Electricity Report

AUSTRALIAN ENERGY REGULATOR

20 – 26 September 2020

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $18/MWh in South Australia to $42/MWh in Tasmania. Q3 quarter to date VWA prices ranged from $34/MWh in Queensland to $55/MWh in Victoria.

A planned outage to the Muswellbrook to Tamworth (88) line in New South Wales saw high FCAS prices in Queensland raise 60 second services on 22 September.

Generator rebidding, demand forecast variations and windy conditions throughout the week saw our weekly reporting thresholds breached on 25 occasions in South Australia and on two occasions in Queensland. Only one of these breached the greater than $250/MWh threshold. Further analysis is provided 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 20 to 26 September 2020.

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

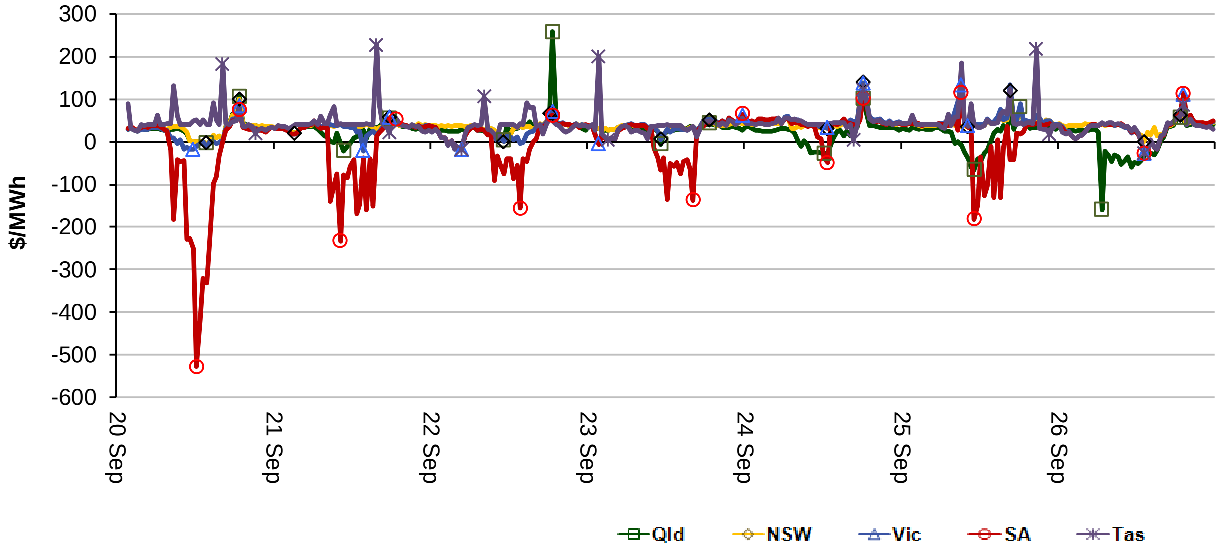


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

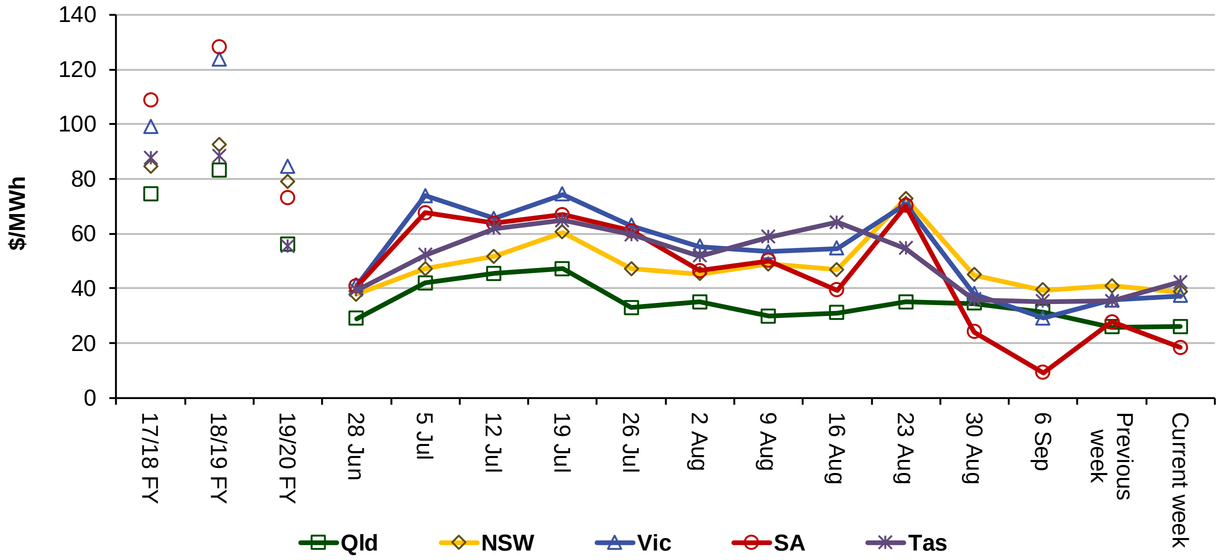


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	26	39	37	18	42
Q3 2019 (QTD)	66	86	103	83	69
Q3 2020 (QTD)	34	48	55	47	51
18-19 financial YTD	66	86	103	83	69
19-20 financial YTD	34	48	55	47	51

