Electricity Report

11 to 17 August 2013

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.

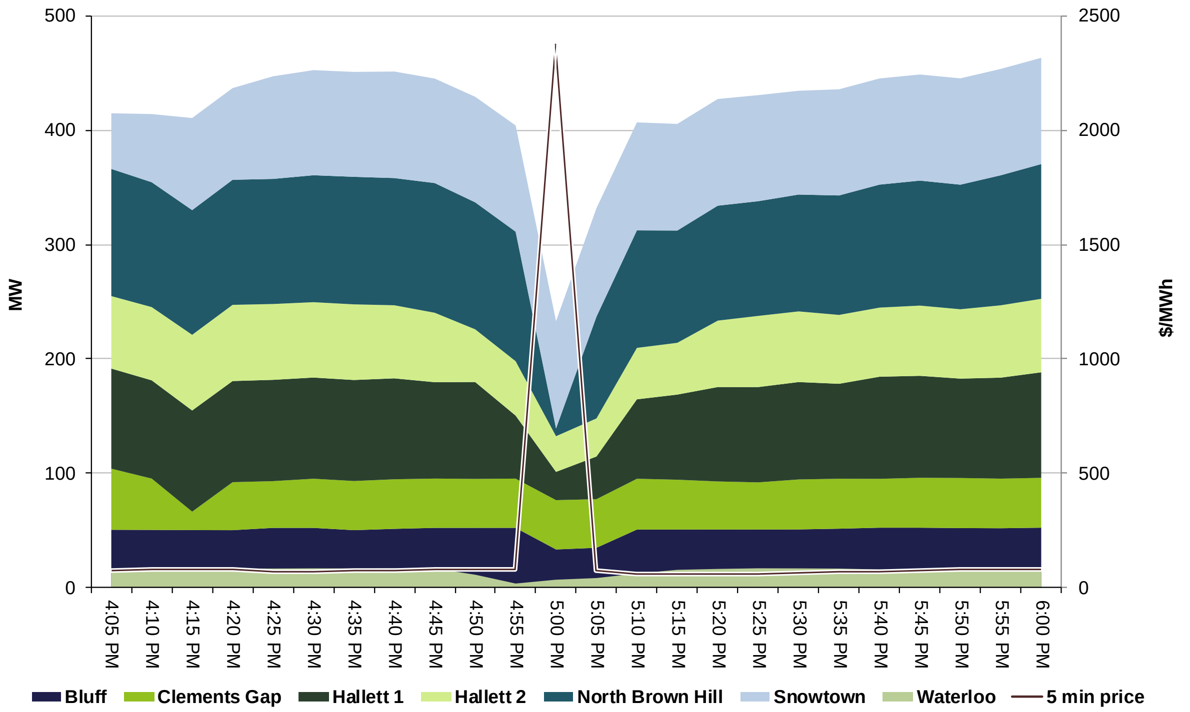
Weekly spotlight

This week's spotlight highlights how the intermittent nature of wind generation can have significant price impacts in South Australia. At around 1200 MW, wind generation (scheduled plus non-scheduled) constitutes around a quarter of total installed generation capacity in South Australia.

In setting the target for the following dispatch interval for a wind generator, AEMO's systems assume approximately the same level of output for that generator from the previous dispatch interval.

On 16 August at 4.55 pm there was around a 140 MW reduction in wind generation in the mid north of the region. This led to a reduction in targets at 5 pm for those generators of around 150 MW, as shown in the spotlight figure below. With other generators in South Australia unable to respond to this sudden reduction in generation, imports across the Heywood interconnector increased above the limit causing a constraint to violate and the dispatch price to increase to $2376/MWh.

Spotlight figure: Wind generation targets and dispatch price in South Australia 16 August



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In July of this year, the AER published a report into high price outcomes in April and May (*Special report - Market outcomes in South Australia during April and May 2013*). The report explores the relationship between wind generator output and spot prices in South Australia during the period and found that low levels of wind output were associated with high prices. With more wind projects committed in South Australia, spot price volatility may become more prevalent in the future.

More detailed analysis of the events of 16 August can be found in the *Detailed market analysis of significant price events* section of this report.

