Electricity Report

AUSTRALIAN ENERGY REGULATOR

22 - 28 July 2018

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 22 – 28 July 2018.

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

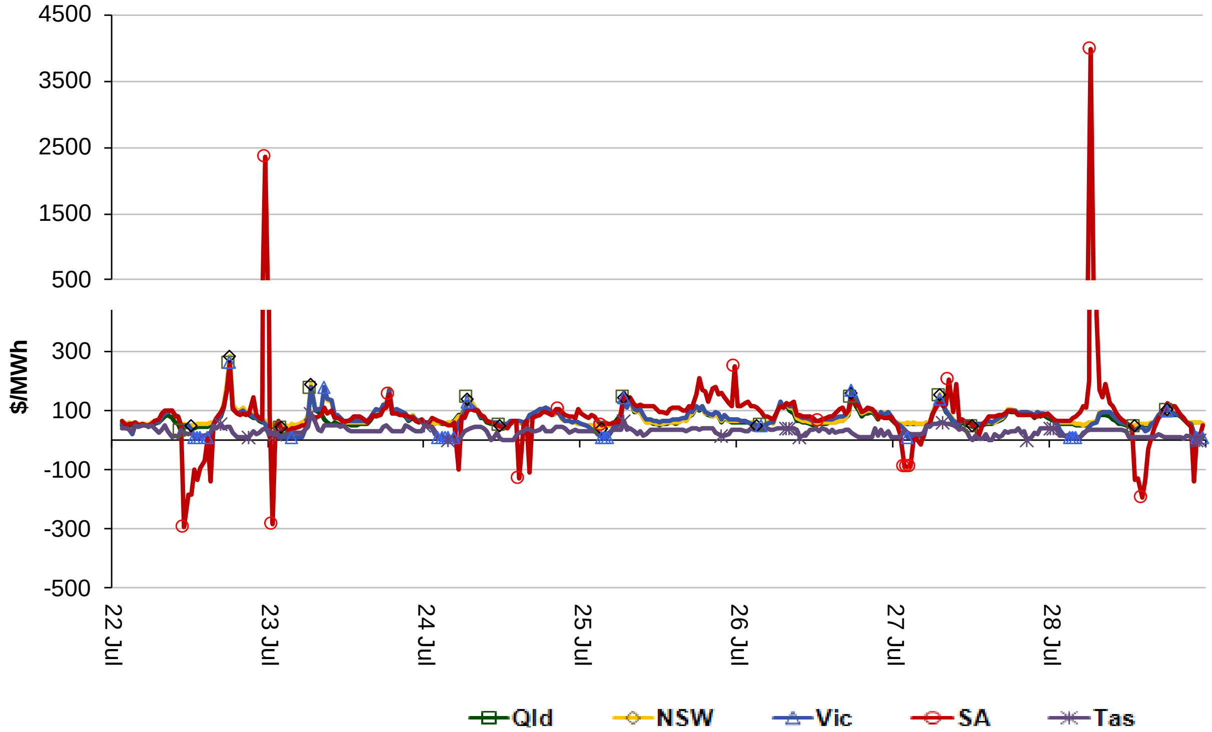


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

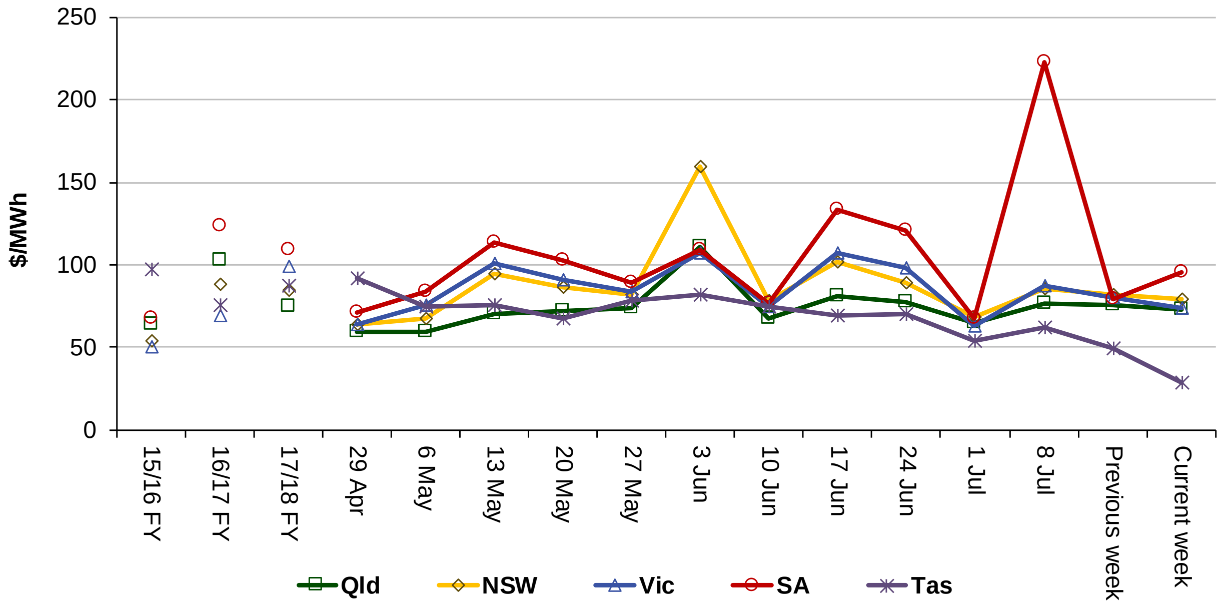


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	73	79	74	96	29
17-18 financial YTD	79	93	121	118	119
18-19 financial YTD	72	79	76	117	48

