

# Electricity Report

8 to 14 September 2013



## 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

### Summary

On 8 and 10 September the planned outage of the Heywood to Portland to Tarrone No. 1 500 kV line combined with generation at Mortlake power station led to large requirements for local Frequency Control Ancillary Service (FCAS) in South Australia. The price for local lower FCAS in South Australia exceeded \$5000/MW on 12 occasions for a total cost of around \$980 000, which is paid for by South Australian customers.

Generation at Mortlake at the same time as the Heywood-Portland-Tarrone line outage requires higher exports across Heywood into Victoria to manage voltage conditions at the Portland (APD) 500 kV busbar. Exports from South Australia, across the Heywood interconnector, to Victoria increase the Lower FCAS services requirement in South Australia. If the Heywood interconnector was to fail under export conditions from South Australia, then local “lower” services would be required to rapidly reduce local generation and lower the frequency. To manage this, lower contingency FCAS must be sourced from suppliers in South Australia (typically generators) in proportion to the flow across the interconnector from South Australia to Victoria.

There are only three power stations registered to provide the Lower FCAS in South Australia:

- Northern Power Station (owned by Alinta Energy);
- Torrens Island A and B (owned by AGL); and
- Pelican Point Power Station (owned by GDF Suez).

On both days Northern Power station and five Torrens Island units were offline and, therefore, unable to provide FCAS.

AGL, through Torrens Island is the most significant provider of lower frequency control services in South Australia. On the days in question, through day-ahead offers (and rebidding), AGL offered, the majority of the capacity for these services above \$5000/MW.

### 8 September

On 8 September Mortlake was forecast to start generating after the Heywood-Portland-Tarrone outage had been completed at 5.30 pm. At around 5 pm the network outage was extended. At 5.40 pm Mortlake received a target to generate and by 5.50 pm was targeted at 180 MW. Flow on the Heywood interconnector changed from importing 250 MW into South Australia at 5.45 pm to forced

export of 55 MW to Victoria at 5.50 pm. South Australia requires Local FCAS lower services when power flows from South Australia to Victoria which could only be met by high-priced capacity and the price exceeded \$5000/MW as shown in the below table. These prices were not forecast

**Spotlight Table 1: Lower FCAS requirements and prices**

Time	Lower reg		Lower 6 sec		Lower 60 sec		Lower 5 min	
	Requirement MW	Price \$/MW	Requirement MW	Price \$/MW	Requirement MW	Price \$/MW	Requirement MW	Price \$/MW
5.55 pm	38.72	1.5	72	13100	121.45	13100	30	0.9
6 pm	90	9000	72	13100	153	13100	50.17	9000

**10 September**

At around 3.55 pm ramping constraints were invoked in preparation for the outage which forced flow out of South Australia into Victoria. By 4.35 pm flows were being forced into Victoria at 106 MW. This led to an increase in requirements for lower 60 sec services which could only be met by high-priced capacity and the price reached the price cap as shown in the table below. These prices were forecast.

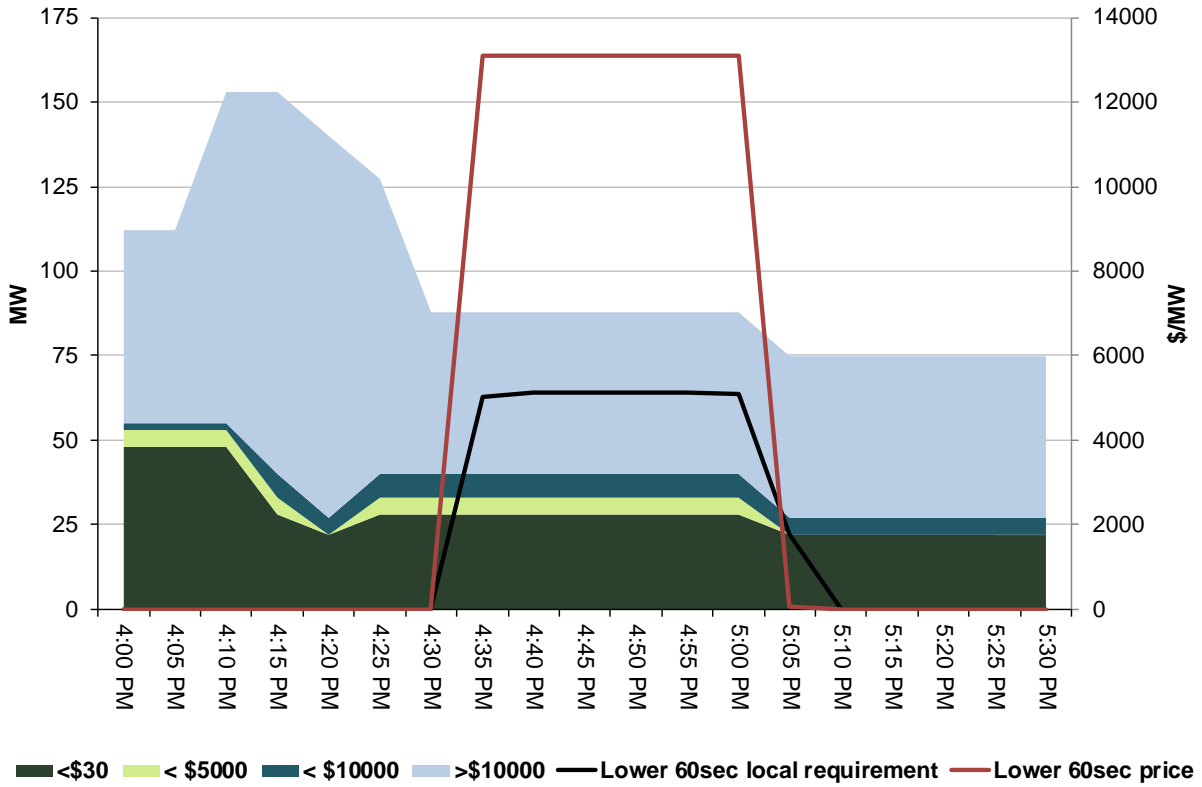
**Spotlight Table 2: Lower FCAS requirements and prices**

