Electricity Report

AUSTRALIAN ENERGY REGULATOR

30 August – 5 September 2020

Weekly Summary

Volume weighted average prices (VWA) for the week ranged from $24/MWh in South Australia to $45/MWh in New South Wales. Q3 2020 quarter to date VWA prices are down $17/MWh to $40/MWh compared to a year ago.

On 30 August, a non-credible contingency event occurred in Tasmania as the Lindisfarne - Risdon No 1 110 kV line and the Arthurs Lake pump tripped, whilst the Nyrstar load was also reduced. Despite this, no significant prices eventuated.

This week saw 15 negative prices in South Australia breach our weekly reporting threshold. Several factors contributed to these prices, including participant rebidding, and are further explored in the detailed market analysis section.

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 30 August to 5 September 2020.

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

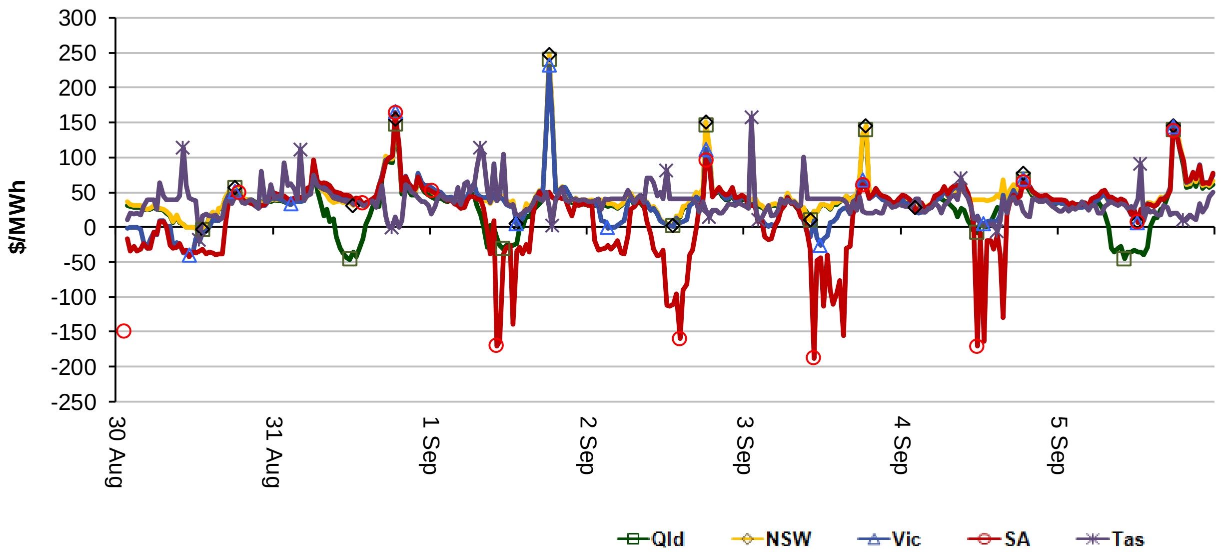


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

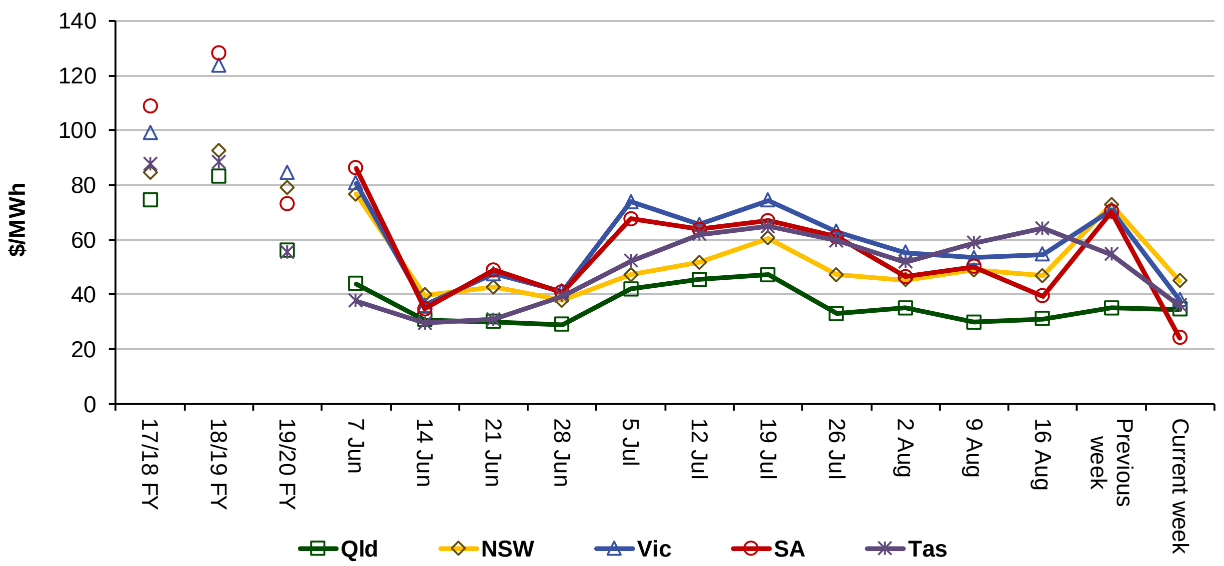


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	34	45	38	24	36
Q3 2019 (QTD)	64	81	100	83	72
Q3 2020 (QTD)	37	51	60	54	55
19-20 financial YTD	64	81	100	83	72
20-21 financial YTD	37	51	60	54	55

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 247 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	17	12	0	1
% of total below forecast	10	50	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

