Electricity Report

29 June to 5 July 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.

Weekly Spotlight

From 1 July, the market price cap increased from $13 100/MWh to $13 500/MWh in line with CPI.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 29 June to 5 July 2014. The spot price reached $1966/MWh in South Australia on 1 July.

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

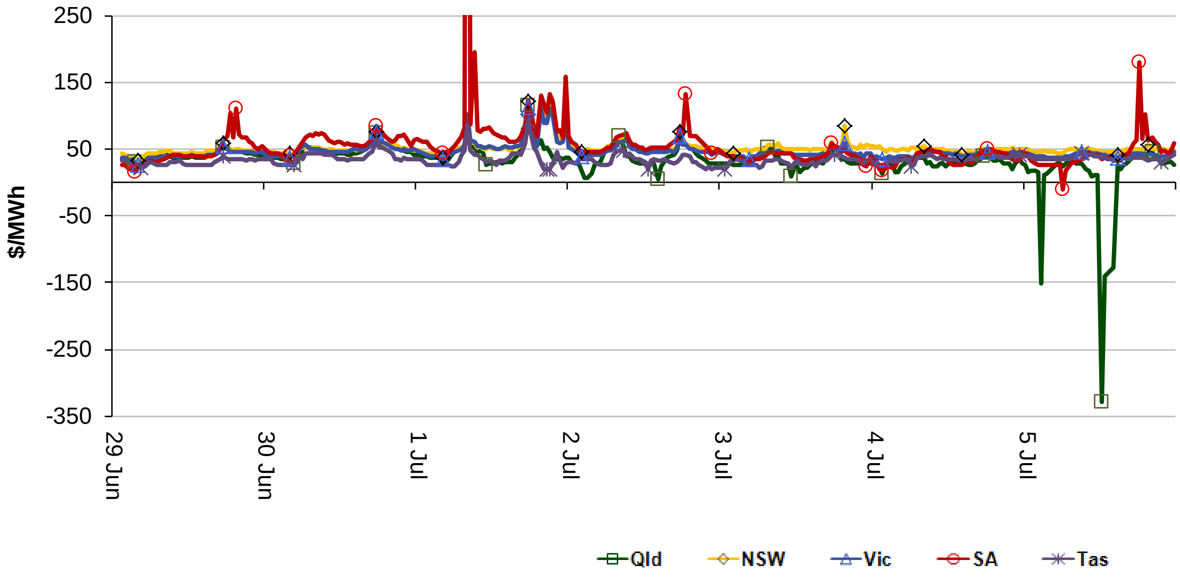


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

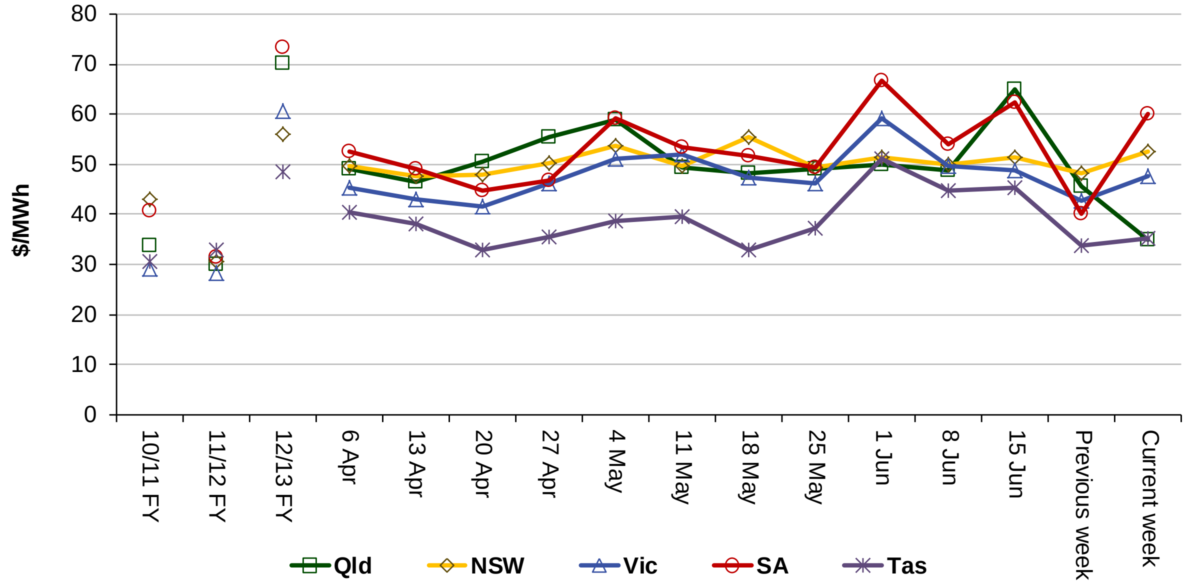


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	35	53	48	60	35
12-13 financial YTD	70	56	61	73	49
13-14 financial	61	53	54	68	42

