Electricity Report

15 – 21 November 2020

Weekly Summary

Weekly volume weighted average (VWA) prices were between $40/MWh in South Australia and $110/MWh in New South Wales. Higher prices in New South Wales were driven by high price events on 16 and 20 November. These will be analysed in our upcoming reports on energy prices above $5000/MWh. The high price in Queensland on 17 November was due to high FCAS prices which we will analyse in an upcoming report on FCAS prices above $5000/MW.

Despite the high prices, quarter to date VWA prices remain at least $27/MWh lower than the same time each year across all regions.

Purpose

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 15 to 21 November 2020.

Figure 1: Spot price by region ($/MWh)

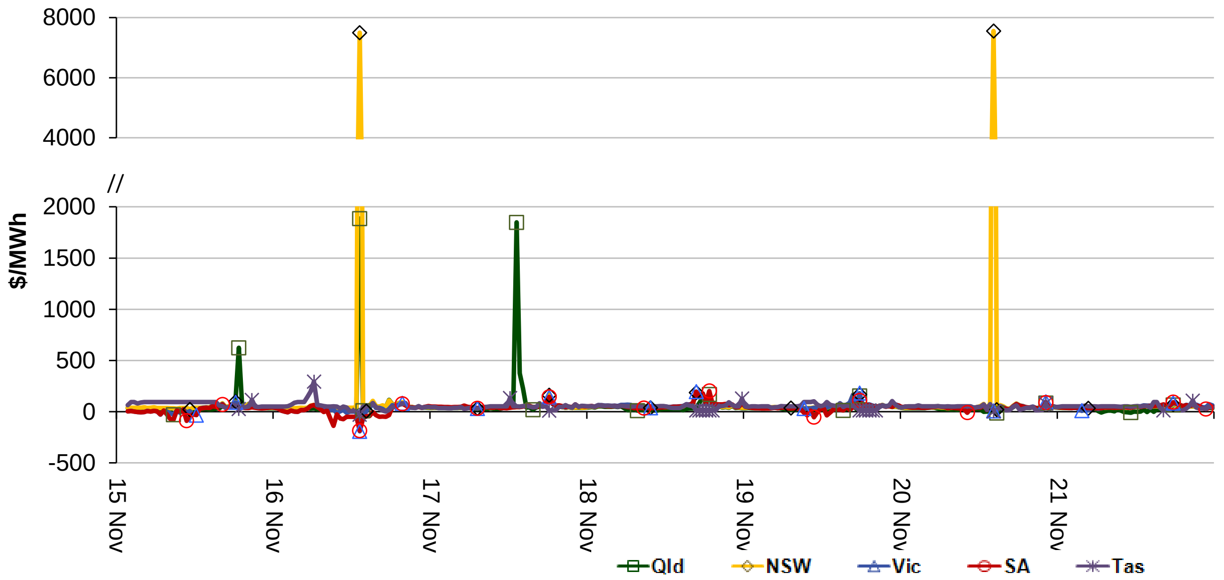


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

Figure 2: Volume weighted average spot price by region ($/MWh)

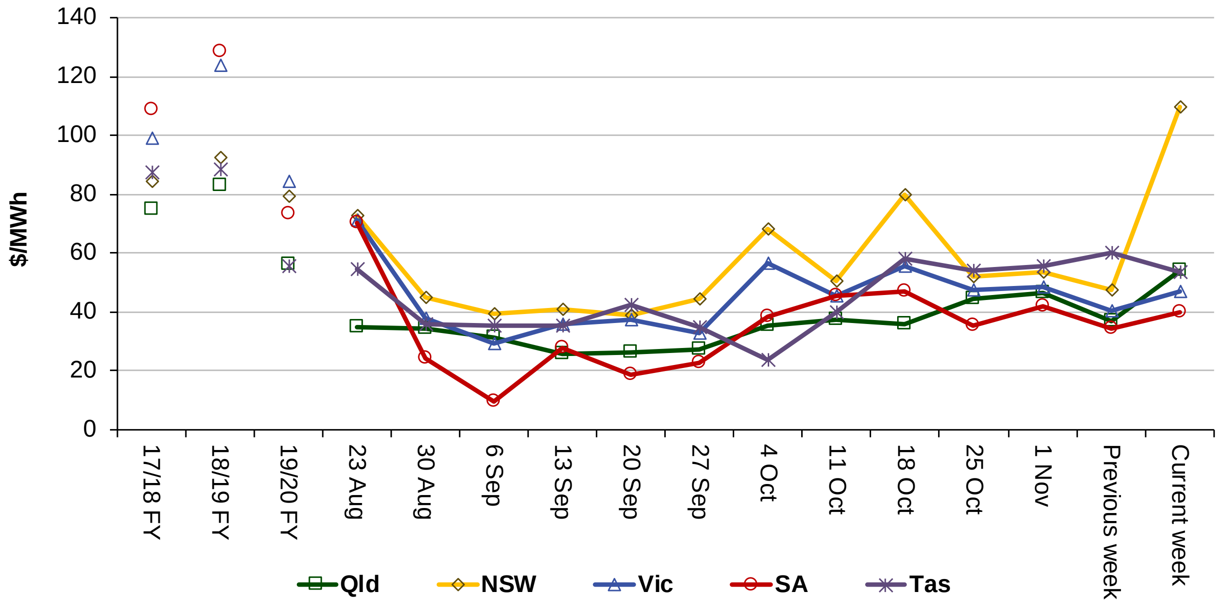


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	54	110	47	40	54
Q4 2019 QTD	71	92	92	67	93
Q4 2020 QTD	41	65	46	38	47
19-20 financial YTD	68	88	99	77	77
20-21 financial YTD	37	54	52	44	50

Longer-term statistics tracking average spot market prices are available on the AER website.

Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 257 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2019 of 204 counts and the average in 2018 of 199. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

Table 2: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	5	31	1	1
% of total below forecast	19	34	0	9

Note: Due to rounding, the total may not be 100%.

Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

Figure 3: Queensland generation and bidding patterns

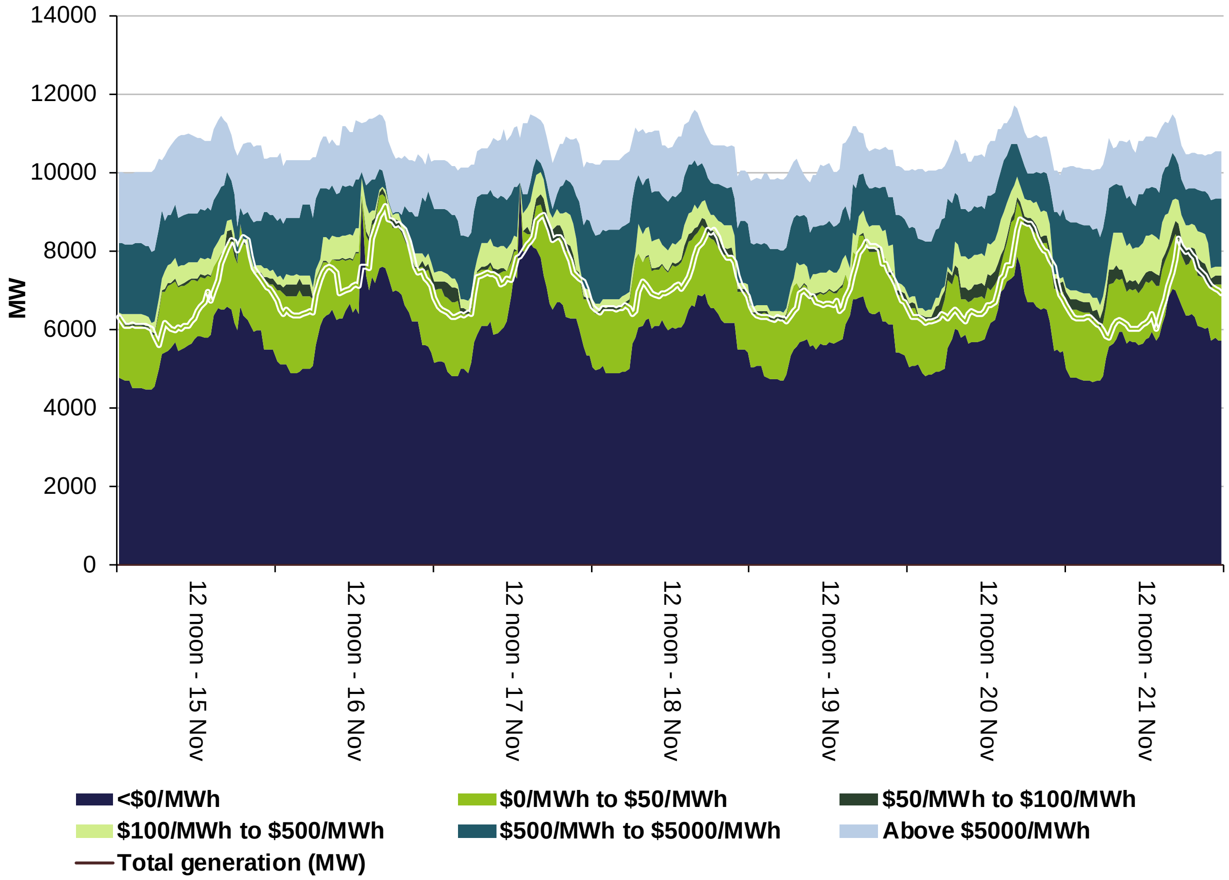


Figure 4: New South Wales generation and bidding patterns

