

Electricity Report

6 to 12 October 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.

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)

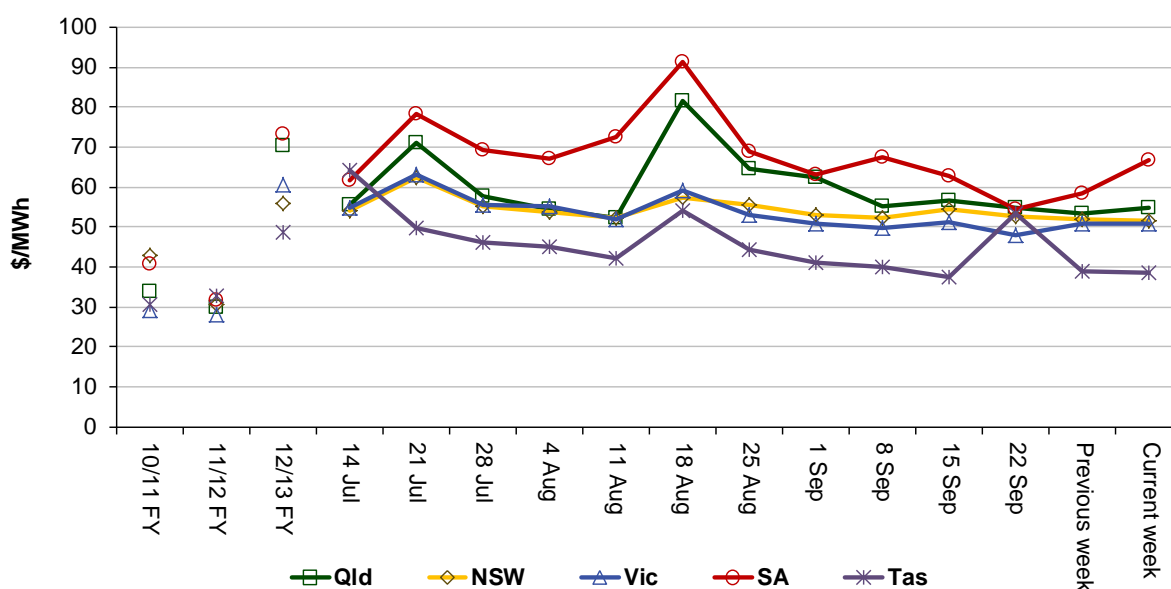


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	55	52	51	67	39
12-13 financial YTD	57	60	62	66	49
13-14 financial YTD	60	55	55	69	46

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 46 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	4	9	0	8
% of total below forecast	18	47	0	13

