Electricity Report

AUSTRALIAN ENERGY REGULATOR

27 October – 2 November 2019

Introduction

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 27 October to 2 November 2019.

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

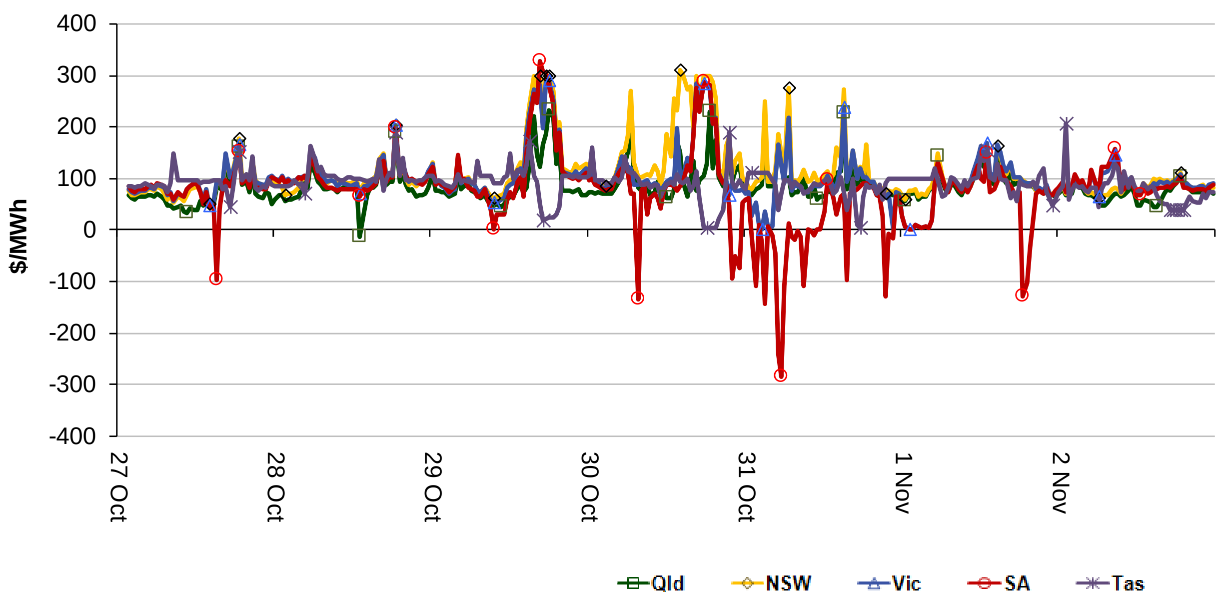


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

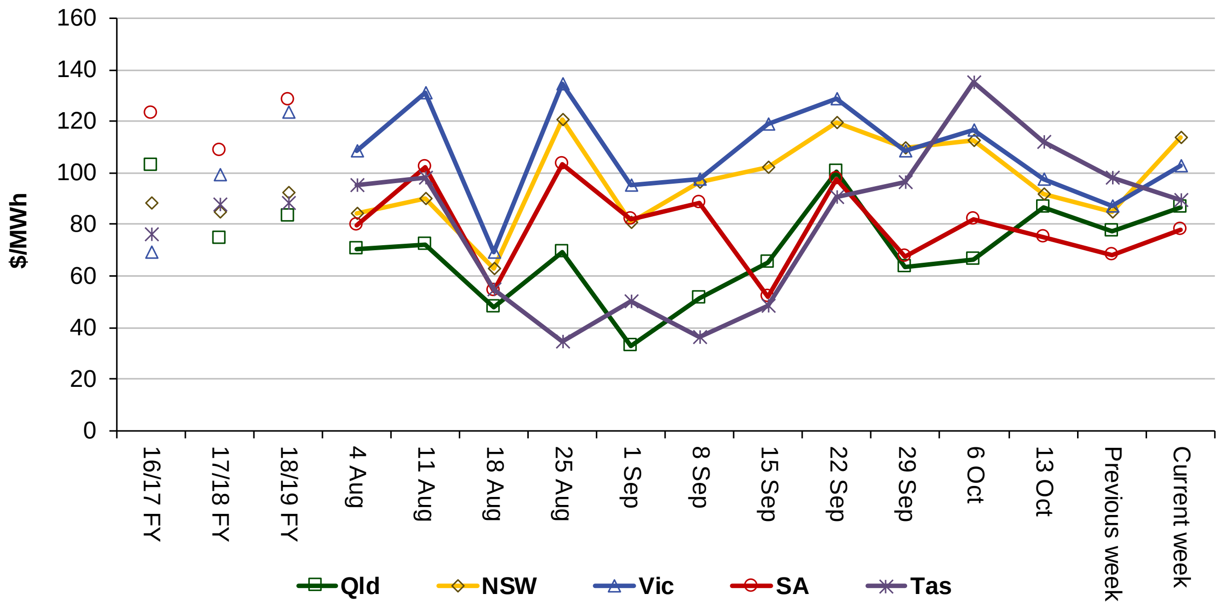


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	86	114	103	78	89
18-19 financial YTD	80	90	88	96	56
19-20 financial YTD	69	90	103	80	78

