Electricity Report

AUSTRALIAN ENERGY REGULATOR

29 August – 4 September 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged between $19/MWh in Tasmania and $63/MWh in Queensland. High wind generation in South Australia during the middle of the week (Figure 6) resulted in negative prices, and saw its weekly VWA price drop by over half from the previous week (see price event analysis). Despite the low VWA prices for the week, Q3 2021 quarter to date VWA prices for all mainland regions are at least $15/MWh higher than 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 29 August to 4 September 2021.

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

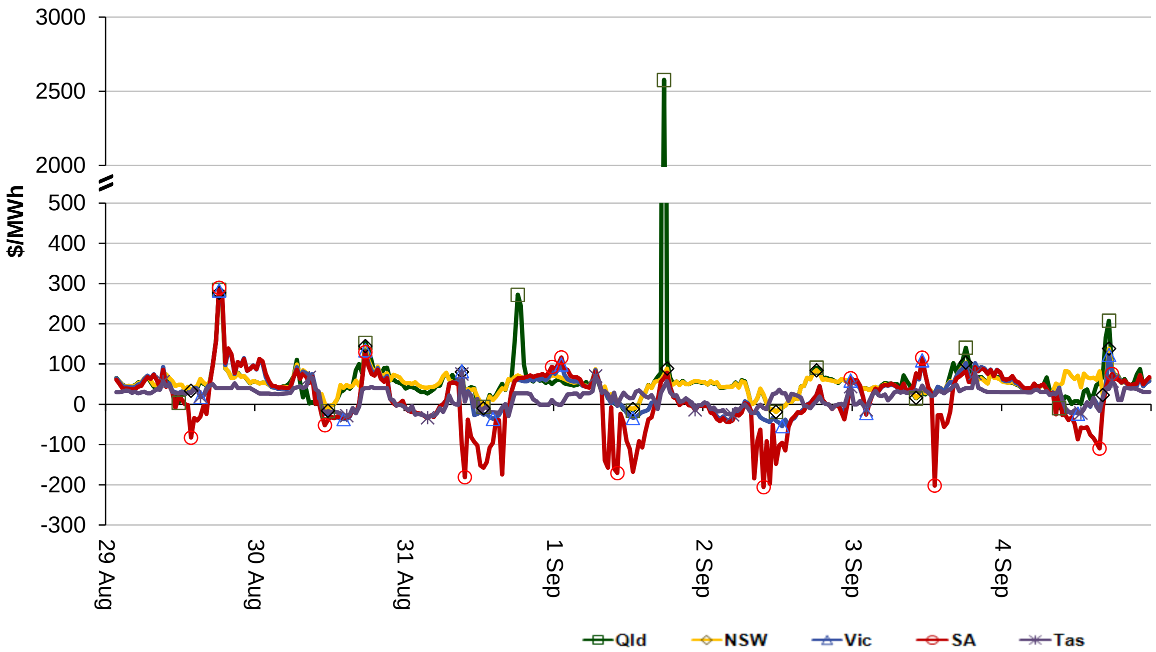


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

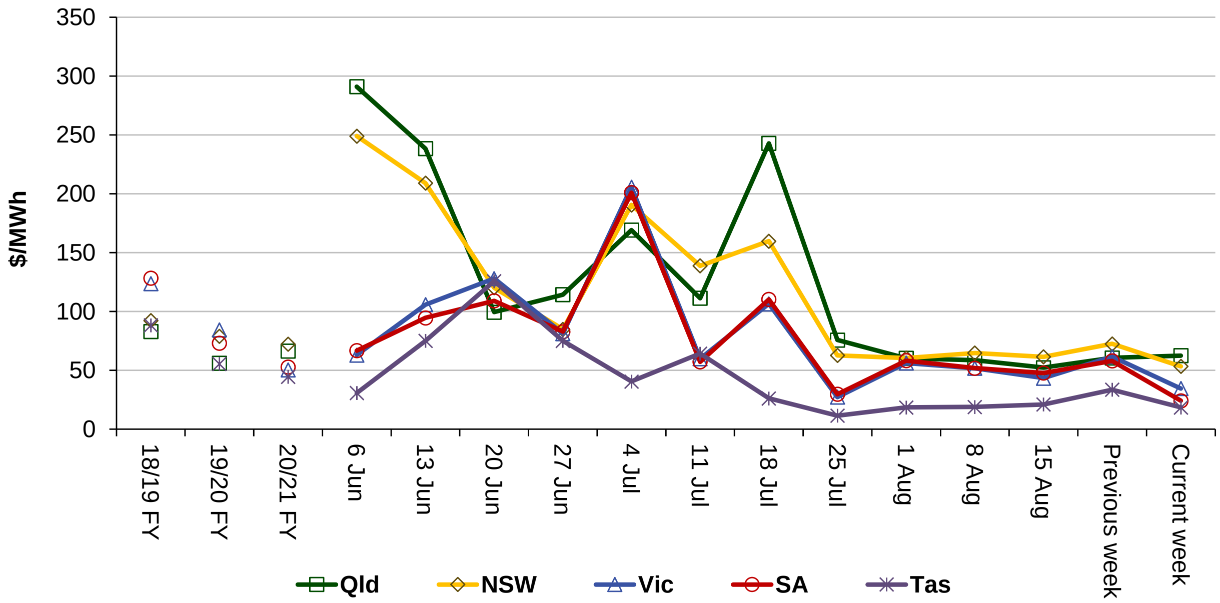


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	63	53	35	24	19
Q3 2020 QTD	37	51	60	54	55
Q3 2021 QTD	103	99	75	74	30
20-21 financial YTD	37	51	60	54	55
21-22 financial YTD	103	99	75	74	30

