Electricity Report

AUSTRALIAN ENERGY REGULATOR

14 – 20 March 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $26/MWh in Victoria to $44/MWh in Queensland. Higher weekly prices in Queensland were driven by small periods of price volatility. 2020-21 financial year to date VWA prices were below $53/MWh across all regions, down from $63/MWh to $100/MWh at the same time a year earlier.

On Sunday 14 March, AEMO issued an instruction to Electranet to maintain demand in South Australia above 400 MW due to insufficient local demand to maintain the system in a secure state. This involved the network service provider reducing the amount of rooftop solar generation from 2.30 pm to 3.55 pm. During this time, South Australian prices ranged from -$470/MWh to -$630/MWh.

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 14 to 20 March 2021.

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

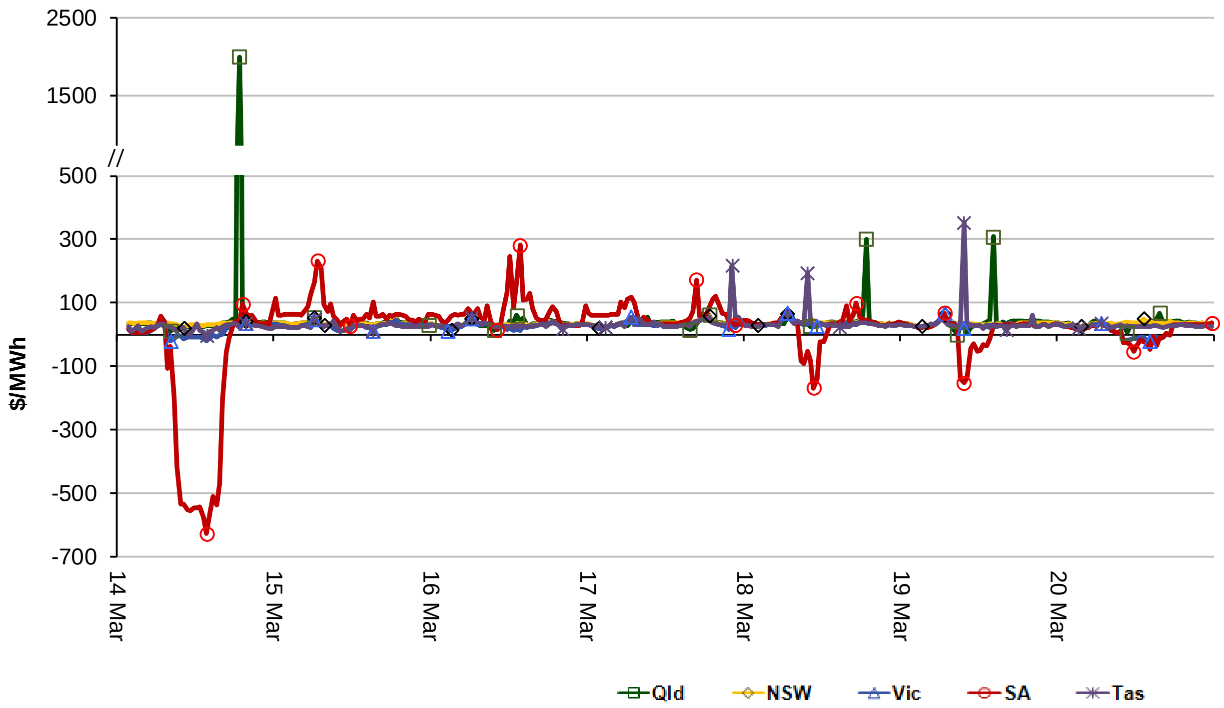


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

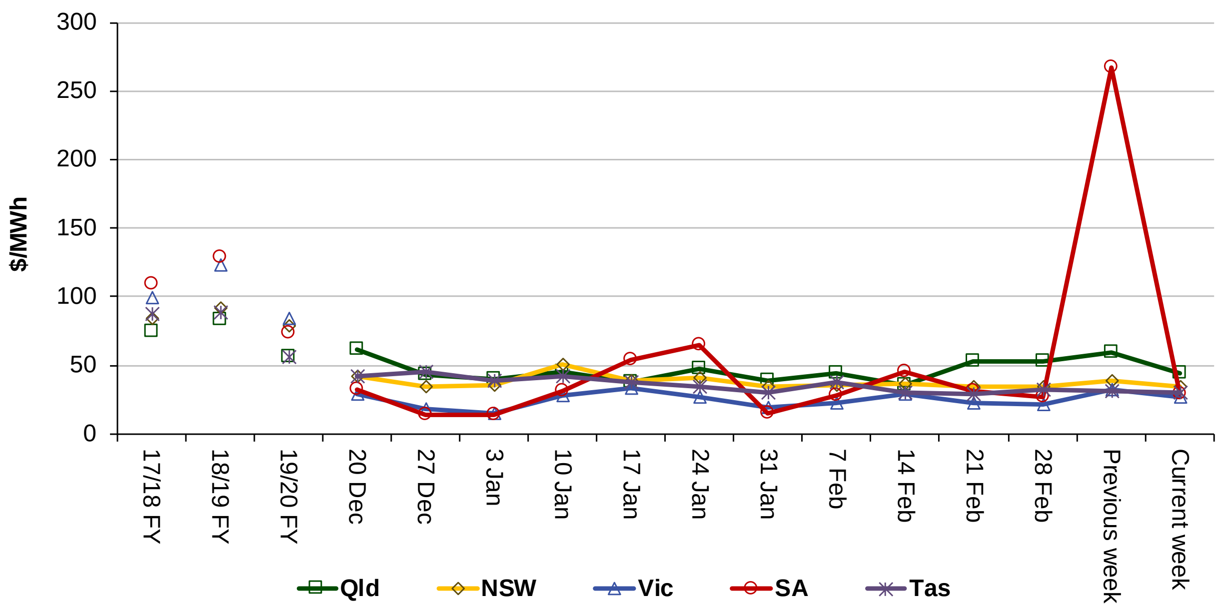


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	44	35	26	29	30
Q1 2020 (QTD)	59	115	117	85	45
Q1 2021 (QTD)	45	38	25	54	34
19-20 financial YTD	63	92	100	85	65
20-21 financial YTD	43	53	41	45	44

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 243 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2020 of 233 counts and the average in 2019 of 204. 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	10	14	0	3
% of total below forecast	7	58	0	9

