6 – 12 November 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 6 - 12 November 2016. Details on the high price events on 8 November in Queensland and New South Wales can be found in the "Detailed market analysis of significant price events" section of this report.

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

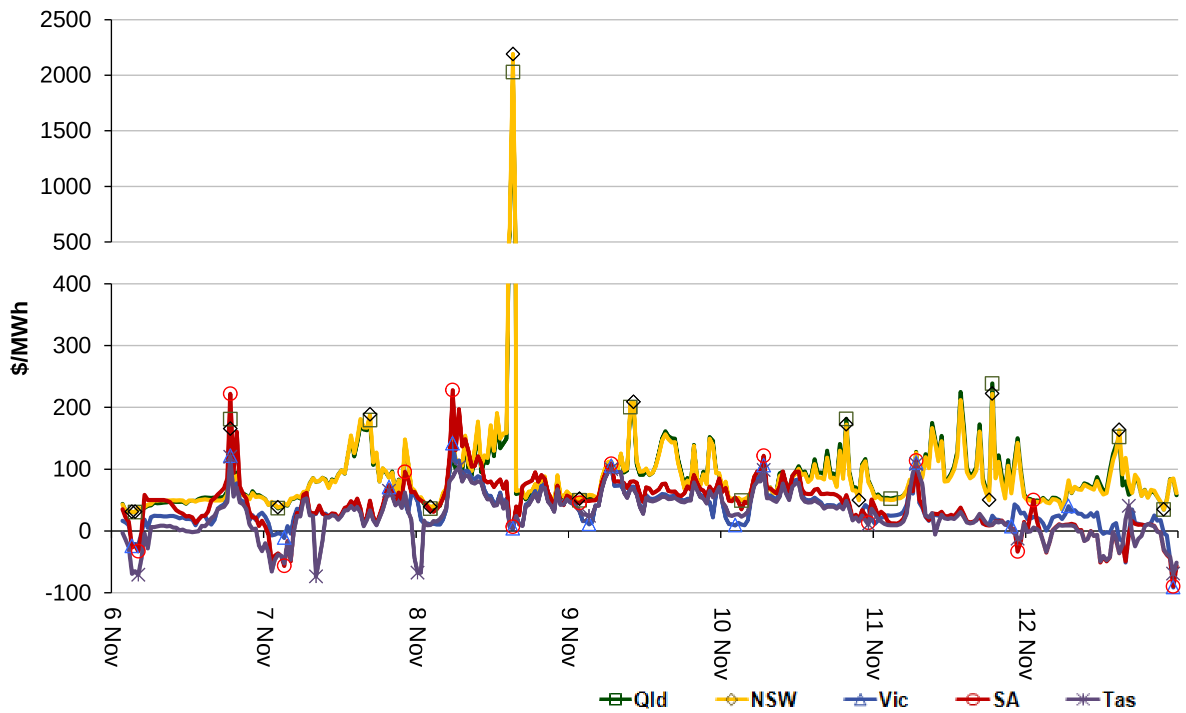


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

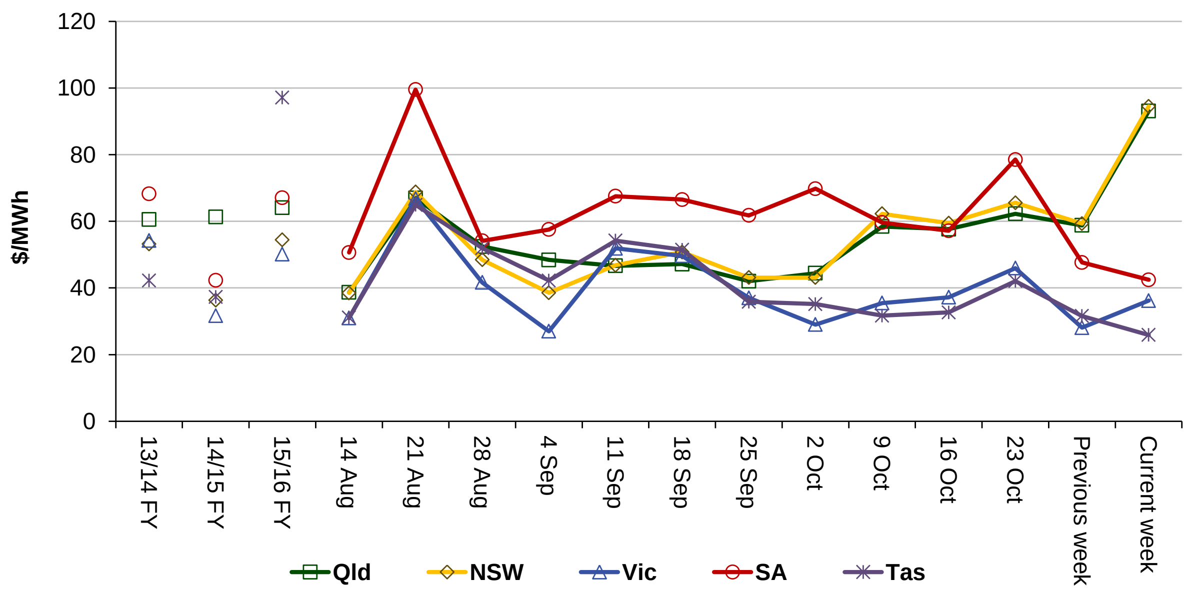


