Electricity Report

AUSTRALIAN ENERGY REGULATOR

6 – 12 September 2020

Weekly Summary

Weekly volume weighted average (VWA) prices were between $9/MWh in South Australia and $39/MWh in New South Wales. Financial year to date VWA prices were between $17/MWh to $41/MWh lower than the same time last year.

The low South Australian price was driven by low demand and high wind output leading to a significant number of negative spot prices (see Figure 1). There were almost 100 instances of negative prices over the week, though not all breached our reporting thresholds.

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 September 2020.

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

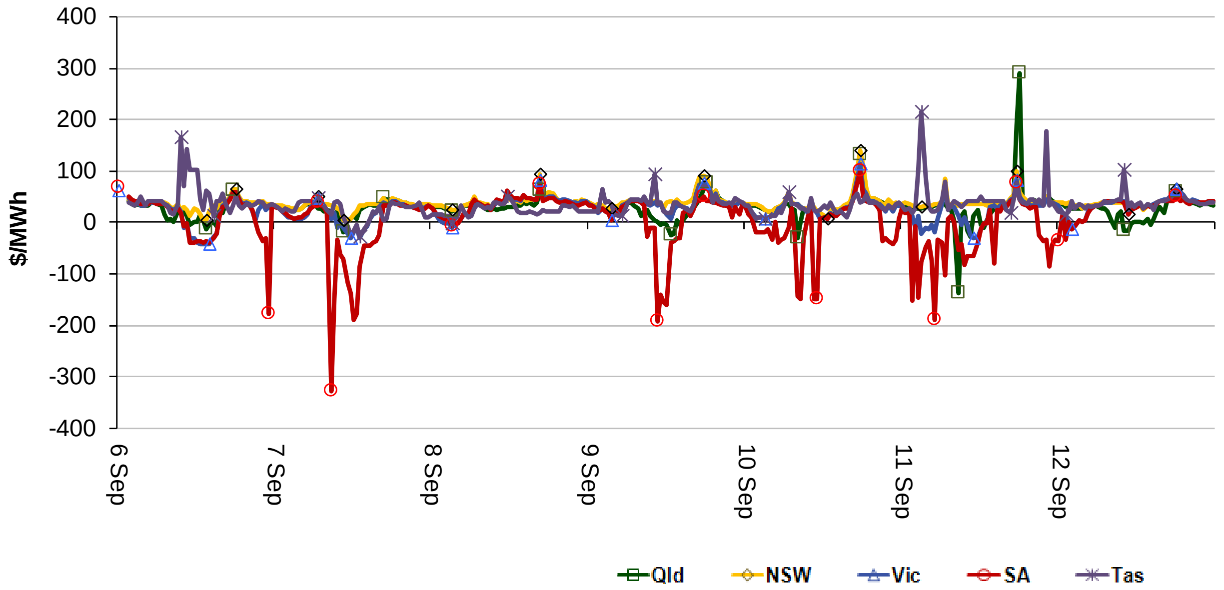


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

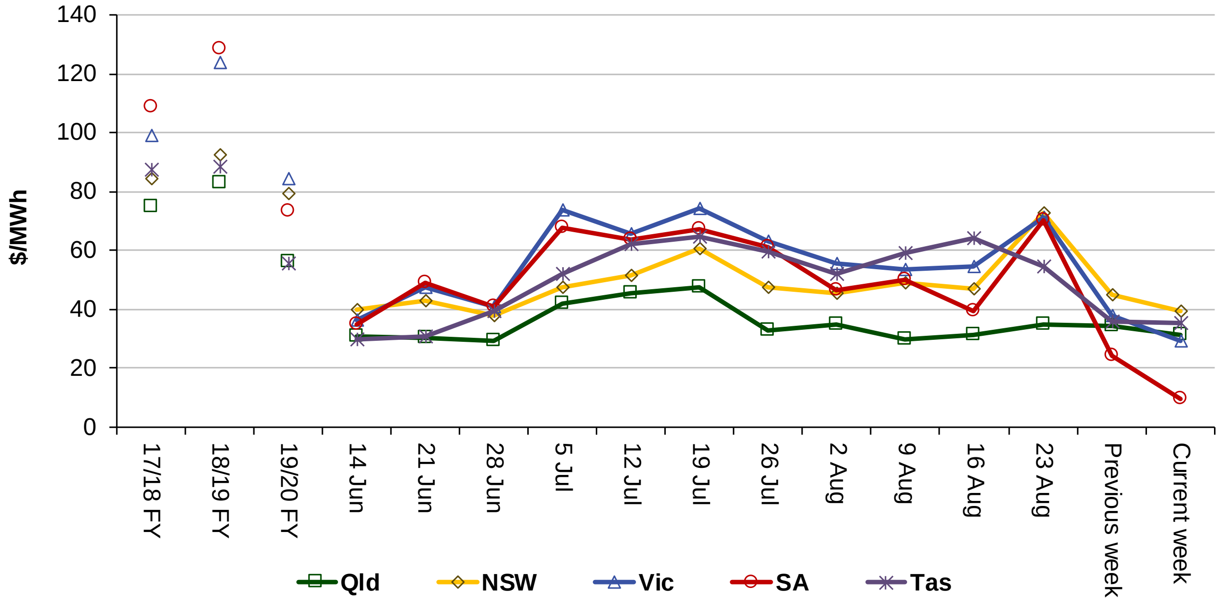


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	31	39	29	9	35
Q3 2019 QTD	63	81	99	83	70
Q3 2020 QTD	36	50	58	50	53
19-20 financial YTD	63	81	99	83	70
20-21 financial YTD	36	50	58	50	53

