

# Electricity Report 19 – 25 July 2015



AUSTRALIAN ENERGY  
REGULATOR

## 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 19 to 25 July 2015. There were six occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$75/MWh and above \$250/MWh. There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of \$45/MWh and above \$250/MWh. These are discussed later in this report.

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

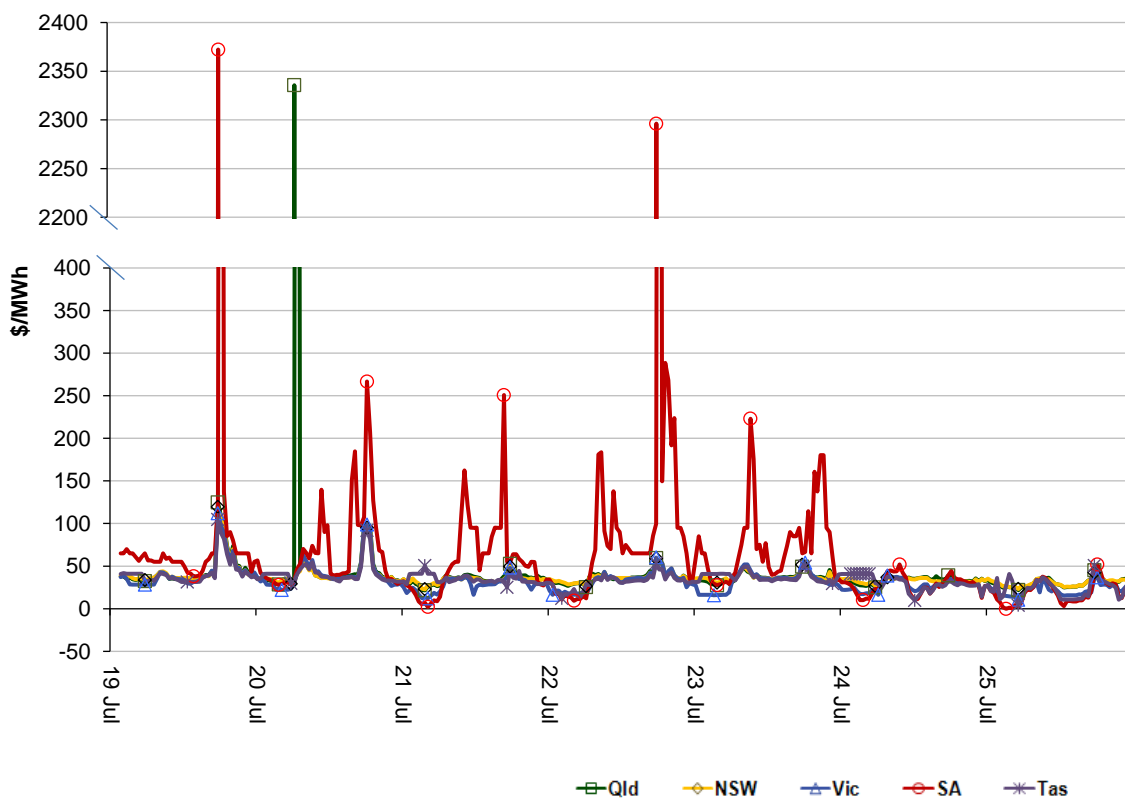
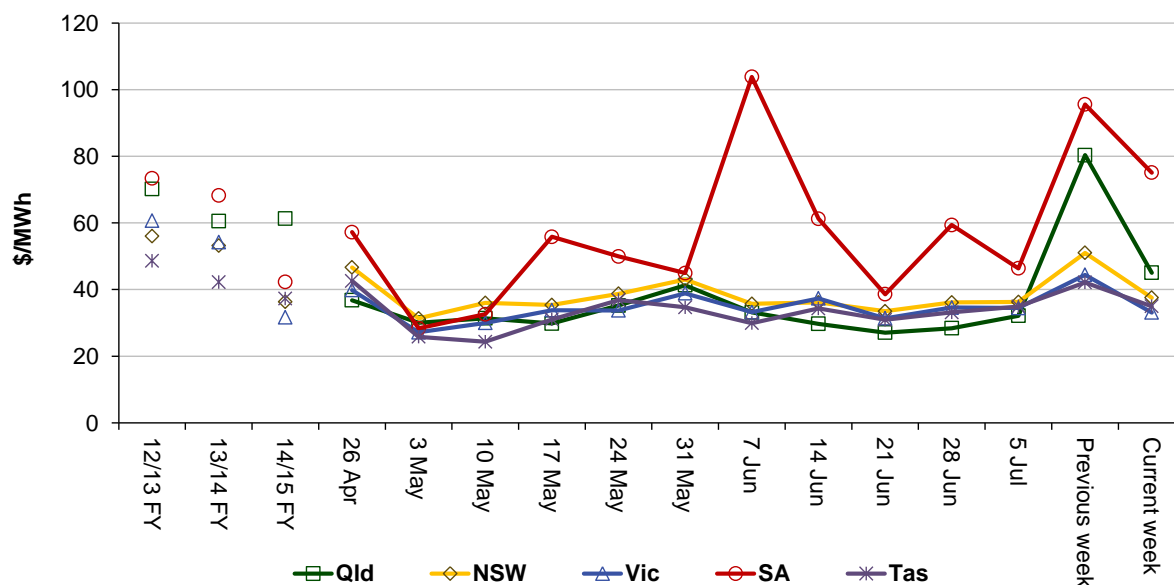