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 2018 of 199 counts and the average in 2017 of 185. 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	7	39	0	1
% of total below forecast	9	35	0	9

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

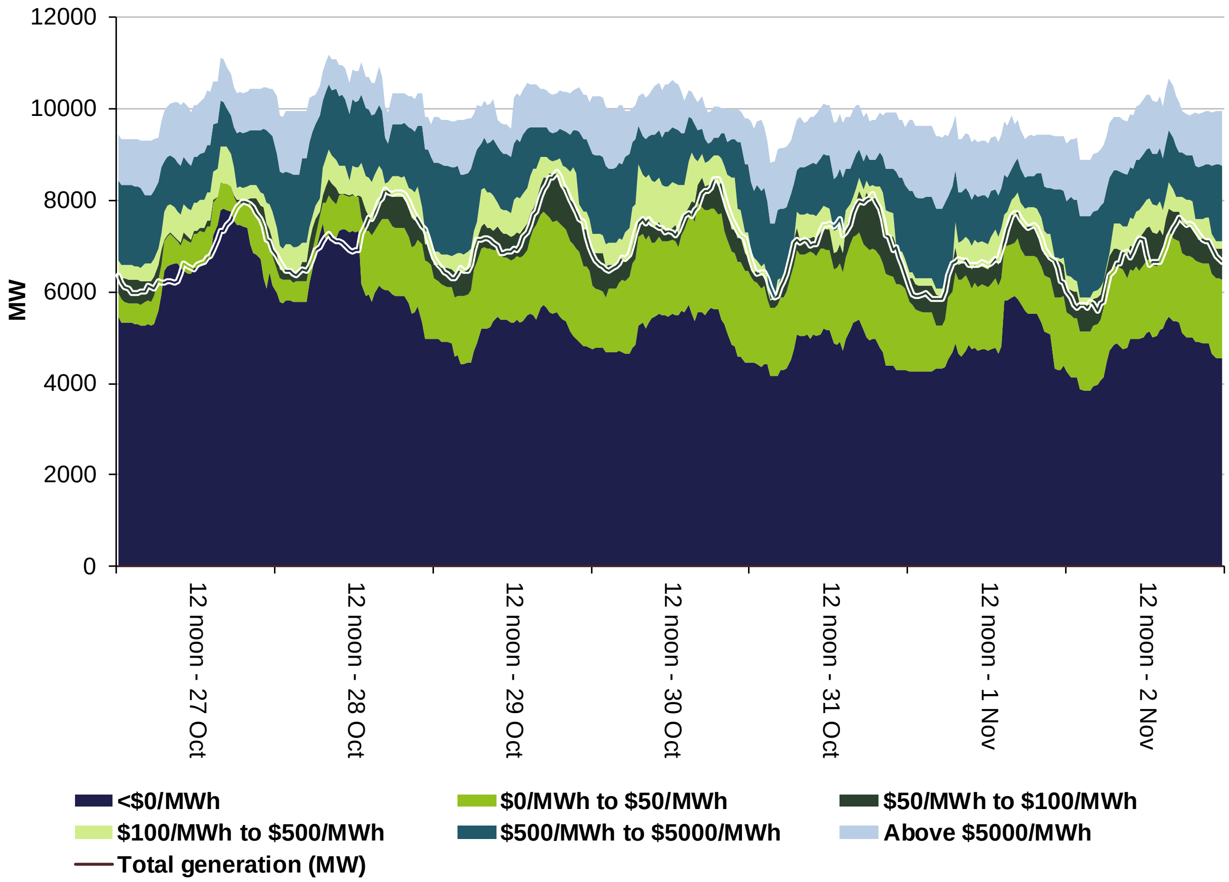


Figure 4: New South Wales generation and bidding patterns