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 279 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	2	15	0	3
% of total below forecast	16	54	0	10

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

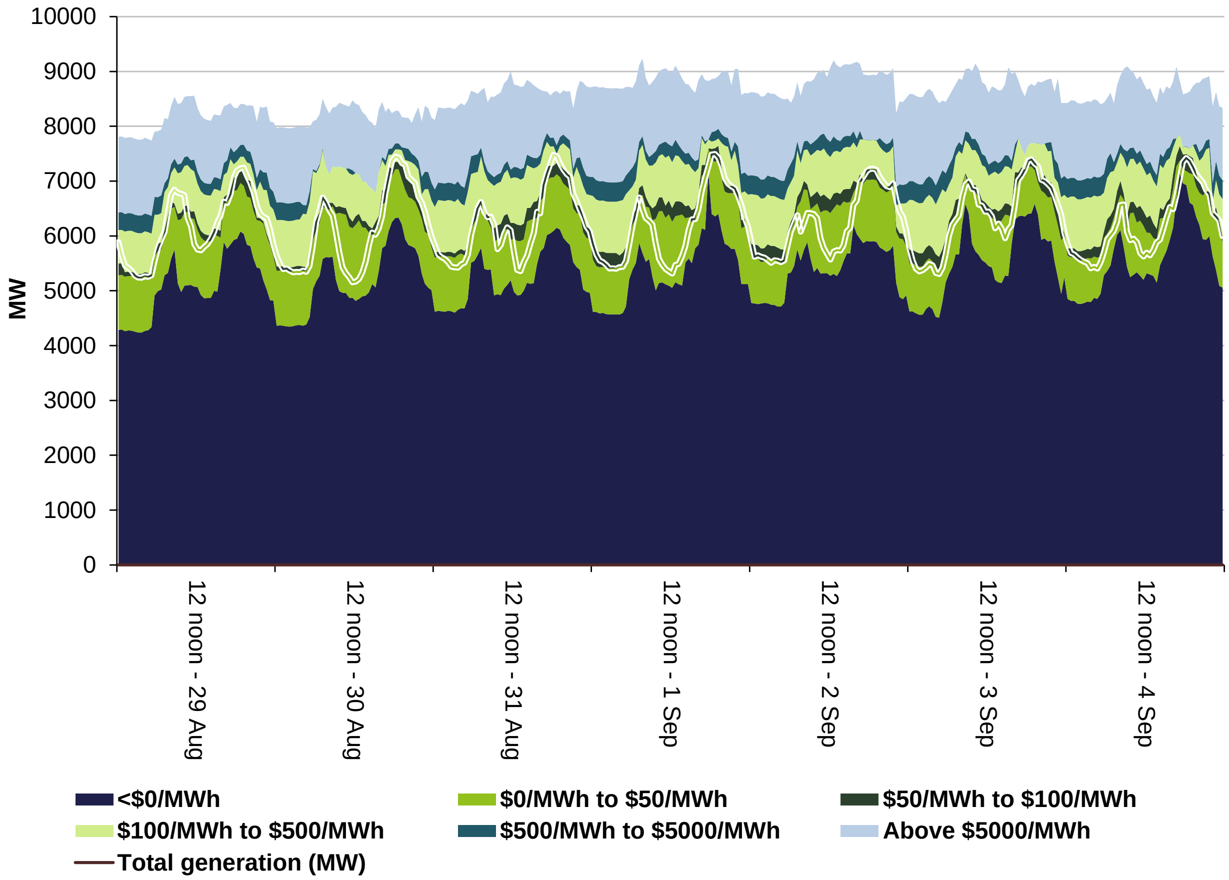


Figure 4: New South Wales generation and bidding patterns

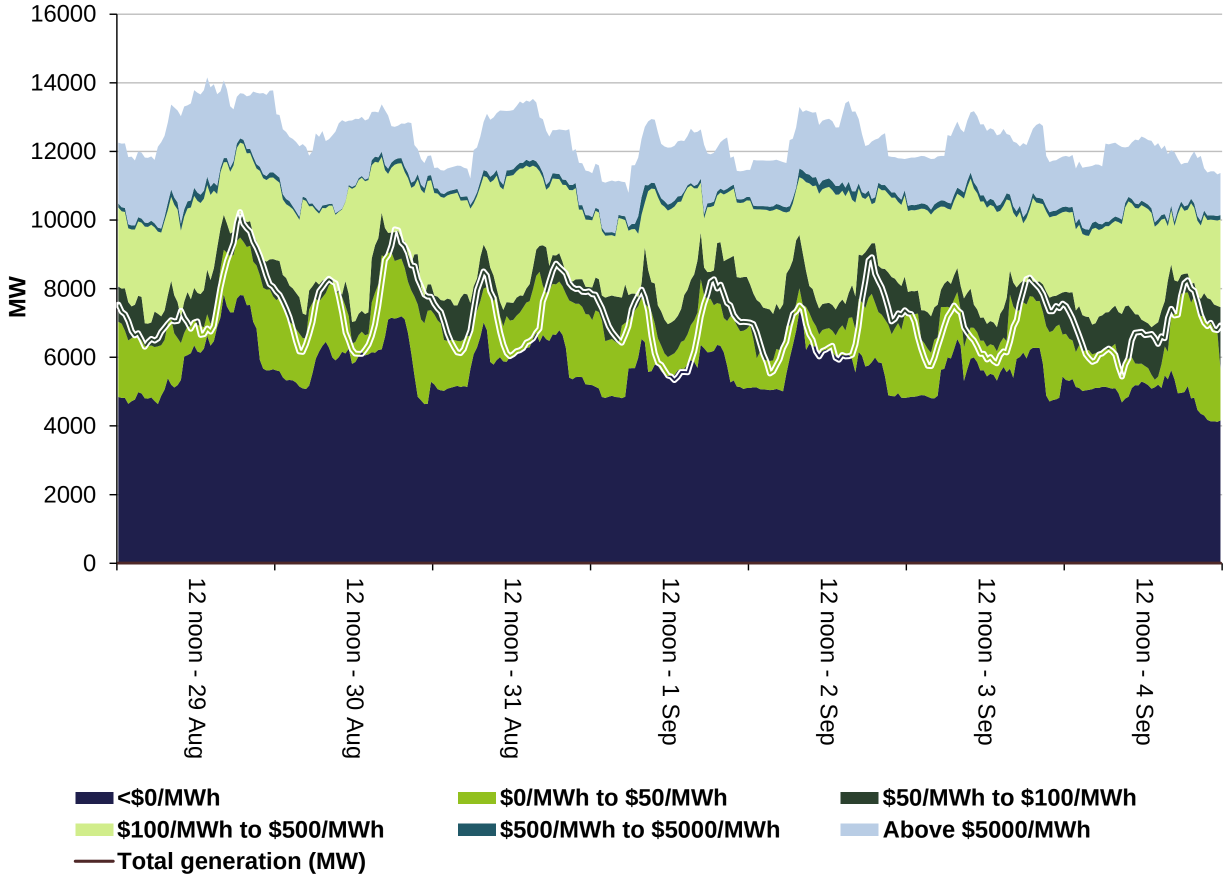


Figure 5: Victoria generation and bidding patterns

