Electricity Report
23 – 29 August 2015

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 23 to 29 August 2015. There were two occasions in South Australia where the spot price exceeded the AER reporting threshold in South Australia. These are discussed later in this report.

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

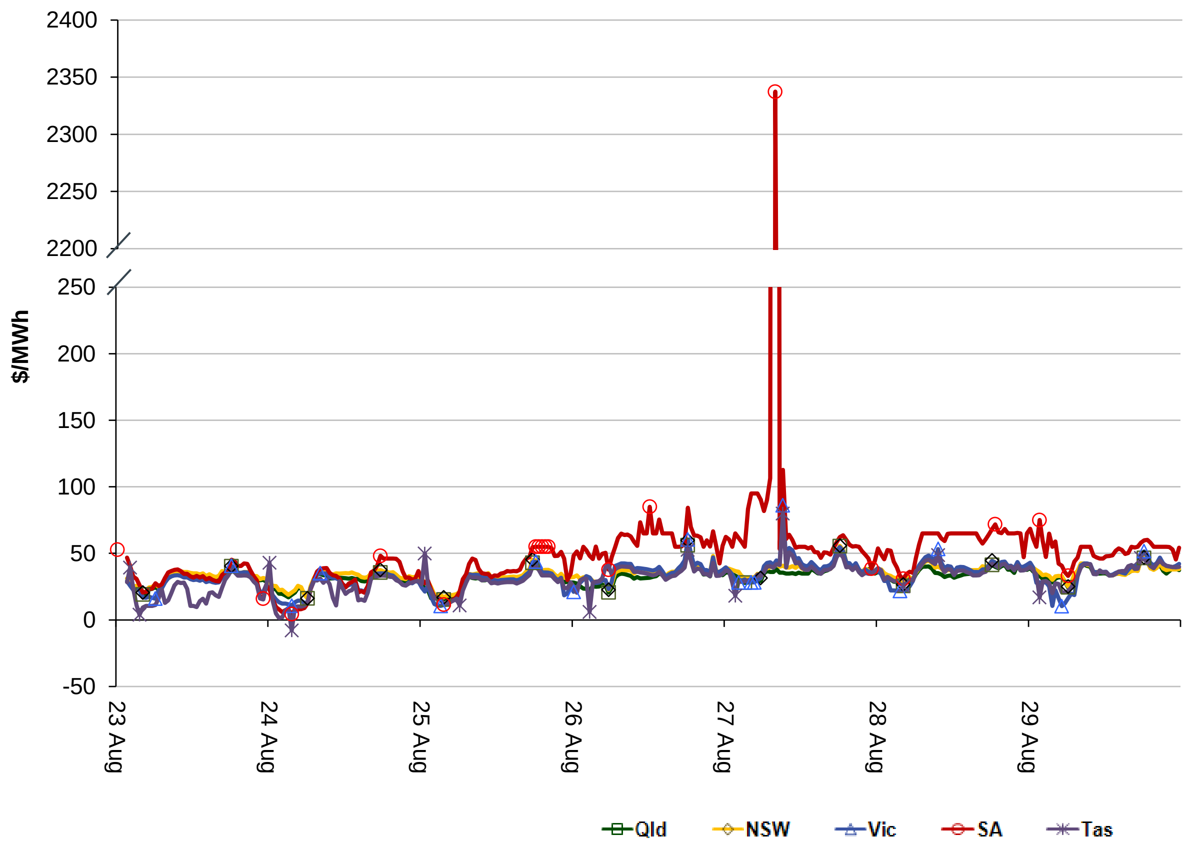


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

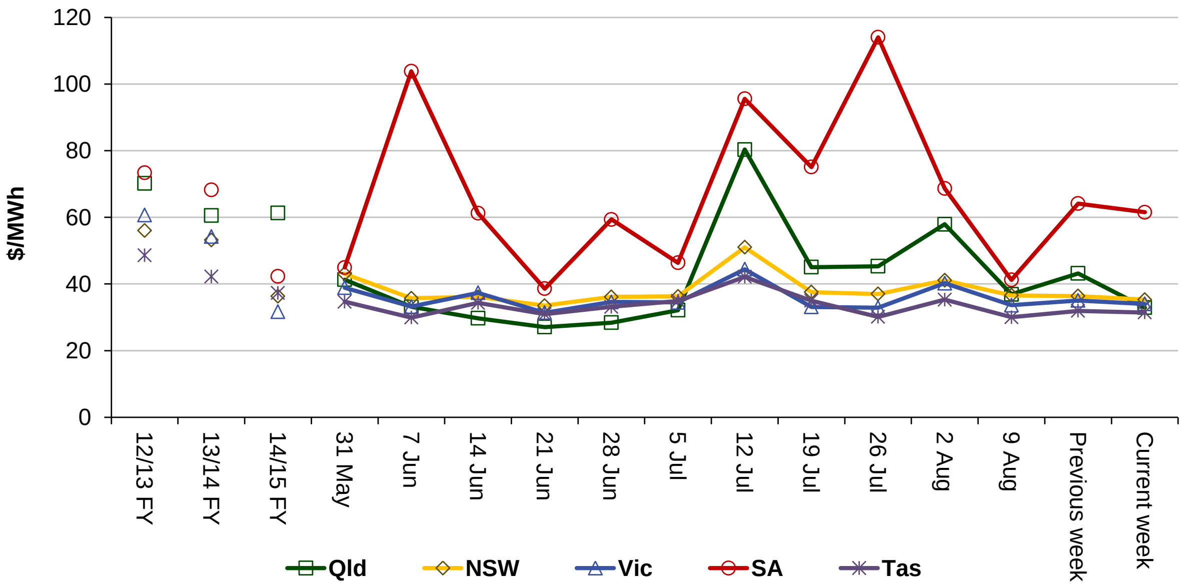


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	33	35	34	62	31
14-15 financial YTD	30	40	38	50	35
15-16 financial YTD	46	39	36	71	34

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 88 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2014 of 71 counts and the average in 2013 of 97. 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	13	17	0	2
% of total below forecast	56	13	0	0

