

Electricity Report

17 to 23 August 2014



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 17 to 23 August 2014. The figure shows that the spot price reached \$2285/MWh in South Australia on 20 August, and \$815/MWh and \$2278/MWh in Tasmania on 20 and 21 August respectively. The reasons behind these price spikes are explained below in *Detailed market analysis*.

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

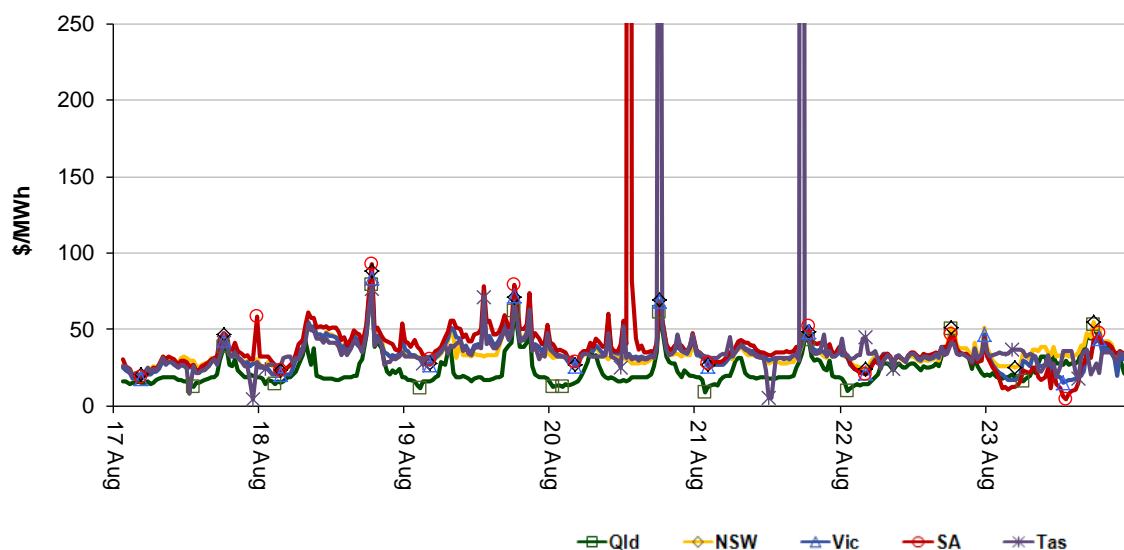


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

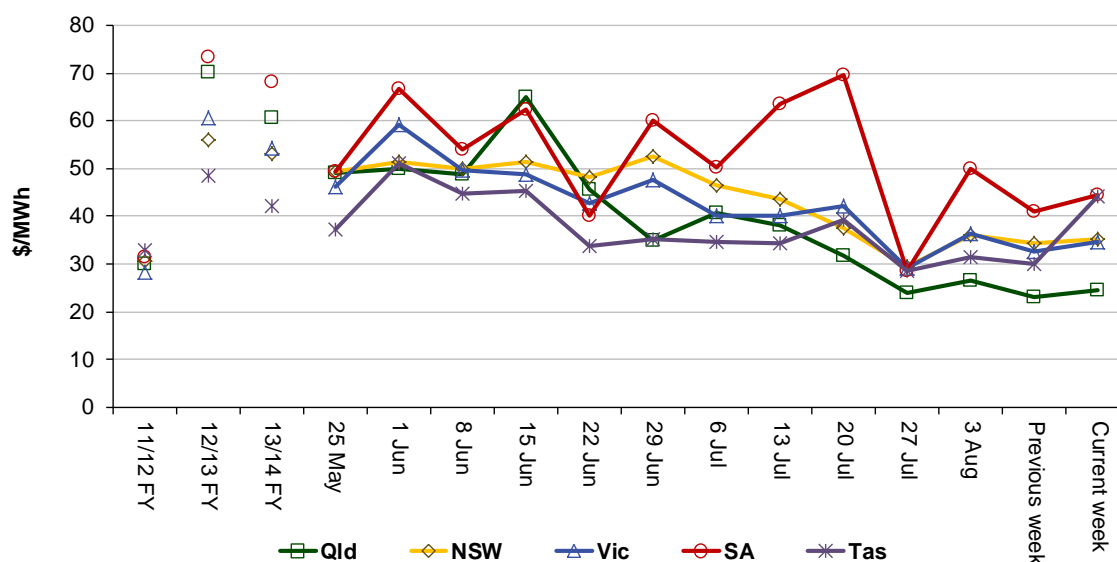


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	25	35	35	44	44
13-14 financial YTD	62	57	58	74	50
14-15 financial YTD	30	39	38	51	35