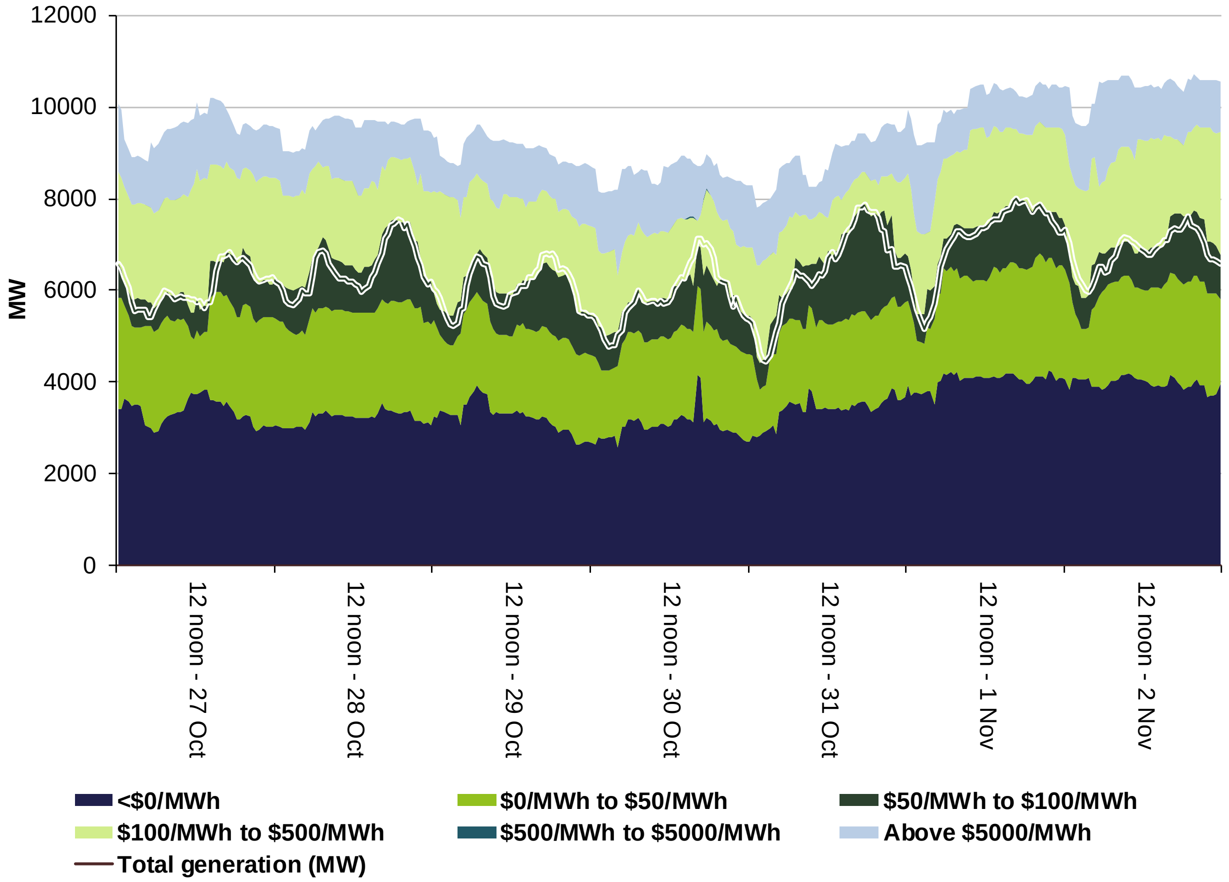


Figure 5: Victoria generation and bidding patterns

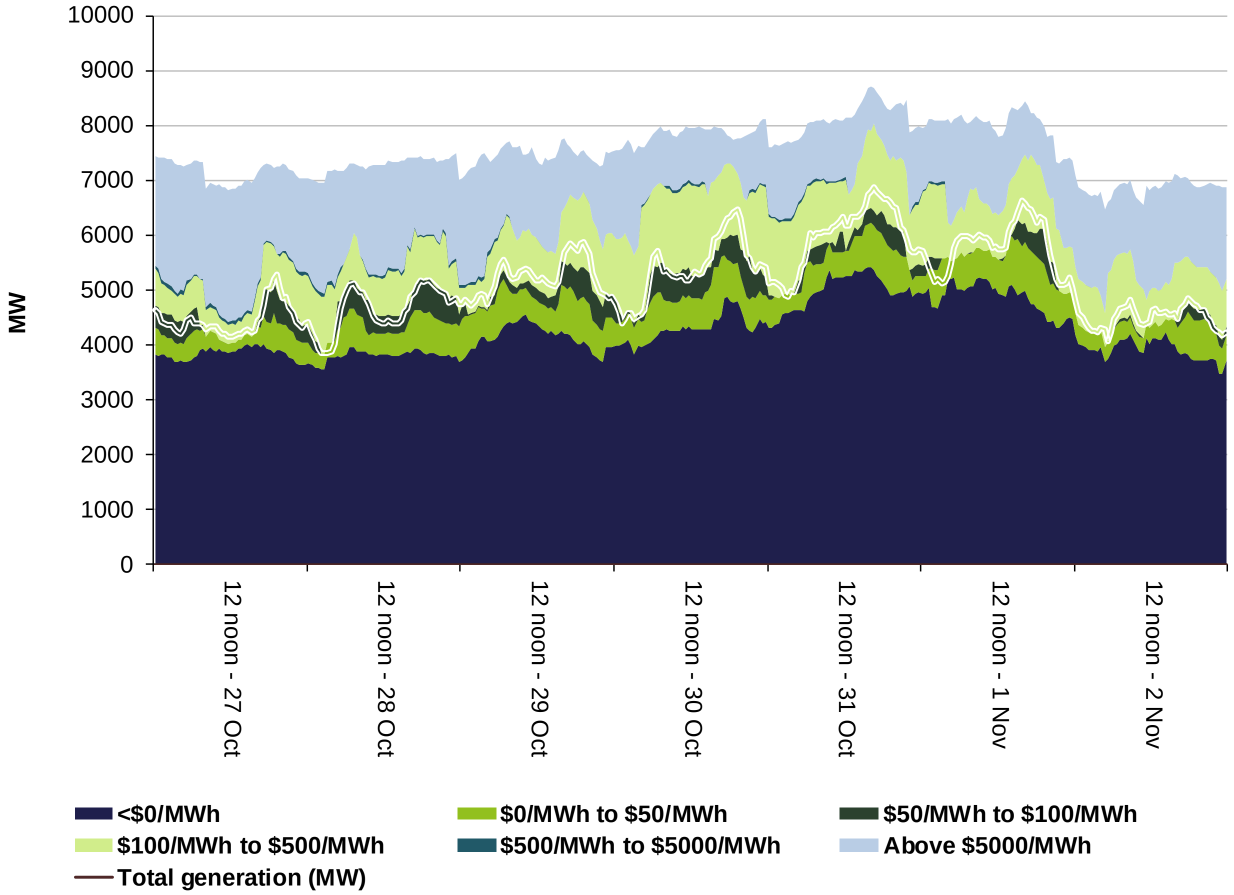


Figure 6: South Australia generation and bidding patterns