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 80 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

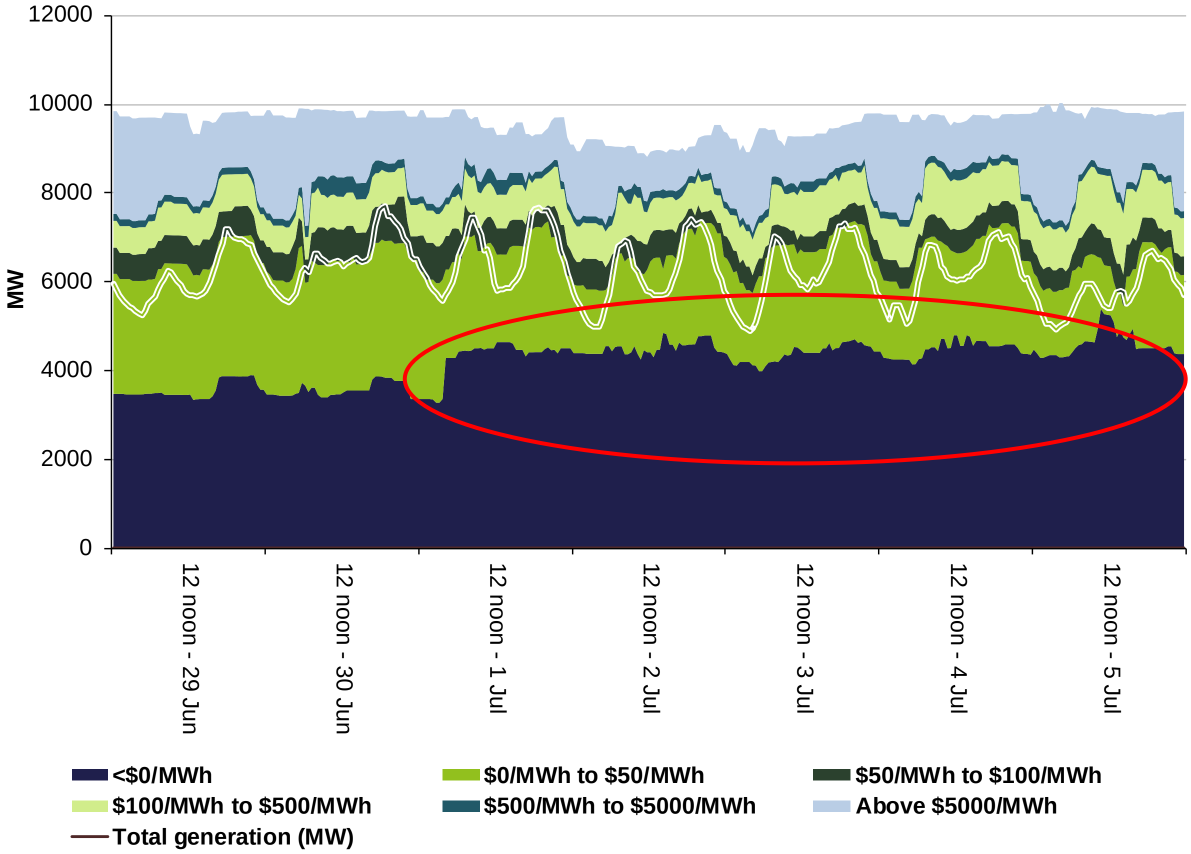
	Availability	Demand	Network	Combination
% of total above forecast	13	34	0	3
% of total below forecast	12	27	0	11

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. 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



A change in CS Energy's offer profile saw an increase of around 900 MW in energy offers priced just below $0/MWh from 1 July 2014, contributing to lower prices in the Queensland region this week.

