Electricity Report

26 October – 1 November 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.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 26 October to 1 November 2014. The spot price in Queensland reached $338/MWh and $275/MWh at 3 pm and 5 pm respectively on 27 October and $264/MWh at 5 pm on 28 October. The spot price in Tasmania reached $1732/MWh at 6.30 am on 28 October.

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

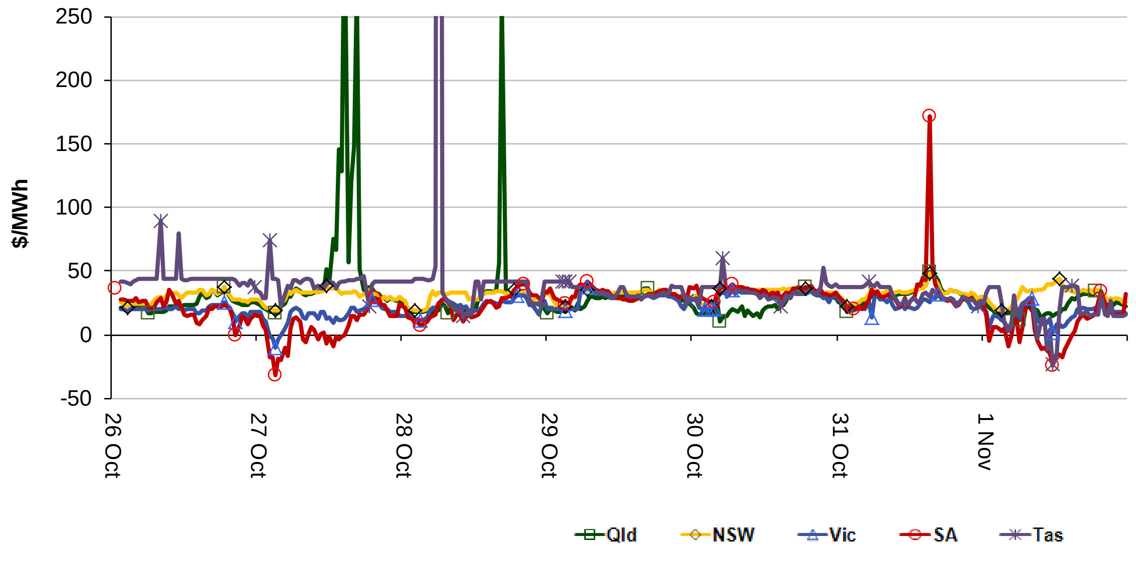


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years. The figure shows that the average weekly spot price in Queensland has moved back in line with other regions, following record lows for the previous few weeks.

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

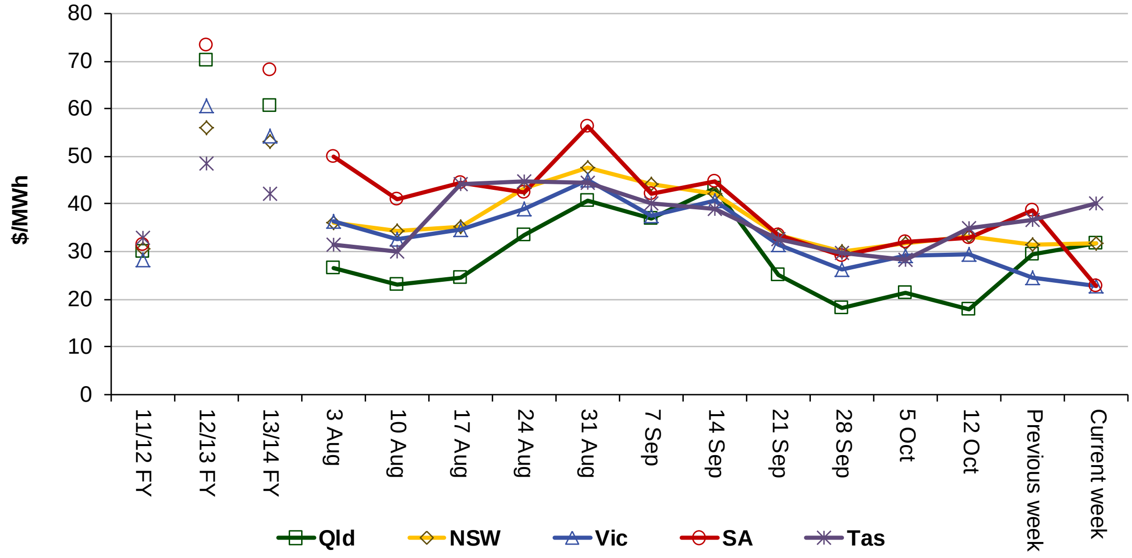


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	32	32	23	23	40
13-14 financial YTD	61	55	54	67	45
14-15 financial YTD	30	38	35	44	36

