8 – 14 November 2015

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 8 to 14 November 2015. 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.

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

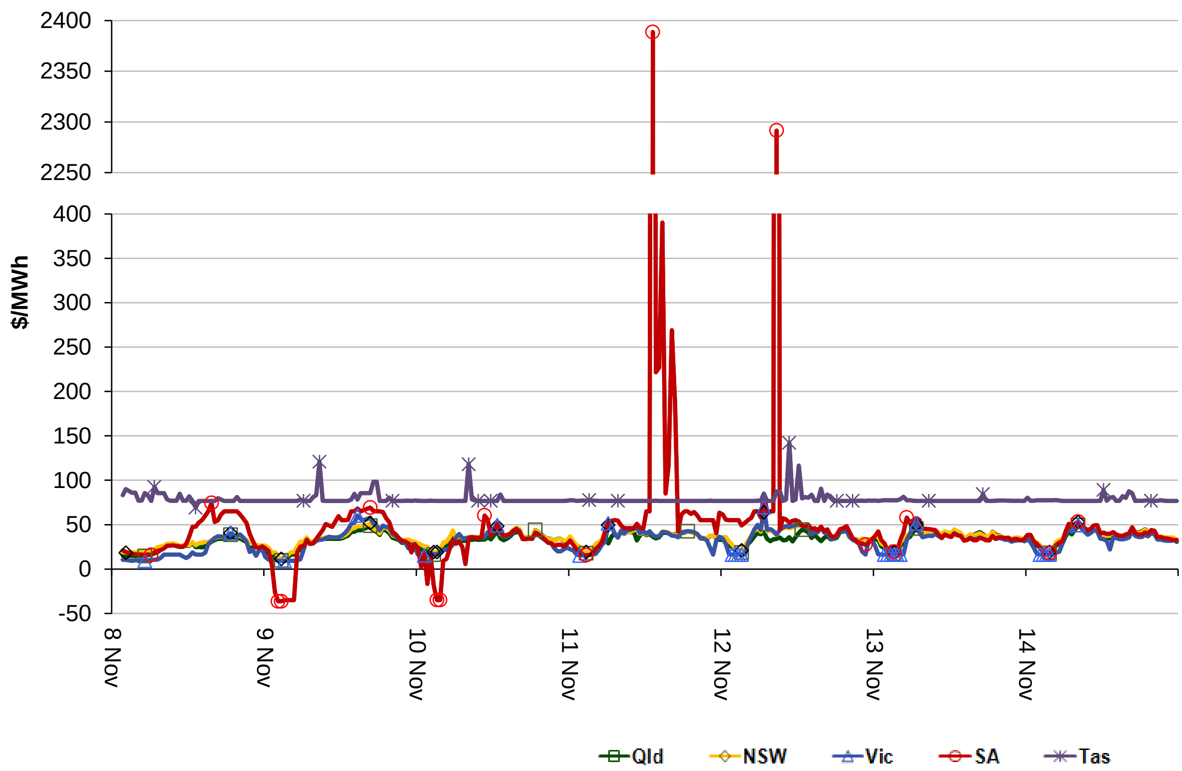
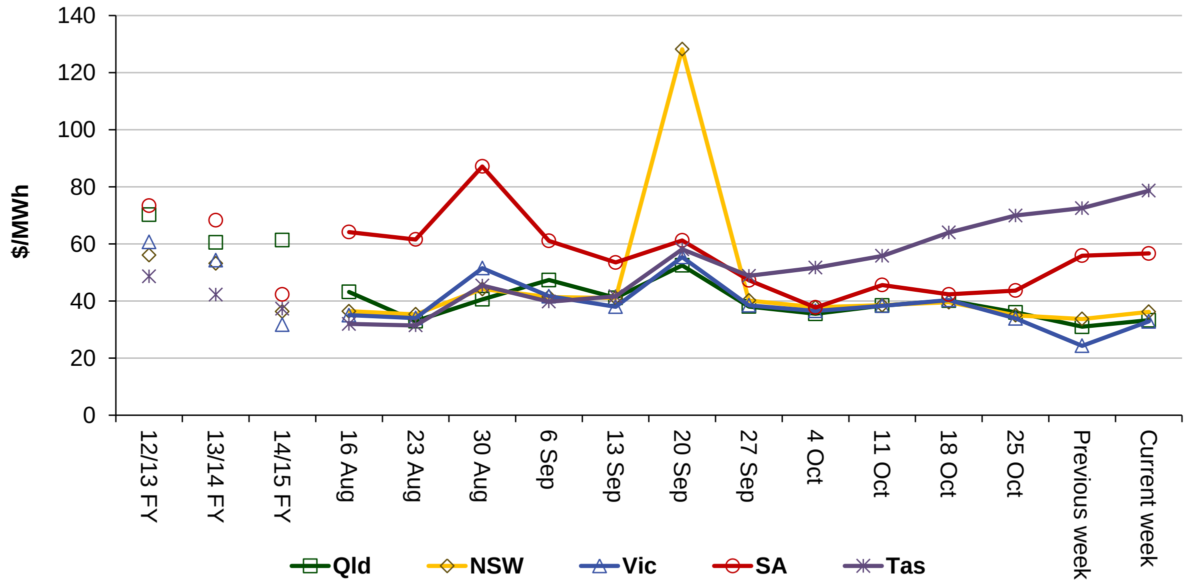