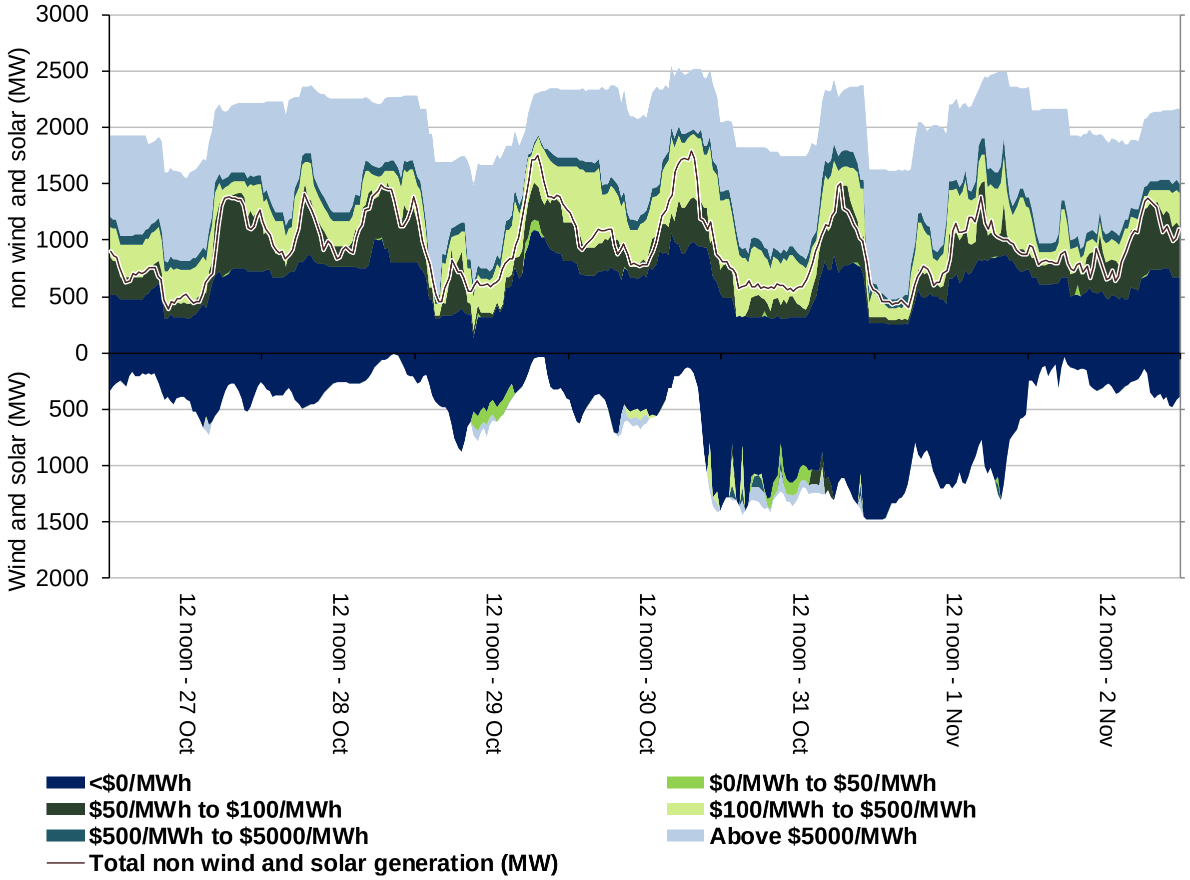
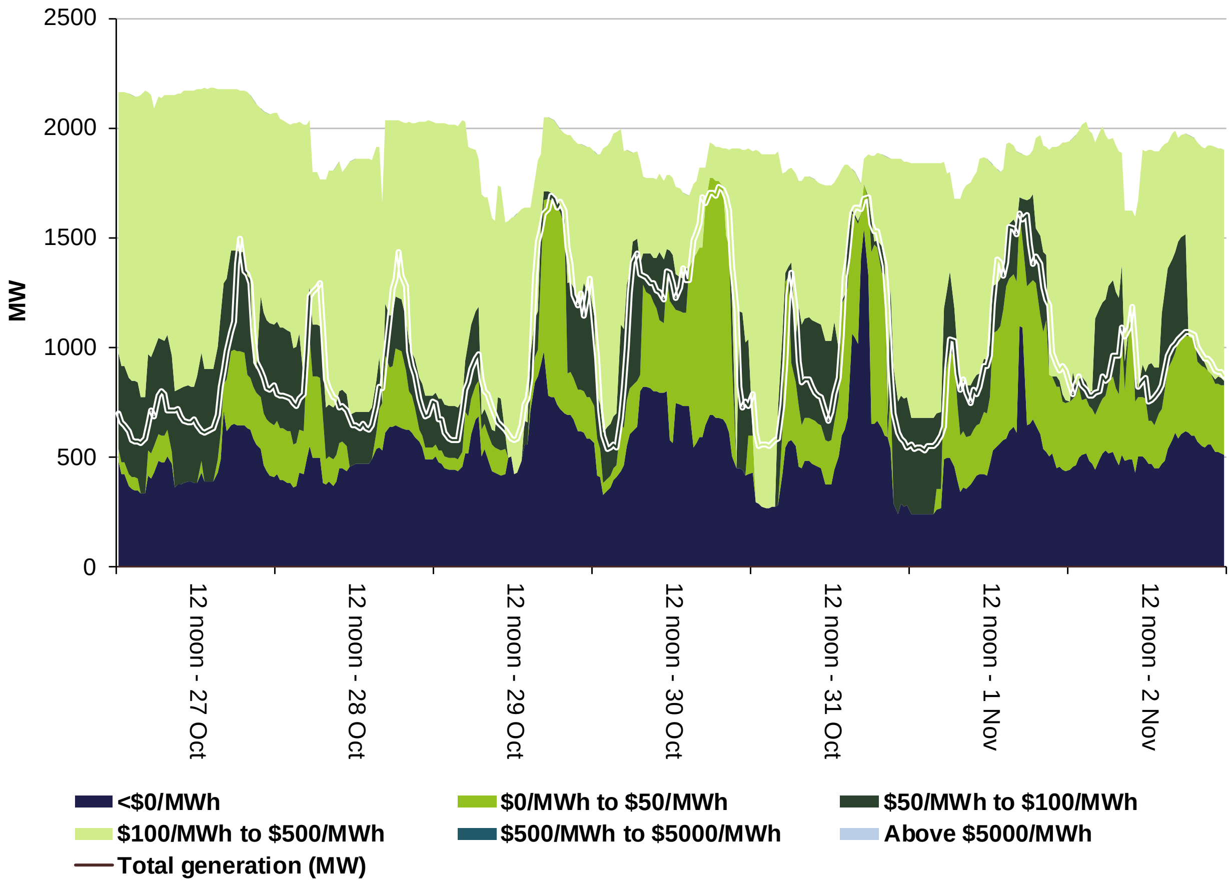


Figure 7: Tasmania generation and bidding patterns



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.