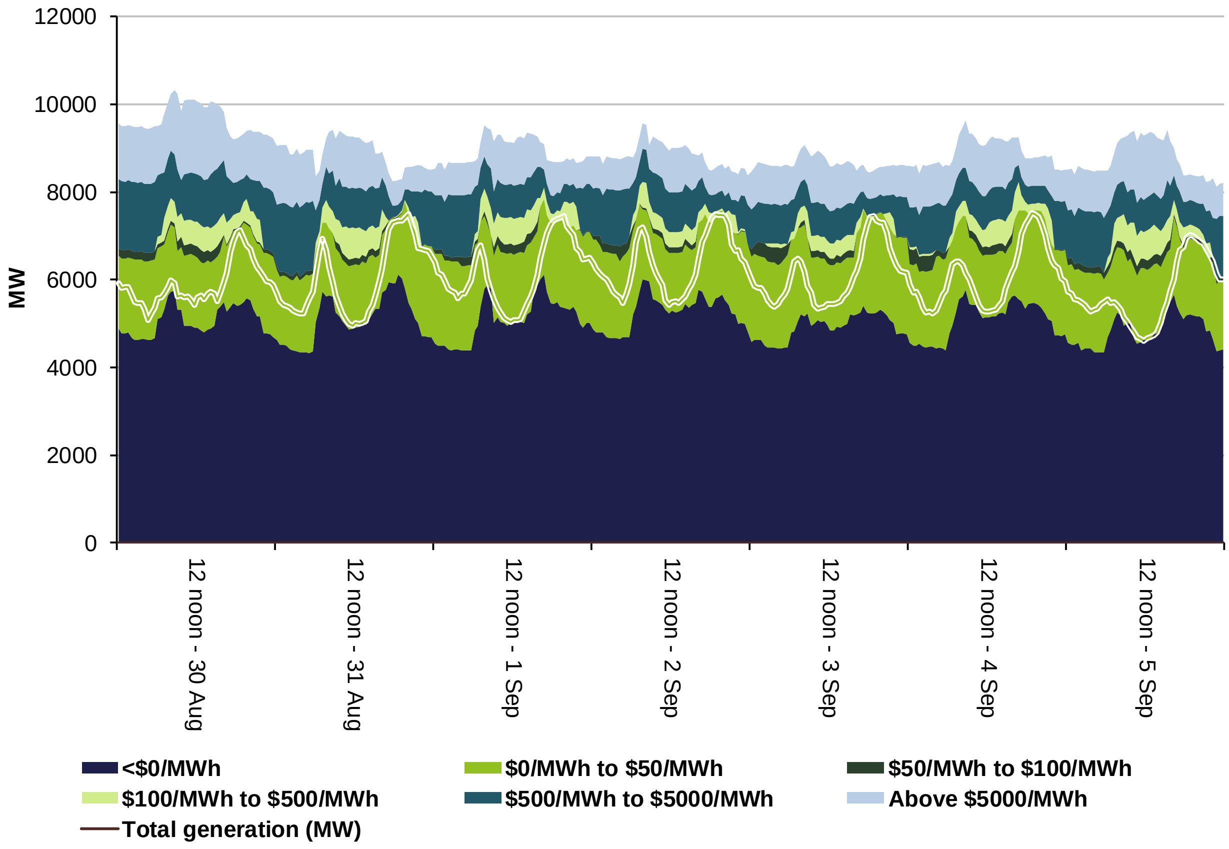


Figure 4: New South Wales generation and bidding patterns

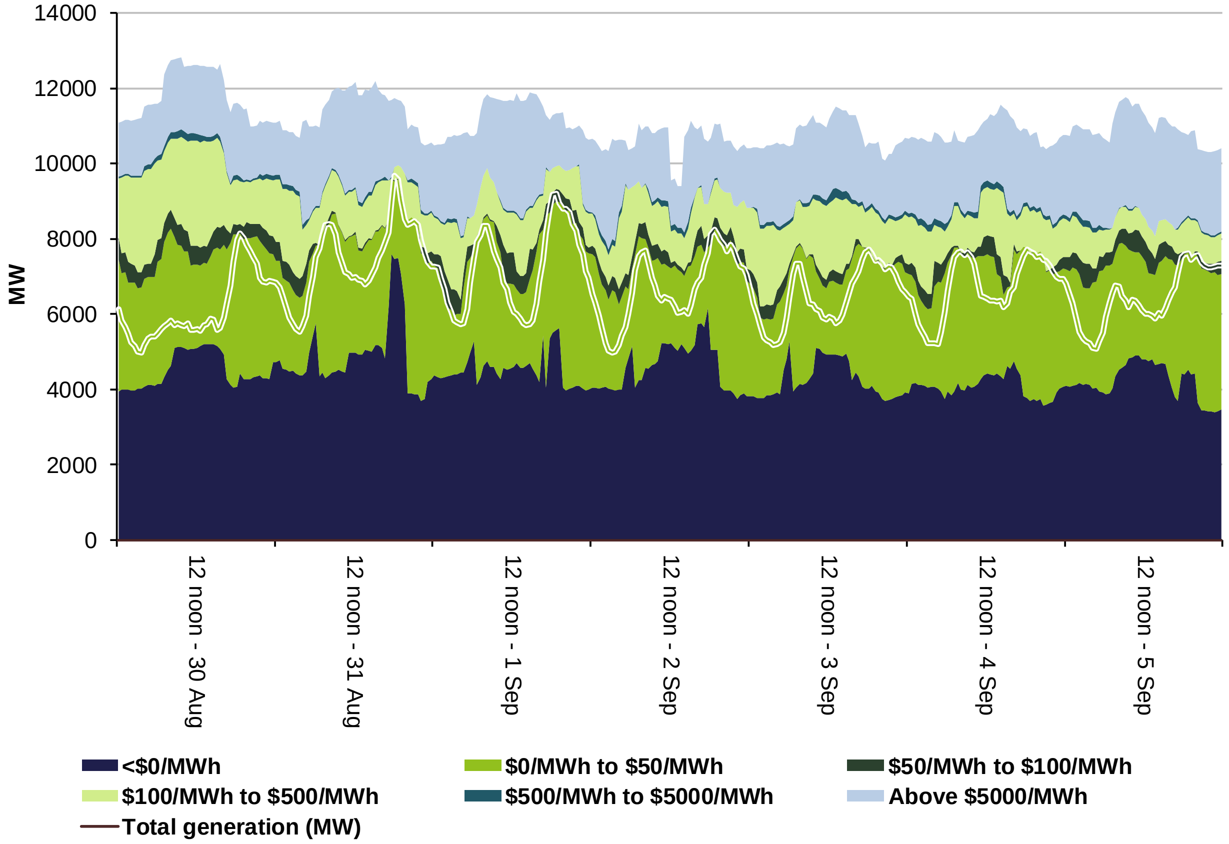