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	93	94	36	42	26
15-16 financial YTD	42	43	38	63	45
16-17 financial YTD	56	58	47	113	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 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 309 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

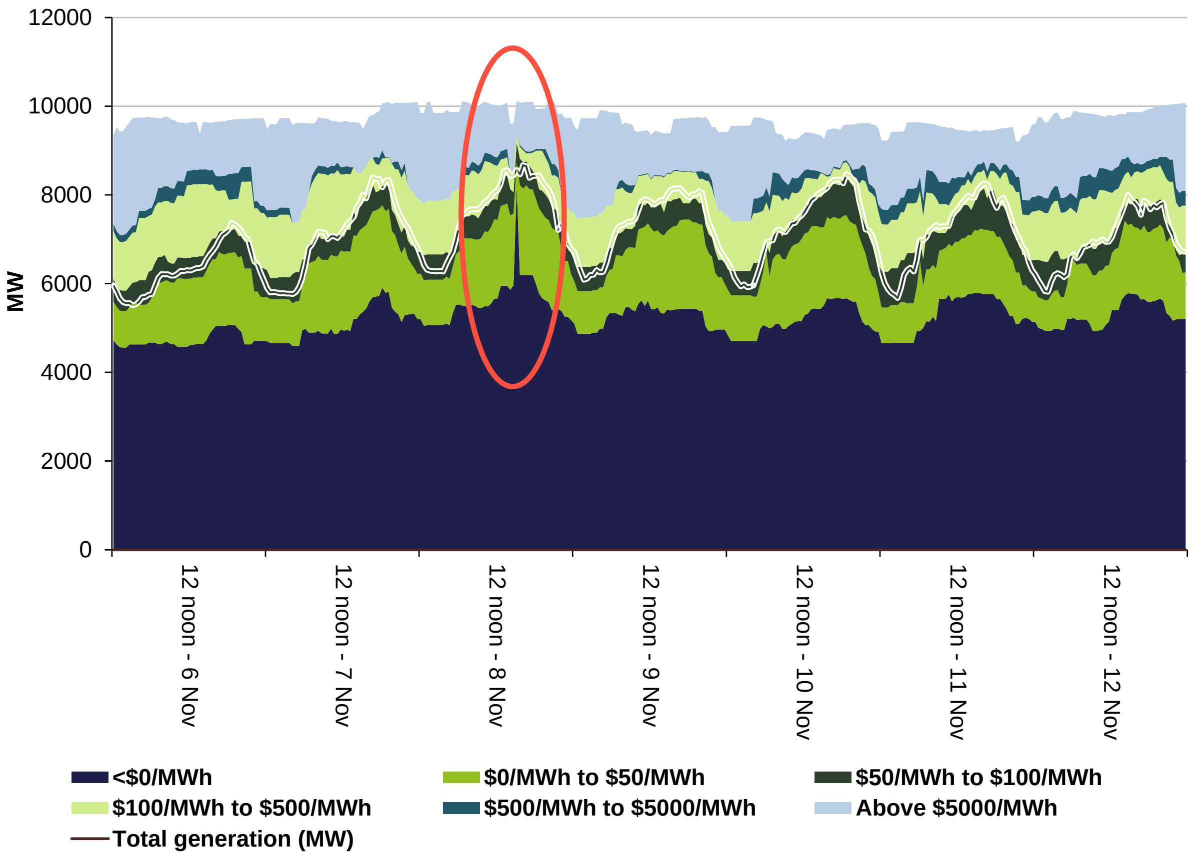
	Availability	Demand	Network	Combination
% of total above forecast	5	19	0	3
% of total below forecast	40	23	0	11

Note: Due to rounding, the total may not be 100 per cent.