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 69 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2013 of 97 counts and the average in 2012 of 60. 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	50	3	0
% of total below forecast	36	0	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. Figures 3 to 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

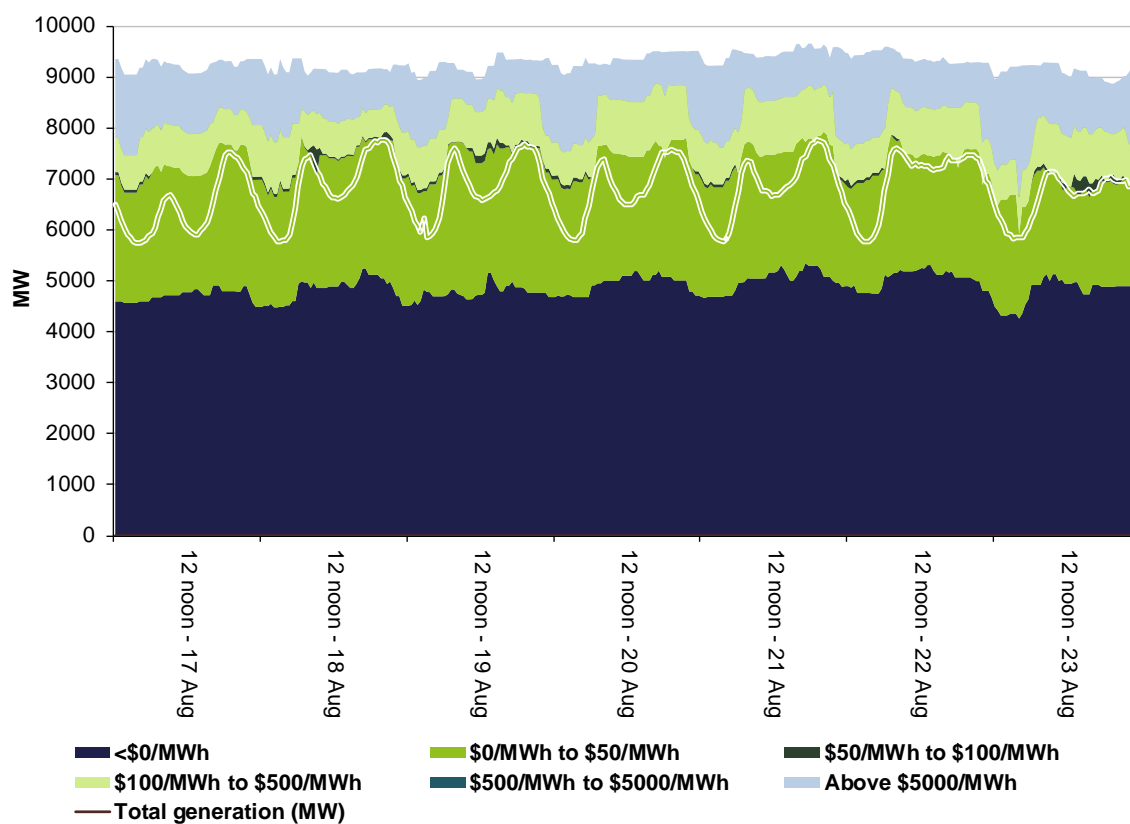