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 152 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

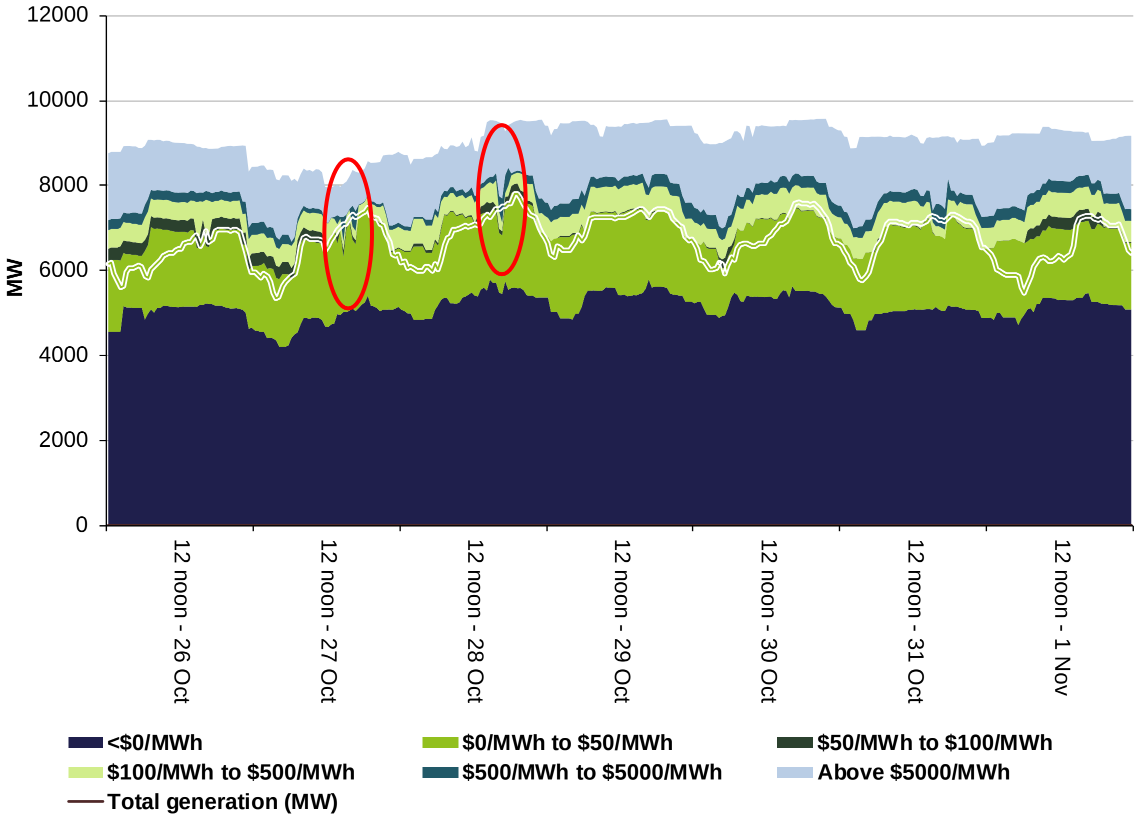
	Availability	Demand	Network	Combination
% of total above forecast	11	21	0	3
% of total below forecast	38	24	1	3

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



The red circles show the rebidding by Stanwell described in the "Detailed market analysis of significant price events".