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. Figure 3 to

Figure 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

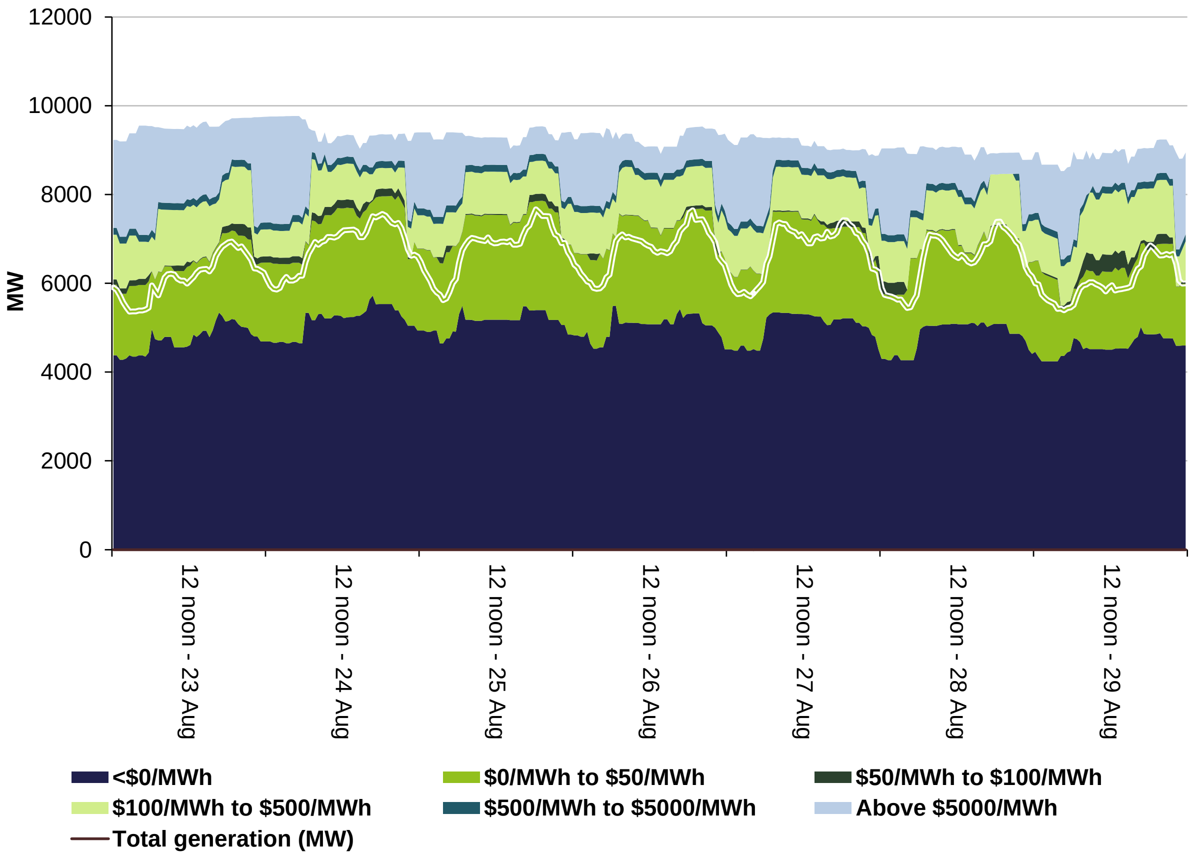


Figure 4: New South Wales generation and bidding patterns