Figure 4: New South Wales generation and bidding patterns

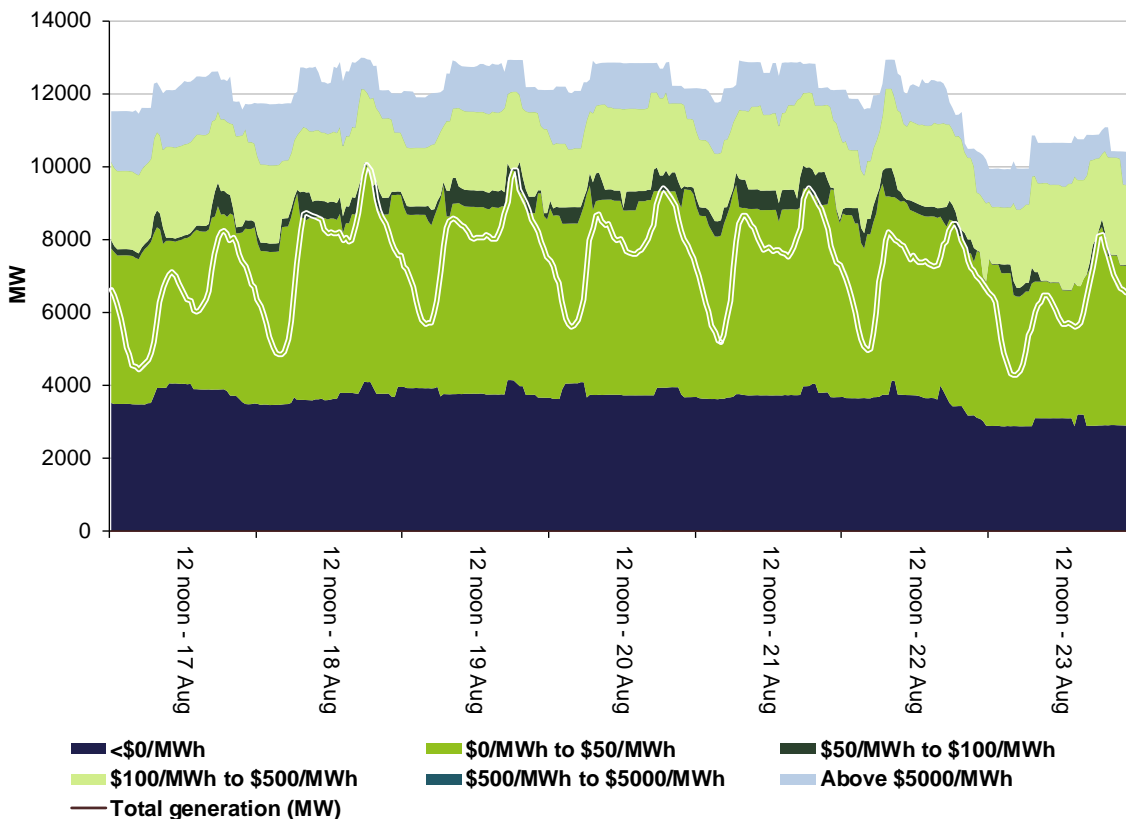
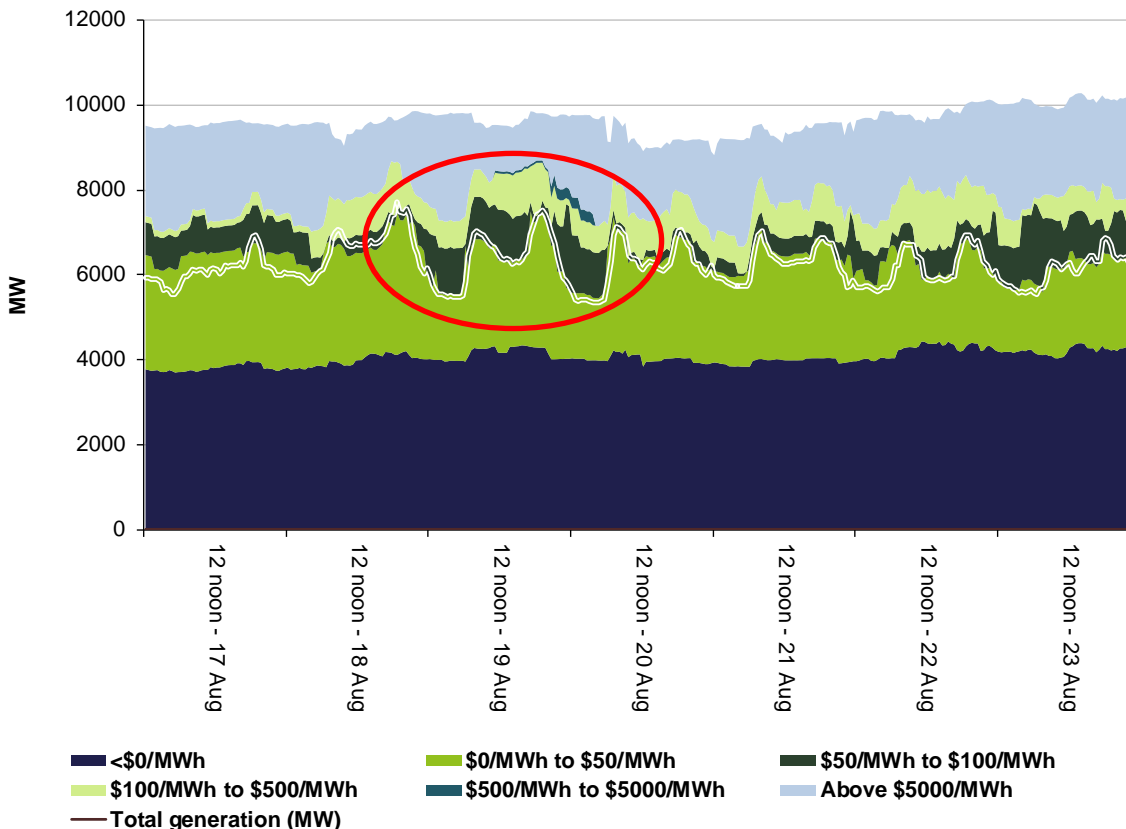
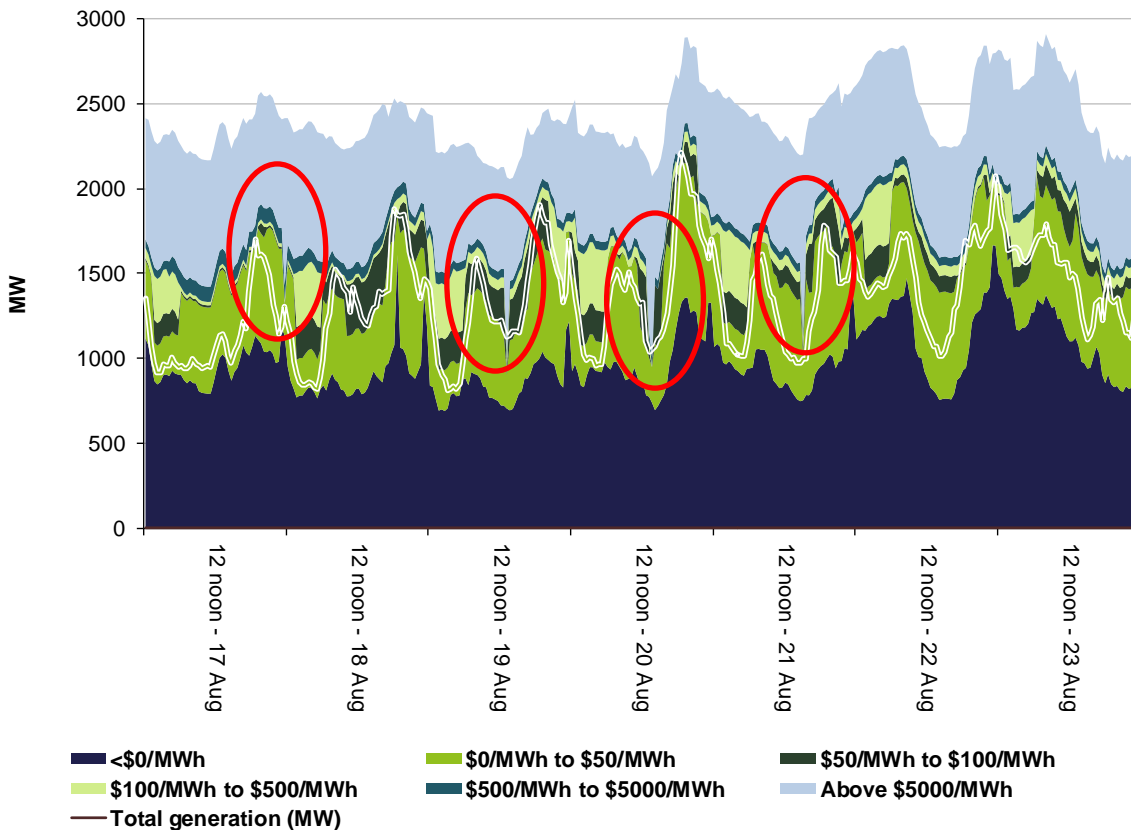


