Electricity Report

AUSTRALIAN ENERGY REGULATOR

17 – 23 July 2016

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 17 to 23 July 2016.

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

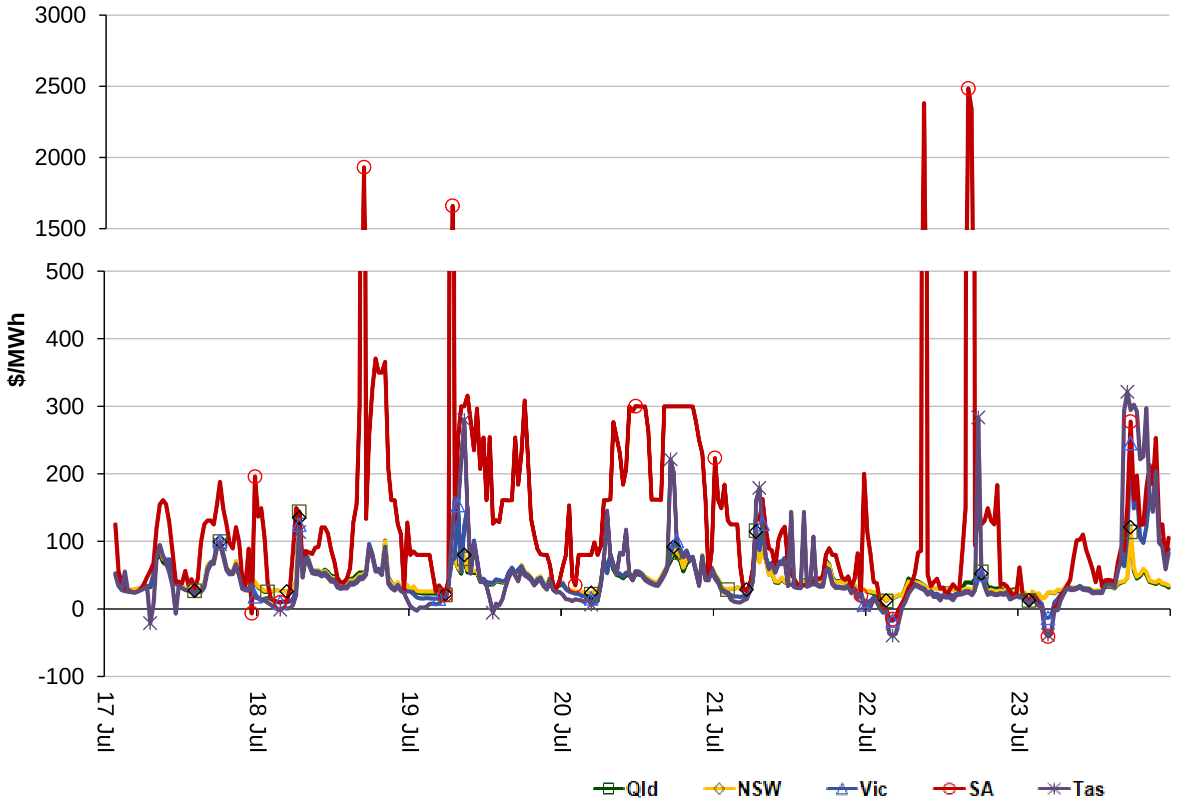


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

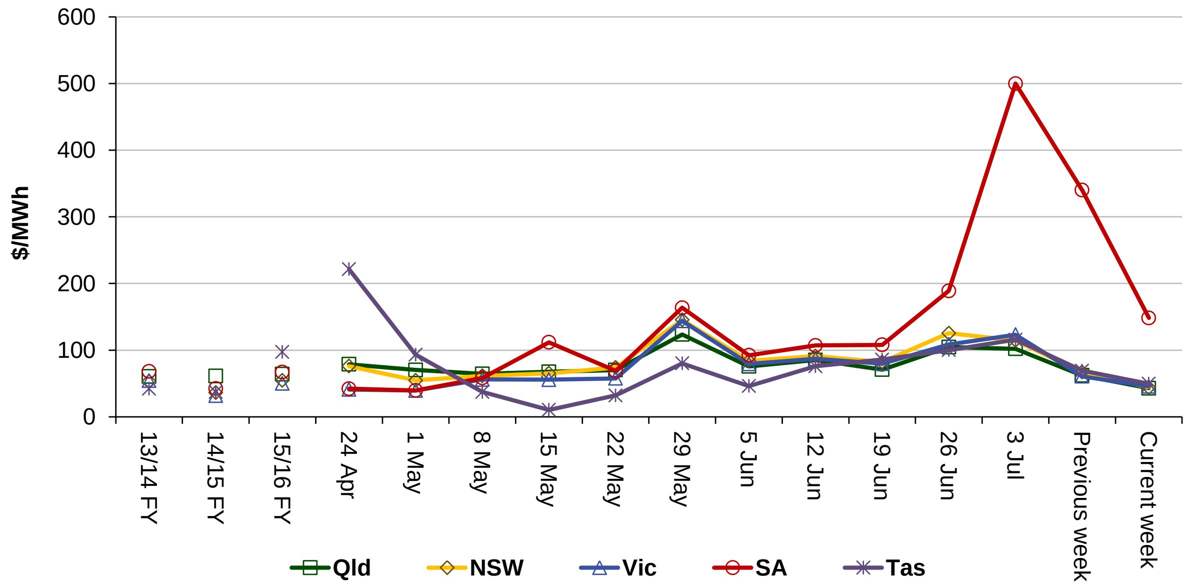


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	43	44	46	148	50
15-16 financial YTD	51	42	38	76	38
16-17 financial YTD	72	81	79	320	79

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 312 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71. 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	42	0	2
% of total below forecast	31	16	0	2