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)

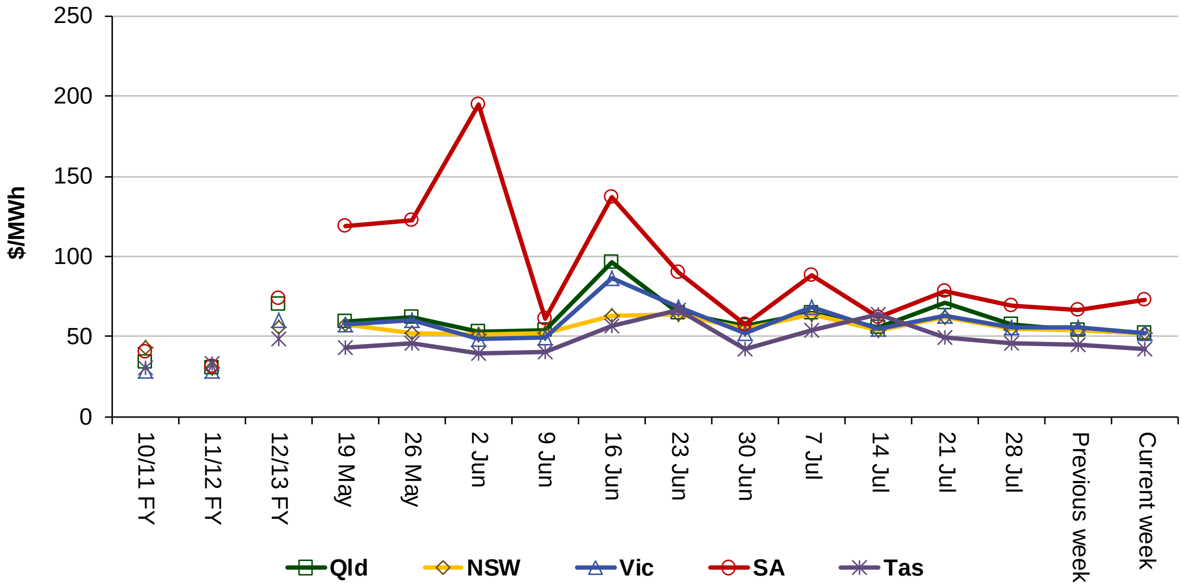


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	52	52	52	73	42
12-13 financial YTD	63	65	70	77	57
13-14 financial YTD	59	57	57	71	49

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 53 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
% of total above forecast	1	35	5	3
% of total below forecast	45	11	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