Figure 4: New South Wales generation and bidding patterns

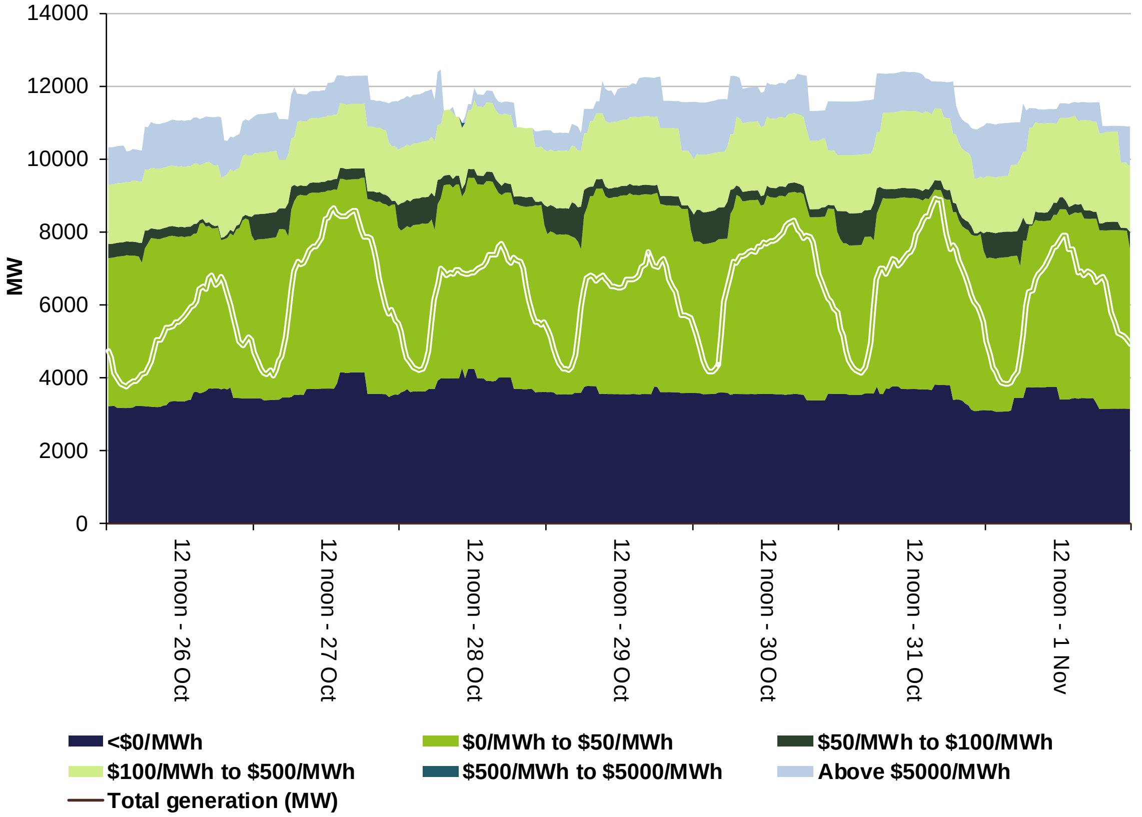


Figure 5: Victoria generation and bidding patterns