Time	Lower 60 sec	
	Requirement MW	Price \$/MW
4.35 pm	62.83	13100
4.40 pm	64.1	13100
4.45 pm	64.24	13100
4.50 pm	64.23	13100
4.55 pm	64.1	13100
5 pm	63.44	13100

**Rebidding**

At 4.05 pm AGL rebid 20 MW of lower 60sec services from prices below \$1/MW to above \$9000/MW (15 MW at the price cap). The reasons given were “15:40A chg in forecast::price incr sa lower60 \$13100 5MPD VS PD”.

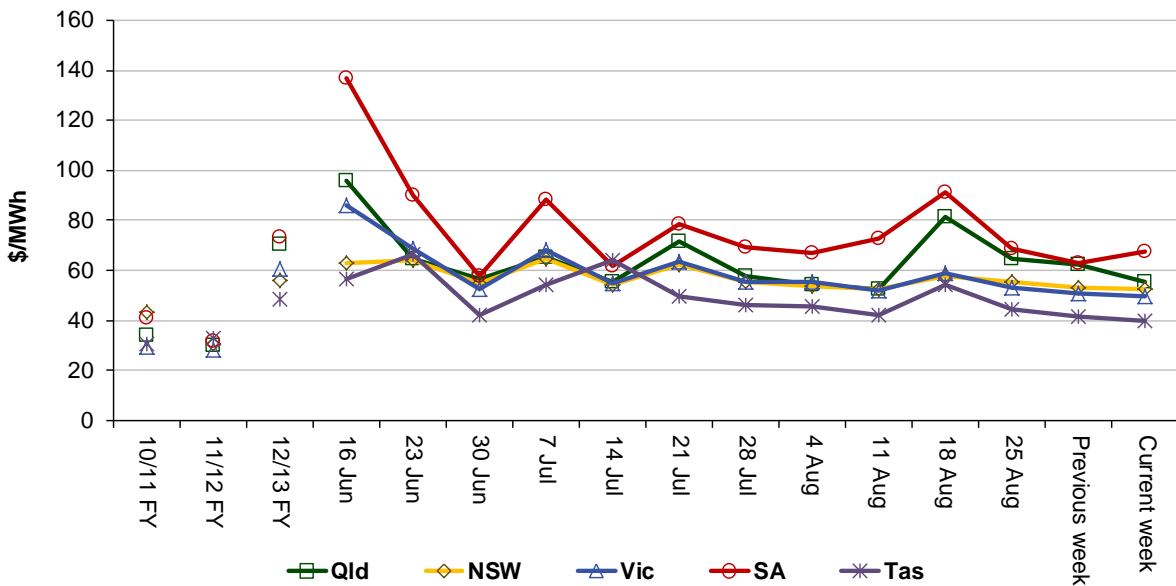
**Spotlight Figure 1: Lower 60 second services effective offers, requirement and price in South Australia for 10 September**



### Spot market prices

Figure 1 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 1: Volume weighted average spot price by region (\$/MWh)**



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

Region	Qld	NSW	Vic	SA	Tas
<b>Current week</b>	55	52	50	67	40
<b>12-13 financial YTD</b>	59	61	65	71	52
<b>13-14 financial YTD</b>	62	56	56	72	47

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 40 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2012 of 60 counts and the average in 2011 of 78. 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**

