Electricity Report

AUSTRALIAN ENERGY REGULATOR

6 – 12 December 2020

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $3/MWh in South Australia up to $44/MWh in Queensland. This week marked a record lowest weekly VWA price in South Australia of $3/MWh and the second lowest of $14/MWh in Victoria. Mild temperatures and high wind generation drove negative prices, more than 40% of the week in South Australia and more than 25% in Victoria.

Q4 quarter to date VWA prices ranged from $36/MWh in South Australia to $62/MWh in New South Wales, at least $20/MWh below levels seen at the same time last year.

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 6 to 12 December 2020.

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

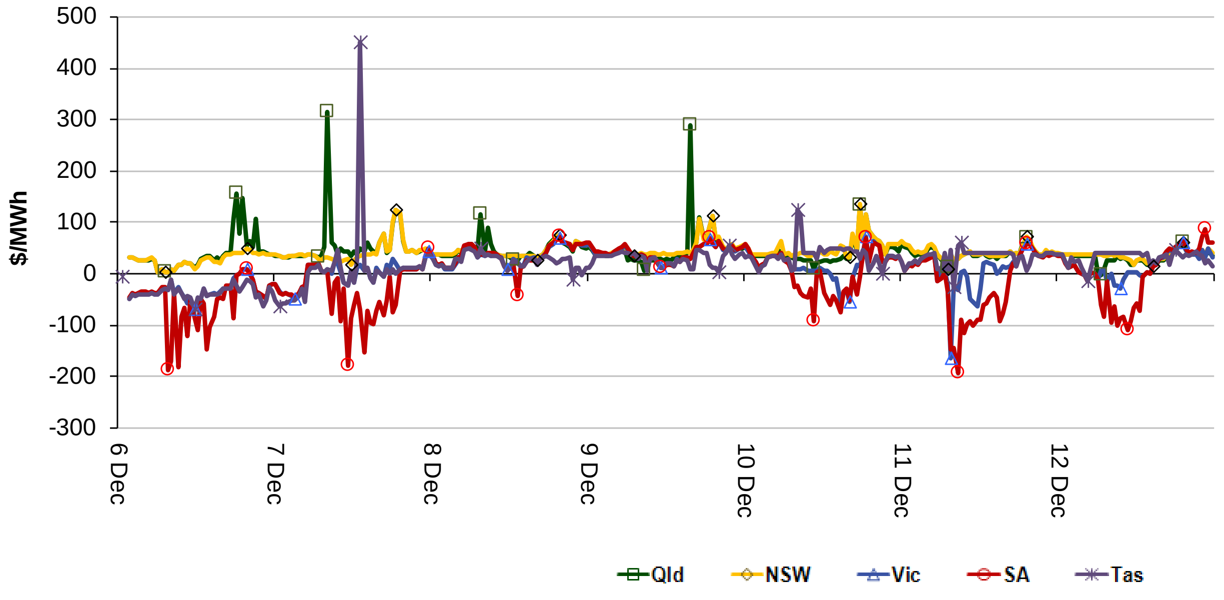


Figure 2 shows the VWA prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

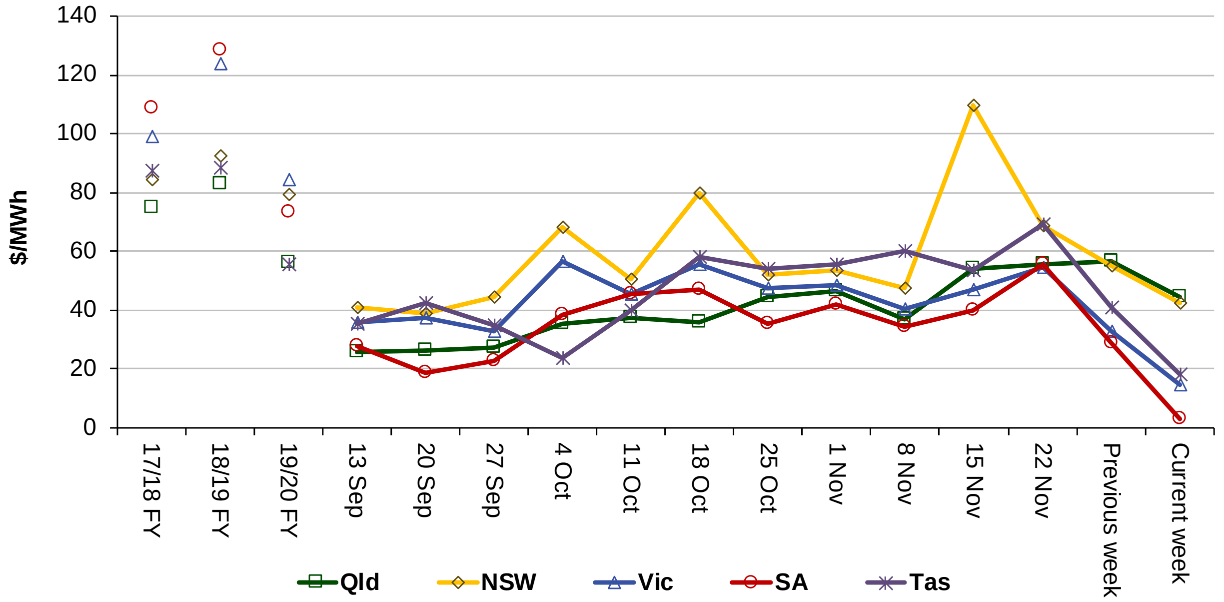


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	44	43	14	3	18
Q4 2019 QTD	68	82	80	61	80
Q4 2020 QTD	44	62	43	36	46
19-20 financial YTD	67	84	93	74	74
20-21 financial YTD	39	54	50	42	49

