Electricity Report

18 - 24 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.

Spot market prices

Figure 1 shows the volume weighted average (VWA) prices for this 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)

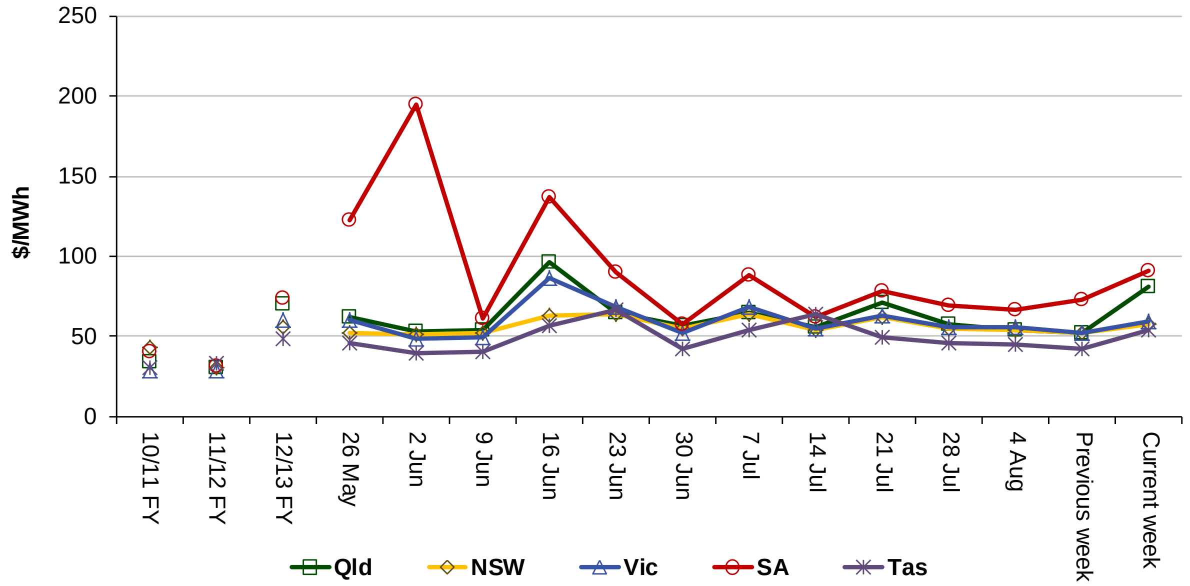


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	81	57	59	91	54
12-13 financial YTD	61	64	68	76	56
13-14 financial YTD	62	57	58	74	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 100 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	7	19	4	1
% of total below forecast	30	25	2	14