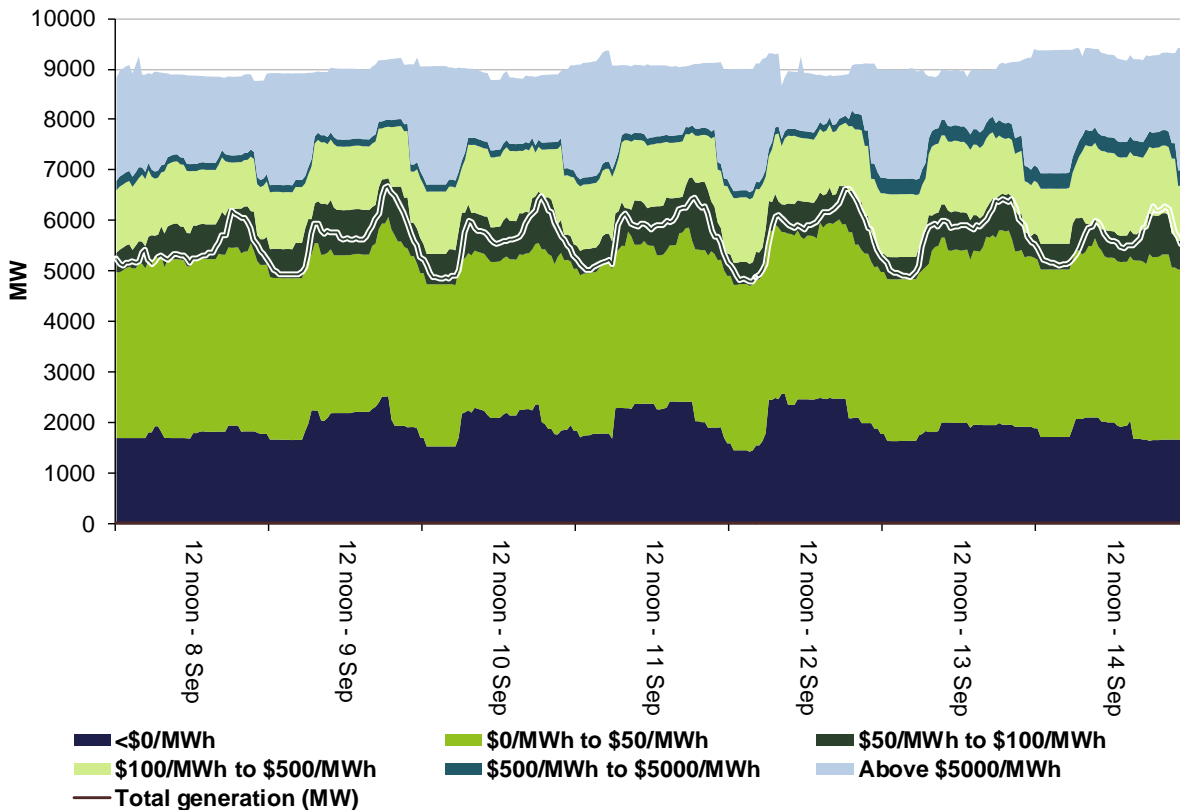
Reason for variation	Availability	Demand	Network	Combination
<b>% of total above forecast</b>	9	8	0	3
<b>% of total below forecast</b>	23	56	0	0

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

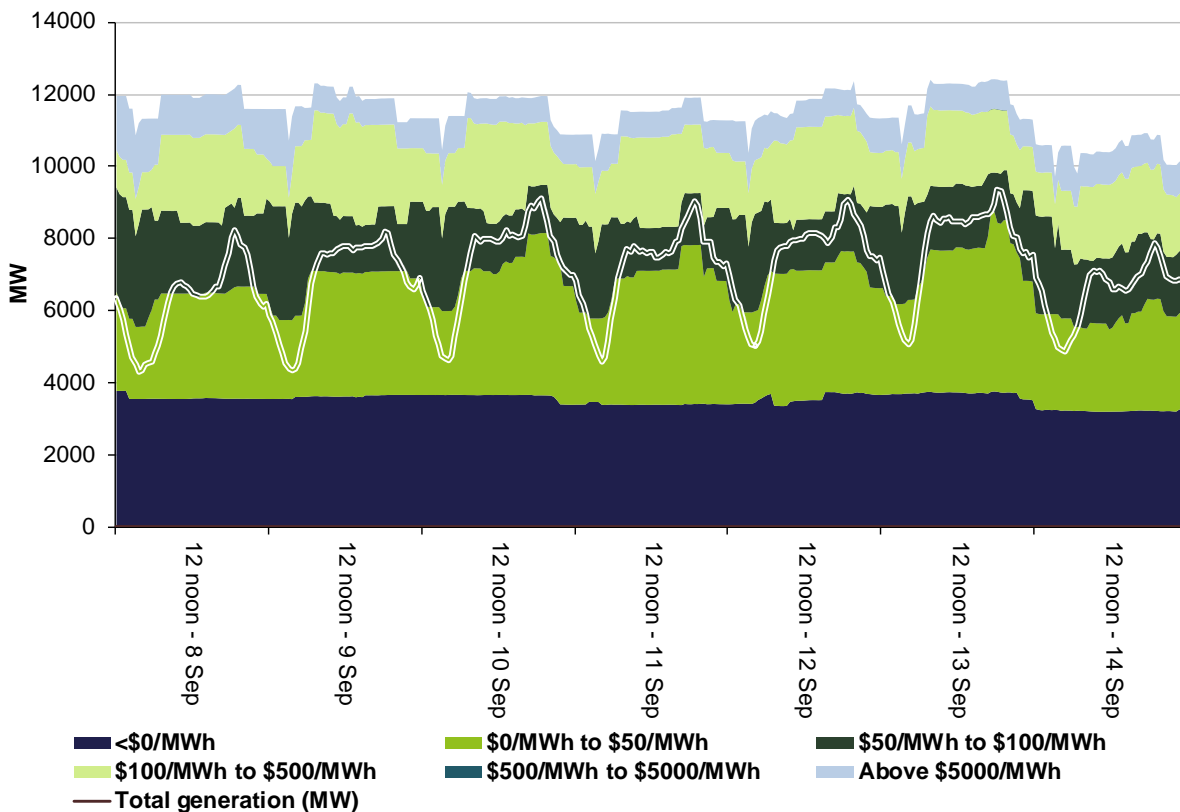
## Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figures 2 to 6 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