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

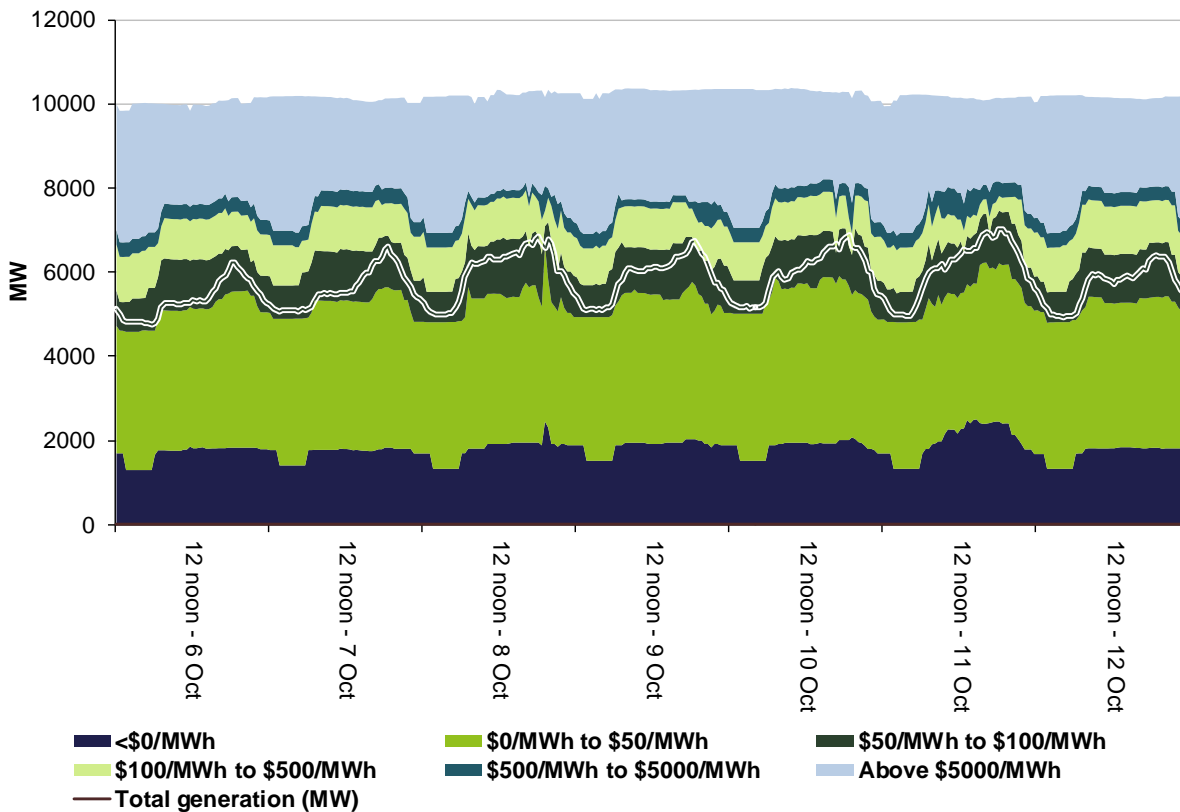


Figure 3: New South Wales generation and bidding patterns

