16 – 22 August 2020

Weekly Summary

Weekly volume weighted average (VWA) prices were between $31/MWh in Queensland and $64/MWh in Tasmania. QTD VWA prices continue to be about $30/MWh lower than the same time last year.

Reduced availability of generation in Victoria and South Australia at the start of the week was mainly due to outages at Yallourn and lower wind generation (see Figures 5 and 6).

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 16 to 22 August 2020.

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

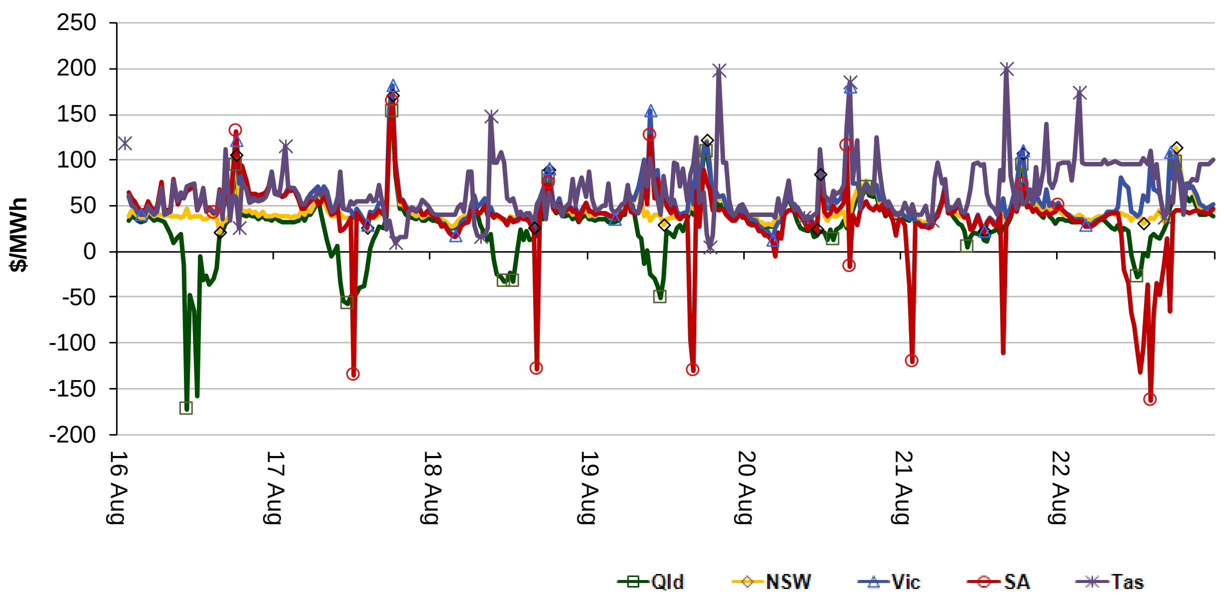


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

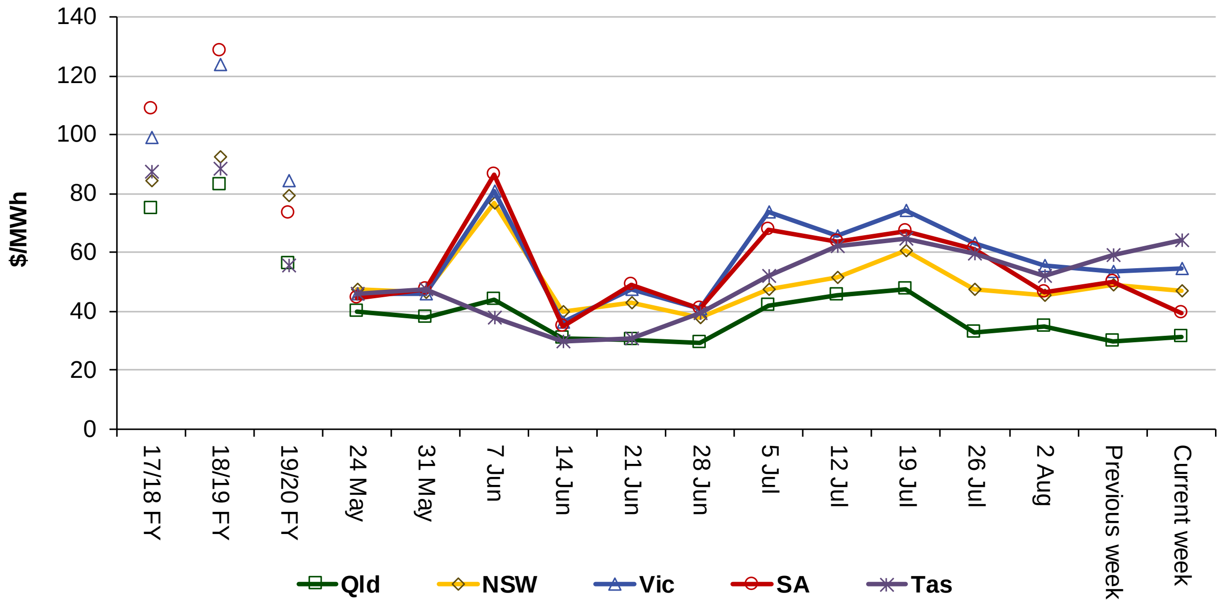


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	31	47	55	39	64
Q3 2019 QTD	67	76	97	81	81
Q3 2020 QTD	37	49	61	55	57
19-20 financial YTD	67	76	97	81	81
20-21 financial YTD	37	49	61	55	57

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 278 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	9	25	0	3
% of total below forecast	12	44	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