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 238 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	6	38	0	1
% of total below forecast	10	38	0	7

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

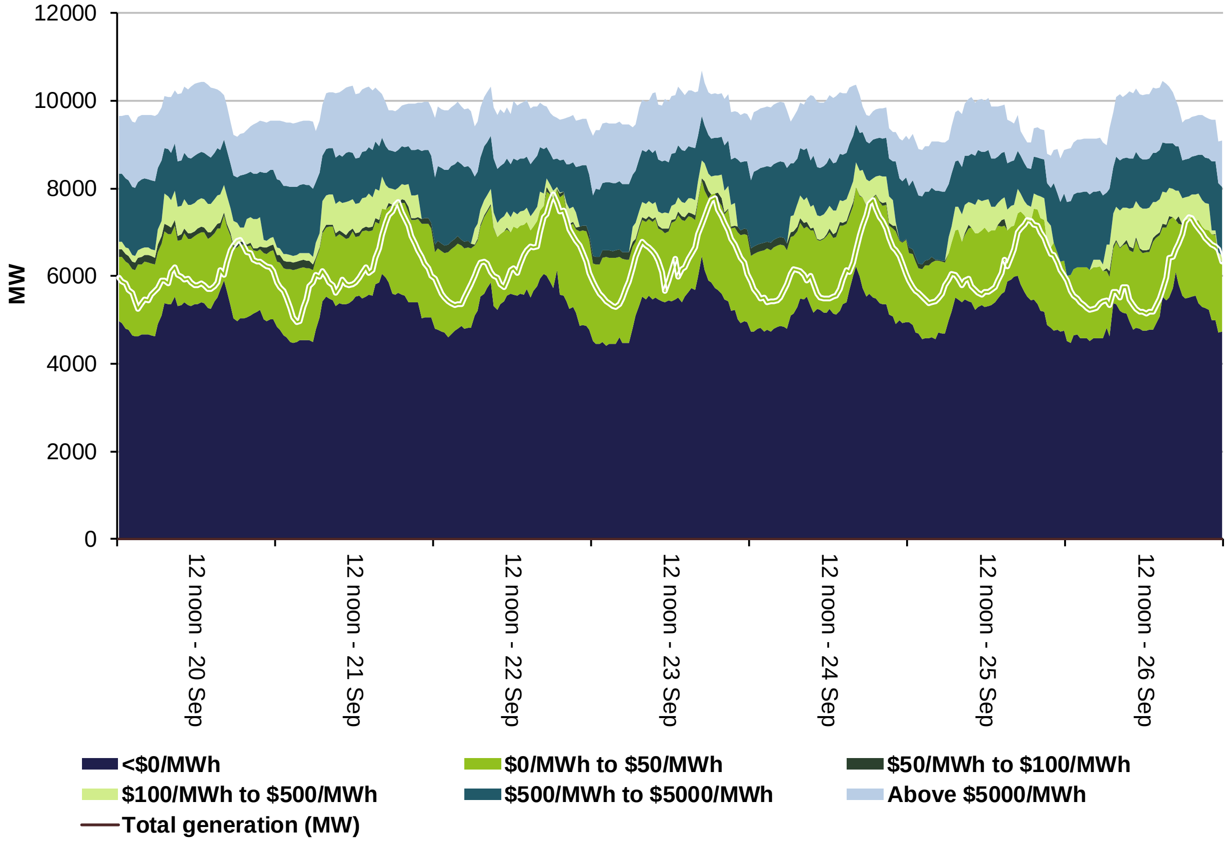


Figure 4: New South Wales generation and bidding patterns

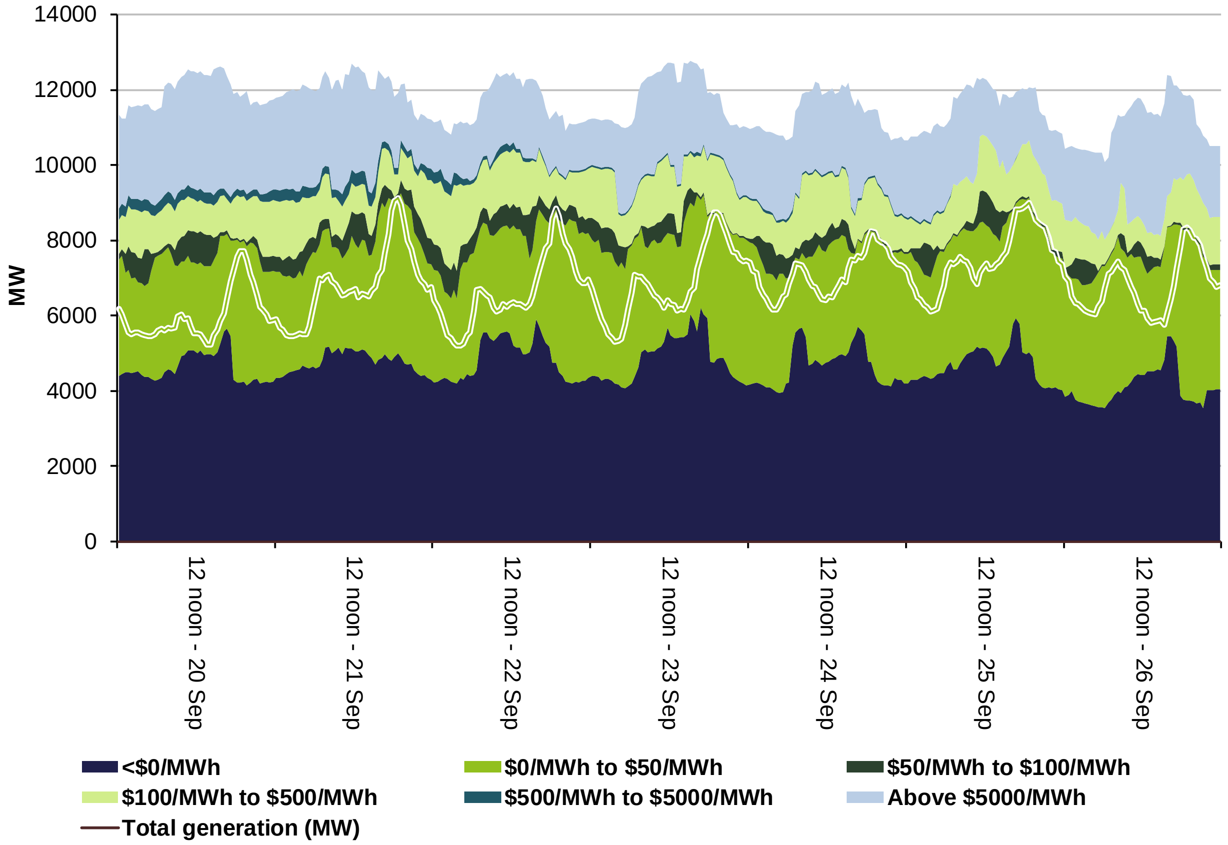


Figure 5: Victoria generation and bidding patterns