Generation and bidding patterns

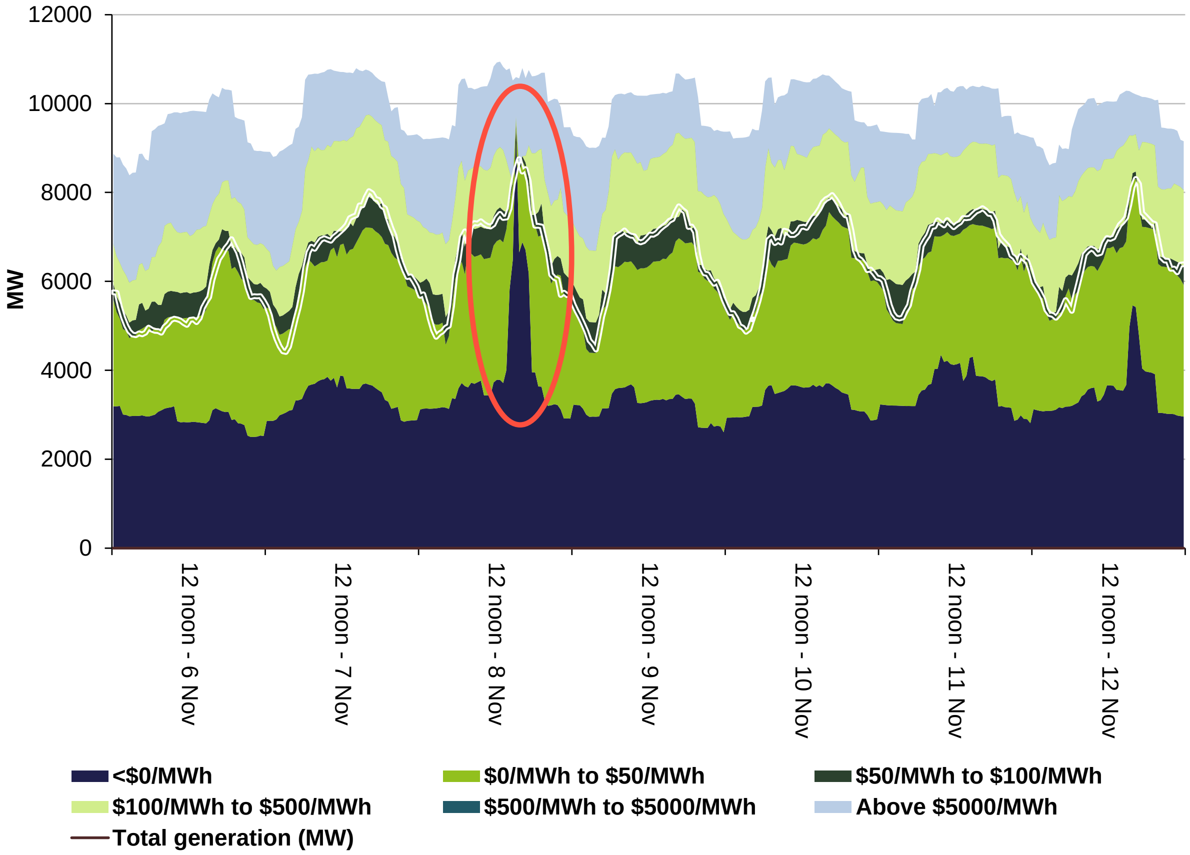
The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

Figure 3: Queensland generation and bidding patterns



The sudden increase in low price capacity on 8 November (circled red) was due to participant rebidding following a high price event. More details on the pricing event can be found in the “Detailed market analysis of significant price events” section.

Figure 4: New South Wales generation and bidding patterns



The sudden increase in low price capacity on 8 November (circled red) was due to participant rebidding following a high price event. More details on the pricing event can be found in the “Detailed market analysis of significant price events” section.

