Electricity Report

AUSTRALIAN ENERGY REGULATOR

16 –22 October 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 16 to 22 October 2016.

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

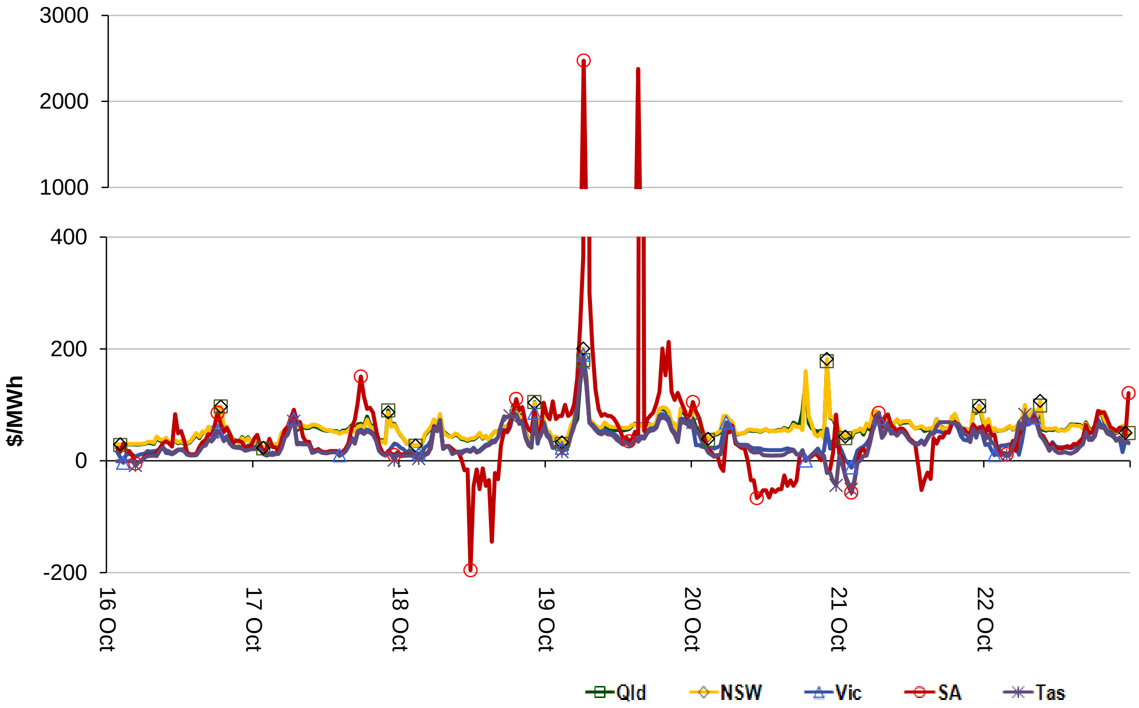


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

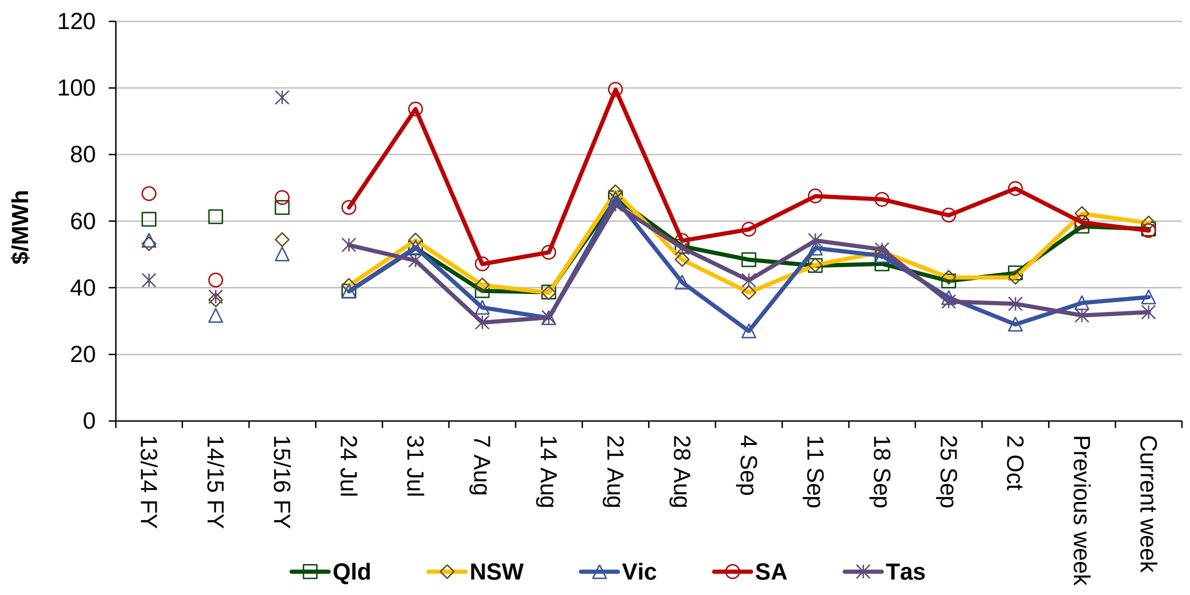


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	58	59	37	57	33
15-16 financial YTD	44	45	39	64	41
16-17 financial YTD	54	56	49	122	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 276 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	4	29	0	1
% of total below forecast	42	20	0	3

