Electricity Report

AUSTRALIAN ENERGY REGULATOR

9 – 15 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.

System Black in South Australia

Wednesday, 28 September

At 4.18 pm EST, a System Black event occurred in South Australia. South Australia separated from the NEM, all generation in the State ceased and all State load was shed. In accordance with the Rules, AEMO suspended the market in South Australia, from 4.25 pm EST. Further to this, there was Ministerial direction under the Essential Services Act 1981 (SA) to continue with market suspension until 10.30 pm 11 October. During this time, most participants continued to be dispatched according to their bids for generation and ancillary services. Market pricing during the suspension was determined in accordance with the market suspension pricing schedule, where AEMO determines reasonable estimates of typical market prices for the region for participants[1]. The pricing schedule is published 14 days before the first day the schedule is effective. The energy and ancillary service prices are an average of the weekday and weekend spot prices for each trading interval 28 days prior to publishing the schedule.[2]

While the administered market pricing was in place, the spot price in South Australia exceeded our reporting threshold at midnight on 10 October ($329/MWh - see Figure 1). This was a result of a spot price of $2361/MWh in South Australia at midnight on 5 September that lifted administered weekend average price for that period. This high price was due to increased demand due to hot water load and is discussed in the Electricity Report 4 – 10 September 2016.

On 11 October the South Australian market suspension was lifted. State regulations/licence conditions imposed on ElectraNet resulted in the implementation of a network constraint to ensure the Rate of Change of Frequency (ROCOF) in South Australia would not exceed 3Hz/sec following the loss of the Heywood interconnector. This constraint limits flows on the Heywood interconnector and may force generation on in South Australia to provide inertia.

[1] See: AEMO's Market Suspension Pricing Schedule

[2] For documentation on Market Suspension Pricing see Automation of Market Suspension Pricing Schedules:

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 9 to 15 October 2016.