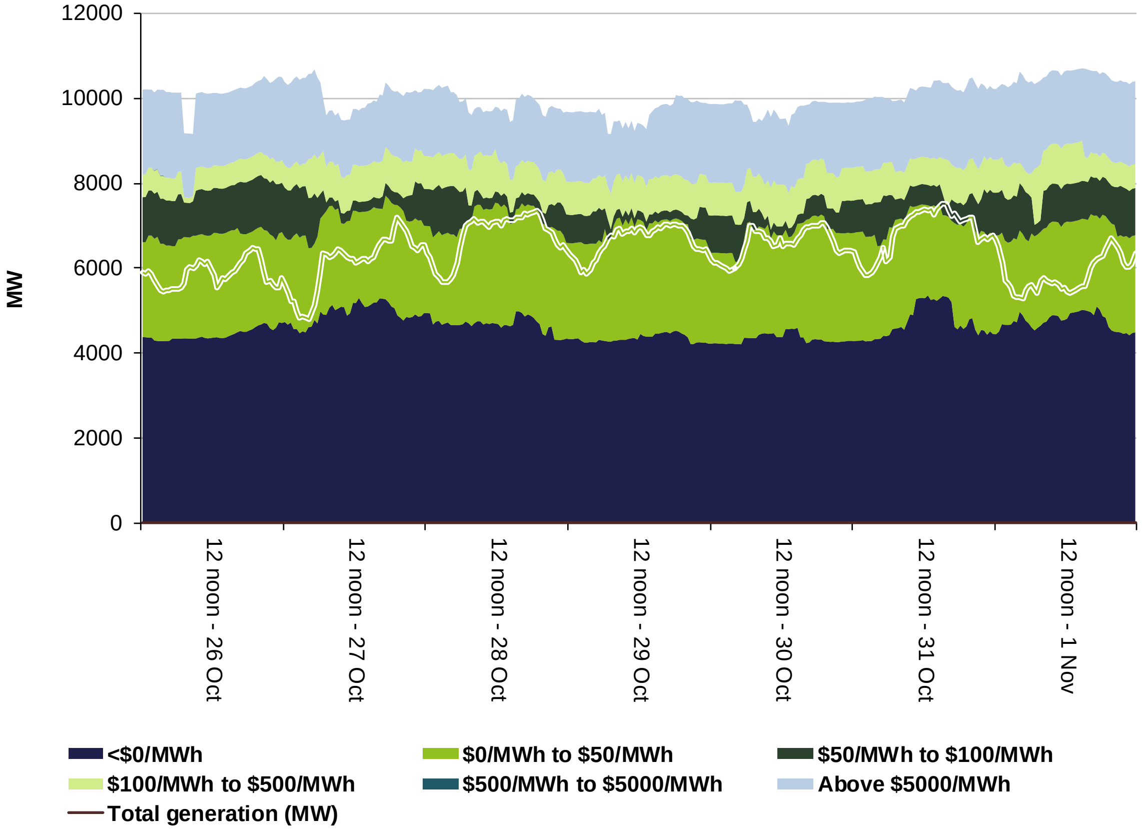


Figure 6: South Australia generation and bidding patterns

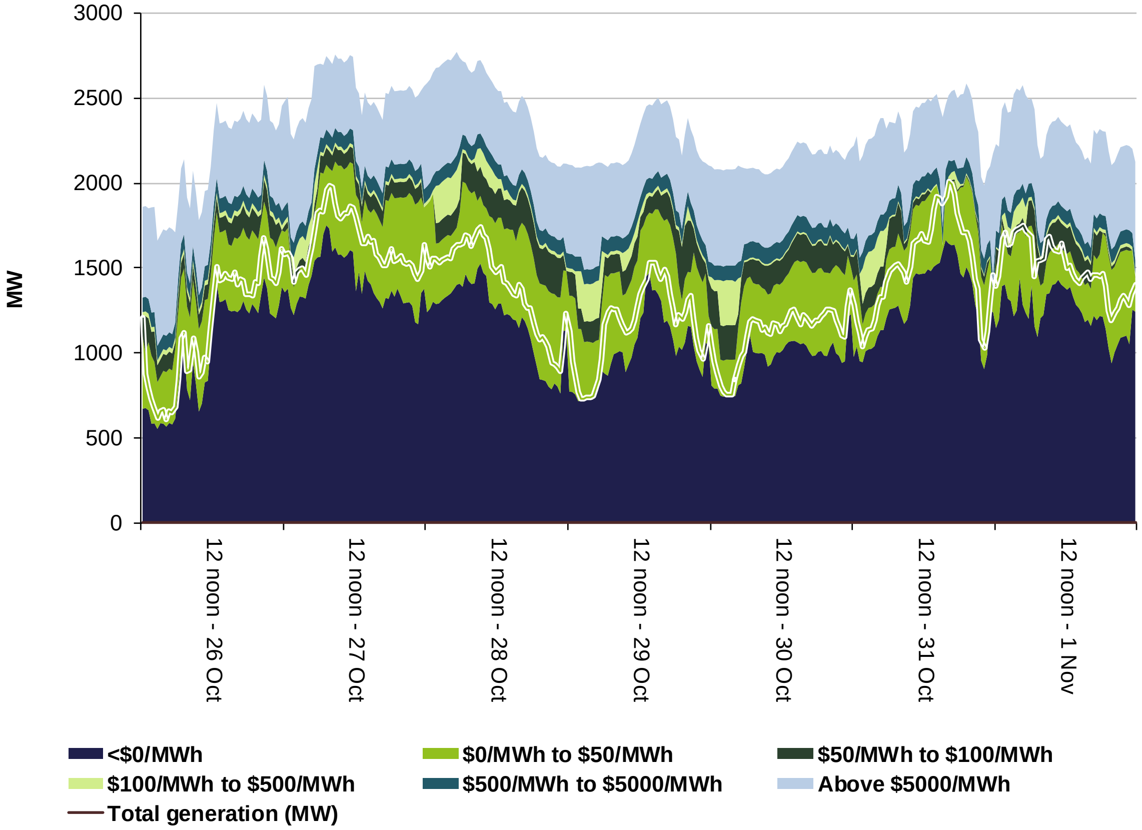