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

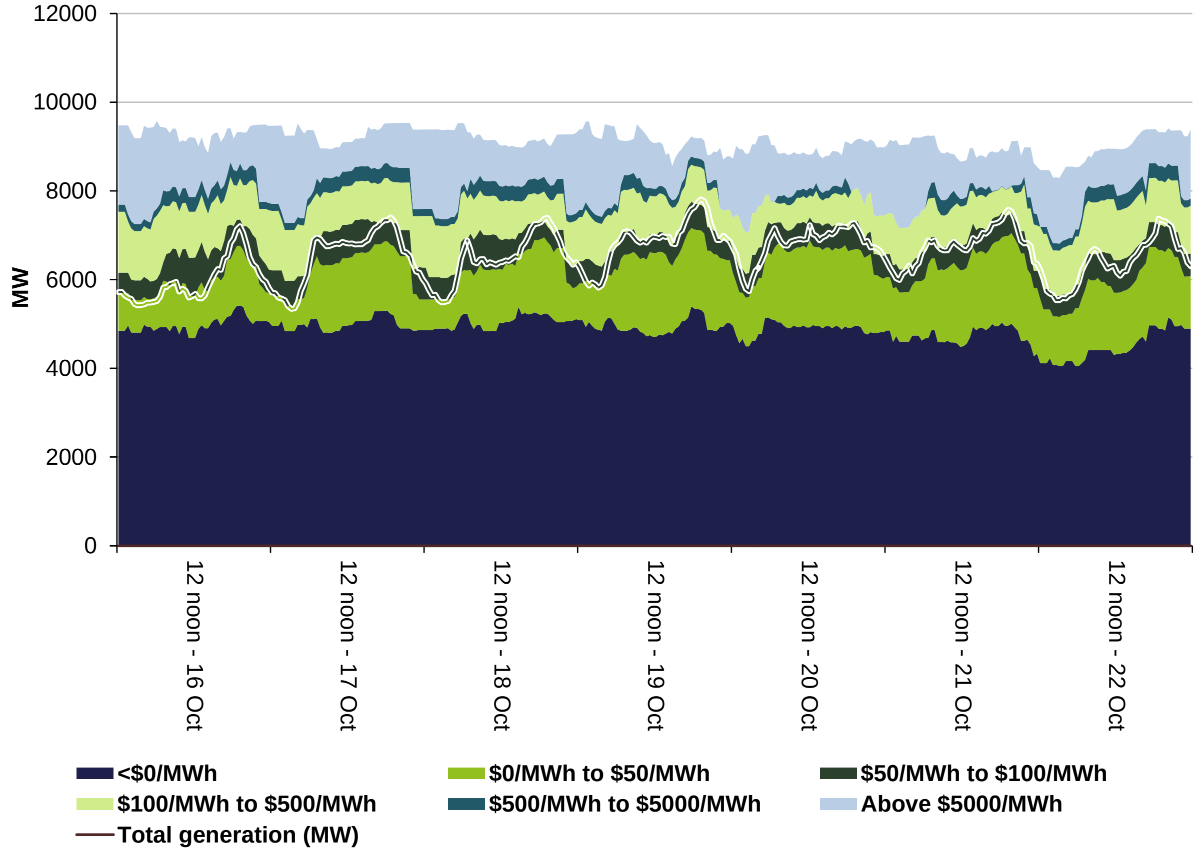


Figure 4: New South Wales generation and bidding patterns