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 timeframes within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 296 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. 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	13	0	0
% of total below forecast	5	60	0	16

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

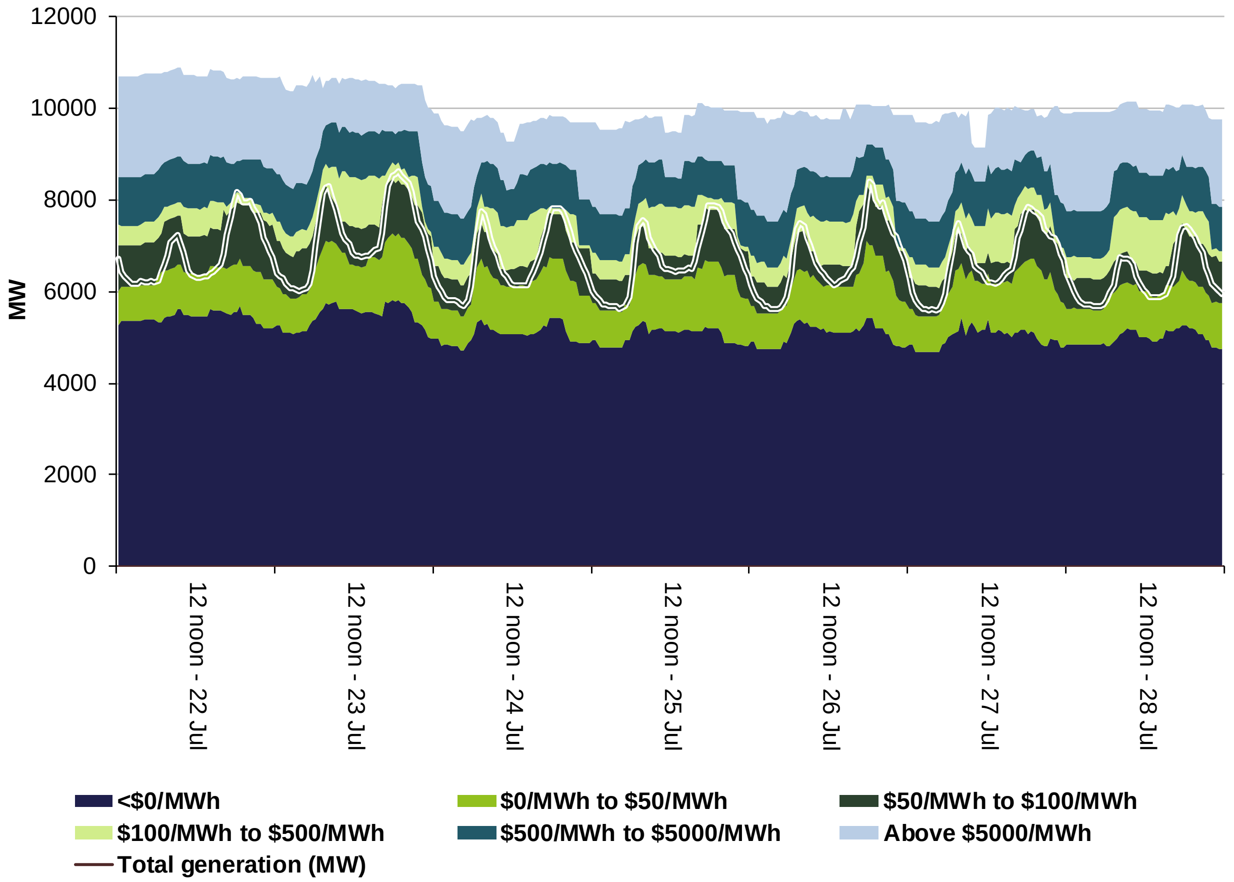


Figure 4: New South Wales generation and bidding patterns

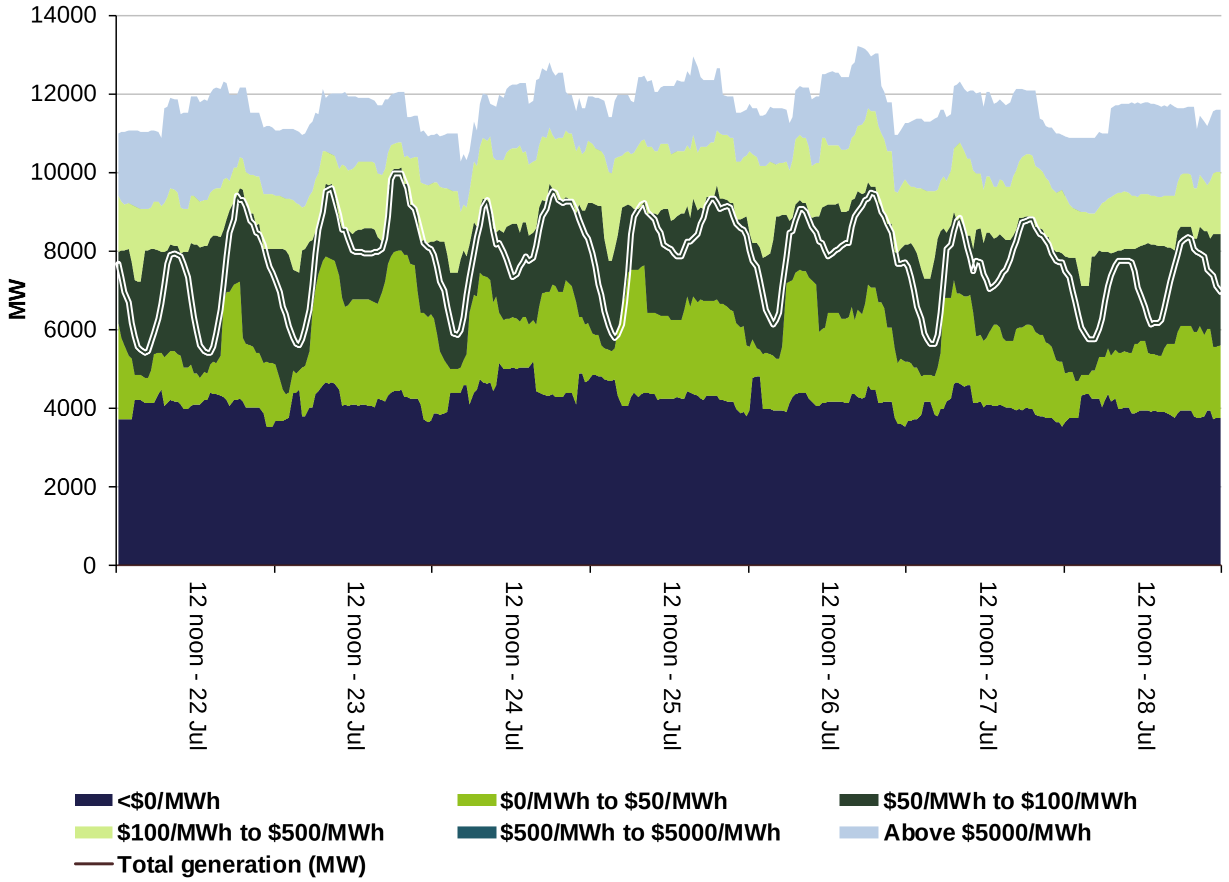


Figure 5: Victoria generation and bidding patterns