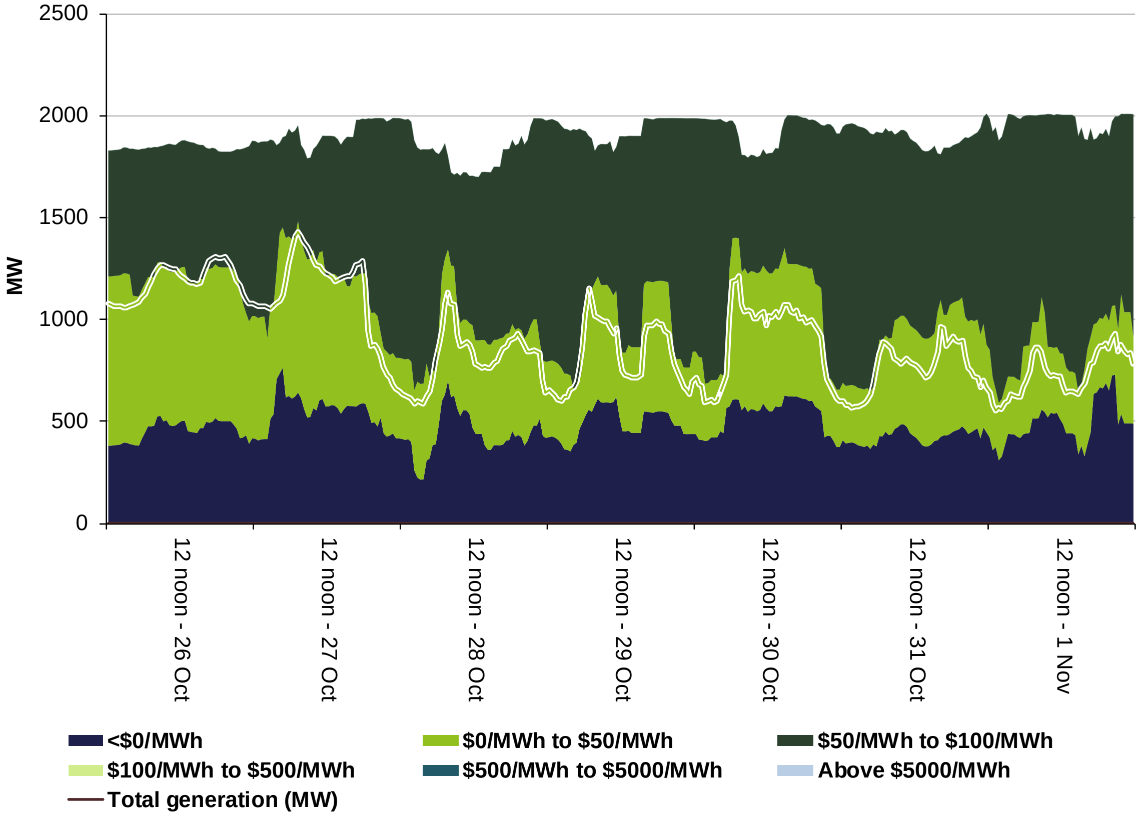


Figure 7: Tasmania generation and bidding patterns



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.