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 265 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	8	32	0	2
% of total below forecast	15	35	0	8

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

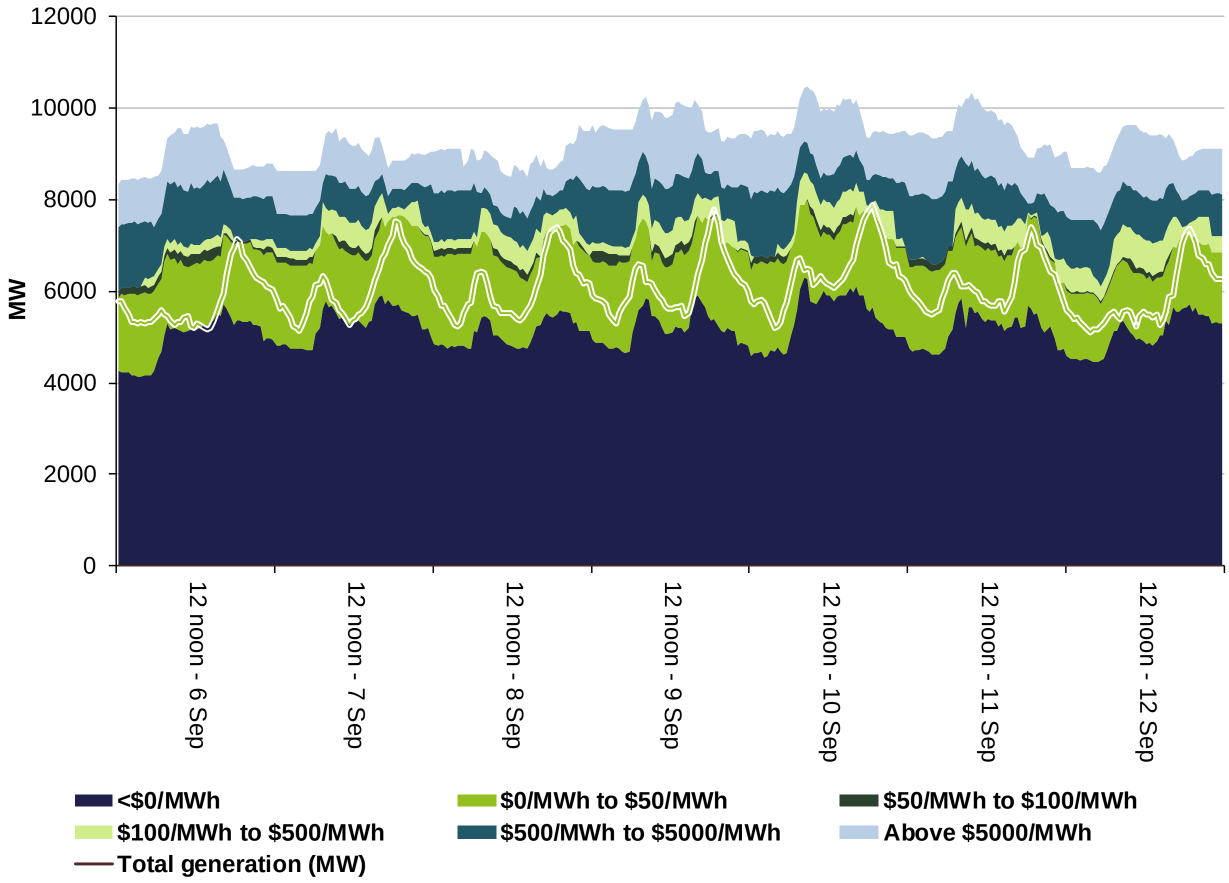


Figure 4: New South Wales generation and bidding patterns

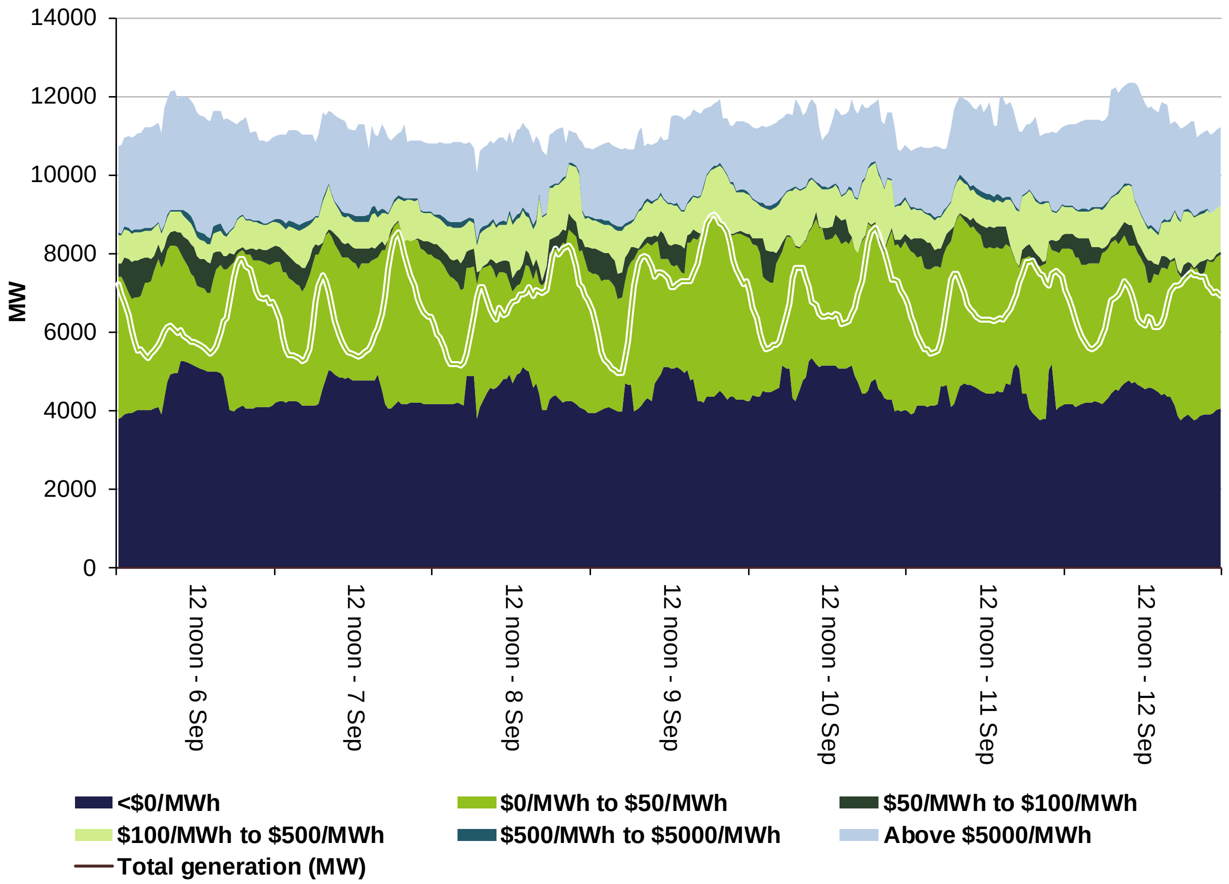


Figure 5: Victoria generation and bidding patterns