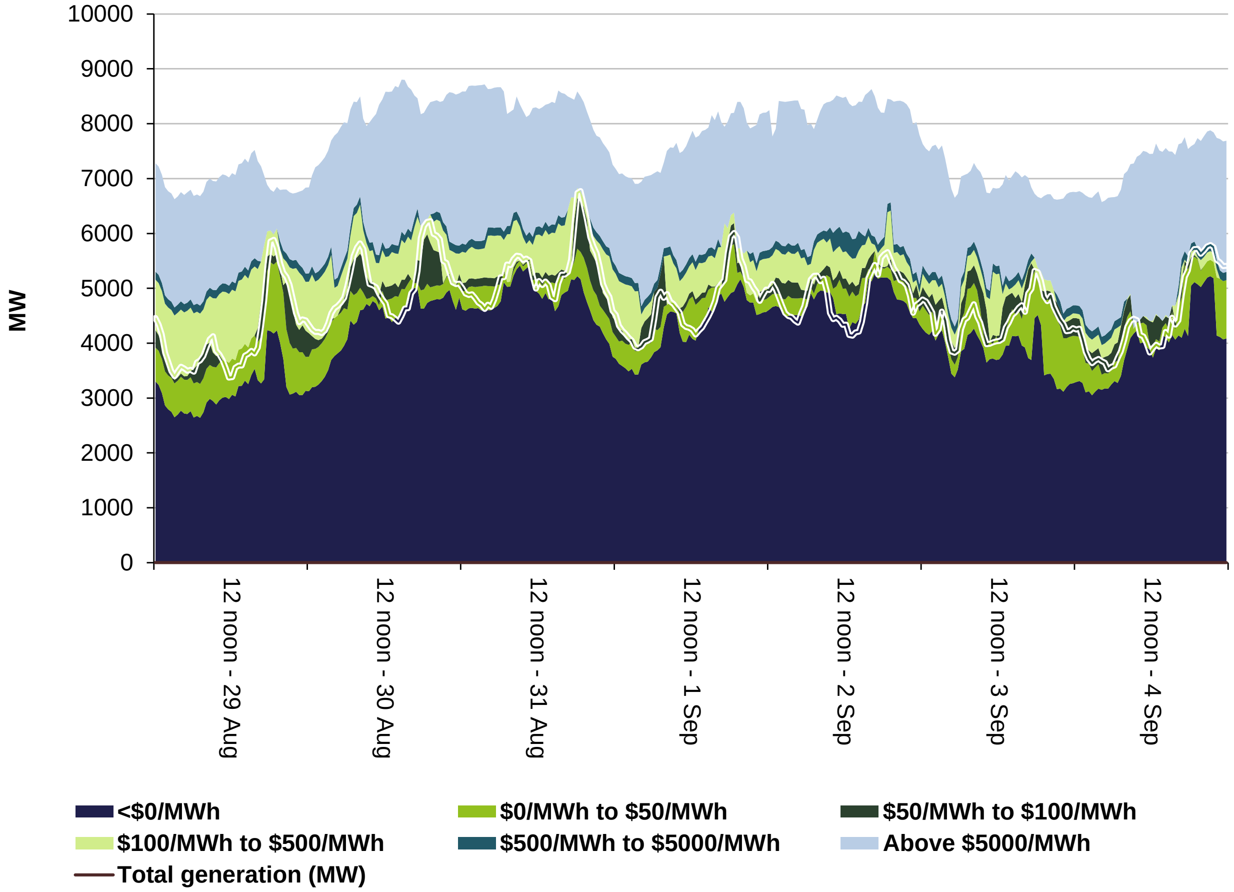


Figure 6: South Australia generation and bidding patterns

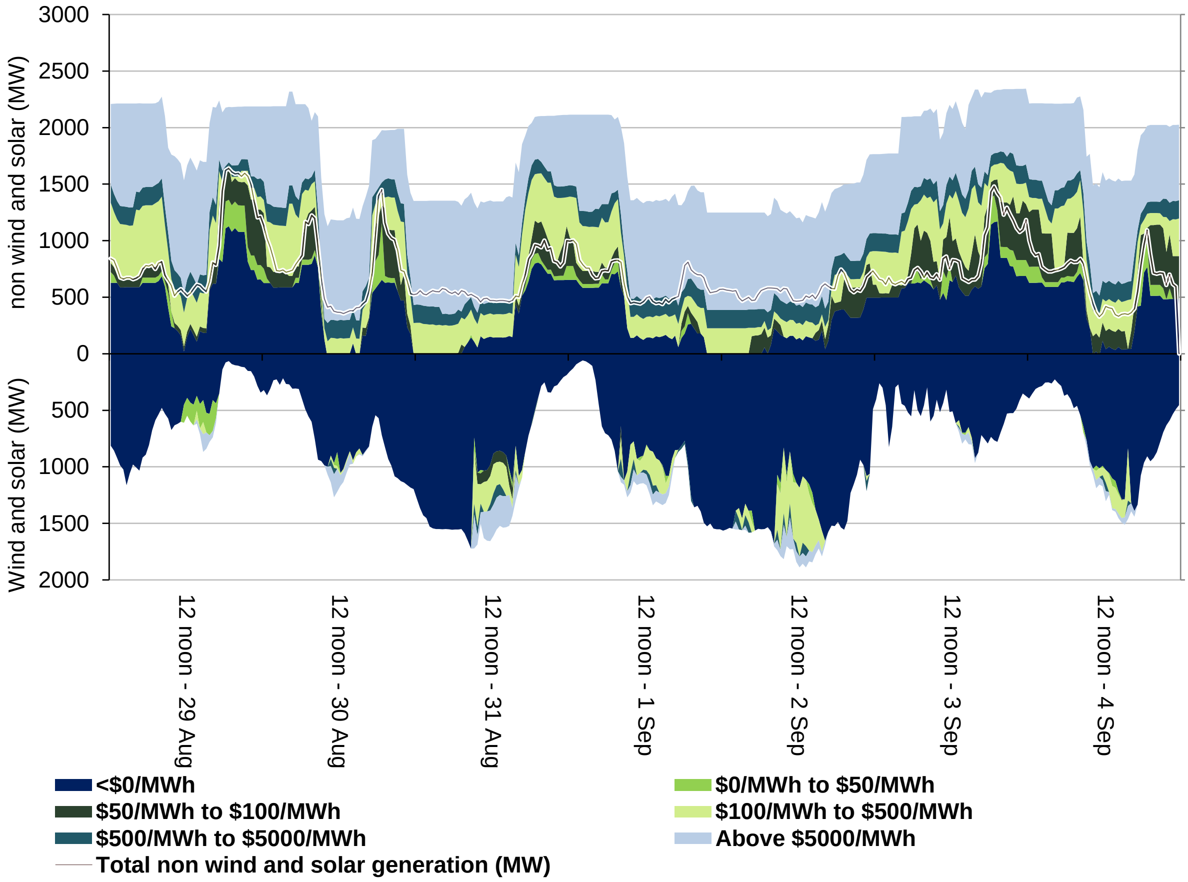
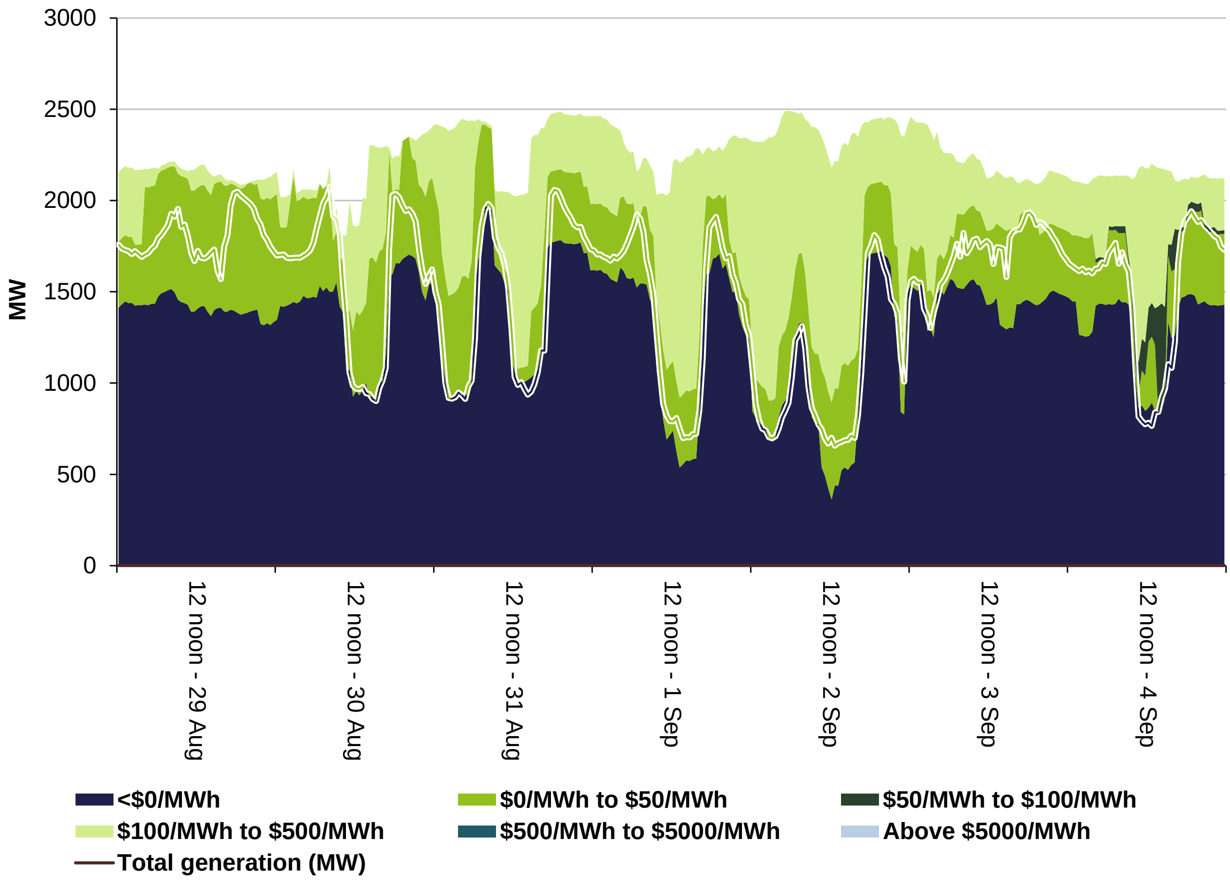