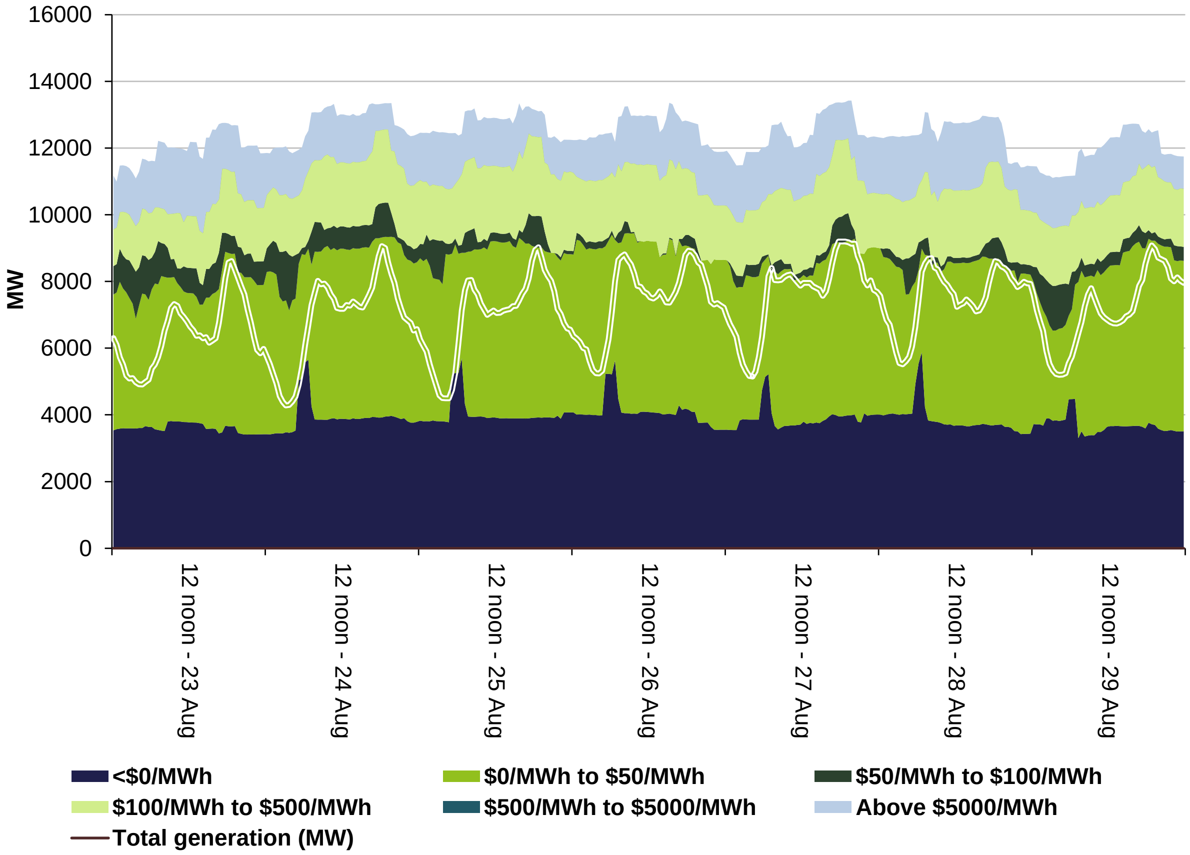


Figure 5: Victoria generation and bidding patterns