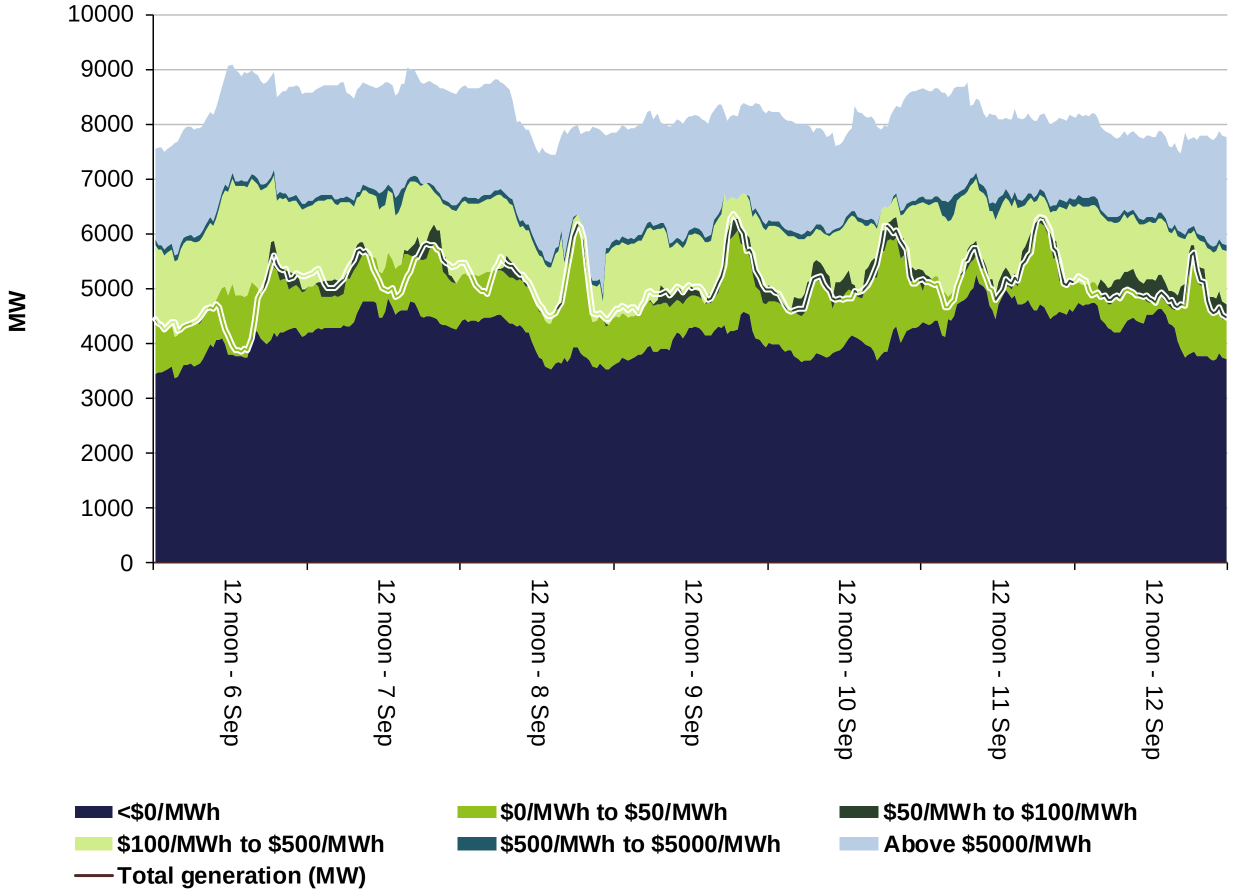


Figure 6: South Australia generation and bidding patterns

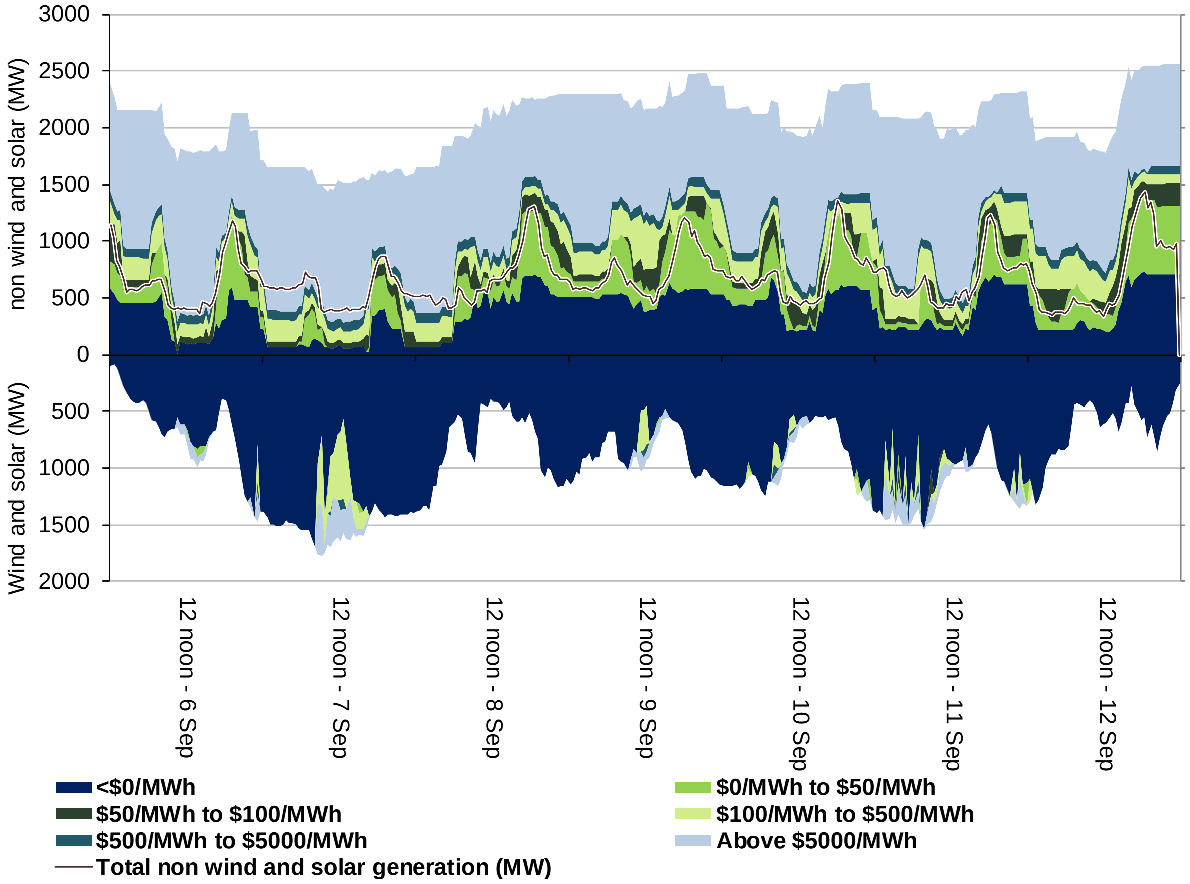
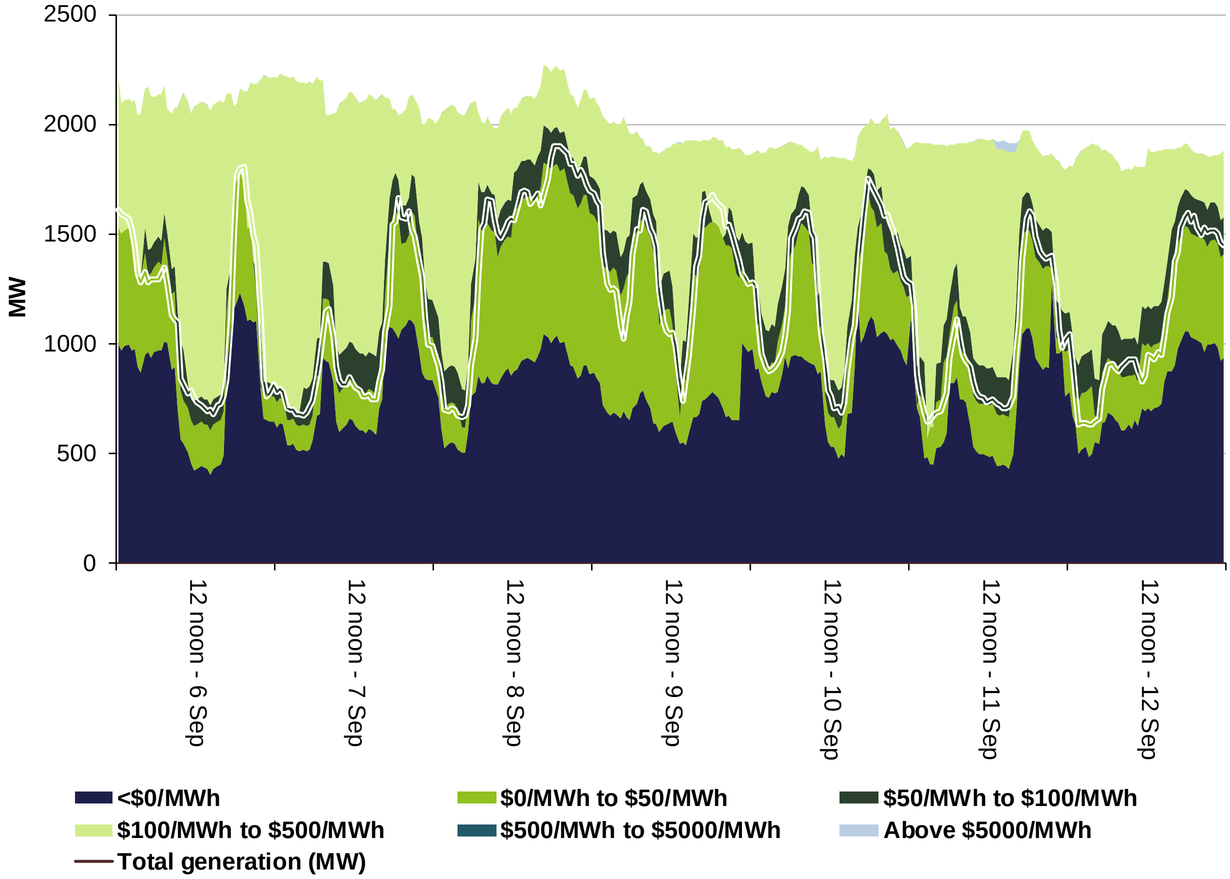