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

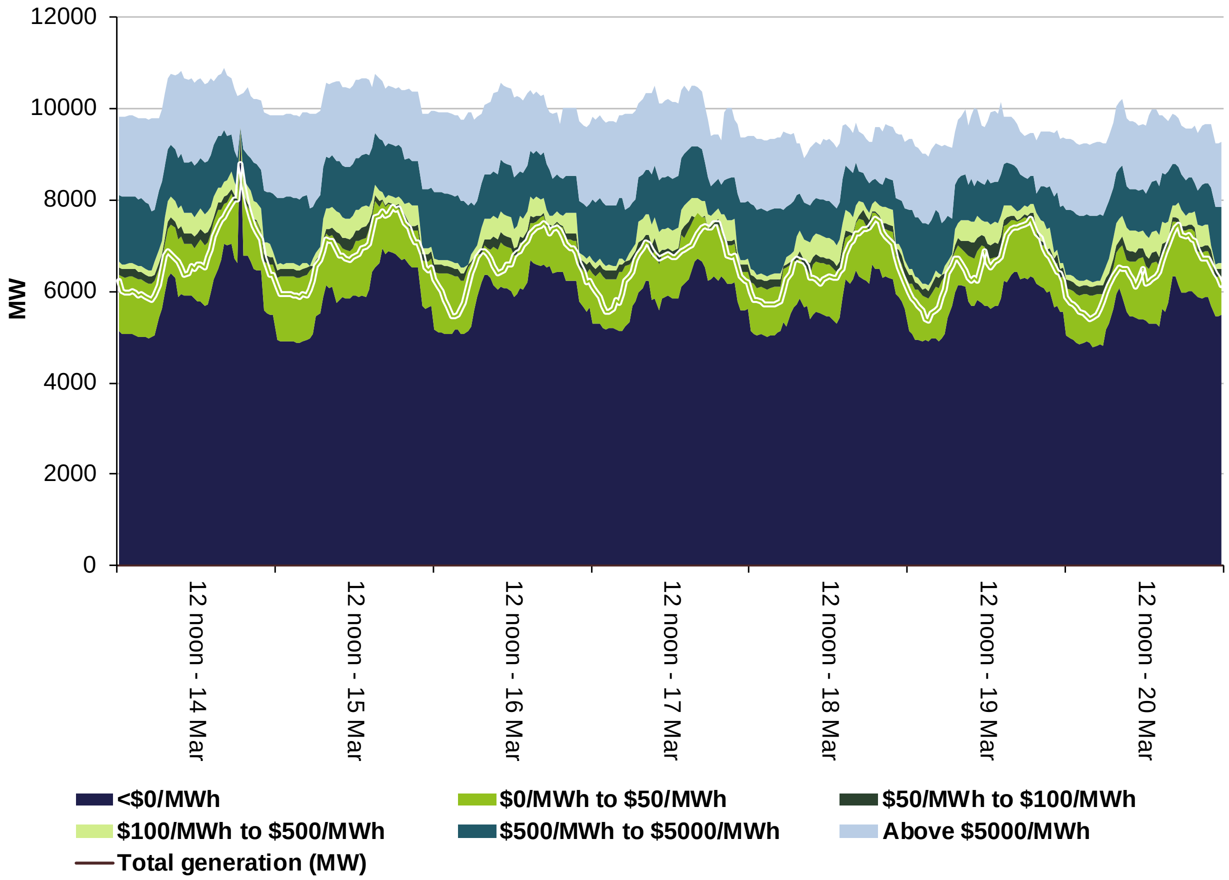


Figure 4: New South Wales generation and bidding patterns