Figure 5: Victoria generation and bidding patterns

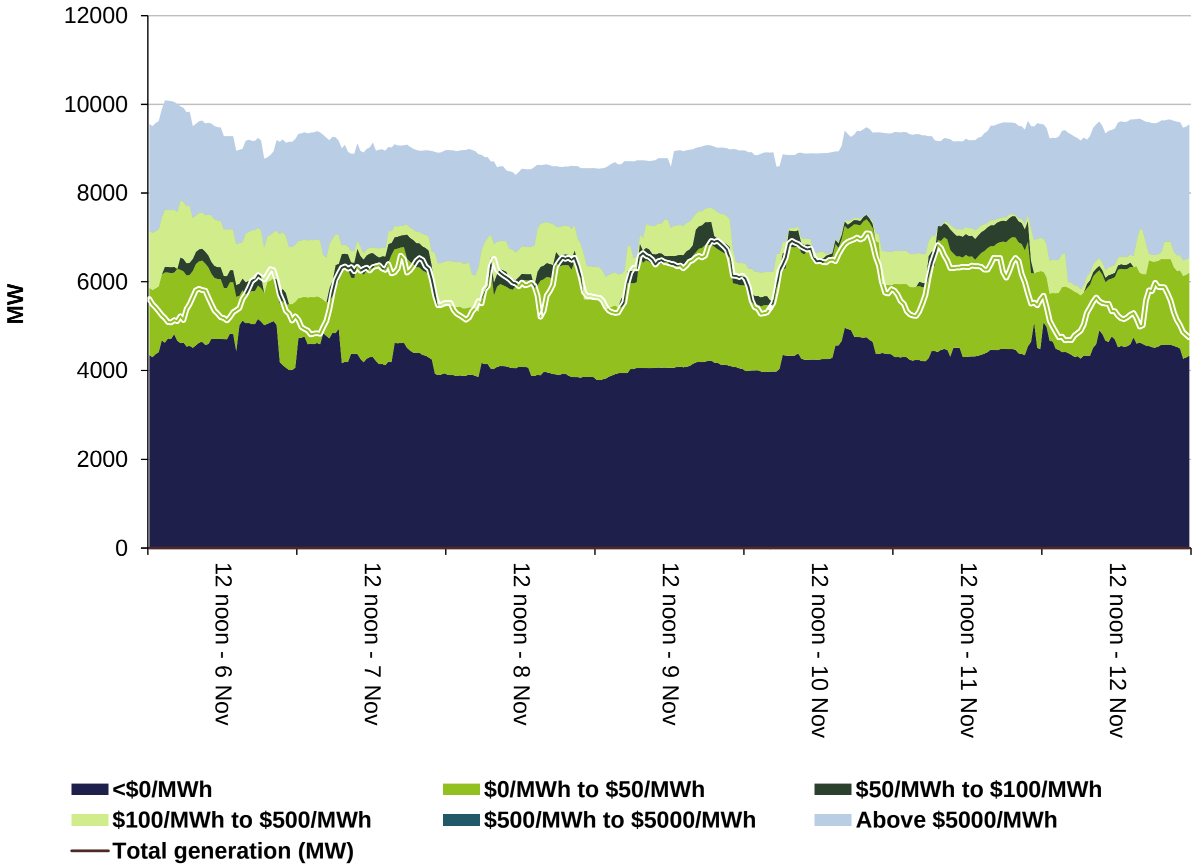


Figure 6: South Australia