Figure 7: Tasmania generation and bidding patterns



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.

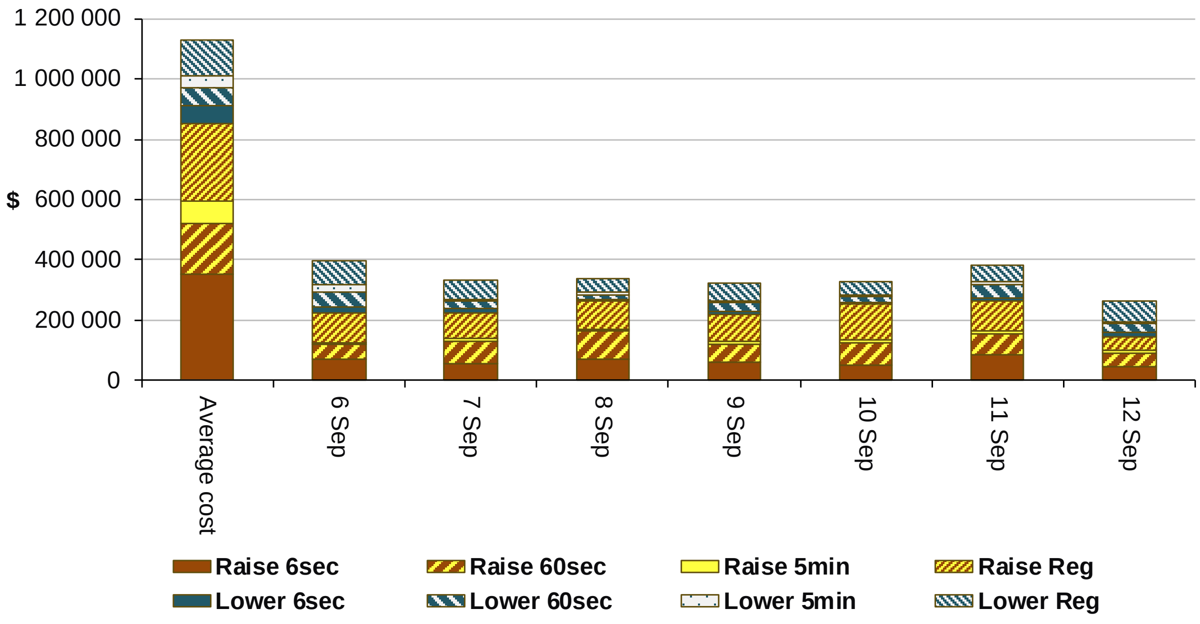
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 095 500 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $274 000 or around 4 per cent 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 was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $31/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Friday, 11 September

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
9 am	-136.41	19.80	18.75	5483	5732	5690	10 380	10 333	10 379
6.30 pm	291.21	156.50	44.55	6702	6780	6778	8915	9011	9472

A planned outage on the Muswellbrook to Tamworth line in New South Wales limited exports from Queensland into New South Wales over the QNI interconnector to a maximum of 250 MW for the majority of the day. Net flows from Queensland into New South Wales were up to 200 MW lower than forecast during the daytime.