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 280 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	31	42	0	2
% of total below forecast	3	17	0	5

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

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

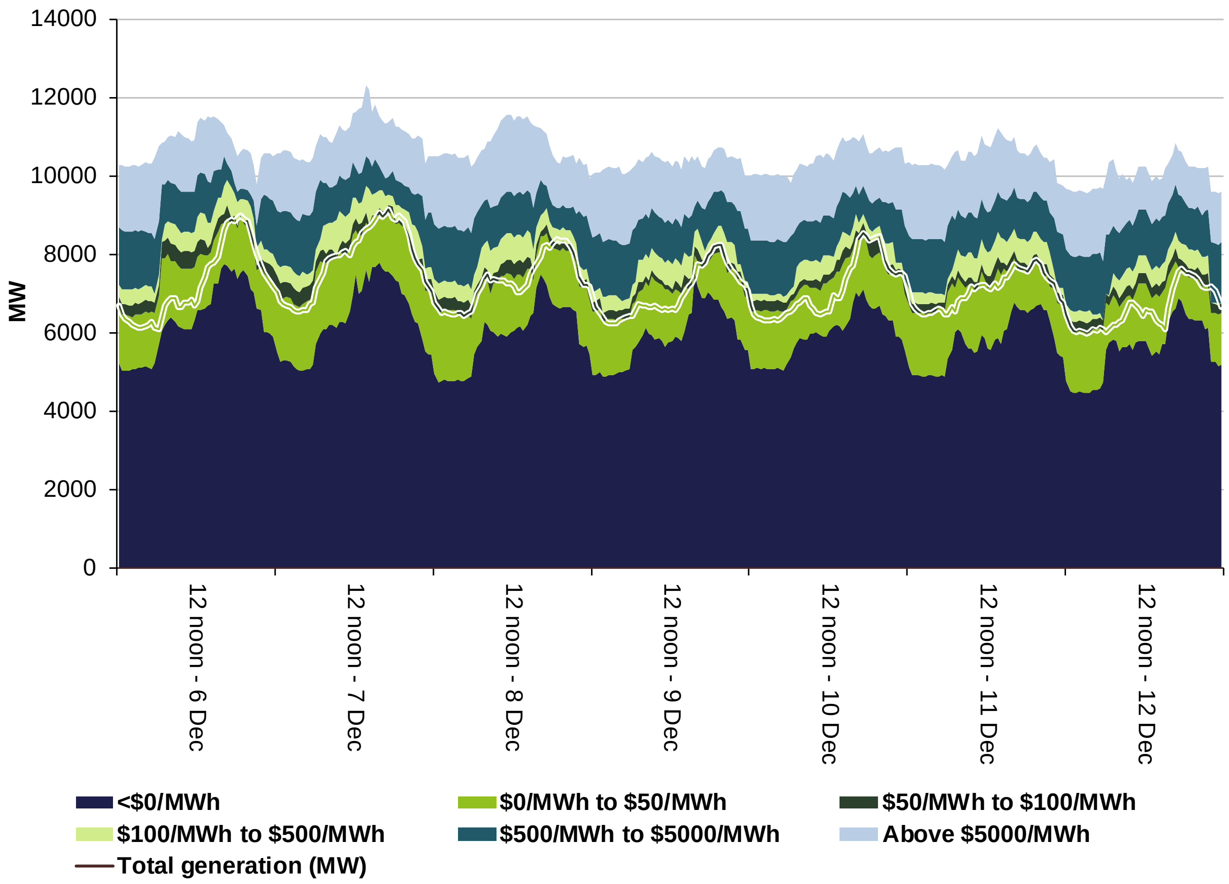


Figure 4: New South Wales generation and bidding patterns

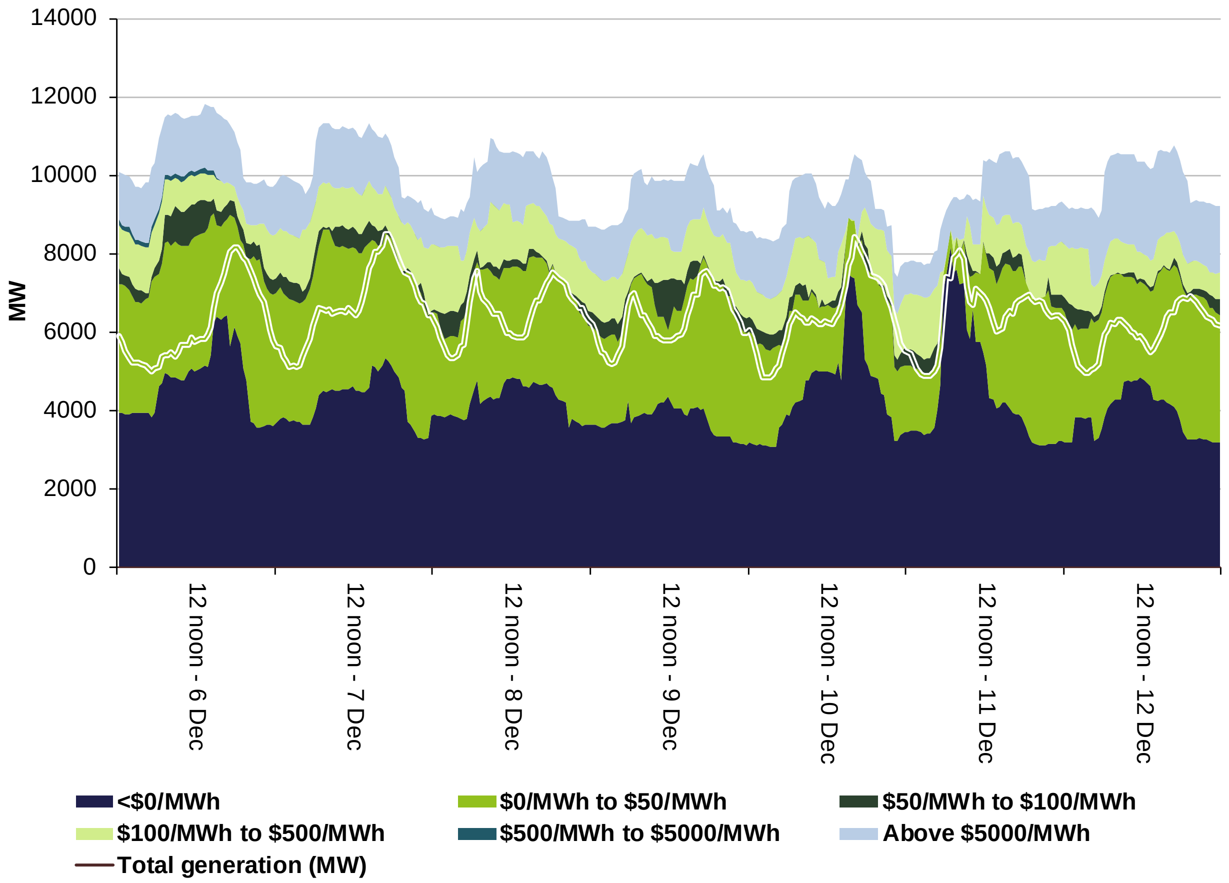