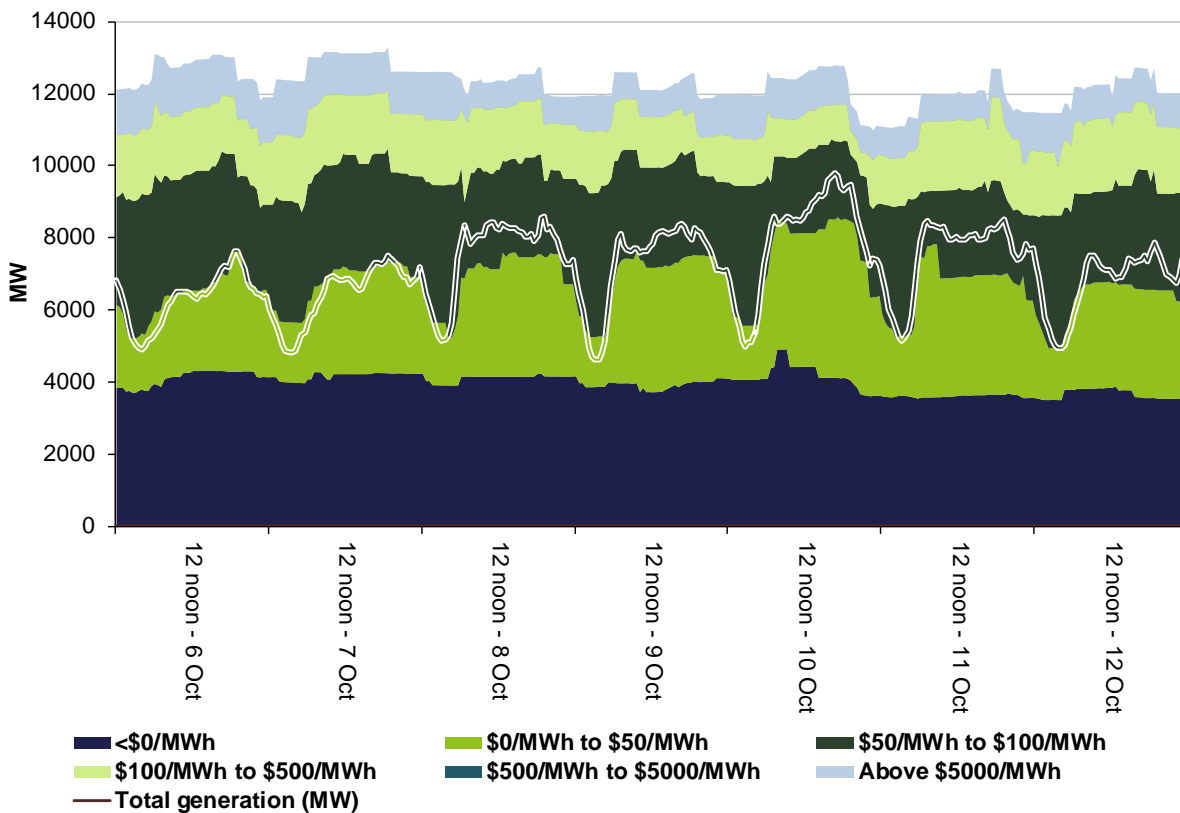


Figure 4: Victoria generation and bidding patterns

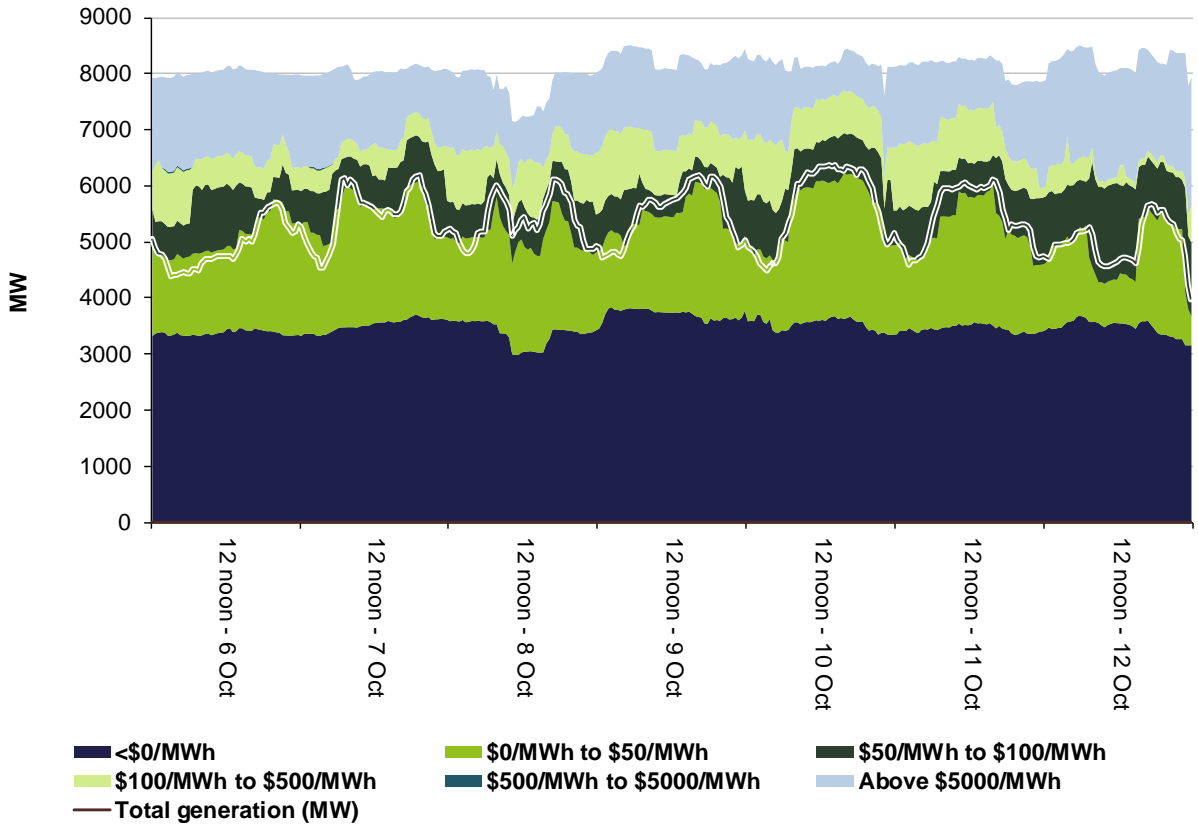