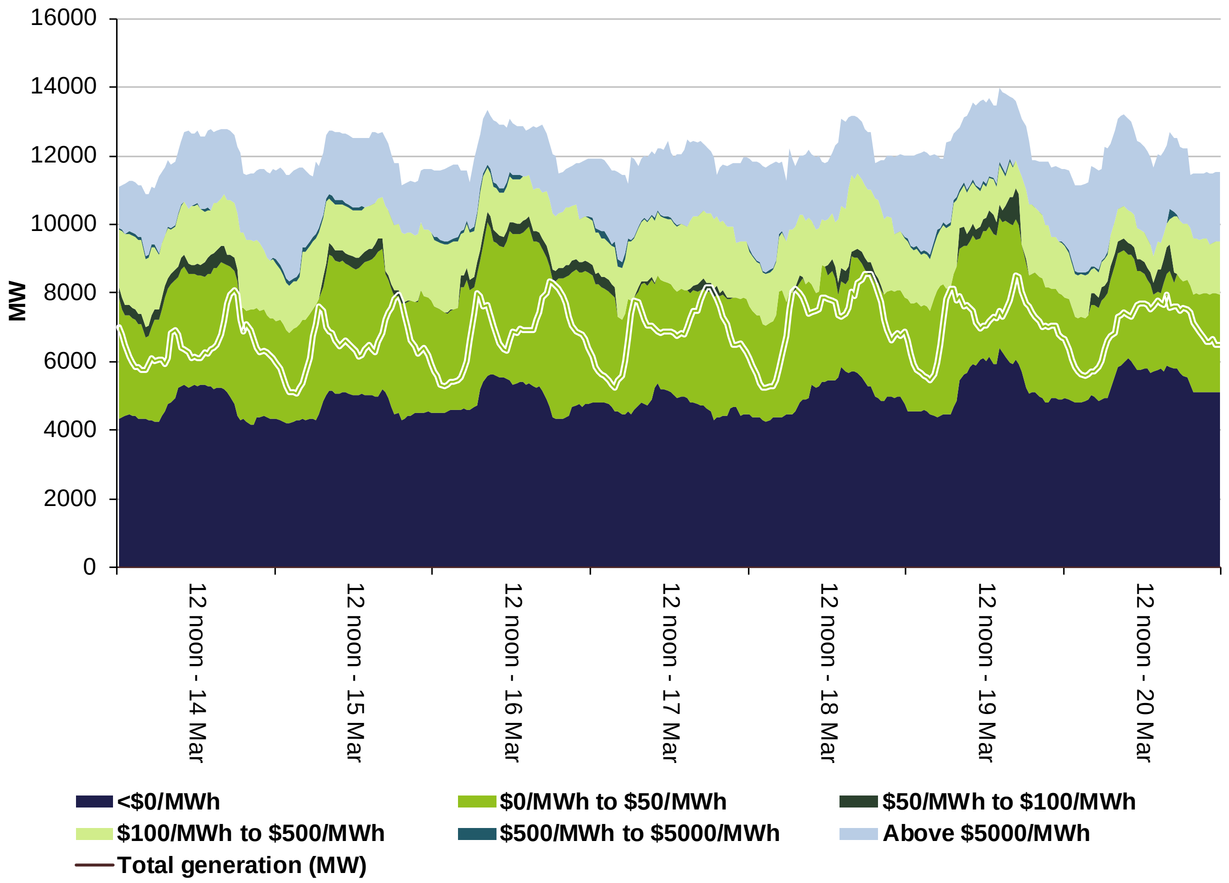


Figure 5: Victoria generation and bidding patterns

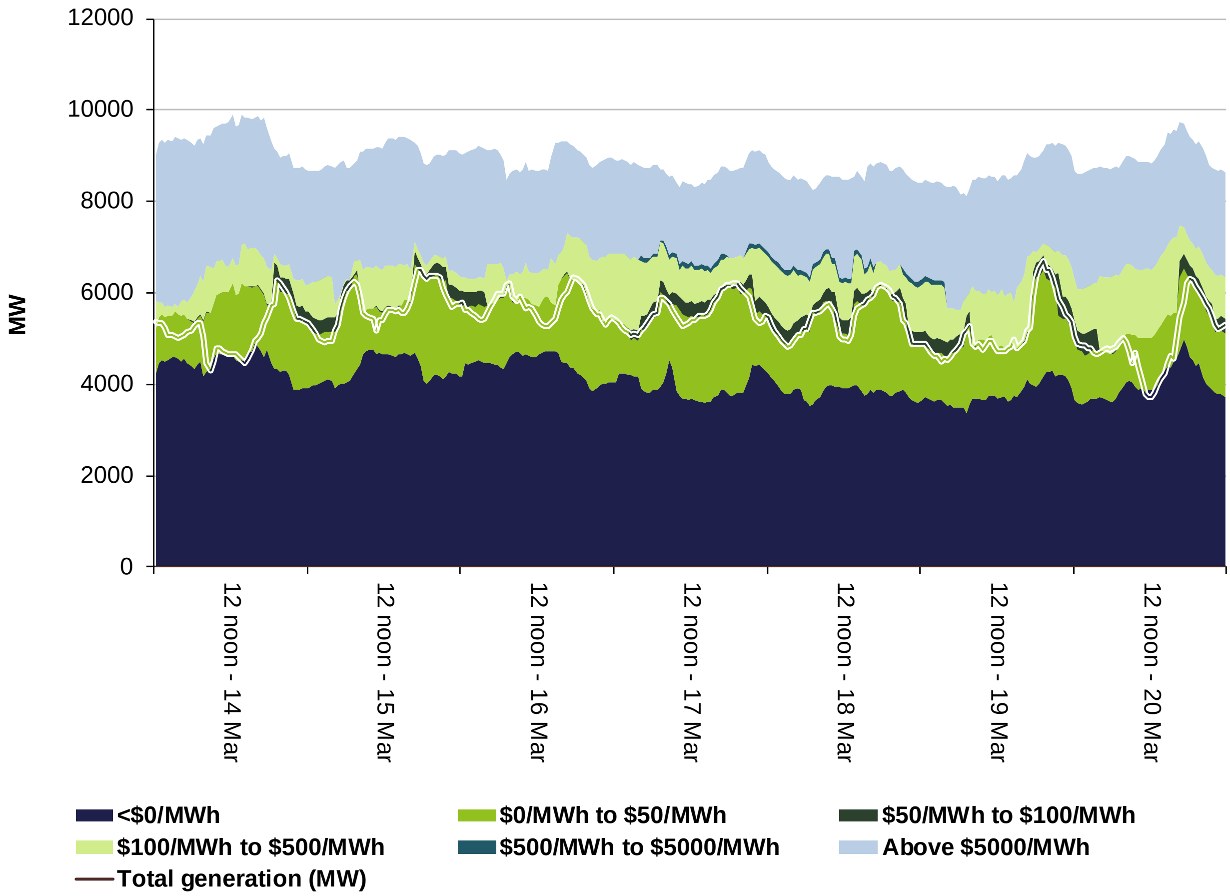