For the 9 am trading interval, demand was 249 MW lower than forecast while availability was 47 MW higher than forecast, four hours prior. At 8.35 am demand dropped by 85 MW and with some higher priced generation ramp down-constrained and unable to set price, the price fell close to the floor for one dispatch interval.

For the 6.30 pm trading interval, demand was 78 MW lower than forecast and availability was 96 MW lower than forecast, four hours prior. At 6.05 pm, with demand increasing for the evening peak and cheaper priced generation ramp up-constrained, around 30 MW of higher priced capacity was needed to meet demand. As a result, the price was set at $1535/MWh for five minutes. In response to the higher price, over 300 MW of capacity was rebid by participants from prices above $1500/MWh to the price floor and prices fell between $33/MWh and $55/MWh for the remainder of the trading interval.

South Australia

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

Sunday, 6 September

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
11.30 pm	-177.13	-3.10	-37.00	1111	1069	1072	3450	3118	3456

Demand was 42 MW higher than forecast and availability was 332 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation. Effective 11.25 pm, rebids by Trustpower for Snowtown Wind Farm and by Lincoln Gap Wind Farm shifted over 330 MW of capacity from the cap to the price floor in response to forecast prices. As a result, the price fell to the price floor at 11.25 pm.

Monday, 7 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
9 am	-328.41	26.98	29.96	907	1076	1078	3236	3045	3059
9.30 am	-148.27	0	0	1017	979	983	3239	3084	3108
11.30 am	-117.95	-1000	-1000	731	654	677	3118	3041	3051
Midday	-138.74	-1000	-1000	722	644	699	3158	3128	3135
12.30 pm	-189.39	-1000	-1000	666	629	683	3185	3138	3132
1 pm	-176.99	-1000	-1000	633	612	676	3096	3133	3133

For the 9 am trading interval demand was 169 MW lower than forecast while availability was 191 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation. At 8.55 am demand dropped by 35 MW and with higher priced generation ramp-down constrained and unable to set price, the price dropped to the floor for the remainder of the trading interval.

For the 9.30 am trading interval, demand was close to forecast and availability was 155 MW higher than forecast, four hours prior. Higher availability was due to higher than forecast wind generation. Effective 9.15 am, demand fell by 50 MW and rebids at by Infigen Energy for Lake Bonney 2 and 3 and Trustpower for Snowtown Wind Farm shifted over 300 MW of capacity from prices above -$39/MWh to the floor in response to constraints in place. As a result, the price fell to the price floor for one dispatch interval.

For the 11.30 am and midday trading intervals, demand was around 80 MW higher than forecast and availability was close to forecast, four hours prior. From around 7 am, over 870 MW of capacity was rebid by participants from the price floor to higher prices in response to the forecast price of -$1000/MWh. This resulted in prices between -$30/MWh and -$350/MWh for both trading intervals.

For the 12.30 pm and 1 pm trading intervals, demand and availability were both close to forecast, four hours prior. Following the price falling to the floor as forecast early in each trading interval, participants rebid between 270 MW and 544 MW of capacity from the price floor to prices greater than $150/MWh which resulted in prices above -$33/MWh for the rest of both trading intervals.

Wednesday, 9 September

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
11 am	-192.62	-39.00	-1000	671	749	777	3087	3009	2958
11.30 am	-139.82	-37	-39	674	691	724	3211	2910	2847
Midday	-154.96	-996.22	-37	621	637	681	3176	2842	2749
12.30 pm	-160.73	-996.22	-3.10	607	592	621	3097	2791	2660

For the 11 am trading interval, demand and availability were both close to forecast, four hours prior. Effective 11 am, Infigen for Snowtown Wind Farm rebid 99 MW of capacity from the cap to the price floor in response to forecast demand. At the same time, demand dropped by 30 MW and price dropped to the floor for one dispatch interval.

For the 11.30 am trading interval, demand was close to forecast and availability was 301 MW higher than forecast, four hours prior. Higher availability was due to higher than forecast wind generation, most of which was priced below $0/MWh. Effective 11.05 am, a rebid by Infigen for Snowtown Wind Farm shifted 99 MW of capacity from the cap to the floor This resulted in price dropping to the floor for the first dispatch interval

For the midday and 12.30 pm trading intervals, demand was close to forecast and availability was between 306 MW and 334 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. The dispatch price dropped to the floor as forecast once during each trading interval. In response to the low price, participants rebid at least 360 MW of capacity from the price floor to prices greater than $150/MWh.

Thursday, 10 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	-144.40	40.19	40.44	1266	1241	1261	3310	2990	2934
9 am	-148.66	35.26	38.21	1190	1149	1162	3321	3024	2965
11 am	-148.94	-1000	26.53	701	696	710	2739	2676	2662
11.30 am	-150.54	-1000	-3.10	661	629	633	2750	2790	2602

For all trading intervals, higher than forecast availability was primarily due to higher than forecast wind or solar generation, most of which was offered below $0/MWh.