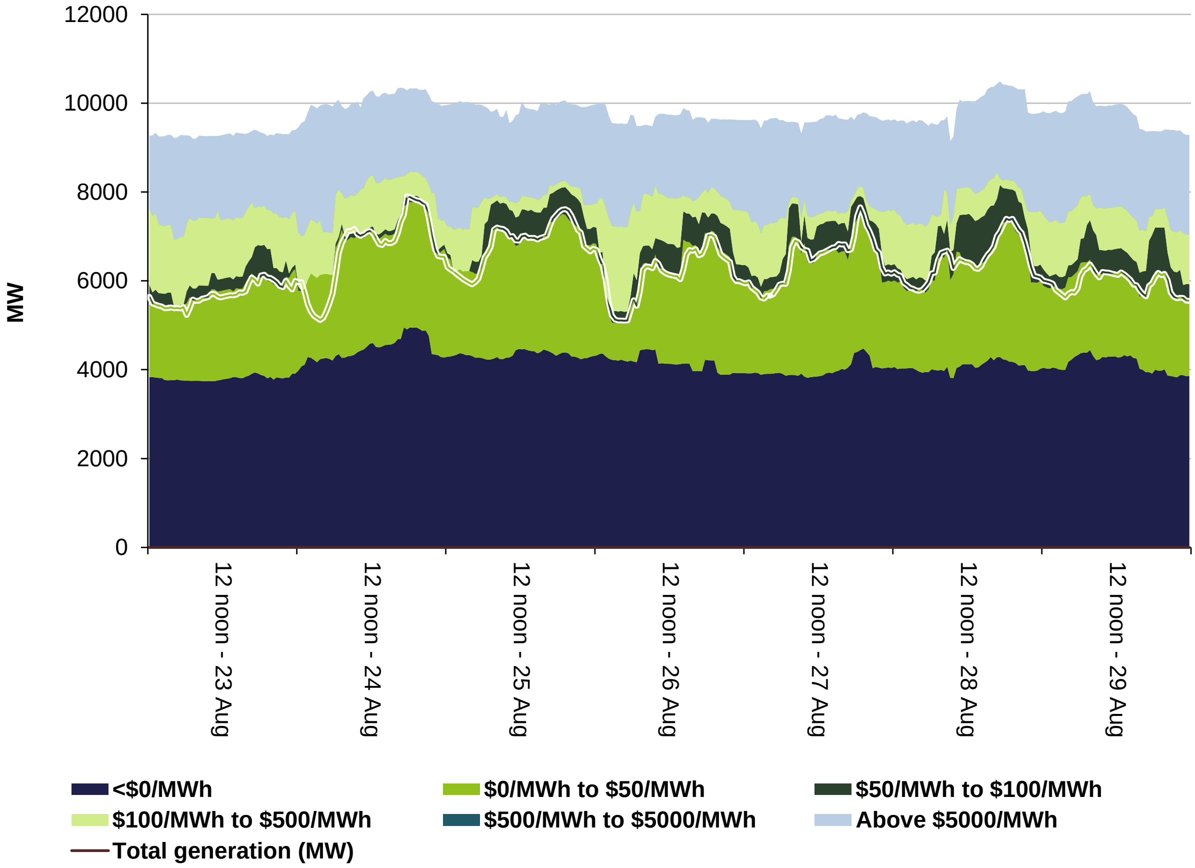
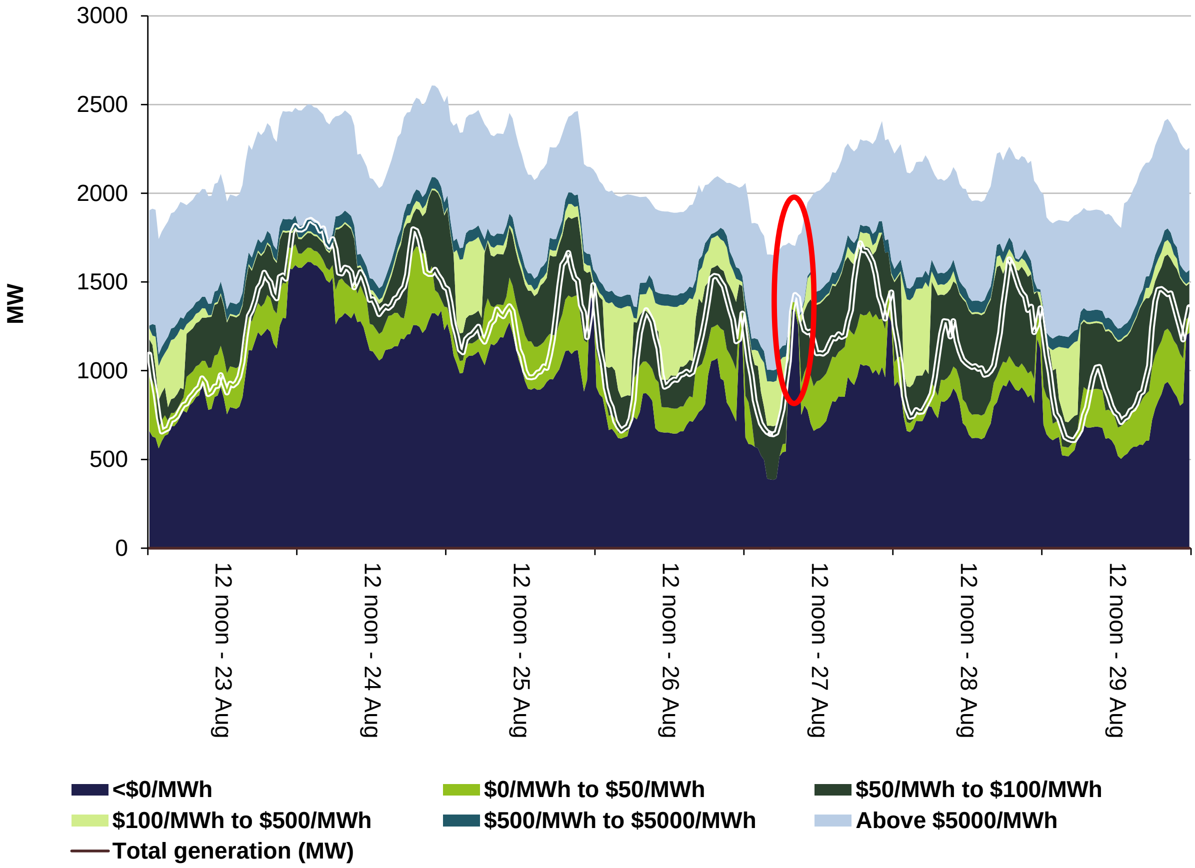
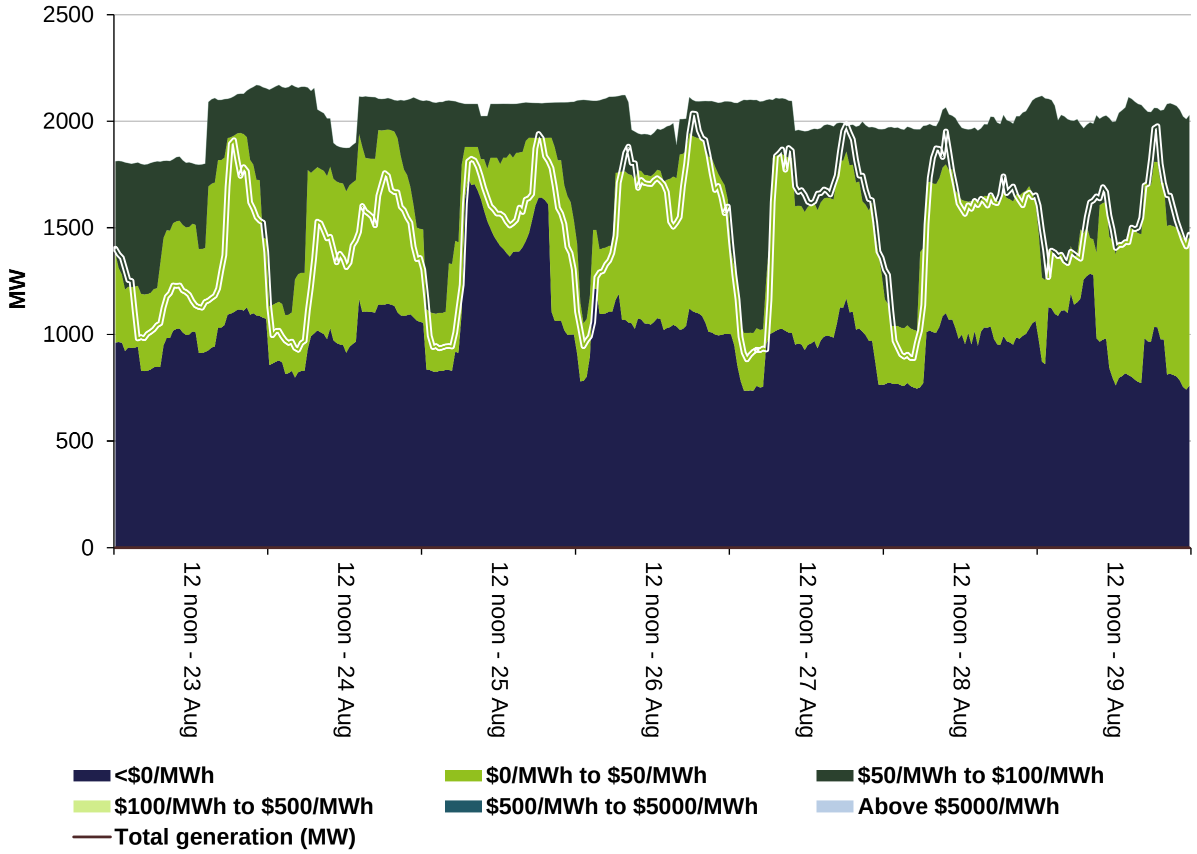