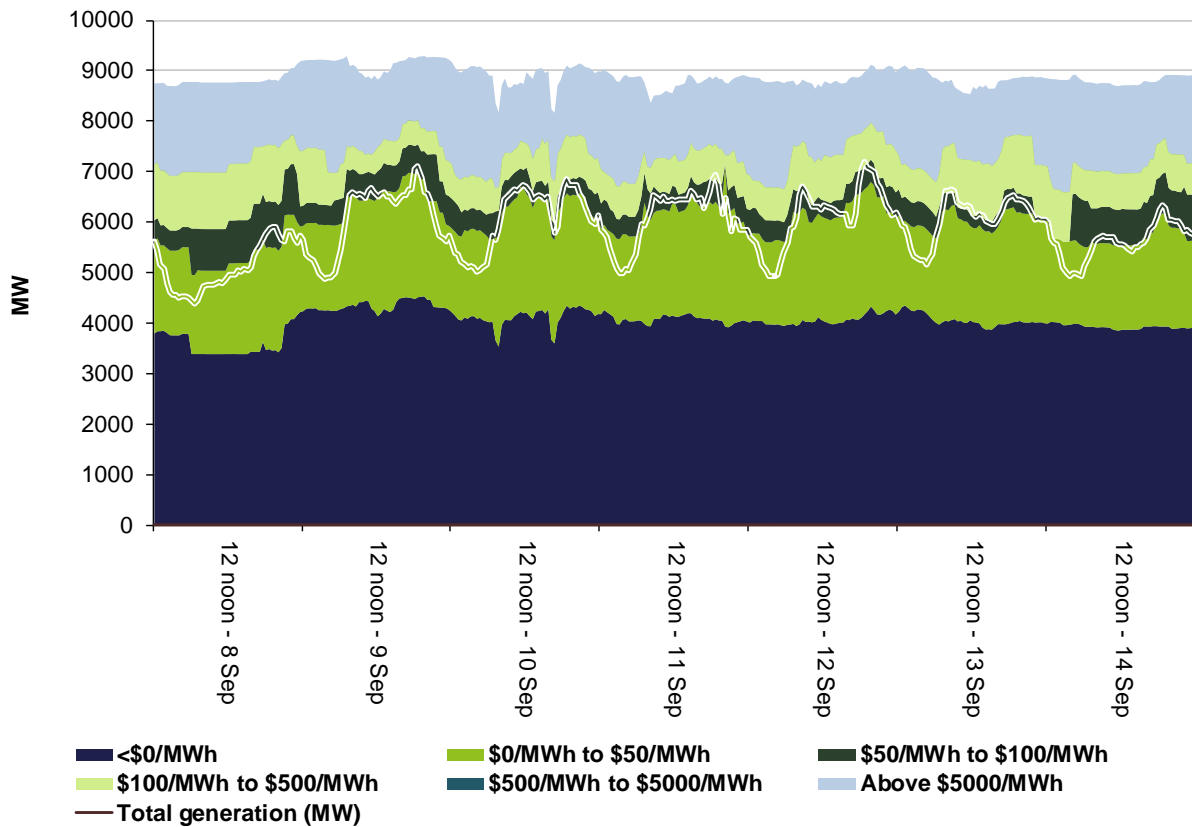
**Figure 2: Queensland generation and bidding patterns**