Figure 5: Victoria generation and bidding patterns



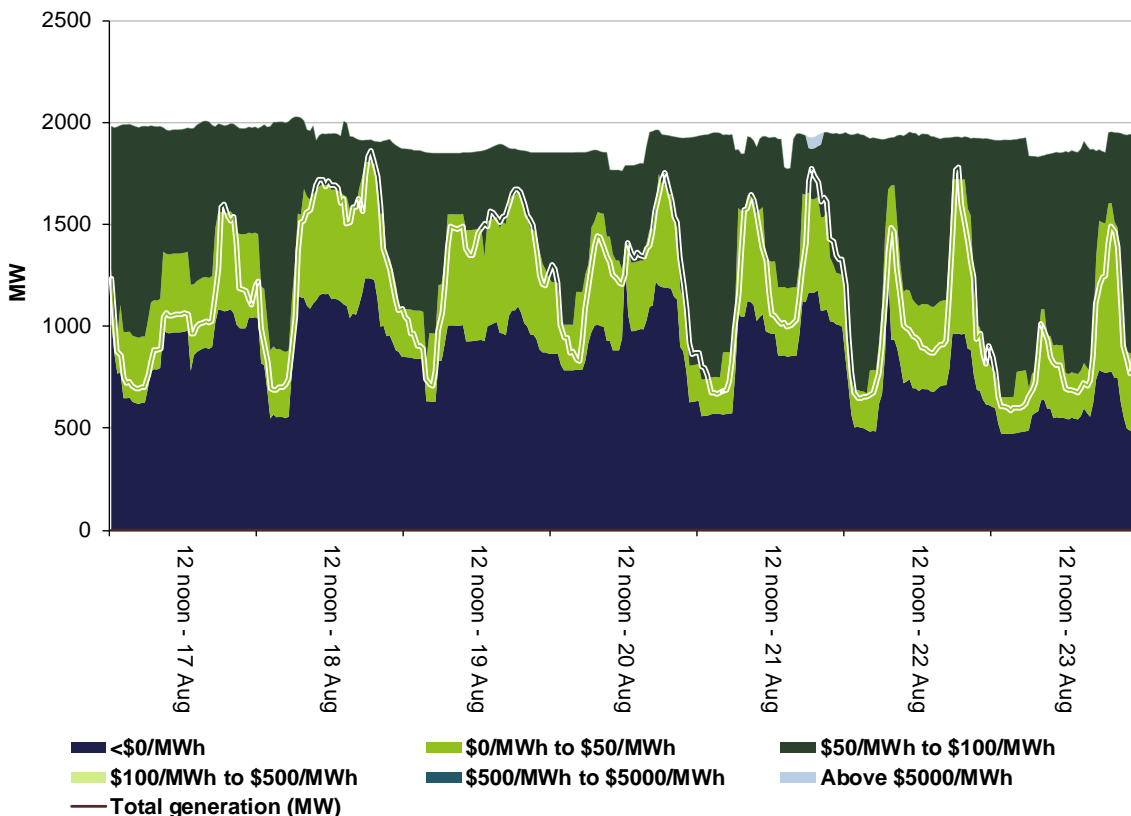
The red circle in Figure 5 highlights rebidding by AGL at Loy Yang A and Origin at Mortlake. Origin shifted over 500 MW at Mortlake from below \$50/MWh to around \$100/MWh. The reason given related to “line pack management”. AGL rebid around 700 MW at Loy Yang A from around \$40/MWh to around \$100/MWh. The rebid reason related to “coal conservation”. This rebidding did not, however, result in any high price outcomes.

Figure 6: South Australia generation and bidding patterns



The red circled areas in figure 6 show an increase in high price capacity on 17, 19, 20 and 21 August. This was the result of late rebidding of capacity into high prices by AGL, which resulted in the spot price reaching \$2285/MWh on 20 August (as discussed under *Detailed market analysis*).

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.