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

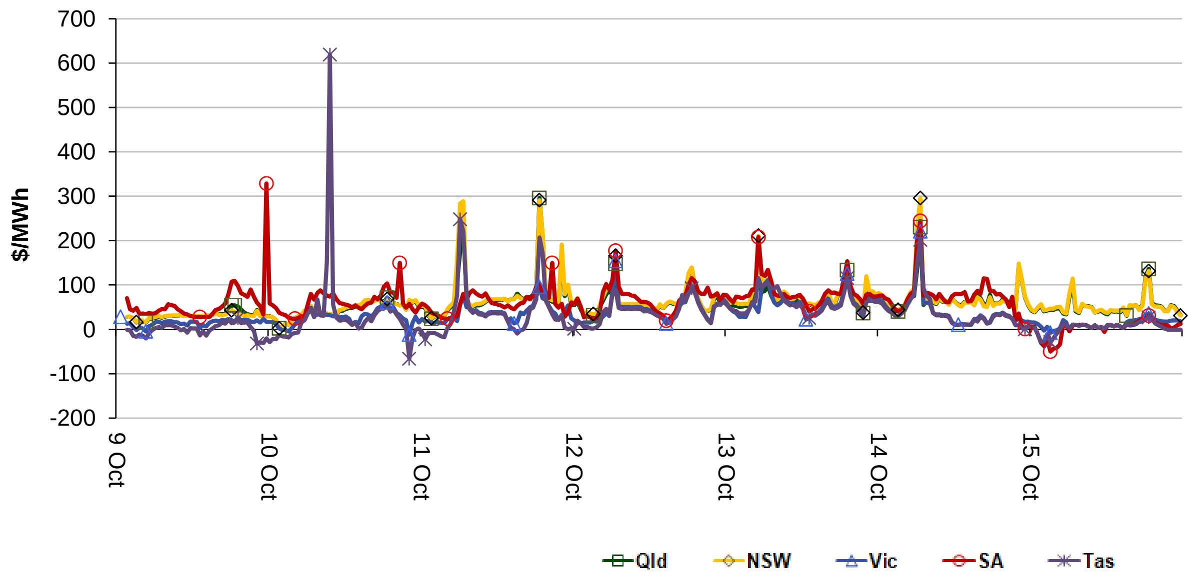


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

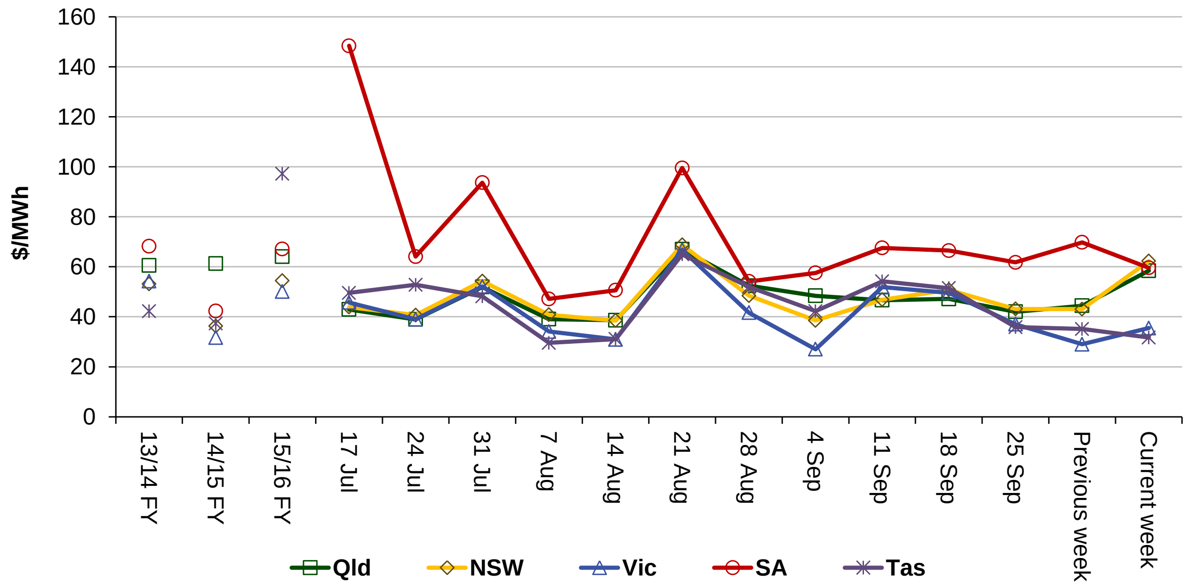


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	58	62	35	60	32
15-16 financial YTD	44	45	39	66	40
16-17 financial YTD	53	56	50	126	52

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 311 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	34	0	7
% of total below forecast	36	15	0	4