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

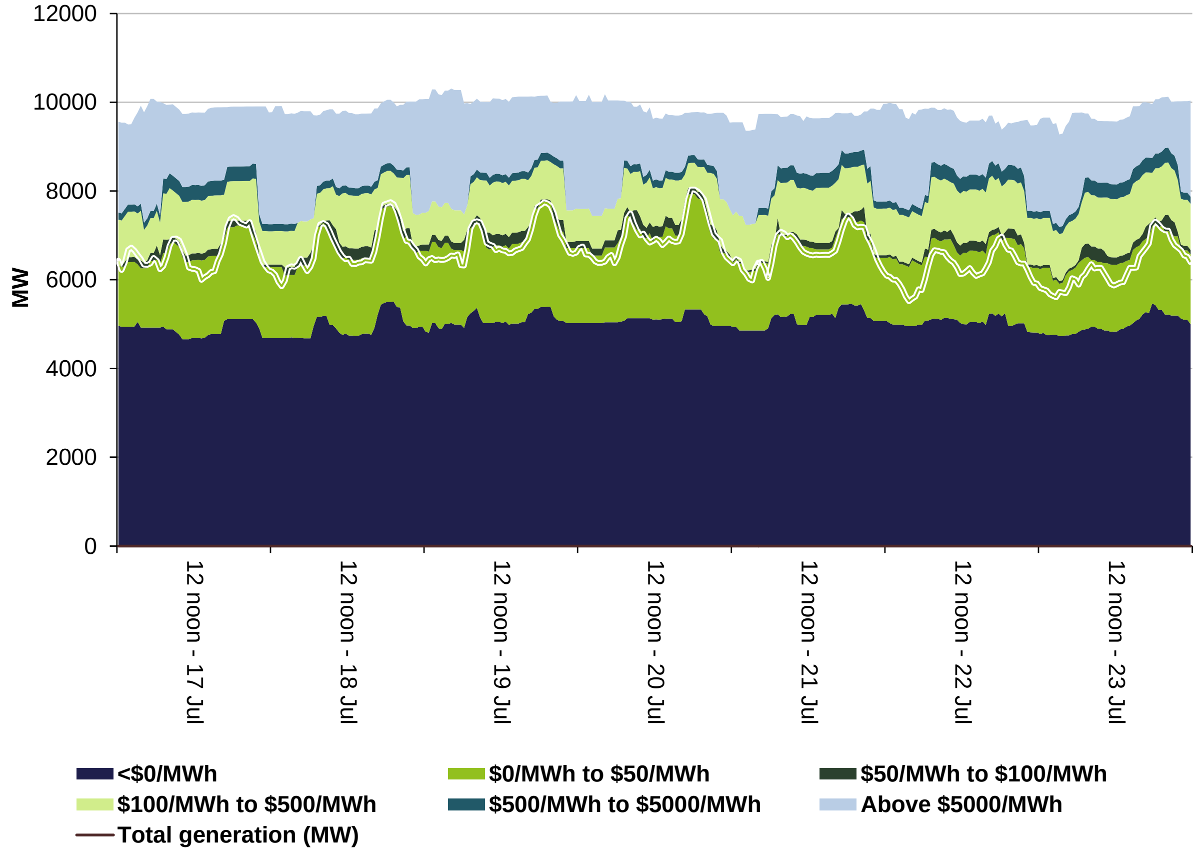


Figure 4: New South Wales generation and bidding patterns