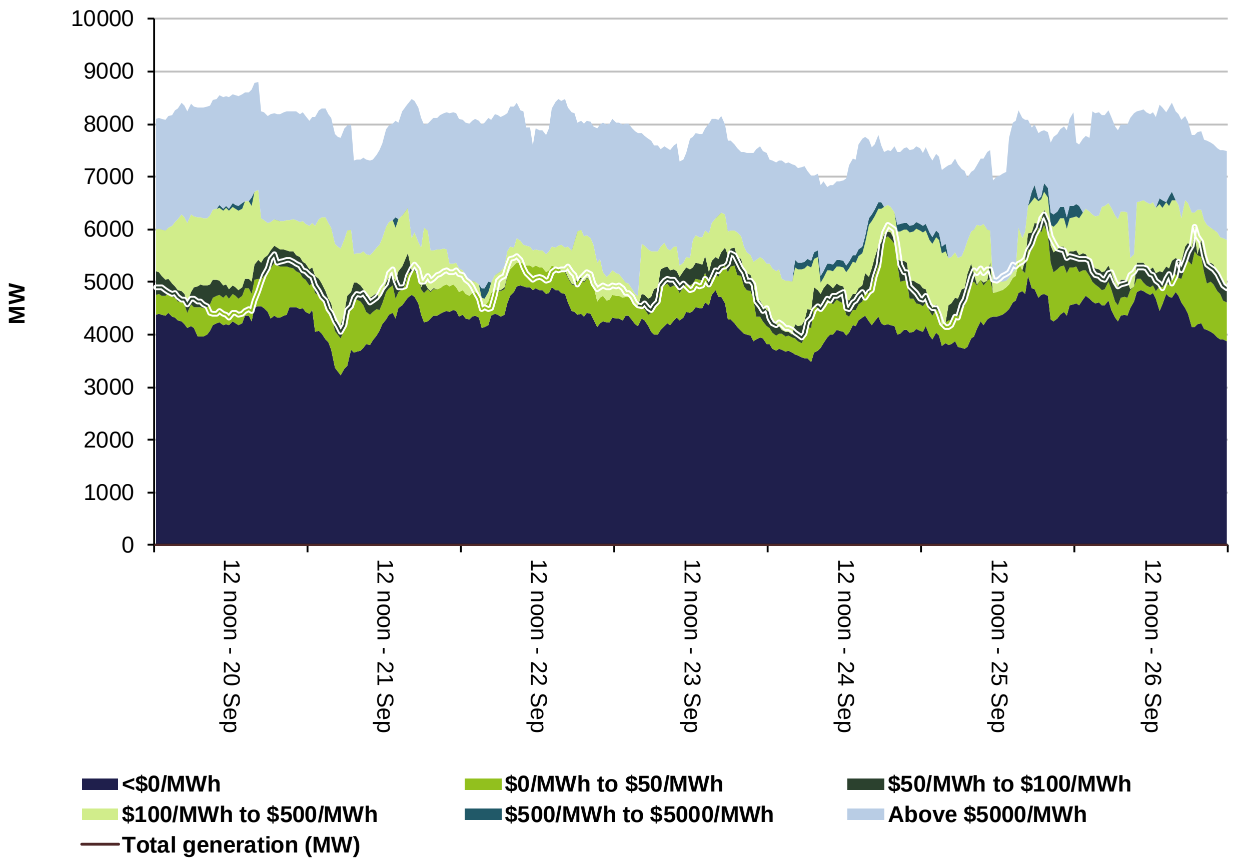


Figure 6: South Australia generation and bidding patterns

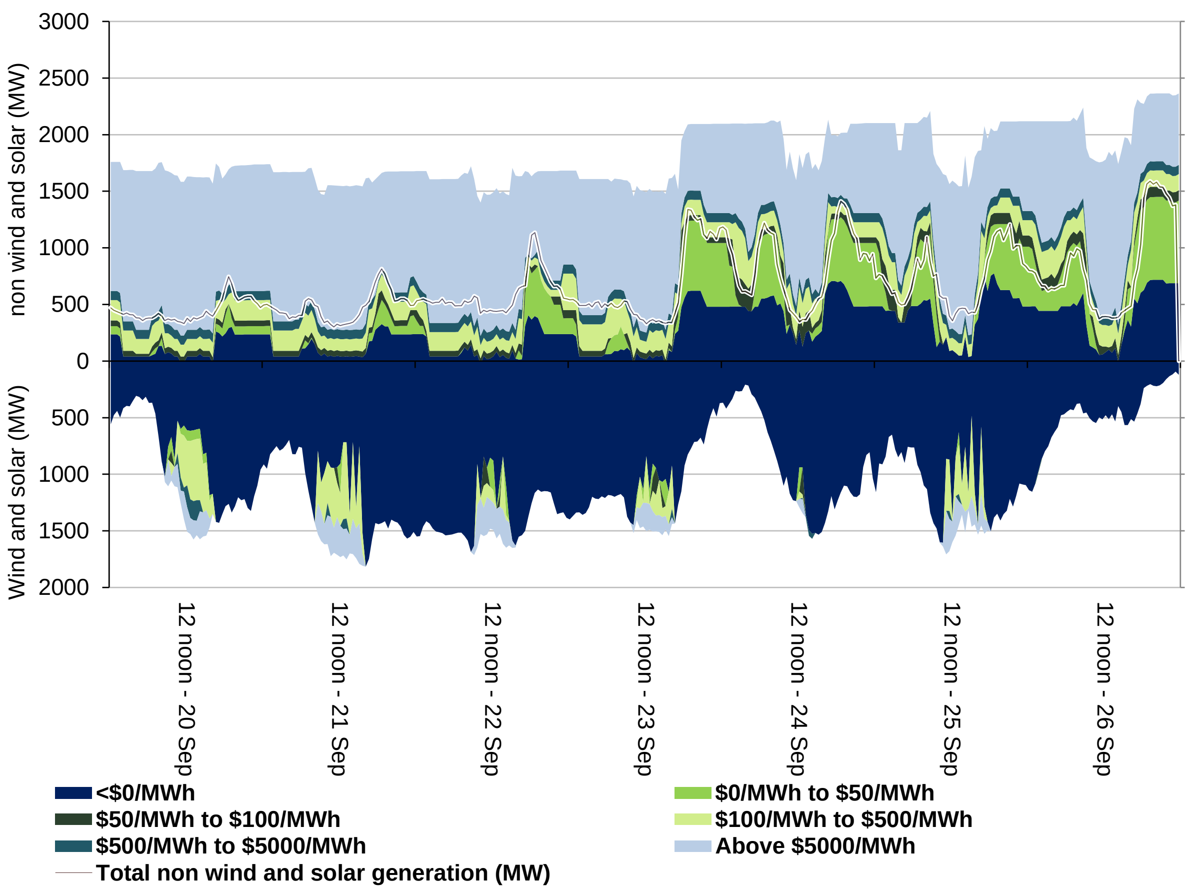
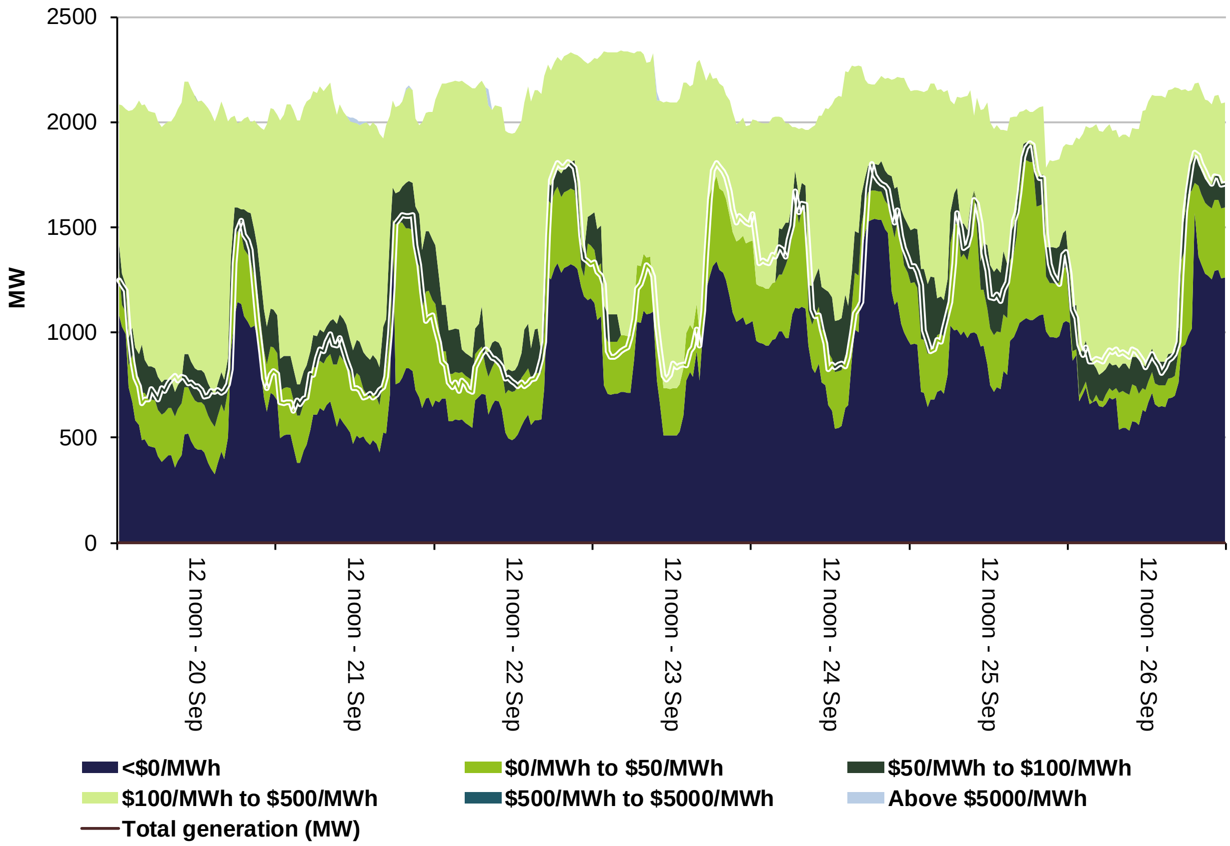