Figure 4: New South Wales generation and bidding patterns

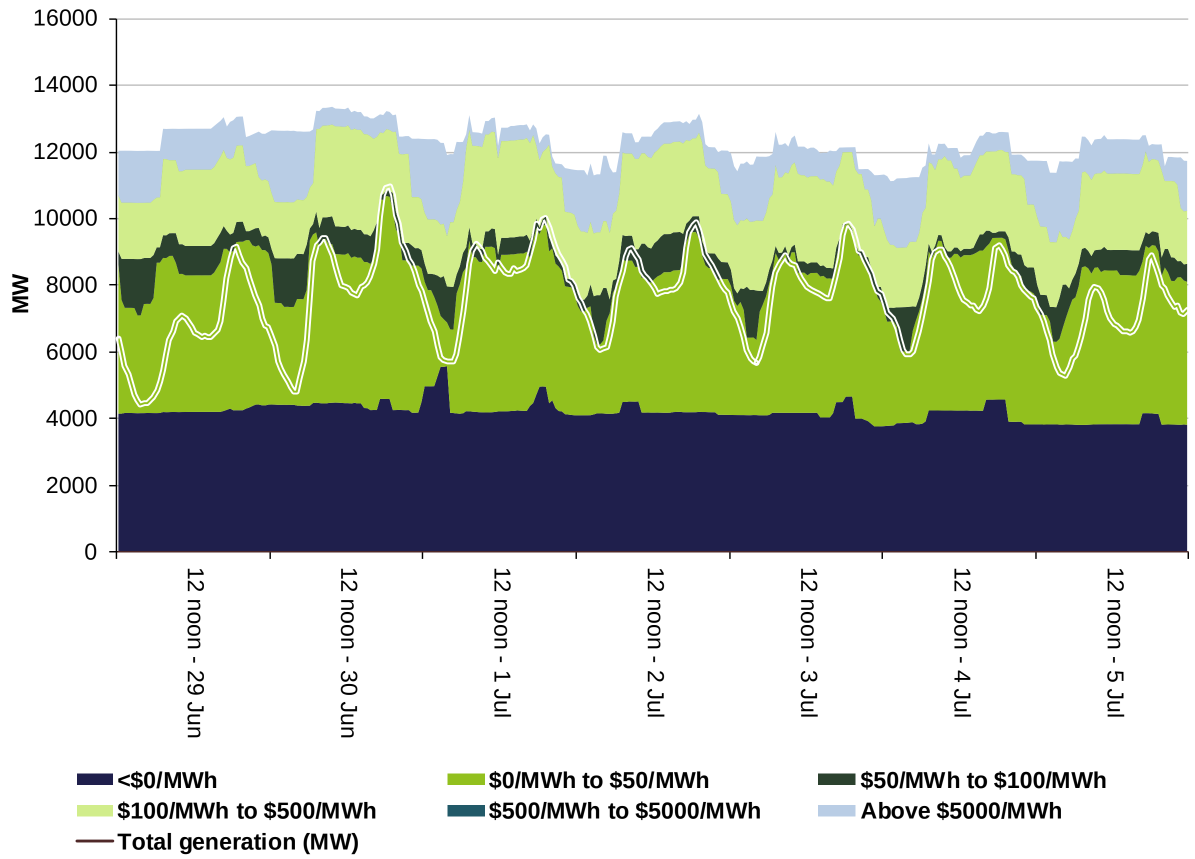