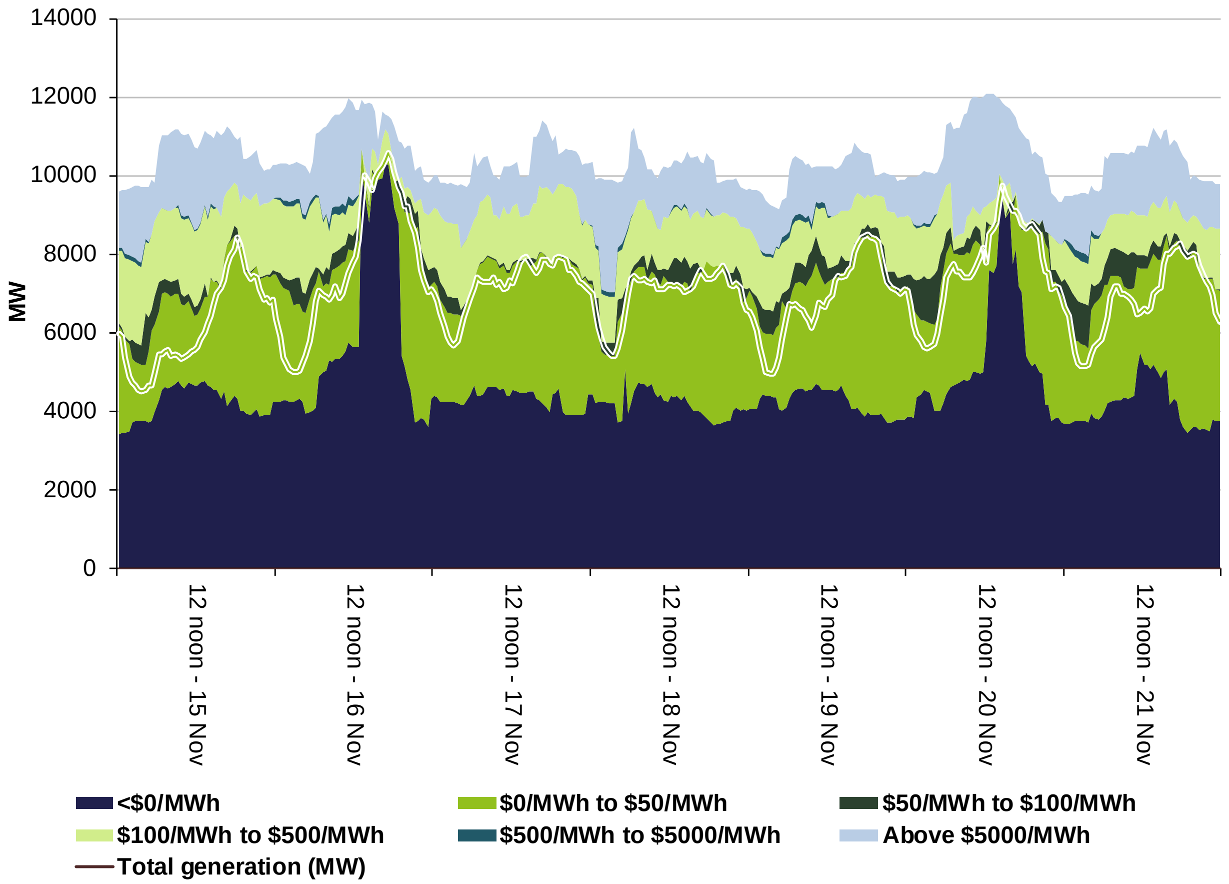


Figure 5: Victoria generation and bidding patterns

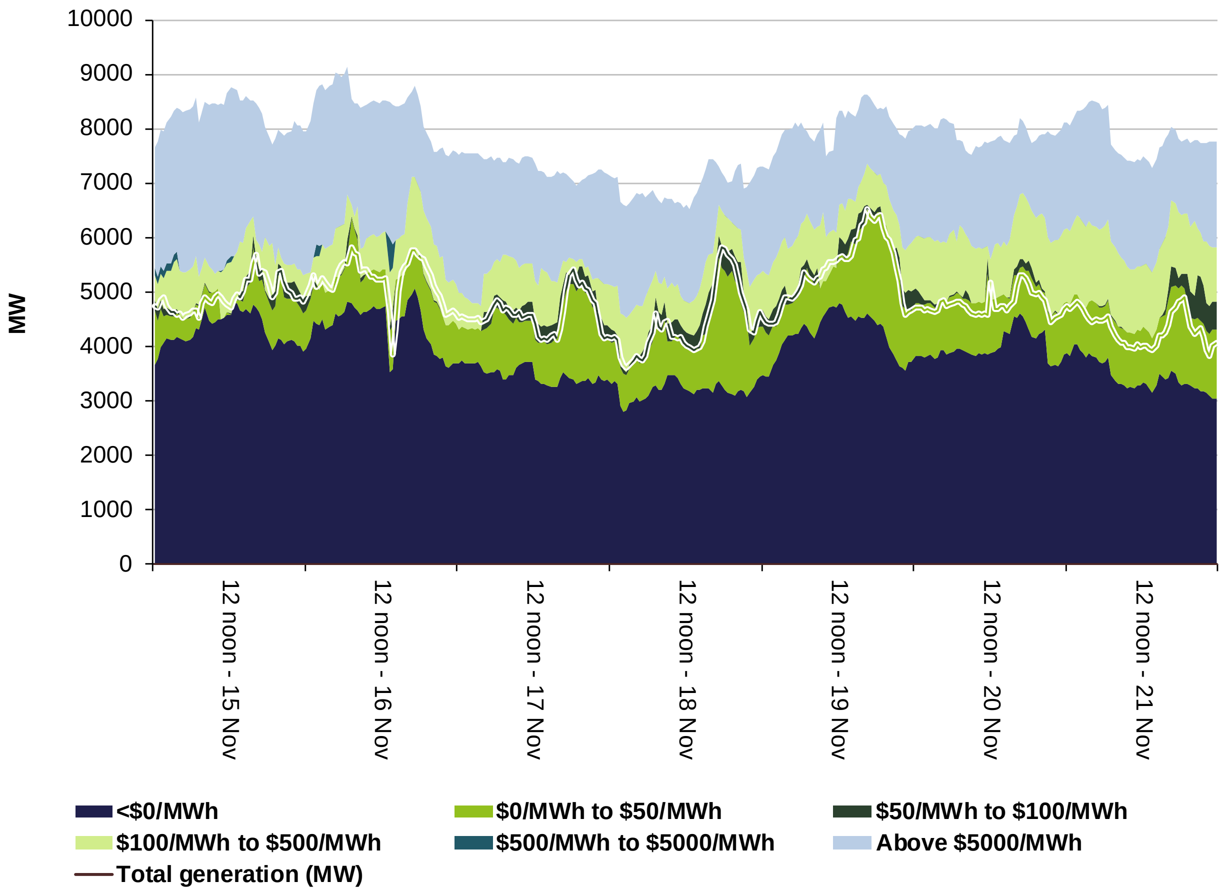


Figure 6: South Australia generation and bidding patterns

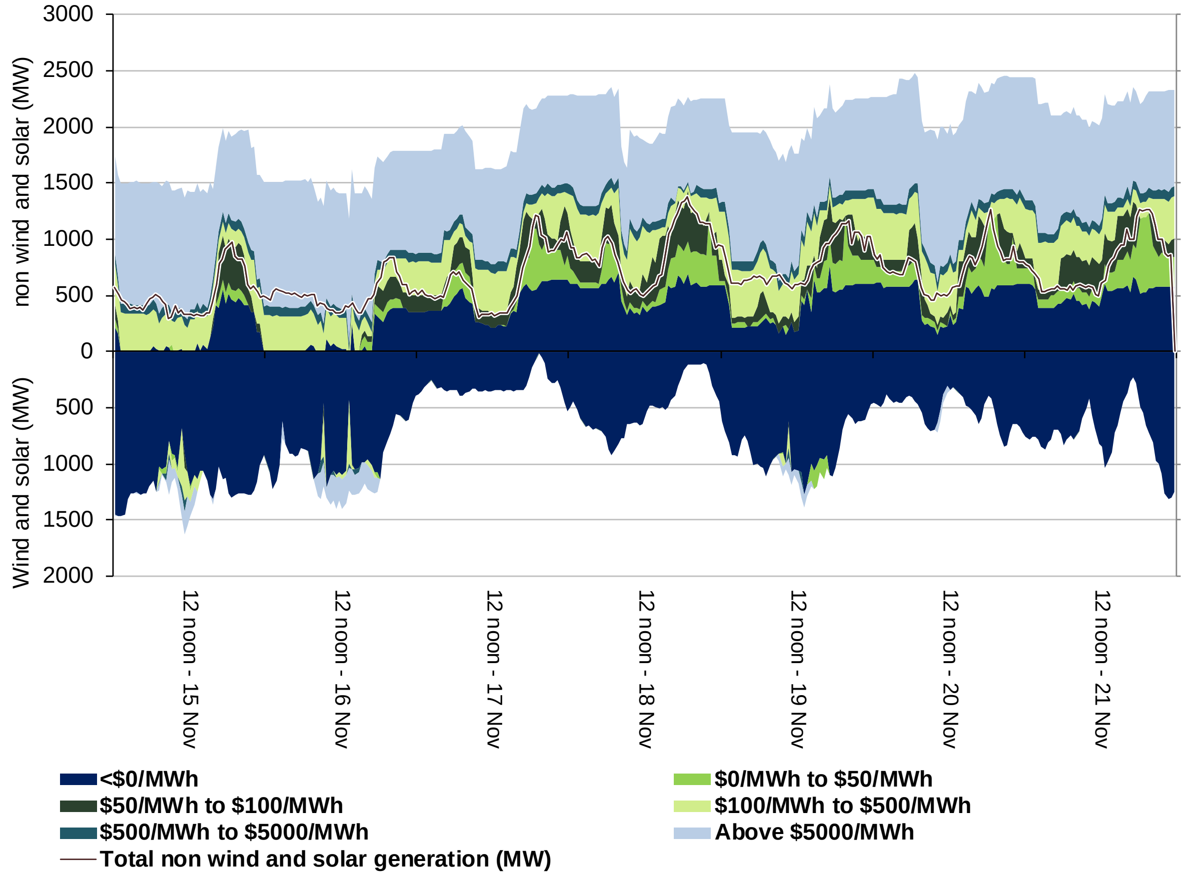
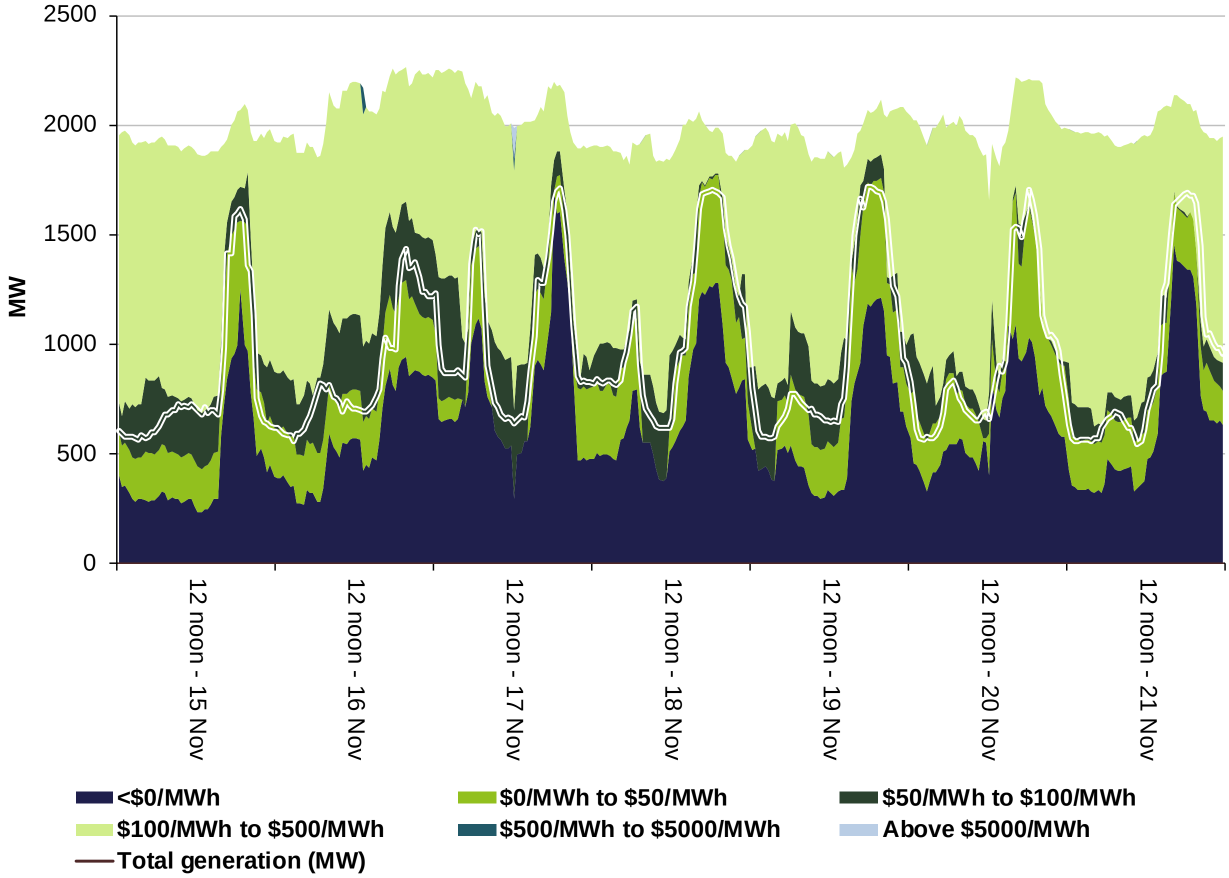