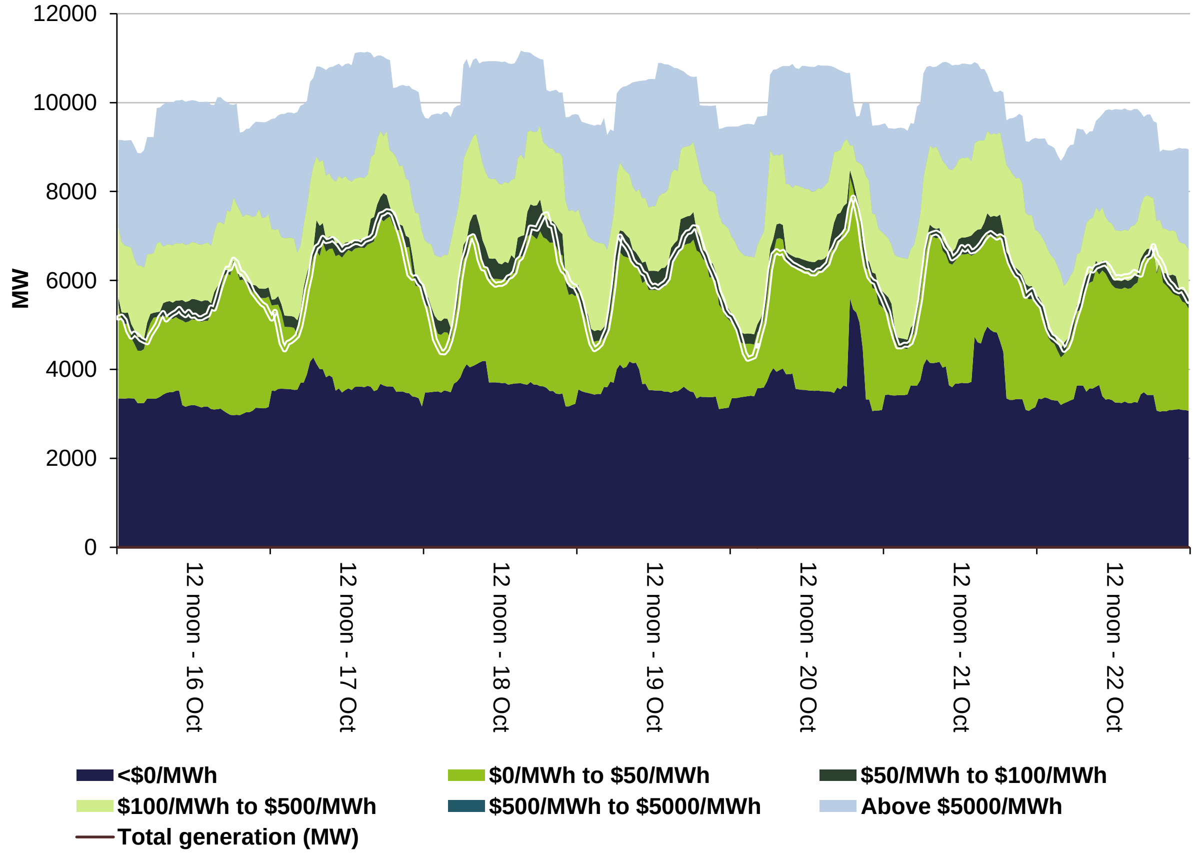


Figure 5: Victoria generation and bidding patterns

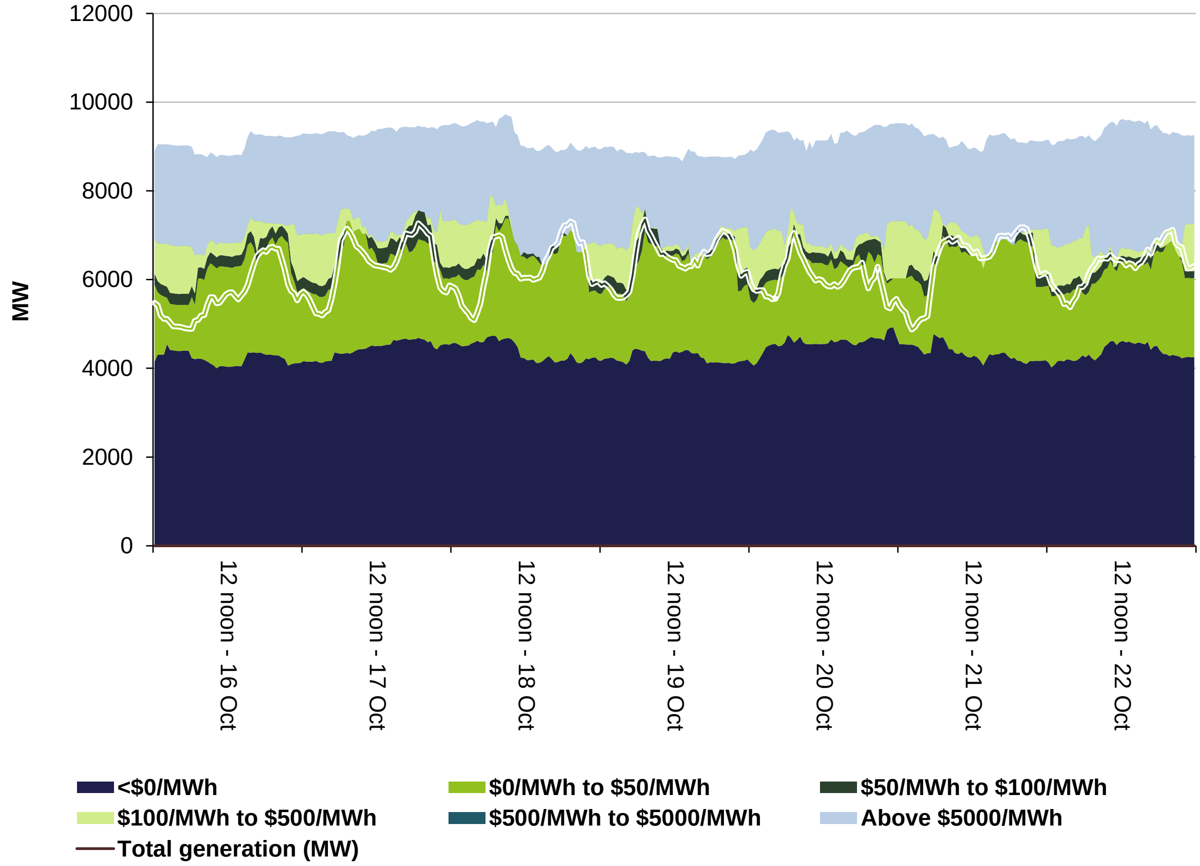