For the 8.30 am trading interval demand was close to forecast and availability was 320 MW higher than forecast, four hours prior. Effective 8.10 am, AGL Energy rebid 88 MW of capacity at Barker Inlet Power Station from $0/MWh to the price floor in response to forecast price. This resulted in the price falling to the price floor for five minutes.

For the 9 am trading interval demand was close to forecast and availability was 297 MW higher than forecast, four hours prior. At 8.45 am wind generation picked up by almost 100 MW, demand fell by 24 MW and with higher priced generation ramp down-constrained and unable to set price, the price dropped to the price floor for five minutes.

For the 11 am and 11.30 am trading intervals, demand was close to forecast and availability was up to 63 MW higher than forecast, four hours prior. Following the dispatch price falling to the floor as forecast in each trading interval, participants rebid around 340 MW of capacity from the floor to prices above $71/MWh. As a result, prices were around $30/MWh for the remainder of the trading intervals.

Friday, 11 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
2 am	-152.39	27.84	27.12	992	1064	1069	3549	3251	3129
3 am	-147.06	-115	13.52	1102	997	982	3456	3194	3079
5.30 am	-189.63	-51.00	-1000	1087	949	941	3580	3227	3234
7 am	-103.90	22.47	28.12	1197	1106	1105	3440	3218	3255

For all trading intervals, availability was between 222 MW and 353 MW higher than forecast, four hours prior. Higher than forecast availability was primarily due to higher than forecast wind generation, most of which was offered below $0/MWh.

For the 2 am trading interval, demand was 72 MW lower than forecast, four hours prior. There was little capacity priced between the floor and $32/MWh so small changes in demand or availability could cause large fluctuations in price. Effective 1.55 am, Trustpower rebid 270 MW of capacity across Snowtown North and Snowtown South Wind Farms from prices greater than -$115/MWh to the price floor in response to a constraint in place. At the same time, demand fell by almost 50 MW and the price dropped to the floor for 5 minutes.

For the 3 am trading interval demand was 105 MW higher than forecast, four hours prior. Rebids by Trustpower at Snowtown North and South and by Lincoln Gap Wind Farm shifted more than 380 MW of capacity from prices above -$115/MWh to the price floor in response to constraints in place or forecast price, effective 2.35 am. As a result, the price fell to -$1000/MWh for one dispatch interval.

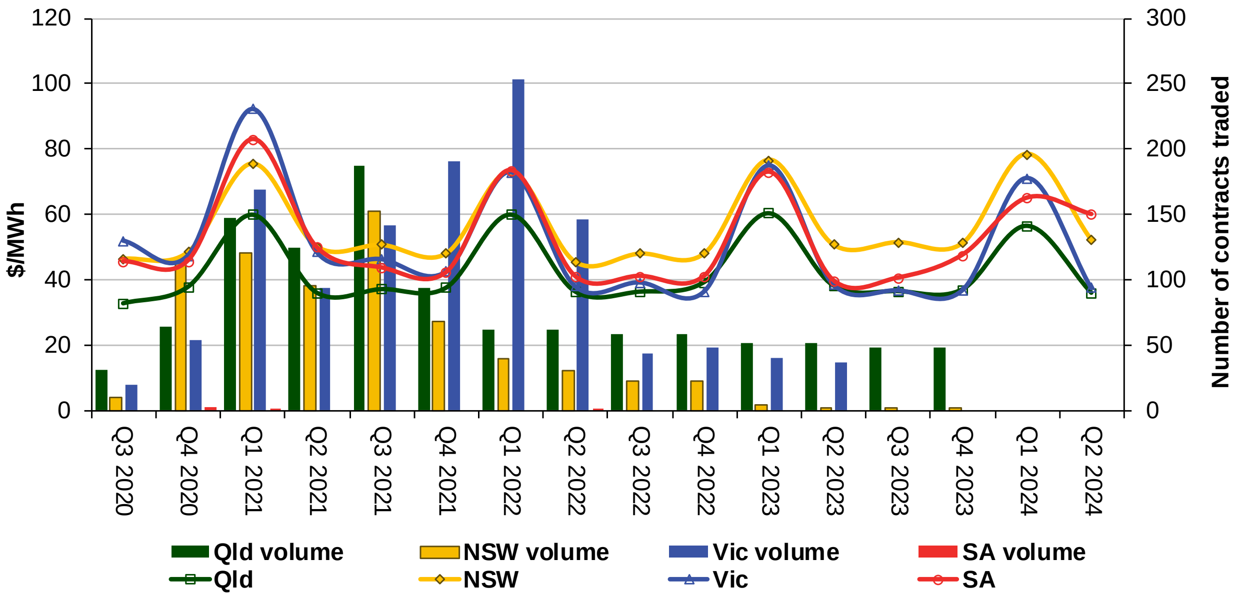
For the 5.30 am trading interval demand was 138 MW higher than forecast, four hours prior. Effective 5.30 am, rebids at by Infigen for Snowtown Wind Farm and by Lincoln Gap Wind Farm shifted over 310 MW of capacity from $15 000/MWh to the price floor in response to forecast prices and the price fell to -$1000/MWh for five minutes.