Figure 5: Victoria generation and bidding patterns

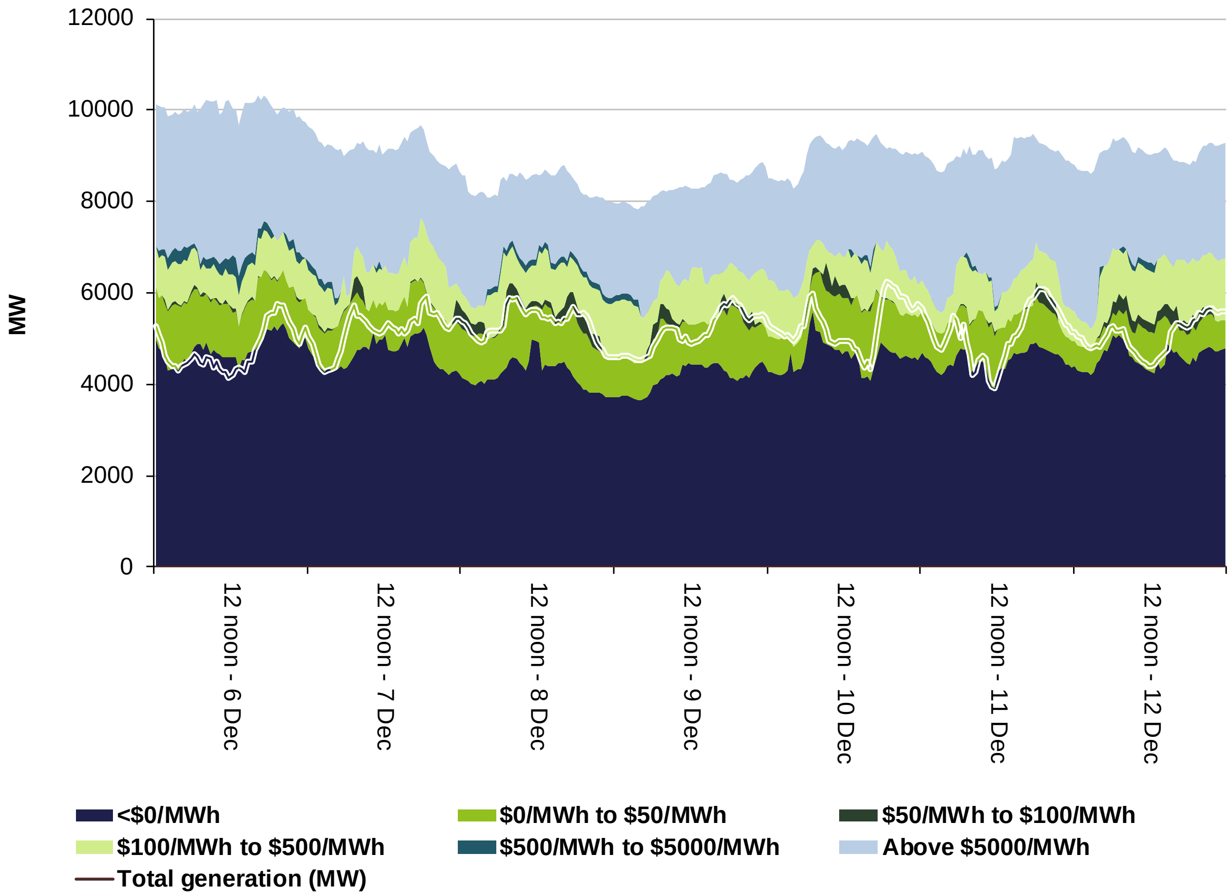


Figure 6: South Australia generation and bidding patterns

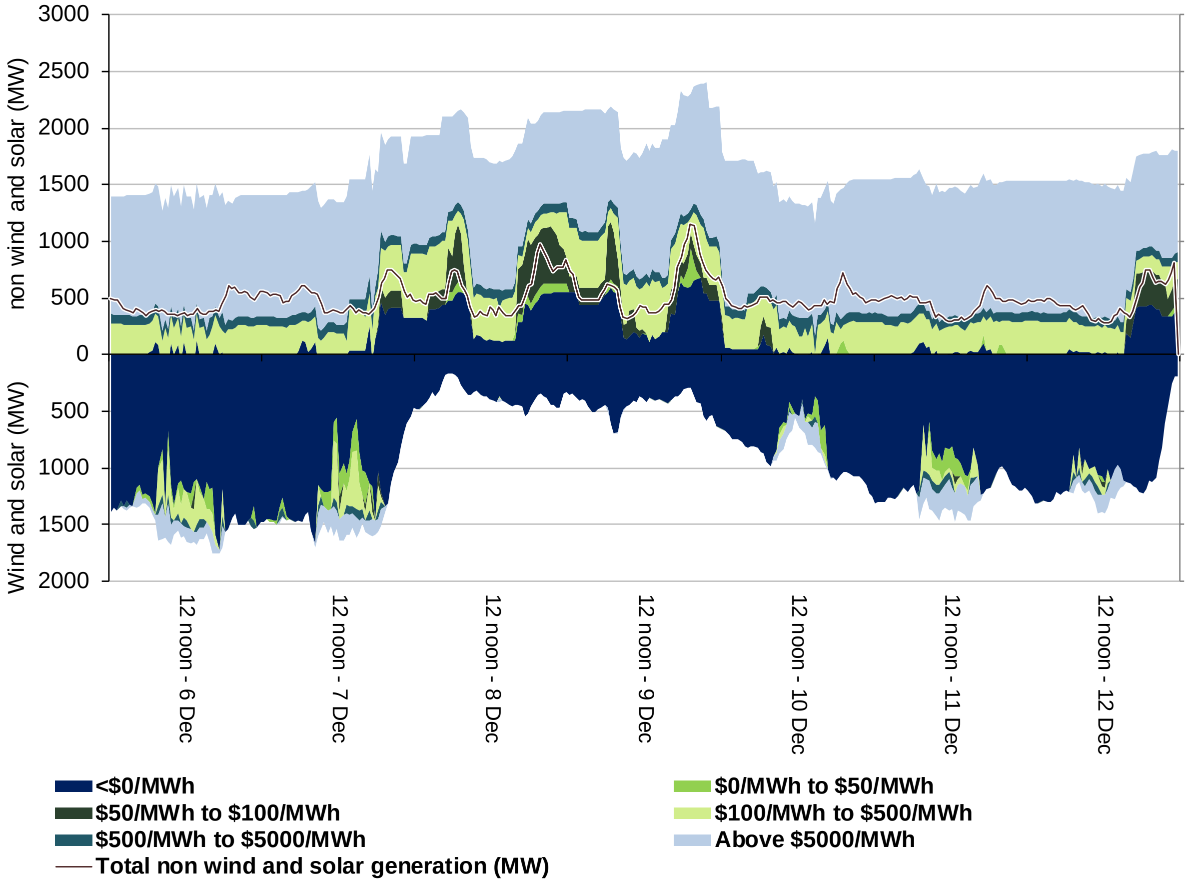
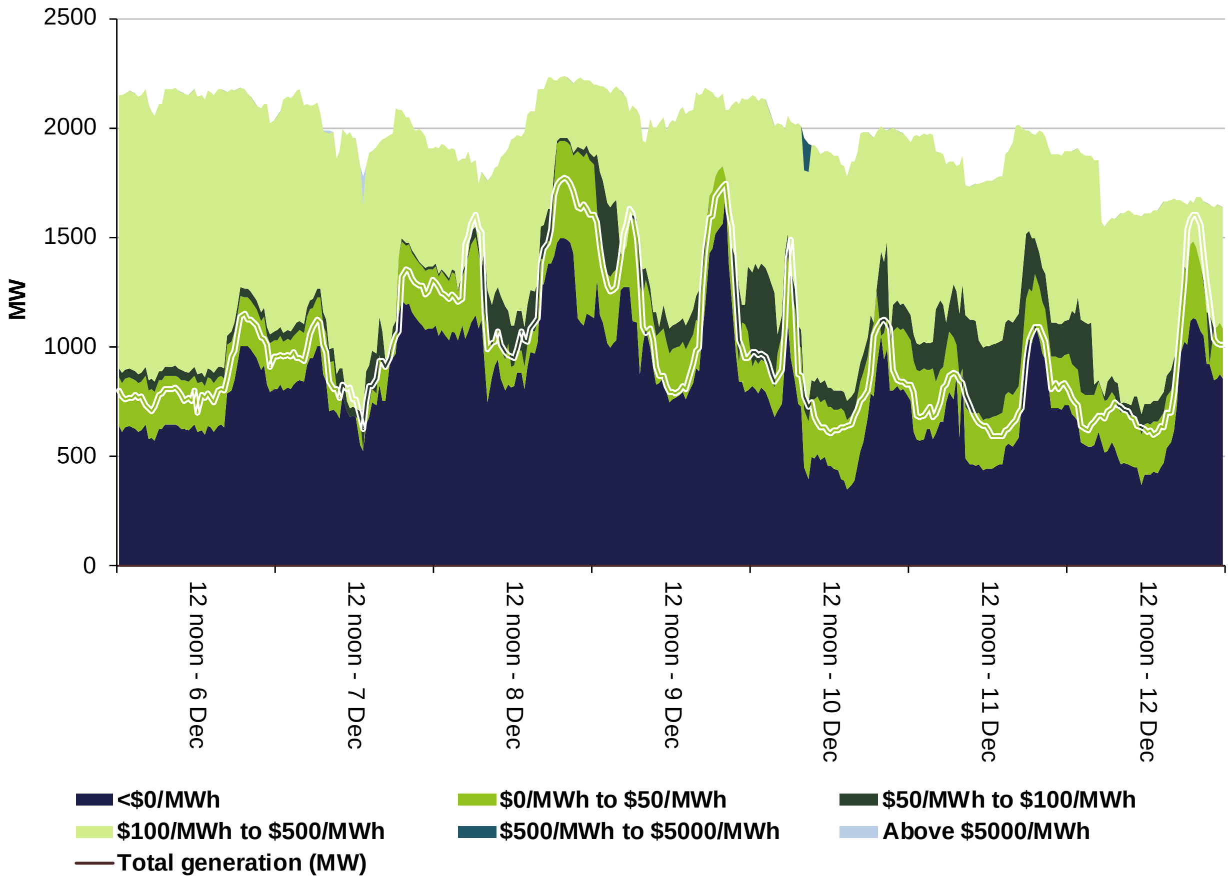