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

**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	45	38	33	75	35
14-15 financial YTD	36	45	43	62	36
15-16 financial YTD	49	41	37	72	37

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 199 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**

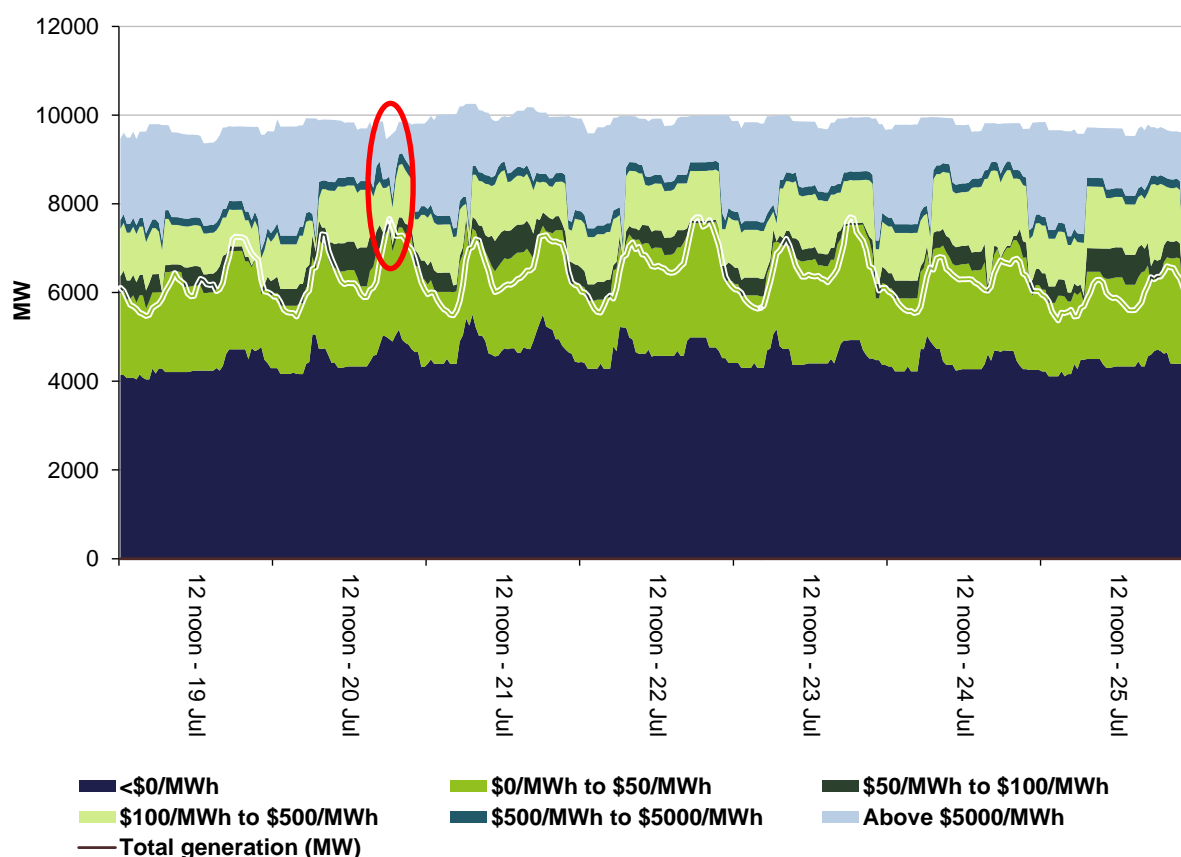
	Availability	Demand	Network	Combination
% of total above forecast	11	30	0	3
% of total below forecast	33	18	0	5