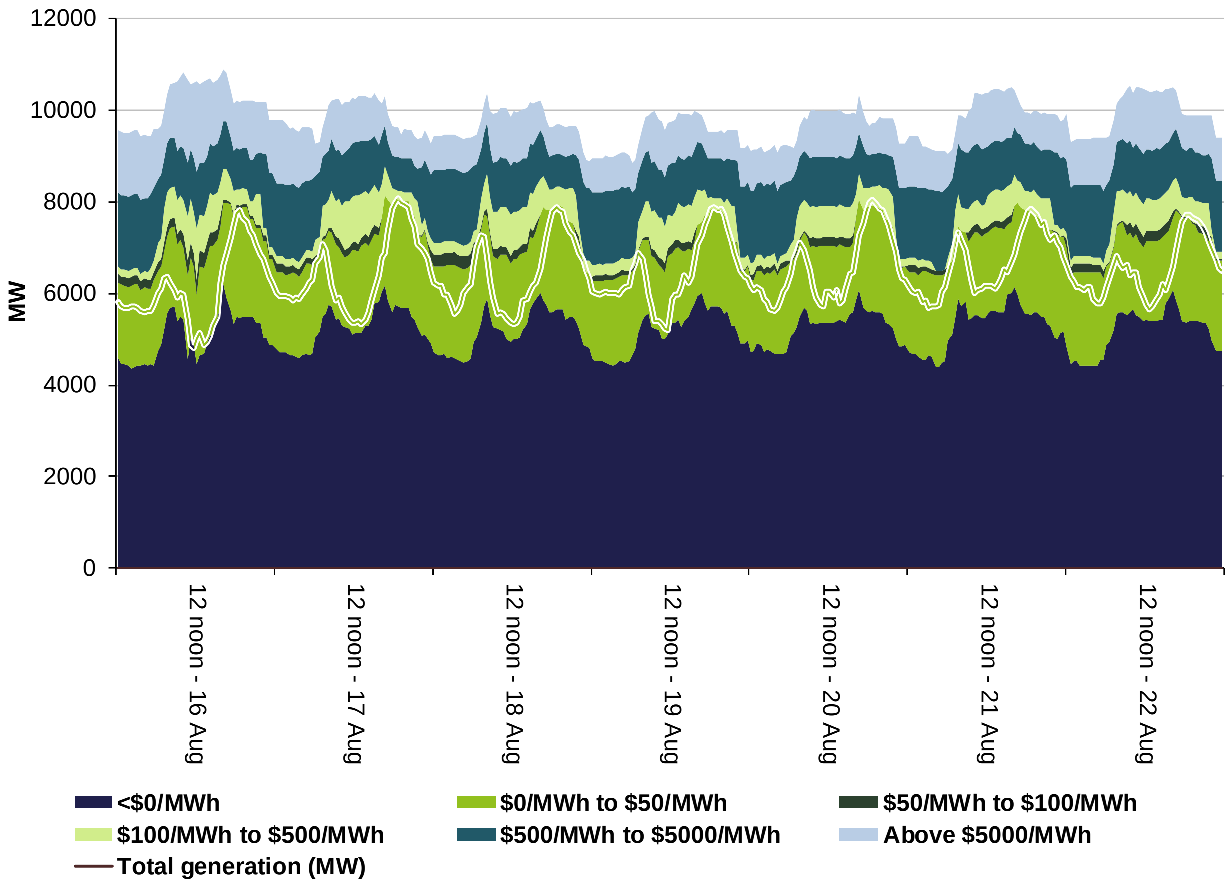


Figure 4: New South Wales generation and bidding patterns

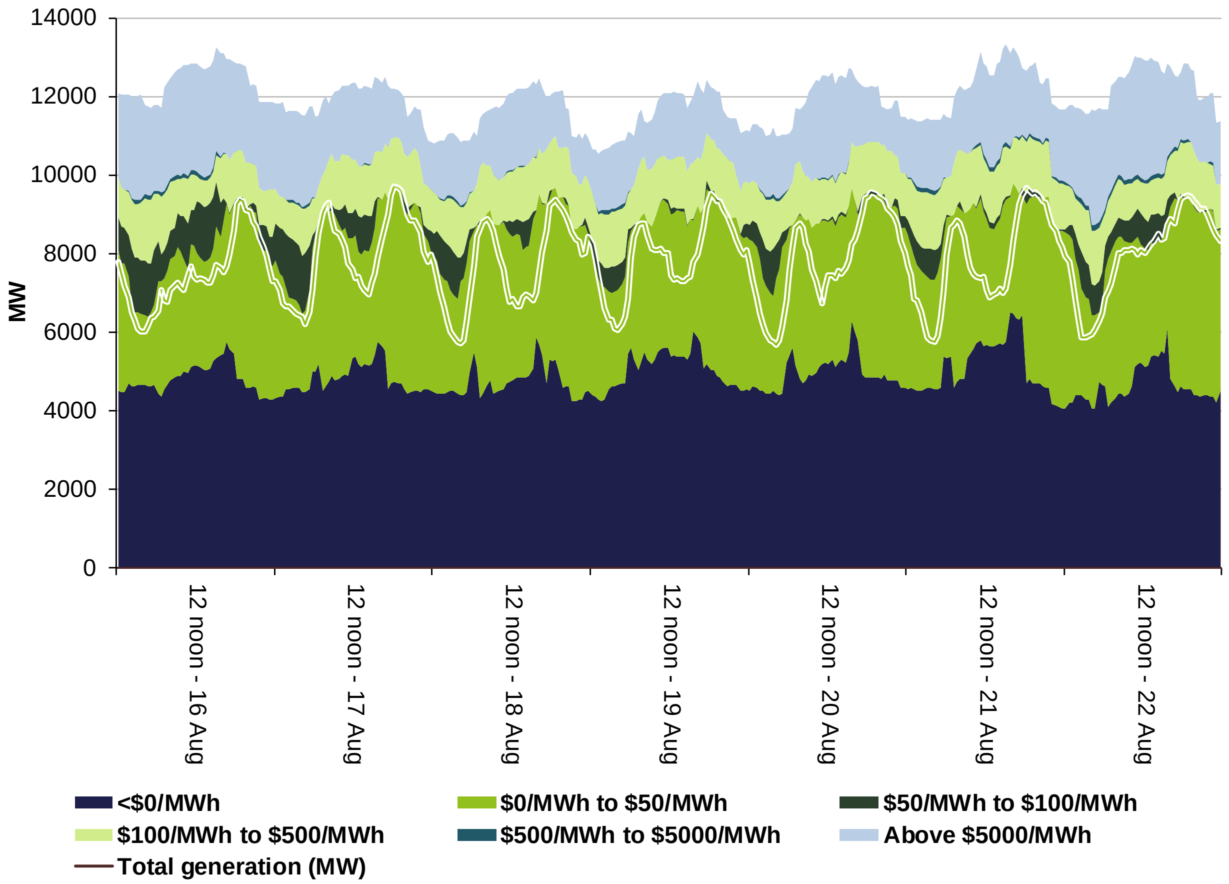