Figure 5: Victoria generation and bidding patterns

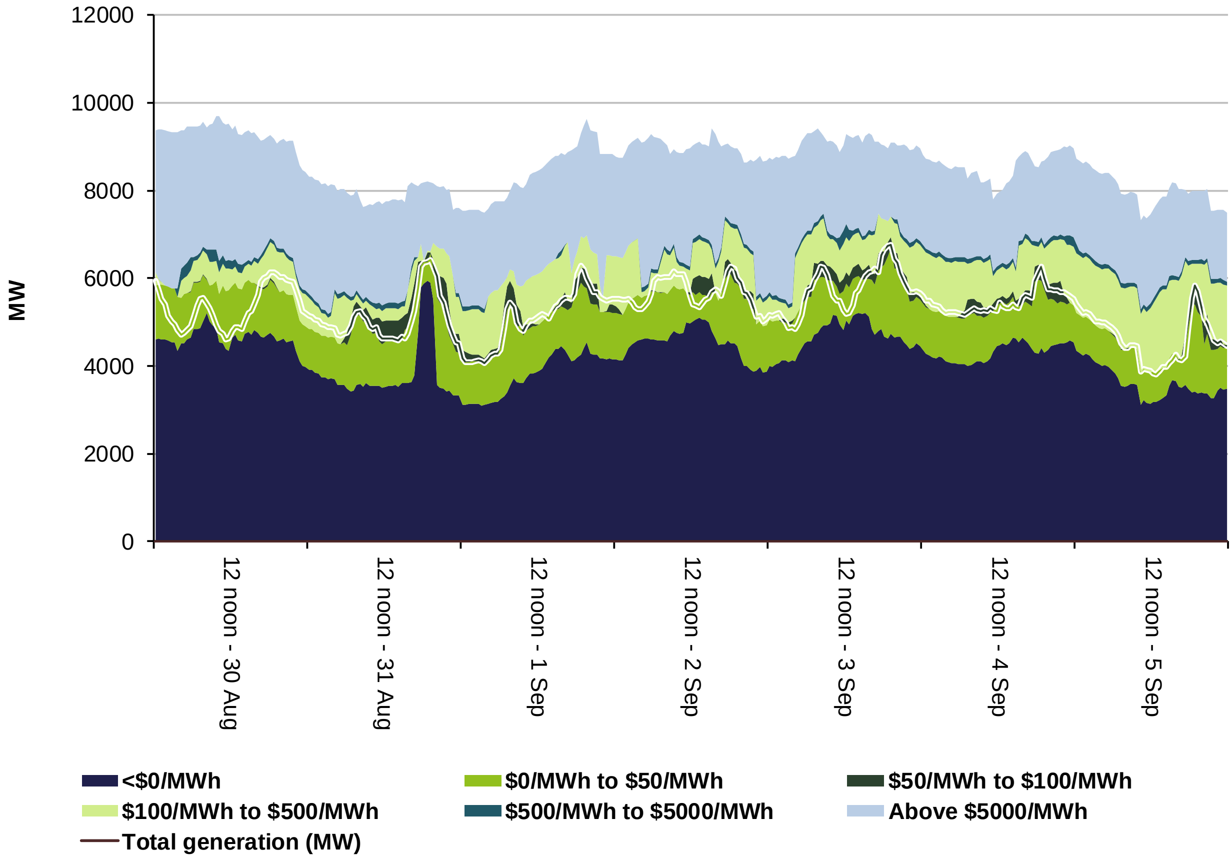