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

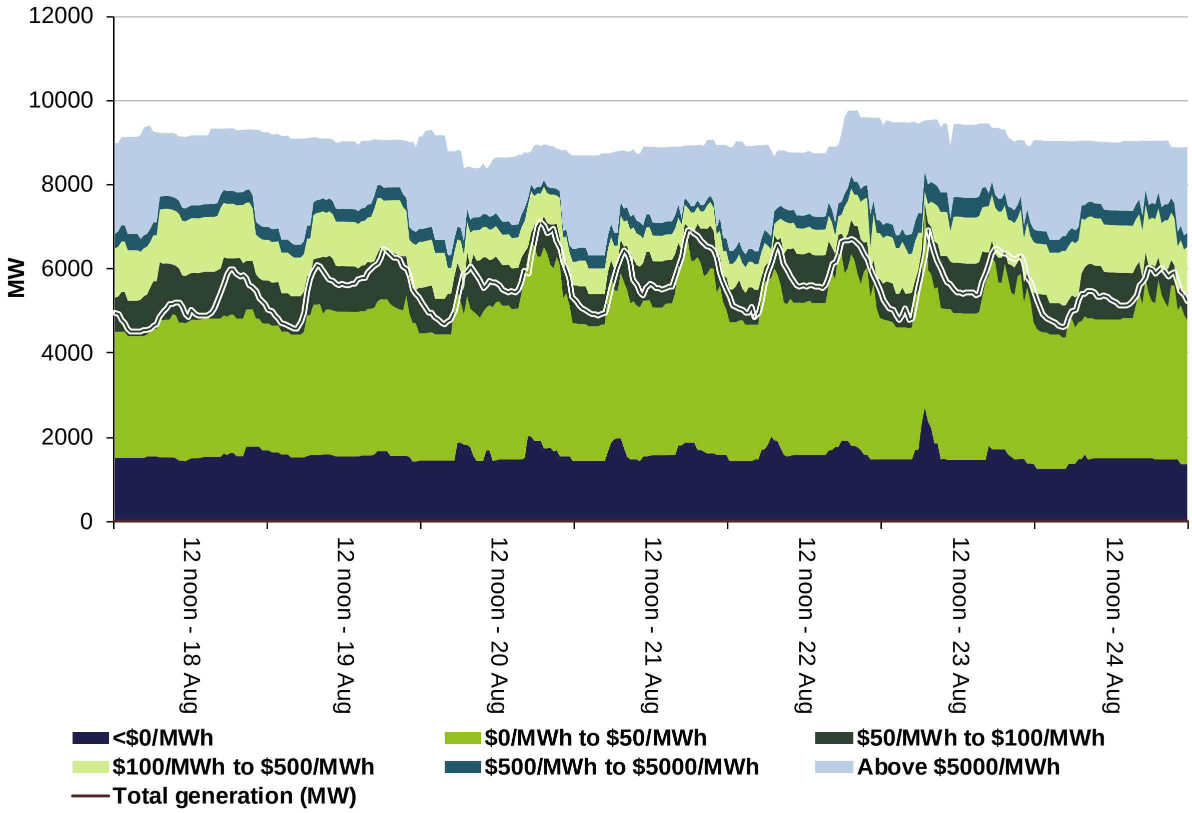


Figure 3: New South Wales generation and bidding patterns

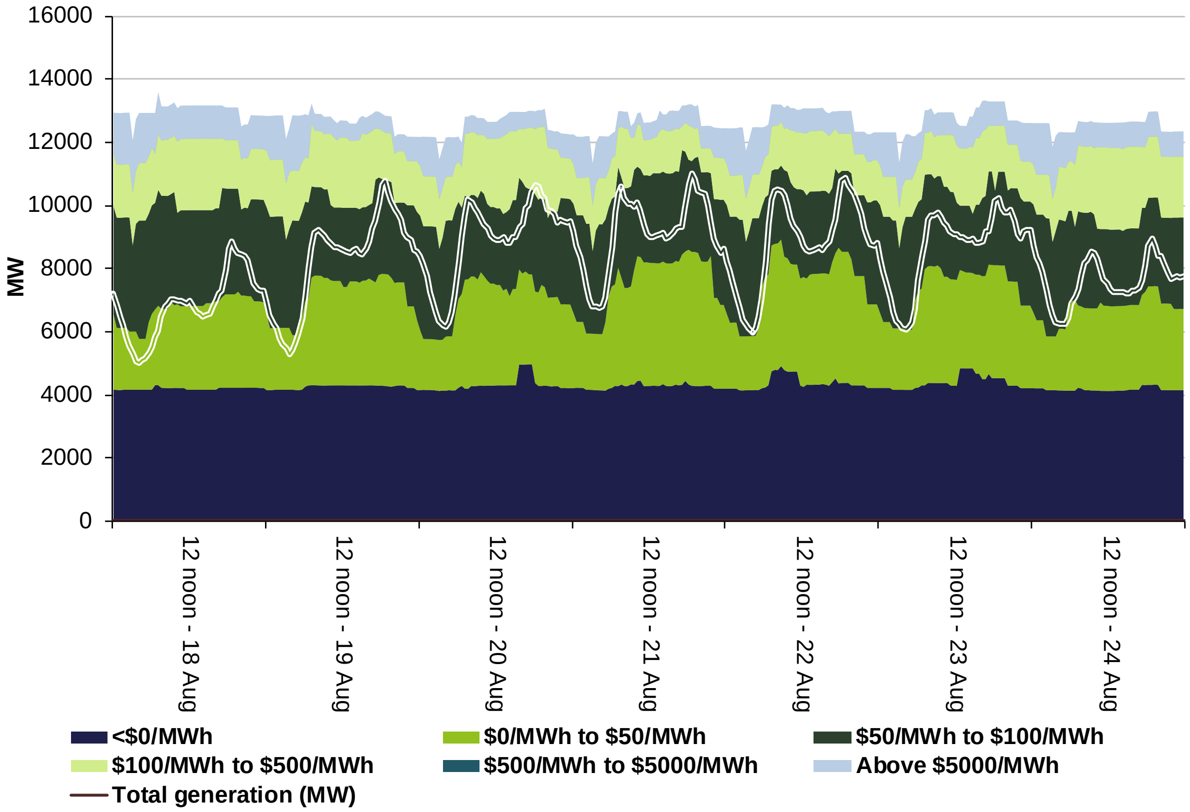