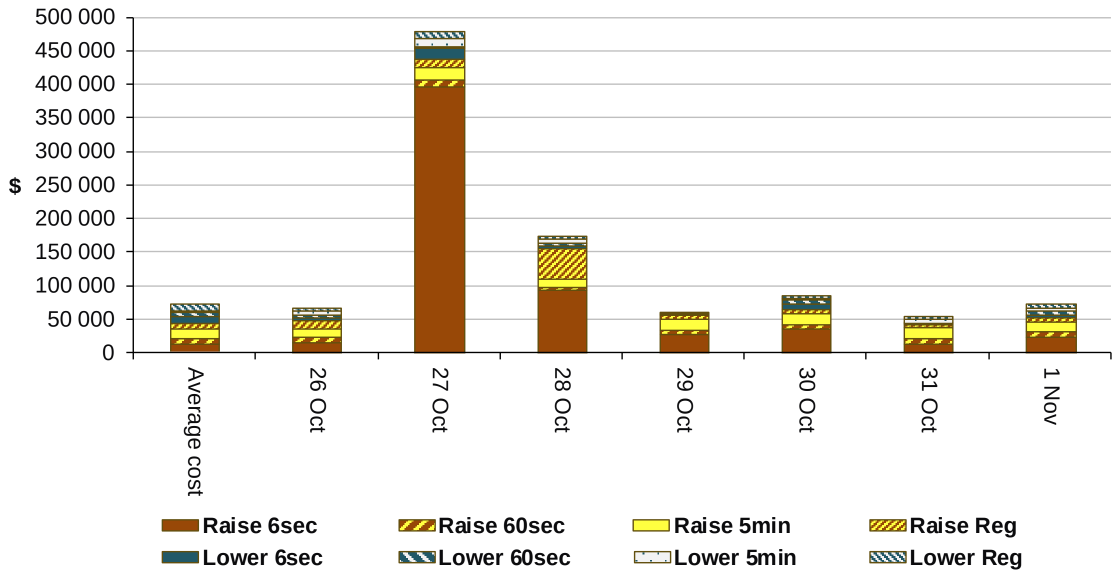
The total cost of FCAS on the mainland for the week was $316 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $667 500 or around 9 per cent of energy turnover in Tasmania. On 27 October the price for raise 6 second services exceeded $4300/MW between 3 am and 3.45 am inclusive. Basslink was on a planned outage therefore Tasmanian FCAS had to be sourced locally. At 2.35 am the loss of both Farrell to Sheffield lines were declared a credible contingency and a constraint was invoked to manage the raise 6 second requirement. This constraint manages generation at Reece, Bastyan and John Butters. At 3 am the constraint was constraining down the supply of raise 6 second services from these units. However, the constraint violated when other generators were unable to supply sufficient raise 6 second services to compensate. This saw prices reach around $4400/MW for ten dispatch intervals at a cost of around $325 000.

On 28 October the price for raise 6 second services reached the price cap at 6.25 am as a result of the co-optimisation of the FCAS and energy markets. See the "Detailed market analysis of significant price events" section below for further details.

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.

Queensland

There were three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $32/MWh and above $250/MWh.

Table 3: Monday 27 October

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 pm	337.71	93.25	56.85	7185	7366	7411	8015	8756	8844

Demand and availability were around 200 MW and 740 MW lower than forecast four hours respectively.

Over several rebids from 11.30 am, Stanwell reduced the available capacity of Tarong North by a total of 360 MW, almost all of which was priced at the price floor. The reasons given all related to the unit tripping and its delayed return to service.

At 12.30 pm AGL reduced the available capacity at Yabulu by 152 MW, all of which was priced at or below zero. The reason given was “unexpected plant limitations::delay in steamer rts”.

Over two rebids at 1.51 pm and 2.16 pm, Millmerran Energy Trading reduced the available capacity of Millmerran unit 2 by a total of 185 MW after the unit had tripped. All of the capacity was priced at the price floor.

At 2.50 pm, effective from 3 pm only, CS Energy rebid 90 MW of capacity at Wivenhoe unit 1 from prices below $145/MWh to above $1380/MWh. The reason given was “Dispatch price higher than 30min forecast-SL”. At 2.51 pm, effective for 3 pm only, Stanwell rebid 535 MW of capacity across its portfolio from prices below $30/MWh to above $1390/MWh. The reason given was “Material change Qld 5 min RRP v 5 min PD 1455 –SL”. This resulted in the dispatch price increasing from $94/MWh at 2.55 pm to $1400/MWh at 3 pm with Stanwell setting the price.

Table 4: Monday 27 October

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
5 pm	275.13	41.01	93.25	7346	7616	7789	8332	9158	9249

Demand and available capacity were 270 MW and 800 MW lower than forecast four hours ahead, respectively. Over two rebids from 2.36 pm, CS Energy reduced the available capacity of Kogan Creek and Gladstone unit 5 by a total of 520 MW, all of which was priced below $20/MWh. The reasons given all related to the updated unit ramp up schedule.