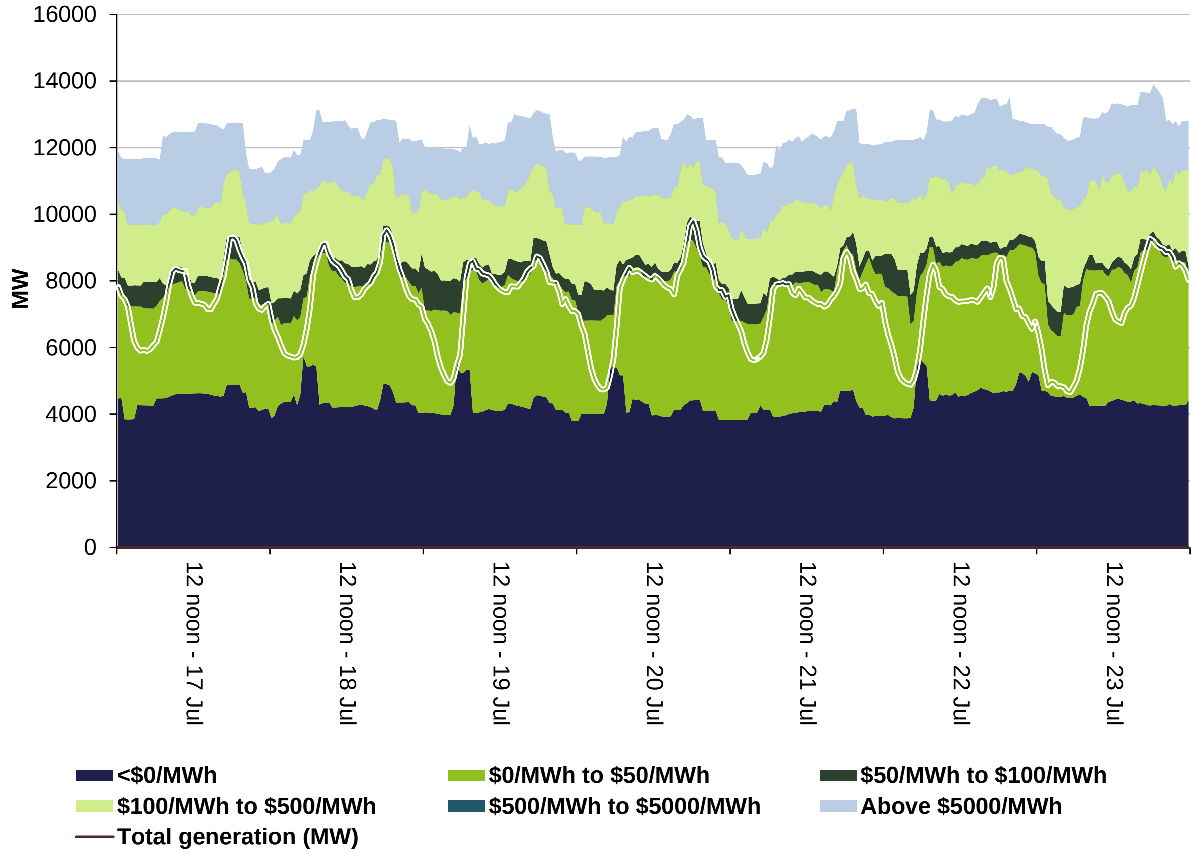


Figure 5: Victoria generation and bidding patterns

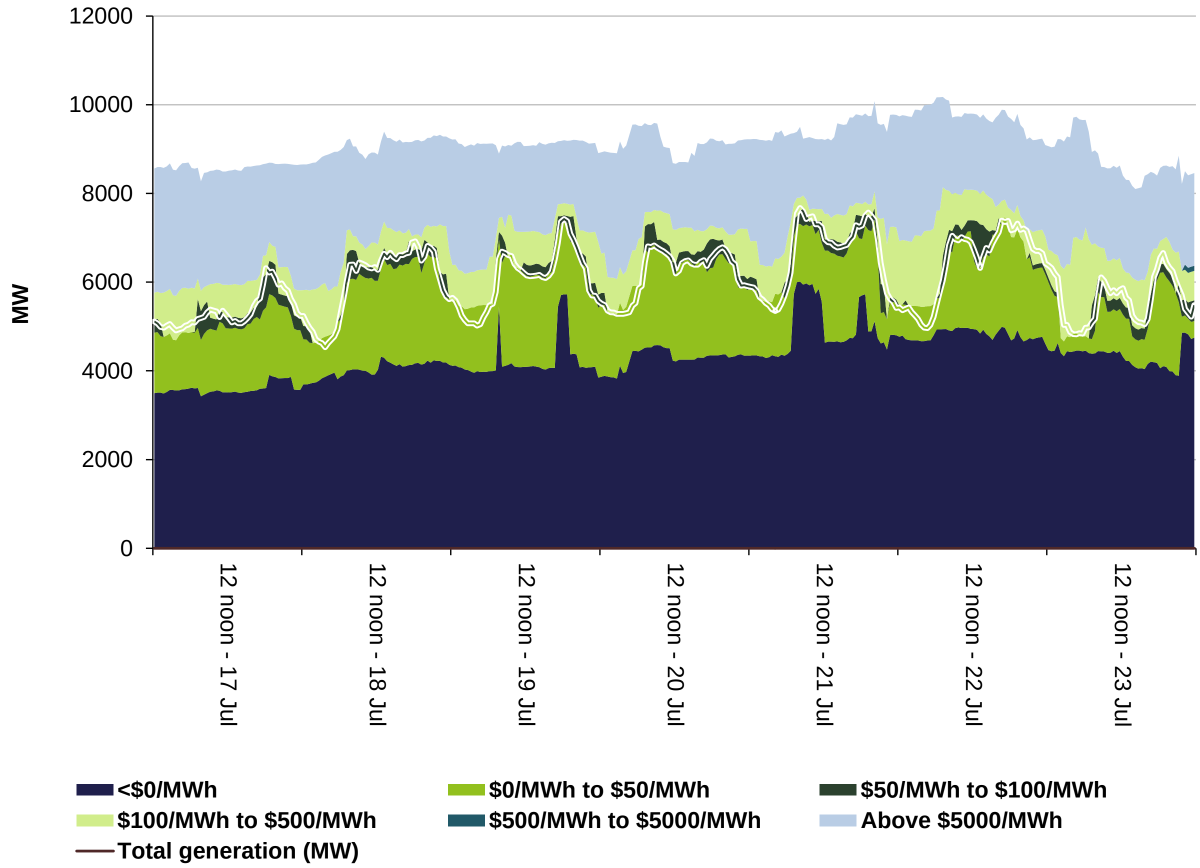