Figure 7: Tasmania generation and bidding patterns



Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

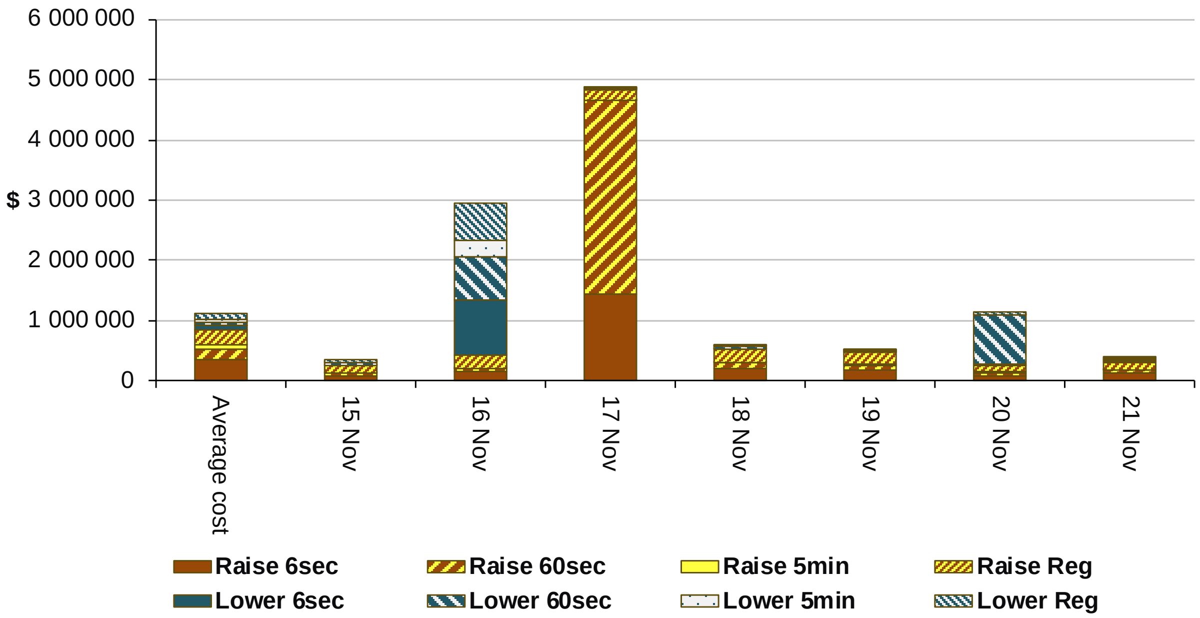
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $10,305,500 or around 4% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $525,000 or less than 6% of energy turnover in Tasmania.