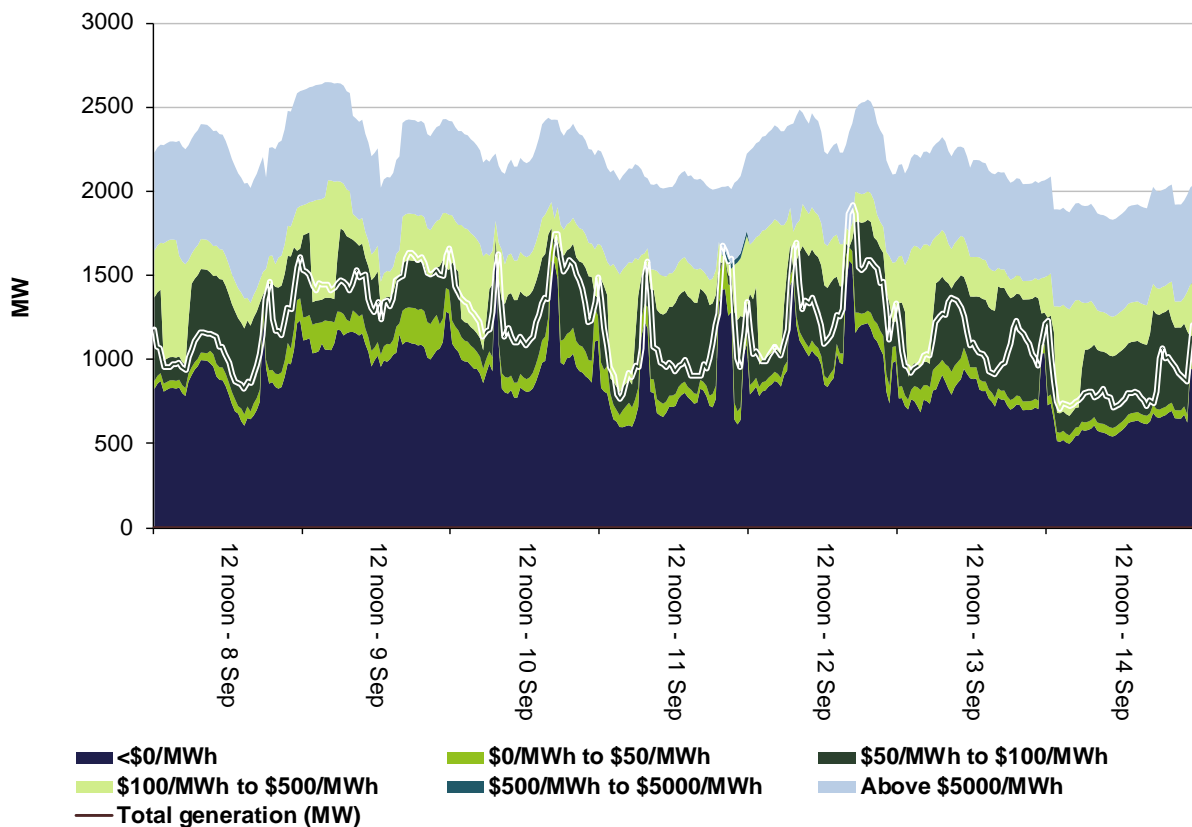
**Figure 3: New South Wales generation and bidding patterns**



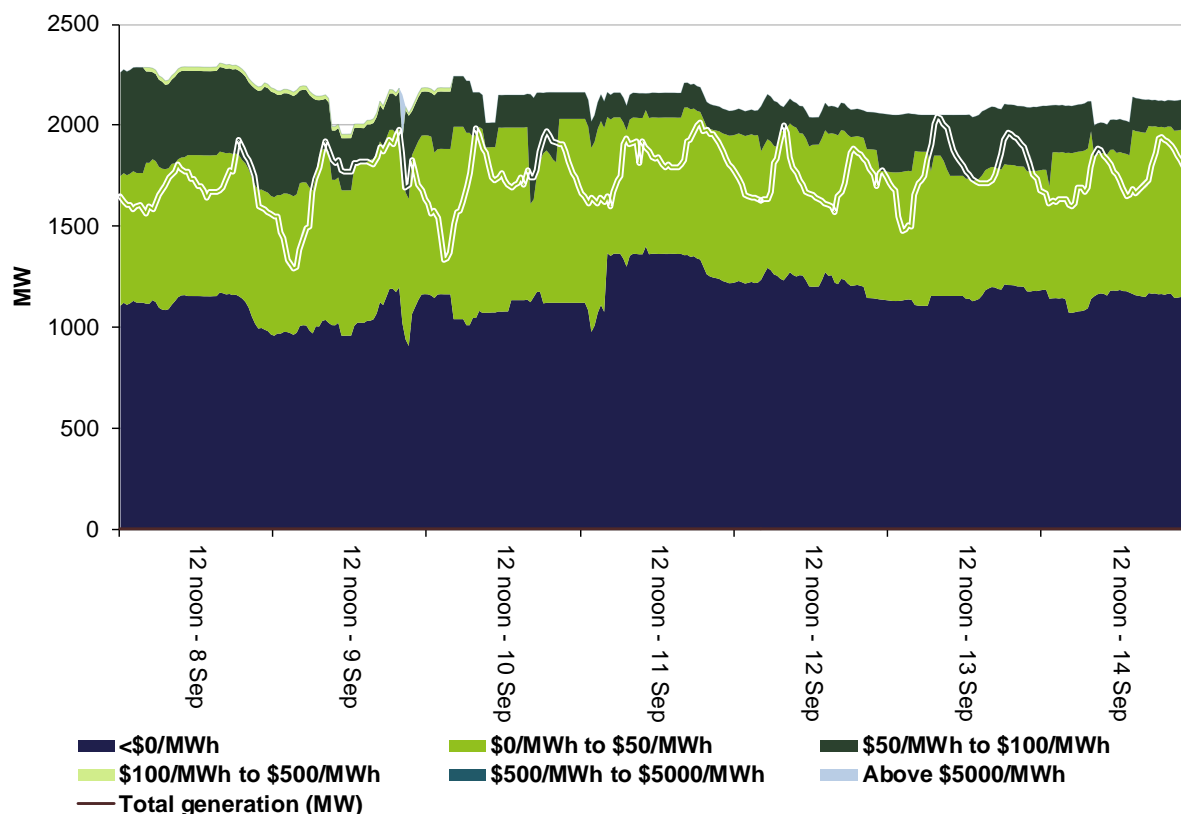
**Figure 4: Victoria generation and bidding patterns**