Figure 6: South Australia generation and bidding patterns

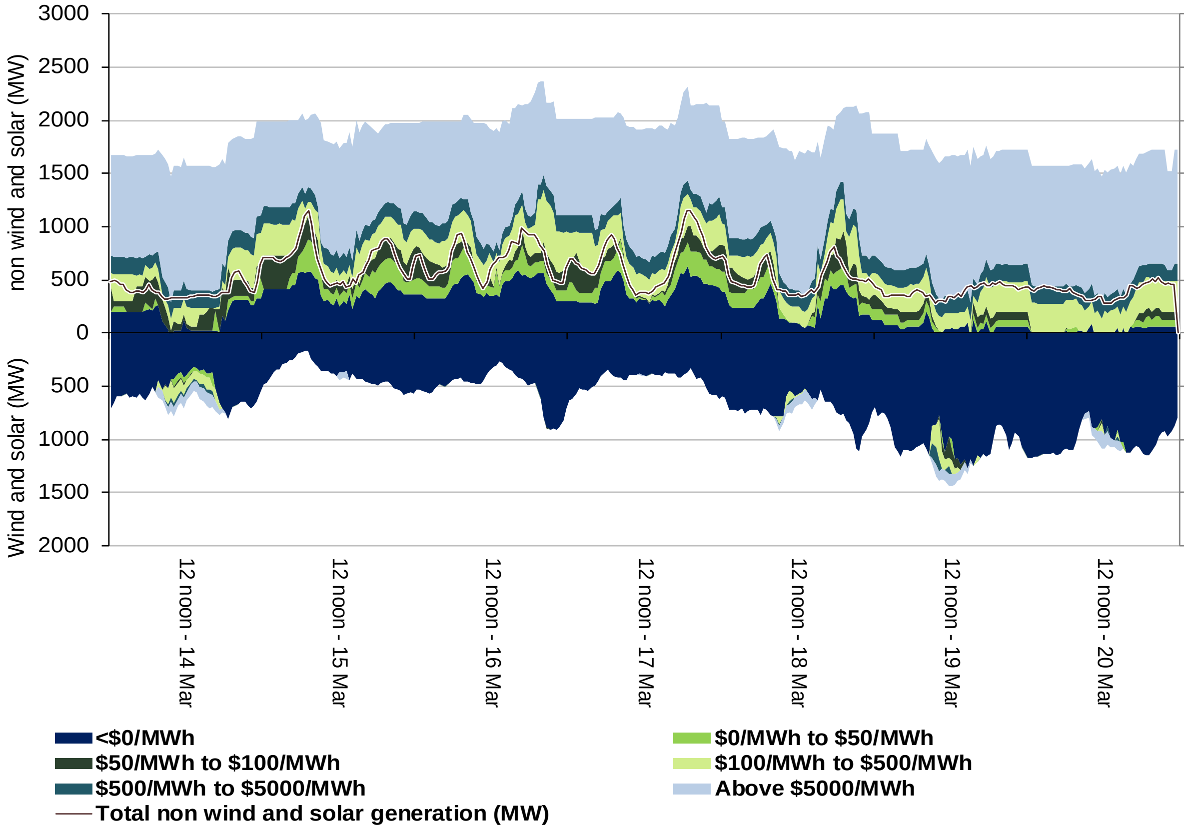
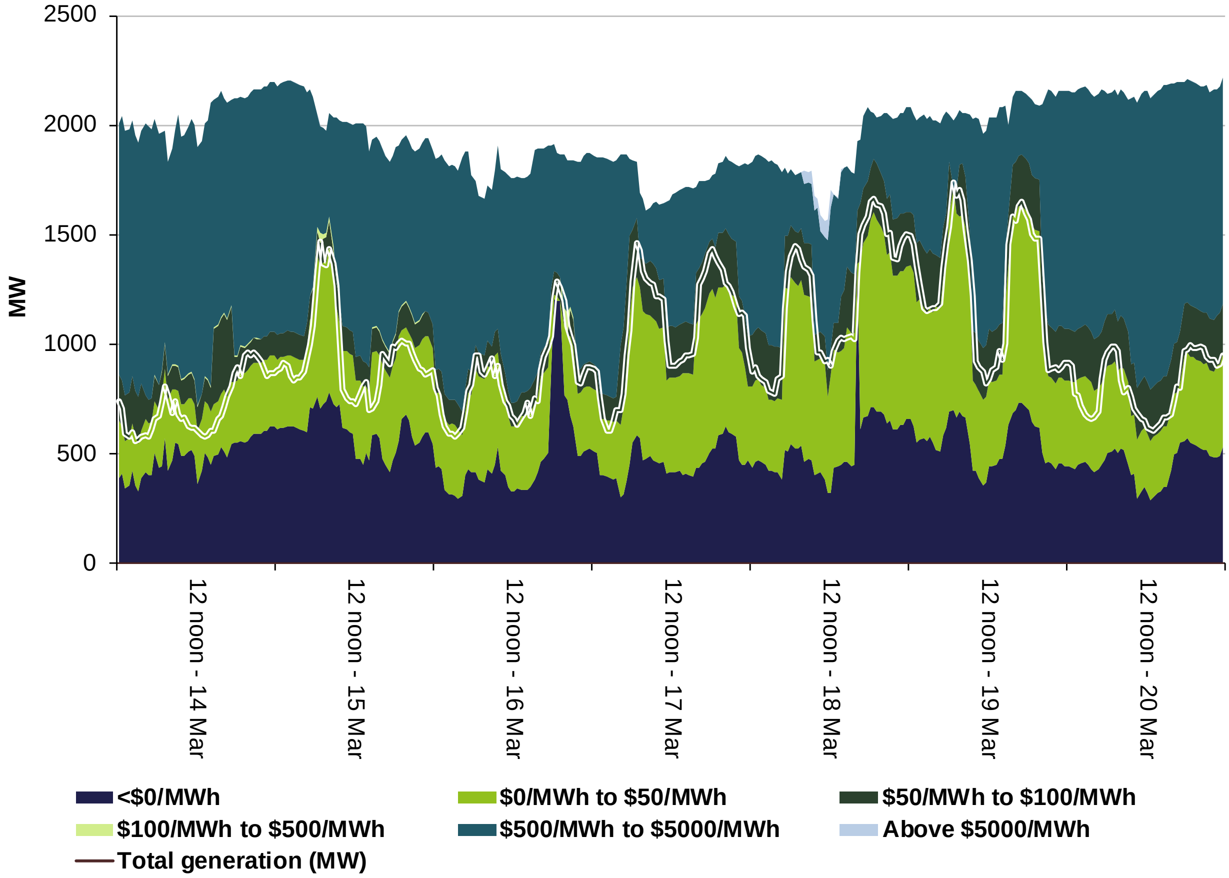