Figure 4: Victoria generation and bidding patterns

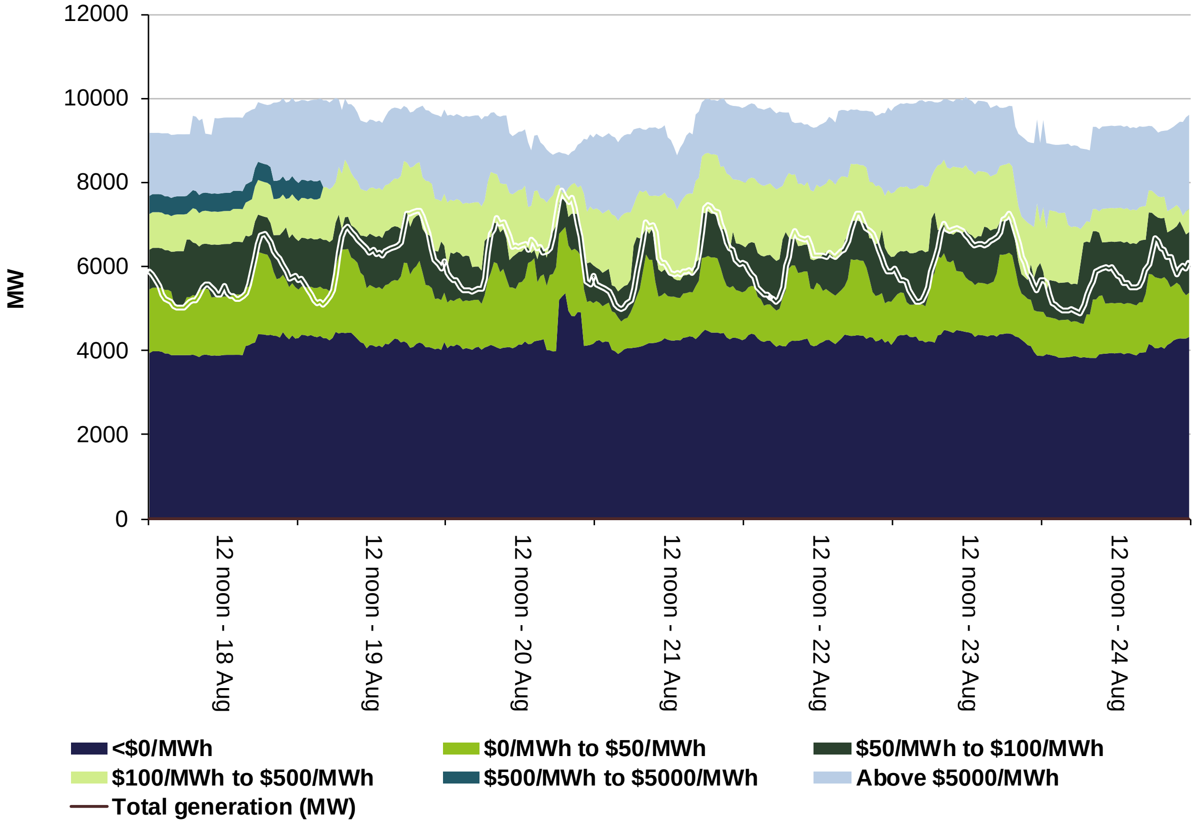


Figure 5: South Australia generation and bidding patterns