Figure 5: South Australia generation and bidding patterns

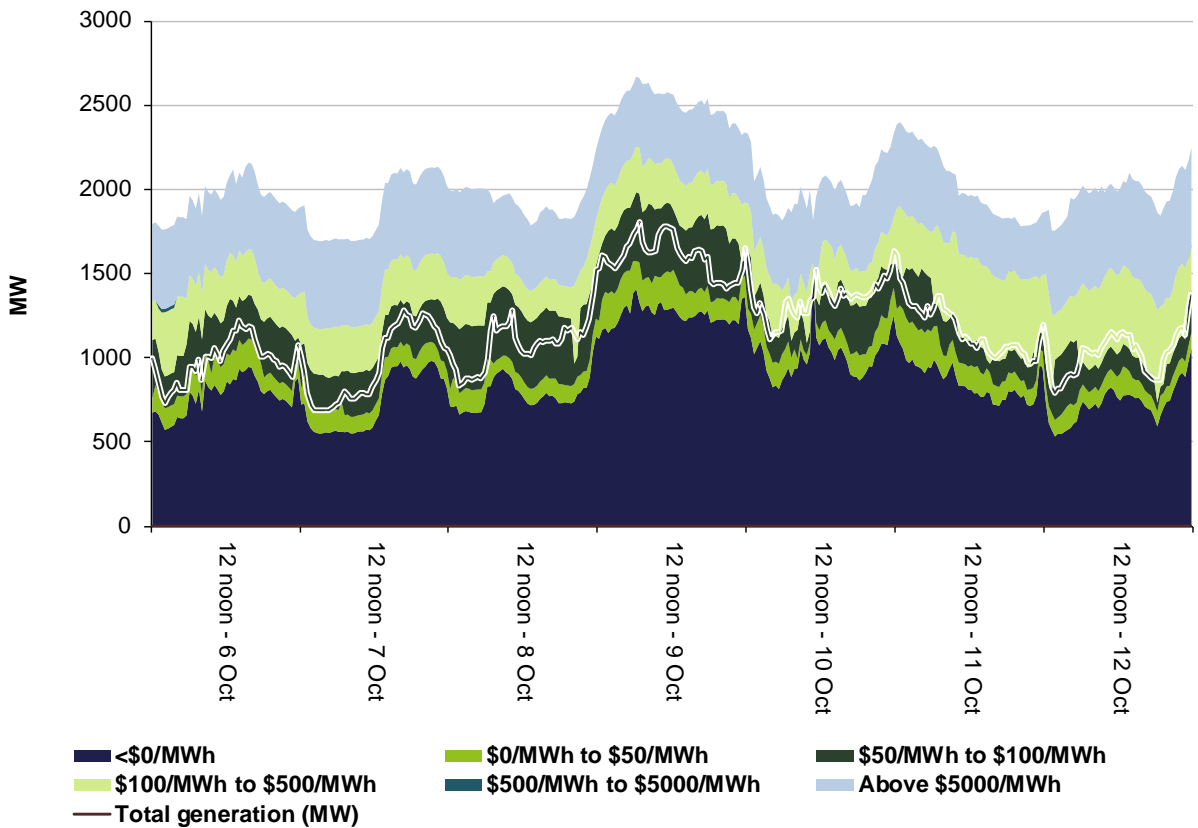
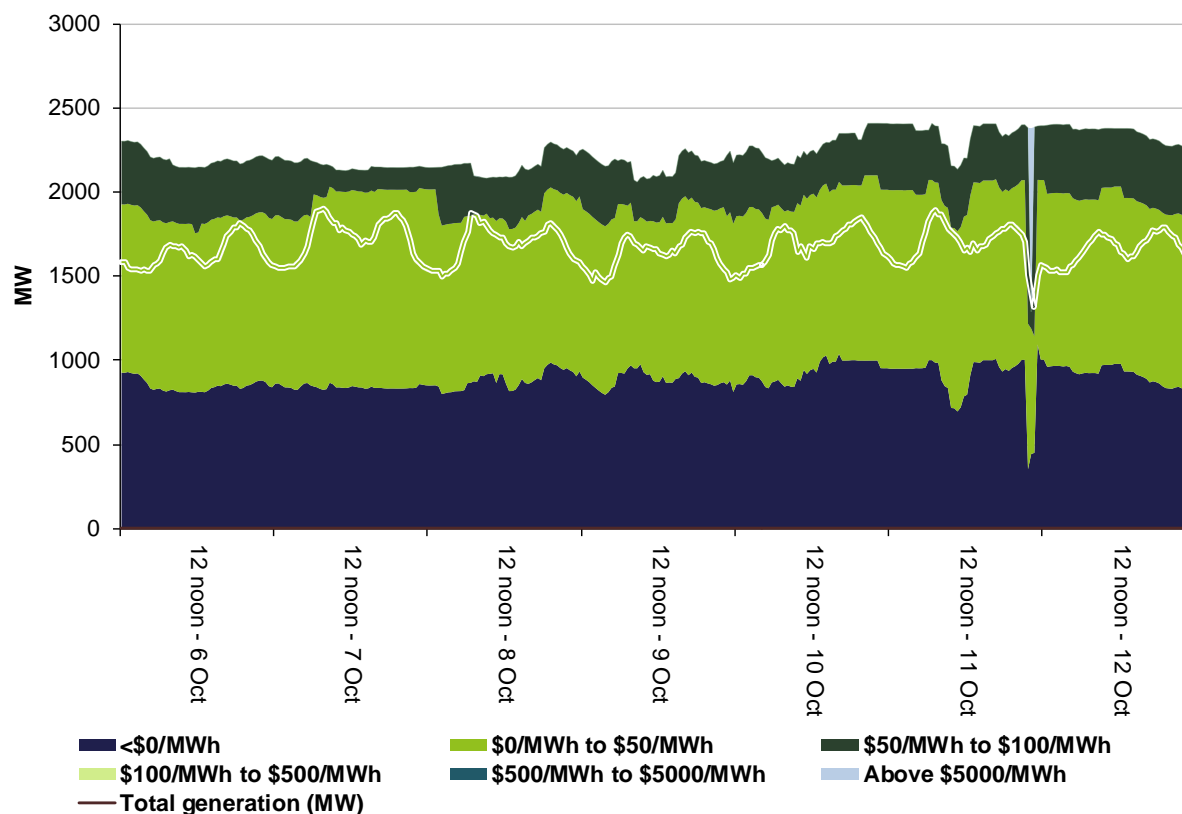