Figure 7: Tasmania generation and bidding patterns



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.

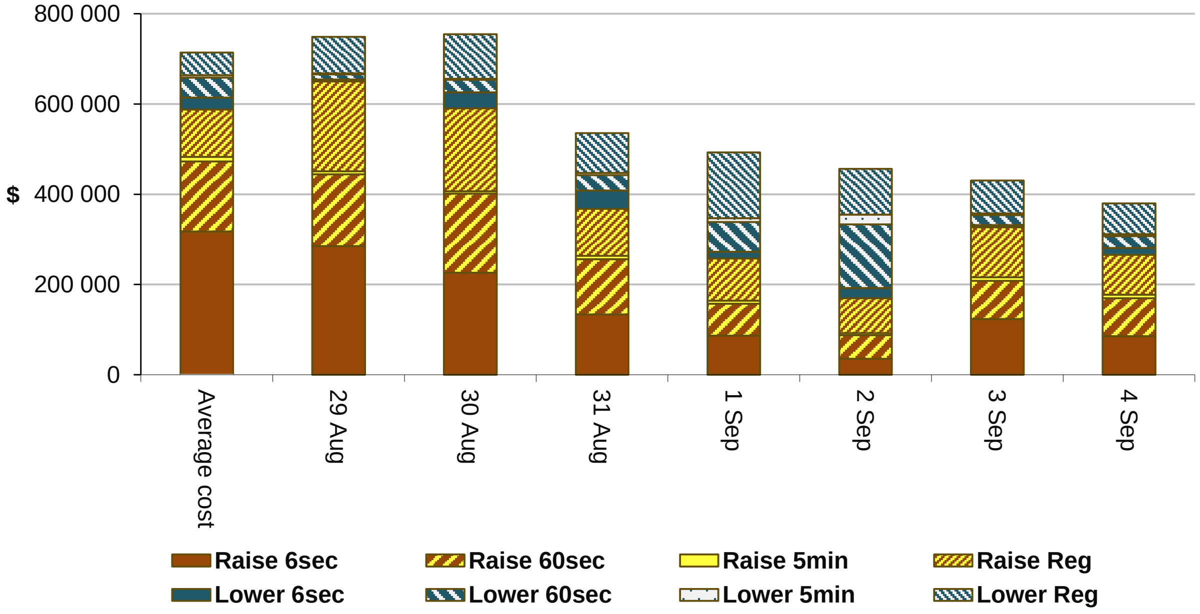
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3,351,000 or around 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $447,000 or less than 12% 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

Mainland

There were 2 occasions where the spot price in New South Wales was greater than 3 times the New South Wales weekly average price of $53/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Sunday, 29 August

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
6.30 pm	277	288	277	25,020	24,738	24,303	30,939	30,834	30,497
7 pm	247	180	235	25,267	24,986	24,620	31,121	30,992	30,669

Prices were close to forecast.

