Electricity Report
16 – 22 August 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 16 to 22 August 2015. There were two occasions in South Australia and one occasion in Queensland where the spot price exceeded the AER reporting threshold. These are discussed later in this report. 2 negative spot prices were also recorded in Tasmania but these were not less than the -$100/MWh reporting threshold.

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

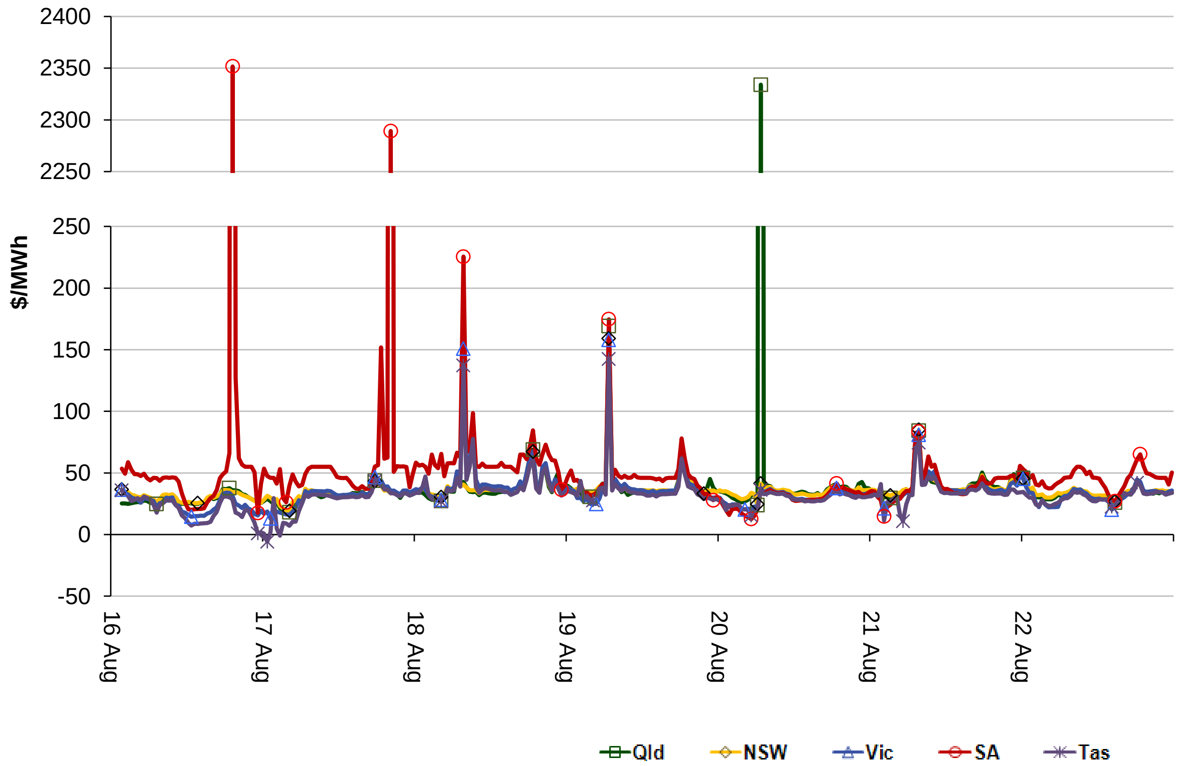


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

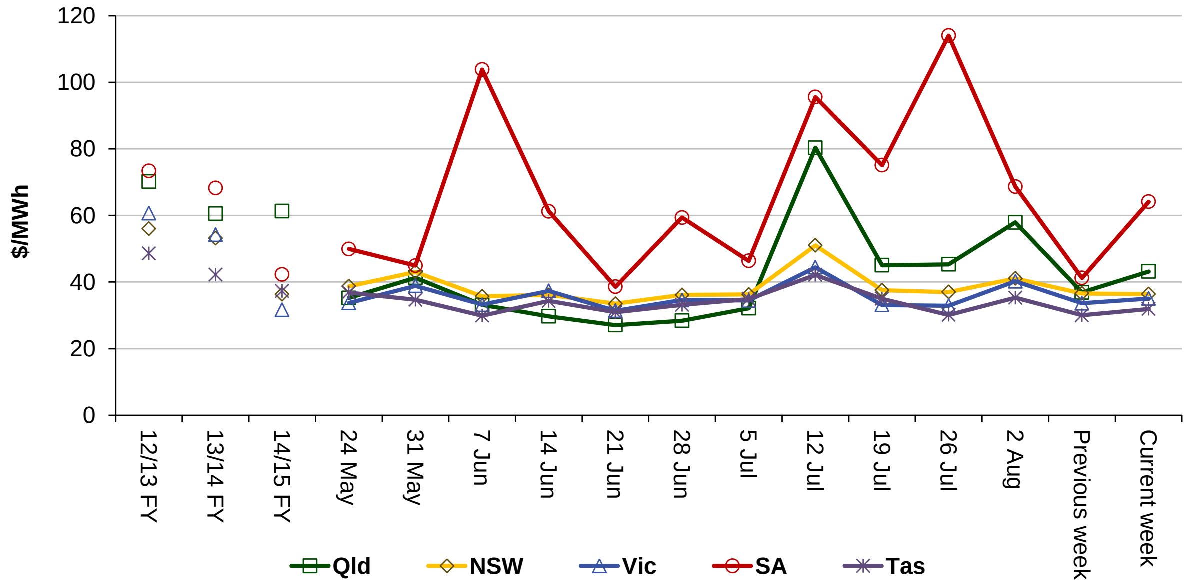