Figure 7: Tasmania generation and bidding patterns



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.

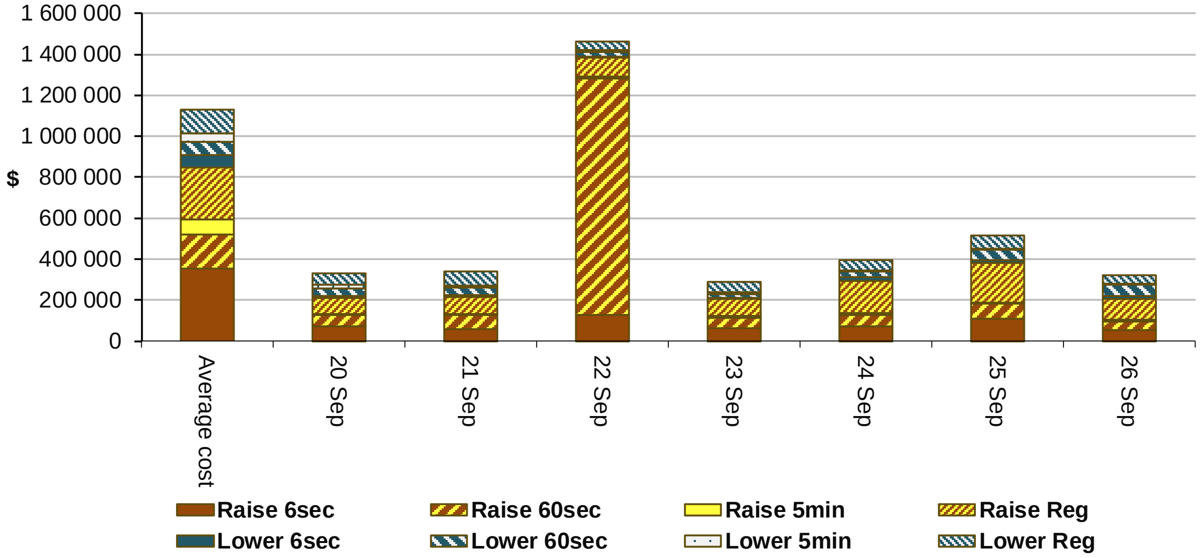
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 266 000 or around 3 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $385 000 or less than 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



22 September saw Queensland raise 60 sec prices reach the price cap between 6.45 pm and 7 pm. This was due to high raise service requirements resulting from a planned outage to the Muswellbrook to Tamworth (88) line.