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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



The increase in price in Tasmania as a result of the change to Hydro Tasmania's bidding patterns and the impact of the high spot prices in SA are clearly visible in Figure 2.

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

Region	Qld	NSW	Vic	SA	Tas
Current week	33	36	33	57	79
14-15 financial YTD	29	37	34	43	36
15-16 financial YTD	42	43	38	62	46

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 115 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2014 of 71 counts and the average in 2013 of 97. 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	40	1	1
% of total below forecast	30	22	0	0

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

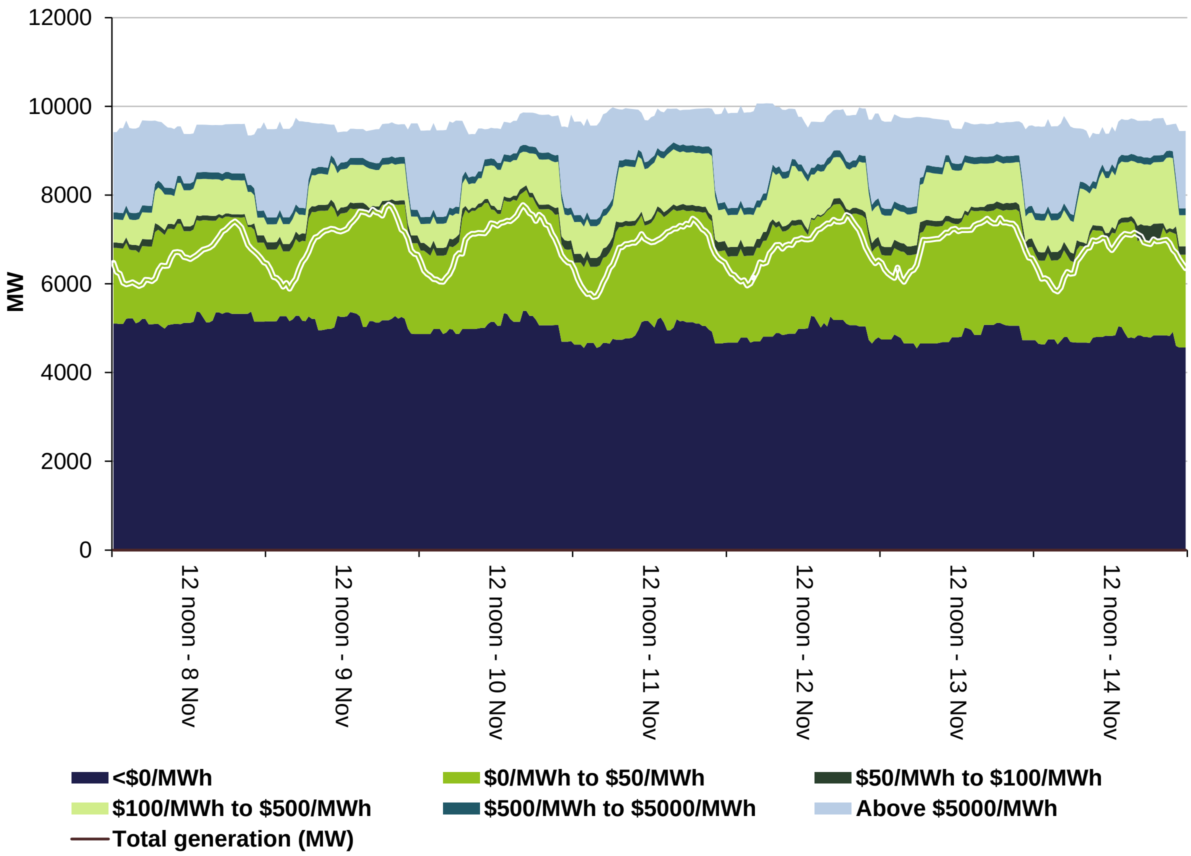


Figure 4: New South Wales generation and bidding patterns

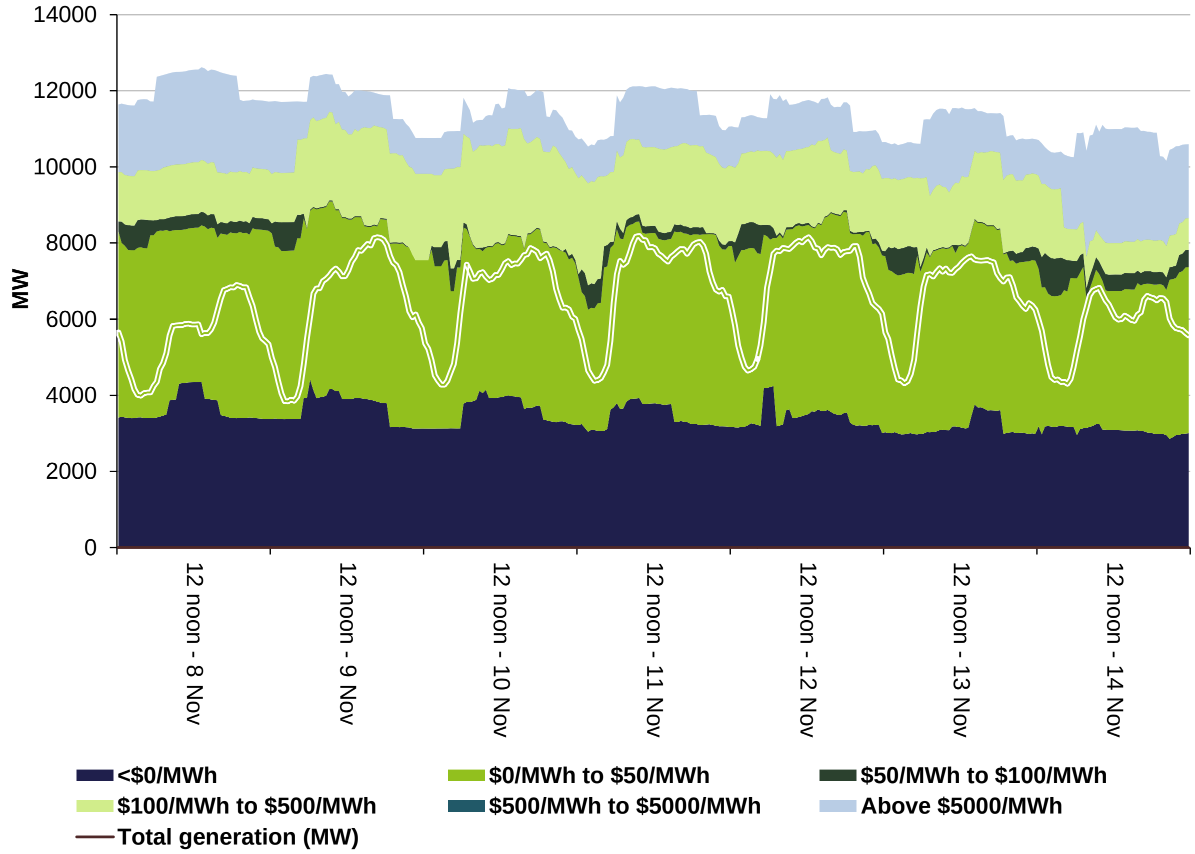


Figure 5: Victoria generation and bidding patterns