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

## Generation and bidding patterns

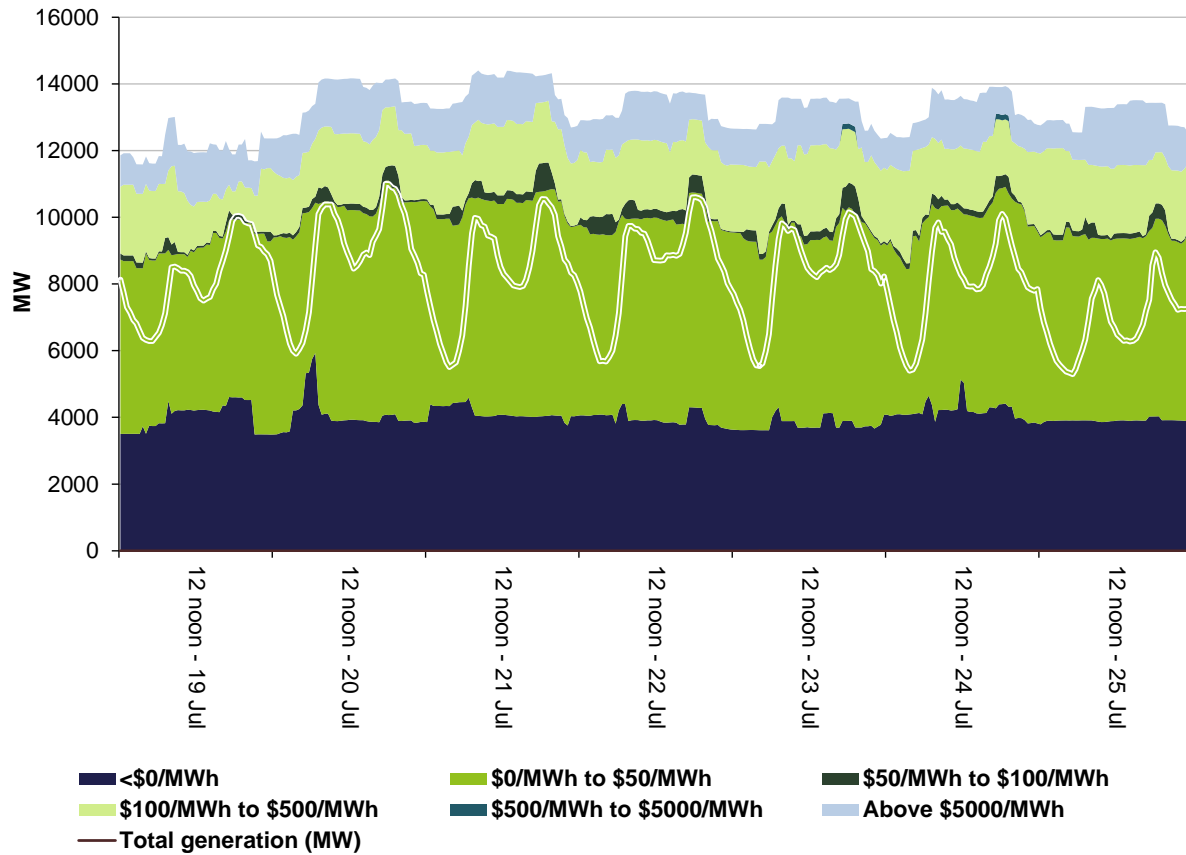
The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