Figure 6: South Australia generation and bidding patterns

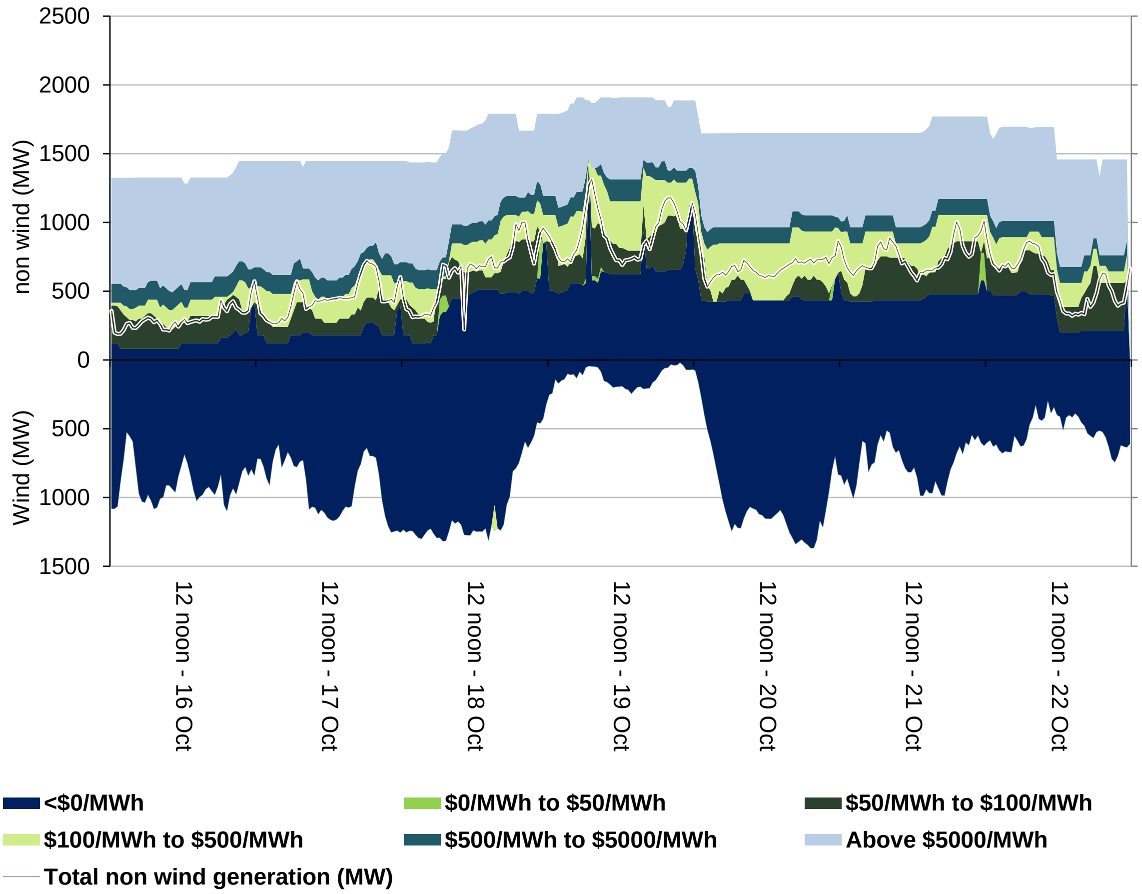