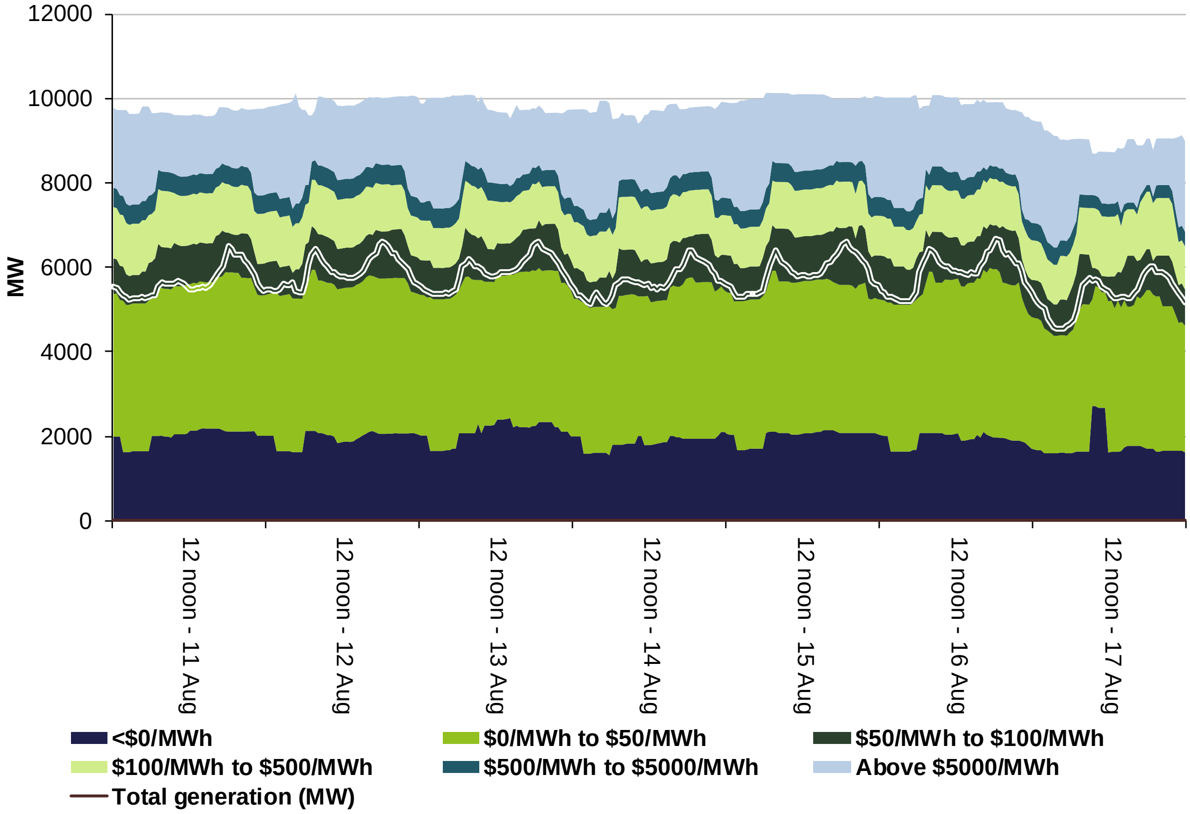


Figure 3: New South Wales generation and bidding patterns

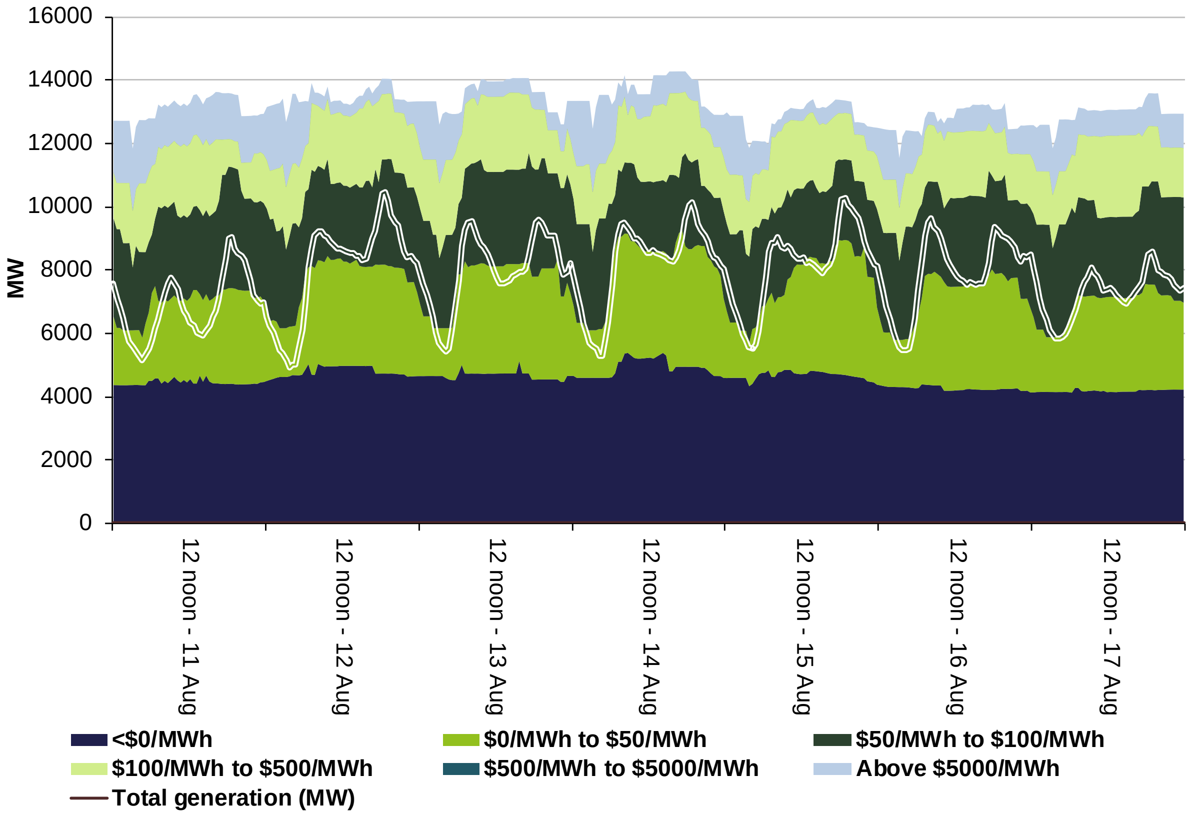