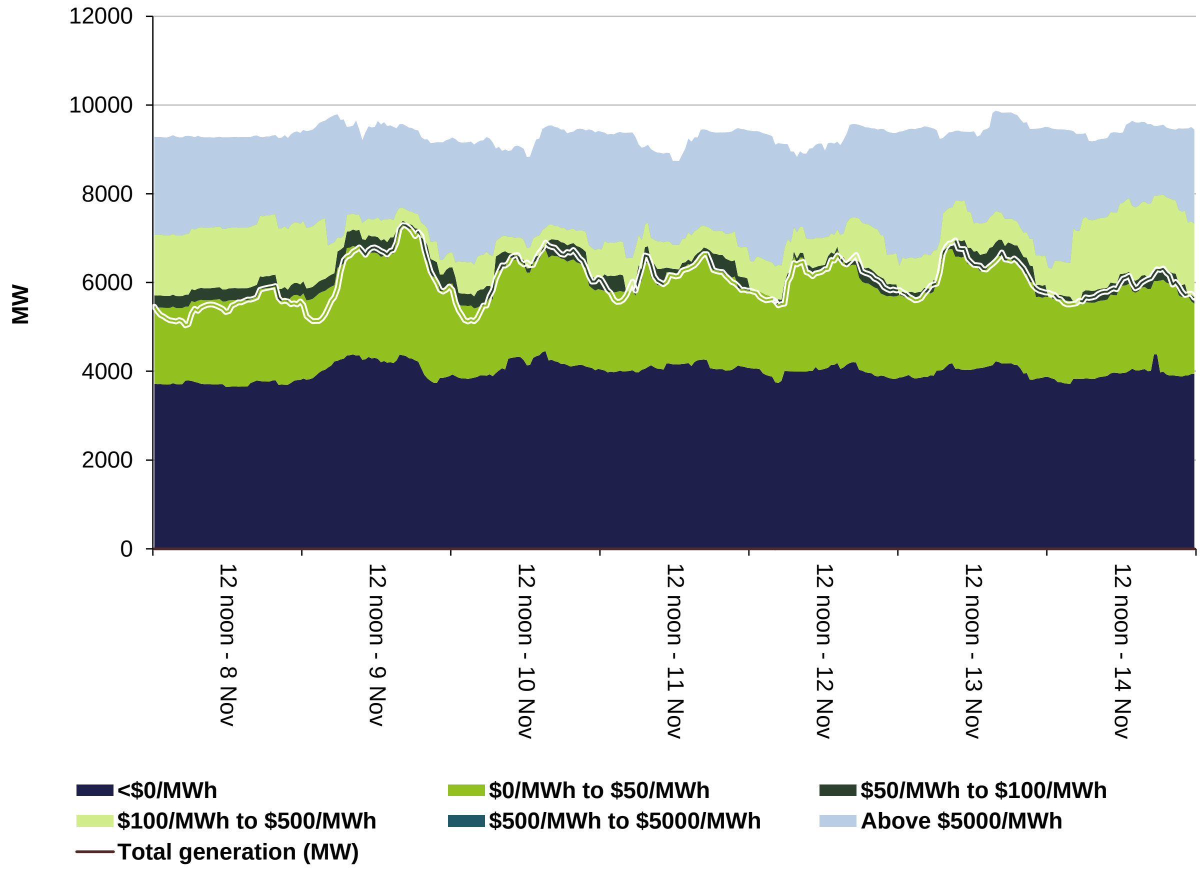


Figure 6: South Australia generation and bidding patterns

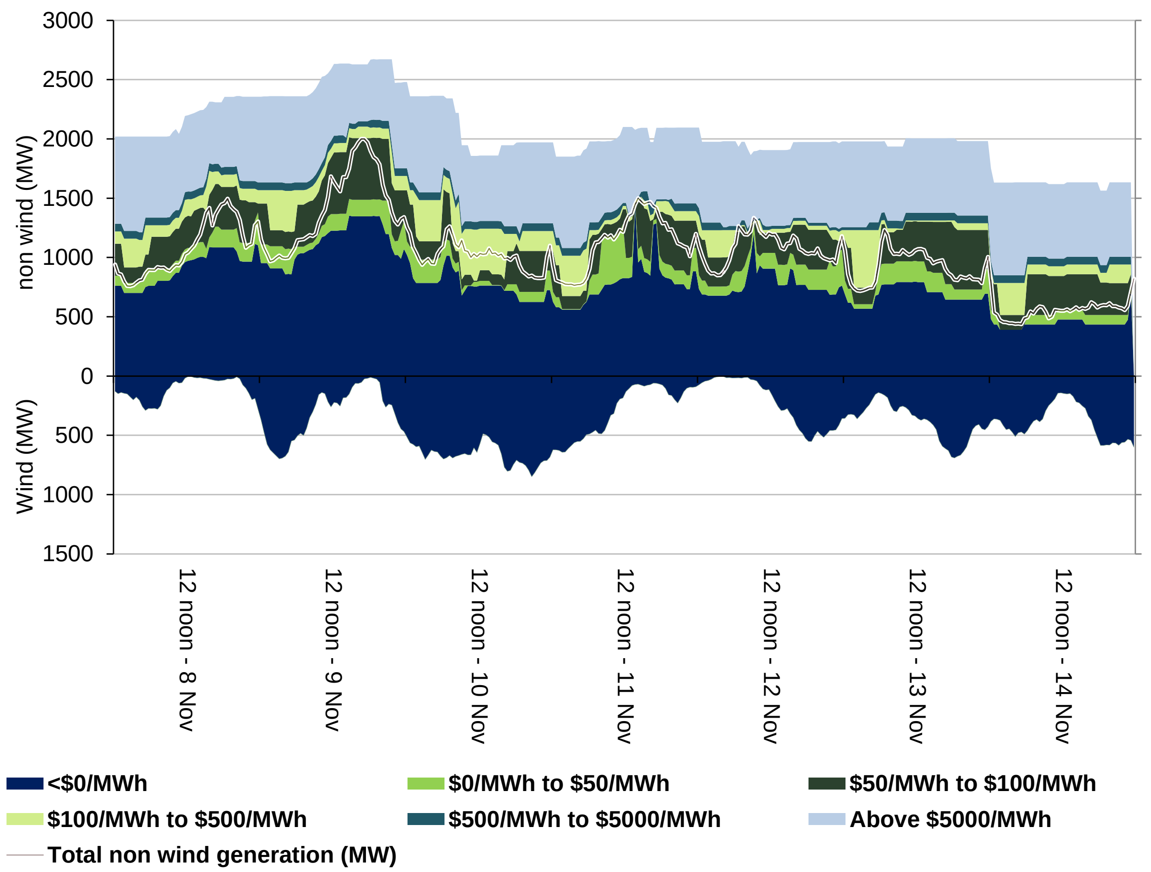
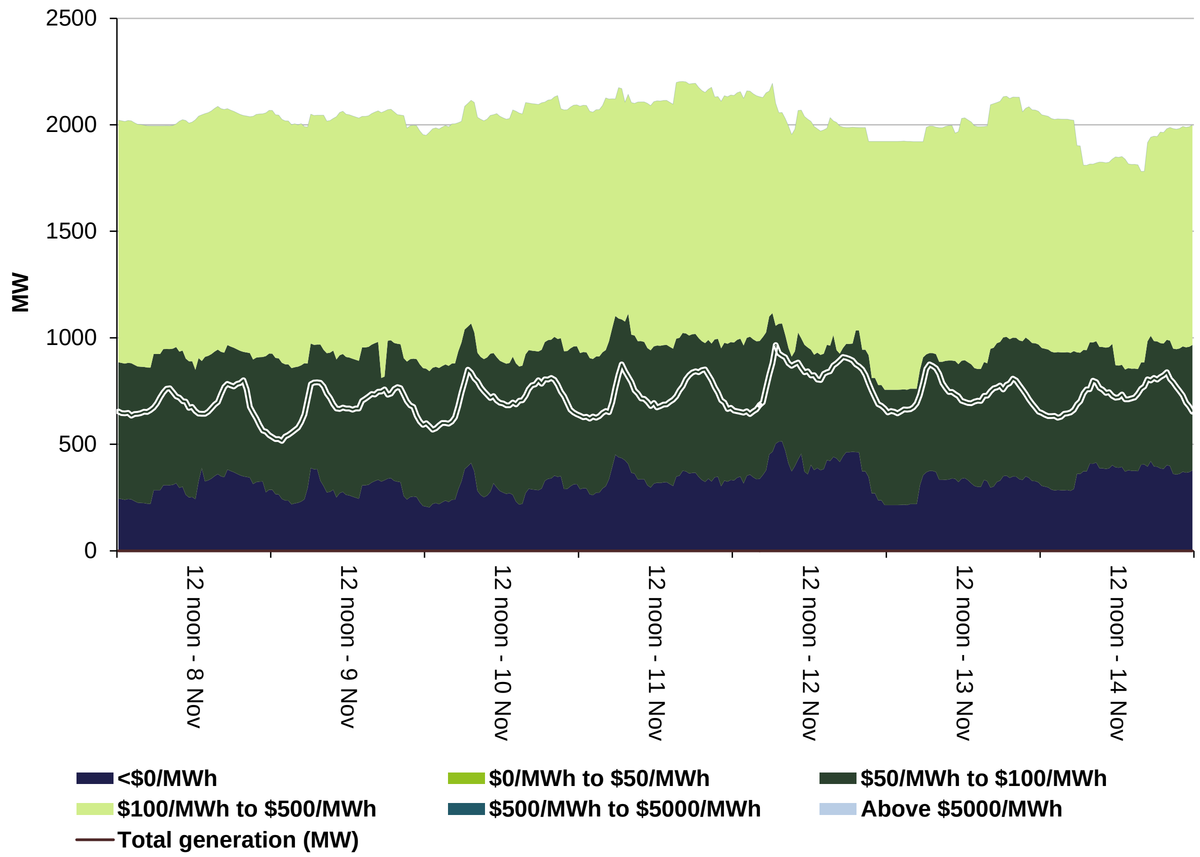


Figure 7: Tasmania generation and bidding patterns



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.