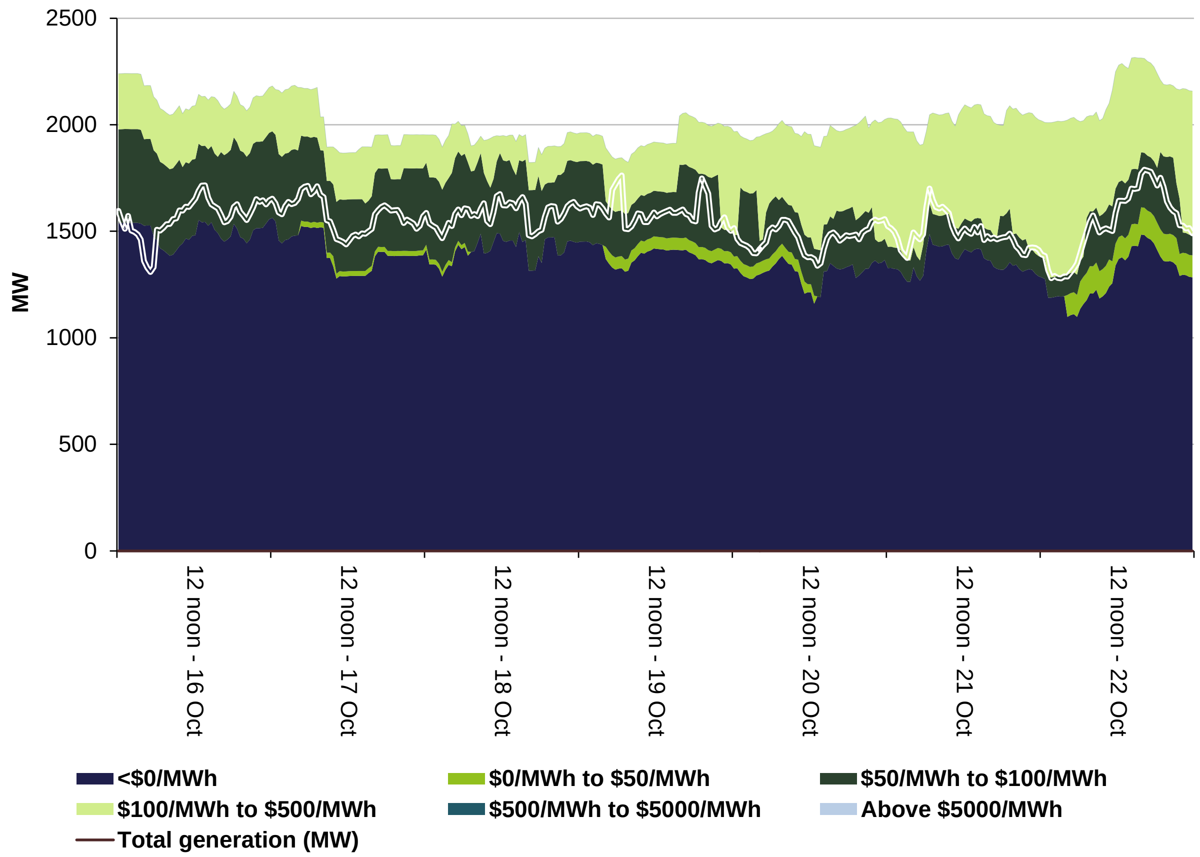


Figure 7: Tasmania generation and bidding patterns



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.