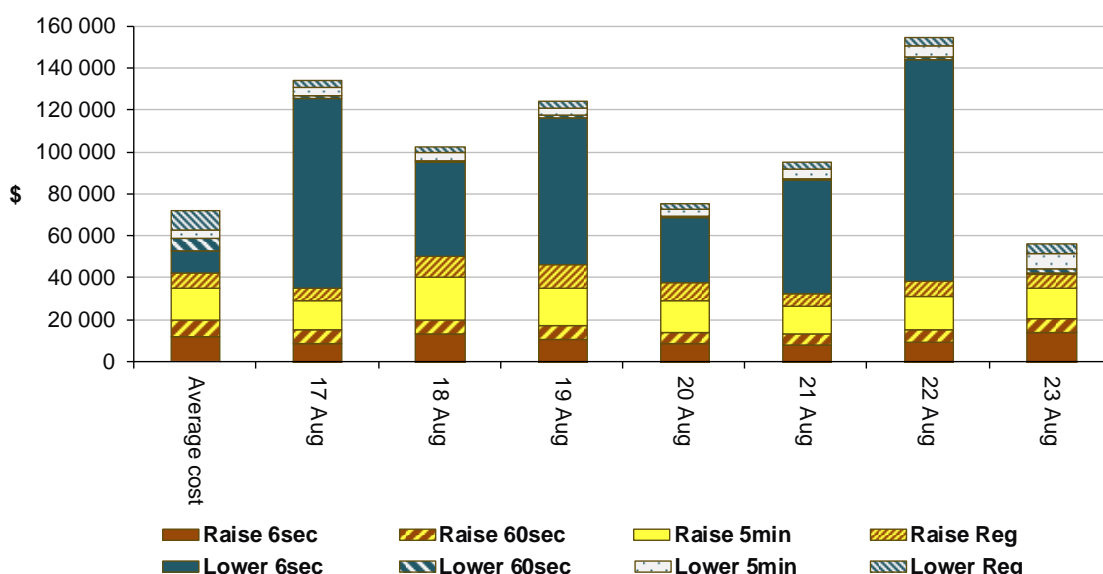
The total cost of FCAS on the mainland for the week was \$276 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$464 000 or less than 6 per cent of energy turnover in Tasmania.

Figure 8 shows that FCAS costs across the NEM were above average for most days of the week, and that high lower 6 second services costs were the main reason. The majority of this cost accrued in Tasmania, where the dispatch price exceeded \$2000/MW on six occasions throughout the week primarily caused by the co-optimisation of energy and lower six second services.

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.

There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of \$44/MWh and above \$250/MWh.

Table 3: Wednesday 20 August

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	2284.78	35.49	35.49	1476	1456	1491	2149	2139	2114

Actual demand and available capacity was close to forecast. The Murraylink interconnector was on an unplanned outage at the time of high prices.

At 1.19 pm, effective for 1.30 pm only, AGL rebid a total of 390 MW across Torrens Island units B2, B3 and B4 from prices below \$71/MWh to the price cap. The reason given was “13:15A Chg in dispatch::SA price decrease vs. 12:00 30PD”.

With very little wind generation (under 100 MW), significant other generation either off line, ramp limited, or at maximum generation, and the Heywood interconnector importing at its limit, the high price generation at Torrens Island was dispatched. This saw the five-minute price increase from \$50/MWh at 1.25 pm to the price cap at 1.30 pm.

There was no other significant bidding.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of \$44/MWh and above \$250/MWh.

Table 4: Wednesday 20 August

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 PM	815.43	48.31	36.15	1420	1423	1489	1942	1953	1934

Conditions at the time saw demand close to that forecast 4 hours ahead and available capacity close to forecast.

An increase in flows across the Sheffield to Georgetown 220 kV line caused the T>>T_NIL_BL_EXP_6E constraint to bind, causing generation in Tasmania to be constrained off. The constraint (which is a system normal constraint) manages post contingent flows on the Sheffield to Georgetown 220 kV lines, preventing an overload on the parallel line in the event of a trip. The constraint affects all Tasmanian generation except for generation at Tamar Valley (which was offline) and forces exports into Victoria across Basslink.

Exports to Victoria reduced from 253 MW at 6 pm to 41 MW at 6.05 pm. With generators either stranded or trapped in FCAS or offline, Tasmanian generation reduced by around 200 MW.