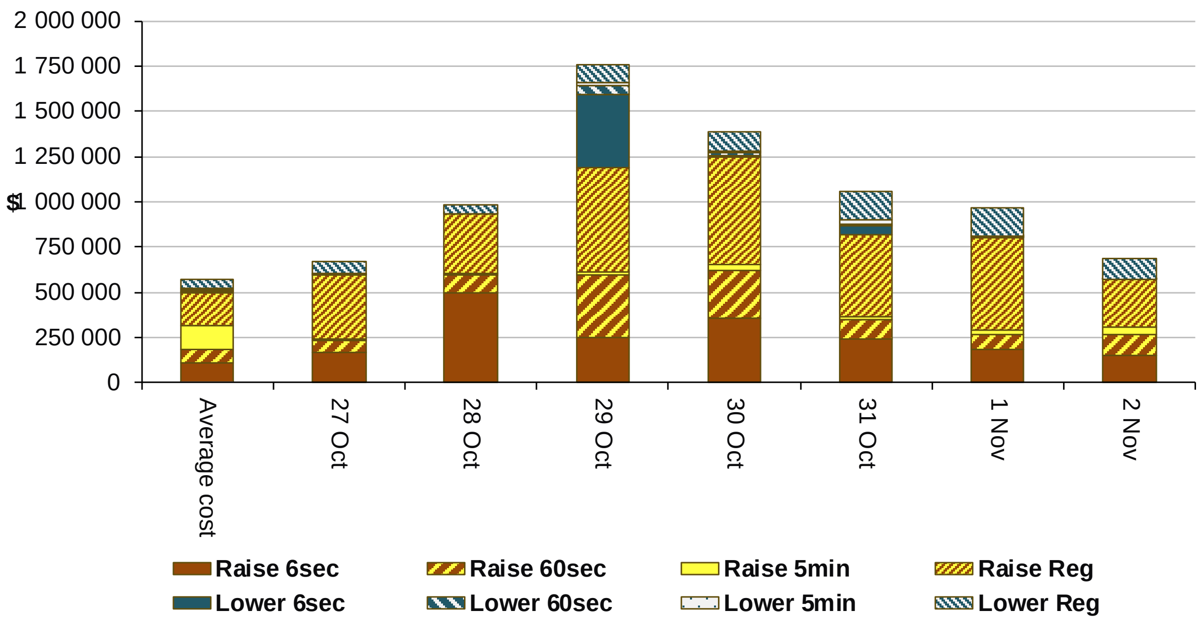
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $6 686 000 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $819 500 or less than 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



A planned outage around Heywood saw South Australia electrically isolated from the rest of the NEM and have to supply FCAS locally on 29 to 31 October. As a result lower 6 second service price peaked at the price cap at midday on 29 October.

Detailed market analysis of significant price events

South Australia

There were nine occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $78/MWh and above $250/MWh and there were ten occasions where the spot price was below -$100/MWh.

Tuesday, 29 October

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
4 pm	263.47	115	83.25	1216	1234	1203	2218	2436	2522
5 pm	326.82	255.08	148	1469	1432	1406	2217	2444	2508
5.30 pm	307.13	229.71	127.51	1578	1503	1485	2213	2449	2459
6 pm	305.67	286.30	256.17	1676	1562	1550	2343	2359	2405
6.30 pm	281.53	318.93	294.91	1701	1606	1592	2369	2362	2387

For the 4 pm trading interval, demand was close to forecast and availability was 218 MW lower than forecast, four hours prior. Rebids by Engie at Pelican Point removed 224 MW of availability priced below $77/MWh for plant reasons. As a result, prices were around $263/MWh throughout the trading interval.

For the 5 pm and 5.30 pm trading intervals, demand was between 63 MW and 75 MW higher than forecast while availability was between 227 MW and 236 MW lower than forecast, four hours prior. Lower than forecast availability was due to plant issues at Torrens Island and Pelican Point which removed between 265 MW and 310 MW of capacity priced below $248/MWh in the 5 pm and 5.30 pm trading intervals respectively. With no capacity offered between the forecast price and $380/MWh and less expensive generation trapped or stranded in FCAS, small changes in demand caused the dispatch price to increase to above $380/MWh during each trading interval.

For the 6 pm and 6.30 pm trading intervals, prices were close to forecast, four hours prior.

Wednesday, 30 October

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
8 am	-133.56	77.50	77.50	1309	1329	1314	3070	2960	2981

Demand was close to forecast while availability was 110 MW higher than forecast four hours ahead, mainly due to higher than forecast wind generation which was generally priced below $0/MWh.

With little capacity priced between $77/MWh and the price floor, the increase in available capacity and a small decrease in demand saw the price fall to the floor at 8 am.

Wednesday, 30 October

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
5 pm	277.05	115	115	1728	1738	1715	2703	2800	2759
6 pm	286.71	141.36	253.14	1900	1872	1854	2701	2699	2724
6.30 pm	285.11	189.20	257.50	1906	1889	1891	2673	2655	2678
7 pm	281.51	195.52	318.90	1911	1891	1895	2657	2593	2617

For the 5 pm trading interval, demand was close to forecast and availability was 97 MW lower than forecast, four hours ahead. Lower availability was mostly due to lower than forecast wind generation, approximately half of which was priced below $0/MWh. Demand was close to forecast and availability was close to forecast, four hours prior, for the remaining trading intervals.

Four hours ahead, interconnector flows were forecast to be around 40 MW into South Australia. However an outage of the Moorabool to Tarrone line in Victoria forced flows out of South Australia and into Victoria across the Heywood interconnector on numerous occasions. This resulted in the dispatch price being set at around $280/MWh for the entire time.