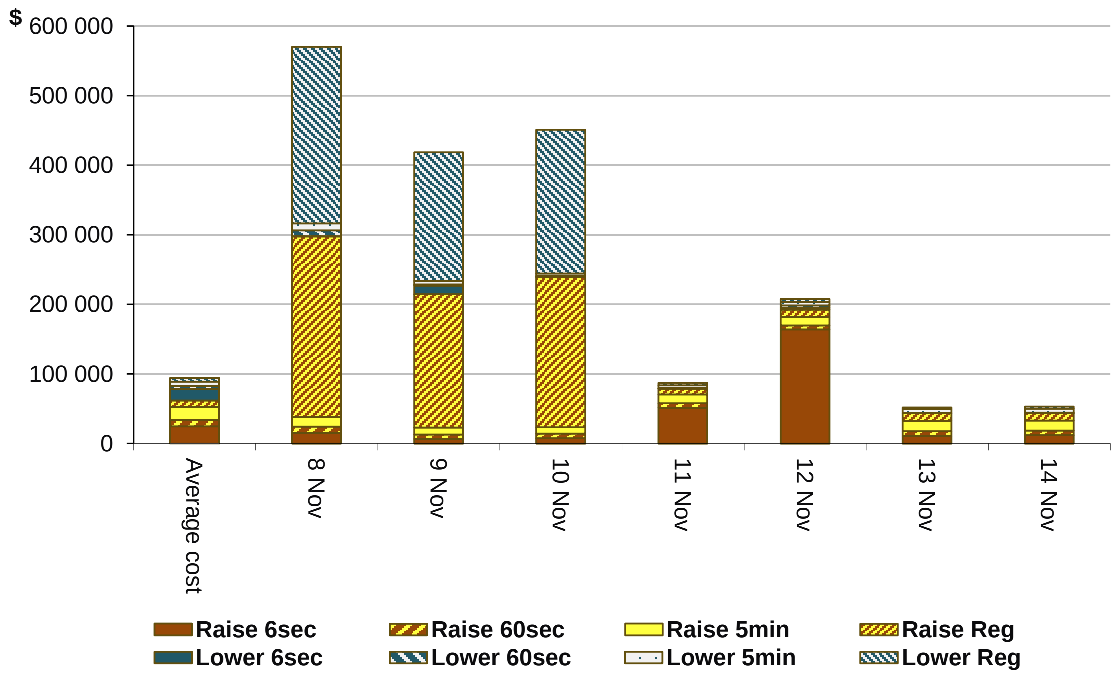
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$1 576 000 or around 1.5 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$264 500 or around 2 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



An outage of one Haywood transformer resulted in the requirement of 35 MW of both Raise and Lower regulation services for 8 to 10 November in South Australia. The price of both these service were around \$300/MW for a majority of the time during the outage which finished at around 5 30pm on 10 November, at a cost of around \$1.3 million.

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 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.

Wednesday, 11 November

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
1.30 pm	2388.72	94.99	95.76	1370	1407	1446	2181	2222	2176

Conditions at the time saw demand and available capacity close to forecast.

Planned outages of the South East-Tailem Bend line and the Waubra to Horsham line, resulted in the Heywood and Murraylink interconnectors being constrained. Heywood was limited to importing around 21 MW into South Australia whilst Murraylink was being forced to export around 35 MW into Victoria.

Wind generation was around 170 MW during the trading interval.

Table 4: Rebids the 1.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.30 am		EnergyAustralia	Hallett	40	590	13 482	11:27 A ADJ BAND DUE TO CHG IN SA SENS SL
12.34 pm		AGL Energy	Torrens Island	95	<65	Price cap	1230~A~040 CHG IN AEMO DISP~41 DEMAND INCREASEVS PD SA 81MW

The above rebids contributed to a steep supply curve, with only 53 MW priced between $100/MWh and $12 500/MWh. Following small increases in demand at 1.25 pm and 1.30 pm, dispatch prices increased to $590/MWh and $13 482/MWh respectively (set by Hallet) as lower priced generation was either ramp rate limited or stranded in FCAS.

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
3 pm	390.29	94.99	95.76	1417	1410	1474	2168	2208	2198

Conditions at the time were similar to those during the 1.30pm trading.