Over two rebids from 3.07 pm, Stanwell reduced the available capacity of Tarong North by a total of 360 MW, 250 MW of which was priced at the floor. The reasons given all related to the delayed return to service of the unit.

At 4.51 pm, effective for 5 pm only, Stanwell rebid 618 MW of capacity across its portfolio from prices below $30/MWh to above $1350/MWh. The reason given was “change 5 min PD Qld demand 1635-1650-SL”. This resulted in the dispatch price increasing from $37/MWh at 4.55 pm to $1400/MWh at 5 pm, with Stanwell’s Swanbank E setting the price.

Table 5: Monday 28 October

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
5 pm	263.95	31.00	21.65	7336	7150	7264	9465	9561	9726

Demand was 185 MW higher than forecast four hours ahead, and available capacity was close to forecast.

At 4.50 pm, effective for 5 pm only, Stanwell rebid a total of 751 MW of capacity across its portfolio to the price cap, the majority of which was priced below $50/MWh. The reason given was “material change in QNI flow DI1650”. At 4.51 pm, effective for 5 pm only, CS Energy rebid 200 MW of capacity at Gladstone from prices below $150/MWh to $1400/MWh. The reason given was “QNI flow > 30min forecast- SL”. These rebids resulted in the dispatch price increasing from $38/MWh at 4.55 pm to $1400/MWh at 5 pm.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $40/MWh and above $250/MWh.

Table 6: Sunday 28 October

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
6.30 am	1731.78	43.02	23.74	1279	1174	1144	1813	1983	1984

At 6.25 am there was a 42 MW increase in demand, during which time all available generation was either ramp up limited or trapped or stranded in FCAS. With Basslink importing at its limit, FCAS had to be sourced locally to meet requirements, which in turn led to high FCAS prices (as discussed in the FCAS section above). The co-optimisation of energy and FCAS set the price at $10 007/MWh at 6.25 am.

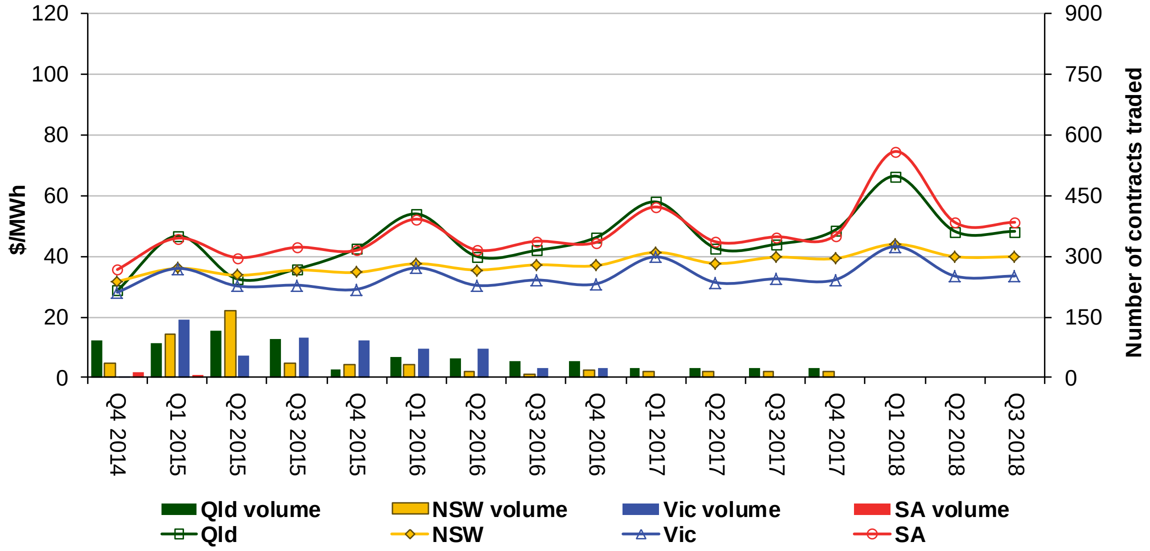
At 6.30 am the dispatch price fell to $44/MWh when Nystar reduced its load by around 70 MW, presumably in response to the high price.

There was no 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.