Figure 5: Victoria generation and bidding patterns

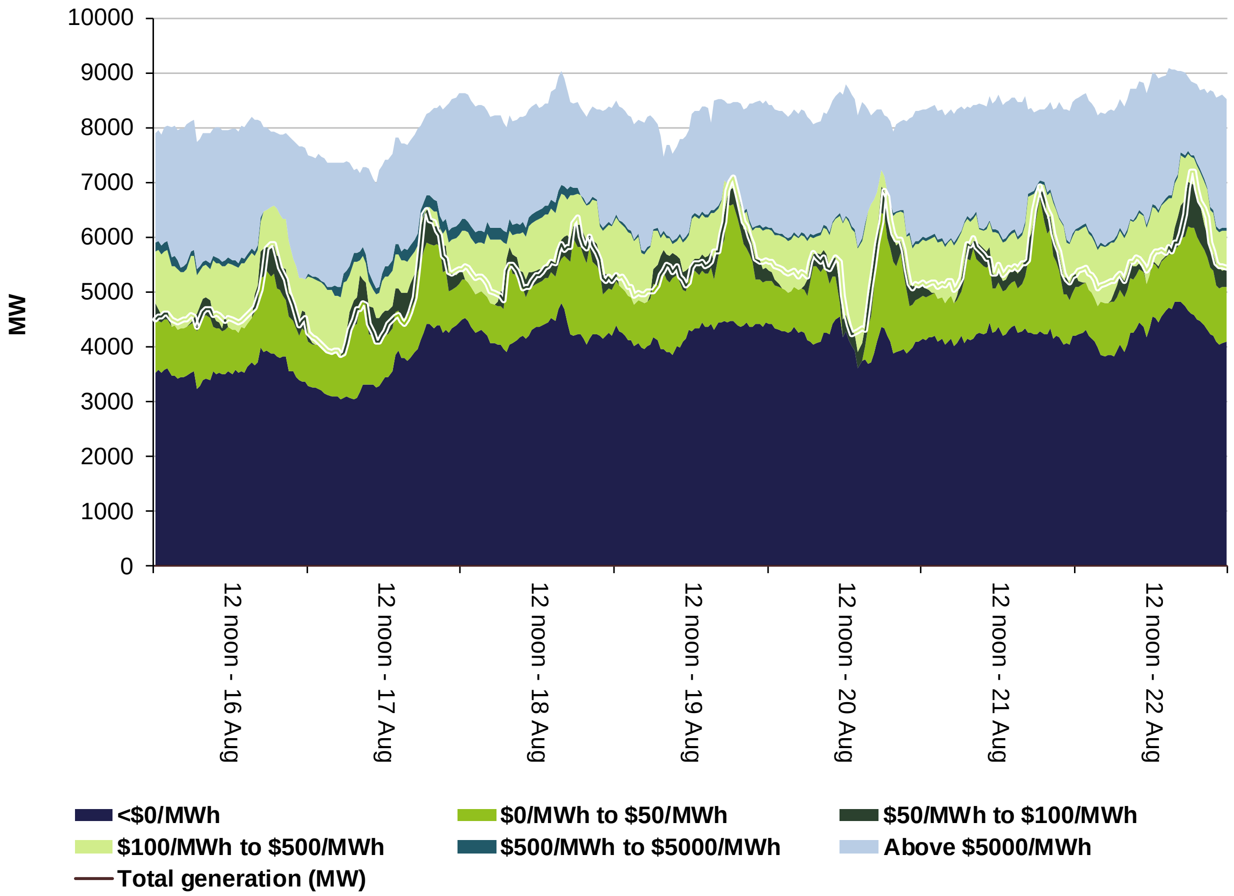