Figure 6: South Australia generation and bidding patterns

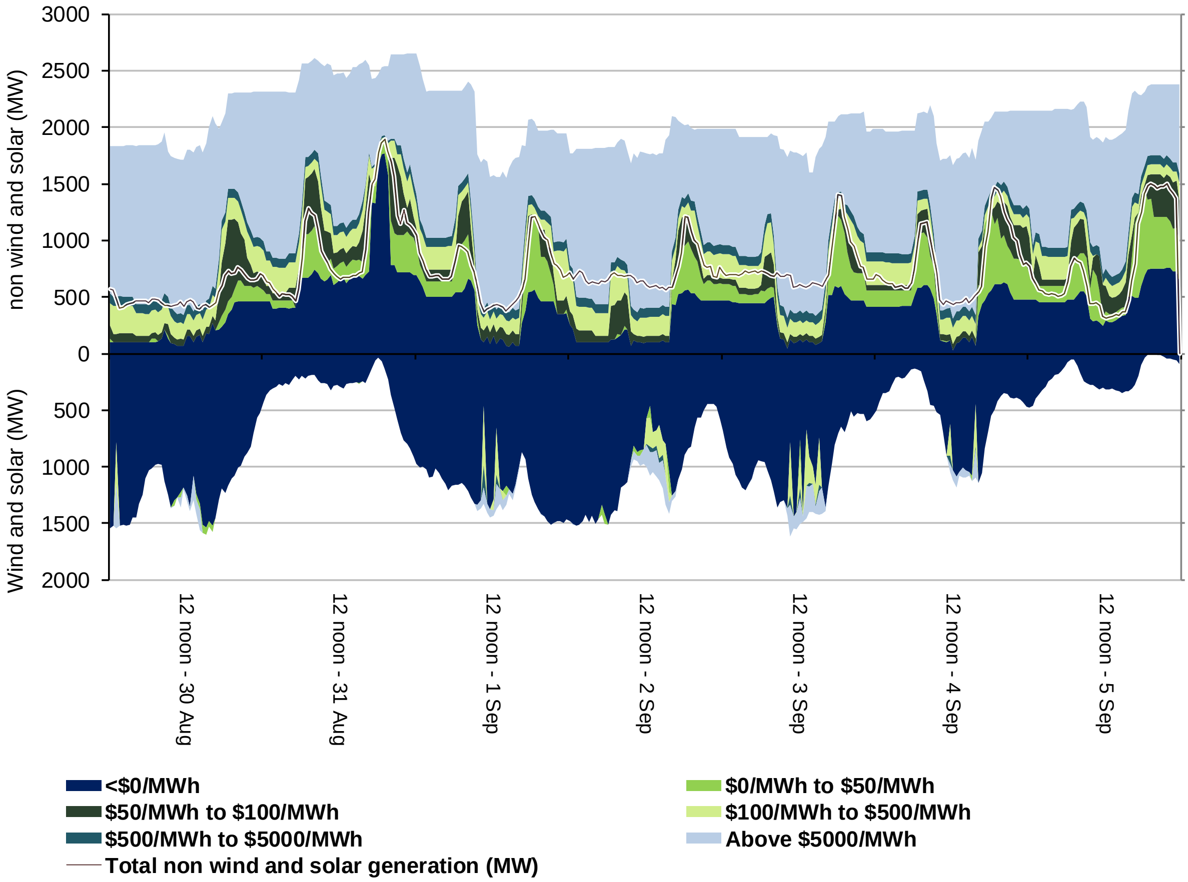
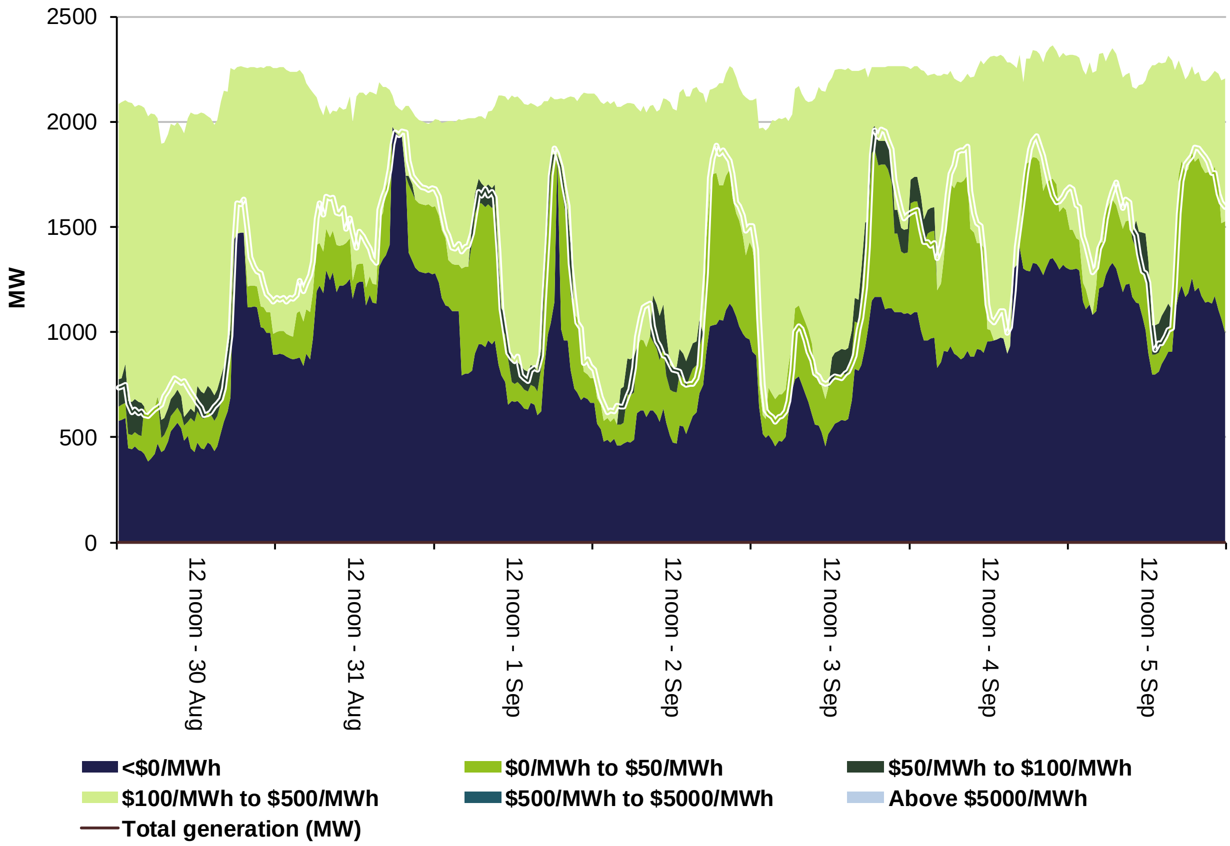


Figure 7: Tasmania generation and bidding patterns



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.