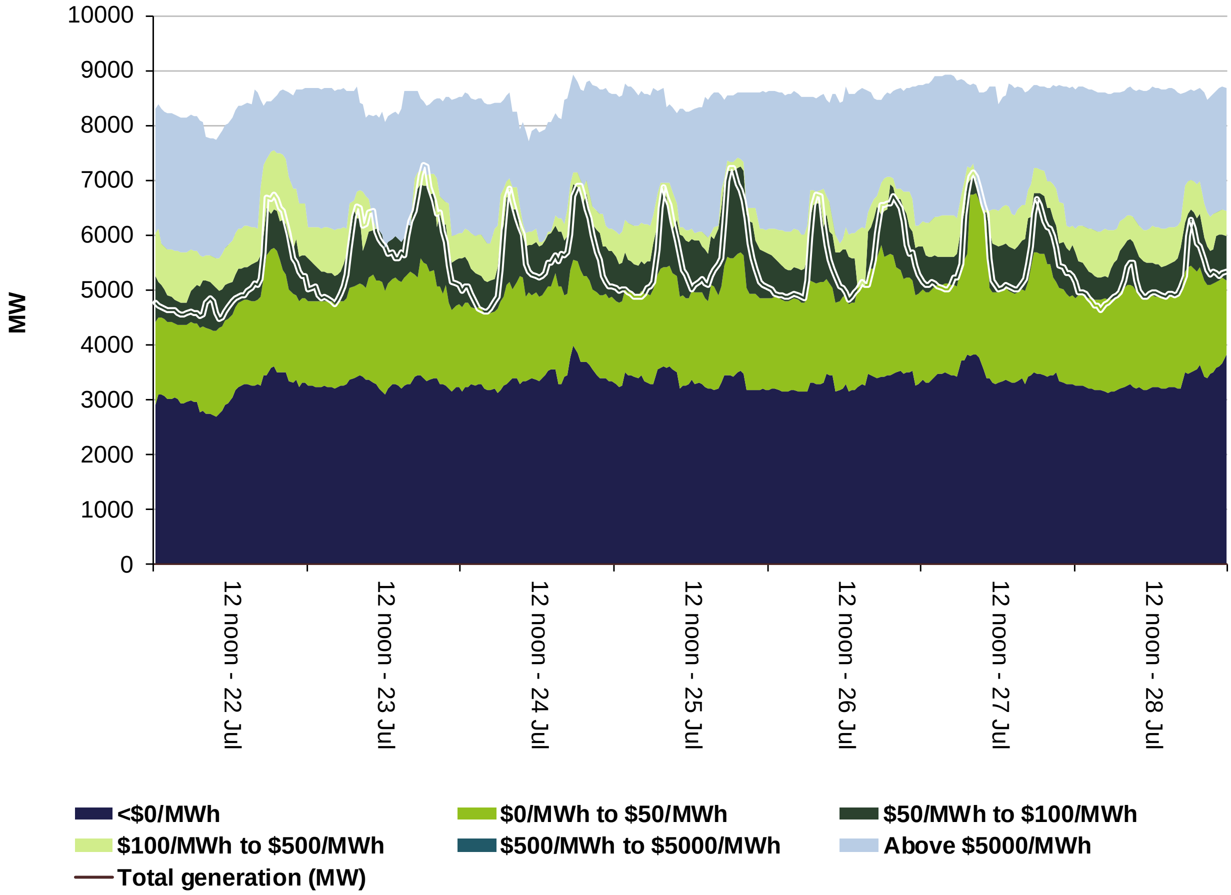


Figure 6: South Australia generation and bidding patterns

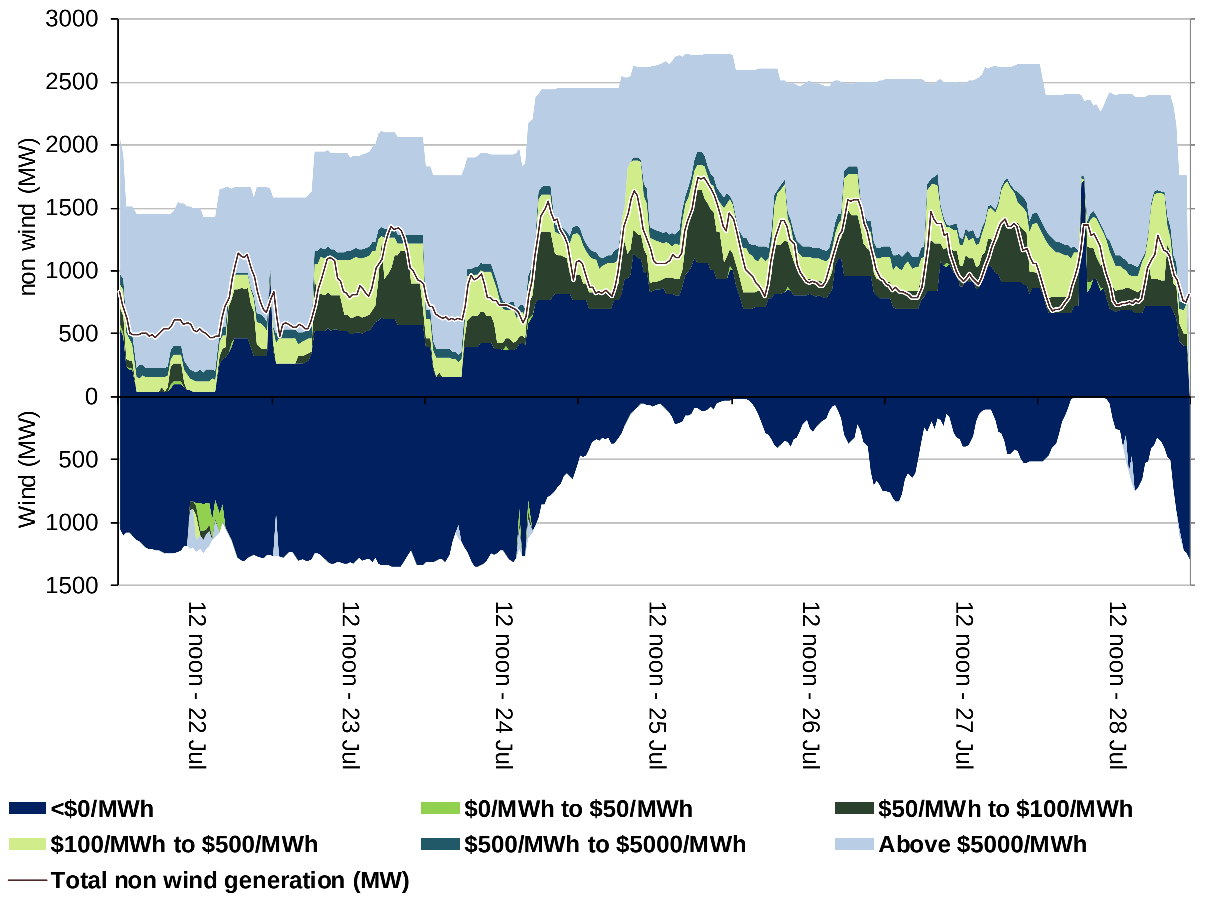
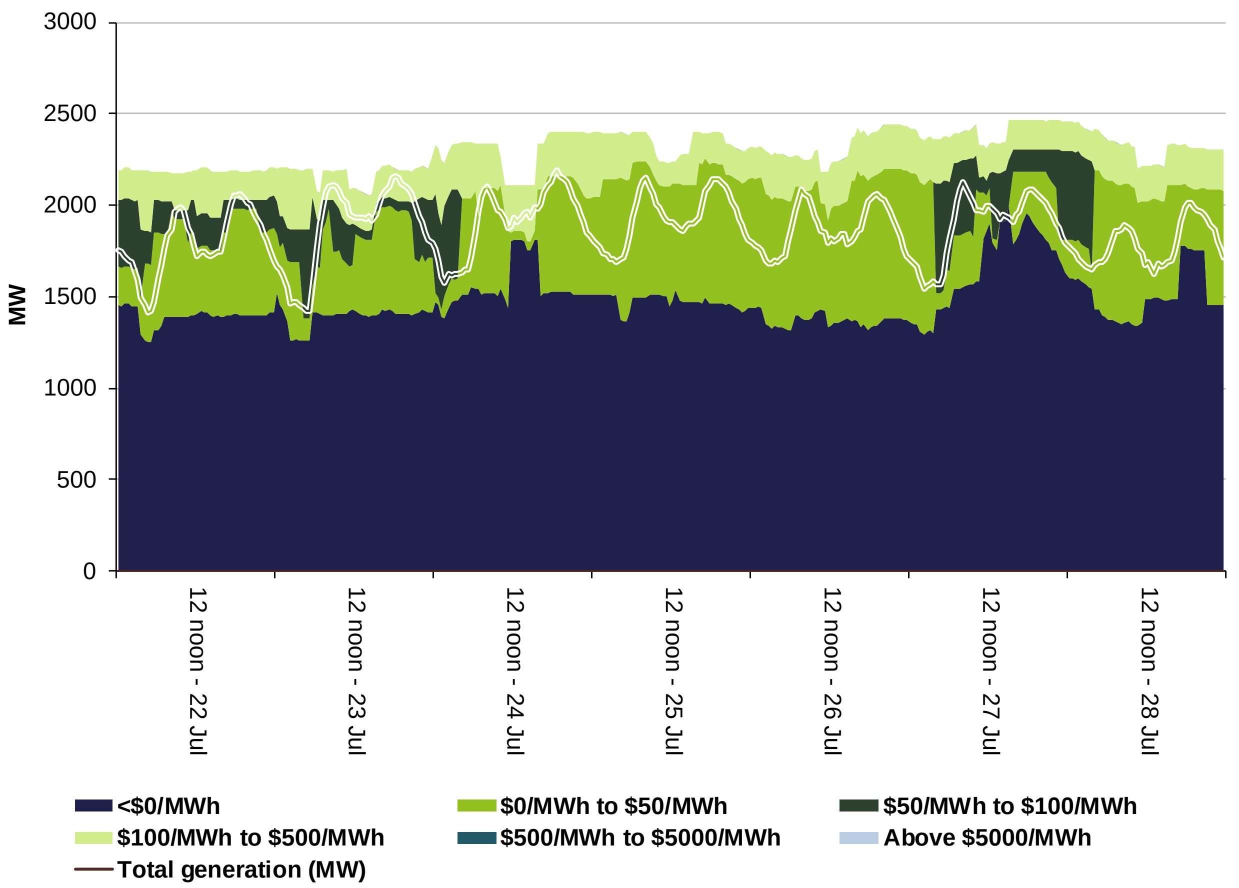


Figure 7: Tasmania generation and bidding patterns