generation and bidding patterns

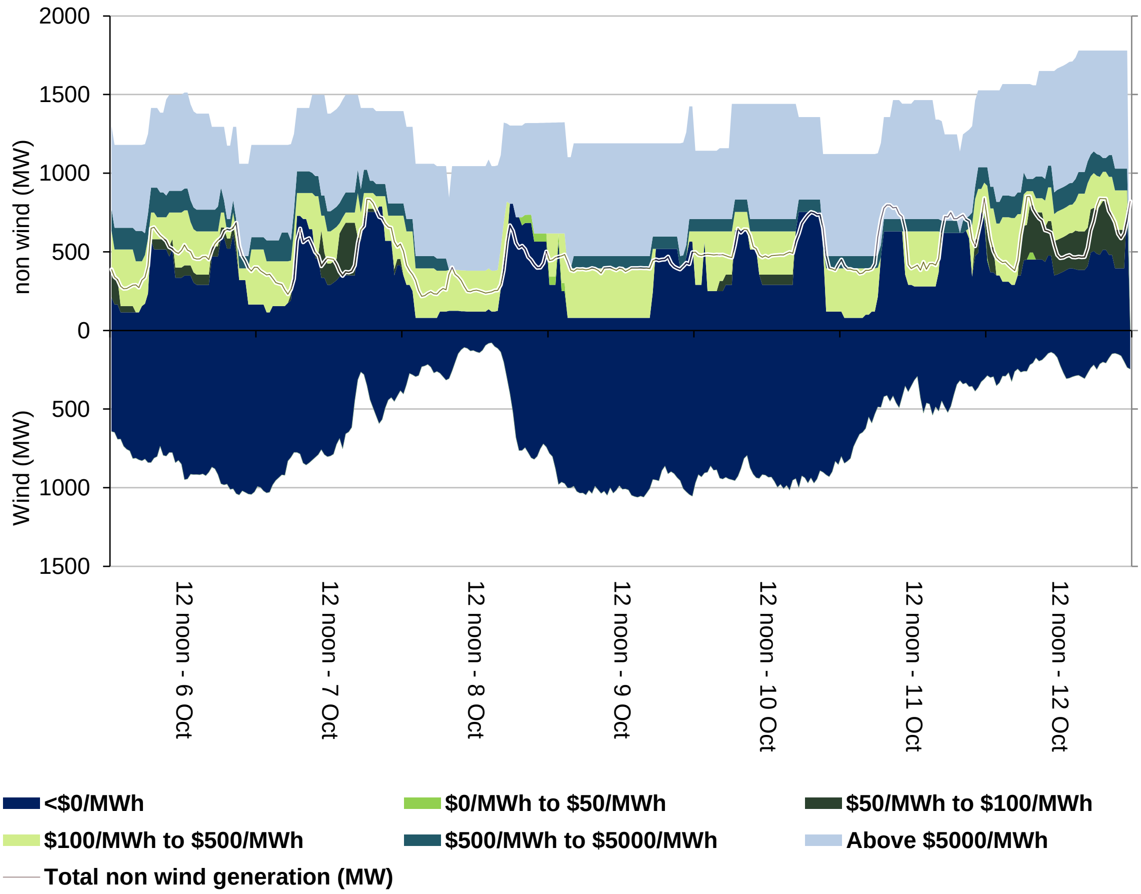
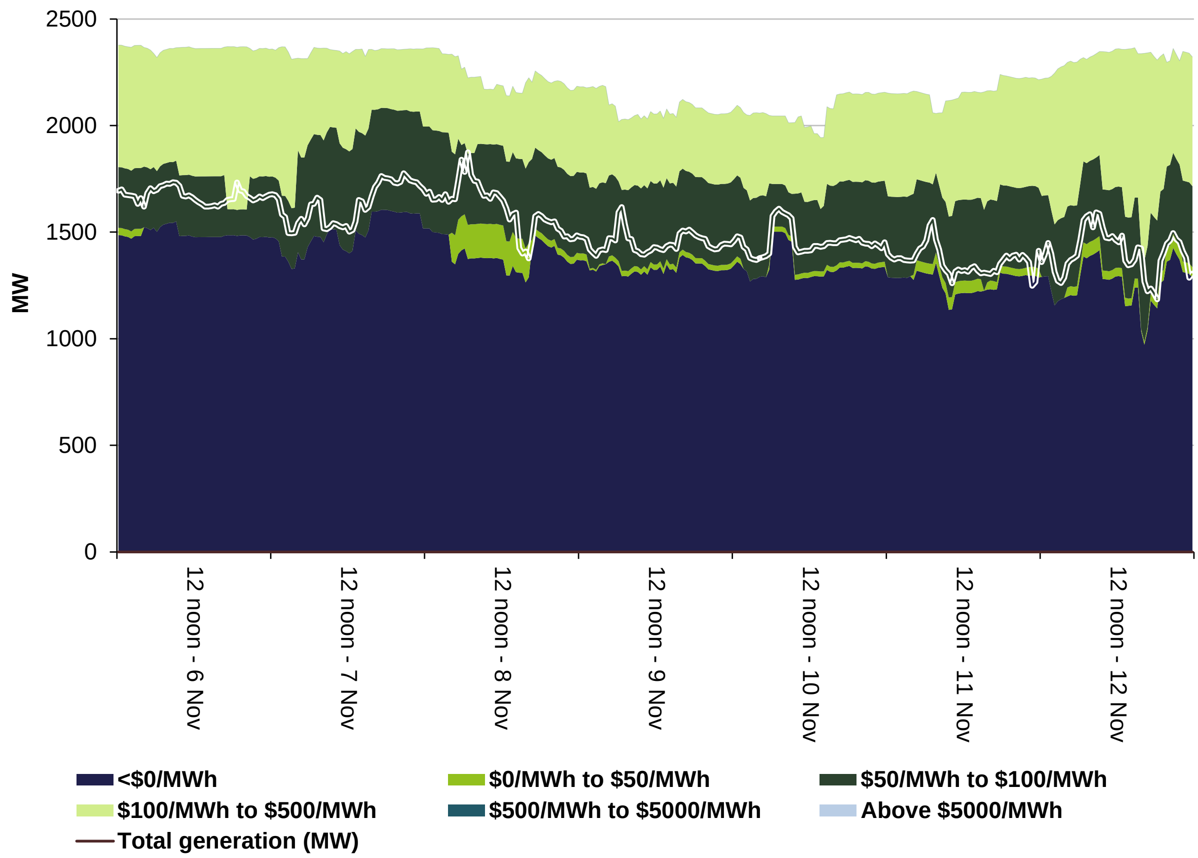