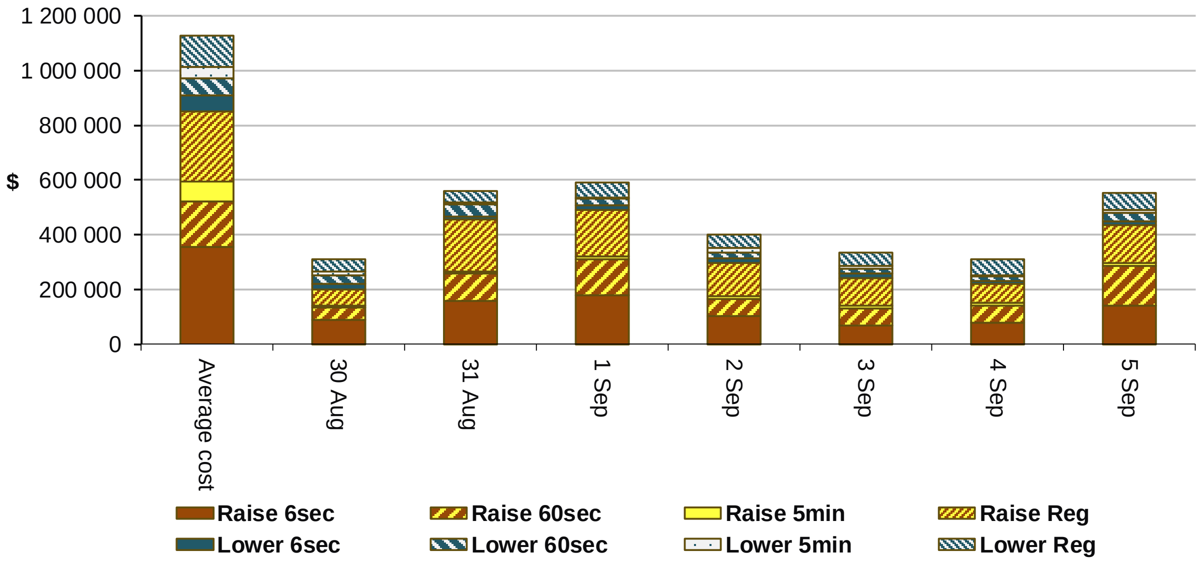
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 699 000 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $359 000 or around 5 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

South Australia

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

Sunday, 30 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
1.30 am	-149.35	14.20	15.42	1165	1125	1142	3384	3205	3158

Demand was close to forecast while availability was 179 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced low.

Rebids by Trustpower and Lincoln Gap Wind Farm effective 1.20 am shifted 311 MW from the cap to the floor due to forecast prices. As a result, the dispatch price fell to the floor. In response, participants rebid over 700 MW from the floor to higher prices.

Tuesday, 1 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
10.30 am	-170.27	32.03	34.28	1029	1052	1060	3075	3131	3092
11 am	-163.51	-76.70	-1000	1014	944	939	3045	3186	3182
1 pm	-139.03	-1000	-1000	756	675	677	2947	3209	3199

For the 10.30 and 11 am trading intervals, demand was between 23 MW lower and 70 MW higher than forecast, while availability was between 56 MW and 141 MW lower than forecast, for hours prior. Lower than forecast availability was due to the removal of capacity by participants due to technical reasons and changes in forecast prices

Rebids by Snowtown Wind Farm and Lincoln Gap Wind Farm due to changes in forecast prices shifted 311 MW to the floor for at least one dispatch interval in both trading intervals. This resulted in price falling to the floor for one dispatch interval. For the 10.30 am trading interval, the dispatch price fell to the floor in the last dispatch interval, therefore no participant rebidding in response occurred. For the 11 am and 1 pm trading intervals, participants rebid over 900 MW to higher prices in response.

For the 1 pm trading interval, demand was 81 MW higher than forecast, while availability was 262 MW less than forecast, four hours prior. Less than forecast availability was due to less than forecast wind generation and the removal of capacity by Quarantine due to technical reasons.

At the start of the trading interval, the price was as forecast. In response to the low price, participants rebid over 400 MW from the floor to higher prices. Price was set around $30/MWh for the remainder of the trading interval.

Wednesday, 2 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
12.30 pm	-111.90	-1000	-1000	690	641	657	2782	3090	3094
1 pm	-113.22	-1000	-96.16	722	616	631	2846	3030	3105
1.30 pm	-110.67	-1000	-1000	701	600	605	2817	3003	3105
2.30 pm	-159.85	-94.37	-1000	748	647	671	2876	2850	3092

For the 12.30 pm to 1.30 pm trading intervals, demand was between 49 MW and 106 MW higher than forecast, while availability was between 184 MW and 308 MW lower than forecast, four hours prior. Lower than forecast availability was due to lower than forecast wind generation.

In addition to lower than forecast wind, between 384 MW and 726 MW was rebid from the price floor in the lead up to the start of each trading interval. As a result, the spot price settled higher than forecast, four hours prior.