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	43	36	35	64	32
14-15 financial YTD	30	39	38	51	35
15-16 financial YTD	47	39	36	72	34

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 118 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

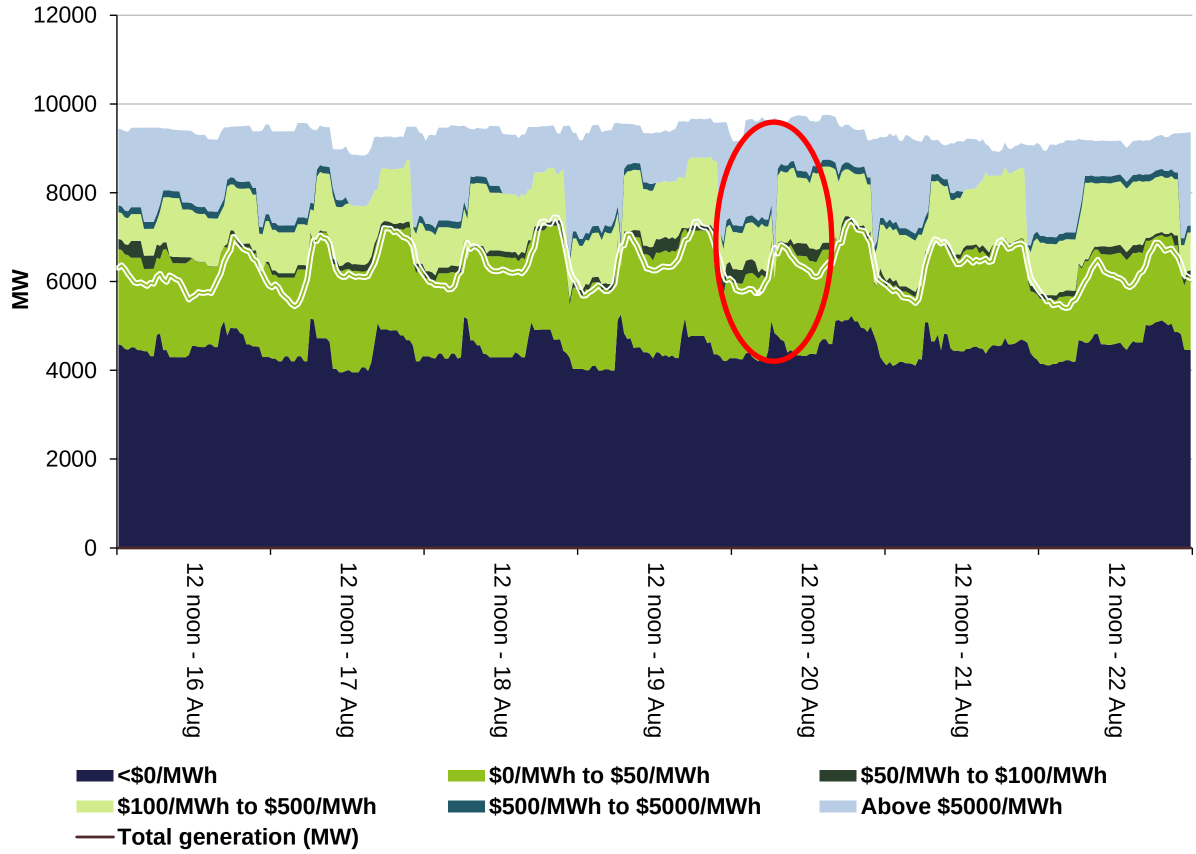
	Availability	Demand	Network	Combination
% of total above forecast	6	37	0	3
% of total below forecast	39	14	0	2

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



Red ellipses have been added to Figure 3 and Figure 6 to highlight the times where the rebidding has contributed to the high prices. These events are discussed in greater detail later in the report.