Figure 7: Tasmania generation and bidding patterns



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:

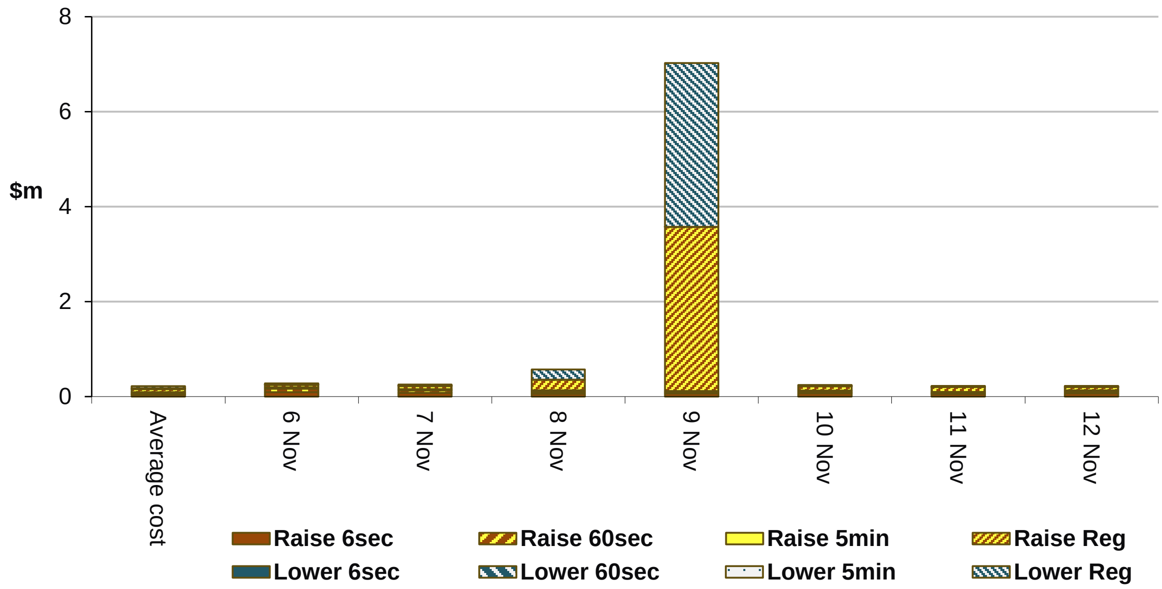
- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal 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 $8 647 000 or around 3 per cent of energy turnover on the mainland. The total cost of FCAS in Tasmania for the week was $167 500 or around 3 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



On 9 November the price of raise and lower regulation services in South Australia exceeded $6000/MW for 175 consecutive dispatch intervals from 4.05 am to 6.35 pm at a cost of around $6.8 million. The Cumulative Price Threshold of $1.26 million was breached and prices were capped at $300/MW from 6.40 pm. A planned outage by AusNet of the Heywood to Mortlake line, which commenced at 6 am the previous day, created a single contingency which if occurs separates South Australia from the rest of the NEM. This would mean that South Australia has to source its regulation services locally.

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

Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $93/MWh and above $250/MWh. These high prices coincided with high prices in New South Wales. The following analysis relates to the high prices in both regions.

Tuesday, 8 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
3 pm	578.76	199.99	10 870	7589	7936	7975	9635	10 046	10 174
3.30 pm	2029.11	270.10	10 807	7562	7974	8055	9987	10 005	10 175

For the 3 pm price, conditions at the time saw both demand (around 350 MW) and availability (around 400 MW) less than that forecast four hours ahead.

At 2.08 am, all three units at Braemar 2 power station tripped. As a result, over 370 MW of low-priced capacity (less than $50/MWh) became unavailable.