**Figure 3: Queensland generation and bidding patterns**

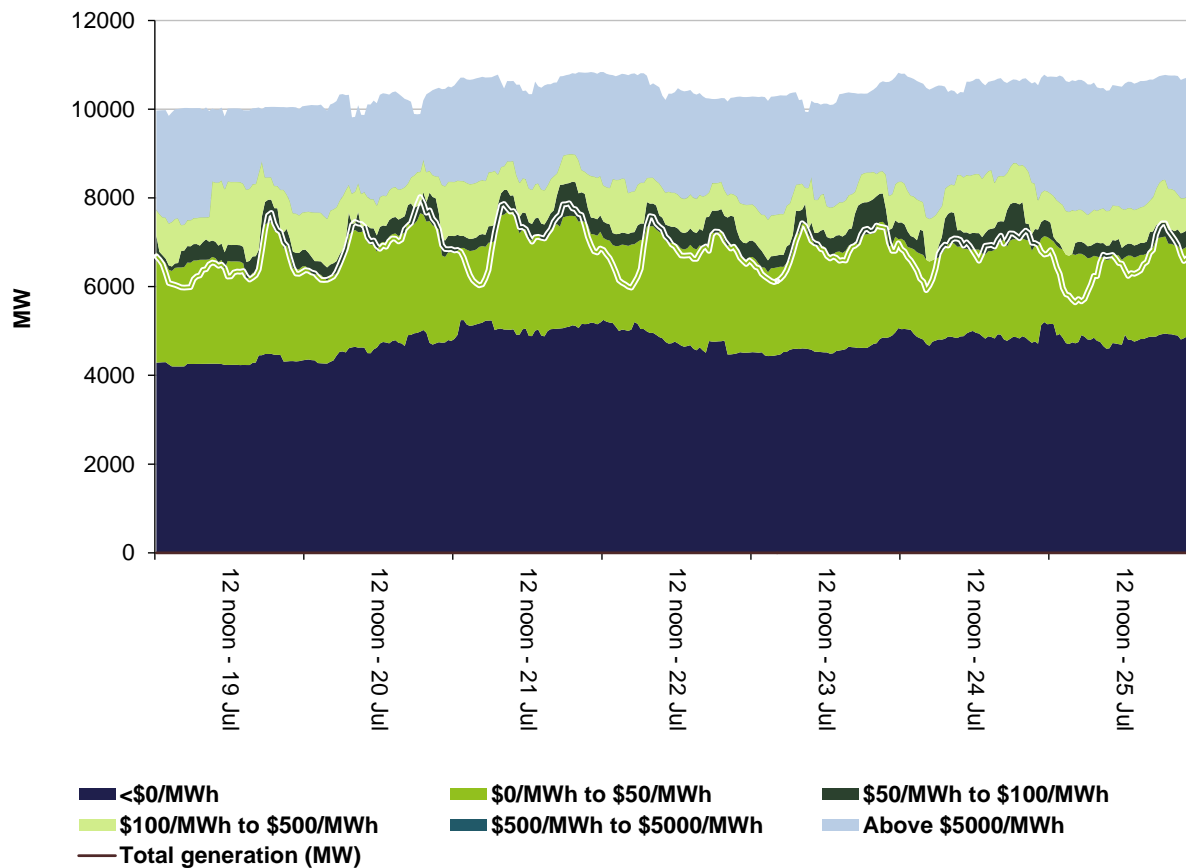


The red ellipse highlights where Queensland participants rebid from low to high price causing a high spot price detailed in the “Detailed market analysis of significant price events” section below.

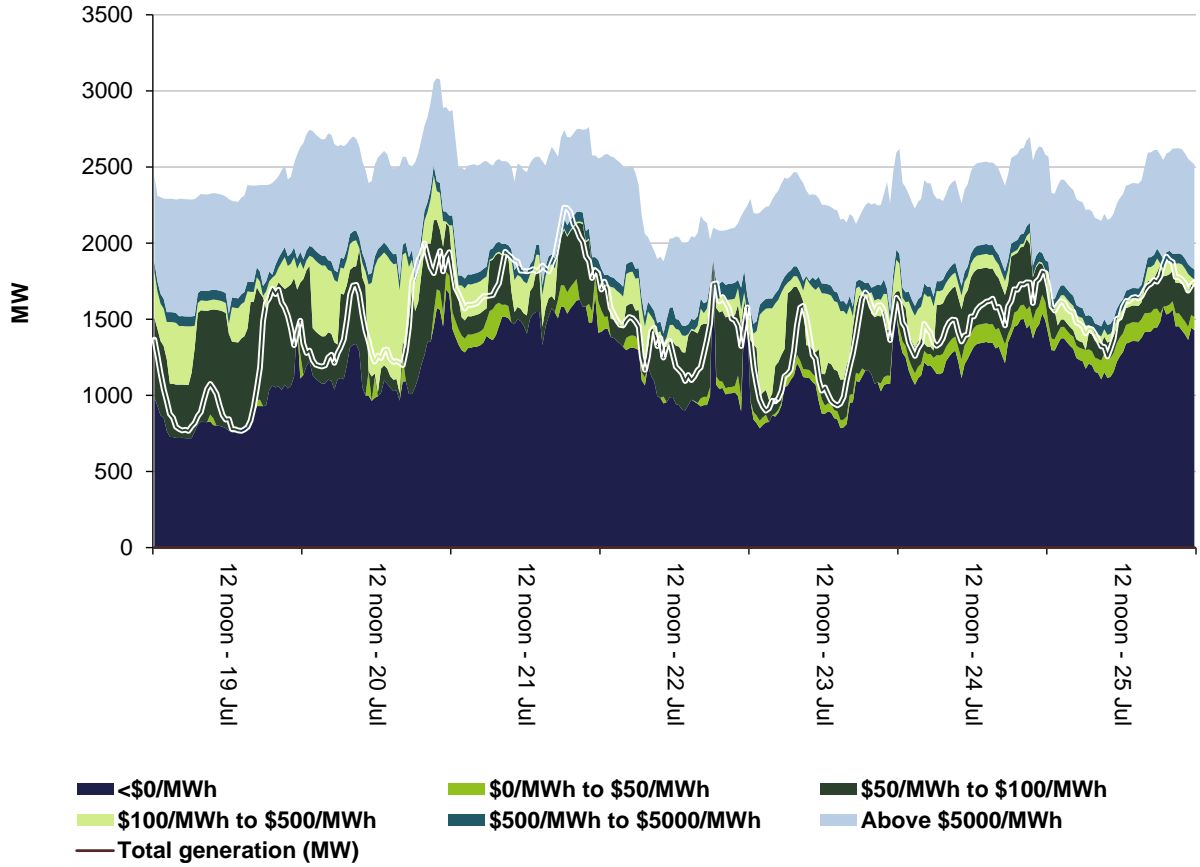
**Figure 4: New South Wales generation and bidding patterns**