Figure 4: Victoria generation and bidding patterns

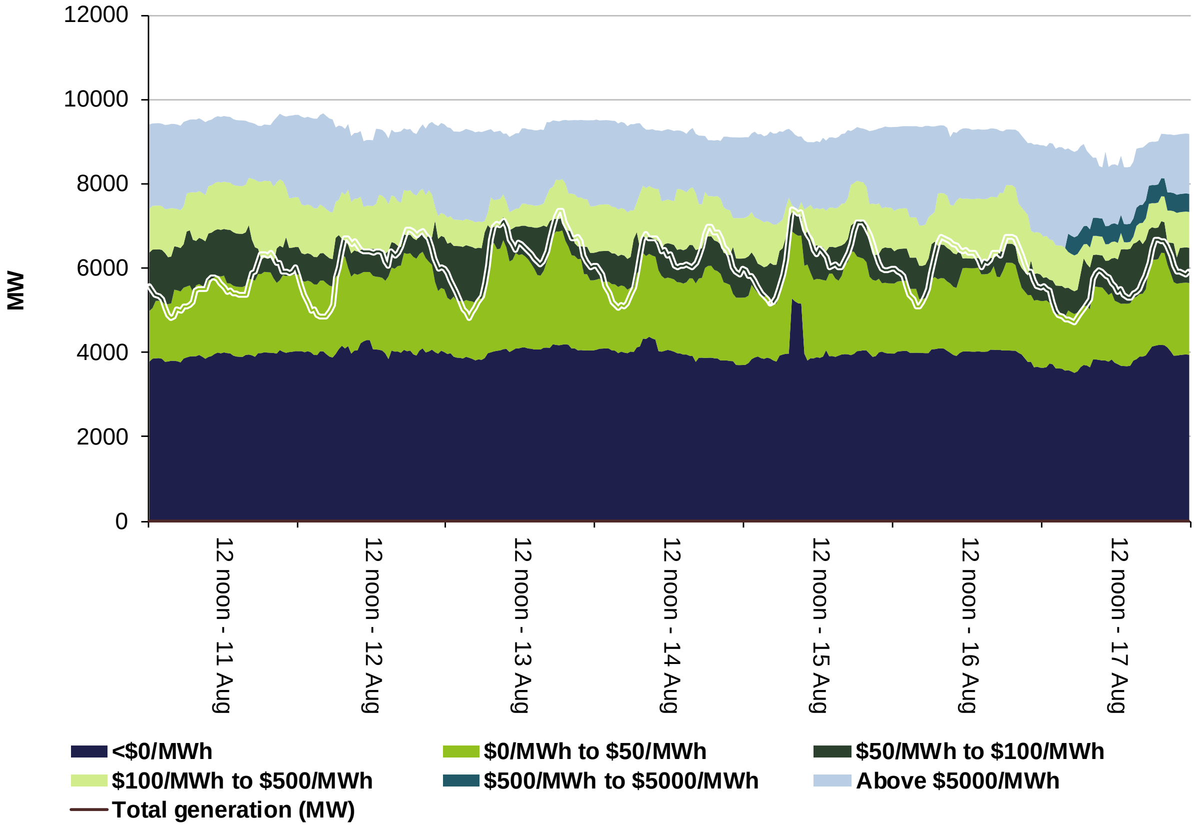


Figure 5: South Australia generation and bidding patterns

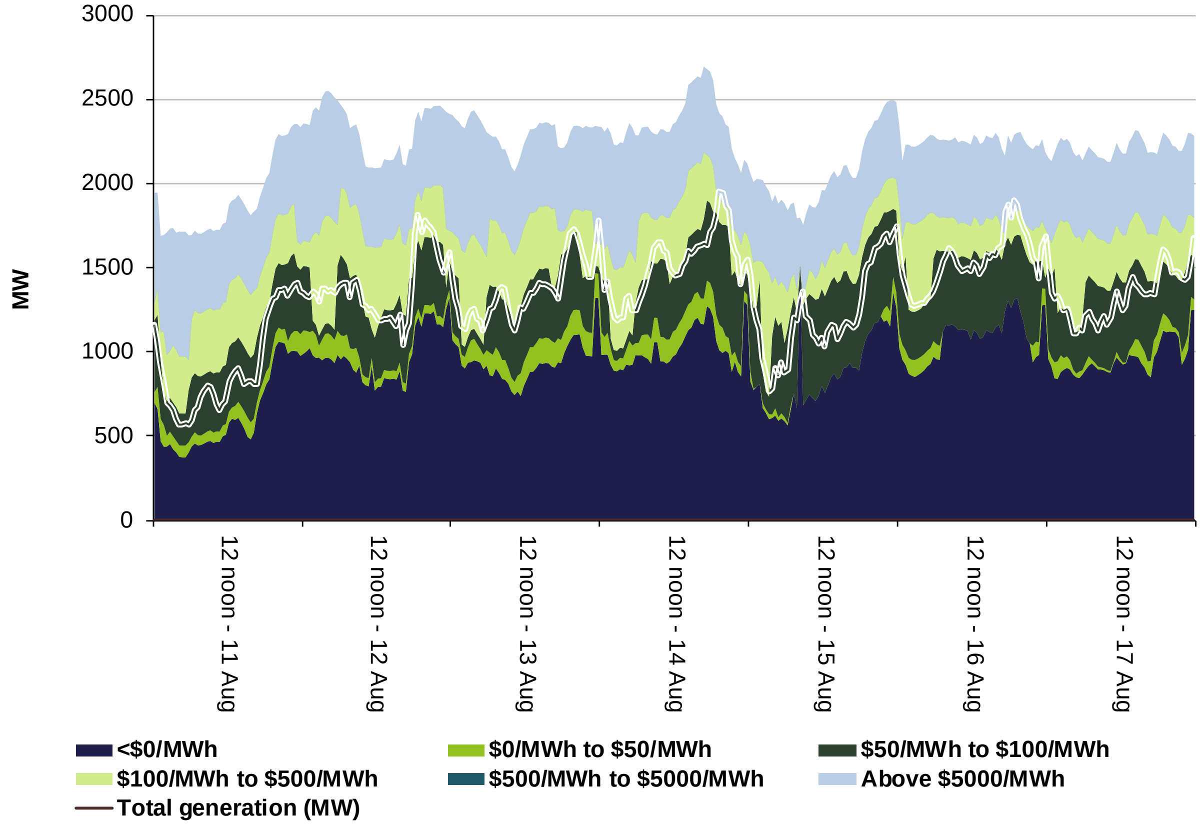