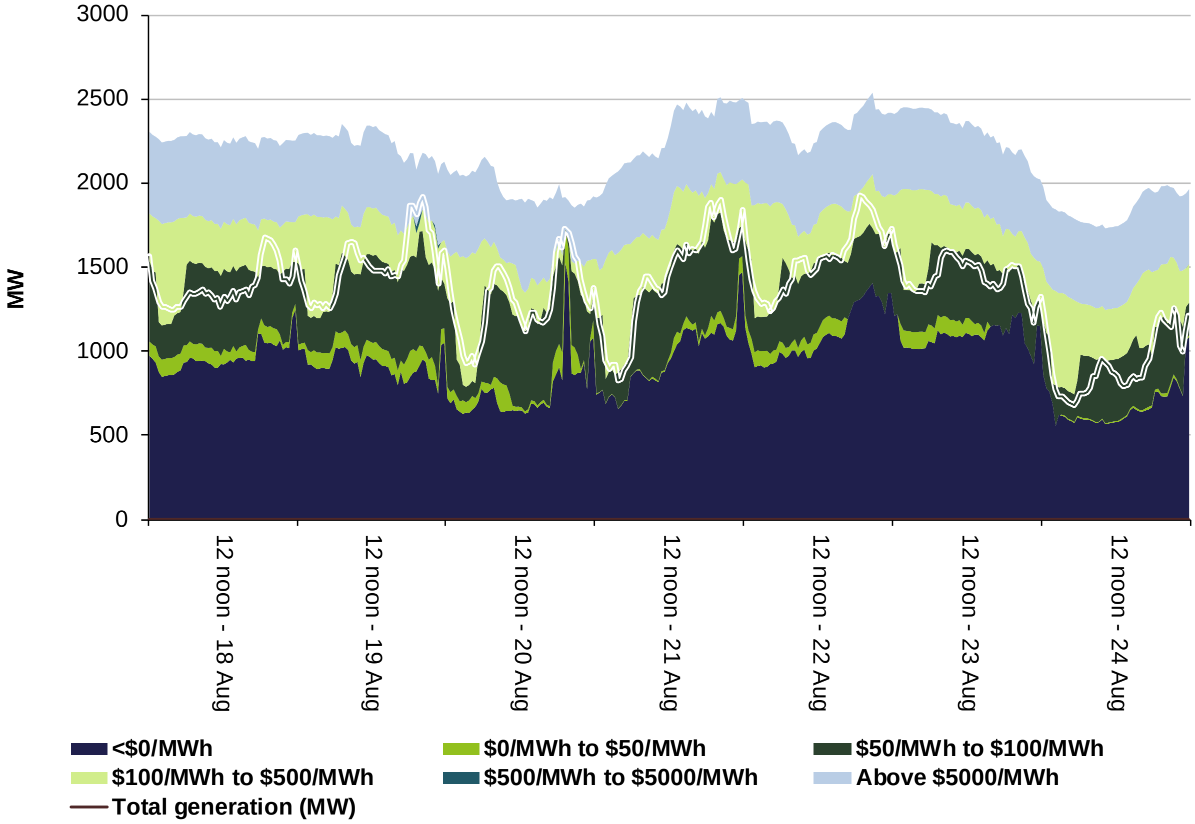
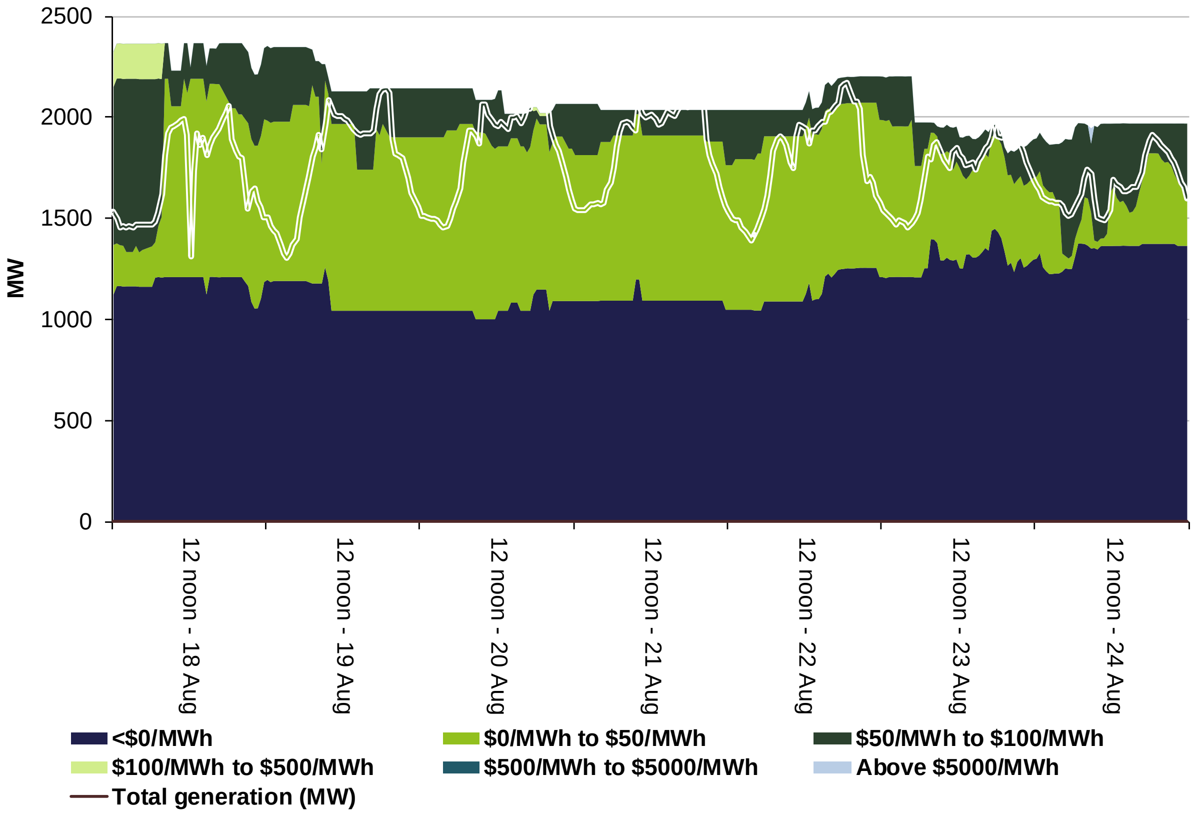


Figure 6: Tasmania generation and bidding patterns



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:

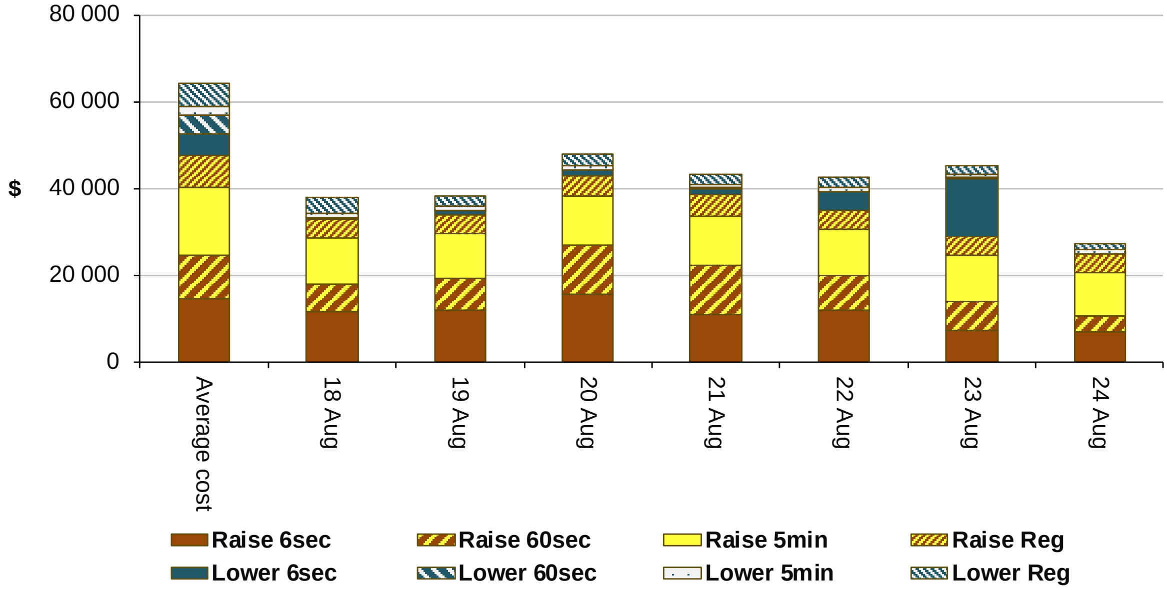
- *fast services*, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- *slow services*, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- *delayed services*, which return the frequency to the 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 $239 000 or less than one 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 $43 000 or less than one 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 average weekly price in a region and above $250/MWh or was below -$100/MWh.

There were eight such occasions during this week, three of which occurred in Queensland, two occurred in South Australia and three in Tasmania. The tables below show actual regional price, demand and available capacity outcomes, for each of the prices of interest, compared to those forecast 4 and 12 hour ahead.

Table 3: Queensland, Wednesday 21 August

7:00 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2251.10	320.03	320.03
Demand (MW)	6085	6028	6049
Available capacity (MW)	8796	8889	8979

Demand was close to forecast and available capacity was slightly lower than that forecast four ahead.

Over two rebids from 4.12 am, CS Energy reduced the available capacity of Gladstone unit 2 by 100 MW, all of which was priced below $30/MWh. The reason given was “unit rts revised –sl”. As part of these rebids, CS Energy reduced the ramp up and down rates at Gladstone unit 2 from 5 MW/min to 1 MW/min.

At 6.45 am, effective from 6.55 am, Origin Energy reduced the available capacity at its Darling Downs power station by 12 MW, all of which was priced below $55/MWh. The reason given was “Change in avail – ambient temps SL”.

At 6.37 am, effective from 6.45 am, Alinta Energy rebid 48 MW of capacity at Braemar unit one from prices below $50/MWh to above $12 000/MWh. The reason given was “0636P 0655PD $432.50 vs $90.38@06.37”. At 6.51 am, effective from 7 am, Alinta Energy reversed this rebid shifting 48 MW of capacity from prices above $12 000/MWh to below $50/MWh. The reason given was “0650A spot price $99.25 vs pd $80.92@06:51”.

Demand increased from 6062 MW at 6.50 am to 6159 MW at 6.55 am and to 6271 MW at 7 am (209 MW in total). Over the same period, scheduled flows across the QNI interconnector into Queensland increased by 60 MW to the limit of 172 MW (the Directlink interconnector was out of service). The remaining increase in demand of around 150 MW was unable to be satisfied by local low-price generation, some of which was ramp rate limited and 1586 MW of which was fast start plant (with 716 MW priced at $2100/MWh or less) which was unable to come online in time. In addition, a significant amount (788 MW) of online generation capacity at the Stanwell power station was priced at close to the price cap.

As a result high priced generation was dispatched to meet the increase in demand, which saw the five-minute price increase from $99/MWh at 6.55 am to the price cap at 7 am.

At 7.05 am an increase in output from some low-price generators saw the five-minute price fall to around $55/MWh.

There was no other significant rebidding.