Thursday, 31 October

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
2 am	-107.42	57.74	42.12	1201	1122	1154	3356	2965	3063
3.30 am	-143.43	22.37	48.91	1087	999	1057	3255	2904	2834

For 2 am and 3.30 am trading intervals, demand was between 79 MW and 88 MW higher than forecast while availability was between 351 MW and 391 MW higher than forecast, four hours prior. The increased availability was due to wind output being higher than forecast, all of which was priced below $0/MWh. This resulted in the lower than forecast prices.

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
5.30 am	-243.14	-1000	-900	1217	1051	1076	3135	3002	2927
6 am	-286.36	-1000	-900	1302	1139	1140	3143	3006	2943
6.30 am	-107.79	-900	-900	1397	1210	1200	3182	2995	2930
9.30 am	-109.92	-1000	-1000	1199	1067	1061	2976	3095	3074

Demand was between 132 MW and 187 MW higher than forecast and availability was between 119 MW and 187 MW higher than forecast, four hours prior.

The higher than forecast prices were a result of participants rebidding between 495 MW and 885 MW of capacity across their renewable generators from prices below -$900/MWh to above -$150/MWh. The reasons given related to a change in forecast prices.

Thursday, 31 October

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
10 pm	-130.34	63.07	52.47	1597	1504	1522	3752	3510	3541

Demand was 93 MW higher than forecast and availability was 242 MW higher than forecast, four hours prior. Higher availability was mainly due to higher than forecast wind generation which was mainly priced below $0/MWh.

At 9.45 am, demand fell by 31 MW and energy consumption at Hornsdale power reserve fell by 40 MW to zero. This resulted in generation in South Australia decreasing by more than 75 MW. There were only a few generation units in South Australia offering capacity between the forecast price and the price floor at the time. These units were either backed off or became ramp down-constrained and the price fell to the floor for one dispatch interval.

Friday, 1 November

Table 9: Price, Demand and Availability

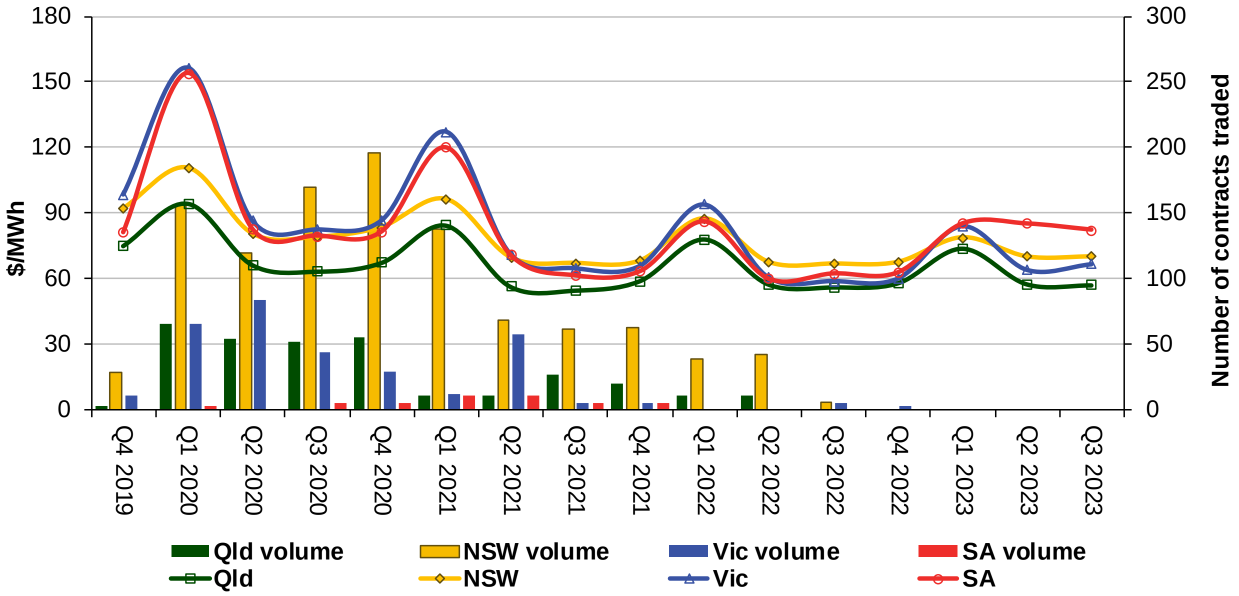
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 pm	-130.42	91	248	1505	1418	1433	3622	3199	3116
7.30 pm	-104.43	102.85	140.60	1504	1421	1439	3746	3109	3055

Demand was between 83 MW and 87 MW higher than forecast while availability was between 423 MW and 637 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. As a result, the price fell to -$1000/MWh for 7 pm and 7.05 pm until rebids shifting capacity from the floor to above $85/MWh became effective and the price increased to around $75/MWh for the rest of the 7.30 pm 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.