Figure 5: Victoria generation and bidding patterns

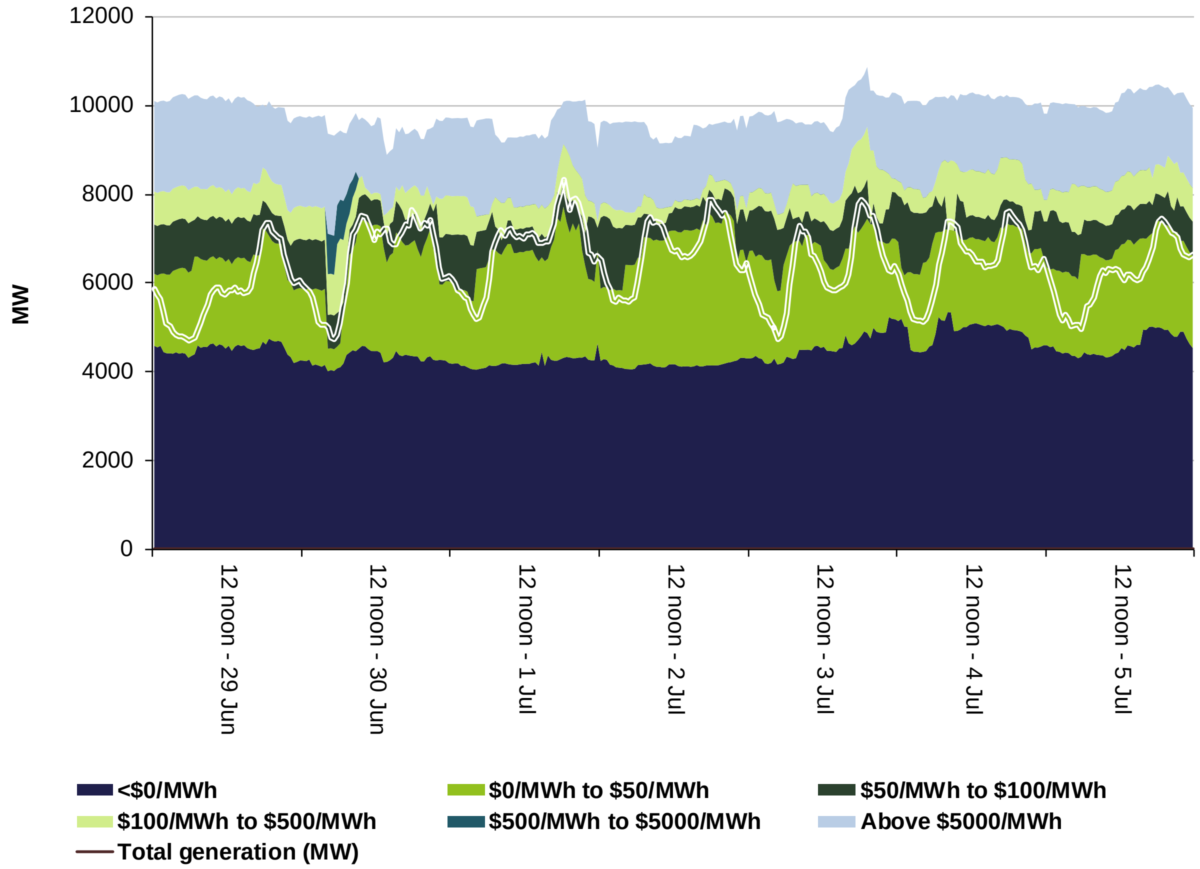