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

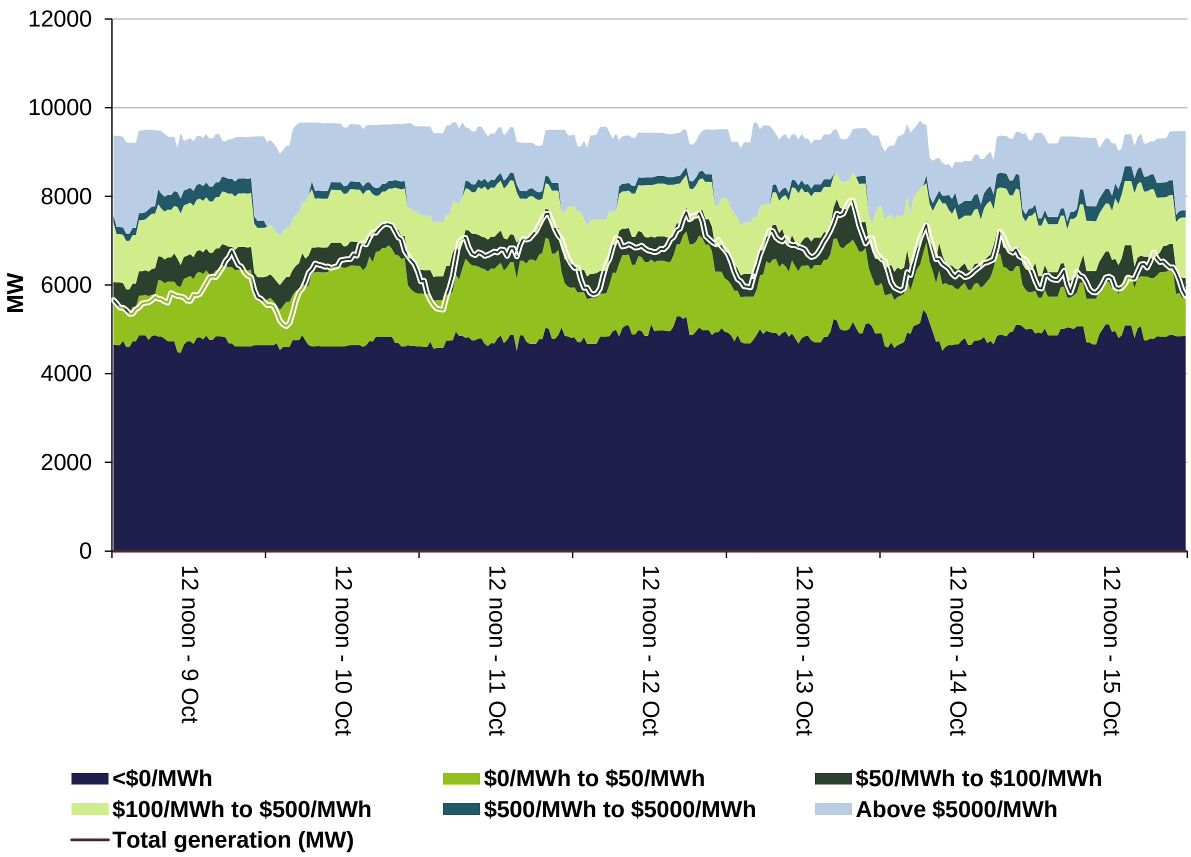


Figure 4: New South Wales generation and bidding patterns