However, this was not enough to meet the constraint requirements, causing the constraint to violate at 6.05 pm, and the five minute price to reach \$4567/MWh.

Prices returned to previous levels in the following dispatch interval due to a reduction in flow across the Sheffield to Georgetown 220 kV line and a demand side response from the Nyrstar smelter.

There was no significant rebidding.

Table 5: Thursday 21 August

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
6.00 PM	2277.62	36.06	40.81	1327	1273	1397	1936	1938	1938

Actual demand was slightly higher than forecast four hours ahead and available capacity was close to forecast.

An increase in flows across the Sheffield to Georgetown 220 kV line caused the T>>T_NIL_BL_EXP_6E constraint to bind, causing generation in Tasmania to be constrained off. The constraint (which is a system normal constraint) manages post contingent flows on the Sheffield to Georgetown 220 kV lines, preventing an overload on the parallel line in the event of a trip. The constraint affects all Tasmanian generation except for generation at Tamar Valley (which was offline) and forces exports into Victoria across Basslink.

Exports to Victoria reduced from 187 MW at 5.55 pm to 26 MW at 6 pm. With generators either stranded or trapped in FCAS or offline, Tasmanian generation reduced by 154 MW. However, this was not enough to prevent the constraint violating at 6 pm and the five minute price to increase from \$35/MWh at 5.55 pm to price cap at 6 pm.

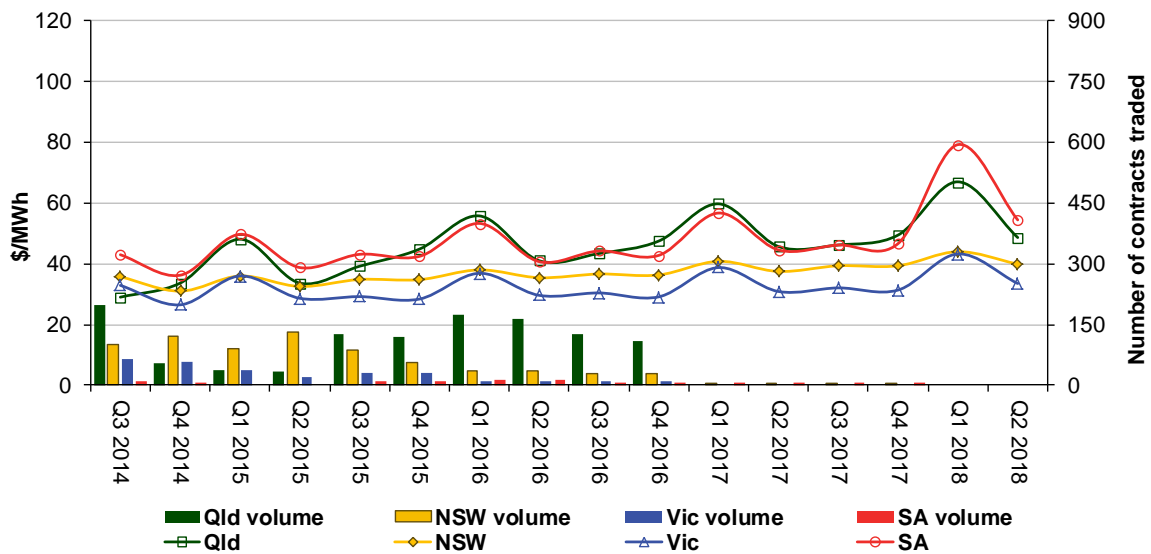
The dispatch price fell to \$46/MWh at 6.05 pm due to a reduction in flow across the Sheffield to Georgetown 220 kV line.

There was no significant rebidding.

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.