Figure 7: Tasmania generation and bidding patterns



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.

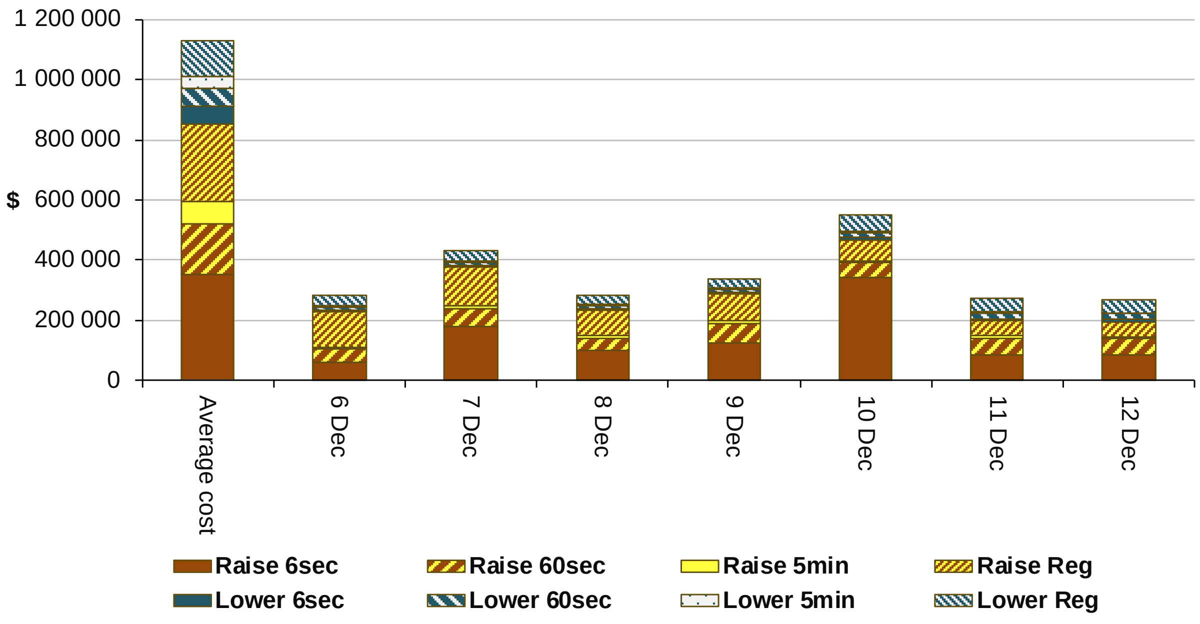
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1,714,500 or less than 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $713,000 or less than 23% 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



Detailed market analysis of significant price events

Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $44/MWh and above $250/MWh.