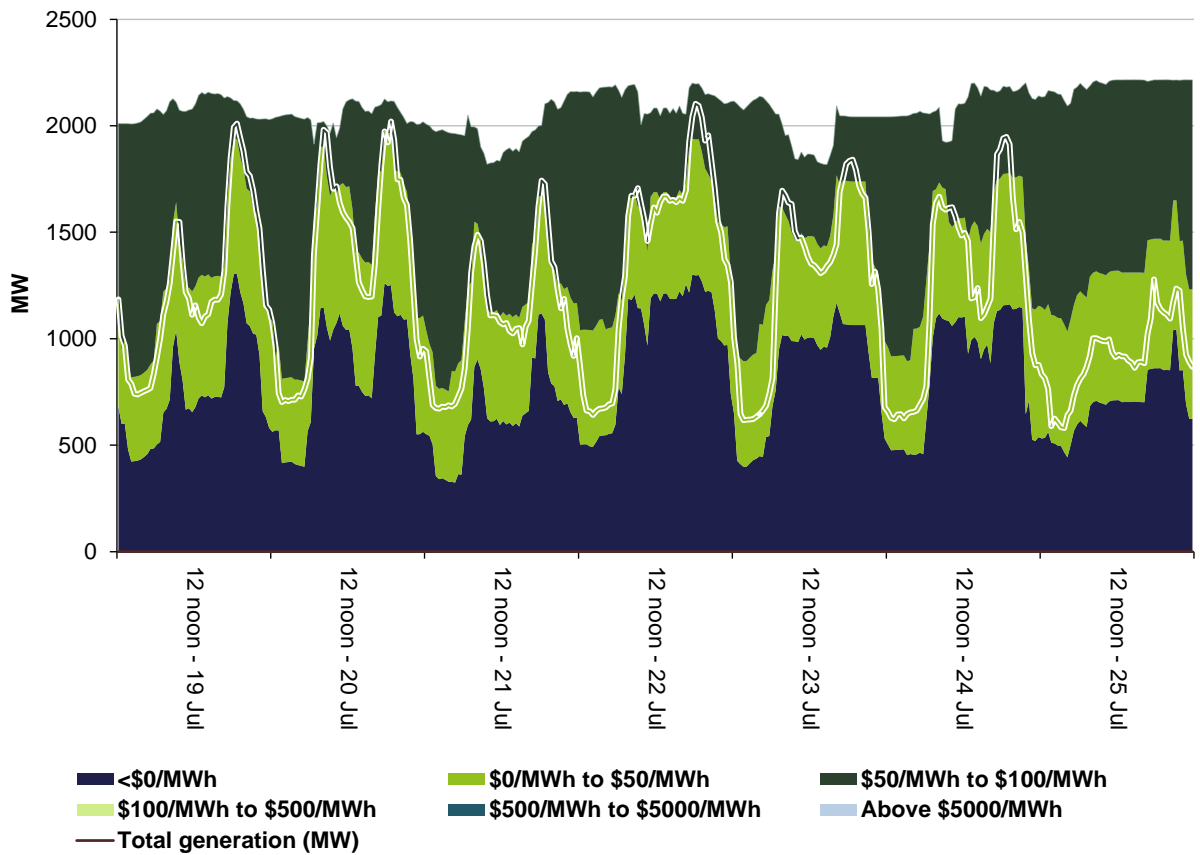
**Figure 5: Victoria generation and bidding patterns**



**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.

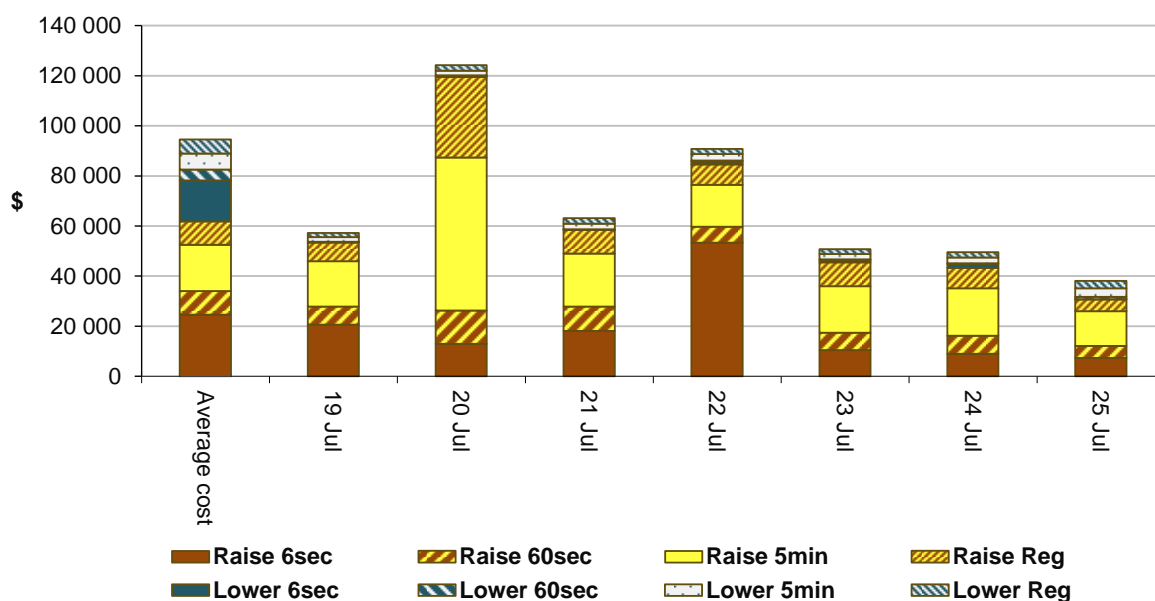
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$338 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$135 500 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**