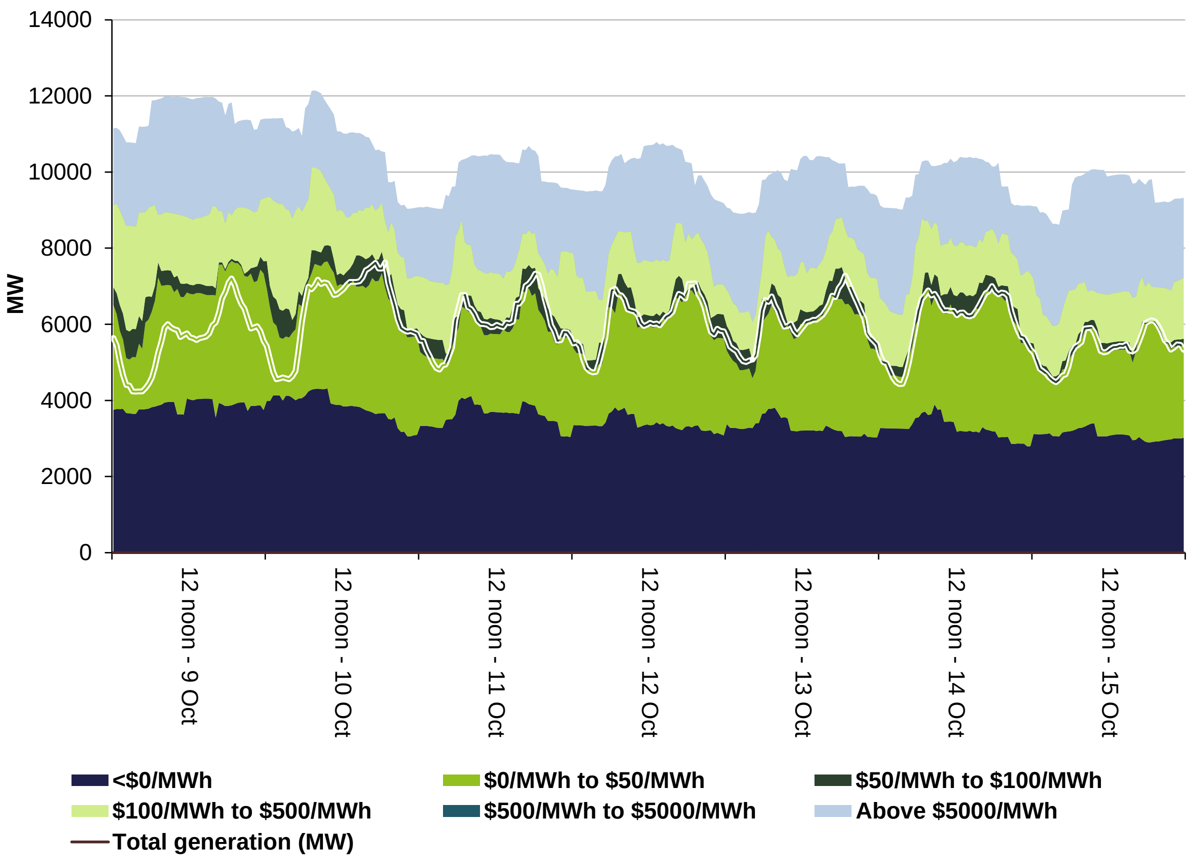


Figure 5: Victoria generation and bidding patterns

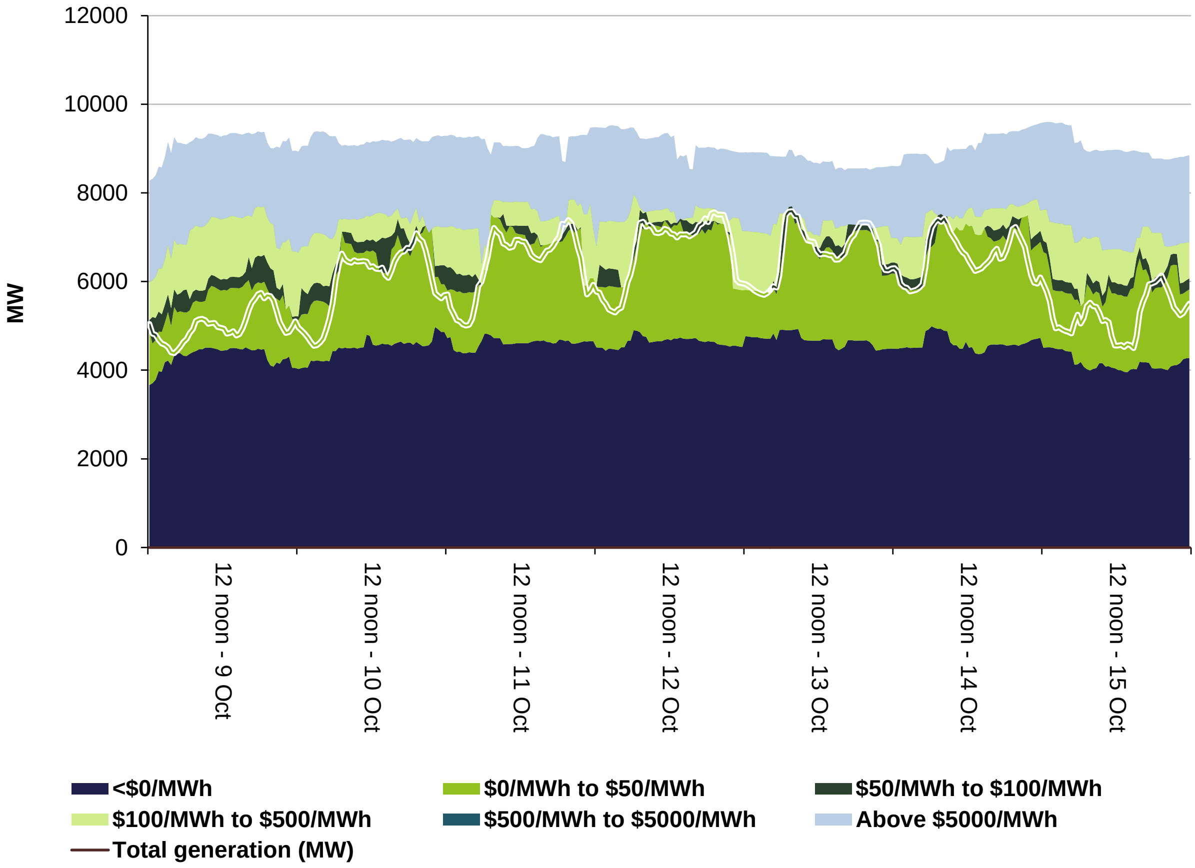