Monday, 7 December

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
8.30 am	316.34	36.69	35.85	7752	7299	7323	10,852	11,059	11,113

Demand was 453 MW higher than forecast and availability was 207 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast solar generation which was offered at prices below $0/MWh.

At 8.15 am, demand increased by nearly 70 MW and with cheaper priced generation either ramp constrained or trapped or stranded in FCAS, the price increased to $1,550/MWh for 5 minutes. From 8.20 am, demand fell by 225 MW and cheaper priced generation was no longer ramp constrained. As a result, the price returned to between $40/MWh and $90/MWh for the rest of the trading interval.

Wednesday, 9 December

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
4 pm	287.76	37.98	33.70	7163	7182	6986	10,610	11,051	11,057

Demand was close to forecast and availability was 441 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast solar generation and rebids that removed more than 350 MW of low priced capacity across Darling Downs power station for constraint management, Millmerran for plant reasons and Condamine due to “market conditions”.

At 3.45 pm, demand increased by around 60 MW and with cheaper priced generation either ramp constrained or trapped or stranded in FCAS, the price increased to $1,550/MWh for one dispatch interval. In response, participants rebid around 600 MW of capacity to the price floor, resulting in prices being set between $30/MWh and $38/MWh for the remainder of the trading interval.

Victoria

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

Friday, 11 December

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
8 am	-165.86	-30.65	9.18	4430	4403	4377	9210	8944	9002

Prices were aligned with South Australia and will be discussed as one region.

Demand was collectively 136 MW higher than forecast and availability was 227 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was price below $0/MWh.

At 7.45 am, Snowy Hydro rebid around 1300 MW of capacity across its two Tumut stations in New South Wales to the price floor. With a line outage between there and Sydney flows from New South Wales into Victoria increased by around 660 MW and with more expensive generation either ramp-down constrained or trapped or stranded in FCAS, the price fell to -$1,000/MWh in Victoria and -$800/MWh in South Australia for 5 minutes.

South Australia

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

Sunday, 6 December

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
8 am	-187.68	-53.67	-40.93	917	837	825	3039	2788	2763
8.30 am	-170.75	-58.05	-649.33	914	800	783	3037	2735	2798
9.30 am	-183.07	-200	-1000	831	699	692	3051	2763	2828
11 am	-121.90	-649.33	-1000	550	574	552	2946	2767	2836
12.30 pm	-109.88	-1000	-1000	499	436	465	3053	2795	2829
2 pm	-148.89	-200	-1000	564	467	441	3078	2807	2833
2.30 pm	-104.33	-200	-1000	498	525	494	3019	2836	2837

For the 8 am and 8.30 am trading intervals, demand was between 80 MW and 114 MW higher than forecast and availability was 251 MW to 302 MW higher than forecast, 4 hours prior. Higher than forecast availability was mostly due to higher than forecast wind generation which was mostly offered at prices below $0/MWh. Due to the combination of higher than forecast wind and lower than forecast demand, the price fell to -$1,000/MWh once in each trading interval before over 600 MW of capacity was rebid from the floor to above $30/MWh.

For the 9.30 am trading interval, price was close to that forecast 4 hours ahead.

For the 11 am, 12.30 pm, 2 pm and 2.30 pm trading intervals, demand was between 27 MW less than forecast and 97 MW higher than forecast while availability was up to 271 MW higher than forecast, four hours prior. Higher than forecast availability was primarily due to higher than forecast wind generation which was mostly offered at prices below $0/MWh. Rebids up to 4 hours prior to the start of each trading interval shifted between 110 MW and 350 MW of capacity from below to above forecast prices in response to changes in forecast prices. As a result, prices were above forecast for most of each of the trading intervals.

Monday, 7 December

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
11.30 am	-179.76	-1000	-1000	936	623	676	2973	2850	2917
2 pm	-152.63	-469.01	-1000	713	481	532	3150	3046	3108

For the 11.30 am and 2 pm trading intervals, demand was up to 313 MW higher than forecast and availability was up to 123 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh.

For the 11.30 am trading interval over 500 MW of capacity was rebid to the price floor by 11.15 am which saw the price fall to floor. In response around 400 MW of capacity was rebid to higher prices and the price reaching $27/MWh at the end of the trading interval.

For the 2 pm trading interval the price was higher than forecast due to the higher than forecast demand.