## 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.

### Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of \$45/MWh and above \$250/MWh.

### Monday, 20 July

**Table 3: Rebids for the 7 am trading interval**

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
<b>7 am</b>	2335.61	41.90	33.95	6373	6390	6474	9925	9935	10 255

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

**Table 4: Rebids for the 7 am trading interval**

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
6.37 am	6.45 am	Millmerran Energy	Millmerran	190	7	13 800	06:31 A change in dispatch gen 5min pd for DI 0700 (+100MW)
6.43 am	6.50 am	Callide Power Trading	Callide C	126	-1000	13 800	0611A change in dispatch gen 5min pd for DI 0700 (+100MW)
6.55 am	6.55 am	CS Energy	Gladstone	160	13 800	0	0648P portfolio rearrangement due to-QNI close to binding north-

The above rebids contributed to creating a steep supply curve (despite CS Energy's rebid) with limited capacity available priced between \$100/MWh and \$12 000/MWh. Consequently, small changes in demand, interconnectors and availability lead to large changes in price.

At 7 am there was a 50 MW increase in demand, with low priced capacity either fully dispatched, ramp rate limited or stranded in FCAS the dispatch price went from \$54/MWh at 6.55 am to the price cap at 7 am. The price set by Stanwell (Tarong and Stanwell) and Millmerran units.

## South Australia

There were six occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$75/MWh and above \$250/MWh.

### Sunday, 19 July

**Table 5: Rebids for the 6.30 pm trading interval**

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
<b>6.30 pm</b>	2372.11	109.65	115.77	2065	2073	2080	2381	2385	2394

Conditions at the time saw demand and available capacity close to forecast four hours ahead. Wind generation was close to zero. Imports across the Heywood and Murraylink interconnectors were close to forecast four hours ahead.

**Table 6: Rebids for the 6.30 pm trading interval**

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
6.18 pm	6.25 pm	Alinta Energy	Northern Power	95	287	13 334	1815~A~spot price higher than pd~

As demand increased over the afternoon peak and with limit capacity priced between \$100/MWh and \$10 000/MWh small changes in demand and rebidding lead to large changes in dispatch prices.

At 6.30 pm there was a 42 MW increase in demand, with all low priced capacity either ramp rate limited, fully dispatched or stranded in FCAS the dispatch increased to \$13 334/MWh, with Northern Power station setting the price

The dispatch price fell back to \$116/MWh at 6.35 pm dispatch interval following a 111 MW fall in demand (most likely due to an increase in South Australian non-scheduled generation).

### Monday, 20 July

**Table 7: Rebids for the 6.30 pm trading interval**

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
<b>6.30 pm</b>	266.62	94.99	94.99	2148	2089	2166	2530	2686	2798

Demand was close to forecast four hours ahead and availability was 100 MW below forecast four hours ahead. Imports across Murraylink and Heywood interconnectors were close to forecasts four hours ahead.



At 5.56 pm, effective from 6.05 pm, Alinta Energy rebid 193 MW of Northern Power's available capacity from below \$95/MWh to \$13 334/MWh. The reason provided was "1750~A~dispatch \$107.79 v 5pd \$95.16~".

The above rebid contributed to an already steep supply curve, as a result of this, minor changes in demand and imports led to the dispatch price fluctuating between \$112/MWh and \$360/MWh during the 6.30 pm trading interval.

## Tuesday, 21 July

**Table 8: Rebids for the 5 pm trading interval**

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
<b>5 pm</b>	250.73	32.32	32.27	1797	1661	1510	2645	2709	2694

Conditions at the time saw demand around 135 MW above forecast four hours ahead and availability was close to forecasts. Both interconnectors were close to forecast four hours ahead.