Table 4: Queensland, Thursday 22 August

7:00 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2251.10	320.03	320.03
Demand (MW)	6085	6028	6049
Available capacity (MW)	8796	8889	8979

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

Demand increased by 140 MW from 6110 MW at 6.45 am to 6250 MW at 6.50 am. Over the same period, scheduled flows across the QNI interconnector into Queensland increased by 38 MW to the limit of 178 MW (the Directlink interconnector was out of service). The remaining increase in demand of around 102 MW was unable to be satisfied by local low-price generation which was either ramp rate limited, trapped or stranded in FCAS and 1565 MW of fast start plant (with 716 MW priced at $2100/MWh or less) was unable to come online in time.

In addition, a significant amount of online generation (768 MW across the Stanwell portfolio)) was priced at close to the price cap.

As a result high priced generation was dispatched, which saw the five-minute price increase from $67/MWh at 6.45 am to the price cap at 6.50 am.

At around 6.50 am, Queensland generators rebid around 40 MW of capacity from prices above $12 000/MWh to close to the price floor. This saw the five-minute price at 6.55 am fall to around $55/MWh.

There was no other significant rebidding.

Table 5: Queensland, Friday 23 August

7:00 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2251.10	320.03	320.03
Demand (MW)	6085	6028	6049
Available capacity (MW)	8796	8889	8979

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

At 6.30 am, effective at 6.40 am, Origin Energy reduced the available capacity at Darling Downs by 15 MW, all of which was priced close to the price floor. The reason given was “0628P Chg in avail – ambient temps SL”.

Demand increased by 77 MW, from 6127 MW at 6.35 am to 6204 MW at 6.40 am. During this time the Directlink interconnector was out of service and flow on QNI was at its limit. The 77 MW of demand was unable to be satisfied by local low-price generation which was either ramp rate limited, trapped or stranded in FCAS and 1735 MW of fast start plant (with 886 MW priced at $2100/MWh or below) was unable to come online in time.

In addition, a significant amount (768 MW) of online generation at Stanwell was priced at close to the price cap.

As a result high priced generation was dispatched, which saw the five-minute price increase from $91/MWh at 6.35 am to the price cap at 6.40 am.

At around 6.40 am Queensland generators rebid around 205 MW of capacity from prices above $12 000/MWh to close to the price floor. This saw the five-minute price at 6.45 am fall to around $60/MWh.

There was no other significant rebidding.

Table 6: South Australia, Tuesday 20 August

7:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1911.56	11 011.69	11 011.69
Demand (MW)	2099	2207	2174
Available capacity (MW)	1912	1980	1967
8:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1916.32	300.07	11 011.69
Demand (MW)	2113	2176	2151
Available capacity (MW)	1889	2009	1958

Conditions at the time saw demand and available capacity close to forecast. Throughout the day, spot prices for the 7.30 pm and 8 pm trading intervals were forecast to exceed $11 000/MWh, but were moderated down below $300/MWh after the 4 hour ahead forecast.

Supply conditions were tight in South Australia, with no available capacity offered between $200/MWh and $10 000/MW. Conditions saw low levels of wind at the time, with output below 150 MW during both trading intervals. Import limits on the Murraylink and Heywood interconnectors were both lower than forecast.

The constraint managing post-contingent flow on a Heywood 500 kV transformer on the loss of the other transformer bound, reducing the import limit by 17 MW for the 7.05 pm dispatch interval. This reduction in supply coincided with a 16 MW increase in five minute demand. With all other online South Australian generation generating at full capacity or trapped in FCAS and both interconnectors at limit, high priced capacity at Hallett Power Station was dispatched, setting the five minute dispatch price at $11 108/MWh for the 7.05 pm dispatch interval. The dispatch price in subsequent dispatch intervals dropped to below $100/MWh as participants rebid capacity into lower price bands.

At approximately 7.45 pm, effective from 7.55 pm, AGL rebid reducing the available capacity at Torrens Island B unit 2 by 13 MW to zero. The reason given was "19:43P Reduction in avail cap:: RTS later than exp ". All of this capacity was offered at the price floor. This reduction in availability of low-price capacity coincided with the constraint managing post-contingent flow on the Heywood transformer reducing the import limit on the Heywood interconnector by 25 MW. At the same time, five-minute demand increased by 34 MW. With both interconnectors at limit and all other online South Australian generation generating at full capacity or trapped or stranded in FCAS, high priced capacity at Dry Creek was dispatched setting the five minute dispatch price at $11 012/MWh for the 7.55 pm dispatch interval.

There was no other significant rebidding.

Table 7: Tasmania, Sunday 18 August

Midday	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	413.43	38.30	38.37
Demand (MW)	1209	1097	1084
Available capacity (MW)	2367	2301	2301
12:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	811.19	38.30	39.86
Demand (MW)	1065	1081	1069
Available capacity (MW)	2247	2301	2300

Conditions at the time saw demand up to 112 MW higher than that forecast 4 hours ahead and available capacity was close to that forecast.