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.

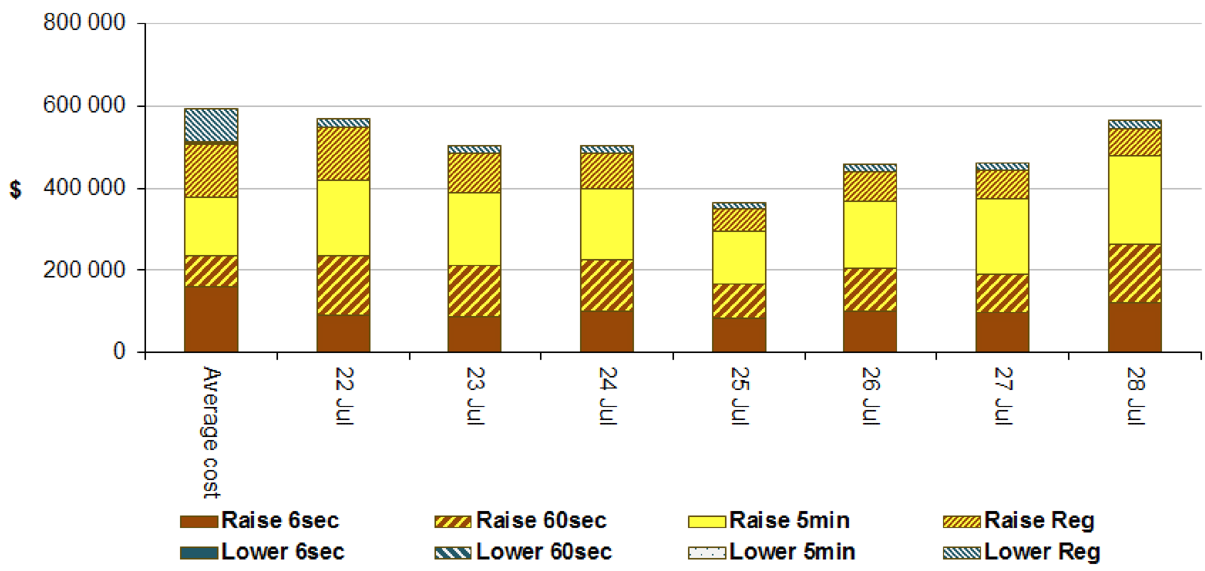
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 341 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $83 500 or around one 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