Figure 6: South Australia generation and bidding patterns



The area highlighted by the red ellipse in Figure 6 shows where rebidding contributed to high prices in South Australia on 27 August, as discussed in later in the report.

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.

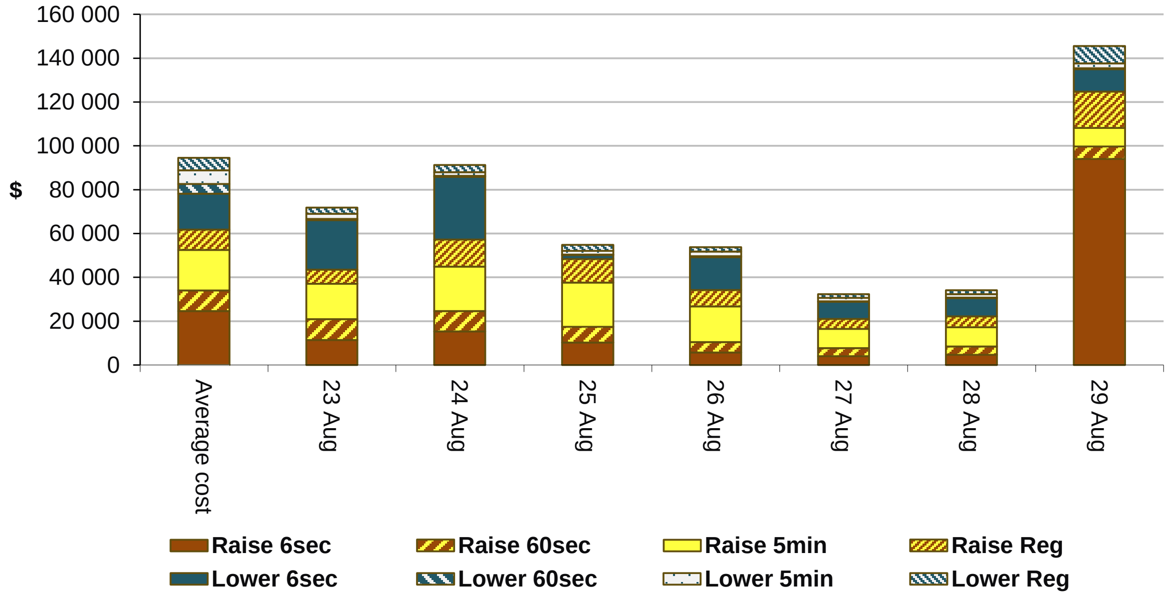
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $250 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $233 500 or around 3.5 per cent of energy turnover in Tasmania.

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



The high total cost of FCAS on 29 August was driven by events in Tasmania.

Over two rebids at 1.16 am and 1.35 am (the 1.35 am rebid became effective at 1.45 am) Hydro Tasmania withdrew a total of 12 MW of available capacity for raise 6 second services at Tungatinah. The reason for these rebids was 'constraint in transmission different from expected'.

At 1.40 am, the system normal constraint managing raise 6 second FCAS requirements in Tasmania for the loss of a Smithton to Woolnorth 110 kV line, or Norwood to Scottsdale to Derby 110 kV lines, bound. Basslink is unable to transfer FCAS when this constraint binds and therefore raise 6 second services must be acquired locally.

At 1.45 am, there was an increase in local raise 6 second services requirements in Tasmania. However, there was insufficient local raise 6 second services available to meet the increased requirements, and as a result the constraint violated. The local price of raise 6 second services increased from $9/MW at 1.40 am to the price cap at 1.45 am.

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.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $62/MWh and above $250/MWh.

Thursday, 27 August

Table 3: Price, Demand and Availability

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
8 am	2337	288	55	1672	1747	1767	1708	1755	2219
8.30 am	1835	127	65	1728	1814	1833	1704	1846	2271

Demand and available capacity were both lower than forecast four hours ahead.

Table 4: Rebids for the 8 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.03 am		Alinta Energy	Northern	-78	-1000	N/A	0600~p~revised unit availability~
7.18 am		AGL Energy	Torrens Island	45	<65	13800	0701~a~050 chg in aemo pd~54 pd price decrease [sa1] [$512 @8:00][$10,408 @ 8:30]

The above rebids contributed to creating a steep supply curve. Consequently, small changes in demand, interconnectors and availability led to large changes in price.

At 7.35 am demand increased by 85 MW (mostly from a reduction in non-scheduled generation). With lower priced generation ramp rate limited or fully dispatched, high priced generation had to be dispatched to meet demand. This resulted in the dispatch price increasing from $300/MWh at 7.30 pm to the price cap at 7.35 am.