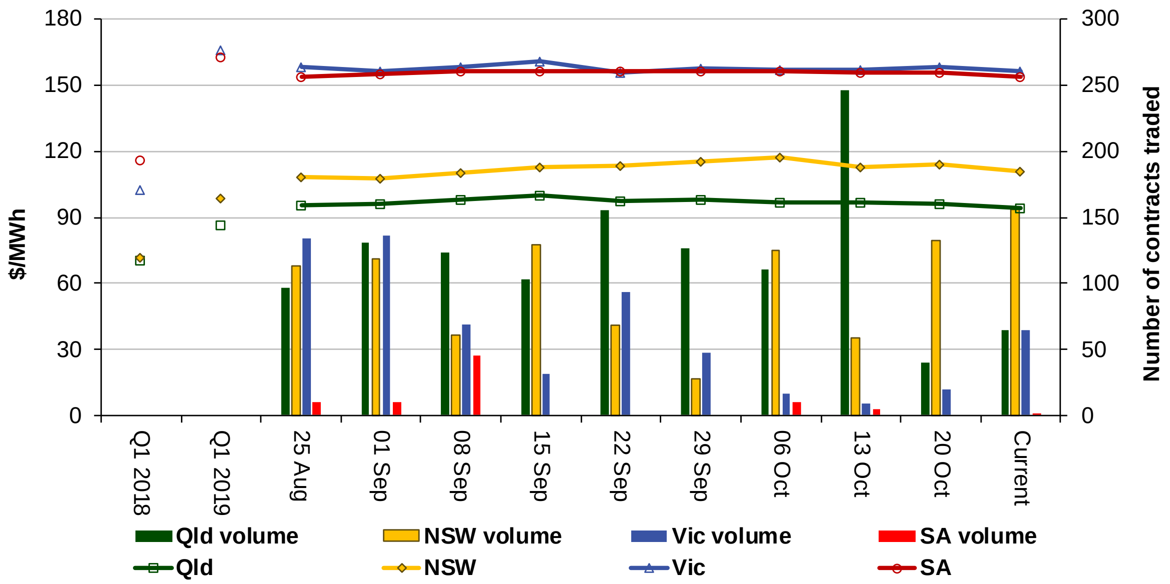
Figure 9: Quarterly base future prices Q4 2019 – Q3 2023



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 2020 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 2019 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

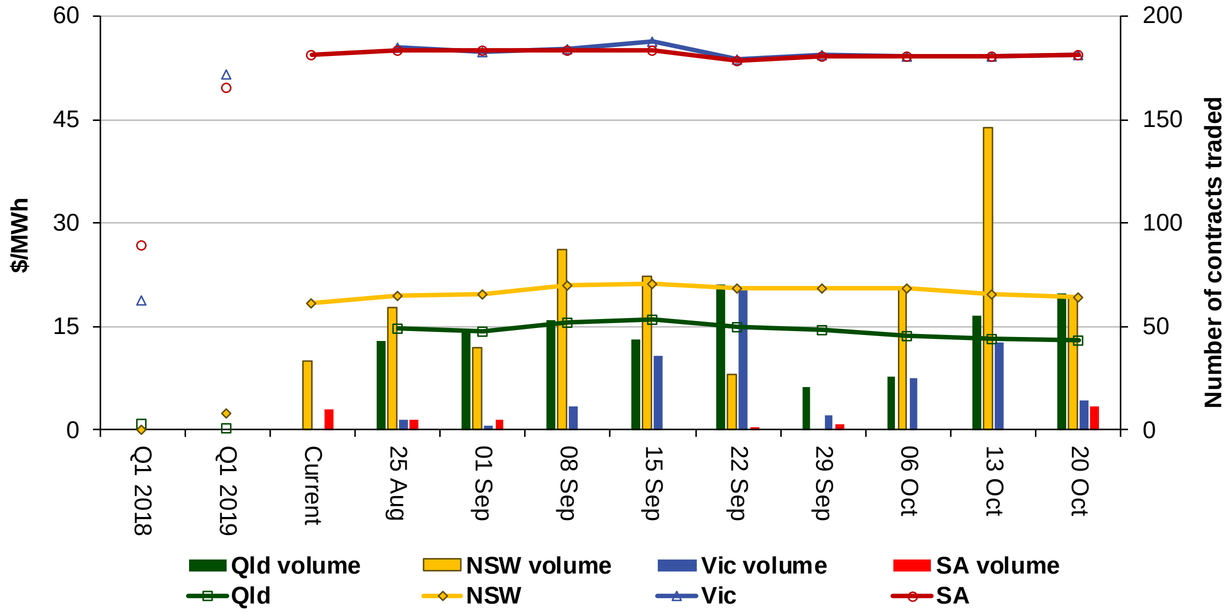
Figure 10: Price of Q1 2020 base contracts over the past 10 weeks (and the past 2 years)



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 quarter 1 2020 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 2019 prices are also shown.

Figure 11: Price of Q1 2020 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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