Friday, 11 December

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
8 am	-146.45	-249.80	-649.33	1079	970	977	2850	2889	2879
8.30 am	-145.72	-303.19	-649.33	933	843	859	2791	2846	2898
9 am	-195.09	-834.15	-1000	816	699	713	2867	2835	2894
10 am	-115.00	-1000	-1000	736	461	468	2897	2855	2911
11.30 am	-101.23	-1000	-1000	606	295	309	2811	2851	2887

For the 8 am trading interval, prices were aligned with Victoria. See Victorian section for analysis.

For the 8.30 am trading interval, demand was 90 MW higher and availability was 55 MW lower than forecast, 4 hours prior. This resulted in prices between -$367/MWh and -$1/MWh during the trading interval.

For the 9 am trading interval, demand was 117 MW higher than forecast and availability was close to forecast, 4 hours prior. Rebids effective 8.35 am shifted 400 MW of capacity to the price floor, resulting in the price falling to -$1000/MWh for one dispatch interval. In response, participants rebid more than 610 MW of capacity from the price floor to higher prices, resulting in prices for the rest of the trading interval being set between -$46/MWh and -$20/MWh.

For the 10 am and 11.30 am trading intervals, demand was around 300 MW higher than forecast, while availability was close to forecast, 4 hours prior. This combined with some minor rebidding of capacity from low to high prices saw prices were generally between -$200/MWh and -$35/MWh.

Saturday, 12 December

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	-100.37	-190	-571.91	961	925	907	2728	2700	2793
11 am	-111.33	-90.74	-649.33	860	948	881	2790	2723	2799

For the 9.30 am trading interval, demand and availability were slightly higher than forecast, 4 hours prior. Across the trading interval, changes in demand and wind generation saw prices fluctuate between -$200/MWh and $5/MWh. As a result, the spot price was set higher than forecast.

For the 11 am trading interval, prices were close to forecast 4 hours prior.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $18/MWh and above $250/MWh.

Monday, 7 December

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
1.30 pm	451.04	40.34	-36.17	1001	958	949	1792	1987	1978

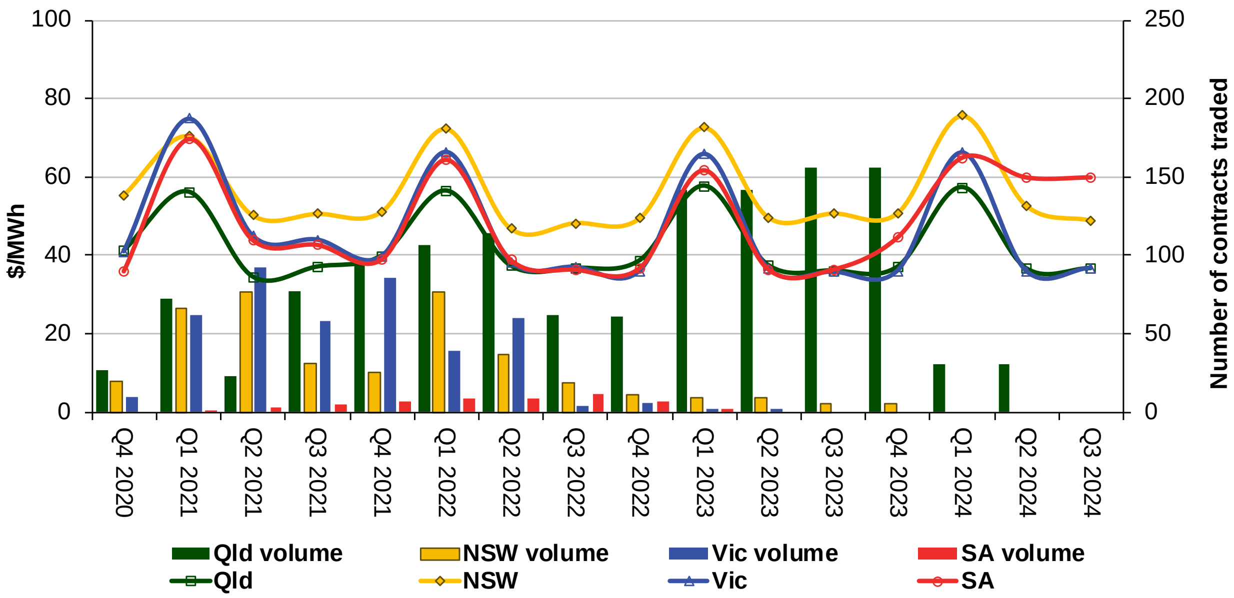
Demand was close to forecast while availability was 195 MW lower than forecast, 4 hours prior. Lower than forecast availability was mostly due to rebids that removed 120 MW of capacity at Gordon for a change in scheduled outage.

Effective 1.15 pm, rebids at Cattle Hill wind farm shifted 144 MW of wind generation from the price floor to $2,000/MWh. With cheaper priced generation ramp constrained or trapped or stranded in FCAS and unable to set price, the price was set at $2,000/MWh for 5 minutes. Effective 1.20 pm, rebids at Cattle Hill wind farm shifted 144 MW of capacity back to -$1,000/MWh.