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

Figure 8: Daily frequency control ancillary service cost



High FCAS costs throughout the week were driven by local prices in Queensland. On 16 November, the price for lower services was high in the afternoon coinciding with energy prices exceeding $5,000/MWh in NSW. On 17 November, raise 60 second prices exceeded $5,000/MW from 1.10 pm to 2.15 pm except for the 1.20 pm dispatch interval. This will be analysed as part of our upcoming report into FCAS prices above $5,000/MW.

Detailed market analysis of significant price events

Queensland

There were four occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $54/MWh and above $250/MWh.

Sunday, 15 November

Table 3: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 pm	623.88	294.83	156.50	8063	7955	7811	10 593	10 678	11 046

Demand and availability were both close to forecast, four hours prior.

In the four hours leading up to the trading interval, InterGen withdrew 60 MW of capacity at Millmerran priced at the floor due to temperature and plant issues. CS Energy also shifted 630 MW of capacity at Gladstone from prices below $1450/MWh to the cap due to forecast prices.

At the start of the trading interval InterGen withdrew a further 70 MW of capacity at Millmerran which was also priced at the floor due to a change in forecast prices. Imports across both interconnectors were at their limits, so further lower priced generation from other regions could not be sourced. At 6.35 am, demand increased by 101 MW and with lower priced generation was either ramp constrained or trapped in FCAS the dispatch price was set at $3500/MWh. In response to the high prices, participants then rebid over 750 MW of capacity from prices above $591/MWh to prices below $50/MWh. As a result the dispatch price was between $37/MWh and $79/MWh for the remainder of the trading interval.

Monday, 16 November

Table 4: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
1.30 pm	1885.87	35.85	32.34	6884	6979	6843	11 347	11 237	11 216

Demand and availability were both close to forecast, four hours prior.

At 1.10 pm an unplanned outage of the Upper Tumut – Stockdill 330 kV line in New South Wales led to all interconnectors to New South Wales operating above their limits. Forced exports into New South Wales increased by 415 MW from Queensland and local generation in Queensland increased by 502 MW. This lead to a dispatch price of $14,348/MWh. In response, participants in Queensland rebid over 3000 MW of capacity to the floor during the rest of the trading interval and the dispatch price was set at the floor for the last three dispatch intervals.

The New South Wales spot price exceeded $5000/MWh for this trading interval, triggering our reporting threshold. The AER will publish a report of our findings in the coming weeks.

Tuesday, 17 November

Table 5: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
1.30 pm	1848.38	41.91	37.53	7593	7276	7115	11 206	10 993	11 083
2 pm	376.66	125.55	39.75	7825	7438	7267	11 301	10 961	11 125

Across the two trading intervals demand and availability were between 213 MW and 387 MW greater than forecast, both four hours prior.

The 1.30 pm trading interval had one dispatch interval priced at the cap. For the 1.10 pm dispatch interval, a system normal constraint, which avoids the Raglan to Larcom Creek line from overloading, constrained off generation at Haughton Solar Farm. This generation was priced at the price floor and higher priced capacity had to be dispatched in its place. With all other local generation unable to set price because units were either constrained, at maximum availability or inflexible, the price was co-optimised between the FCAS and energy markets at $15,000/MWh. Following this interval, participants rebid over 1500 MW of capacity to the floor, leading to the dispatch price settling at the floor.

For the 2 pm trading interval, demand increased by 172 MW at 1.40 pm. Both interconnectors were operating beyond their limits so unable to transfer further generation from neighbouring regions. In order to meet demand, the dispatch price was set at $1799/MWh because lower priced generation was either dispatched in FCAS, constrained or at maximum availability.

New South Wales

There were two occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $110/MWh and above $250/MWh.

Monday, 16 November

Table 6: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
1.30 pm	7495.63	39.00	39.11	9689	9394	9290	11 847	12 201	11 663

An unplanned outage of the Upper Tumut – Stockdill 330 kV line in New South Wales led to this spot price above $5000/MWh. The drivers of this price will be discussed in the AER's forthcoming report into energy prices above $5000/MWh.

Friday, 20 November

Table 7: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
2.30 pm	7550	68.01	69.87	9934	9204	9152	11 928	11 748	11 694

Network constraints and rebidding led to this spot price above $5000/MWh. The drivers of this price will be discussed in the AER's forthcoming report into energy prices above $5000/MWh.

Victoria

There was one occasion where the spot price in Victoria was below -$100/MWh.

Monday, 16 November

Table 8: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
1.30 pm	-191.13	-49.70	-260.45	3961	3396	3557	8491	8244	8216

Prices were aligned across Victoria and South Australia and will be treated as one region.