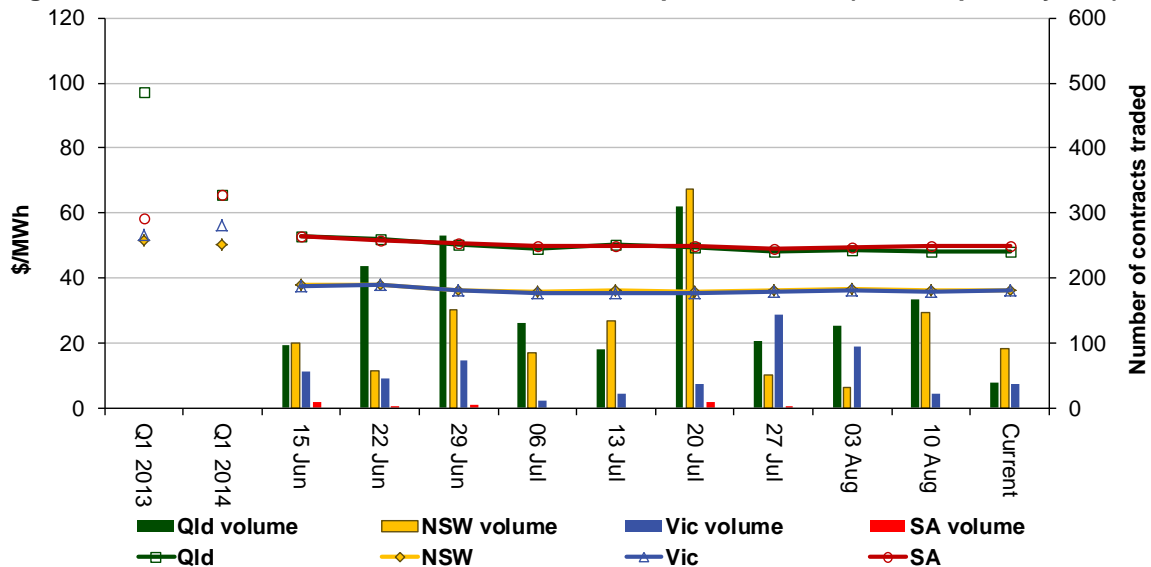
Figure 9: Quarterly base future prices Q3 2014 – Q2 2018



Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2015 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2013 and quarter 1 2014 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 2015 base contracts over the past 10 weeks (and the past 2 years)



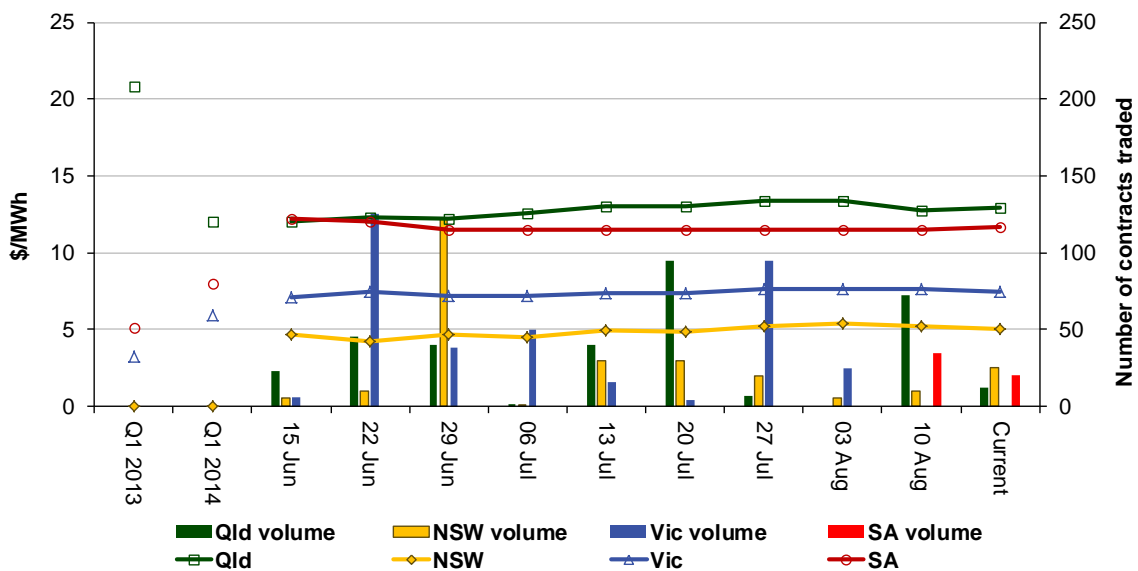
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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 2015 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2013 and quarter 1 2014 prices are also shown.

Figure 11: Price of Q1 2015 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

Australian Energy Regulator

September 2014