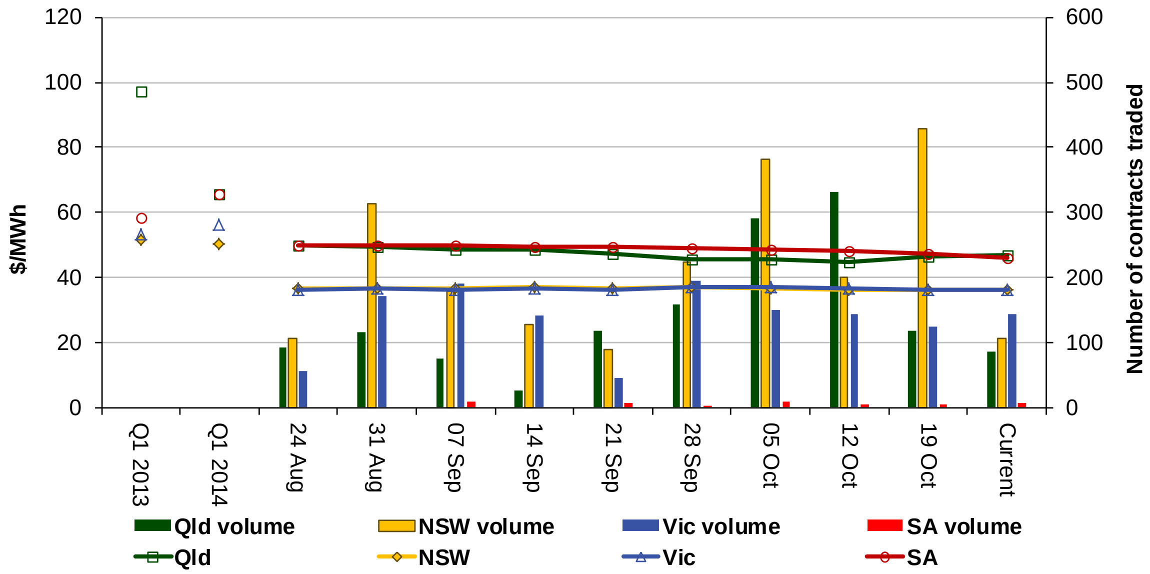
Figure 9: Quarterly base future prices Q4 2014 – Q3 2018



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)



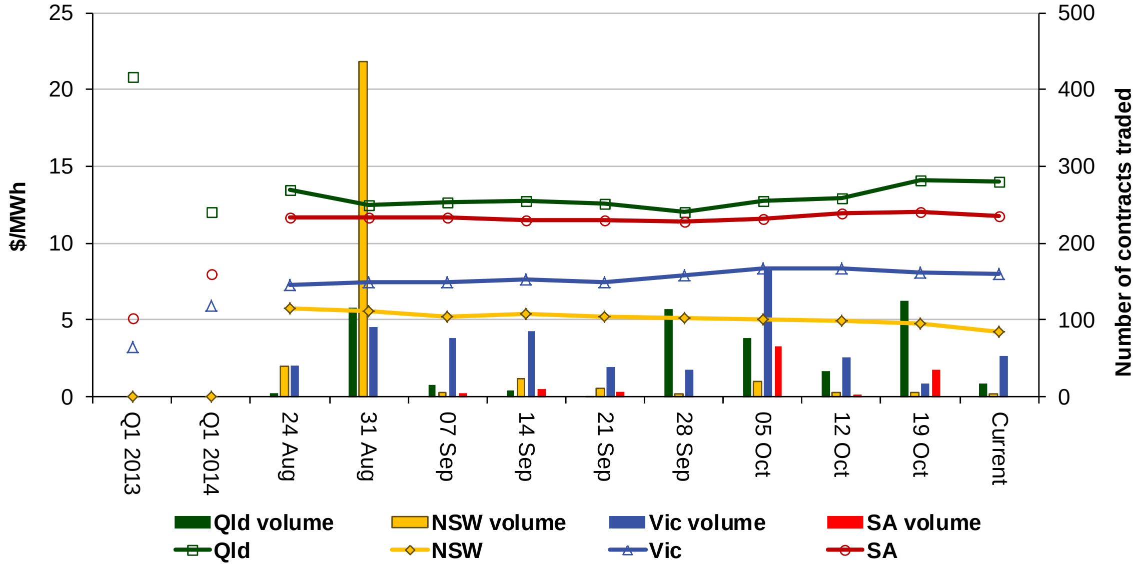
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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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