Figure 6: South Australia generation and bidding patterns

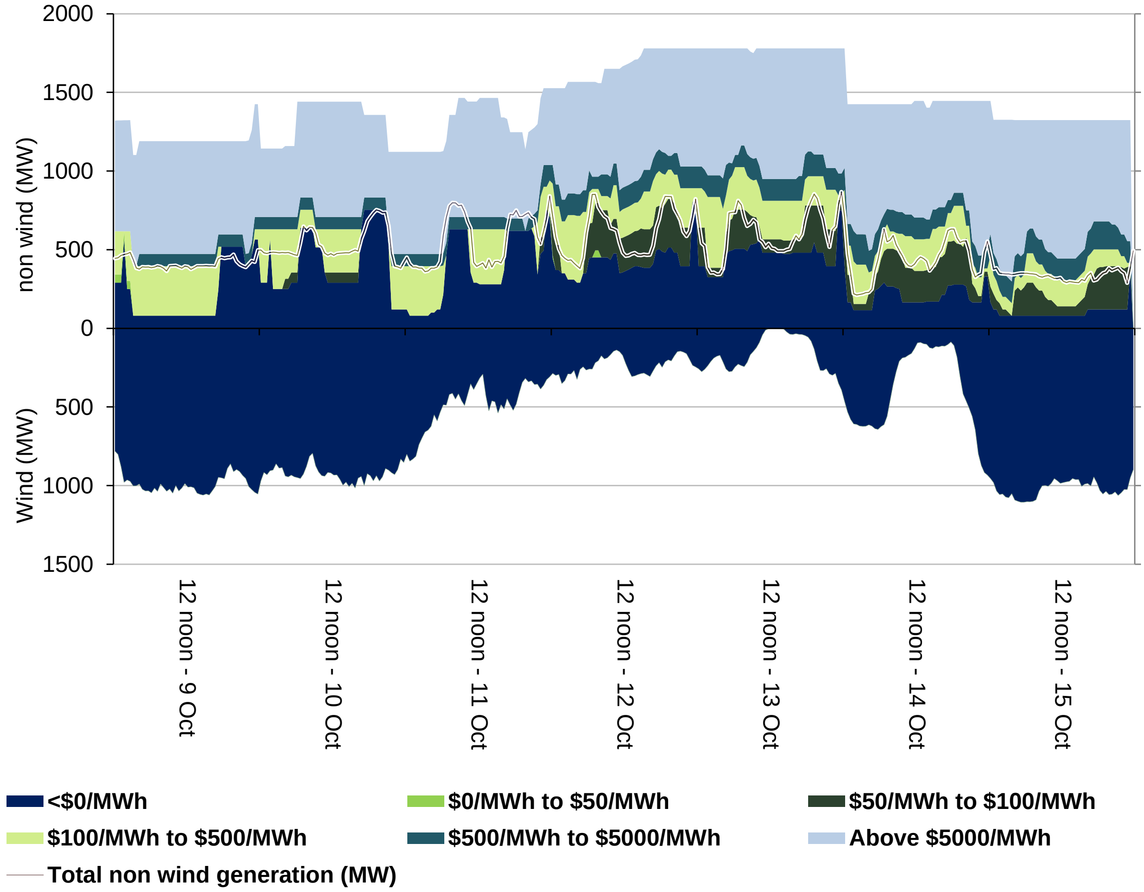
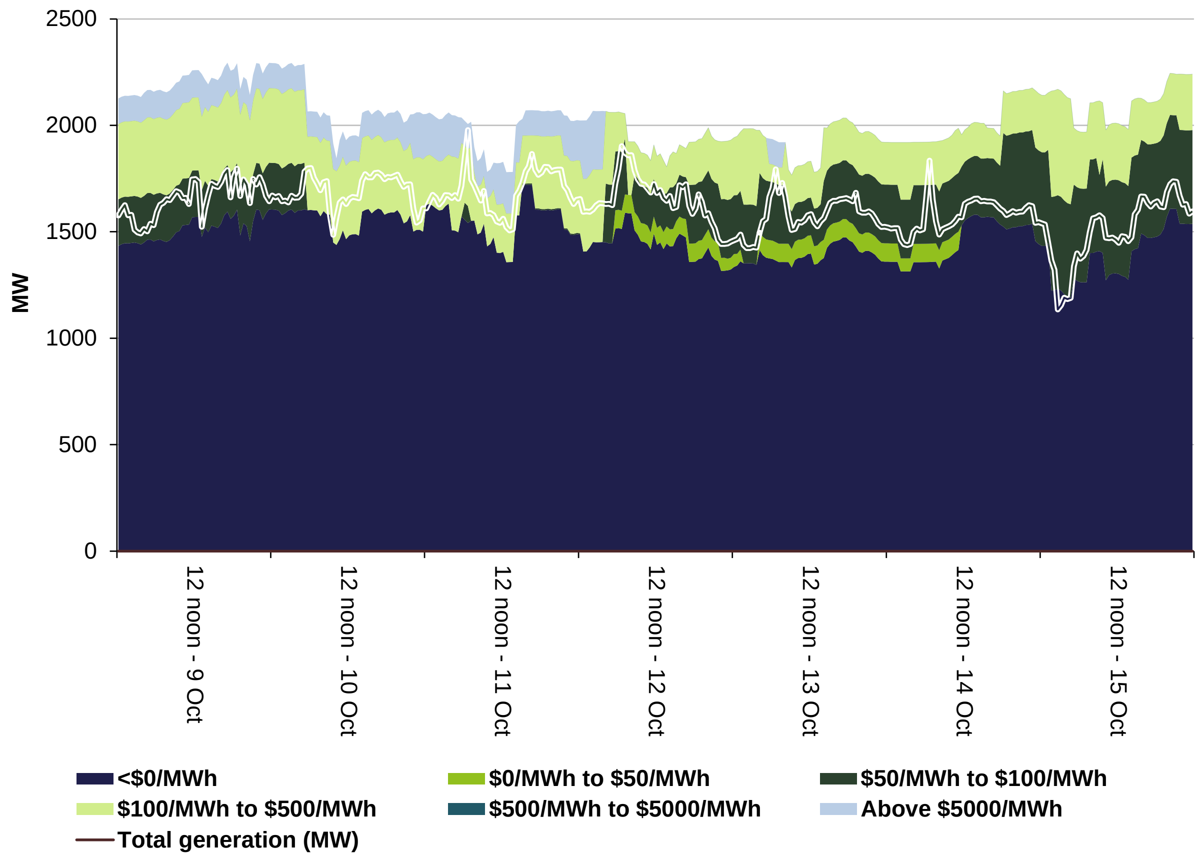