Rebidding from low prices to the price cap by participants in New South Wales and Queensland (rebids detailed in Table 4) further reduced the volume of low-priced capacity in both regions. The reduction in low-priced generation, coupled with a small increase in demand of 67 MW in Queensland saw the price in both regions increase to around $1400/MWh in Queensland and $1500/MWh in New South Wales at 2.50 pm.

Braemar 2 power station returned to service at around 3 pm and AEMO reclassified the simultaneous loss of the power station as a credible contingency. At 3.05 pm, an automatic constraint (CA_SPS_4733E84B_01) was invoked to maintain power system security. The constraint limits generation from 16 units in NSW as well as the Vic-NSW interconnector. The constraint bound immediately and saw the dispatch price in both regions increase to over $12 900/MWh. Prices reduced to around $90/MWh at 3.10 pm when a number of participants rebid capacity from high to low prices.

Over this high priced period, the Vic-NSW interconnector was flowing counter price at its limit into New South Wales, and, as a result around $300 000 of negative settlement residues accrued.

Table 4: Relevant rebidding in NSW and Queensland for the 3 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MWh)	Rebid reason
2.22 pm	2.35 pm	Millmerran Energy Trader	Millmerran	50	10	14000	14:21 A 4 X VOLL SPIKE IN 5MIN PD - SL
2.24 pm	2.35 pm	AGL Energy	Bayswater	60	<97	>14000	1420~A~050 CHG IN AEMO PD~GENERATION DECREASE [QLD-495MW] SEE LOG

New South Wales

There were two occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $94/MWh and above $250/MWh.

Tuesday, 8 November

Table 5: Price, Demand and Availability

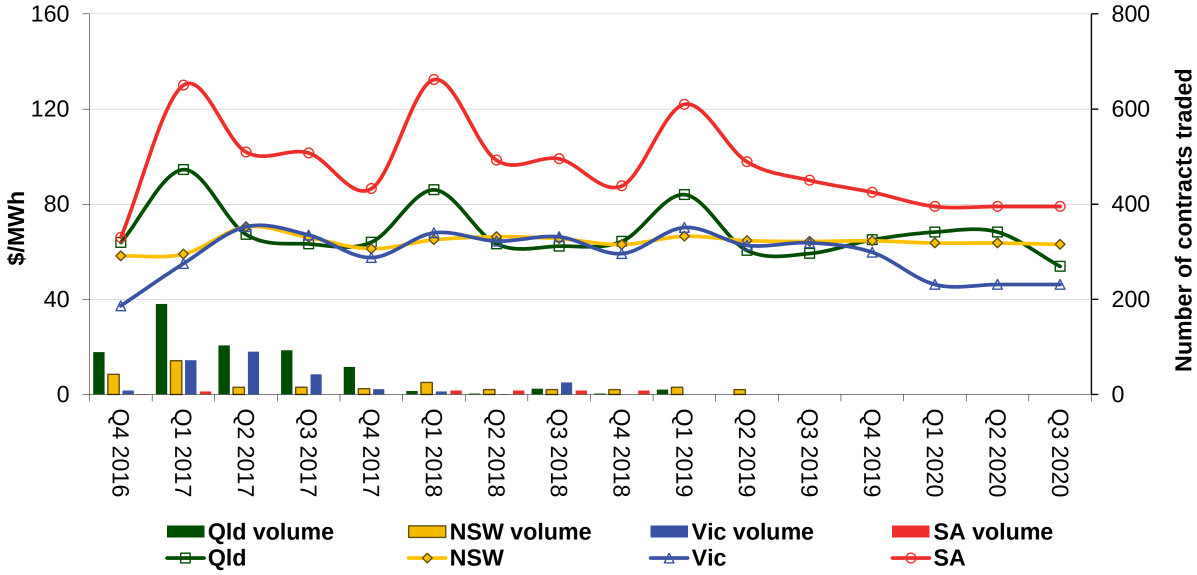
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
3 pm	626.77	199.35	11 217	9205	8909	9208	10 707	11 108	11 072
3.30 pm	2190.99	270.92	11 217	9198	8908	9300	10 575	11 071	11 018

This event coincided with the high price event in Queensland and is explained in the Queensland section.

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.