**Figure 5: South Australia generation and bidding patterns**



**Figure 6: 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.

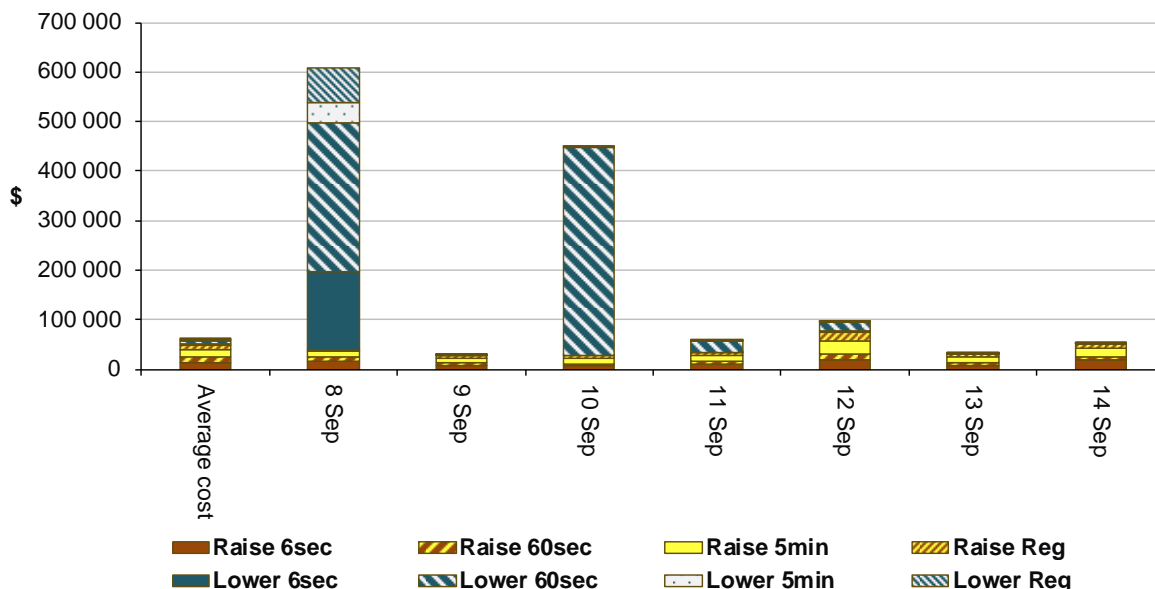
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$1.3 M or less than 1 per cent of energy turnover on the mainland. A majority of this cost (\$982 000) accrued in South Australia on 8 and 10 September for lower services. See the weekly spotlight for detailed analysis.

In Tasmania (which requires dedicated services for much of the time) the total cost for the week was \$40 500 or less than 1 per cent of energy turnover in Tasmania.

Figure 7 shows the daily breakdown of costs for each service, as well as the average daily costs for the previous financial year.

**Figure 7: 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 three such occasions this week in South Australia.

### Sunday 8 September

**Table 3: South Australia, Sunday 8 September**

6 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	350.07	56.51	56.69
Demand (MW)	1169	1235	1185
Available capacity (MW)	2203	2174	2169

Demand and available capacity were close to forecast.

Earlier in the day the Heywood to Portland to Tarrone No. 1 500kV line was taken out of service on a planned outage and was due to return to service at 5.30 pm. AEMO invoked a constraint to manage this outage which only effects Mortlake Power Station and the Heywood interconnector.

Mortlake was to commence generation at 5.35 pm (after the outage was complete) with all its capacity priced either at the price floor or around \$50/MWh.



At around 5 pm the outage was extended. At 5.40 pm Mortlake received a target to generate and by 5.50 pm was targeted at 180 MW. The Heywood interconnector changed from importing 250 MW into South Australia at 5.45 pm to 55 MW forced export to Victoria at 5.50 pm to offset the increase in Mortlake generation. The step change across Heywood was not enough to meet the constraint requirements and the constraint violated between 5.50 pm and 6 pm. This saw the 5 minute price reach \$768/MWh at 5.50 pm, \$398/MWh at 5.55 pm and \$753/MWh at 6 pm.

The above conditions led to an increase in the requirement for lower FCAS in South Australia.

Prices returned to previous levels at 6.05 pm after Origin rebid all capacity at Mortlake to around \$120/MWh and received targets to reduce generation to zero by 6.10 pm. The reason given was “Constraint mgmt. – V\_HYML1\_5 SL”.

There was no other significant rebidding.

## Tuesday 10 September

**Table 4: South Australia, Tuesday 10 September**

7.30 AM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	2195.17	54.40	67.61
Demand (MW)	1202	1257	1312
Available capacity (MW)	2219	2250	2019

Demand and available capacity were close to forecast.

At around 6.50 am ramping constraints were invoked in preparation for a planned outage of the Heywood to Tarrone to Moorabool No.1 500kV line in Victoria. This saw flows across the Heywood interconnector change from 22 MW into South Australia at 6.55 am to 177 MW forced into Victoria (counter-price) at 7.05 am.