At 2.35 pm, demand increased by 147 MW, mainly as a result of a reduction in output from non-scheduled generation. With cheaper generation ramp rate limited or stranded in FCAS, the dispatch price rose from $65/MWh at 2.30 pm to $1500/MWh at 2.35 pm. Subsequent rebids by GDF Suez saw the dispatch price fall to $590/MWh at 2.40 pm. The dispatch price remained low for the remainder 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	269.02	287.65	287.69	1460	1482	1535	2147	2227	2233

Conditions at the time saw price, demand and available capacity close to forecast.

Thursday, 12 November

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	2291.49	65.49	64.84	1343	1369	1367	1920	2037	2072

Conditions at the time saw demand and available capacity slightly below forecast 4 hours ahead.

At 8.44 am an unplanned outage on the Horsham-Redcliffs 220kV line triggered the operation of the Murraylink runback scheme and AEMO invoked a 0 MW constraint on Murraylink to mimic its physical performance in NEMDE at 8.55 am. This constraint was revoked at 9.50 pm and imports into South Australia reached 134 MW at 9.55 am.

Table 8: Rebids the 9 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.56 am		AGL Energy	Torrens Island	60	<95	N/A	0755~P~020 REDUCTION IN AVAIL CAP~203 PLANT FAILURE 60MW FAN ISSUE
8.41 am	8.50 am	AGL Energy	Dry Creek	47	12 303	N/A	0840P DC1 ELECTRICAL FAULT INVESTIGATION - UNIT UNAVAIL

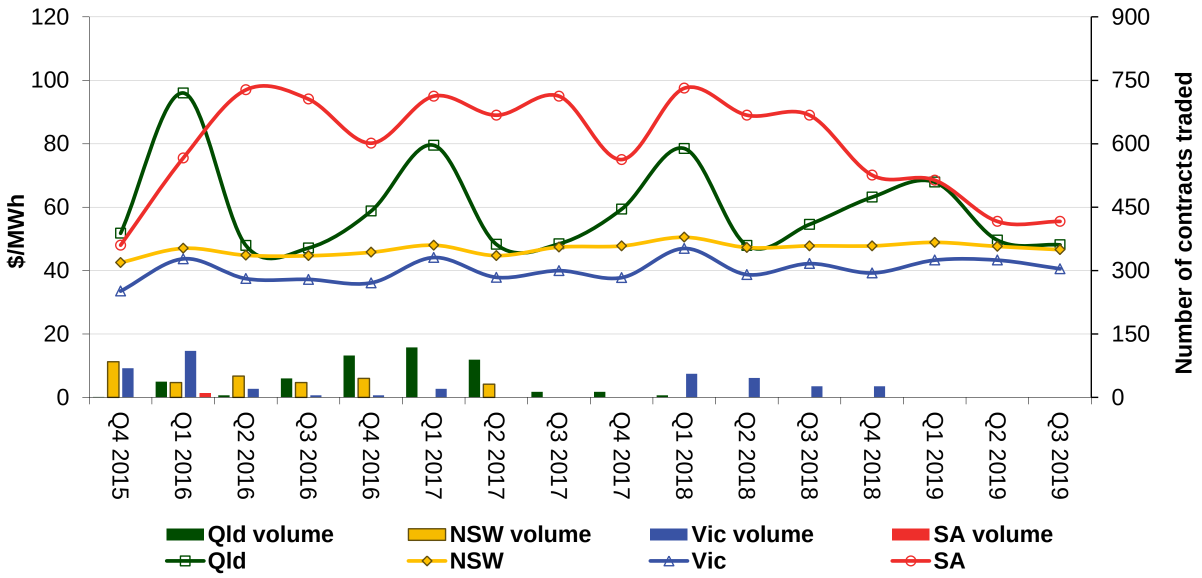
The above rebids contributed to creating a steep supply curve with little mid-priced generation available. The 144 MW step reduction in imports into South Australia could not be met by low priced generation as it was ramp rate limited, and the dispatch price increased from $55/MWh at 8.50 am to $13 482/MWh at 8.55 am.

Subsequent rebidding by EnergyAustralia and AGL Energy saw the dispatch price fall to $37/MWh for the 9 am dispatch 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.