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.

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



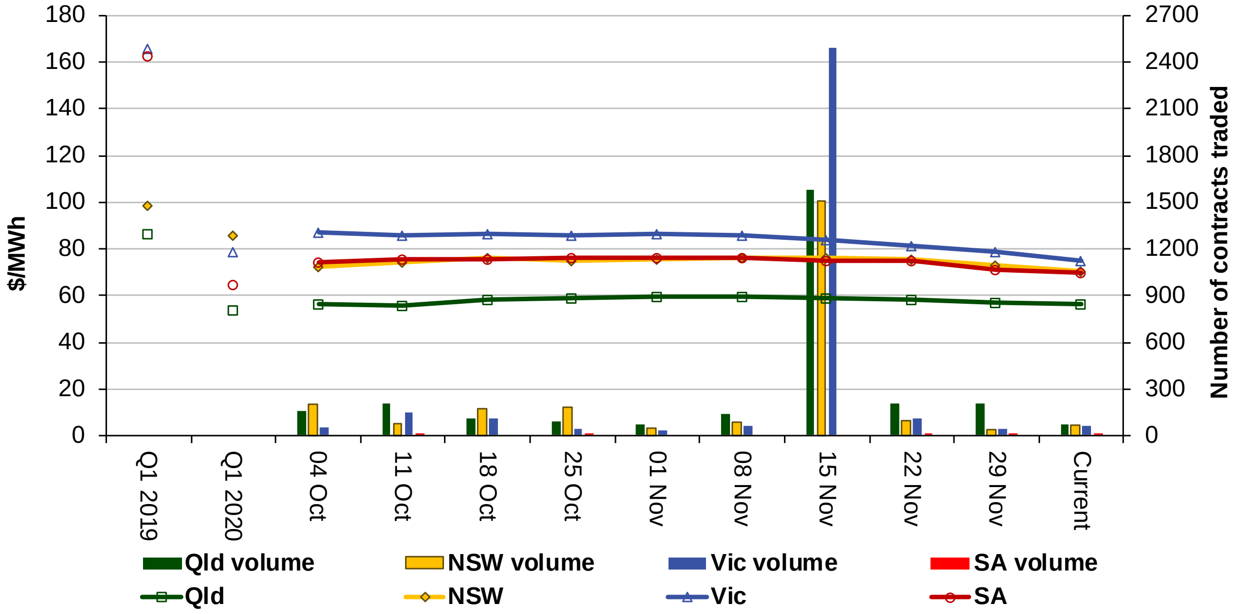
Source. ASXEnergy.com.au

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on 19 November 2020.

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.

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on 19 November 2020.

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

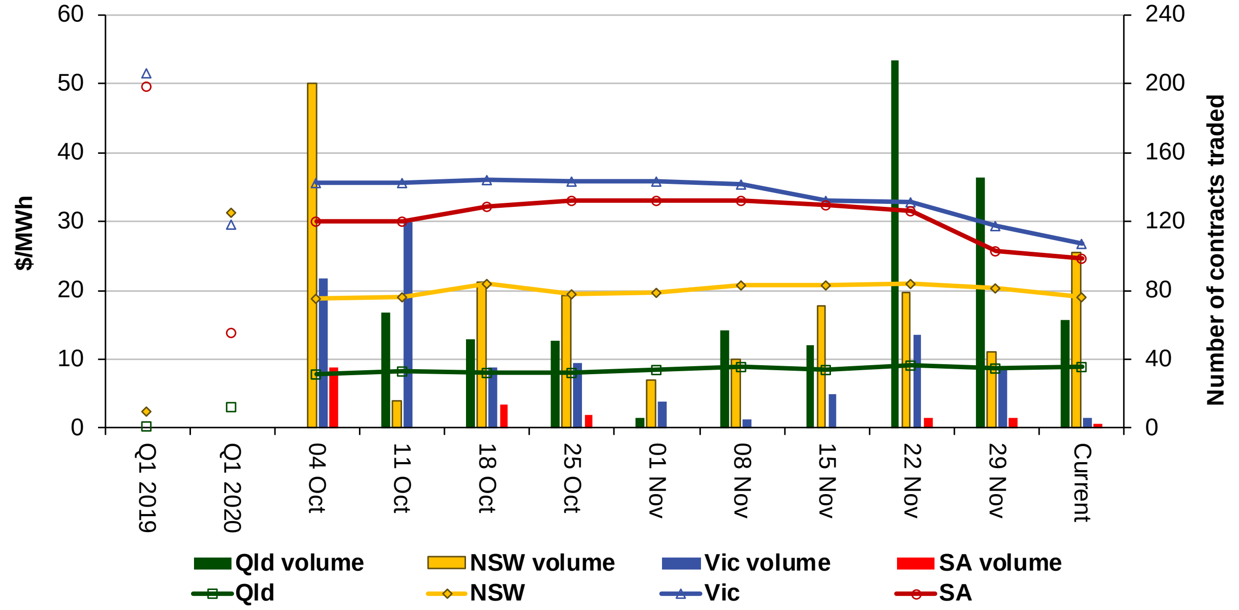


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

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