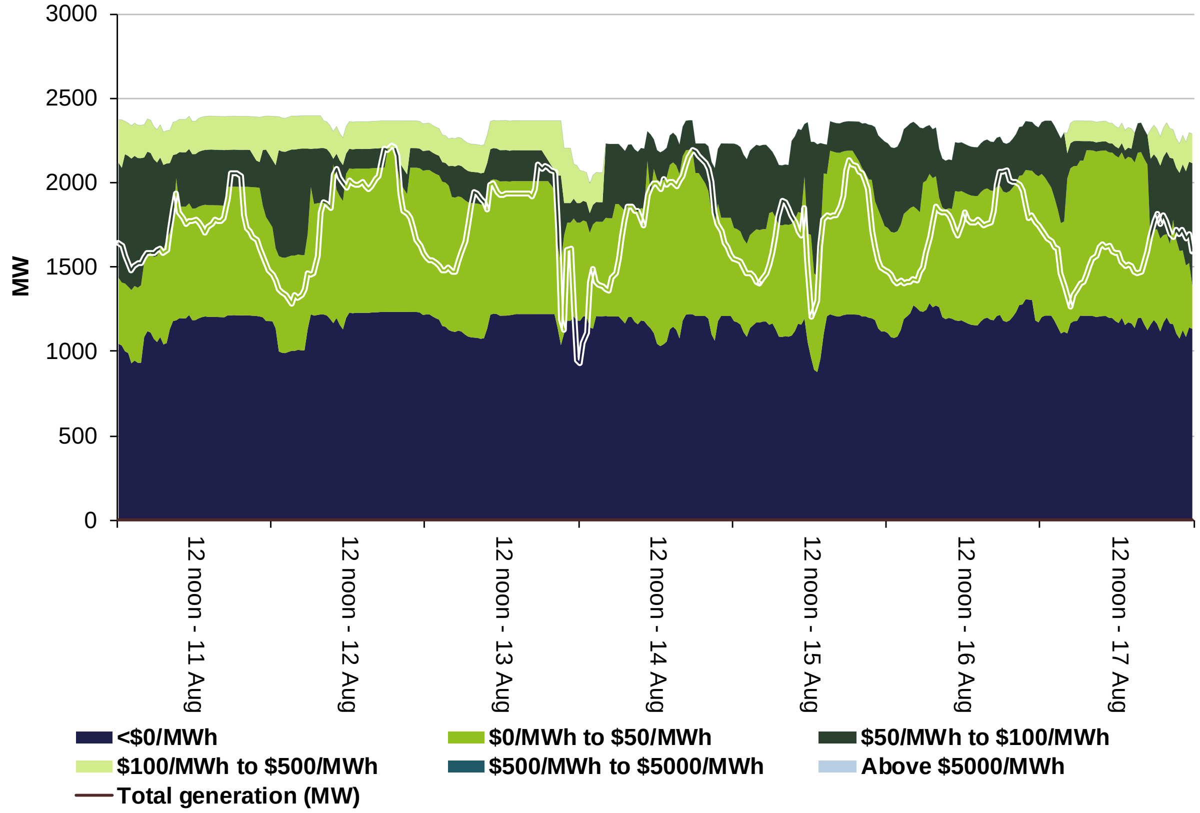


Figure 6: Tasmania generation and bidding patterns



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:

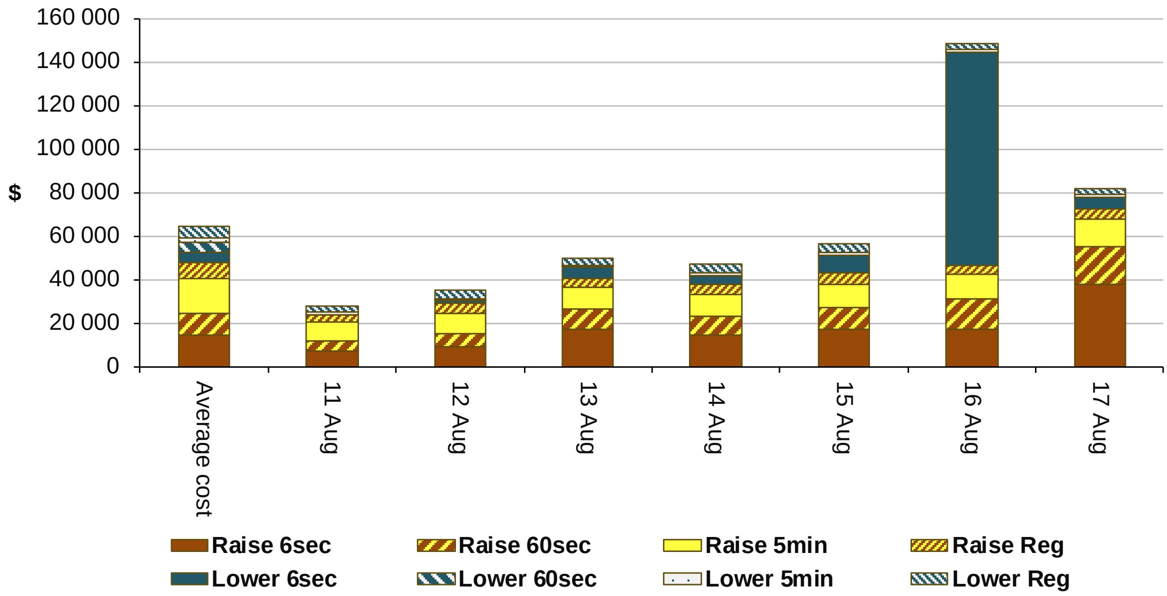
- *fast services*, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- *slow services*, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- *delayed services*, which return the frequency to the 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 $298 500 or less than 1 per cent of energy turnover on the mainland. In Tasmania (which requires dedicated services for much of the time) the total cost for the week was $147 500 or around 1.7 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



The significant lower 6 second costs on Friday 16 August were a result of events in Tasmania. At around 11.50 am on 15 August Basslink tripped while exporting to Victoria. According to AEMO, a Rio Tinto potline subsequently tripped as a result of a protection mal-operation. Considering the event would be likely to reoccur, AEMO reclassified the tripping of Basslink and the potline as a credible contingency event from 5.30 pm until further notice.

At 9.58 am on 16 August 2013, Hydro Tasmania rebid all of its lower 6 second (L6) services across its portfolio (447 MW) from prices under $2/MW to close to the cap. The reason given was “0955A constraint in transmission dif from expected +sl”.

At 4.50 pm an updated constraint was invoked by AEMO to manage the reclassification. It immediately bound with the requirement for L6 services increasing from 0 MW at 4.45 pm to 44 MW at 4.50 pm. As Hydro Tasmania was the only provider of L6 services in Tasmania its high priced offer set the price at $12 900/MW for the 4.50 pm and 4.55 pm dispatch intervals.

At 5 pm prices returned to previous levels when a rebid by Hydro Tasmania which reversed its earlier rebid became effective.

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, two in South Australia on 15 August and 16 August and one in Tasmania on 13 August. The tables below show the actual price, demand and available capacity outcomes compared to those forecast 4 and 12 hours ahead.

Table 3: South Australia, Thursday 15 August

8:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2099.68	90.80	90.80
Demand (MW)	1791	1750	1731
Available capacity (MW)	1781	1903	1932

Conditions at the time saw demand close to forecast, while available capacity was 122 MW below that forecast four hours ahead.

According to AEMO, at 6.35 am the Whyalla Terminal to Yadnarie and Yadnarie to Port Lincoln 132 kV lines tripped, causing the electrical islanding of the Eyre Peninsula from the rest of the South Australia region.

ElectraNet has a contract with GDF Suez’s Port Lincoln power station for transmission support during network outages to meet local load. Over several rebids from 6.45 am, GDF Suez shifted 48 MW of capacity at Port Lincoln from prices above $11 400/MWh to close to the price floor to make itself available. The reason given was “units required for Port Lincoln transmission support”.

At around 7.35 am the 132kV transmission lines returned to service. At 8.09 am, effective from 8.15 am, GDF Suez rebid all 48 MW of available capacity at its Port Lincoln power station from close to the floor back to prices above $11 400/MWh. The reason given was “0808P units no longer needed for network support”. This coincided with a 51 MW increase in demand (from 8.10 am to 8.15 am) and a reduction in imports across Heywood of 25 MW. The Heywood transformer constraint reduced the import limit from Victoria by 25 MW as a result of increased metered flow exceeding the import limit.

With lower priced generation unable to synchronise to meet the increase in demand and reduction in imports, higher priced generation was dispatched resulting in the 5 minute price reaching $12 195/MWh at 8.15 am.

Prices returned to previous levels in the subsequent dispatch intervals, after generators rebid around 700 MW of capacity close to the price floor and there was an increase in non-scheduled generation.

There was no other significant rebidding.

Table 4: South Australia, Friday 16 August

5:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	461.77	60.81	57.74
Demand (MW)	1738	1417	1337
Available capacity (MW)	2224	2284	2270

Conditions at the time saw demand around 320 MW above that forecast four hours ahead, while available capacity was close to forecast.