Figure 4: New South Wales generation and bidding patterns

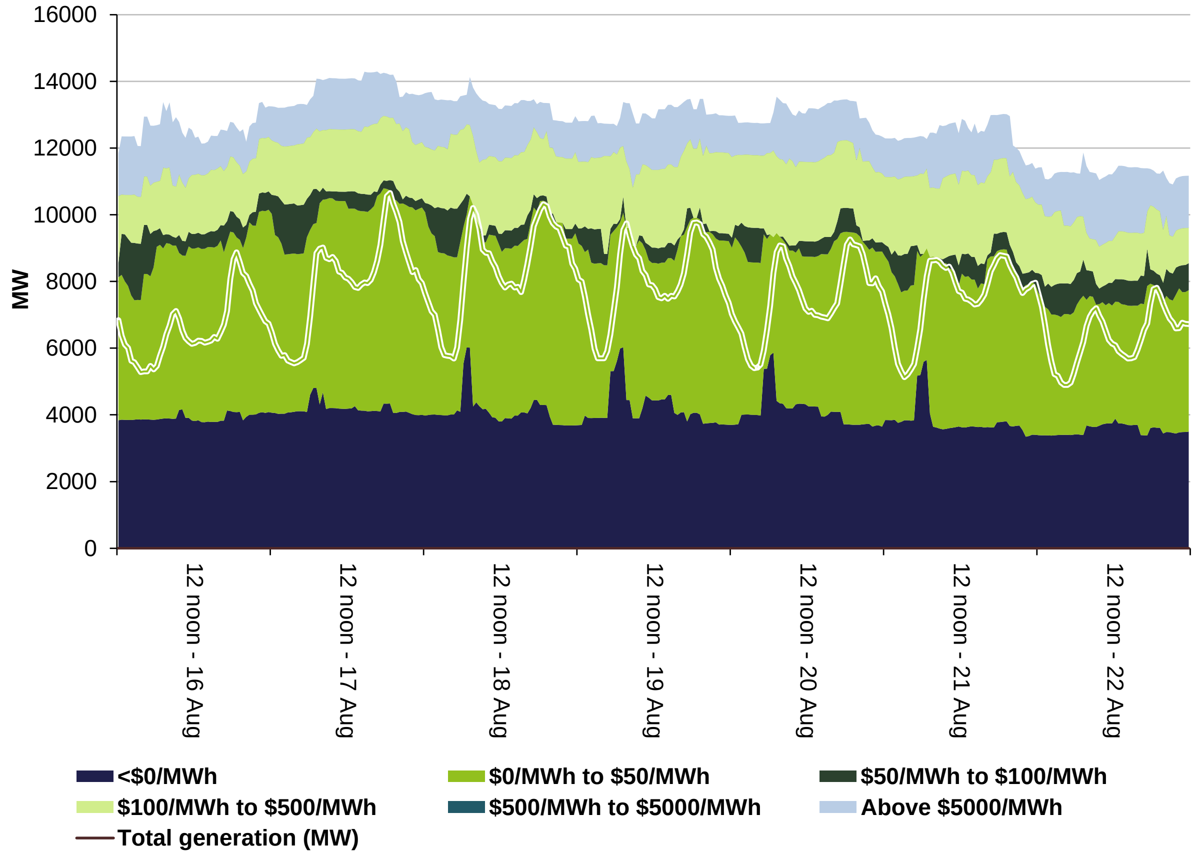