Figure 6: South Australia generation and bidding patterns

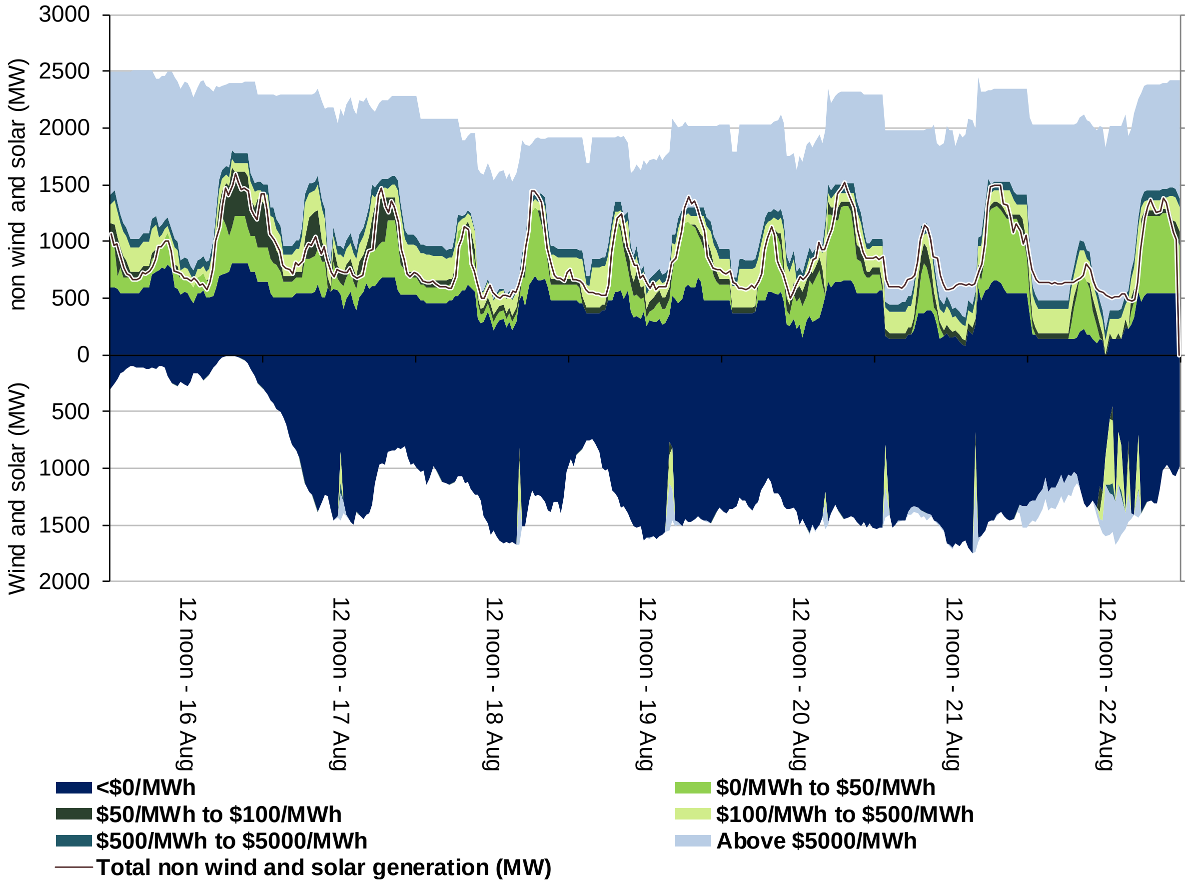
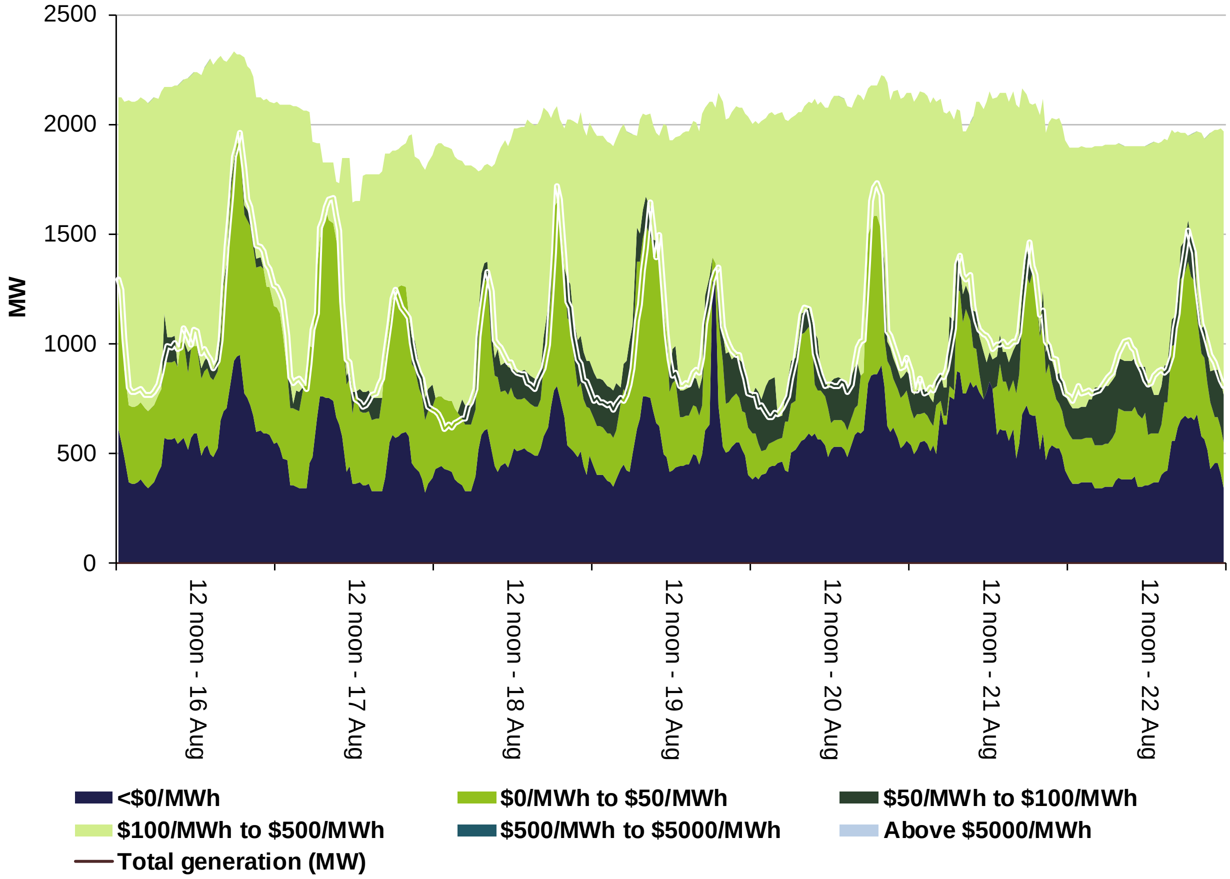


Figure 7: Tasmania generation and bidding patterns



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.