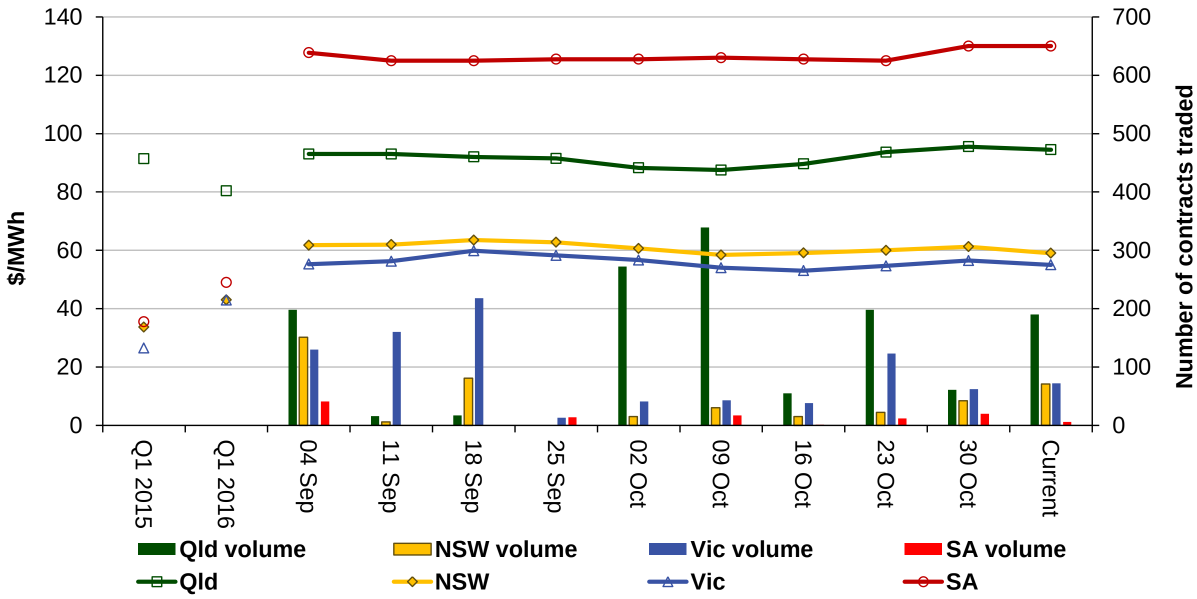
Figure 9: Quarterly base future prices Q4 2016 – Q3 2020



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)



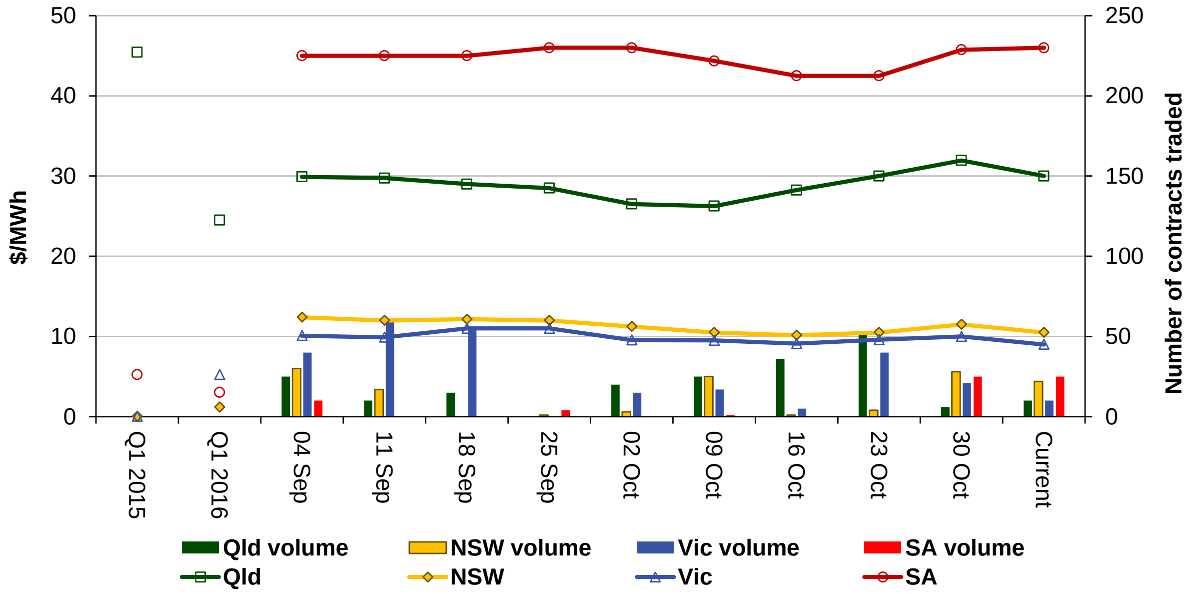
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
November 2016