Mainland

There was one occasion where the spot price was aligned in mainland regions and the New South Wales price was greater than three times the New South Wales weekly average price of $79/MWh and above $250/MWh.

Sunday, 22 July

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
6.30 pm	285.57	148.36	299.50	27 431	26 419	26 921	35 965	36 310	36 414

Conditions on the day saw combined demand across all regions around 1000 MW greater than forecast four hours ahead and availability around 300 MW lower than forecast.

At 5.14 pm, Energy Australia reduced the available capacity at Mount Piper Unit 2 (in New South Wales) by 220 MW, due to plant limitations. The majority of this capacity was priced below $65/MWh. The combined effect of this rebid and demand being higher than forecast led to the high prices on the mainland. For the same trading interval the spot price in Tasmania was only $46/MWh.

South Australia

There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $96/MWh and above $250/MWh and fourteen occasions where the spot price was below -$100/MWh.

Sunday, 22 July

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 am	-296.39	48.56	-1000.00	830	828	764	2718	2527	2553
Midday	-184.29	37.18	-1000.00	812	805	739	2701	2546	2554
12:30 pm	-184.03	33.40	-1000.00	799	759	718	2736	2557	2564
1 pm	-100.59	34.02	-1000.00	780	762	717	2704	2568	2563
1.30 pm	-131.83	33.27	-984.47	802	737	707	2682	2573	2560
3.30 pm	-139.78	44.67	39.89	1008	841	810	2552	2549	2553

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plants in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

Conditions at the time saw demand close to forecast and availability up to 190 MW higher than forecast four hours ahead. With limited amounts of generation priced between $50/MWh and the price floor (-$1000/MWh), small increases in wind generation or decreases in demand resulted in lower than forecast prices.

Sunday, 22 July

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
Midnight	2364.79	128.61	106.50	1375	1383	1337	2903	2775	2823

Conditions at the time saw demand close to forecast and available capacity around 120 MW higher than forecast.

With only a small amount of capacity priced between $150/MWh and $13 100/MWh, the supply curve in South Australia was steep. Due to constraints managing a planned network outage on the South-East 275 kV line, exports were being forced into Victoria across the Heywood interconnector, slightly higher than forecast.

At 11.50 pm, there was a 28 MW increase in demand and a 39 MW increase in exports across the Heywood interconnector. With a number of units taking more than 5 minutes to start, the 5-minute price increased to $14 493/MWh for one dispatch interval. In response to the high price a number of participants rebid capacity from high prices to low prices causing the 5-minute price to fall to $63/MWh for the following dispatch interval.

Monday, 23 July

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
1 am	-281.60	75.79	64.13	1271	1260	1247	2851	2765	2830

Conditions at the time saw demand close to forecast and availability 86 MW greater than forecast.

With no capacity priced between $80/MWh and the floor, at 12.45 am wind generation increased by 72 MW, increasing lower priced capacity and the price decrease to the floor for two dispatch intervals.

Tuesday, 24 July

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
3 pm	-129.10	37.93	32.75	1146	1161	1221	3172	3009	3243
4.30 pm	-108.49	54.34	55.68	1266	1296	1315	3290	3367	3344

For the 3 pm trading interval, conditions at the time saw demand close to forecast and availability around 160 MW greater than forecast. Since early in the morning a (system normal) constraint which manages system strength in South Australia and limits wind generation to less than 1295 MW had been binding.

By 2.35 pm the constraint stopped binding, allowing cheaper priced wind generation to set the price, causing the dispatch price to fall to the price floor. A number of participants then rebid capacity into higher price bands in response to the negative price, causing the dispatch price to increase to around $50/MWh for the remainder of the trading interval.

For the 4.30 pm trading interval, conditions at the time saw demand close to forecast and availability around 80 MW lower than forecast. At 4.05 pm the constraint managing system strength stopped binding again (it had started to bind from 3.20 pm) allowing cheaper priced wind generation to set the price, causing the dispatch price to fall to the price floor. The price then increased to around $70/MWh for the remainder of the trading interval after a number of participants rebid capacity into higher price bands in response to the negative price.