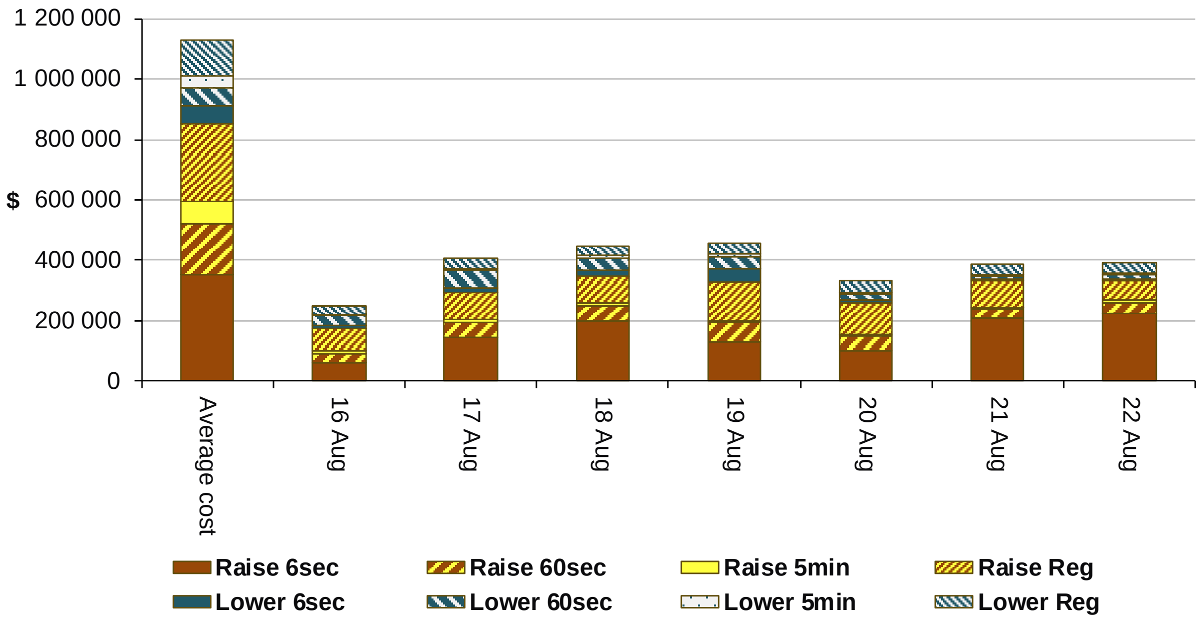
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 853 500 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $813 500 or around 6 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 were two occasions where the spot price in Queensland was below -$100/MWh.

Sunday, 16 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
11 am	-172.50	0.73	11.49	4154	4197	4195	10 666	10 752	10 615
12.30 pm	-158.42	-72.03	-1000.00	3998	4091	4069	10 648	10 696	10 764

For the 11 am trading interval demand was 43 MW lower than forecast while availability was 86 MW lower than forecast, four hours prior. In preparation for a planned outage of the Armidale to Tamworth line in New South Wales, a ramping constraint reduced exports from Queensland into New South Wales from 800 MW at the start of the trading interval down to 420 MW by 10.45 am. At 10.50 am, a constraint forced an 80 MW change in flow across the Terranora interconnector from 50 MW into New South Wales to 30 MW into Queensland while demand dropped by 36 MW. With higher priced generation ramp-down constrained and unable to set price the dispatch price dropped almost to the floor. In response, renewable generation rebid availability to higher prices.

For the 12.30 pm trading interval demand was 93 MW lower than forecast while availability was 48 MW lower than forecast, four hours prior. The outage of the Armidale to Tamworth line had come into effect and exports from Queensland into New South Wales continued to be reduced. At 12.05 pm, demand dropped by 70 MW and with higher priced generation ramp-down constrained and unable to set price, the dispatch price dropped to the floor. At 12.10 pm Pump 2 at Wivenhoe commenced consumption of 240 MW, causing the price to increase up to $20/MWh for the remainder of the trading interval.

South Australia

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

Monday, 17 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
12.30 pm	-134.86	35.21	40.00	1513	1268	1304	3609	3591	3543

Demand was 245 MW higher than forecast while availability was close to forecast, four hours prior. At 12.25 pm, lower priced capacity increased by around 165 MW as availability at Bungala One and Bungala Two Solar Farms increased. This resulted in the price dropping to the floor for one dispatch interval before participants rebid almost 820 MW of capacity from the floor to higher prices in response.

Tuesday, 18 August

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
4.30 pm	-129.20	28.03	29.98	1288	1191	1205	3406	3149	3133

Demand was 97 MW higher than forecast while availability was 257 MW higher than forecast. Higher than forecast availability was due to higher than forecast solar generation.

Offers set up the day prior by Engie at Pelican Point increased availability of capacity priced close to the floor by 160 MW at 4.05 pm. In addition, rebids by Trustpower at Snowtown north and south wind farms moved capacity from prices above $-39/MWh to the price floor, effective 4.05 pm. With no capacity offered between the floor and $85/MWh, and with higher priced generation ramp up constrained or trapped/stranded in FCAS the dispatch price fell to the floor for five minutes. In response to the negative price, participants rebid net 950 MW of capacity from the floor to prices above $71/MWh.