Figure 5: Victoria generation and bidding patterns

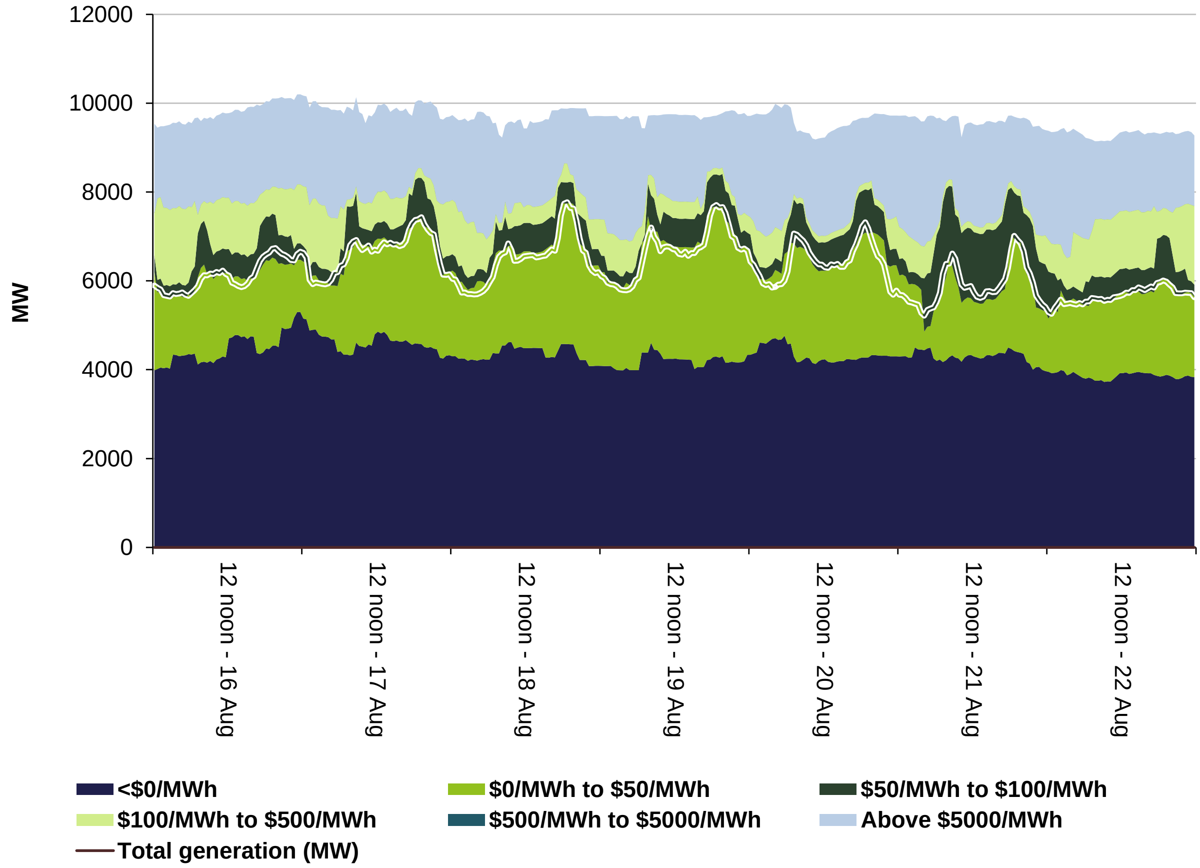


Figure 6: South Australia