Figure 7: Tasmania generation and bidding patterns



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.

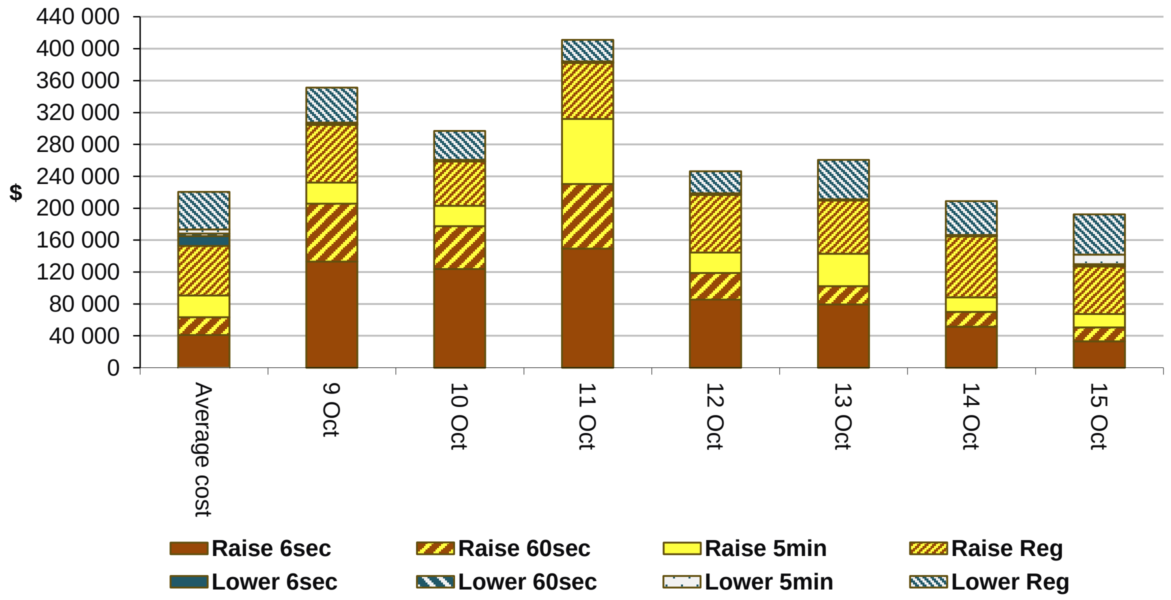
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 766 500 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $200 000 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



Detailed market analysis of significant price events

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $58/MWh and above $250/MWh.

Tuesday, 11 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
7 pm	295.82	97.60	97.60	7052	7135	7269	9143	9634	9544

Conditions at the time saw demand slightly lower than forecast while availability was around 490 MW lower than forecast four hours ahead.

Table 4: Rebids for the 7 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.27 pm		CS Energy	Gladstone	140	<263	14 000	1527P TECHNICAL ISSUES-UNIT FABRIC FILTER ISSUES-SL
3.53 pm		Origin Energy	Darling Downs	-15	55	N/A	1551P CHANGE IN AVAIL - AMBIENT CONDITIONS SL
4.25 pm		Callide Power Trading	Callide C	-26	<16	N/A	1622P C4 MAX CAPABILITY 380MW, EMISSION SMOKE DENSITY HIGH

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.28 pm		Stanwell Corporation	Stanwell	125	-1000	14 000	1728P REVISED LOAD UP AND TESTING PLAN SL
5.39 pm		Stanwell Corporation	Stanwell	-125	14 000	N/A	1728P REVISED LOAD UP AND TESTING PLAN SL
6.16 pm		Stanwell Corporation	Stanwell	-195	<65	N/A	1815P MILL LIMIT SL 1815P RTS DELAYED, HIGH EMMISSIONS SL
6.25 pm	6.35 pm	Stanwell Corporation	Stanwell	-140	-1000	N/A	1824P RTS DELAYED, HIGH EMMISSIONS SL

The above rebidding, which reduced the overall capacity available in Queensland and shifted lower priced generation into higher prices, saw prices in Queensland and New South Wales increase to around $300/MWh for the majority of the trading interval.