Queensland

There were 2 occasions where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $63/MWh and above $250/MWh.

Tuesday, 31 August

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
6.30 pm	272.17	279.99	63.15	7,387	7,217	7,231	8,622	8,704	8,755

Prices were close to forecast, 4 hours prior.

Wednesday, 1 September

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
6 pm	2,576.87	97.98	93.06	7,266	7,094	7,140	8,817	8,722	8,688

Demand was 172 MW higher than forecast and availability was 95 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to Rio Tinto adding in 45 MW capacity at Yarwun due to refinery constraints, and higher than forecast renewable generation which mostly offers in below $0/MWh.

An outage of the Armidale to Dumaresq 330 kV line was originally scheduled to finish at midday, but was extended past 6 pm at short notice. Constraints in place to manage the outage bound at 5.45 pm and forced exports out of Queensland over the Queensland-New South Wales interconnector for system security. At the same time, demand increased by 51 MW. With many generators already at max availability, trapped / stranded in FCAS, or ramp-constrained, price was at $15,100/MWh for 5 minutes. Participants rebid 190 MW from prices above $98/MWh to the floor effective 6 pm, in response to the high dispatch price. The constraints stopped binding at 6 pm and price fell to $102/MWh for the last dispatch interval.

South Australia

There were 23 occasions where the spot price was below -$100/MWh.

Tuesday, 31 August

Table 6: rice, 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	-181	-36	-23	1,091	995	1,020	3,061	2,634	2,669
Midday	-102	-1,000	-1,000	737	620	614	3,008	2,730	2,717
12.30 pm	-152	-1,000	-1,000	653	584	578	2,960	2,726	2,719
1 pm	-157	-1,000	-1,000	624	560	562	2,903	2,733	2,723
1.30 pm	-144	-1,000	-1,000	618	558	555	2,871	2,716	2,688
2 pm	-108	-1,000	-1,000	664	604	603	2,888	2,724	2,693
4 pm	-175	-35	-1,000	953	849	839	2,909	2,655	2,591

For the 10 am trading interval, demand was 96 MW higher than forecast and availability was 427 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast renewable generation which usually offers in at prices below $0/MWh, and Origin adding in 40 MW of capacity at the floor at Osborne.

Effective 9.55 am, participants rebid 156 MW from prices over $5,000/MWh to the floor in response to forecast price. This resulted in price dropping to the floor for 5 minutes. In response to the low price, participants rebid over 480 MW from the floor to prices above $70/MWh.

For the midday to 2 pm trading intervals, demand was between 60 MW to 117 MW higher than forecast and availability was between 155 MW to 278 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation which usually offers in at prices below $0/MWh. From 9.30 am, participants rebid over 500 MW of capacity from the floor to higher prices. This resulted in prices between $-300/MWh and $-40/MWh during all trading intervals.

For the 4 pm trading interval, demand was 104 MW higher than forecast and availability was 254 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation which usually offers below $0/MWh. There was a step change in availability at 3.35 pm, resulting in an additional 314 MW of capacity priced at or close to the floor. Price dropped to the floor for 5 minutes, before participants rebid over 400 MW from the floor to higher prices in response to the low price. The price was close to forecast for the remainder of the trading interval.

Wednesday, 1 September

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
8.30 am	-140	66	65	1,437	1,365	1,364	3,179	2,701	2,683
9 am	-158	59	45	1,260	1,252	1,263	2,843	2,431	2,432
10 am	-160	5	-13	1,061	975	984	2,589	2,205	2,210
10.30 am	-171	-300	-190	922	837	856	2,488	2,283	2,268
12.30 pm	-111	-1,000	-1,000	662	562	541	2,515	2,524	2,493
1 pm	-168	-1,000	-1,000	636	549	539	2,588	2,516	2,511
1.30 pm	-133	-1,000	-1,000	657	574	554	2,700	2,536	2,514
2.30 pm	-108	-1,000	-1,000	734	657	648	2,671	2,520	2,496

For the 8.30 am, 9 am, and 10 am trading intervals, demand was up to 86 MW higher than forecast and availability was between 384 MW to 478 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast renewable generation.

There was very little capacity offered between the floor and $68/MWh, so small changes in demand or availability could cause large fluctuations in price. During each trading interval, price dropped below $-999/MWh when demand dropped between 23 MW to 50 MW.