Figure 7: Tasmania generation and bidding patterns



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.

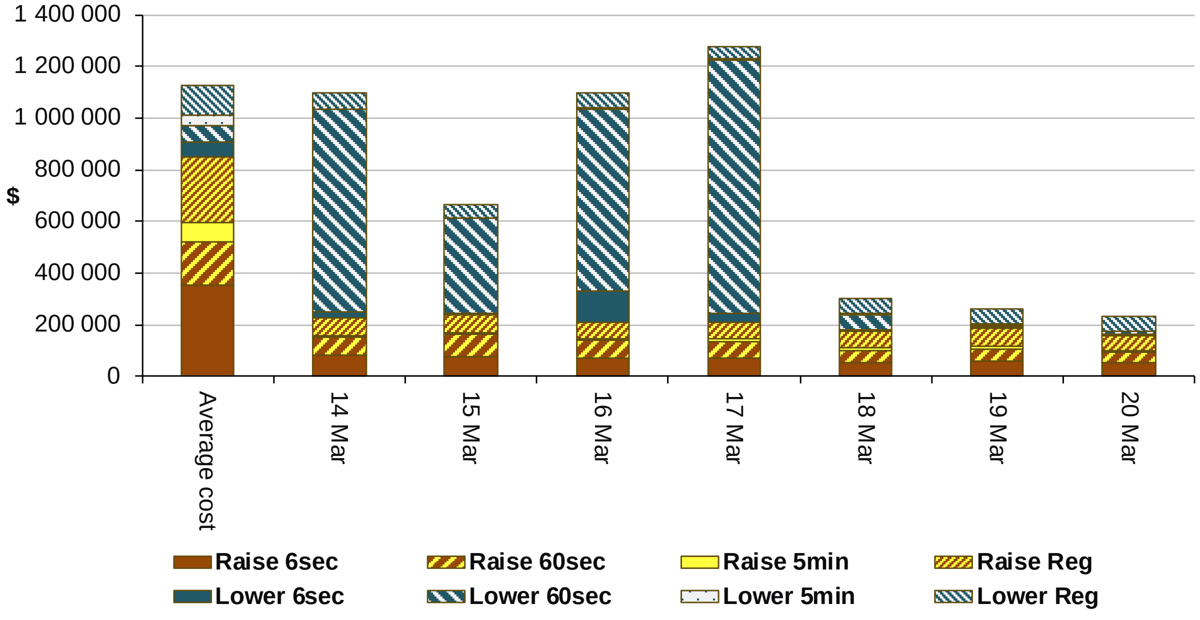
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $4,504,000 or less than 4% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $423,000 or around 8% 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 costs for lower 60 second services from 14 to 17 March were driven by many prices around $1,000/MW in South Australia. This coincided with periods when line outages limited flows on the Heywood interconnector and increased the requirement for South Australia lower 60 second services.