New South Wales

There were four occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $62/MWh and above $250/MWh.

Tuesday, 11 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
7 pm	290.70	99.71	97.47	8383	8403	8372	10 456	10 554	10 604

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

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
6.30 am	283.46	299.60	299.60	7763	7675	7720	10 250	10 307	10 300
7 am	288.55	299.60	299.60	7950	7987	8031	10 320	10 408	10 401

The spot price, demand and availability were close to what was forecast four and twelve hours ahead.

Friday, 14 October

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
7 am	295.56	290.34	286.01	8700	8541	8521	10 168	10 281	10 286

While demand at the time was around 160 MW greater than forecast, prices were close to what was forecast four and twelve hours ahead.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $32/MWh and above $250/MWh.

Monday, 10 October

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
10 am	618.67	23.01	22.90	1160	1092	1099	1915	1948	1948

Conditions at the time saw demand above forecast while availability was close to what was forecast four hours ahead.

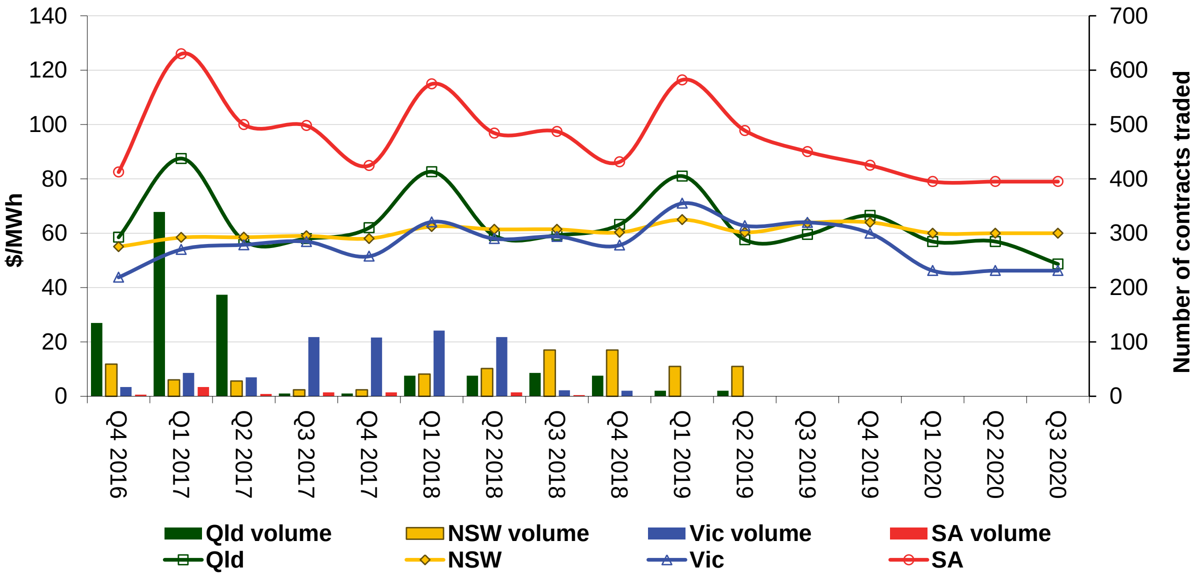
At 7.35 am on 10 October, an outage on the Tungatinah to Meadowbank to New Norfolk backed off generation in the south. At 9.12 am, AEMO reclassified a non-credible contingency event on the Farrell–Sheffield No.1 and No.2 220 kV lines in Tasmania due to lightning. This limited the imports from Victoria into Tasmania on the Basslink interconnector. This meant that all Tasmanian FCAS services had to be sourced locally.

The trade-off in generation caused by the interaction of the two constraints resulted in the constraint managing the Farrell-Sheffield reclassification to violate at 10 am and the dispatch price rose to $2733/MWh.

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.