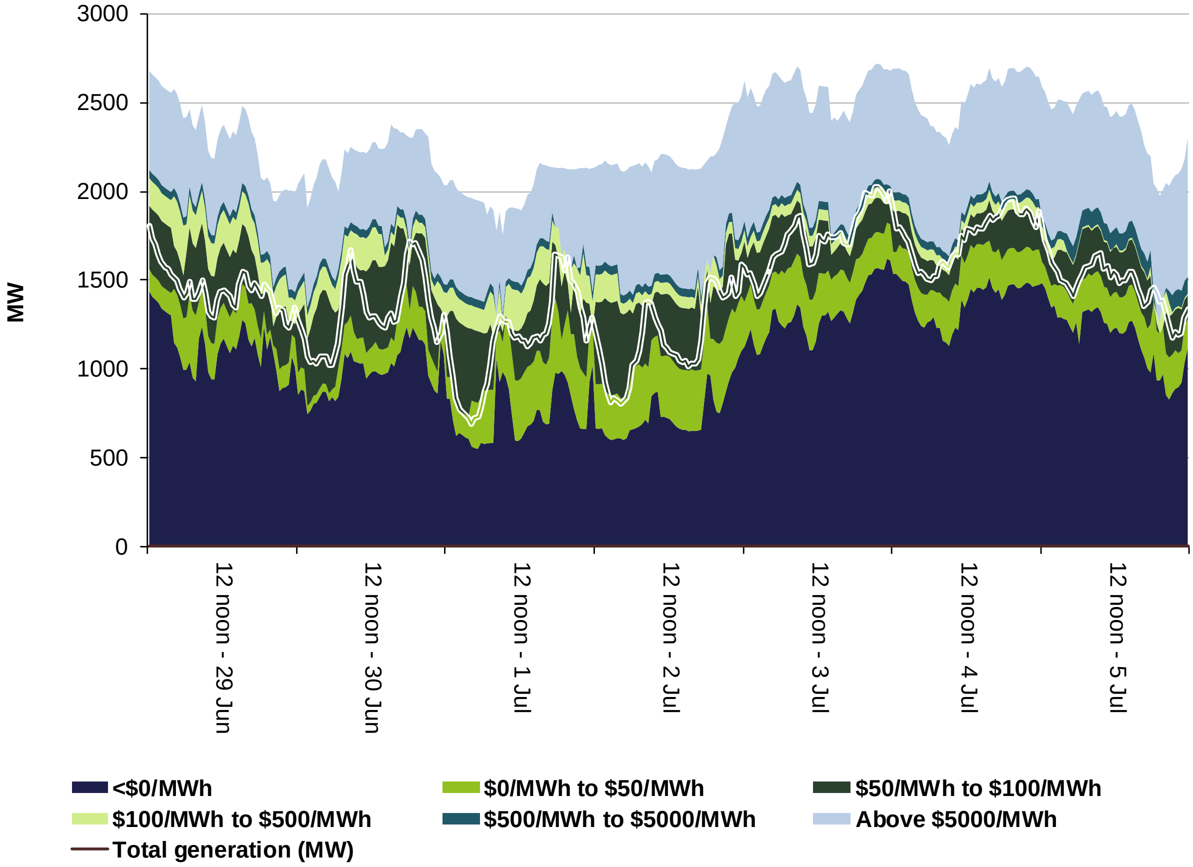
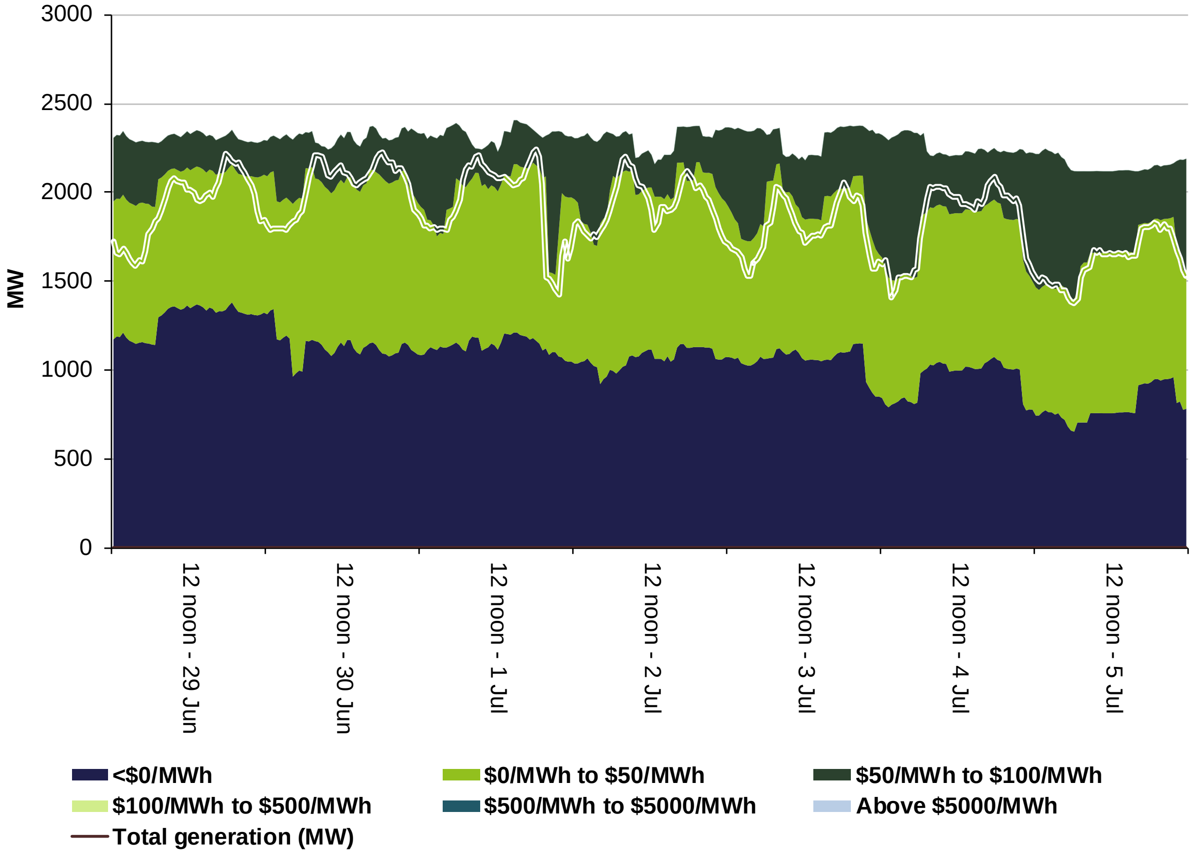