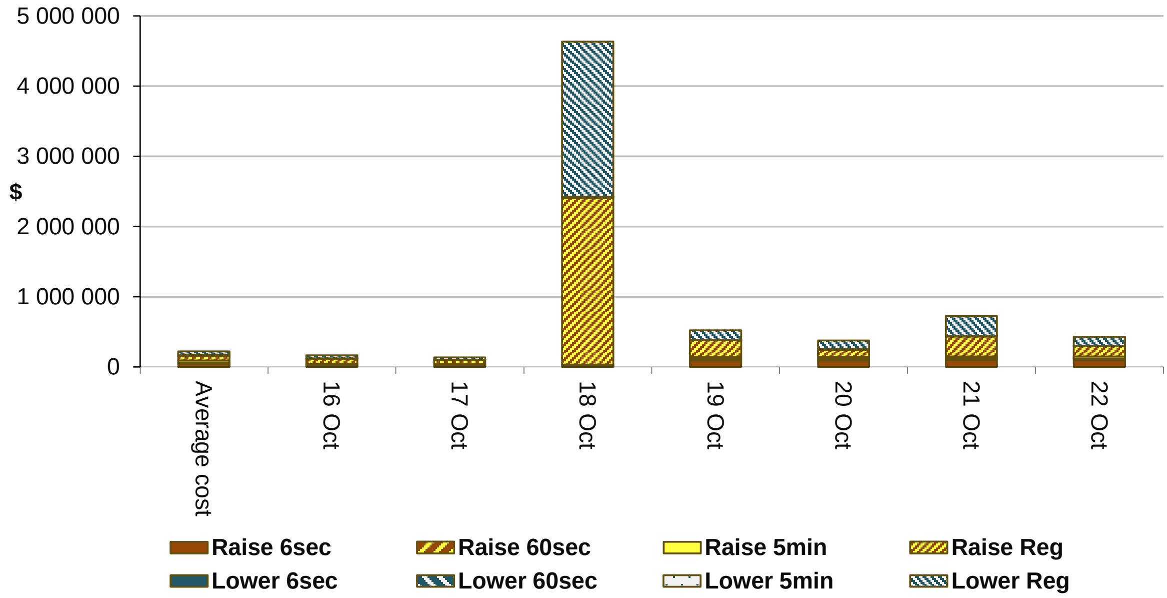
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $6 920 000 or around 4 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $66 500 or around 1 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 by AusNet of the Heywood to South East 2 275 kV line in Victoria, which started on 18 October and completed on 22 October, created a single contingency which if occurs separates South Australia from the rest of the NEM. Under these circumstances South Australia has to source regulation services locally and AEMO invoked the 35 MW regulation services constraints.

In South Australia on 18 October 2016 the price of raise and lower regulation services exceeded $11 000/MW for 62 dispatch intervals between 7.05 am and 11.30 pm. The total cost of regulation services in South Australia during this time was $5.8m. In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to FCAS prices above $5000/MW.

Detailed market analysis of significant price events

South Australia

There were four occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $57/MWh and above $250/MWh and there were two occasions where the spot price was below -$100/MWh.

Tuesday, 18 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
Midday	-195.81	16.08	25.91	1157	1239	1233	2684	2531	2486

Conditions at the time saw demand around 80 MW less than forecast four hours ahead. Available capacity was around 150 MW more than forecast four hours ahead. Semi-scheduled wind was producing around 1000 MW. At 11.50 am, demand decreased by 13 MW and wind increased by 150 MW. This saw the price decreased from $12/MWh to -$1000/MWh, for one dispatch interval. The significant increase in wind generation was not forecast, hence significantly contributed to the price being less than forecast. Wind generation dropped by around 270 MW immediately after the low price and prices returned to previous levels.

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
3.30 pm	-145.03	17.14	27.50	1153	1275	1286	2785	2630	2616

Conditions at the time saw demand around 130 MW less than forecast four hours ahead and available capacity 155 MW higher than forecast four hours ahead.

At 3.05 pm, demand decreased by 79 MW, this saw a number of wind farms setting the 3.05 pm price at -$1000/MWh (a decrease from -$45/MWh at 3 pm). At 3.10 pm demand increased by 78 MW and a drop in wind generation, this saw the price increased to around $24/MWh and stayed near this level for the remainder of the trading interval.