With a steep supply curve, minor changes in demand and interconnectors flows saw the dispatch price fluctuated between \$95/MWh and \$351/MWh during the 5 pm trading interval.

## Wednesday, 22 July

**Table 9: Rebids for the 6.30 pm trading interval**

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
<b>6.30 pm</b>	2296.07	83.31	590.07	2024	2038	2086	2102	2280	2176

Conditions at the time saw demand close to forecast four hours ahead and available capacity around 180 MW below forecast four hours ahead. Both Interconnectors were close to forecast four hours ahead.

**Table 10: Rebids for the 6 pm trading interval**

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
6 pm	6.10 pm	AGL	Torrens Island	100	<65	13 500	1755~F~060 chg in fuel cost~60 increase in f/cast gas value
6.07 pm	6.15 pm	AGL Energy	Torrens Island	100	13500	-1000	1805~A~040 chg in AEMO disp~45 price increase vs PD SA \$13,481.8

At 6.10 pm, as a result of a 50 MW change in demand and AGL's rebid becoming effective, with low priced generation either ramp rate limited, fully dispatched or stranded in FCAS, the

dispatch increased from \$98/MWh at 6.05 pm to \$13 481/MWh at 6.10 pm. The dispatch price then reduced to \$53/MWh at 6.15 pm when AGL's rebid of all available capacity to the price floor took effect.

**Table 11: Rebids for the 7.30 pm and 8 pm trading intervals**

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
<b>7.30 pm</b>	288.60	360.81	12 301.30	2103	2096	2151	2082	2146	2145
<b>8 pm</b>	268.16	360.81	10 750.20	2099	2071	2113	2081	2128	2144

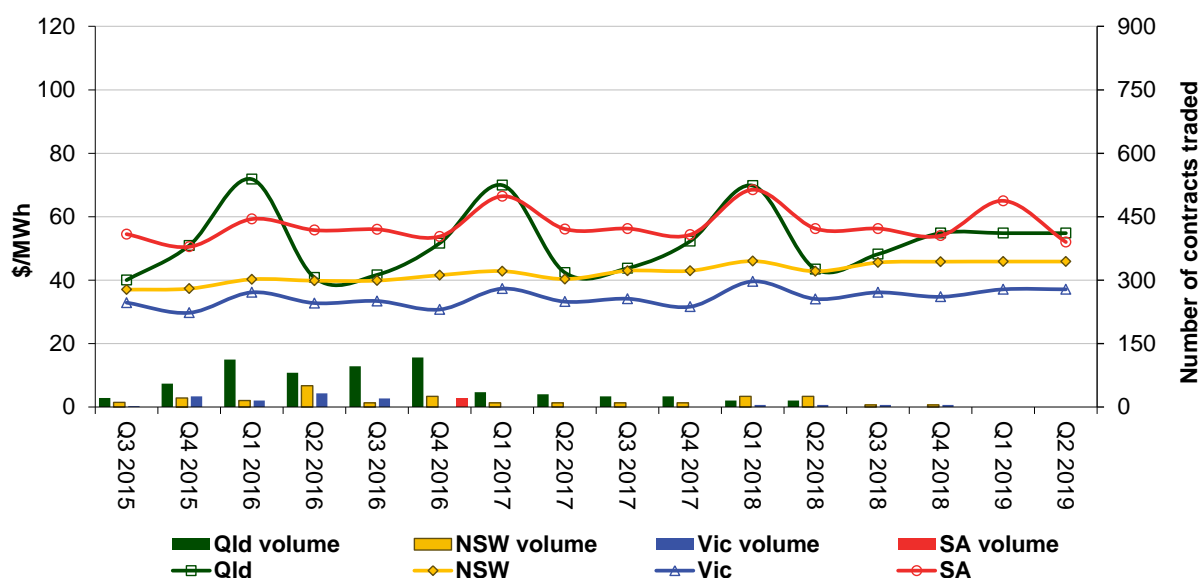
Prices were around \$70/MWh below forecasts four hours ahead and significantly below that forecast 12 hours ahead. Demand and available capacity were close to forecast four and 12 hours ahead. Flows on the Murraylink interconnector were close to forecast four hours ahead whilst Heywood was approximately 30 MW above the forecast.

With a steep supply curve small changes in demand, available capacity, rebidding and imports can lead to large changes in prices. Within 12 hours of dispatch there was around 170 MW of capacity rebid from high to low prices by South Australian participants which saw the forecast price fall to around \$290/MWh by 7 pm. The dispatch prices for the 7.30 pm and 8 pm trading intervals were all around \$300/MWh except for 7.40 pm when there was a small decrease in demand and further capacity was rebid into low prices.