Figure 6: South Australia generation and bidding patterns



On 3 July wind generation in South Australia reached a new record of 1339 MW at 9.30 pm.

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.

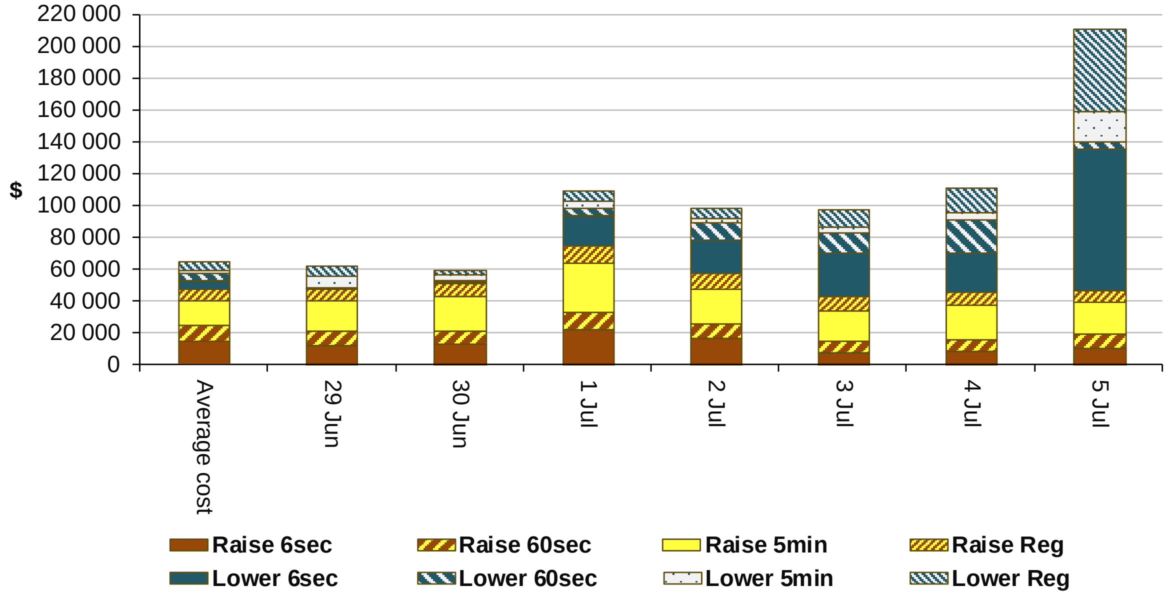
The total cost of FCAS on the mainland for the week was $710 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $35 000 or less than 1 per cent of energy turnover in Tasmania.

A number of days saw high FCAS prices in Queensland from 1 July due to a planned outage on one of the Dumaresq to Bulli Creek and Bulli Creek to Braemar 330 kV lines. QNI exports to New South Wales were reduced to ensure sufficient FCAS availability in Queensland in the event of a loss on the remaining Dumaresq to Bulli Creek to Braemar 330kV lines. This would isolate Queensland from the rest of the market as the Terranora interconnector is still out of service. This resulted in Lower services in Queensland reaching prices of up to $1001/MW on 5 July.

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 were six occasions where the spot price in Queensland was below -$100/MWh and one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of $60/MWh and above $250/MWh.

Table 3: Queensland, Saturday 5 July

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
3.00 AM	-151.27	18.49	16.94	4566	4503	4508	10 011	9937	9755
12.30 PM	-328.02	16.94	17.9	4866	4936	5016	9893	9893	9921
1.00 PM	-140.16	12.56	16.94	4870	4858	4986	9876	9893	9911
1.30 PM	-136.07	16.94	16.94	4899	4886	4972	9883	9893	9901
2.00 PM	-130.54	16.94	16.94	4912	4876	4985	9850	9893	9891
2.30 PM	-126.76	12.56	16.94	4958	4863	4995	9833	9896	9894

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

On 1 July a planned outage of one of the Dumaresq to Bulli Creek and Bulli Creek to Braemar 330 kV lines commenced. Constraints were invoked to manage the lower FCAS requirements (see Frequency control ancillary services section above) by limiting exports from Queensland to New South Wales and the Terranora interconnector was still out of service.

At 2.55 am there was a 74 MW reduction in demand and a 55 MW reduction in exports to New South Wales. With a number of generators ramp down limited or trapped in FCAS, generators priced at the floor set the price at 2.55 am.

From 11.40 am, CS Energy made a number of rebids across its portfolio shifting large amounts of capacity to the price floor (shown in the table below).