At 6.55 am, effective from 7.05 am, Origin Energy rebid 45 MW of capacity at Quarantine unit 5 from prices around \$300/MWh to the price cap. The reason given was “0650A constraint mgmt - V-SA\_RAMP\_I\_F SL”.

At 7.05 am there was also around a 100 MW reduction in wind generation (36 MW of which was from non-scheduled wind farms which reflects as an increase in demand). With fast start plant unable to synchronise within 5 minutes, the Torrens Island units ramp rate limited and no capacity priced between around \$300/MWh and \$11 000/MWh, high-price generation had to be dispatched. This saw the earlier rebid of Quarantine unit 5 setting the 5 minute price at the price cap at 7.05 am.

At 7.10 am prices returned to previous levels as demand reduced, generation was rebid from high prices to low prices and more capacity was available through ramp rates.

There was no other significant rebidding.

Wednesday 11 September

Table 5: South Australia, Wednesday 11 September

8 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	524.26	80.80	81.34
Demand (MW)	1588	1762	1787
Available capacity (MW)	2029	2034	2043

Demand was 174 MW lower than that forecast 4 hours ahead and available capacity was close to forecast.

At around 7.30 pm ramping constraints were invoked in preparation for a planned outage of the Heywood to Tarrone to Moorabool No.1 500kV line in Victoria. This saw flows across the Heywood interconnector change from 444 MW into South Australia at 7.25 pm to 197 MW forced into Victoria (counter-price) at 7.40 pm.

At 6.44 pm, effective from 7.35 pm, GDF Suez rebid 55 MW of capacity priced around \$70/MWh at its Pelican Point power station to the price cap. The reason given was "Constraint management #R009183\_024\_RAMP\_V@1930".

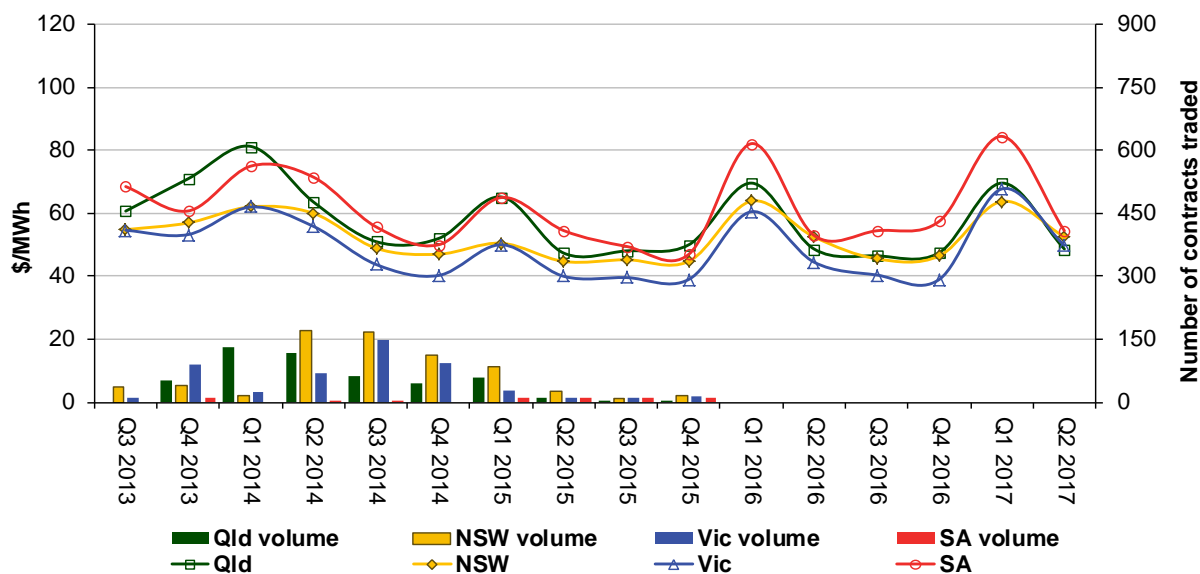
The ramping constraints violated for the 7.35 pm and 7.40 pm dispatch intervals which saw the 5 minute price reach \$797/MWh and \$788/MWh, respectively. 5 minute prices remained between \$300/MWh and \$425/MWh for the remainder of the 8 pm trading interval.

There was no other significant rebidding.

## Financial markets

Figure 8 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.