Figure 6: South Australia generation and bidding patterns

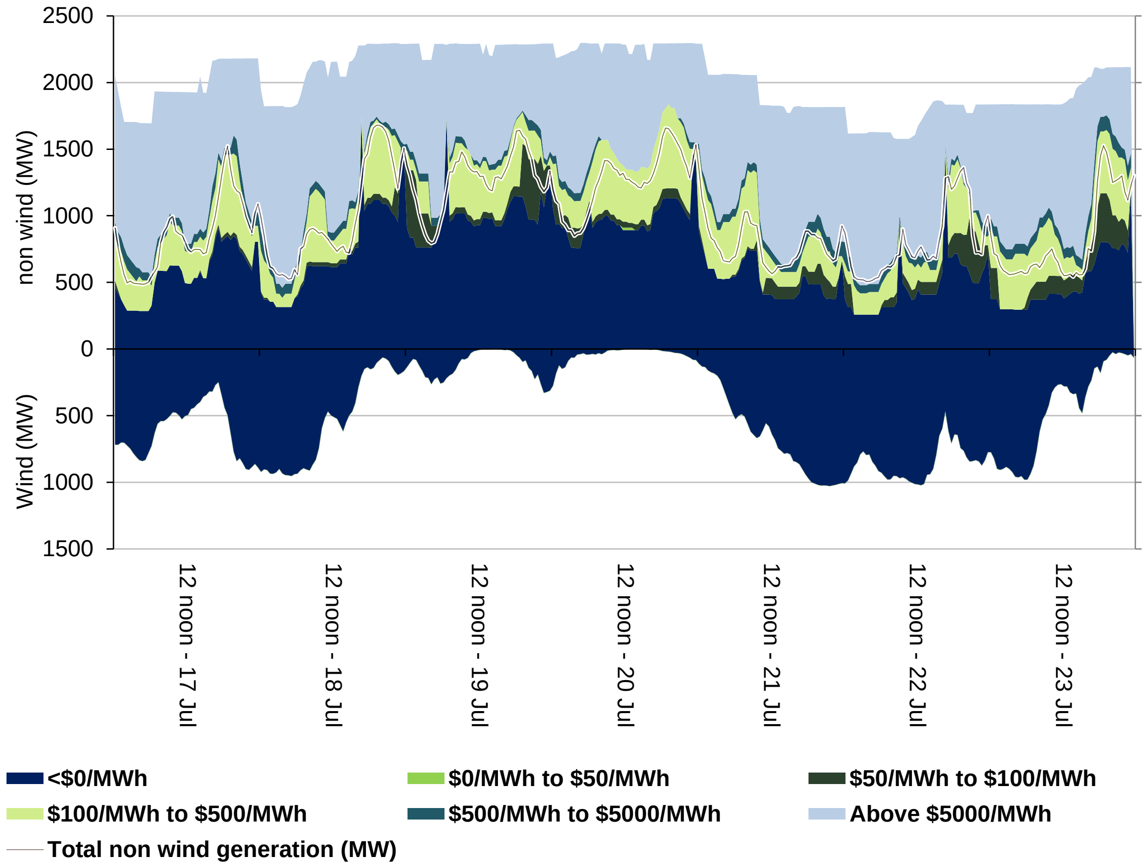
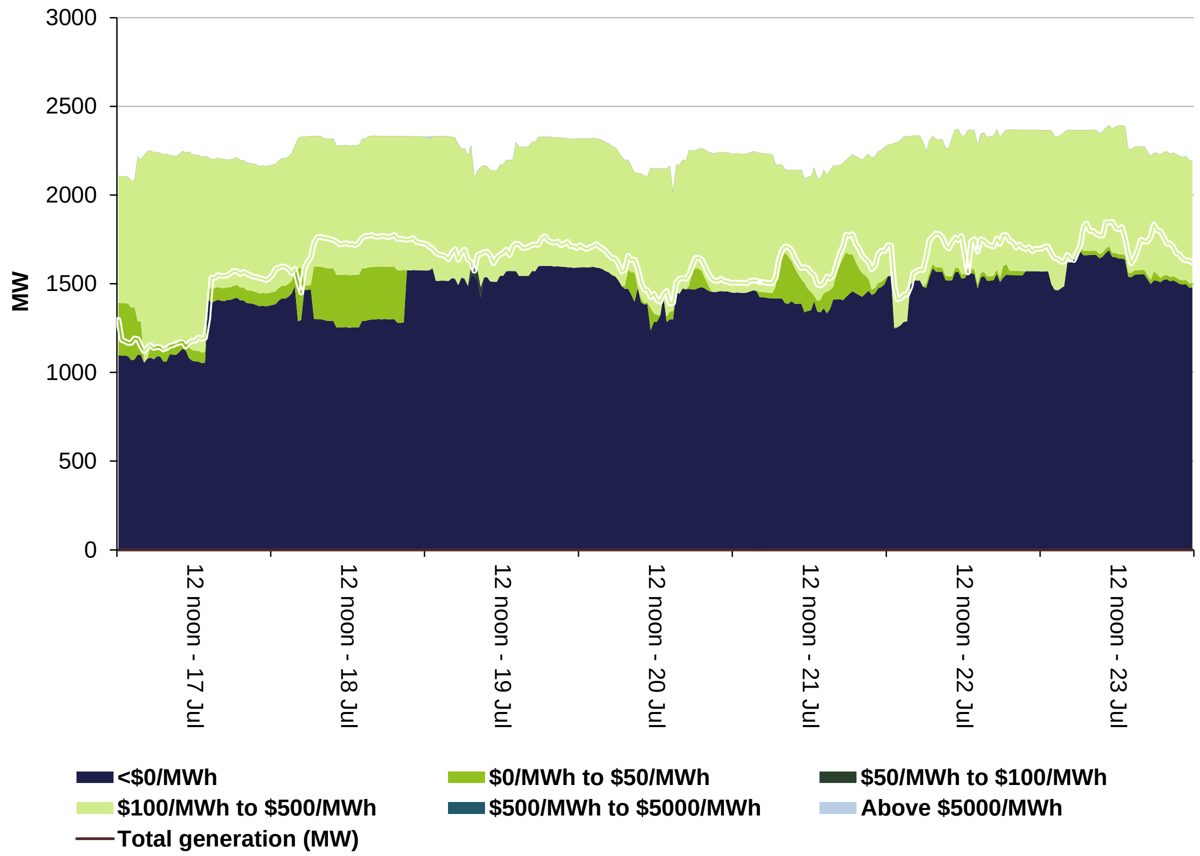