Due to lightning in the area throughout the morning, at 11.55 am AEMO declared the simultaneous loss of the George Town to Sheffield and the George Town to Hadspen 220 kV lines as credible contingency events and invoked constraints accordingly. The constraints invoked affect all generation in Tasmania (with the exception of Tamar Valley generation, which was offline at the time).

From 11.55 am to 12.10 pm the constraints managing the credible contingency reduced Tasmanian generation by around 770 MW but the changes were insufficient to meet the constraint requirements, causing at least one constraint to violate for the 11.55 am to 12.15 pm dispatch intervals. The reduction in generation led to flows on Basslink changing from exports to Victoria to imports into Tasmania (crossing the no go-zone between 12.05 pm to 12.10 pm). As a result the five minute price was above $1000/MWh from 11.55 am to 12.10 pm, reaching a maximum of $3520/MWh at 12.05 pm.

Prices returned to previous levels at 12.20 pm, shortly after Basslink began importing into Tasmania.

There was no significant rebidding.

Table 8: Tasmania, Friday 23 August

8 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1982.56	42.06	98.42
Demand (MW)	1348	1406	1399

Available capacity (MW)	1975	1886	1887

Conditions at the time saw demand up to 58 MW lower than forecast 4 hours ahead and available capacity close to forecast.

At 6.15 am an increase in flows across the Sheffield to Georgetown 220 kV line caused the T>>T_NIL_BL_EXP_6E constraint to bind, causing generation in Tasmania to be constrained off. The constraint (which is a system normal constraint) manages post contingent flows on the Sheffield to Georgetown 220 kV lines, preventing an overload on the parallel line in the event of a trip. The constraint affects all Tasmanian generation except for generation at Tamar Valley (which was offline) and forces exports into Victoria across Basslink. The constraint bound for most dispatch intervals until 7.30 am.

Due to limited ramp rate capability and generators stranded in FCAS the constraint violated at 7.35 am, reducing Tasmanian generation by 174 MW and exports to Victoria from 248 MW at 7.30 am to 63 MW at 7.35 am. This coincided with the morning peak demand and the five minute price reached $11 707/MWh.

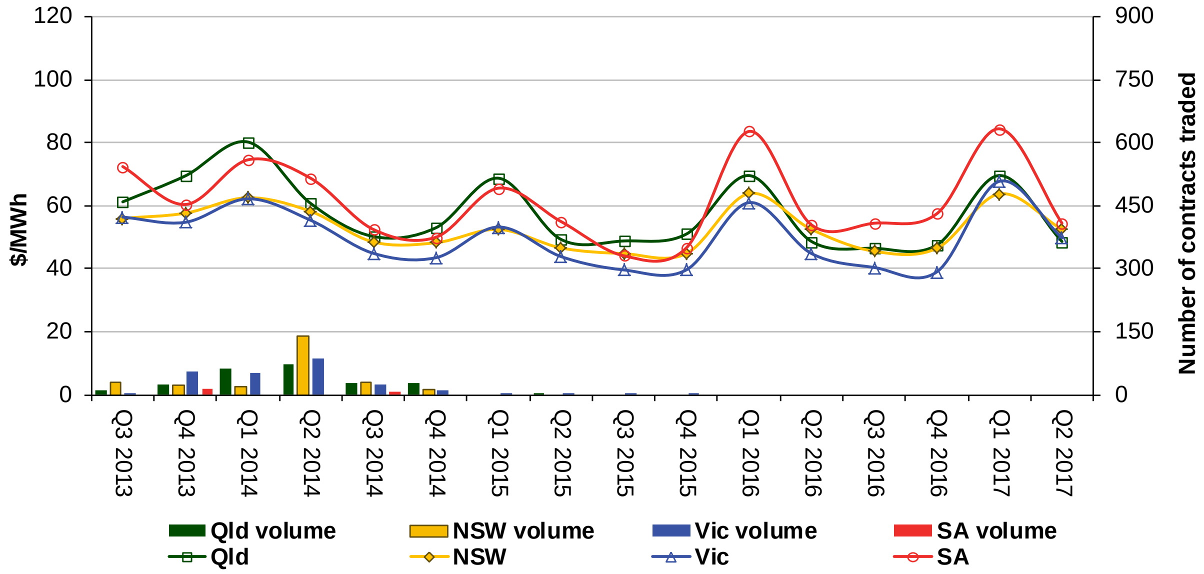
Prices returned to previous levels in the following dispatch interval due to a reduction in flow across the Sheffield to Georgetown 220 kV line and a demand side response from the Nyrstar smelter.

There was no 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.