Demand was collectively 842 MW higher than forecast and availability was collectively 181 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation across both regions, most of which was priced below $0/MWh.

At around 12.50 pm there was an unplanned outage of transmission lines in the Snowy area. At 1.10 pm a number of constraints relating to the line outage violated and this forced a change in flows by over 1100 MW out of NSW and into Victoria across the VIC-NSW interconnector. With many units ramp constrained price was below $-900/MWh for five minutes.

South Australia

There were two occasions where the spot price in South Australia was below -$100/MWh.

Monday, 16 November

Table 9: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
9.30 am	-136.87	-89.50	-575.11	844	651	671	2585	2529	2643
1.30 pm	-184.20	-1000	-1000	576	299	304	2638	2704	2752

For the 9.30 am trading interval, demand was 193 MW greater than forecast and availability was close to forecast, four hours prior.

Effective 9.05 am, Lincoln Gap Wind Farm rebid 212 MW of capacity from prices above -$89/MWh to the price floor. This resulted in price being set at the floor for the first dispatch interval. In response to the price, participants rebid around 1200 MW of capacity from the floor to prices above $71/MWh and price was set over $30/MWh for the remainder of the trading interval.

For the 1.30 pm trading interval, prices were aligned with Victoria and are discussed in the Victoria section.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $54/MWh and above $250/MWh.

Monday, 16 November

Table 10: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6.30 am	293.85	95.32	51.67	1207	1138	1084	1856	2037	2148

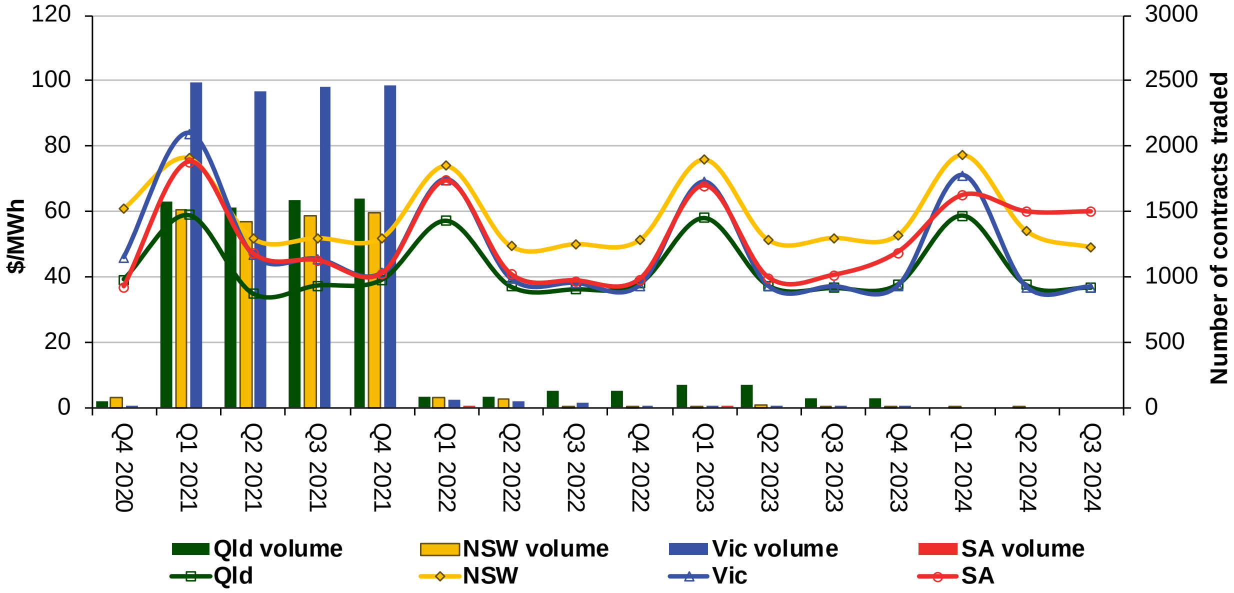
Demand was 69 MW higher than forecast and availability was 181 MW lower than forecast, four hours prior. Lower than forecast availability was mainly due to lower than forecast wind generation, most of which was priced below $0/MWh.

At 5.48 am, Hydro Tasmania rebid 57 MW of capacity at Poatina from $95/MWh to $399/MWh in response to a forecast generation target. There was no capacity offered between $95/MWh and $399/MWh. With a number of generators trapped/stranded in FCAS or ramp constrained and unable to set price, price was set at $399/MWh for the first four dispatch intervals. In response to the prices, effective from 6.20 am Hydro Tasmania rebid the 57 MW of capacity at Poatina back from $399/MWh to $95/MWh. Along with other generators no longer being trapped/stranded in FCAS or ramp constrained, this resulted in price being set below $95/MWh for the remainder of the trading interval.

Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years. The high volume of trades is a result of the conversion of base load options to base future contracts on 19 November 2020.

