/A	4.3%	6.1%	9.1%	6.8%