Figure 7: Tasmania generation and bidding patterns



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.

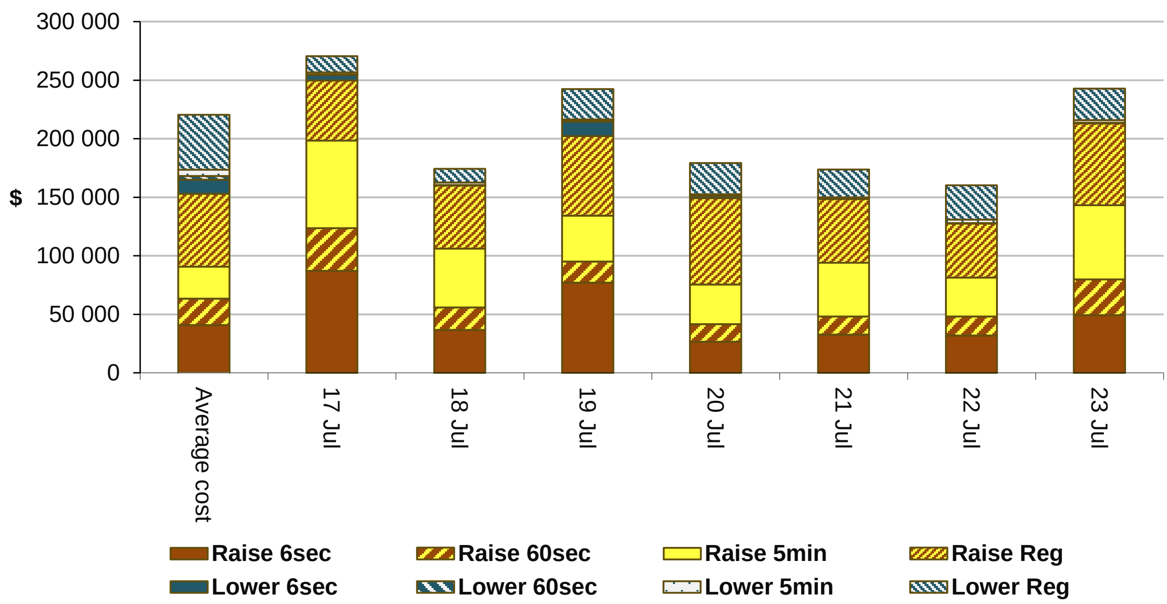
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$1 195 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$247 500 or around 2.5 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

We provide more detailed analysis of events where the spot price was greater than three times the weekly average price in a region and above $250/MWh or was below -$100/MWh.