Figure 6: Tasmania generation and bidding patterns



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:

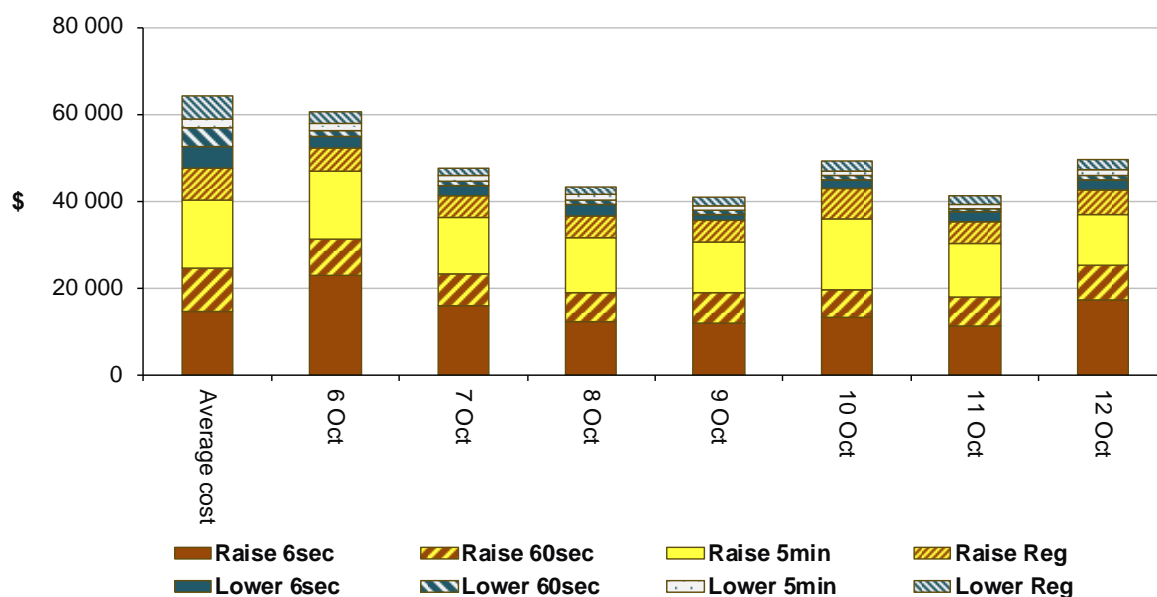
- *fast services*, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- *slow services*, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- *delayed services*, which return the frequency to the 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 \$290 000 or less than 1 per cent of energy turnover on the mainland. The total cost of FCAS in Tasmania for the week was \$42 000 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 two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of \$55/MWh and above \$250/MWh. There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of \$67/MWh and \$250/MWh.