generation and bidding patterns

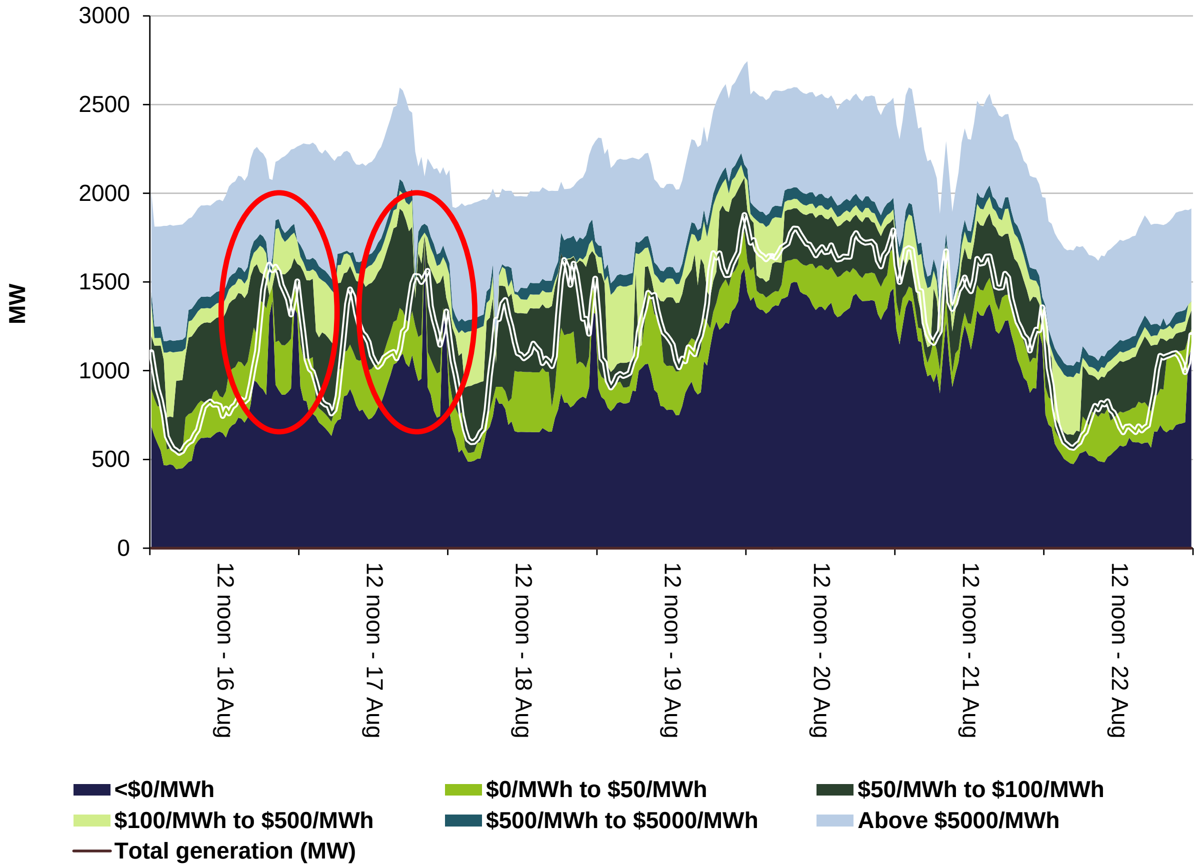
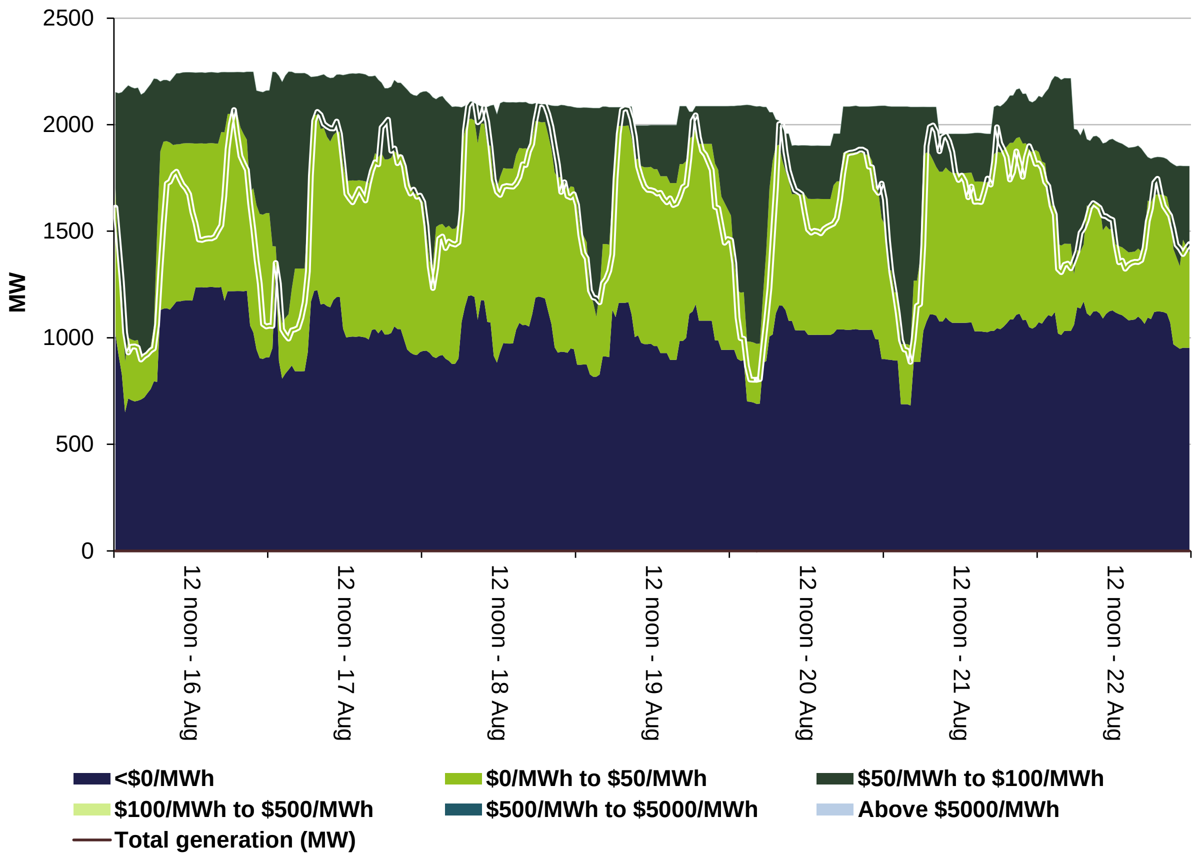