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $148/MWh and above $250/MWh.

Monday, 18 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
5 pm	1930.20	485.18	485.18	1517	1528	1563	2482	2456	2446

The spot price was higher than forecast four hours ahead. Demand and availability were both close to forecast four hours ahead.

An outage of one South East to Tailem Bend 275 kV line was forecast to force exports of 2 MW across Heywood into Victoria four hours ahead. However, the outage actually forced 80 MW of exports across Heywood. Flows across Murraylink into South Australia were at the import limit of 220 MW, as forecast.

There were tight supply conditions, with only 15 MW of capacity priced between $301/MWh and $10 569/MWh, meaning small changes in demand or rebidding could lead to high prices.

Energy Australia rebid 35 MW of capacity from low prices to the price cap, effective at 4.40 pm. The reason given was ‘16:29 a band adj for mat change in SA price SL.’ With all lower priced generation being fully dispatched or ramp rate constrained and demand increasing by 28 MW at 4.45 pm, the dispatch price increased from $579/MWh at 4.40 pm to $10 569/MWh at 4.45 pm. Lumo subsequently rebid 104 MW of capacity from the price cap to the price floor and the dispatch price fell to $71/MWh at 4.50 pm. The dispatch price remained low for the rest of the trading interval.

Tuesday, 19 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
7 am	1659.54	122.54	124.99	1441	1390	1402	2525	2483	2523

Spot price, demand and availability were all higher than forecast four hours ahead.

A planned outage of one South East to Tailem Bend 275 kV line was restricting flows across Heywood into South Australia to less than 10 MW.

In preparation for a planned outage of the Red Cliffs – Wemen 220 kV line, a soft ramping constraint was invoked that resulted in a significant reduction in import flows to around 100 MW across Murraylink into South Australia. The constraint was not forecast to bind four hours ahead.

There were tight supply conditions, with only 40 MW of capacity priced between $301/MWh and $10 579/MWh, meaning small changes in demand, availability or rebidding could lead to high prices.

Demand increased by 21 MW at 6.40 am and wind generation was 31 MW lower than forecast four hours ahead, resulting in the dispatch price increasing from $301/MWh at 6.35 am to $10 570/MWh at 6.40 am. Lumo rebid 101 MW from the price cap to the price floor effective at 6.45 am and the dispatch price fell to $77/MWh. The dispatch price remained low for the rest of the trading interval.

Friday, 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
9.30 am	2380.68	79.99	247.38	1409	1342	1376	2568	2559	2579

Spot price and demand were both higher than forecast four hours ahead. Availability was close to forecast four hours ahead.

A constraint managing a planned outage of one South East to Tailem Bend 275 kV line was forcing exports of 170 MW across Heywood into Victoria. Flows across Murraylink into South Australia were at the import limit of 220 MW.

At 9.20 am the constraint led to low priced generation from Lake Bonney 2 and 3 being constrained off. At the same time demand increased by 85 MW.

With low priced capacity either ramp rate limited or fully dispatched, the dispatch price increased from $80/MWh at 9.15 am to $14 000/MWh at 9.20 am. Prices reduced to $28/MWh at 9.25 am, when market participants rebid 278 MW of capacity from the price cap to the price floor and demand reduced by 31 MW. The dispatch price remained low for the rest of the trading interval.

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	2484.65	37.49	35.50	1535	1398	1324	2483	2766	2727
5 pm	2337.47	39.07	41.72	1592	1422	1369	2331	2787	2724

Prices were higher than forecast four hours ahead. Demand was significantly higher than forecast four hours ahead, while availability was significantly lower than forecast.

A planned outage of one South East to Tailem Bend 275 kV line was forcing close to 50 MW of exports across Heywood into Victoria.

Wind generation was 441 MW and 577 MW lower than forecast four hours ahead for the 4.30 pm and 5 pm trading intervals, respectively. Further, demand was 137 MW and 170 MW higher than forecast four hours ahead for the 4.30 pm and 5 pm trading intervals.

With low priced capacity either ramp rate limited or fully dispatched, the dispatch price increased from $300/MWh at 4.25 pm to $14 000/MWh for the 4.30 pm and 4.35 pm dispatch intervals. Market participants subsequently rebid 470 MW from high to low prices, resulting in the dispatch price falling to $18/MWh at 4.40 pm and remaining low for the rest of the trading interval.