For the remaining trading intervals, demand was between 77 MW to 100 MW higher than forecast and availability was up to 205 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast renewable generation which mostly offers in at $0/MWh. From 6 am onwards, participants rebid at over 330 MW of capacity from the floor to higher prices in response to the forecast price. Price was higher than forecast 4 hours prior for almost all dispatch intervals.

Thursday, 2 September

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
8.30 am	-184	-23	-24	1,032	1,188	1,191	2,926	2,429	2,538

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	-206	-1,000	-1,000	916	890	865	3,067	2,670	2,709
11 am	-198	-1,000	-1,000	777	716	664	2,977	2,709	2,699
Midday	-148	-1,000	-1,000	710	520	513	3,059	2,715	2,702
12.30 pm	-103	-1,000	-1,000	703	508	475	3,100	2,658	2,699
1.30 pm	-115	-1,000	-1,000	700	531	502	3,091	2,669	2,687

For the 8.30 am trading interval, demand was 156 MW lower than forecast and availability was 497 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation which mostly offered below $0/MWh, and Origin adding in 130 MW of capacity at the floor at Osborne as it returned to service earlier than expected.

There was no capacity offered between the floor and $87/MWh so small changes in demand or availability could cause large fluctuations in price. At 8.30 am, demand dropped by 13 MW and price dropped to the floor for the last 5 minutes.

For the 10 am and 11 am trading intervals, demand was up to 61 MW higher than forecast and availability was between 268 MW to 397 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation which mostly offers below $0/MWh.

Over 230 MW of capacity was shifted from the floor to higher prices from 5.30 am onwards. Price dropped to the floor once, as forecast, within the first 2 dispatch intervals of each trading interval. In response, participants rebid over 270 MW from the floor to higher prices and was price was set higher for the remainder of the trading intervals.

For the midday, 12.30 pm and1.30 pm trading intervals, demand was between 169 MW to 195 MW higher than forecast and availability was between 344 MW to 442 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation which mostly offered below $0/MWh. In response to forecast prices, participants rebid over 615 MW from the floor to higher prices from 7.30 am onwards. This resulted in prices above forecast for all of the trading intervals.

Friday, 3 September

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
1.30 pm	-202	36	37	812	1,066	1,044	2,907	2,745	2,725

Demand was 254 MW lower than forecast and availability was 162 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast renewable generation, which offered most capacity below $0/MWh. The combination of lower than forecast demand and higher than forecast availability resulted in price settling below forecast.

Saturday, 4 September

Table 10: Price, Demand and Availability

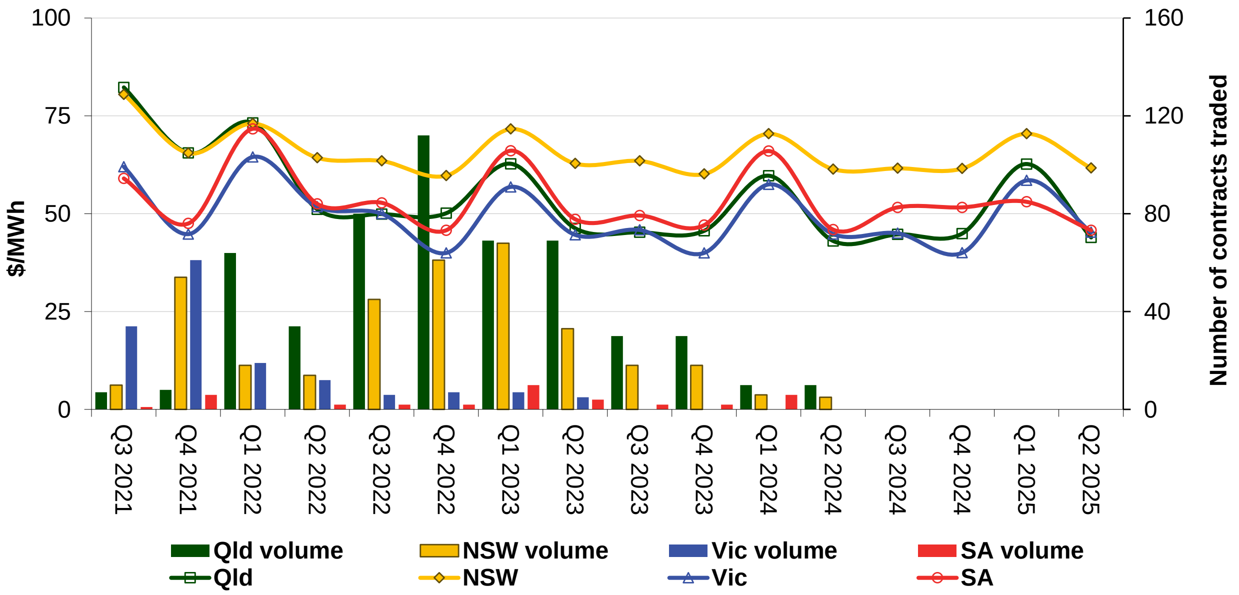
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
4 pm	-110	-80	-541	889	764	747	2,992	2,735	2,716

Price was close to forecast, 4 hours prior.

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.