Figure 7: Tasmania generation and bidding patterns



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.

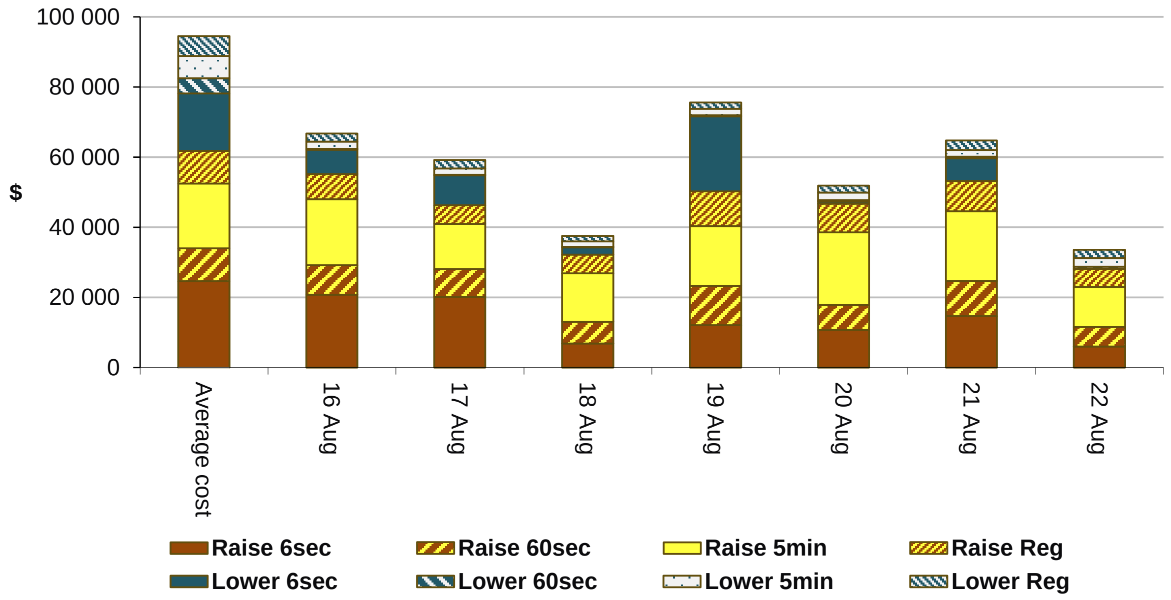
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $290 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $98 500 or around 1.5 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.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $64/MWh and above $250/MWh.

Sunday, 16 August

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
7.30 pm	2351.64	64.99	127.76	1813	1807	1811	2162	2190	2128

Demand and available capacity were close to that forecast four hours ahead. Both interconnectors into South Australia were importing at their limits with Heywood being limited to around 150 MW by a system normal constraint as forecast four hours ahead.

Table 4: Rebids for the 7.30 pm trading interval

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.16 pm	7.25 pm	AGL Energy	Torrens Island B	100	<65	13 800	1901~A~040 chg in AEMO disp~41 demand increase vs PD [SA1] [>60MW]PD18:31-19:01 for TI 9:30-20:00HRS

The dispatch price rose from $67/MWh at 7.20 pm to the price cap at 7.25 am following the above rebid by AGL, with all other available generation fully dispatched or ramp rate limited, Torrens Island set the price.

At 7.30 pm the dispatch price fell to $43/MWh as a result of a 130 MW decrease in demand (mostly from an increase in non-scheduled generation) and EnergyAustralia rebidding 46 MW of capacity to price bands below $300/MWh.

Monday, 17 August

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
8.30 pm	2289.21	64.99	94.80	1979	2051	2110	2143	2220	2242

Demand and available capacity were both slightly lower than that forecast four hours ahead.