At 7.40 am the dispatch price fell to $44/MWh as a result of a 177 MW reduction in demand (mostly from an increase in non-scheduled generation), and rebidding by AGL and GDF Seuz which moved a total 128 MW of capacity from the price cap to the price floor.

Table 5: Rebids for the 8.30 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.03 am		Alinta Energy	Northern	-108	-1000	N/A	0600~p~revised unit availability~
7.18 am		AGL Energy	Torrens Island	45	65	13 800	0701~a~050 chg in aemo pd~54 pd price decrease [sa1] [$512 @8:00][$10,408 @ 8:30]
7.41 am		EnergyAustralia	Hallett	40	<590	13 482	07:41 a band adj due to change in sa price sl
7.53 am		EnergyAustralia	Hallett	60	-1000	10 782	07:53 a band adj due to change in sa generation sl
8.00 am	8.10 am	GDF Suez	Snuggery	12	-1000	13 799	0800p fuel management: turn the unit off

The above rebids contributed to creating a steep supply curve. Consequently, small changes in demand, interconnectors and availability led to large changes in price.

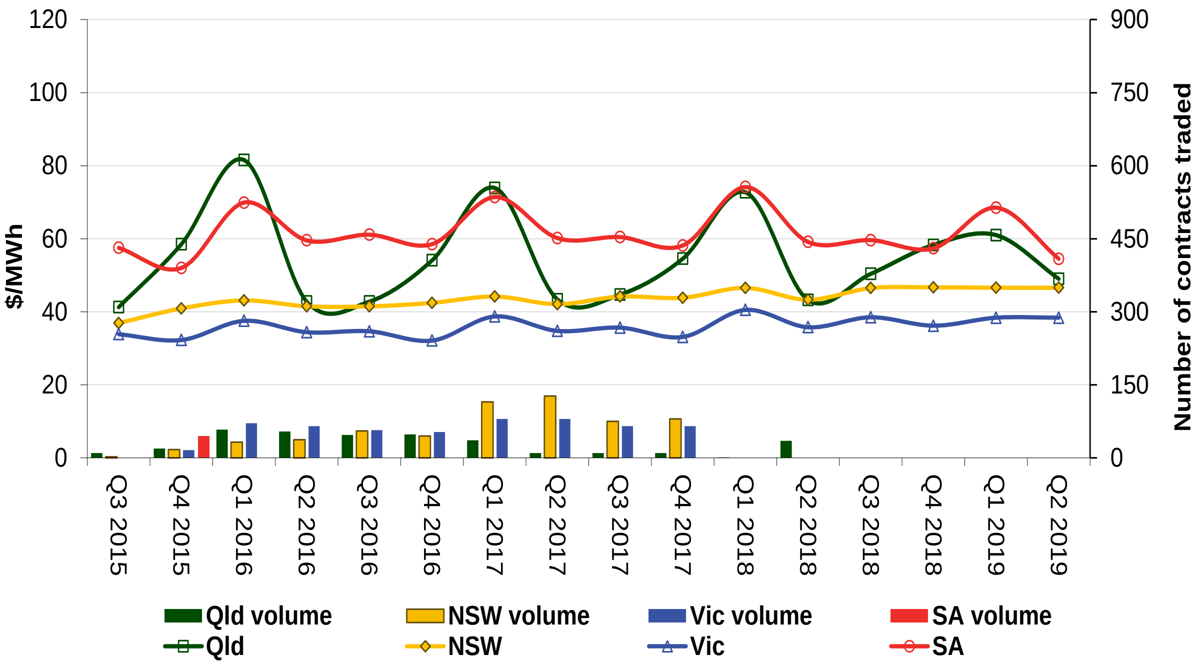
At 8.10 am there was an increase in demand of 137 MW (mostly from a reduction in non-scheduled generation). With lower priced generation fully dispatched or trapped in FCAS, higher priced generation had to be dispatched to meet demand. This resulted in the dispatch price increasing from $65/MWh at 8.05 am to $10 759/MWh at 8.10 am.

At 8.15 am the dispatch price fell to $47/MWh as a result of a 106 MW reduction in demand (mostly from an increase in non-scheduled generation) and by participants rebidding a total of 225 MW of capacity priced above $10 000/MWh to the price floor.

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.