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 $26/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Tuesday, 22 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
7 pm	257.91	109.44	120.11	7331	7370	7384	9609	9468	9547

Demand was close to forecast while availability was 141 MW higher than forecast, four hours prior. Higher than forecast availability was due to Origin adding a total of 141 MW of capacity priced at, or close, to the floor at Darling Downs and Roma Power Stations from 3.30 pm. The reasons given were due to technical reasons and in response to forecast demand. At 6.35 pm, demand increased by 110 MW, resulting in the price reaching $1374/MW for one dispatch interval.

Saturday, 26 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
7 am	-159.06	20.63	20.63	4910	5082	5102	9486	9608	9632

Demand was 172 MW lower than forecast, while availability was 122 MW lower than forecast, four hours prior. At 6.23 am CS Energy removed 140 MW of capacity priced below $50/MWh at Gladstone Power Station due to technical reasons. At 6.40 am demand fell by over 50 MW. With several generators either shut-down or ramp-constrained, the dispatch price fell to the price floor for one dispatch interval. In response, participants rebid 566 MW of capacity from the price floor to higher prices.

South Australia

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

Sunday, 20 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	-182.37	-100	-1000	762	642	632	2737	2601	2737
11 am	-230.00	-1000	-1000	472	414	402	2754	2861	2977
11.30 am	-226.89	-1000	-1000	441	364	355	2892	2901	3014
Midday	-251.95	-1000	-1000	444	321	295	3030	2931	3041
12.30 pm	-528.50	-1000	-1000	440	326	300	3138	2967	3068
1 pm	-419.17	-1000	-1000	415	340	322	3159	3009	3077
1.30 pm	-320.84	-1000	-1000	404	355	340	3203	3038	3070
2 pm	-330.84	-1000	-1000	429	377	345	3163	3053	3069
2.30 pm	-234.33	-1000	-1000	454	423	398	3198	3057	3071

For the 9 am trading interval, demand was 120 MW higher than forecast, while availability was 136 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. Effective 9 am, participants rebid over 300 MW of capacity from prices above $-100/MWh to the price floor due to changes in forecast prices. As a result, the price fell to the floor in the last dispatch interval.

For the 11 am to 2.30 pm trading intervals, demand was up to 123 MW higher than forecast, while availability was between 107 MW lower, and 171 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. From 6.30 am onwards, participants rebid at least 650 MW of capacity from the floor to higher prices due to a variety of reasons including changes in forecast prices and demand, changes to contract positions and constraint management. In each trading interval, the dispatch price fell to the floor as forecast at least once. In response, participants rebid up to 256 MW from the price floor to higher prices. As a result, the spot price was higher than forecast.

Monday, 21 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
9 am	-140.47	26.43	8.07	956	922	940	3039	2936	2942
9.30 am	-101.96	-1000	-1000	967	806	813	3078	3008	2992
10.30 am	-233.71	-1000	-1000	819	615	637	3170	3086	3055
1 pm	-169.59	-1000	-1000	968	546	536	3265	3128	3115
1.30 pm	-147.42	-1000	-1000	856	557	557	3299	3134	3118
2.30 pm	-160.59	-1000	-1000	981	618	604	3255	3108	3106
3.30 pm	-151.31	-190	-1000	924	732	735	3343	3073	3076

For the 9 am trading interval, demand was close to forecast while availability was 103 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast renewable generation, most of which was priced below $0/MWh. At 8.50 am, demand fell by 43 MW and with higher priced capacity ramp constrained the price fell to the floor for one dispatch interval. In response, generators rebid over 250 MW from the price floor to higher prices.

For the 9.30 am trading interval, demand was 161 MW higher than forecast, while availability was 70 MW higher than forecast. Higher than forecast availability was due to higher than forecast renewable generation, most of which was priced below $0/MWh. Higher than forecast demand resulted in prices settle above forecast for the trading interval.

For the 10.30 am and 1 pm, trading intervals, demand was between 204 MW and 422 MW higher than forecast, while availability was between 84 MW and 137 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast renewable generation, most of which was priced below $0/MWh. In addition to higher than forecast demand, from 8.28 am onwards, participants rebid up to 658 MW from the price floor to higher prices due to a variety of reasons including changes in forecast prices and demand, negative spot prices and constraint management. As a result, the spot price was higher than forecast.

For the 1.30 pm trading interval, demand was 299 MW higher than forecast, while availability was 165 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast renewable generation, most of which was priced below $0/MWh. At the start of the trading interval, the dispatch price fell to the price floor as forecast. In response, participants rebid nearly 640 MW of capacity from the price floor to higher prices. As a result, the dispatch price remained above $14/MWh for the remainder of the trading interval.

For the 2.30 pm trading interval, demand was 363 MW higher than forecast, while availability was 147 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast renewable generation, most of which was priced below $0/MWh. Between 10.17 am and 10.24 am, participants rebid 427 MW from the price floor to higher prices due to changes in forecast demand and constraint management. As a result, the spot price was above forecast.