A system normal constraint managing post contingent flows on the Snuggery to Keith 132 kV transmission line (in the event of a trip on the South East to Tailem Bend No.1 275 kV line) was binding for most of the day limiting imports across Heywood to around 175 MW.

At 4.52 pm, effective at 5 pm, Origin Energy reduced the available capacity of Quarantine unit 3 from 25 MW to zero (all priced below zero) after failing to start. The reason given was "1650P change in avail – unit trip on start up et0.5 sl".

At 5 pm there was a demand increase of around 40 MW and a reduction in wind generation in the mid north of South Australia of around 140 MW. This step increase in generation could not be met by South Australian generators as they were either ramp rate limited, trapped in FCAS or offline, resulting in the Heywood interconnector increasing imports (274 MW) to above its limit (217 MW) to meet South Australian demand. As a result the above constraint violated and the 5 minute price increased to $2376/MWh at 5 pm.

The following two dispatch intervals saw an apparent demand side response of close to 200 MW (some of which was non-scheduled generation) and prices returned to previous levels.

There was no other significant rebidding.

Table 5: Tasmania, Tuesday 13 August

11:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	854.16	26.59	34.28
Demand (MW)	1036	1091	1069
Available capacity (MW)	2171	2302	2306

Conditions at the time saw demand close to that forecast, while available capacity was around 130 MW below that forecast ahead of dispatch.

There were lightning storms in Tasmania throughout the evening. At 11.05 pm AEMO declared the simultaneous loss of the Sheffield to Georgetown 220 kV lines and the George Town to Hadspen 220 kV lines as a credible contingency and invoked constraints accordingly. The constraints invoked affect all generation in Tasmania, with the exception of all generation Tamar Valley (which was offline at the time).

Between 11 pm and 11.10 pm the constraints managing the Sheffield to Georgetown lines reduced Tasmanian generation by around 340 MW but the changes were insufficient to meet the constraint requirements, causing the constraint to violate for the 11.05 pm and 11.10 pm dispatch intervals and the constraint managing the Georgetown to Hadspen lines to violate from 11.05 pm to 11.20 pm. The reduction in generation led to flows on Basslink changing from exports to Victoria to imports into Tasmania, crossing the no go-zone at 11.10 pm. As a result the 5 minute price was above $360/MWh from 11.05 pm to 11.20 pm with the maximum reaching $3737/MWh at 11.10 pm.

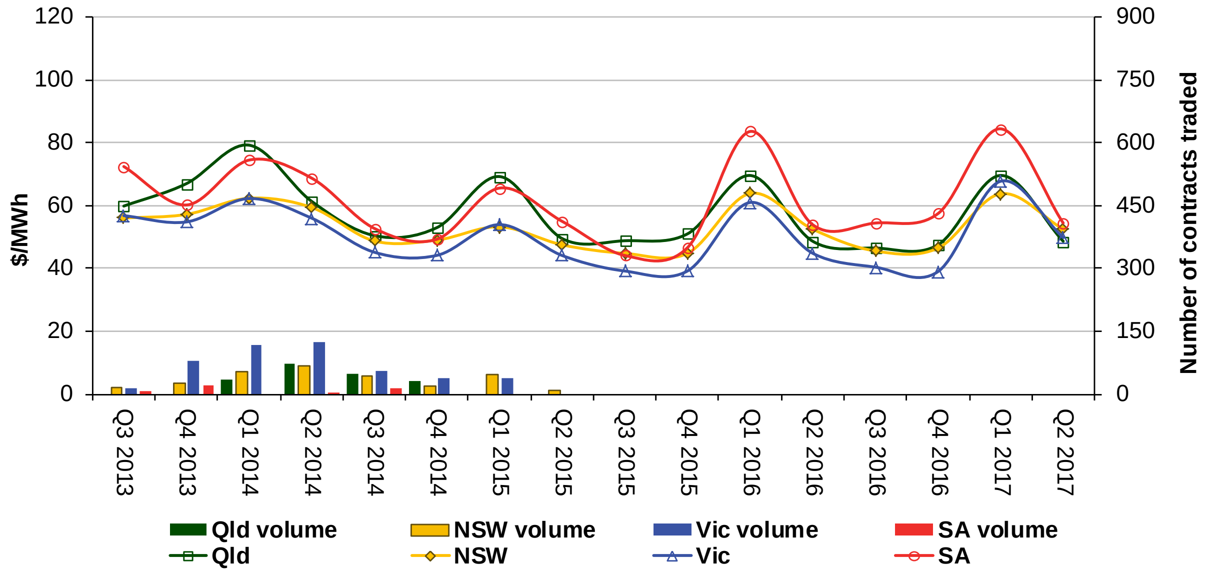
Prices returned to previous levels at 11.25 pm when Basslink was able to import into Tasmania.