For the 2.30 pm trading interval, demand was 101 MW higher than forecast, while availability was close to forecast, four hours prior. High mainland requirement for lower regulation services resulted in co-optimisation between the FCAS and energy markets between 2.10 pm and 2.20 pm. As a result, the dispatch price fell as low as -$656/MWh

Thursday, 3 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	-187.94	0	-100.34	1065	843	852	3412	3150	3186
12.30 pm	-113.61	-1000	-1000	854	655	692	3266	3244	3225
2 pm	-110.36	-1000	-1000	792	708	673	3141	3203	3189
3.30 pm	-155.56	-78.22	-86.02	898	801	793	3205	3120	3088

For the 11 am trading interval, demand was 222 MW higher than forecast, while availability was 262 MW higher than forecast, four hours prior. Higher than forecast availability was largely driven by Pelican Point adding capacity due to unit direction and higher than forecast wind, most of which was priced below $0/MWh. At 10.50 am, demand dropped by over 50 MW resulting in the dispatch price falling to the floor. In response, participants rebid nearly 240 MW to higher prices.

For the 12.30 pm trading interval, demand was 199 MW higher than forecast while availability was close to forecast, four hours prior. While capacity was rebid to higher prices the dispatch price fell to almost -$600/MWh at 12.15 pm. In response over 800 MW of capacity was rebid from negative to positive prices and the price increased to $0/MWh by 12.30 pm.

For the 2 pm trading interval, demand was 84 MW higher than forecast while availability was 62 MW less than forecast, four hours prior. Less than forecast availability was due to less than forecast wind generation. Leading up to the start of the trading interval, over 430 MW were shifted from the price floor to higher prices. As a result the spot price settled above forecast.

For the 3.30 pm trading interval, demand was 97 MW higher than forecast and availability was 85 MW higher than forecast, four hours prior. At 3.10 pm demand fell by 18 MW, and with no capacity priced between -$40/MWh and -$900/MWh, little variations in demand could cause large fluctuations in price. As a result, the dispatch price fell to -$900/MWh for one dispatch interval. In response, participants rebid over 260 MW from the floor into higher price bands.

Friday, 4 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
Midday	-170.95	25.67	14.15	830	832	820	2781	2553	2491
1 pm	-163.75	13.84	13.62	830	749	766	2910	2673	2584
4 pm	-129.87	13.37	16.02	870	889	914	2861	2734	2658

Demand was up to 81 MW higher than forecast while availability was between 127 MW and 237 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation.

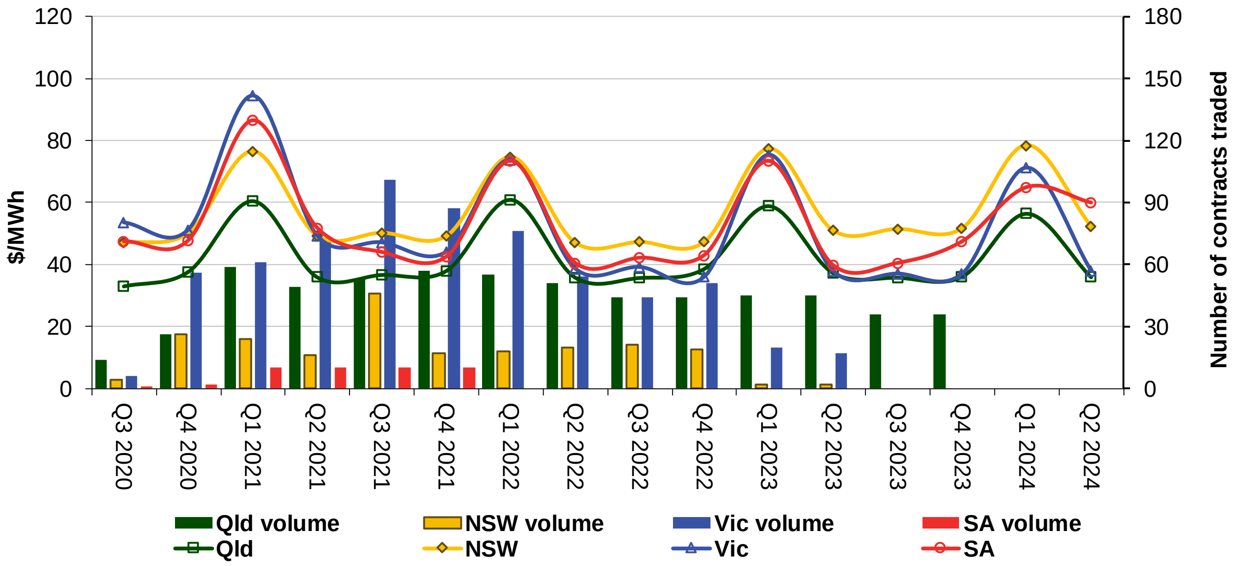
For the Midday and 4 pm trading intervals the dispatch price fell to the floor for one dispatch interval As a result, participants rebid between 575 MW and 1072 MW from the floor to higher prices.

At 12.52 pm Trustpower rebid 270 MW of capacity to the price floor and as a result the price fell to the floor at 1 pm.