The 3.30 pm spot price was close to forecast, four hours prior.

Tuesday, 22 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
2 pm	-156.55	-900	-1000	1070	680	637	3101	2931	2903

Demand was 390 MW higher than forecast, while availability was 170 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. Higher than forecast demand resulted in prices above forecast for most of the trading interval.

Wednesday, 23 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
12.30 pm	-134.58	-200	-1000	881	682	714	3017	2909	2924
4.30 pm	-137.77	7.93	27.23	1089	1065	1074	3018	2821	2836

For the 12.30 pm trading interval, demand was 199 MW higher than forecast, while availability was 108 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. In addition to higher than forecast demand, the dispatch price fell to -$900/MWh at 12.10 pm for one dispatch interval. In response, participants rebid over 360 MW from the price floor to above -$37/MWh. As a result, prices were above forecast for most of the trading interval.

For the 4.30 pm trading interval, demand was close to forecast while availability was 197 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast renewable generation, most of which was priced below $0/MWh. At 4.05 pm the dispatch price fell to the price floor. In response, participants rebid nearly 300 MW of capacity from the price floor to higher prices. As a result, prices remained above $32/MWh for the rest of trading interval.

Wednesday, 25 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
11.30 am	-181.80	-1000	-1000	1069	768	818	3368	3103	3239
Midday	-148.98	-1000	-1000	1039	735	797	3291	3121	3218
1 pm	-127.37	-1000	-1000	999	671	727	3119	3113	3203
1.30 pm	-104.62	-1000	-1000	938	637	671	3028	3171	3220
2.30 pm	-131.27	-1000	-1000	945	669	688	3196	3167	3245
3.30 pm	-131.87	-1000	-1000	973	785	799	3219	3196	3257

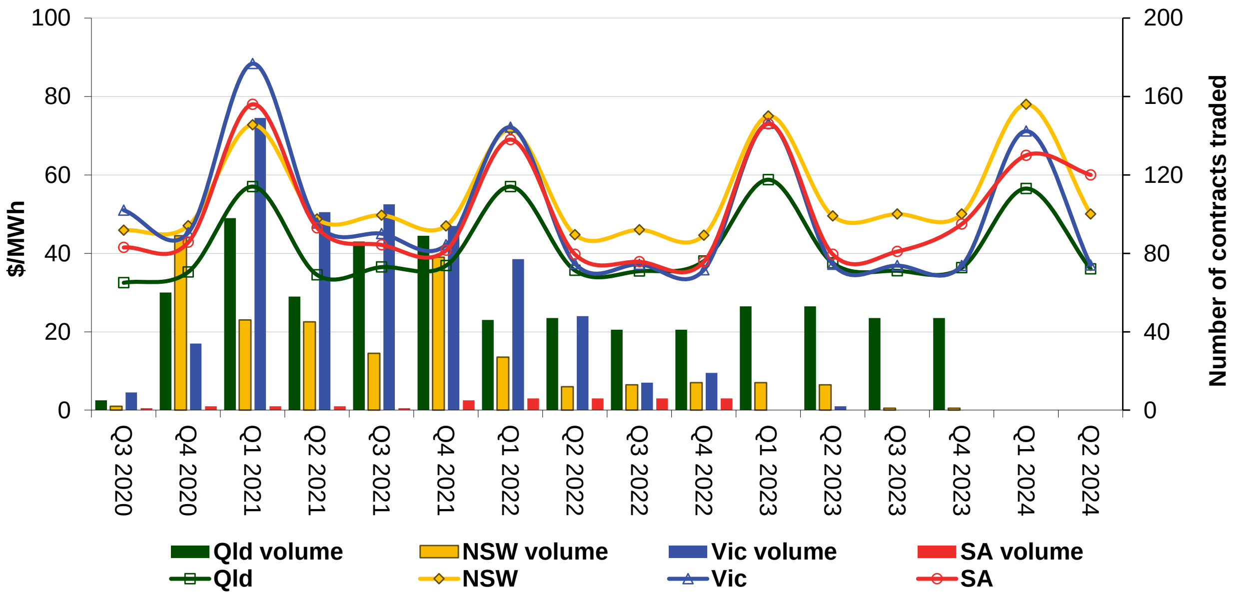
For each trading interval demand was between 188 MW and 328 MW higher than forecast four hours prior. Availability was between 6 MW to 265 MW higher than forecast four hours prior in each trading interval, except in the 1.30 pm trading interval where availability was 143 MW lower than forecast. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh. Lower than forecast availability during the 1.30 pm trading interval was due to AGL removing 105 MW of capacity from Barker Inlet Power Station priced at the cap due to technical reasons, and lower than forecast solar generation (mostly priced $0/MWh).

From 6.58 am, participants removed up to 362 MW from the price floor due to either technical reasons or changes in forecast demand or price. In each trading interval, the dispatch price fell below -$900/MWh at least once as forecast. In response, participants rebid up to nearly 650 MW of capacity from the price floor to higher prices. As a result, the spot price was higher than forecast in each trading interval.