Table 4: CS Energy rebids, Saturday 5 July

Time of rebid	TI effective	From Price ($/MWh)	To Price ($/MWh)	Capacity (MW)	Reason
11.40 AM	12.30 PM 1.00 PM	0-12	-1000	1570	1138A 30 min predispatch prices lower than forecast-sl
12.58 PM	1.30 PM	0-12	-1000	1550	1255A 30 min predispatch prices lower than forecast-sl
1.24 PM	2.00 PM	0	-1000	850	1322A 30 min predispatch prices lower than forecast-sl

Time of rebid	TI effective	From Price ($/MWh)	To Price ($/MWh)	Capacity (MW)	Reason
1.26 PM	2.00 PM	0-12	-1000	600	1326A 30 min predispatch prices lower than forecast-sl
2.03 PM	2.30 PM	0-12	-1000	1450	1402A 30 min predispatch prices lower than forecast-sl

These rebids meant there was around 5000 MW of available capacity in Queensland priced at the price floor between 12.05 pm and 2.30 pm. This combined with low demand of around 4900 MW and limited export capability saw the five minute price fall to the price floor on six occasions from 12.25 pm to 2.05 pm.

There was no other significant rebidding.

Table 5: South Australia, Tuesday 1 July

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 AM	1 966.12	79.45	70.79	1 794	1 754	1 759	1 797	1 937	1 983

Conditions at the time saw demand close to forecast and available capacity 140 MW below that forecast four hours ahead.

Imports into South Australia from Victoria were at their limits across both interconnectors and wind generation was around 15 MW.

At 8.09 am, effective from 8.20 am, Alinta Energy rebid 93 MW of available capacity at Northern unit 1 from price bands below $50/MWh to above $10 700/MWh. The reason given was “0807A sa spot $209 vs pd $106@08:08”.

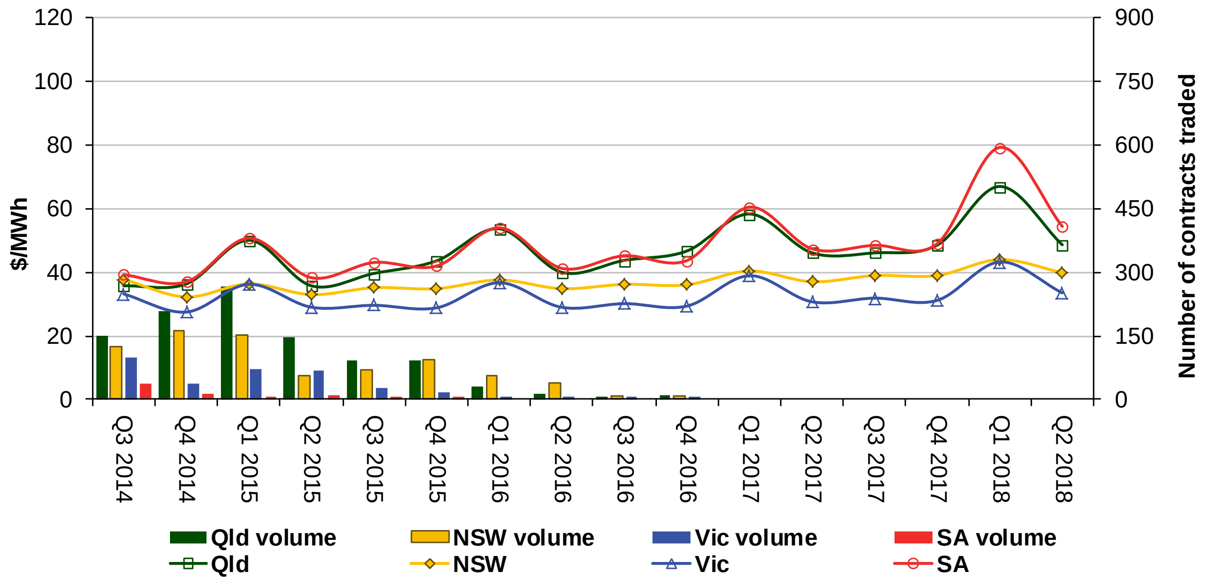
At 8.20 am the five minute price reached $11 000/MWh, being set by Northern unit 1. The following interval saw additional scheduled generation come online and increased output from non-scheduled units at Angaston and Point Stanvac (up to 102 MW), resulting in dispatch prices decreasing below $135/MWh.

There was no other 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.