Tasmania

There were eight occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $50/MWh and above $250/MWh.

Tuesday, 19 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
9 am	279.59	336.05	44.19	1368	1341	1360	2157	2269	2263

The spot price was close to forecast four hours ahead.

Friday, 22 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
6 pm	283.21	24.63	30.02	1392	1352	1353	2324	2392	2392

Demand was higher than forecast four hours ahead, while availability was lower than forecast.

Supply conditions were tight, with no capacity priced between $2/MWh and $249/MWh, meaning small changes in demand, rebidding, wind generation or interconnector limits could lead to high prices.

Wind generation dropped by 32 MW from 5.40 pm to 5.45 pm. With local low priced capacity ramp rate limited, trapped or stranded in FCAS, or fully dispatched, the dispatch price rose from $40/MWh at 5.40 pm to $475/MWh at 5.45 pm. The dispatch price was above $333/MWh for the remainder of the trading interval.

Saturday, 23 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
5 pm	294.23	50.17	25.43	1397	1359	1284	2245	2386	2389

Demand was higher than forecast fours ahead, while availability was lower than forecast.

Supply conditions were tight, with no capacity priced between $2/MWh and $249/MWh, meaning small changes in demand, rebidding, wind generation or interconnector limits could lead to high prices.

Wind generation for the 5 pm trading interval was 31 MW lower than forecast four hours ahead. This combined with the higher than forecast demand resulted in dispatch prices at around $330/MWh for a majority of the trading interval.

Table 10: 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 pm	321.22	338.37	33.62	1442	1433	1344	2217	2385	2387
6 pm	294.51	312.01	35.38	1485	1463	1400	2239	2385	2387
6.30 pm	302.35	254.41	41.38	1492	1455	1397	2237	2267	2387
7 pm	292.32	273.30	42.59	1479	1436	1385	2228	2377	2382

Prices were close to forecast four hours ahead.

Table 11: 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
8.30 pm	297.15	141.09	24.37	1435	1395	1333	2234	2377	2377

Demand was higher than forecast four hours ahead, while availability was lower than forecast.

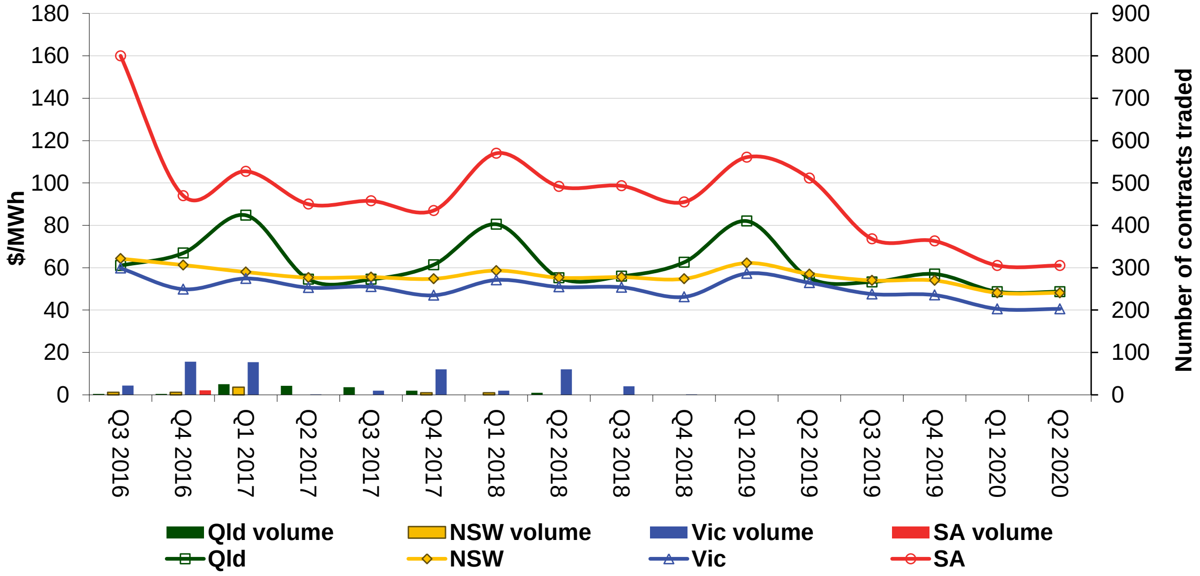
Supply conditions were tight, with no capacity priced between $2/MWh and $249/MWh, meaning small changes in demand, rebidding, wind generation or interconnector limits could lead to high prices.

Wind generation for the 8.30 pm trading interval was 28 MW lower than forecast four hours ahead. This combined with the higher than forecast demand resulted in dispatch prices between $254/MWh and $325/MWh for the entire 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.