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.

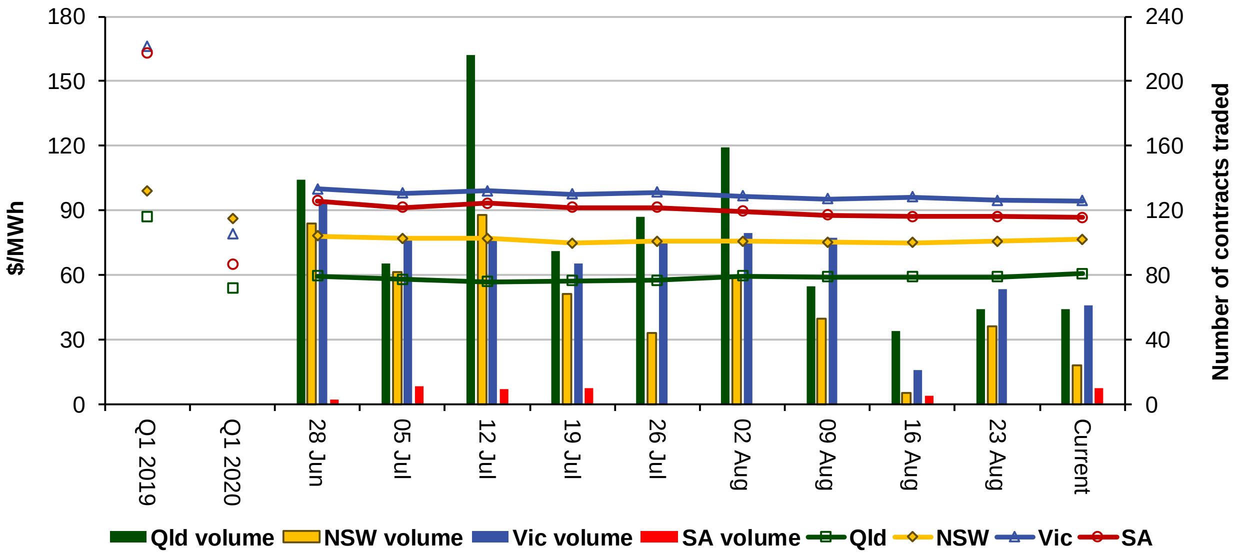
Figure 9: Quarterly base future prices Q3 2020 – Q2 2024



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 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)

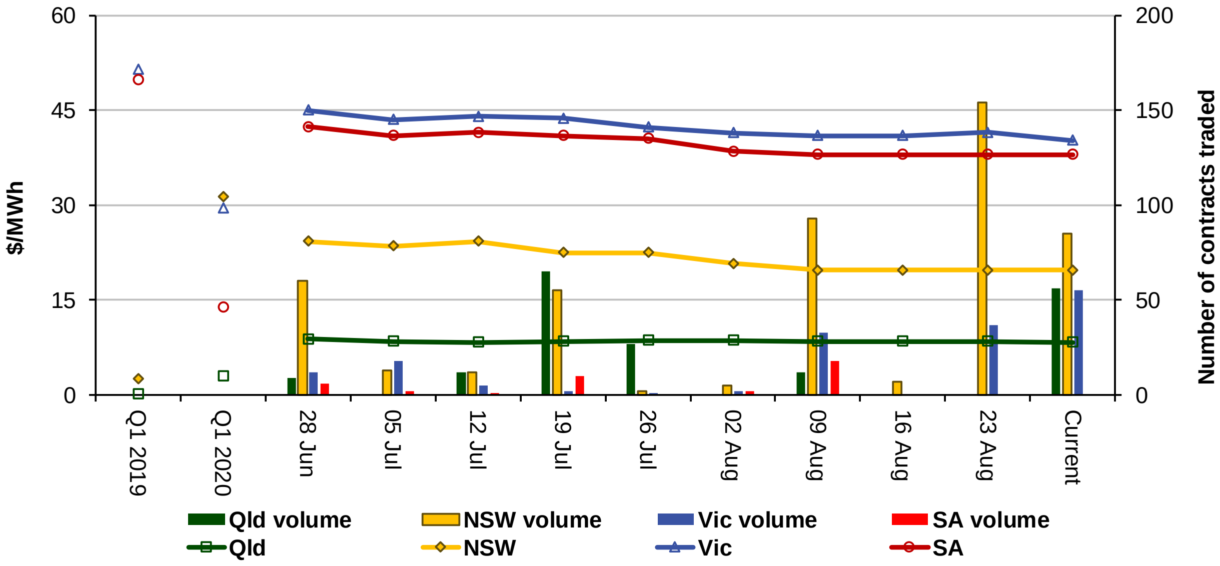


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 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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