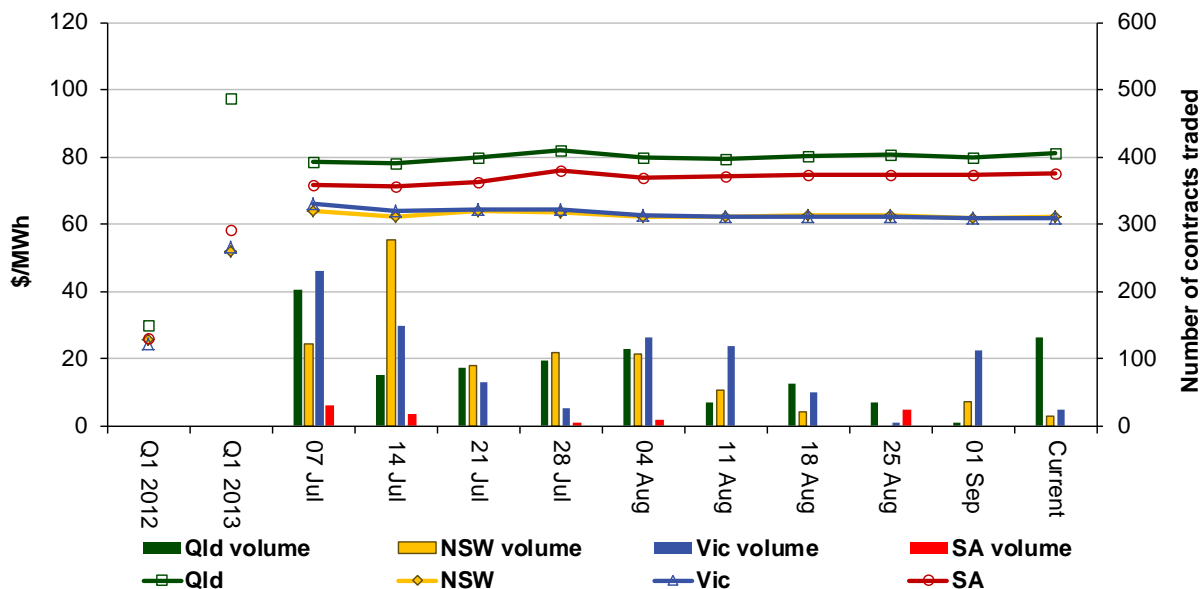
**Figure 8: Quarterly base future prices Q3 2013 – Q2 2017**



Source: [ASXEnergy.com.au](http://ASXEnergy.com.au)

Figure 9 shows how the price for each regional Quarter 1 2014 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Quarter 1 2012 and Quarter 1 2013 prices are also shown.

**Figure 9: Price of Q1 2014 base contracts over the past 10 weeks (and the past 2 years)**



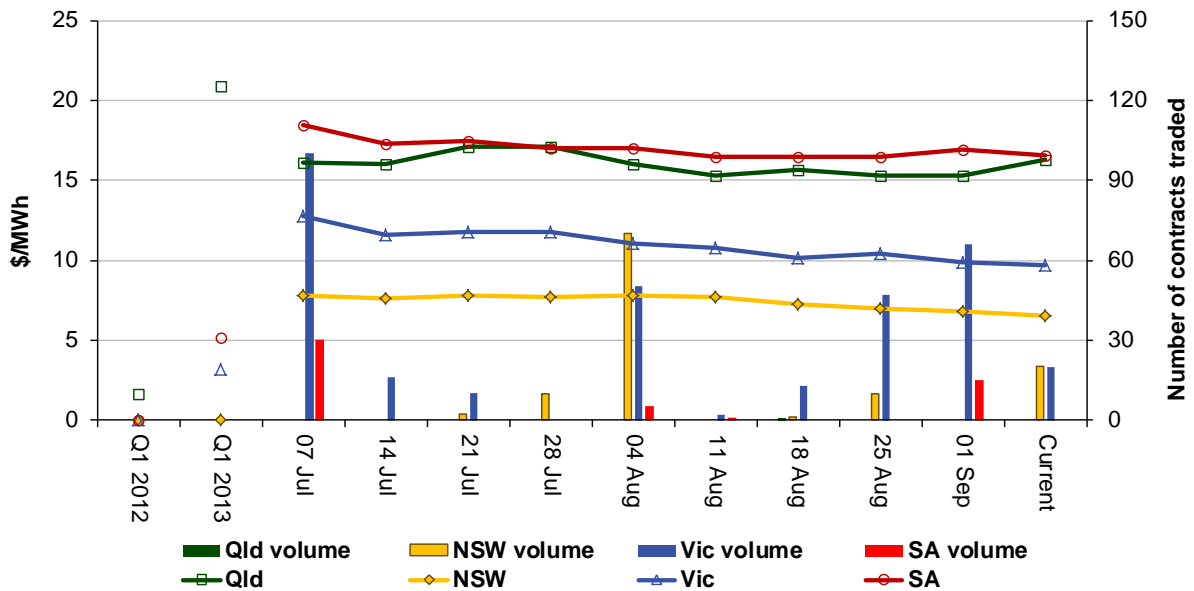
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: [ASXEnergy.com.au](http://ASXEnergy.com.au)

Prices of other financial products (including longer-term price trends) are available in the [Industry Statistics](#) section of our website.

Figure 10 shows how the price for each regional Quarter 1 2014 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Quarter 1 2012 and Quarter 1 2013 prices are also shown. The cap contracts limit exposure to extreme spot prices (above \$300/MWh) and is an indicator of the cost of risk management.

**Figure 10: Price of Q1 2014 cap contracts over the past 10 weeks (and the past 2 years)**



Source: [ASXEnergy.com.au](http://ASXEnergy.com.au)

**Australian Energy Regulator**  
**September 2013**