Wednesday, 19 August

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
4.30 pm	-129.75	0.00	0.00	1334	1221	1186	3487	3461	3465

Demand was 113 MW higher than forecast and availability was 26 MW higher than forecast, four hours prior. At 4.25 pm wind generation increased by 253 MW across the region, most of which was priced at the floor. This resulted in the dispatch price dropping to the floor before participants rebid around 930 MW of capacity from the floor to prices above $150/MWh.

Friday, 21 August

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 am	-120.20	32.01	22.71	1337	1271	1282	3418	3365	3655
4 pm	-111.67	27.13	35.11	1298	1190	1198	3940	3684	3520

Demand was respectively 66 MW and 108 MW higher than forecast for the above trading intervals and availability was 53 MW and 256 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.

Rebidding of capacity to the price floor immediately prior to the start of dispatch resulted in the price dropping to the floor for the first dispatch interval in both trading intervals. Participants then rebid capacity to higher prices for the remainder of the trading intervals.

Saturday, 22 August

Table 8: Price, Demand and Availability

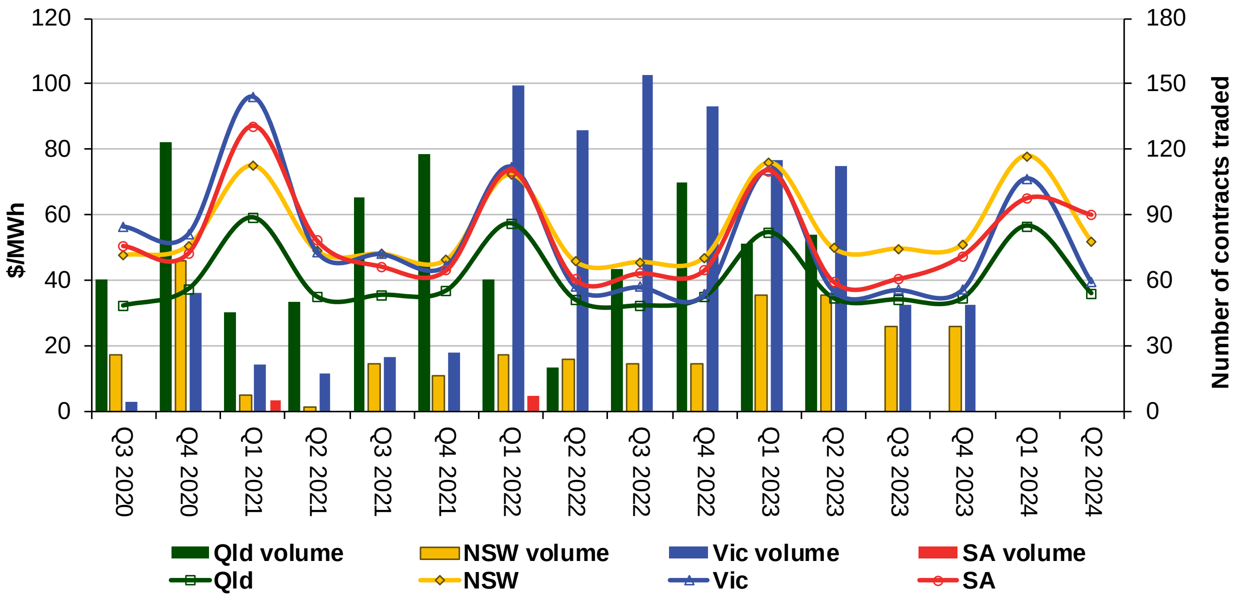
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
12.30 pm	-107.35	-1000.00	-1000.00	875	611	691	3619	3573	3573
1 pm	-132.93	-1000.00	-1000.00	897	548	613	3611	3583	3569
1.30 pm	-105.51	-1000.00	-1000.00	954	535	610	3582	3580	3553
2.30 pm	-162.31	-1000.00	-1000.00	949	608	669	3658	3513	3542

Demand was between 264 MW and 419 MW higher than forecast and availability was close to or up to 145 MW higher than forecast. In all trading intervals, the price was forecast to be at the floor for both the four and 12 hour forecasts. Participants responded to the forecast negative prices by rebidding capacity from the floor to higher price bands. The price dropped below $-500/MWh once during each trading interval, which participants responded to by rebidding additional capacity to higher prices.

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.