Table 3: Queensland, Tuesday 8 October

7:30 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	293.74	55.00	53.46
Demand (MW)	6429	6491	6424
Available capacity (MW)	10 220	10 345	10 345

Conditions at the time saw demand and available capacity close to forecast.

At 6.29 pm, effective from 6.40 pm, Stanwell rebid 370 MW of capacity across its portfolio, from prices below \$55/MWh to above \$1400/MWh. The reason given was “Material change in Qld generation: Darling Downs PS:SL”. Shortly after, at 6.52 pm, effective from 7 pm, Stanwell further rebid all of its capacity at Kareeya power station (66 MW) from prices below zero to the price cap. The reason given was “Material change in generation: Darling Downs PS:SL”.

Stanwell rebidding combined with an 94 MW increase in demand (from 6456 MW at 7 am to 6550 MW at 7.05 pm) saw imports into Queensland across the QNI increase from 203 MW at 7 pm to its limit of 212 MW at 7.05 pm. This caused the “N^AQ_NIL_B1¹” system normal constraint to bind.

¹ The constraint is use to avoid voltage collapse on the loss of Kogan Creek

Directlink was not significantly affected as it was on planned maintenance since August 2013. At the time of high prices, flows on Directlink were forced into New South Wales at around 35 MW.

The rebids, combined with network conditions at the time and a number of units being stranded in FCAS, saw an increase in the five minute price from \$60/MWh at 7 pm to \$1500/MWh at 7.05 pm. Prices returned to below \$60/MWh following a number of Queensland generators rebidding of capacity from high prices to low prices, coinciding with a 59 MW reduction in demand.

There was no other significant rebidding.

Table 4: Queensland, Thursday 10 October

7:30 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	304.37	55.76	55.17
Demand (MW)	6612	6577	6577
Available capacity (MW)	10 280	10 309	10 309

Conditions at the time saw demand and available capacity close to forecast.

Over two rebids at 6.53 pm and 7.09 pm, effective from 7 pm and 7.20 pm respectively, Stanwell rebid a total of 506 MW of capacity across its portfolio from prices below \$90/MWh to above \$1400/MWh (83 MW of which was priced at the price cap). The reasons given were “change in Qld P5@1855 47 MW: P5 1845 – SL” and “QNI transmission constraint”.

At 7.14 pm, effective from 7.25 pm, CS Energy rebid 50 MW of capacity at Gladstone from prices below \$55/MWh to above \$12 000/MWh. The reason given was 1913A interconnector constraint – QNI binding –SL”.

At 7.25 pm, the five minute price increased from \$91/MWh at 7.20 pm to \$1499/MWh at 7.25 pm. Prices returned to below \$60/MWh at 7.30 pm, when a number of Queensland participants rebid capacity from high prices to low prices.

There was no other significant rebidding.

Table 5: South Australia, Thursday 10 October

11:00 AM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	1869.72	55.51	55.87
Demand (MW)	1391	1287	1282
Available capacity (MW)	1872	2031	2089

Conditions at the time saw demand around 100 MW higher than that forecast four hours ahead and available capacity around 160 MW lower than forecast.