For the 7 am trading interval, demand was 91 MW higher than forecast, four hours prior. Effective 6.35 am, Infigen rebid 99 MW of capacity at Snowtown Wind Farm from the cap to the price floor in response to forecast price and the price fell to -$1000/MWh for five 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.

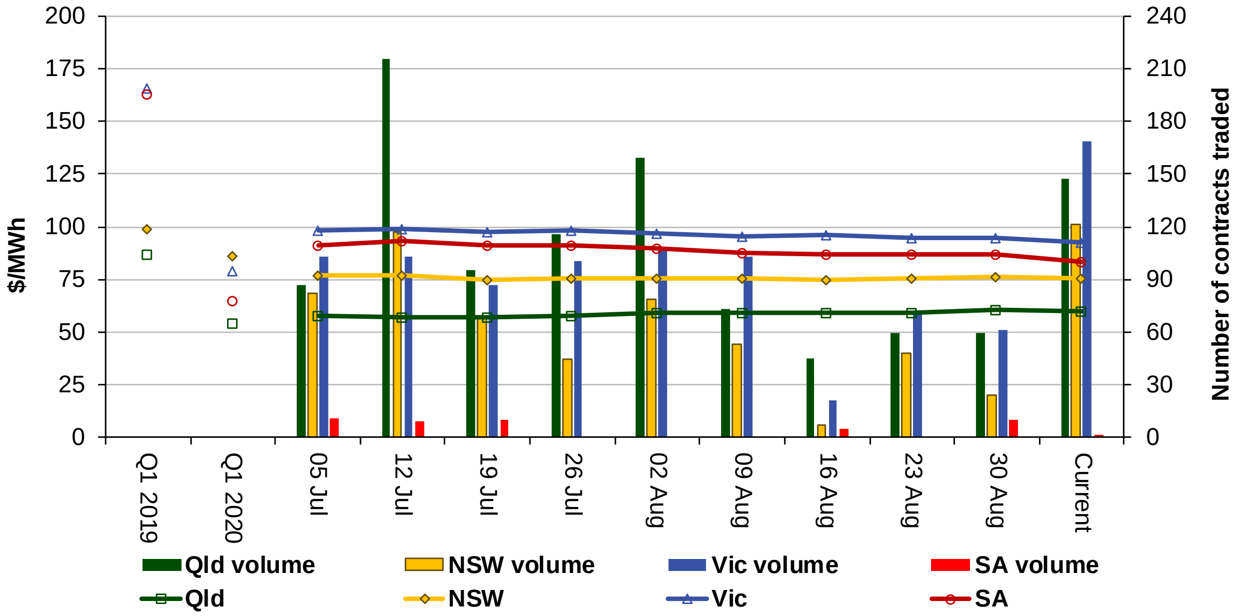
Figure 9: Quarterly base future prices Q3 2020 – Q2 2024



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)

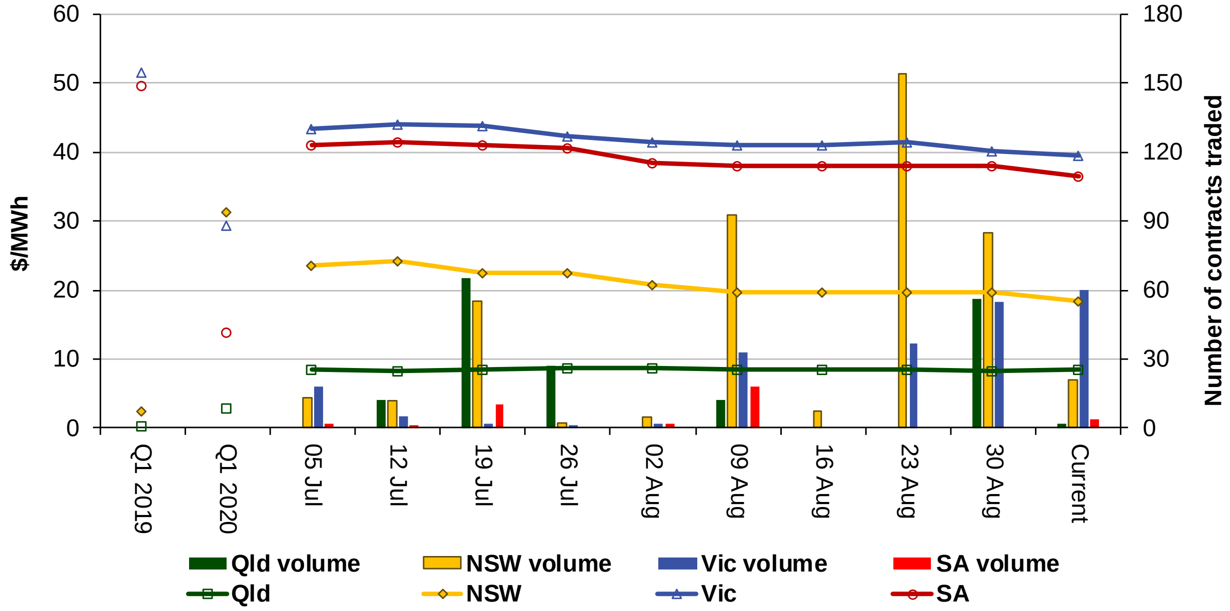


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
September 2020