Table 6: Rebids for the 10 pm trading interval

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
8.08 pm	8.15 pm	AGL Energy	Torrens Island	265	<95	>13 500	2010~A~040 CHG in AEMO DISP~41 demand increase stop of NS plant
8.12 pm	8.20 pm	AGL Energy	Torrens Island	265	>13 500	-1000	2005~A~050 chg in AEMO PD~56 price increase [SA] [$350.96] 5MPD vs PD

At 8.15 pm, the dispatch price rose to $13 500/MWh following the above rebid by AGL, with other available generation fully dispatched, ramp rate limited, or trapped in FCAS, Torrens Island set the price.

At 8.20 pm the dispatch price fell to $35/MWh as a result of a 110 MW decrease in demand (mostly from an increase in non-scheduled generation) and AGL reversed its previous rebid.

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $43/MWh and above $250/MWh.

Thursday, 20 August

Table 9: 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	2333.90	33.75	31.50	6382	6313	6239	9679	9801	9801

Demand was 69 MW higher and available capacity was 122 MW lower than that forecast four hours ahead. Both interconnectors were delivering at their limit into Queensland with QNI being constrained, by an outage of the Armidale Static Var Compensator in New South Wales, to around 90 MW as forecast.

Table 10: Rebids for 7 am trading interval

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.44 am		RTA Yarwun	Yarwun	105	-971	N/A	GT commissioning
5.14 am		RTA Yarwun	Yarwun	60	-971	N/A	GT commissioning
6.36 am	6.45 am	Millmerran	Millmerran	230	7	13 800	06:33 a change in 5MIN PD demand - SL
6.40 am	6.50 am	Callide	Callide C	93	-1000	13 800	0635A change in 5MIN PD demand - SL
6.45 am	6.55 am	CS Energy	Callide B, Gladstone	175	<17	13 800	0644A dispatch price higher than 30MIN forecast-SL

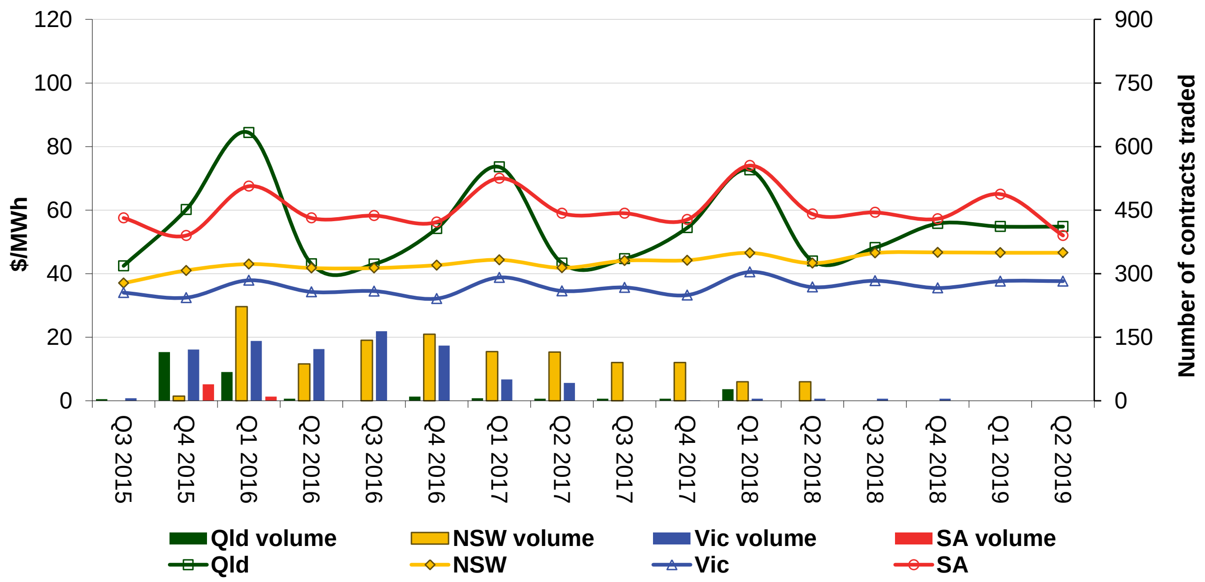
Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.52 am	7 am	CS Energy	Gladstone	200	0	13 800	0651A 5MIN PD higher than 30MIN PD-SL

Rebidding during the trading interval gradually increased the steepness of the supply curve, resulting in the 7.30 pm dispatch price increasing to the cap following a 96 MW increase in demand with low priced generation fully dispatched or ramp rate limited at the time.