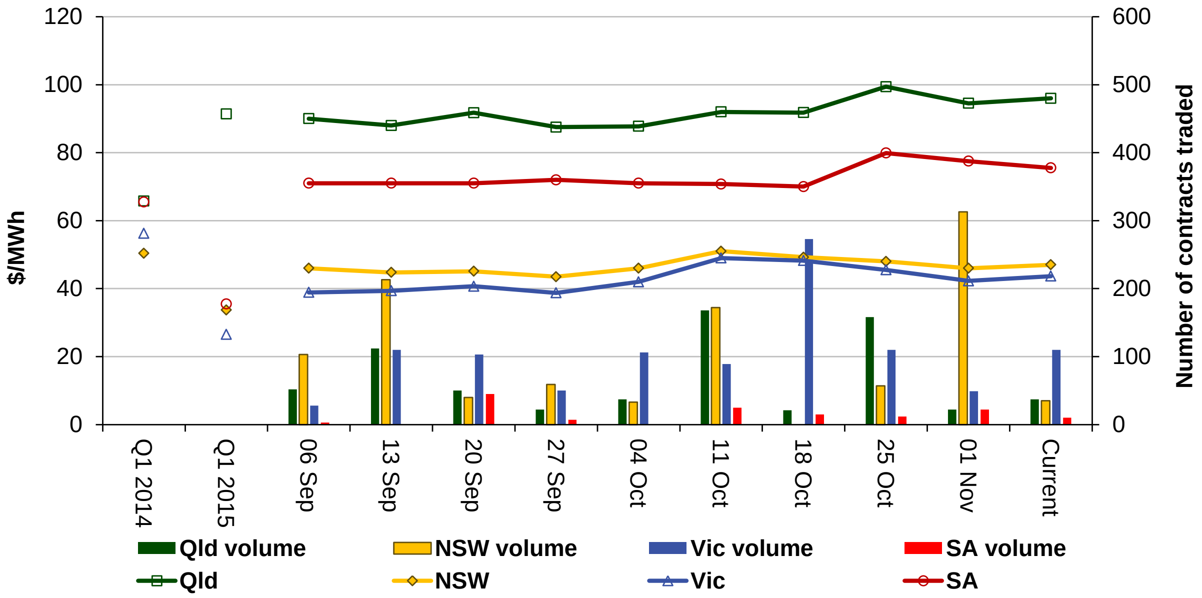
Figure 9: Quarterly base future prices Q4 2015 – Q3 2019



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades. Quarter 1 2016 prices in South Australia again dropped slightly on small trading volumes while prices in other regions rose slightly. It is worth noting that the South Australian price for quarter 1 2016 is around $10/MWh more expensive than for the same quarter in 2014.

Figure 10: Price of Q1 2016 base contracts over the past 10 weeks (and the past 2 years)



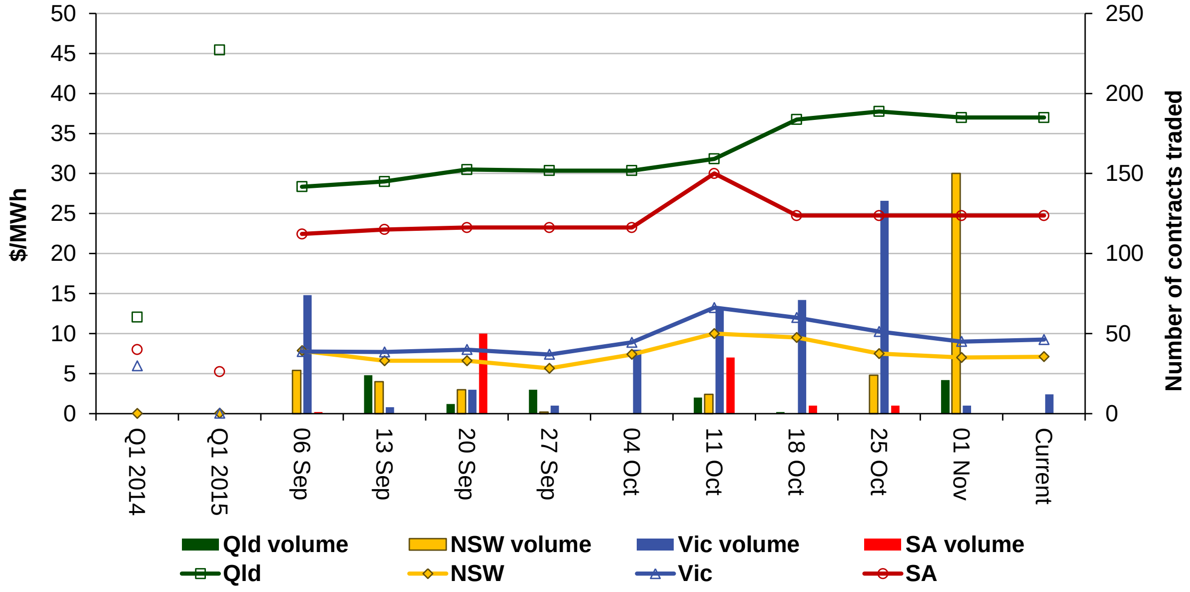
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
December 2015