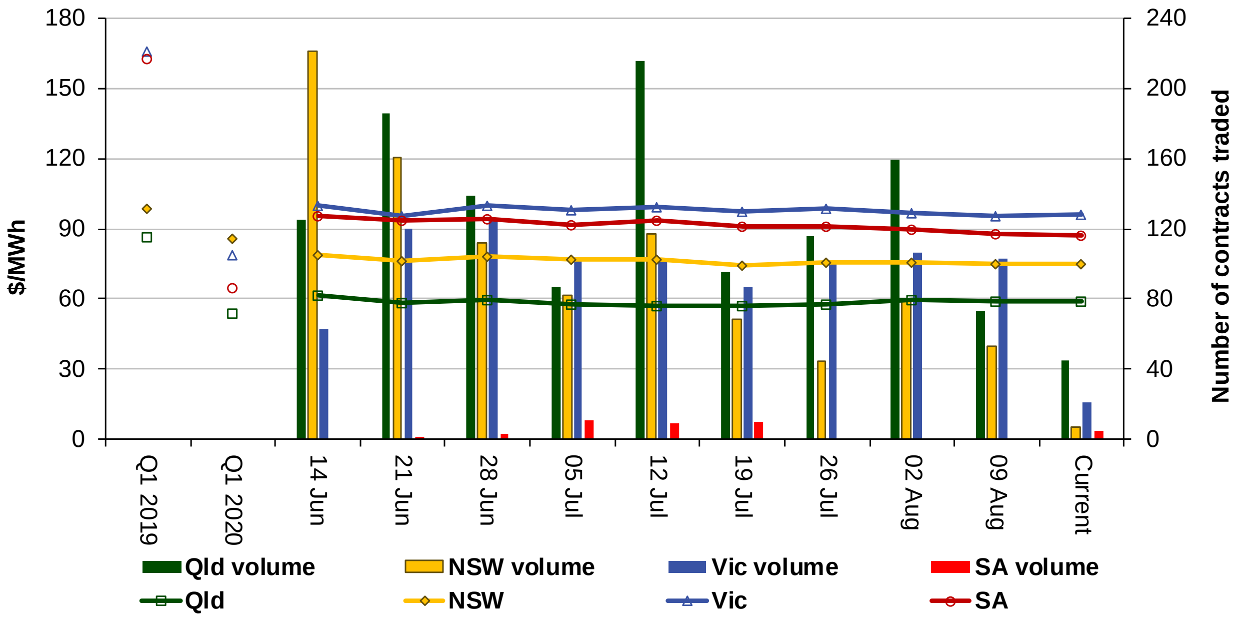
Figure 9: Quarterly base future prices Q3 2020 – Q2 2024



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 Q 1 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)

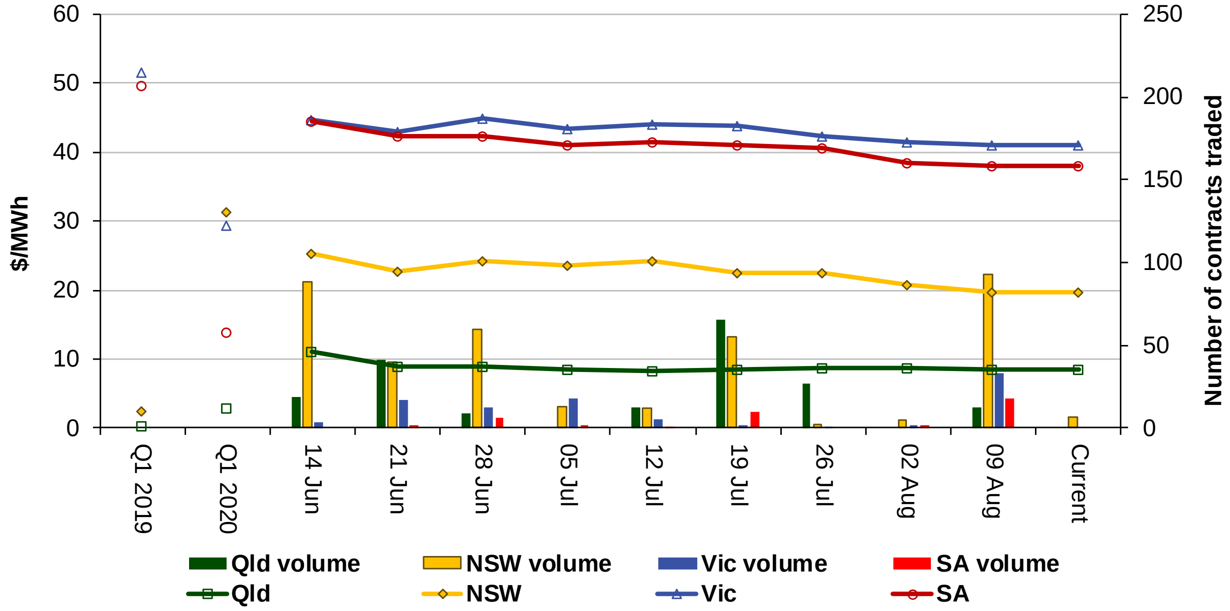


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
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