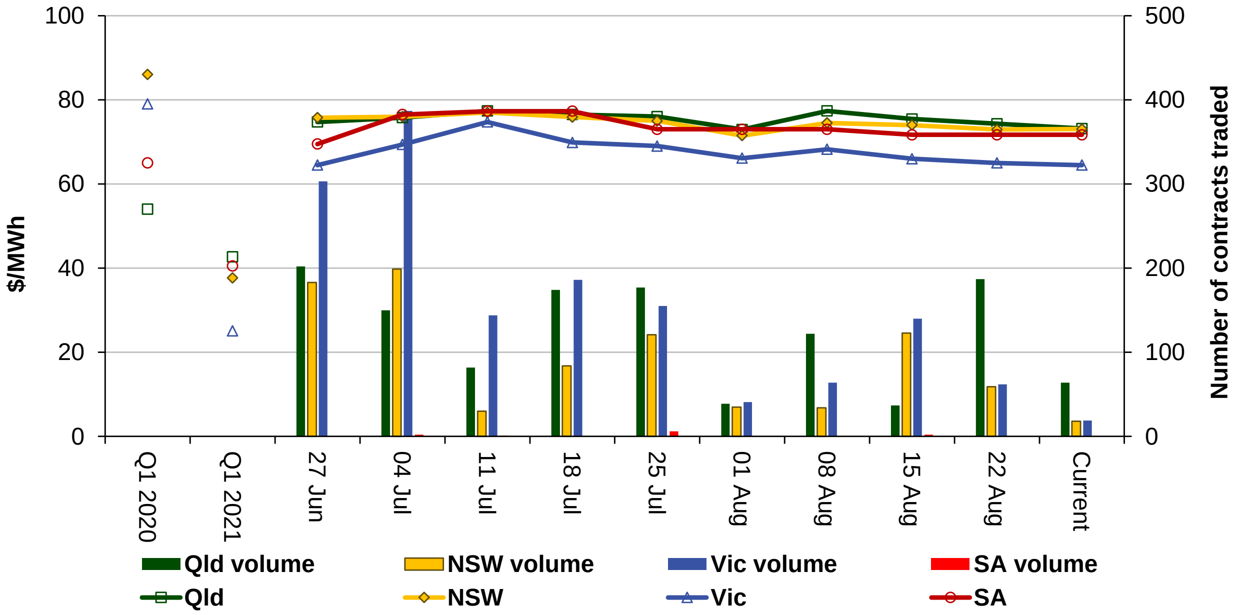
Figure 9: Quarterly base future prices Q3 2021 – Q2 2025



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2022 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 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 2022 base contracts over the past 10 weeks (and the past 2 years)

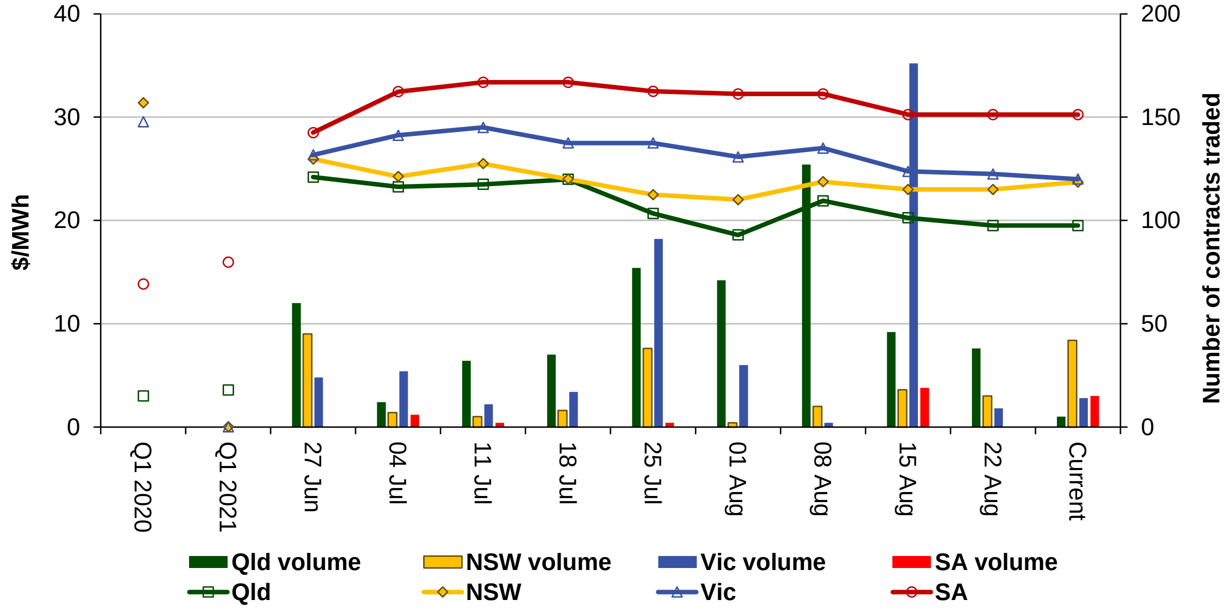


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2022 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 2020 prices are also shown.

Figure 11: Price of Q1 2022 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
September 2021