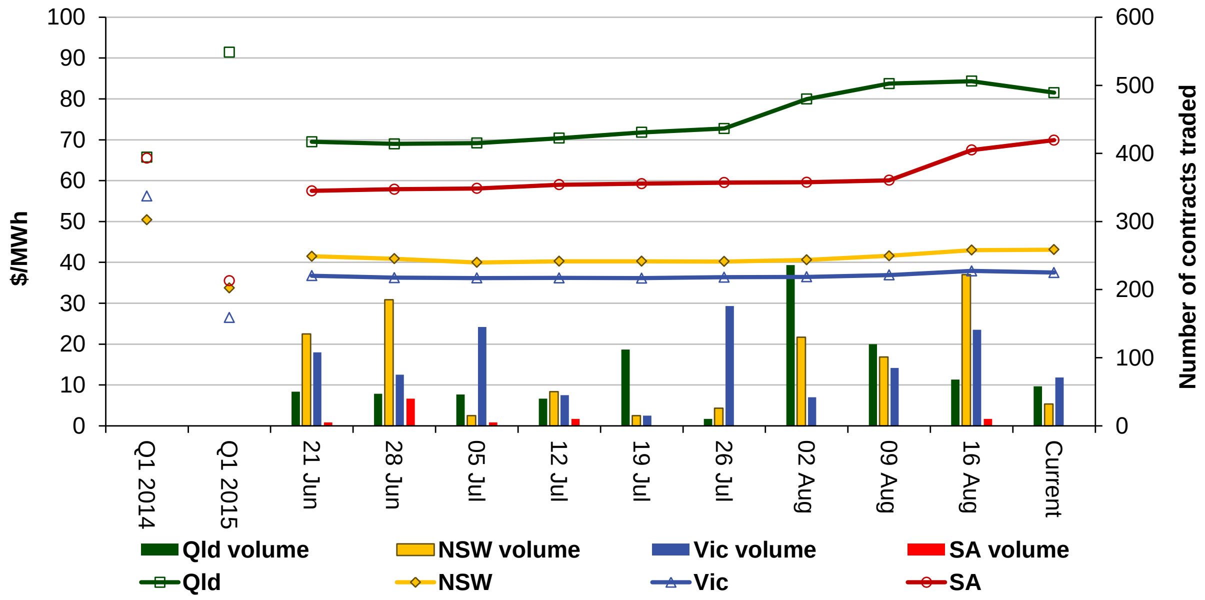
Figure 9: Quarterly base future prices Q3 2015 – Q2 2019



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 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 2016 base contracts over the past 10 weeks (and the past 2 years)



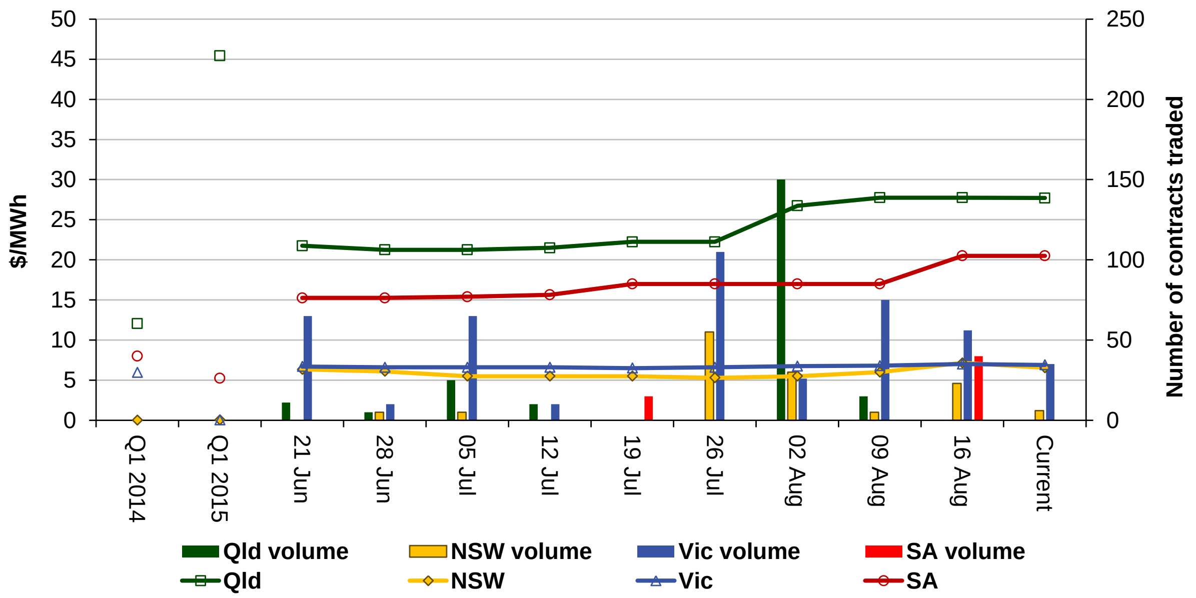
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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