Detailed market analysis of significant price events

Queensland

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

Sunday, 14 March

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	2,004.84	301.11	15,52.01	8,208	8,321	8,290	10,299	10,334	10,138

Demand was 113 MW lower than forecast and availability was 35 MW lower than forecast, 4 hours prior.

At 6.35 pm, demand increased by 81 MW and with cheaper priced generation ramp up-constrained or unable to start in 5 minutes, the price increased to $15,000/MWh. In response to the high price, effective 6.40 pm more than 640 MW of capacity was rebid from $15,000/MWh to the price floor and cheaper priced generation was no longer ramp up-constrained. As a result, the dispatch price fell to the floor for the last half of the trading interval.

Thursday, 18 March

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
7 pm	299.72	50.66	43.73	7,743	7,730	7,720	9,296	9,902	9,933

Demand was close to forecast while availability was 606 MW lower than forecast, 4 hours prior. Lower than forecast availability was mostly due to rebids that removed 570 MW of high priced capacity at Wivenhoe due to delayed return to service.

At 6.45 pm, demand increased by 35 MW and with only 22 MW of generation capacity offered around $50/MWh left to be dispatched and Braemar units unable to start up in 5 minutes, the price increased to $1,556/MWh. At 6.50 pm, demand fell by 46 MW, and the price returned to below $44/MWh for the remainder of the trading interval.

Friday, 19 March

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
2.30 pm	308.08	38.90	38.90	6,703	6,478	6,519	10,056	10,317	10,387

Demand was 225 MW higher than forecast and availability was 261 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to a partial unit outage that removed 55 MW of higher priced capacity at Braemar and lower than forecast wind and solar generation.

At 2.25 pm, low-priced solar generation fell by more than 110 MW and with other generators ramp constrained, trapped or stranded in FCAS or unable to start in 5 minutes, the price increased to $1,556/MWh for one dispatch interval.

South Australia

There was one occasion where the spot price in South Australia was greater than 3 times the South Australia weekly average price of $29/MWh and above $250/MWh and there were 22 occasions where the spot price was below -$100/MWh.

Sunday, 14 March

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	-107.67	-190	-200	1,031	1,021	1,045	2,279	2,400	2,383
9 am	-196.80	-649.33	-942.76	877	883	895	2,281	2,491	2,506
9.30 am	-417.40	-771.47	-934.88	754	804	820	2,357	2,546	2,559
10 am	-533.77	-1,000	-1,000	666	731	739	2,315	2,585	2,635
10.30 am	-535.89	-1,000	-1,000	630	673	677	2,367	2,568	2,620
11 am	-553.45	-1,000	-1,000	565	610	625	2,258	2,541	2,589
11.30 am	-555.78	-1,000	-1,000	523	526	586	2,213	2,501	2,553
Midday	-547.38	-1,000	-1,000	516	466	543	2,262	2,472	2,517
12.30 pm	-548.35	-1,000	-1,000	495	420	510	2,192	2,439	2,478
1 pm	-543.93	-1,000	-1,000	473	380	483	2,154	2,400	2,442
1.30 pm	-576.16	-1,000	-1,000	448	357	463	2,137	2,412	2,441
2 pm	-628.65	-1,000	-1,000	393	341	463	2,132	2,324	2,446

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	-560.16	-1,000	-1,000	353	380	504	2,190	2,356	2,610
3 pm	-512.07	-1,000	-1,000	396	424	538	2,208	2,358	2,618
3.30 pm	-537.40	-781.77	-1,000	480	489	590	2,258	2,340	2,622
4 pm	-470.26	-613.06	-1,000	569	583	665	2,272	2,320	2,620
4.30 pm	-205.04	-562.06	-1,000	681	723	761	2,269	2,331	2,623

Across all trading intervals, demand was between 65 MW lower to 93 MW higher than forecast, while availability was between 48 MW and 288 MW lower than forecast, 4 hours prior. Lower than forecast availability was mostly due to lower than forecast wind and solar generation. With very little capacity offered between -$1,000/MWh and -$33/MWh, small changes in demand or supply could lead to large changes in price. As a result, prices were set higher than forecast.

Tuesday, 16 March

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 pm	280.51	42	42	996	855	851	2,223	2,277	2,227

Demand was 141 MW higher than forecast and availability was 54 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind and solar generation which was mostly priced low. With only one or two generators offering capacity between $42/MWh and $248/MWh, small changes in demand or the availability of low-priced generation could lead in large changes in price. The combination of higher demand, less low-priced generation available and cheaper priced generation trapped or stranded in FCAS, dispatch prices ranged between $241/MWh and $349/MWh throughout the trading interval.