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.

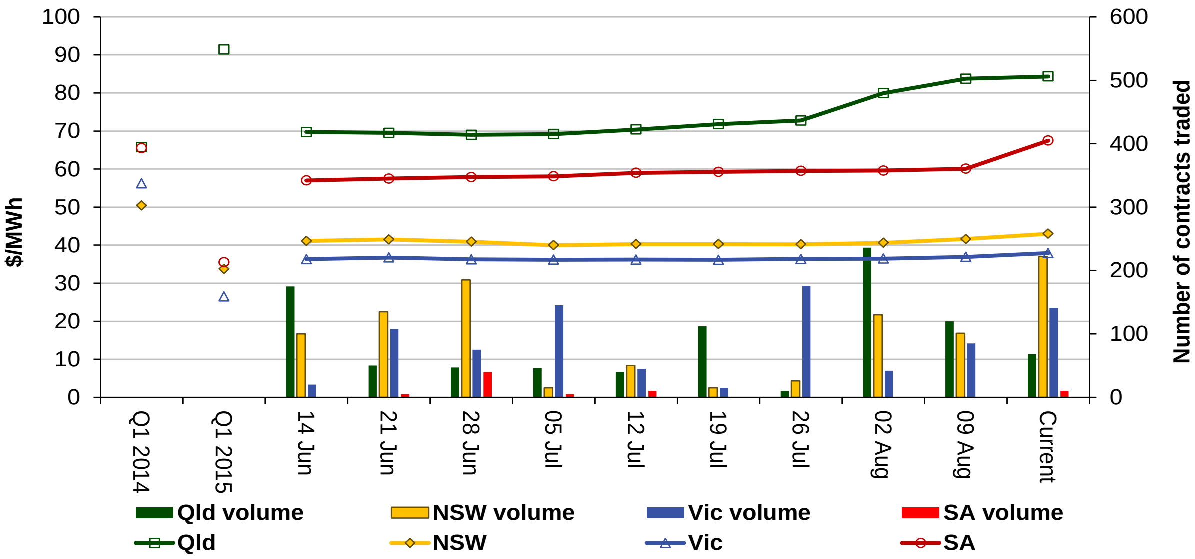
Figure 9: Quarterly base future prices Q3 2015 – Q2 2019



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)



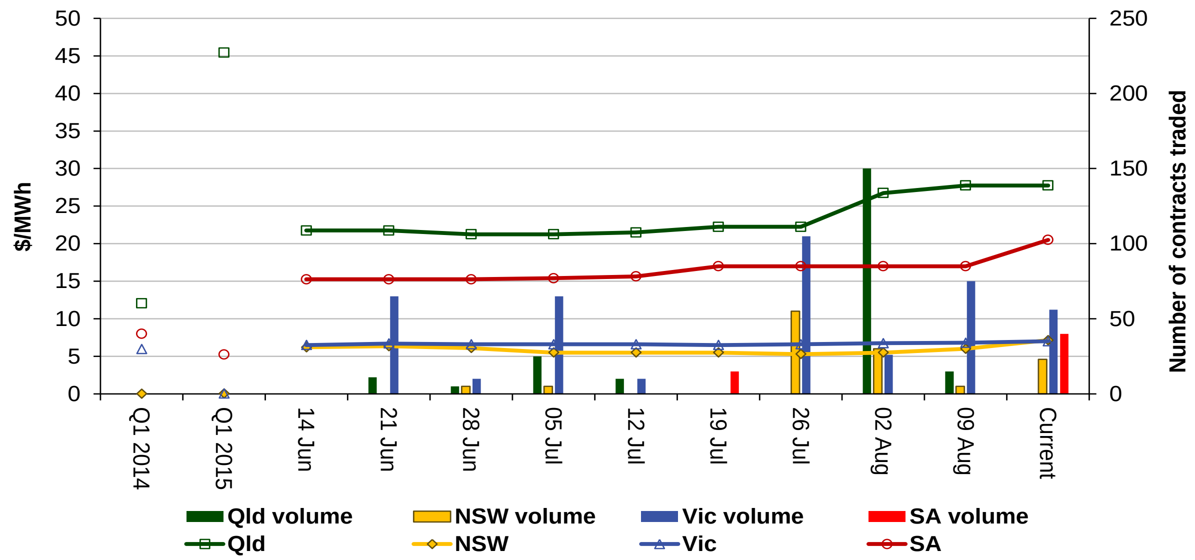
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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

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