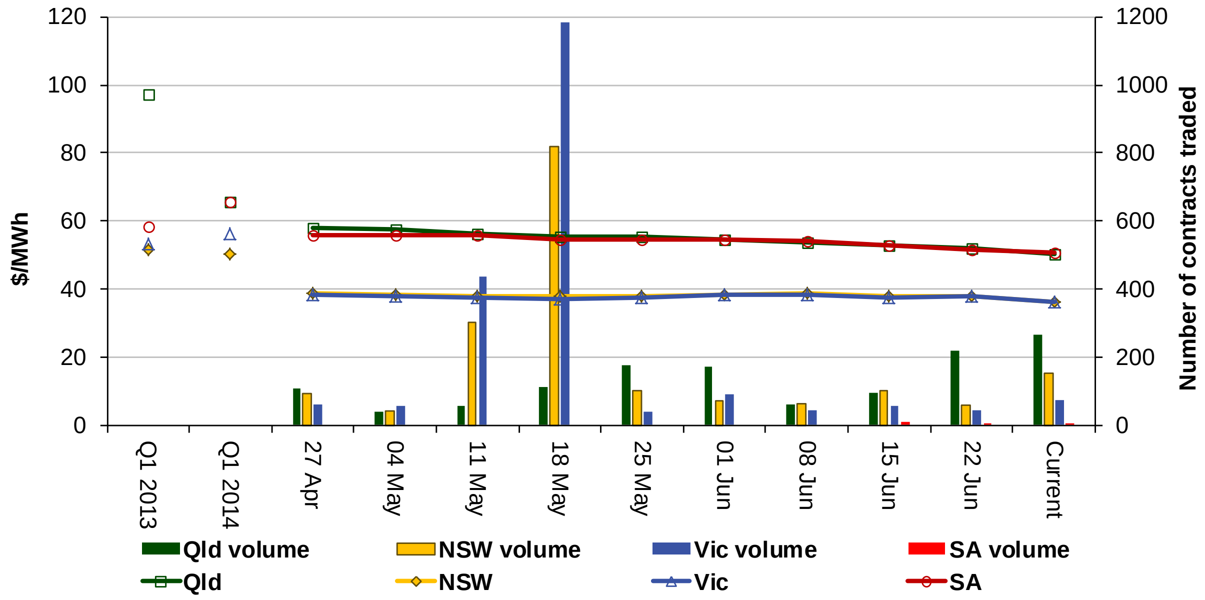
Figure 9: Quarterly base future prices Q3 2014 – Q2 2018



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)



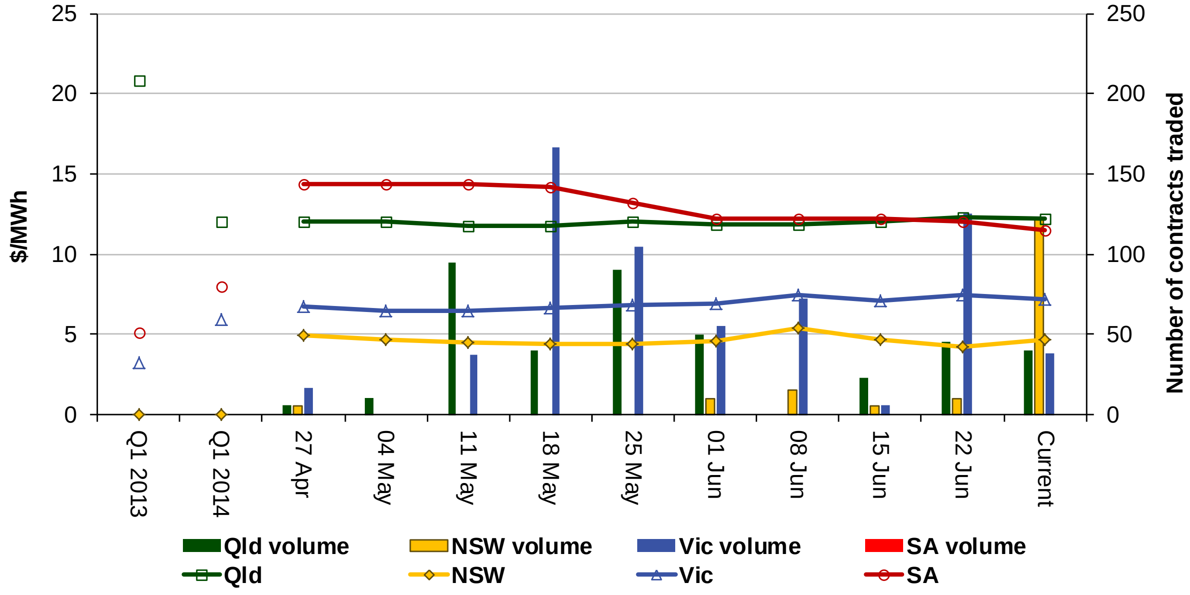
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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

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