Wednesday, 19 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
6.30 am	365.20	124.99	109.01	1577	1404	1344	1950	2017	2122
7 am	2474.13	334.03	267.38	1690	1523	1462	1925	2017	2097
7.30 am	301.11	159.69	119.99	1736	1600	1539	1917	2002	2098

Conditions at the time saw demand up to 173 MW greater than forecast four hours ahead. Available capacity was up to 92 MW less than forecast four hours ahead as a result of lower than forecast wind generation.

At 6.05 am, demand increased by 26 MW, wind output reduced by 36 MW and imports across the Heywood and Murraylink interconnectors were at their limits. With low priced generation either fully dispatched or trapped in FCAS, the dispatch price reached $485/MWh at 6.05 am. Prices remained above $350/MWh for the majority of the trading interval.

At 6.40 am, South Australia had a steep supply curve, with only 118 MW of capacity priced between $300/MWh and $13 300/MWh. Demand increased by 43 MW and with low priced generation either fully dispatched or needing longer than five minutes to start, the dispatch price increased to $13 999/MWh. The price reduced to $147/MWh at 6.45 am, when a number of participants rebid capacity from high to low prices.

The lower than forecast wind generation resulted in the dispatch price being around $300/MWh for the 7.30 am 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 pm	2377.53	79.99	80.02	1145	1211	1166	2078	2038	1992

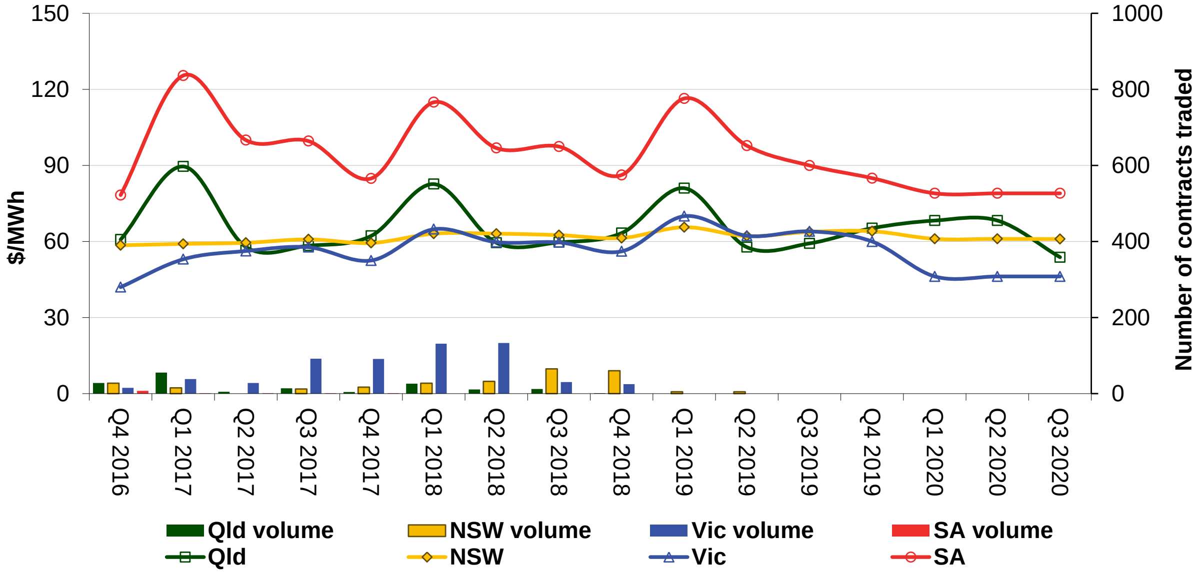
Conditions at the time saw demand and availability close to forecast.

In the afternoon, a transmission network service provider was conducting tests on the Heywood interconnector. During the test, AEMO systems incorrectly picked up a test signal which saw the Heywood interconnector export limit reduced from 250 MW into South Australia to 126 MW into Victoria and dispatch price in South Australia spiked to the price at cap at 3.50 pm. AEMO did not identify this interval to be affected by manifestly incorrect input at the time and hence the price was not corrected. However, upon review, AEMO has declared the interval to be affected by a scheduling error and participants are able to seek compensation.

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.