Saturday, 28 July

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
7 am	3985.64	85.00	145.50	1267	1201	1170	2410	2467	2454
7:30 am	425.19	115.00	148.00	1306	1270	1241	2361	2461	2457

Conditions at the time saw demand close to forecast and availability up to 100 MW lower than forecast.

A planned network outage on the Ararat to Horsham 220 kV line commenced at 6.35 am. At 6.40 am a constraint managing the outage violated, reducing imports into South Australia from Victoria across the MurrayLink interconnector by 80 MW. At the same time demand in South Australia increased by 22 MW. With cheaper priced generation taking longer than five minutes to start, the 5-minute price increased to $12 100/MWh for two dispatch intervals. In response to the high prices participants rebid capacity from high to low prices, causing the dispatch price to fall close to the price floor by 7 am.

The rebids to lower price bands mentioned above were effective for the 7 am trading interval only. At 7.05 am, due to the step change in offers, generation priced above $12 000/MWh was dispatched however was ramp down constrained and unable to set price. This saw the dispatch interval increase to $380/MWh.

Effective from 7.10 am, Engie removed 48 MW at its Dry Creek power station due to plant issues. This capacity was priced below $0/MWh.

At 7.02 am, effective from 7.10 am, Neoen rebid 32 MW of capacity at Hornsdale battery (load) from the price floor to around $5000/MWh. The rebid reason stated “07:00 A SIGNIFICANT INCREASE IN PRICE”. With no available generation priced between $370/MWh and $12 100/MWh, the battery (as a load) set price at $5075/MWh. In response, a number of participants rebid capacity from high to low prices and the dispatch price dropped to around $60/MWh at 7.15 am and then to close to the floor for the remainder of the trading interval.

Saturday, 28 July

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
1:30 pm	-135.26	145.50	53.32	942	1020	968	2810	2387	2434
2 pm	-128.01	78.69	50.23	966	1004	970	2927	2375	2467
2:30 pm	-196.10	46.07	50.35	957	980	964	3002	2682	2510
3 pm	-133.21	44.19	49.95	996	986	975	3096	2706	2556
10:30 pm	-136.96	52.05	59.78	1362	1367	1312	2952	2903	2796

Conditions at the time saw demand close to forecast and availability up to 552 MW greater than forecast.

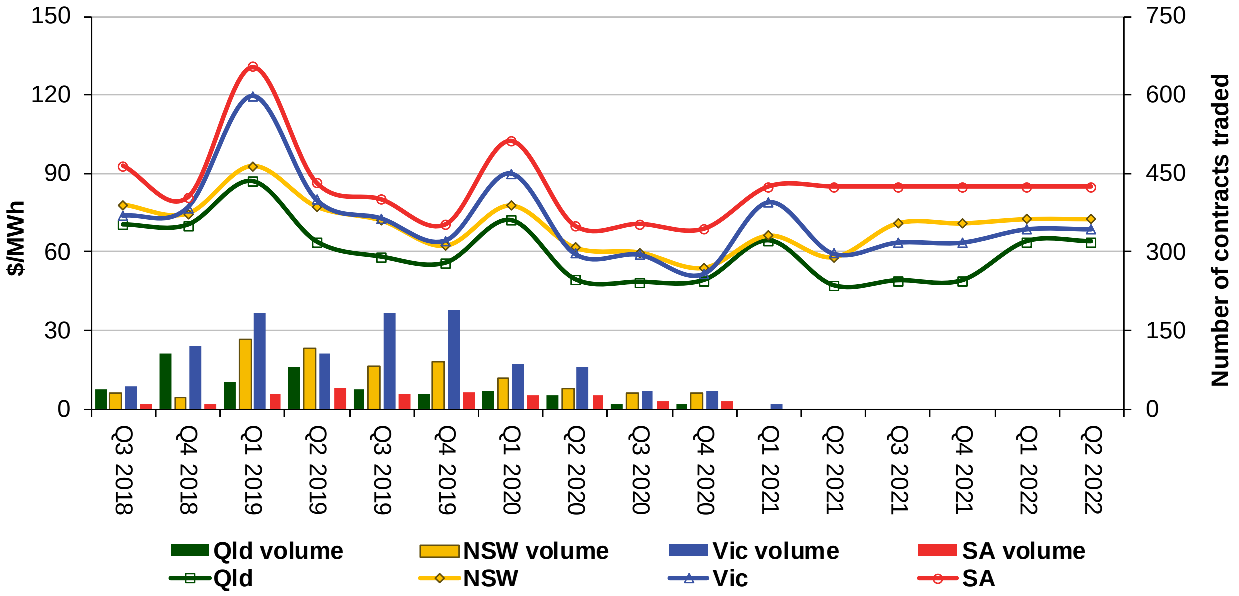
The higher than expected availability was largely due to higher than expected wind generation.