Thursday, 18 March

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
11 am	-169.34	-649.33	-1,000	931	955	932	2,471	2,551	2,576
11.30 am	-141.23	-1,000	-960.28	916	910	889	2,475	2,567	2,591

Across both trading intervals, demand was close to forecast while availability was between 80 MW and 92 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind and solar generation which was mostly offered at low prices. In the lead up to the start of each trading interval, more than 400 MW of capacity was shifted to higher prices mostly due to plant reasons or in response to changes in forecast prices.

For the 11 am trading interval, the combination of lower than forecast wind and solar generation and rebids that shifted capacity to higher prices saw dispatch prices generally range from -$190/MWh to $25/MWh throughout the trading interval.

For the 11.30 am trading interval, the price fell to -$918/MWh once at 11.05 am. In response to the low price, rebids effective 11.10 am shifted more than 170 MW of capacity from low to higher prices. As a result, dispatch prices ranged from $19/MWh to $38/MWh for the remainder of the trading interval.

Friday, 19 March

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	-141.64	26.16	25.97	1,207	1,210	1,222	2,924	2,971	2,916
10 am	-152.67	24.40	-190	1,157	1,127	1,129	3,054	2,996	2,947
10.30 am	-137.13	-69.99	-464.78	1,084	1,054	1,044	3,071	2,986	3,012

For the 9.30 am trading interval, demand was close to forecast and availability was 47 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind generation which was mostly offered at low prices. Rebids effective from 9.05 am to manage binding constraints shifted more than 207 MW of capacity from prices above $26/MWh to the price floor causing the dispatch price to fall to -$1,000/MWh. In response to the low price, rebids effective 9.10 am shifted more than 626 MW of capacity from the price floor to above $26/MWh resulting in dispatch prices around $30/MWh for the remainder of the trading interval.

For the 10 am and 10.30 am trading intervals, demand was 30 MW higher than forecast and availability was between 58 MW and 85 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind and solar generation, mostly offered at low prices. With little generation offered between $24/MWh and the price floor, small changes in demand or low priced supply could result in large changes in price. As a result, the price fell to below -$900/MWh once in each trading interval.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $30/MWh and above $250/MWh.

Friday, 19 March

Table 10: Price, Demand and Availability

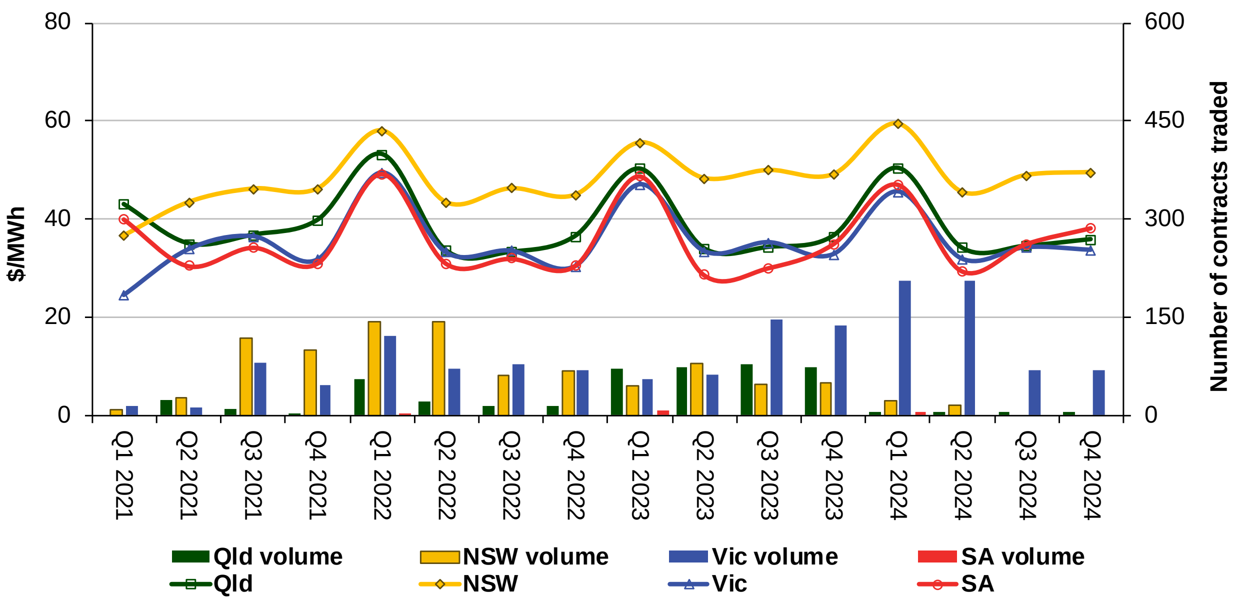
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
10 am	351.94	26.59	27.37	942	977	990	2,029	2,010	2,005

Demand and availability were both close to forecast, 4 hours prior. Effective 9.50 am, rebids by Hydro Tasmania shifted 215 MW of capacity from prices below $25/MWh to $995/MWh in response to prices different to forecast. With only one generator with capacity offered between $26/MWh and $995/MWh, small changes in demand or availability could result in large changes in price. With cheaper priced generation either ramp-constrained or trapped in FCAS following the rebids at 9.50 am, the dispatch price increased to $995/MWh for 10 minutes.