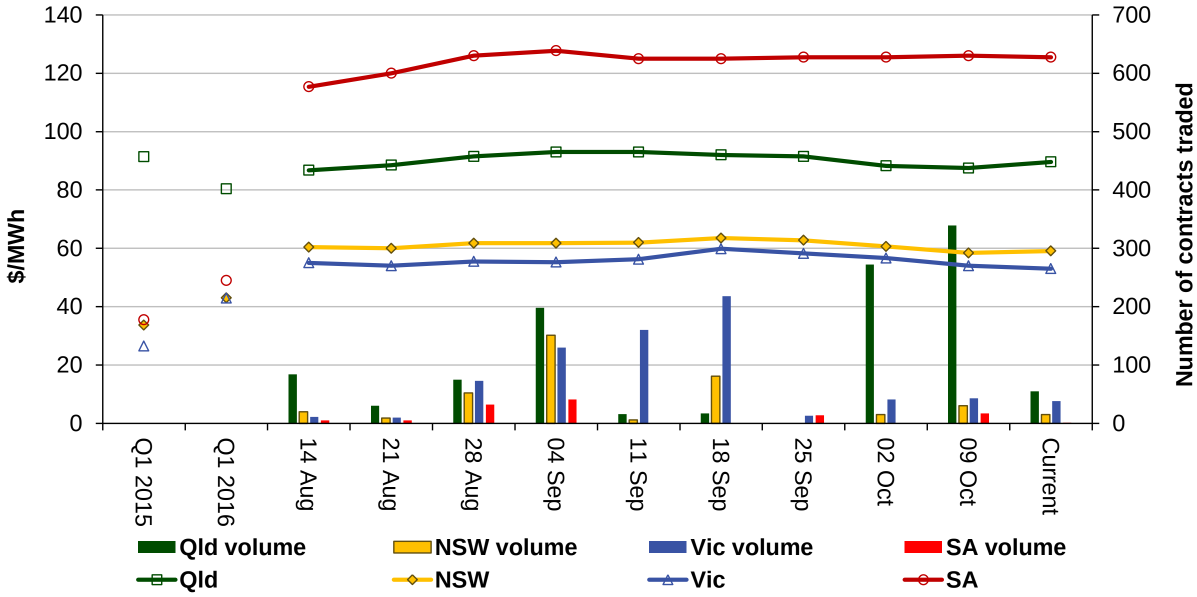
Figure 9: Quarterly base future prices Q4 2016 – Q3 2020



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)



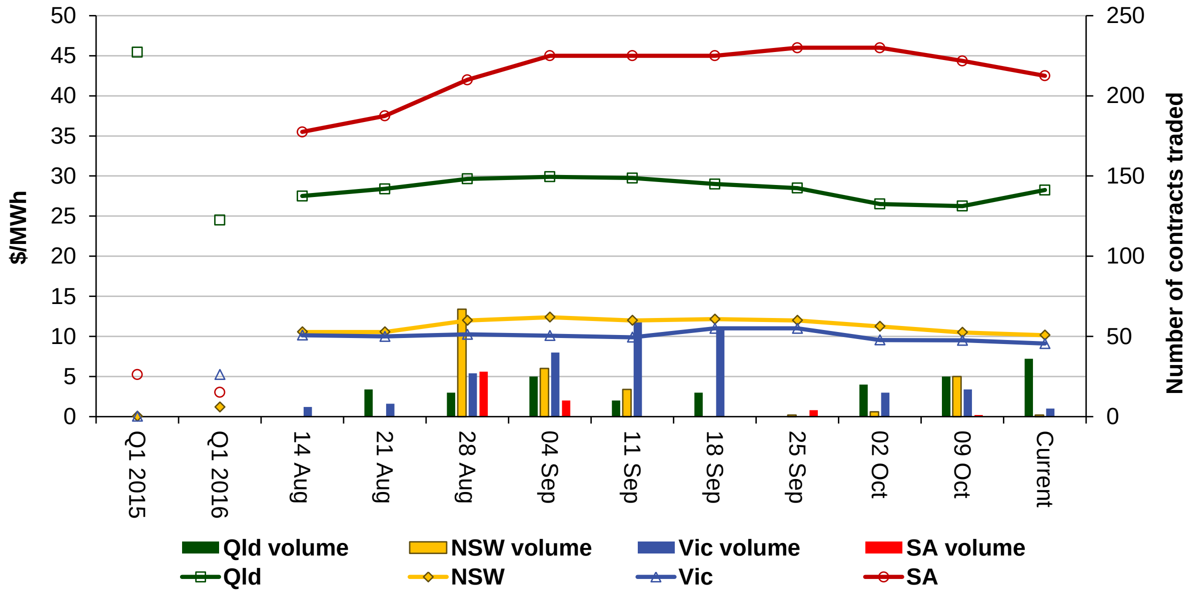
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
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