## 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.

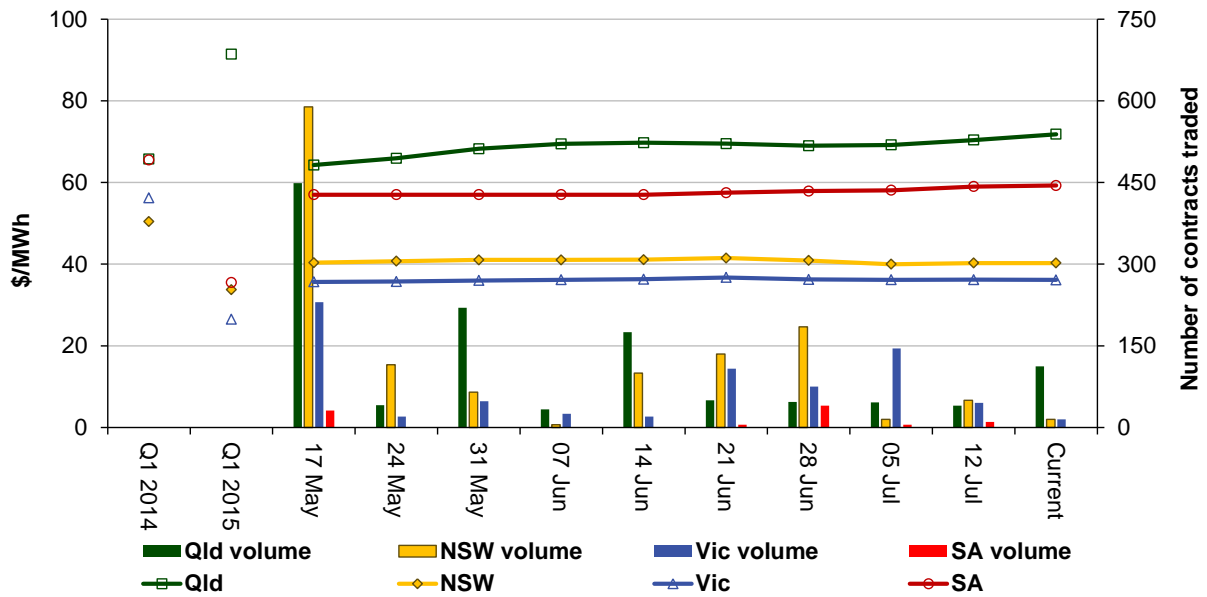
**Figure 9: Quarterly base future prices Q3 2015 – Q2 2019**



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.

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

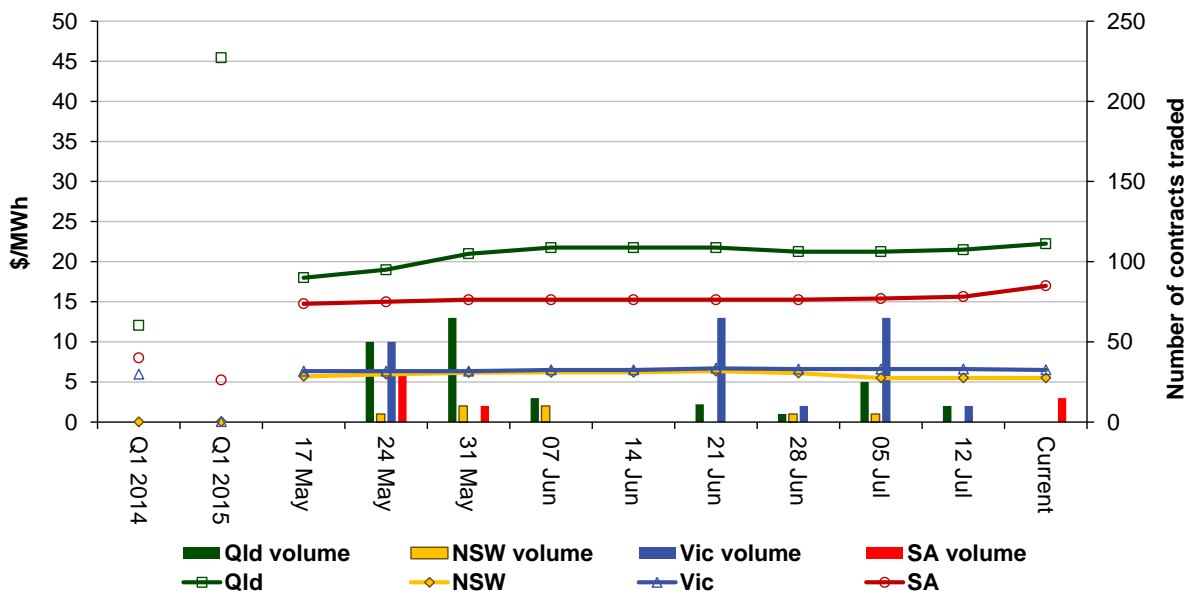


Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Performance of the Energy Sector](#) 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**

**August 2015**