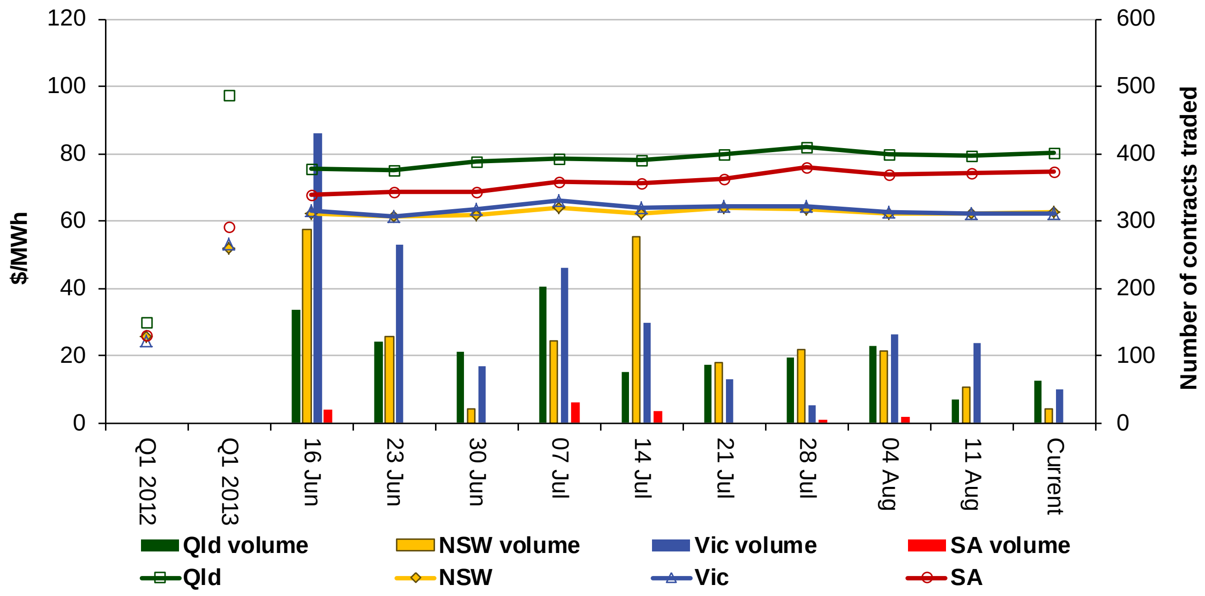
Figure 8: Quarterly base future prices Q3 2013 – Q2 2017



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)



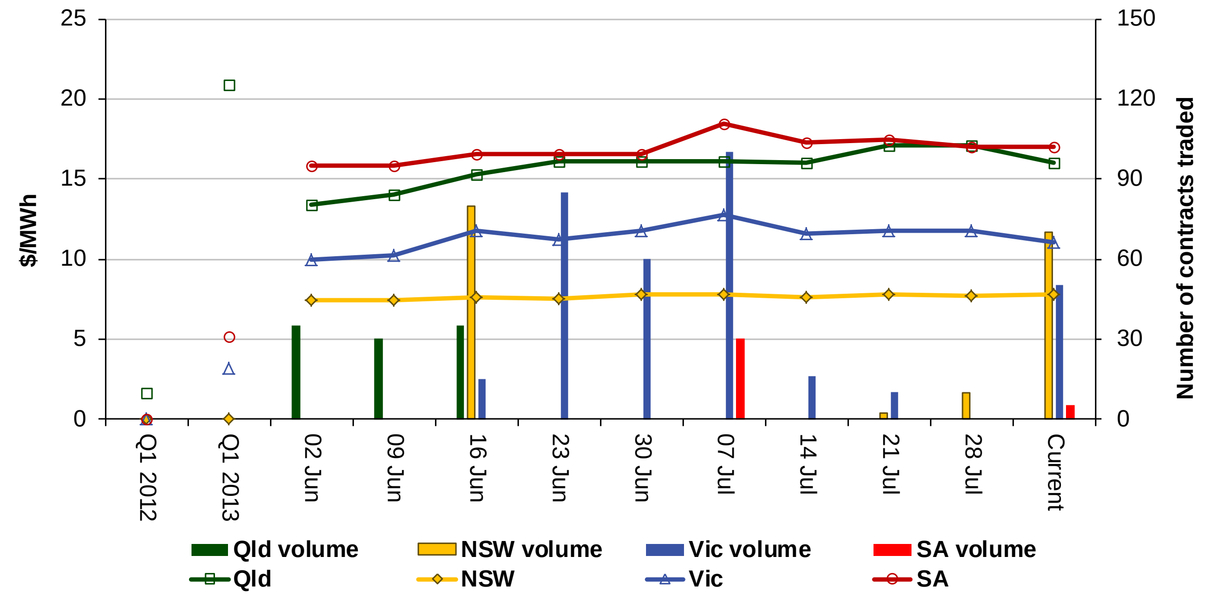
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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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