A combination of higher than forecast wind and the co-optimisation of energy and FCAS markets saw negative dispatch prices nine times (up to -$1000/MWh) across the five lower than forecast trading intervals.

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.

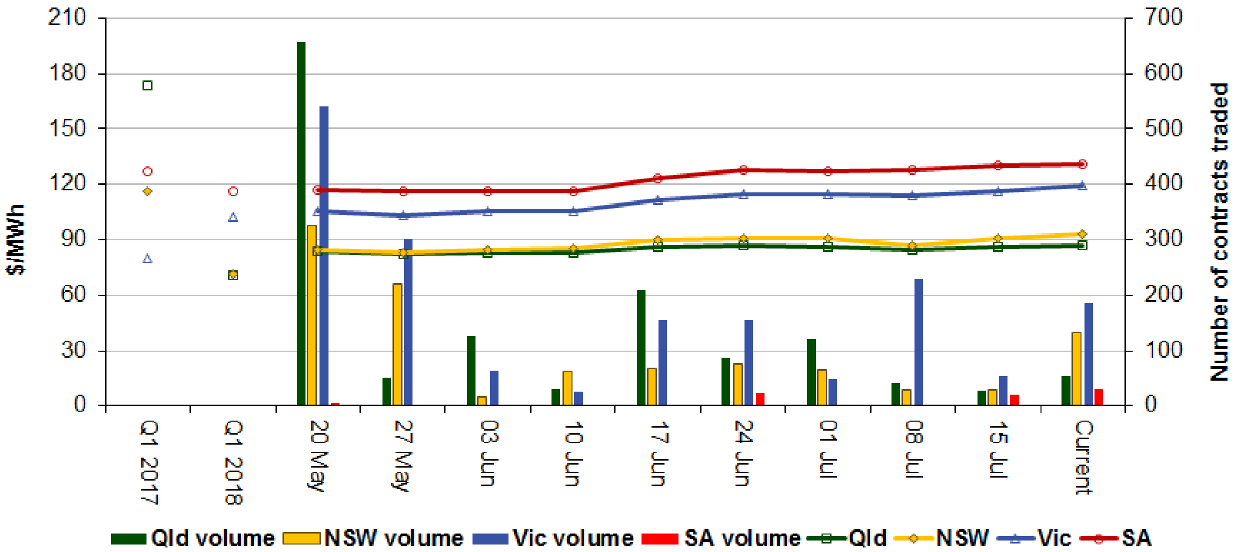
Figure 9: Quarterly base future prices Q3 2018 – Q2 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 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 2019 base contracts over the past 10 weeks (and the past 2 years)



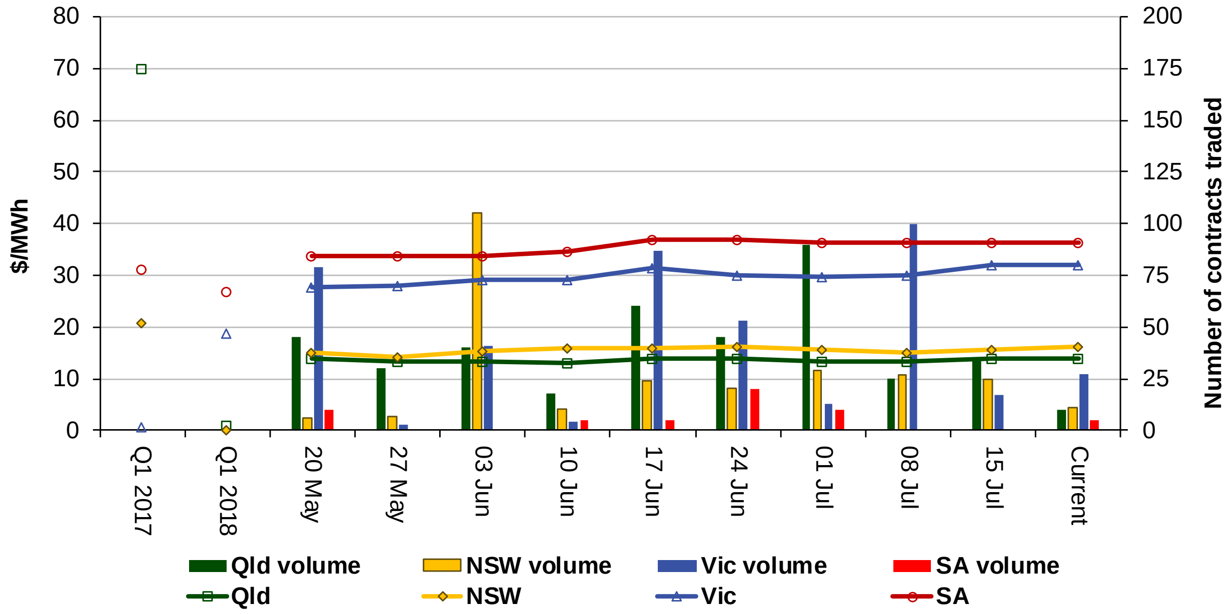
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics section of our website.

Figure 11 shows how the price for each regional quarter 1 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
October 2018