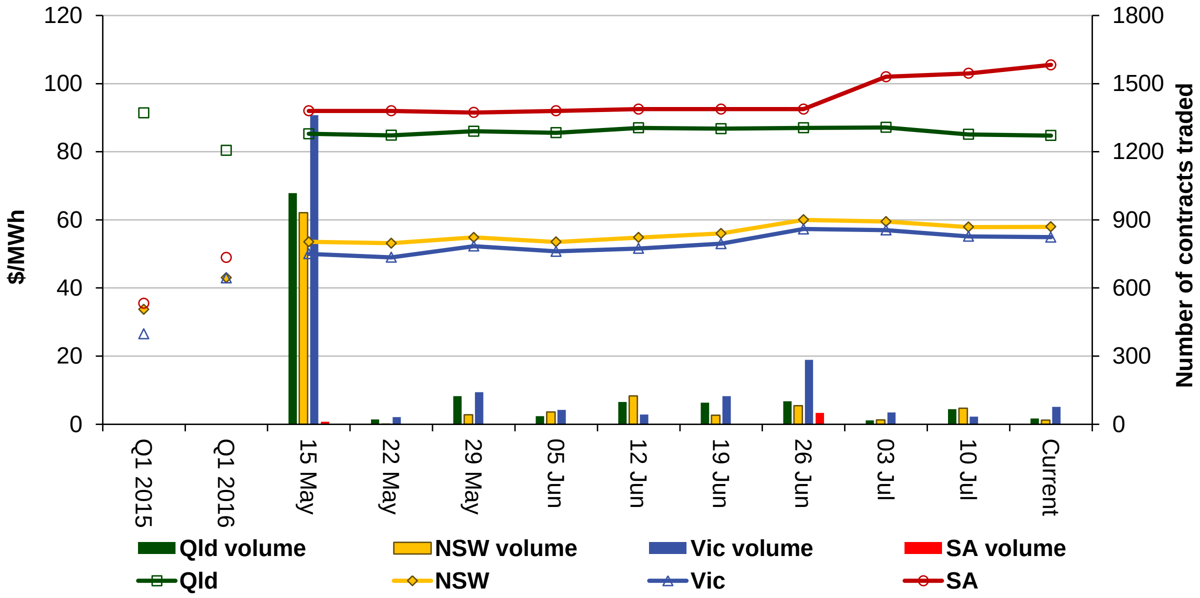
Figure 9: Quarterly base future prices Q3 2016 – Q2 2020



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 2017 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 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 2017 base contracts over the past 10 weeks (and the past 2 years)



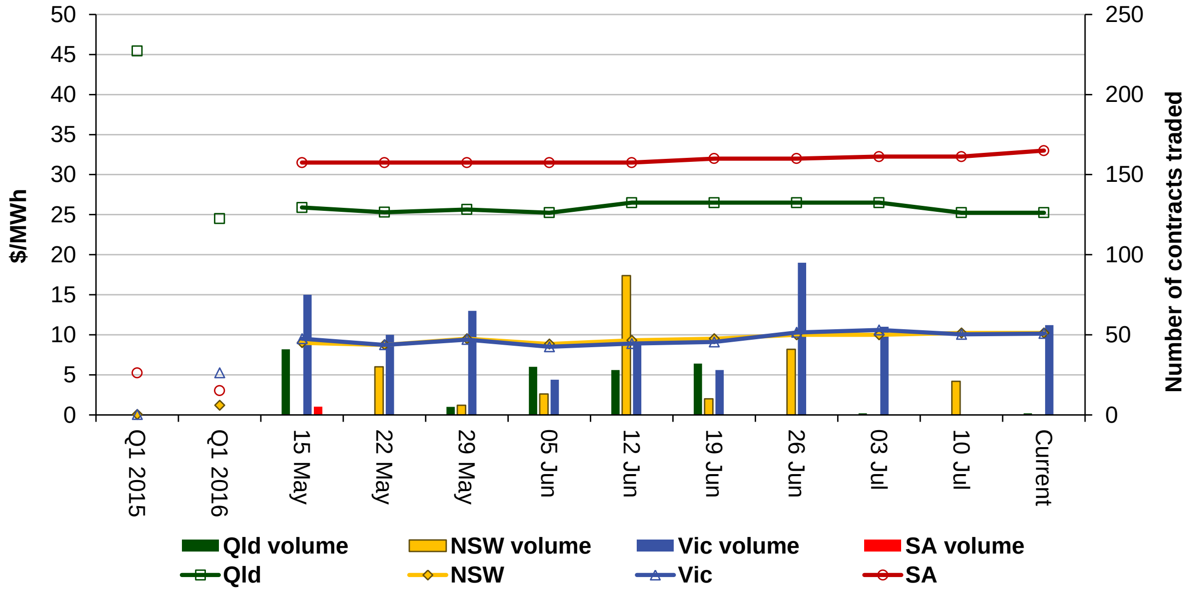
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2017 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown.

Figure 11: Price of Q1 2017 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
August 2016