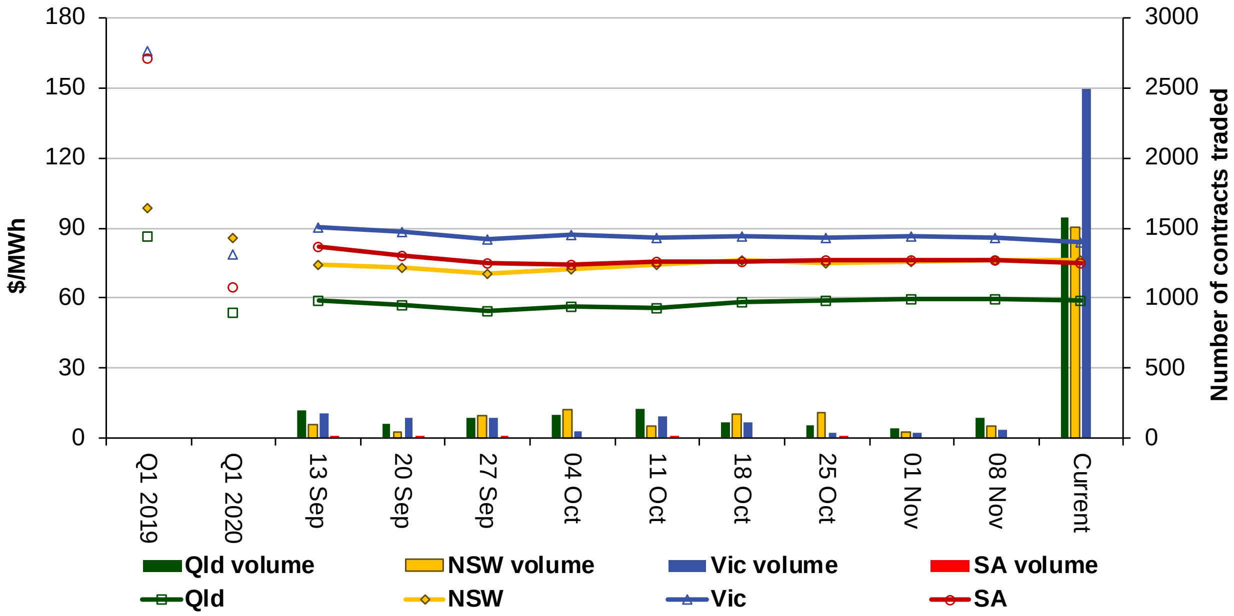
Figure 9: Quarterly base future prices Q4 2020 – Q3 2024



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2021 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q1 2020 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

Figure 10: Price of Q1 2021 base contracts over the past 10 weeks (and the past 2 years)

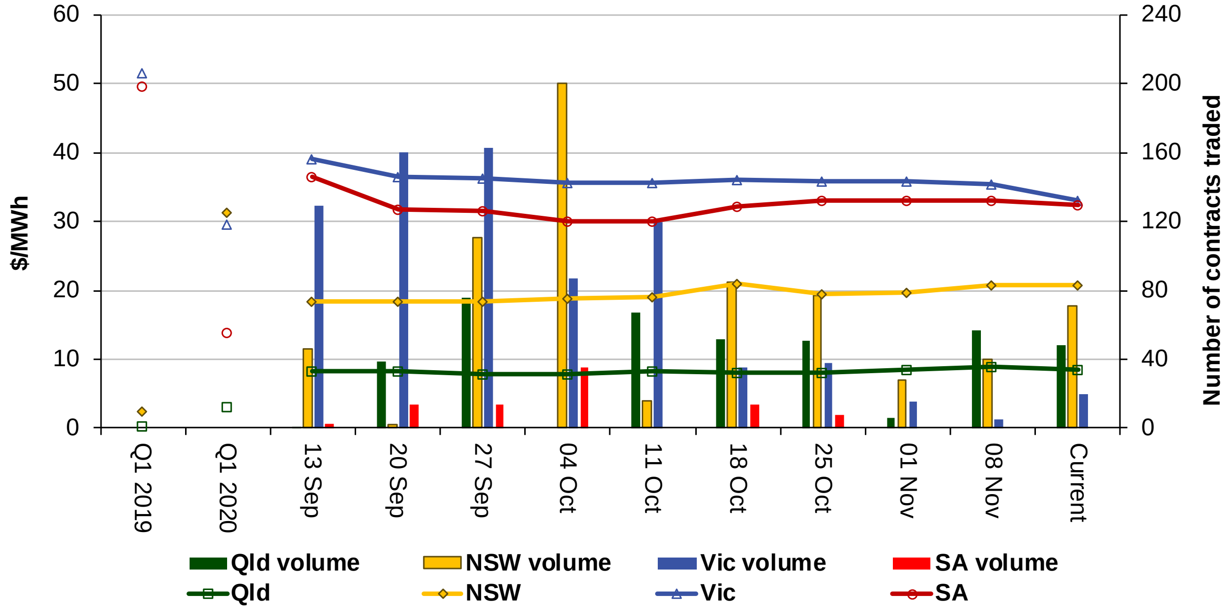


Source: ASXEnergy.com.au

Notes: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Figure 11 shows how the price for each regional Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q1 2020 prices are also shown.

Figure 11: Price of Q1 2021 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Industry Statistics](#) section of our website.

Australian Energy Regulator
December 2020