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.

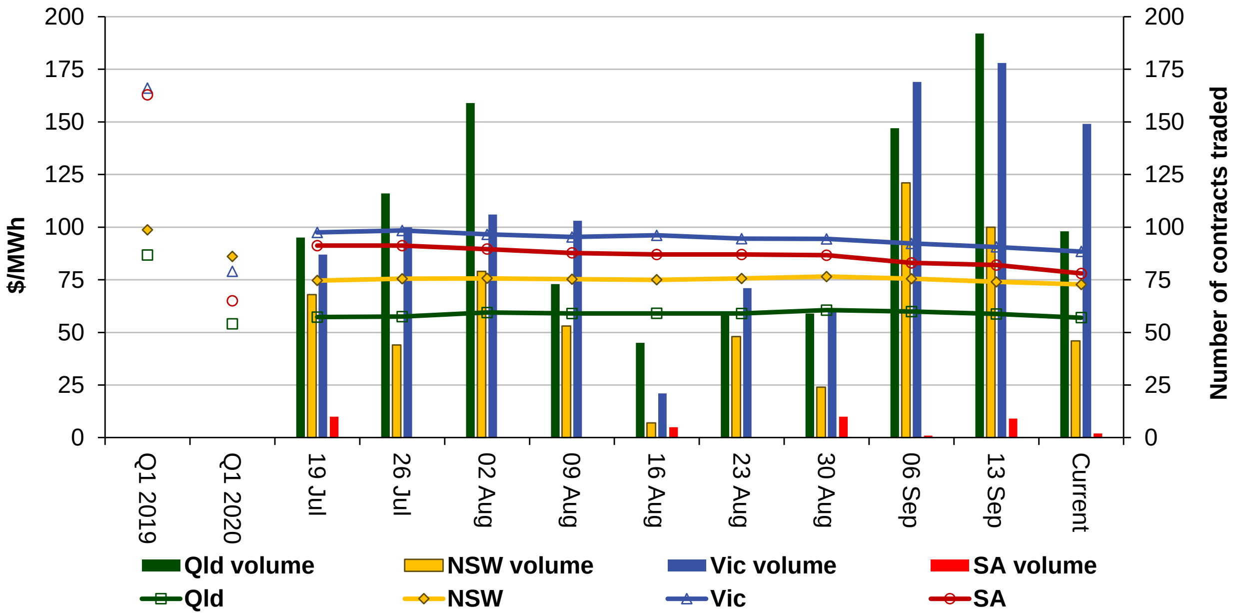
Figure 9: Quarterly base future prices Q3 2020 – Q2 2024



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)

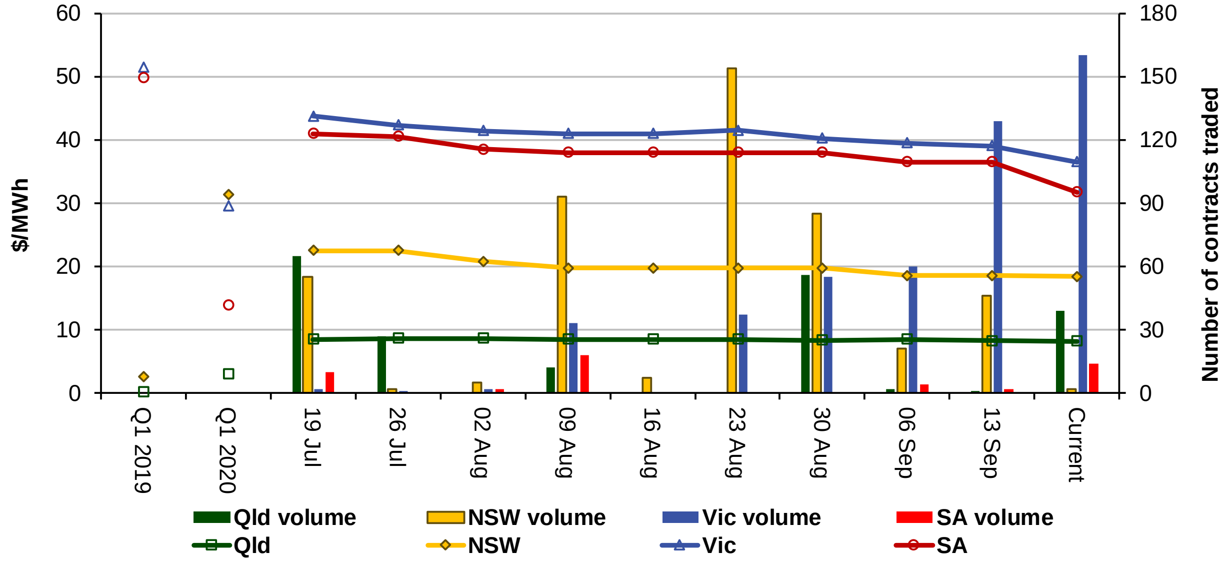


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 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
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