At 10.40 am demand increased by 35 MW from 1439 MW at 10.35 am to 1474 MW at 10.40 am. At the same time semi-scheduled generation targets decreased by 155 MW. The combined 190 MW change was largely met by increased imports into South Australia across Murraylink (from 58 MW to its limit of 159 MW).

There were limited units available to meet demand, with only one Torrens Island unit online which was ramp up limited at the time, Pelican Point was trapped in FCAS services and three of the four remaining non-wind units generating were at maximum levels. Hence high priced capacity at Northern unit 2 was dispatch, setting the 10.40 am price at \$10 928/MWh.

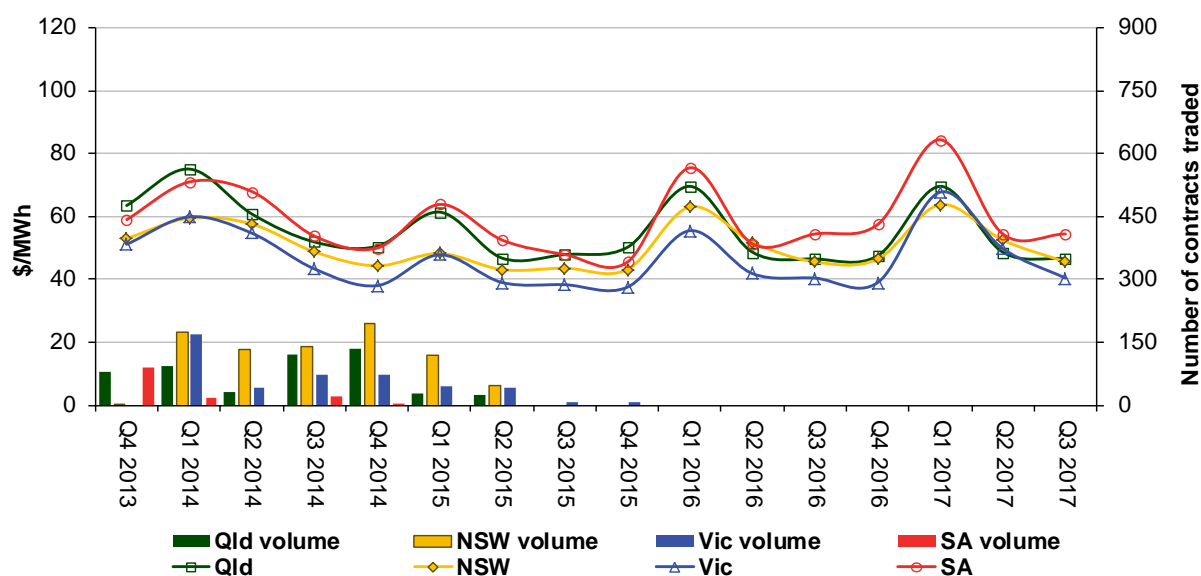
The dispatch price returned to below \$71/MWh at 10.45 am, when a number of South Australian units rebid capacity at prices above \$10 000/MWh to below zero in response to the high dispatch price and around 90 MW of non-scheduled generation came online.

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.