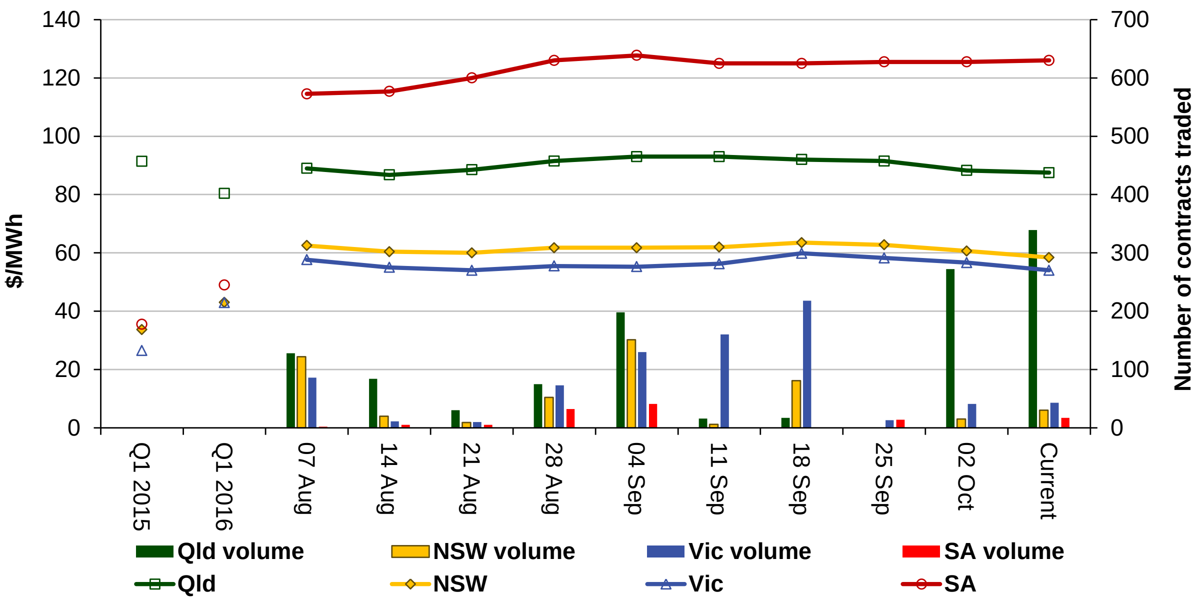
Figure 9: Quarterly base future prices Q4 2016 – Q3 2020



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)



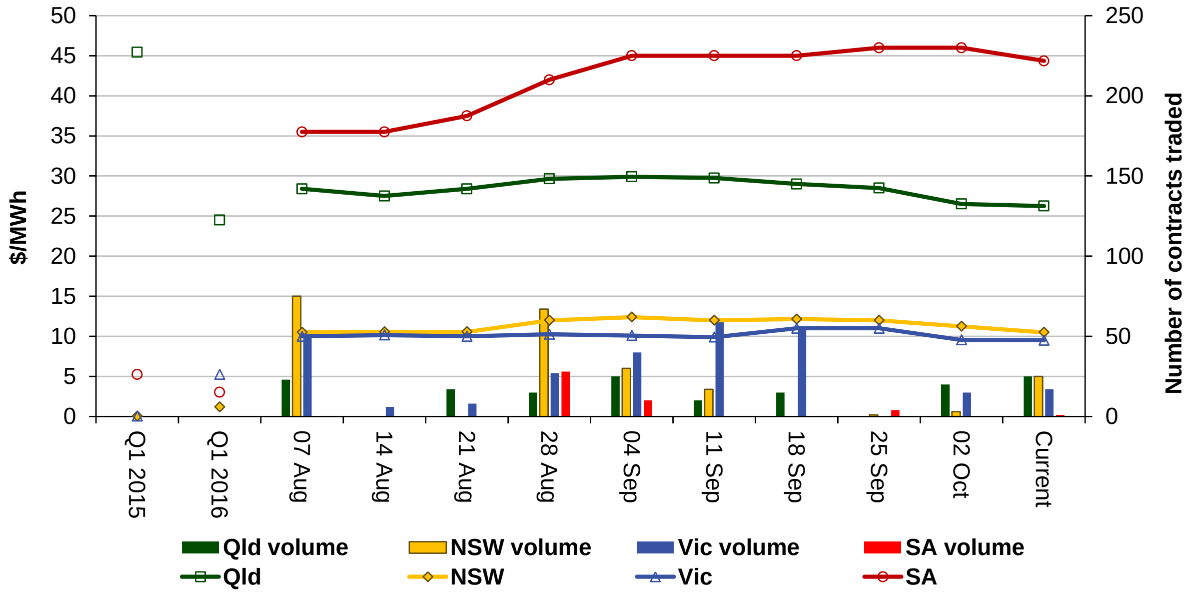
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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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