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.

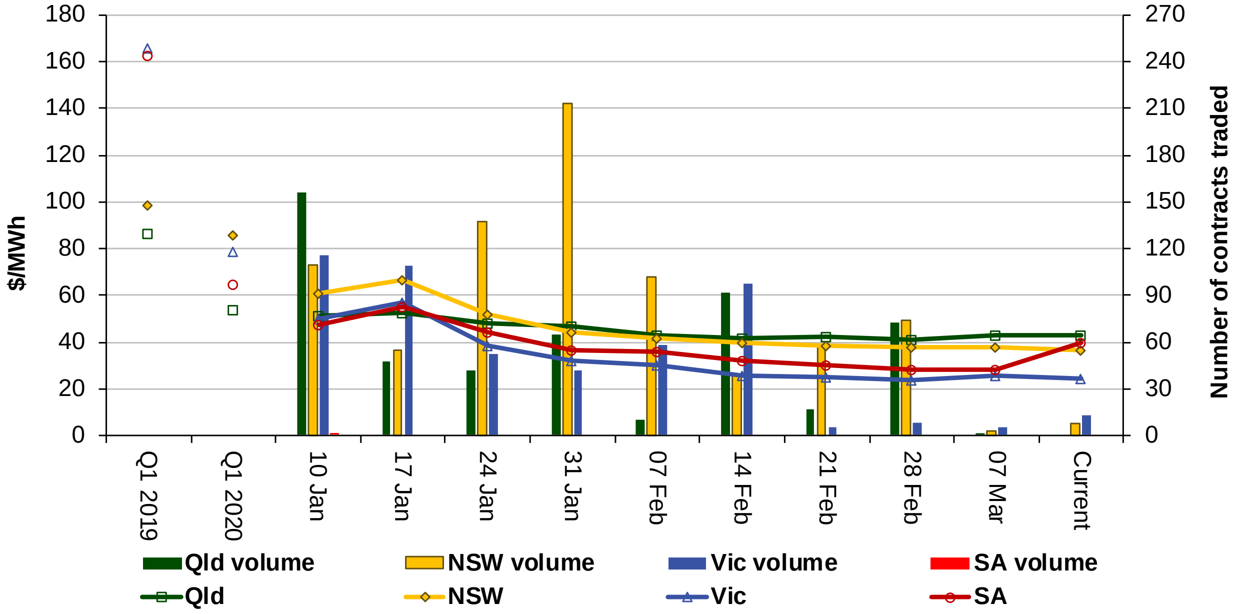
Figure 9: Quarterly base future prices Q1 2021 – Q4 2024



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 2020 and Q1 2019 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)

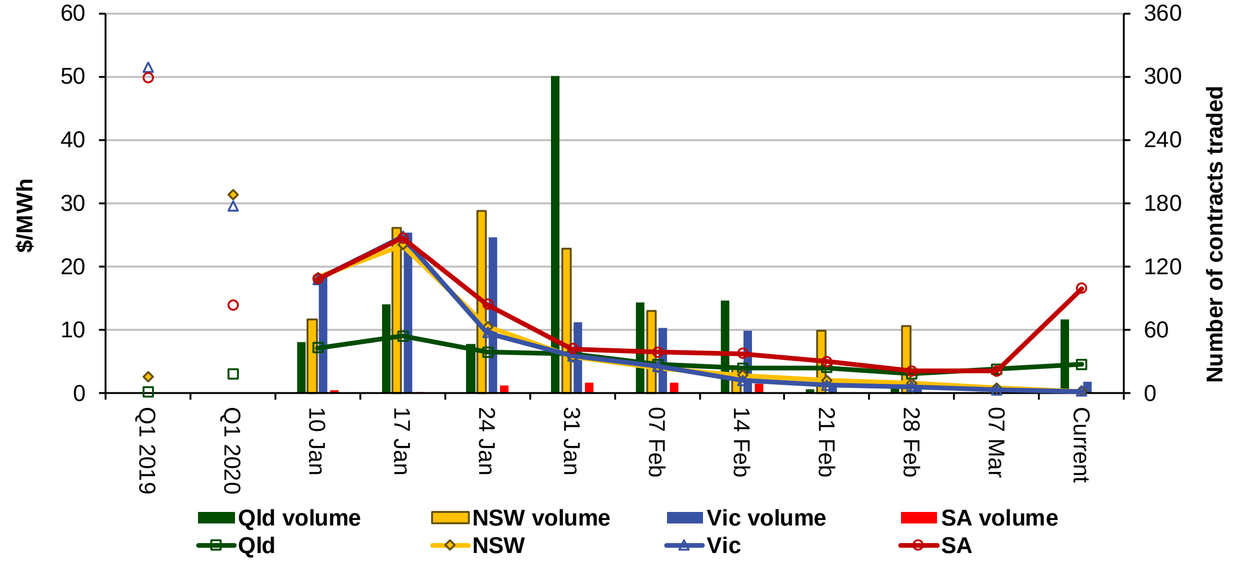


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2020 and Q1 2019 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
April 2021