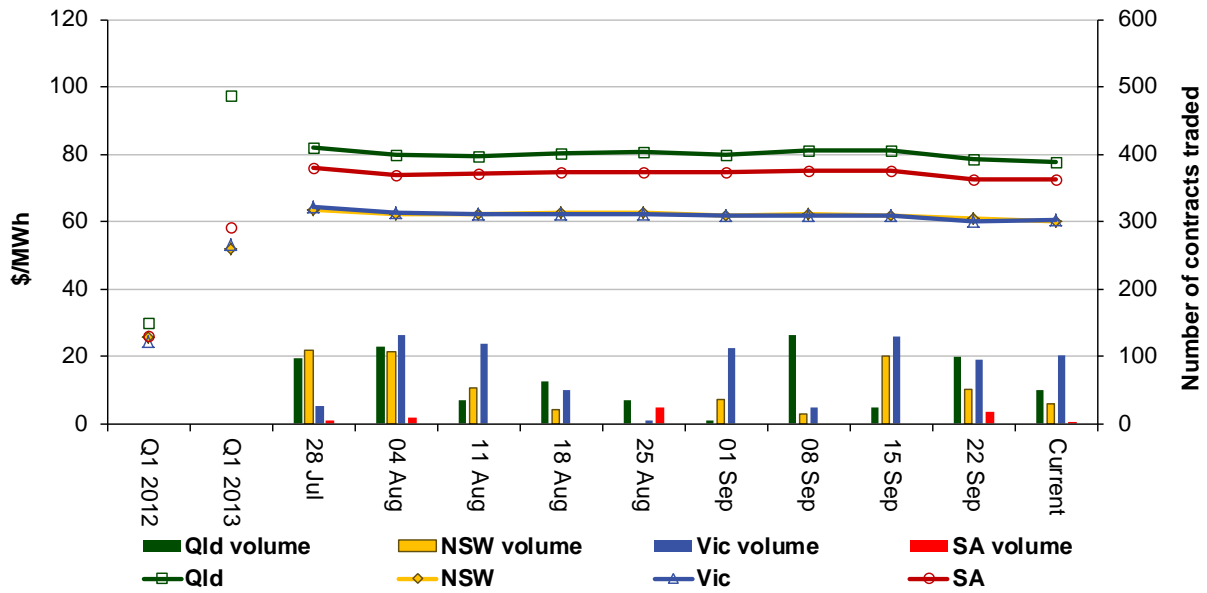
Figure 8: Quarterly base future prices Q4 2013 – Q3 2017



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)



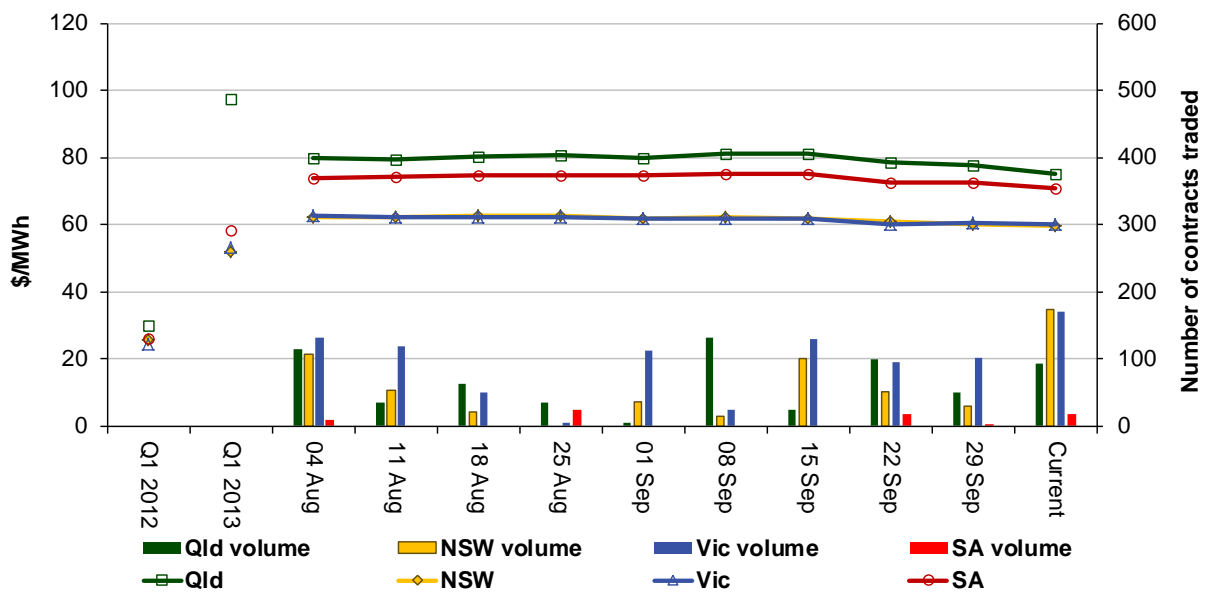
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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