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.

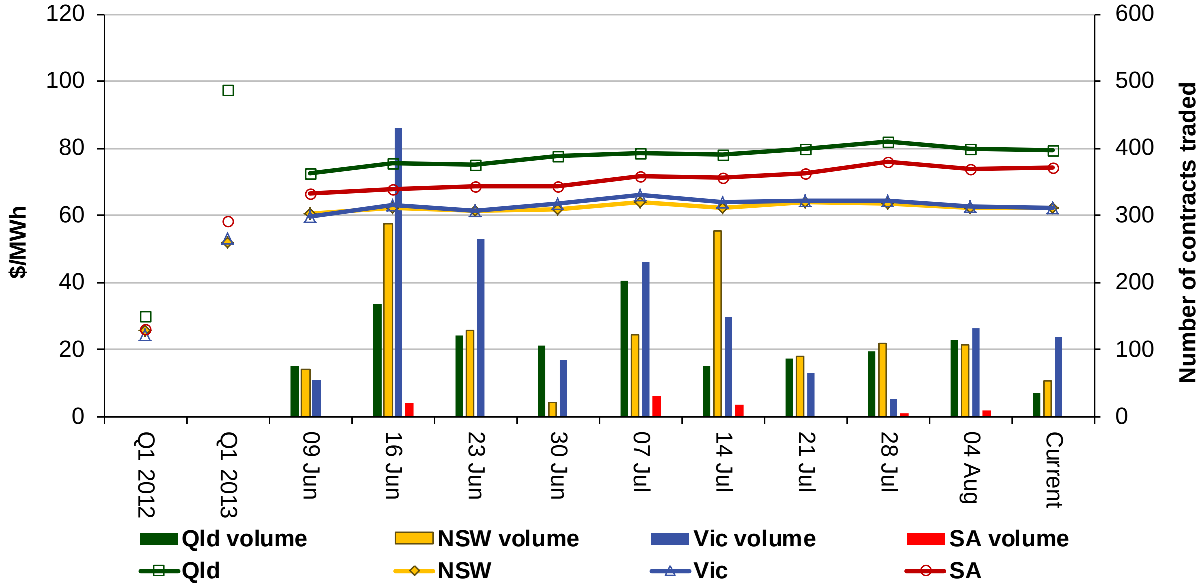
Figure 8: Quarterly base future prices Q3 2013 – Q2 2017



Source: ASXEnergy.com.au

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)



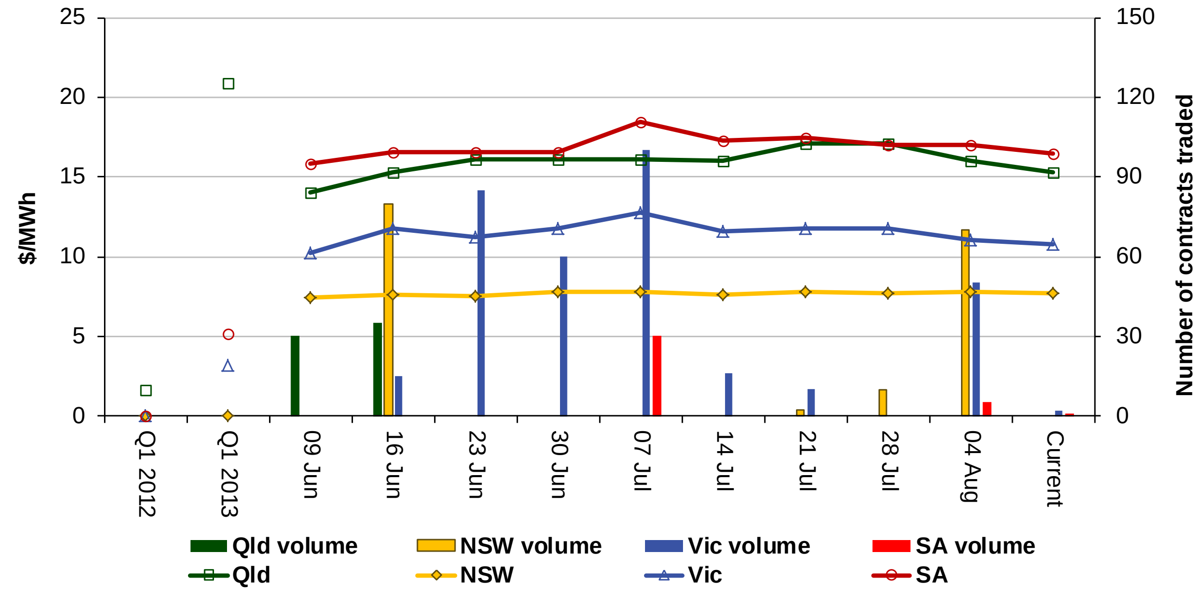
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: ASXEnergy.com.au

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

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