Electricity Report

AUSTRALIAN ENERGY REGULATOR

27 August – 2 September 2017

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 27 August – 2 September 2017.

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

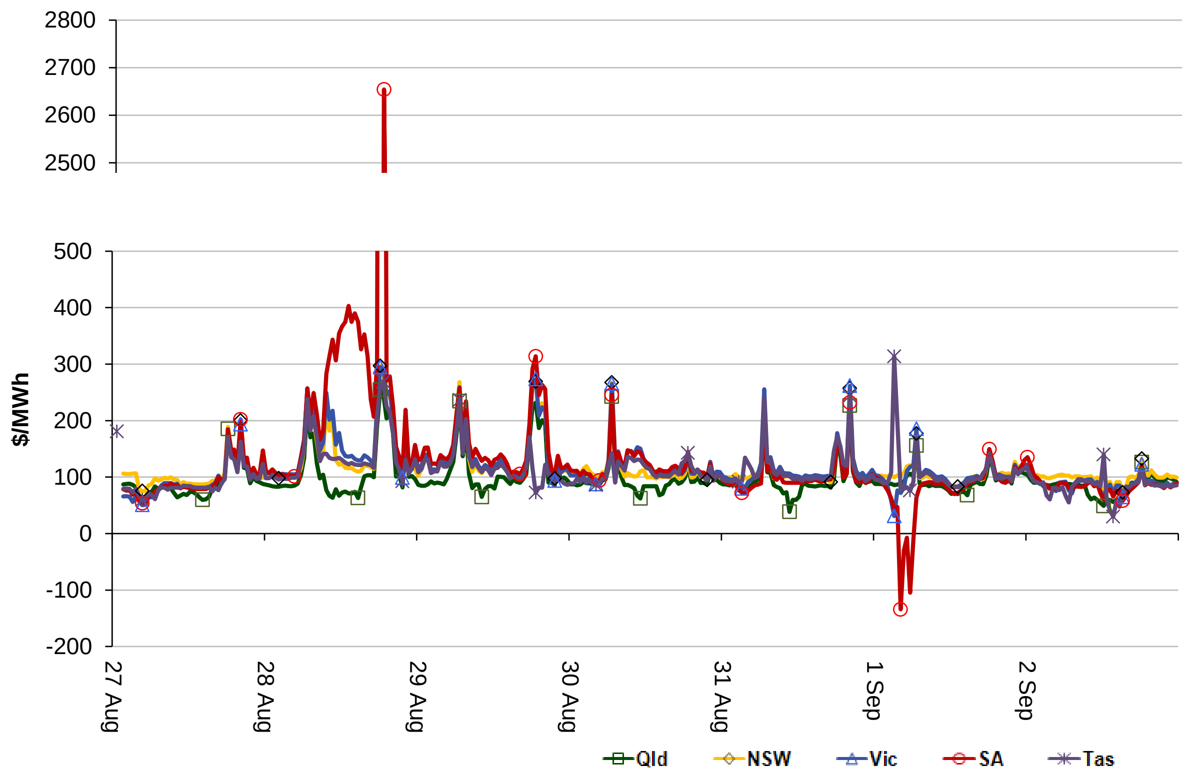


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

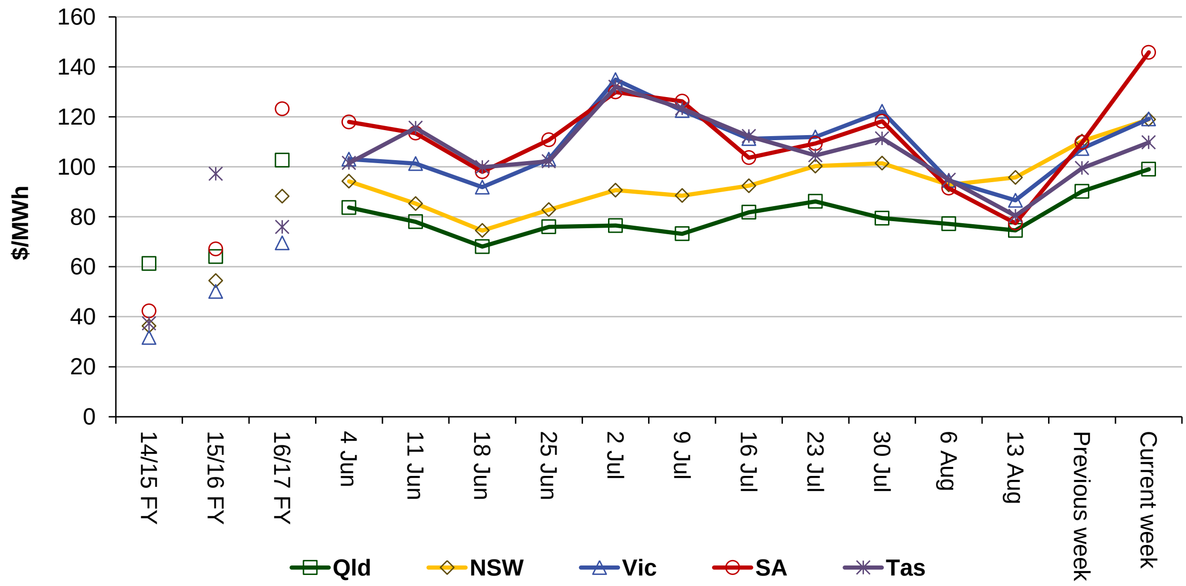


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	99	119	119	146	110
16-17 financial YTD	57	60	57	162	58
17-18 financial YTD	82	99	112	113	108

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 110 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2016 of 273 counts and the average in 2015 of 133. 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	3	42	1	8
% of total below forecast	33	7	0	5

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

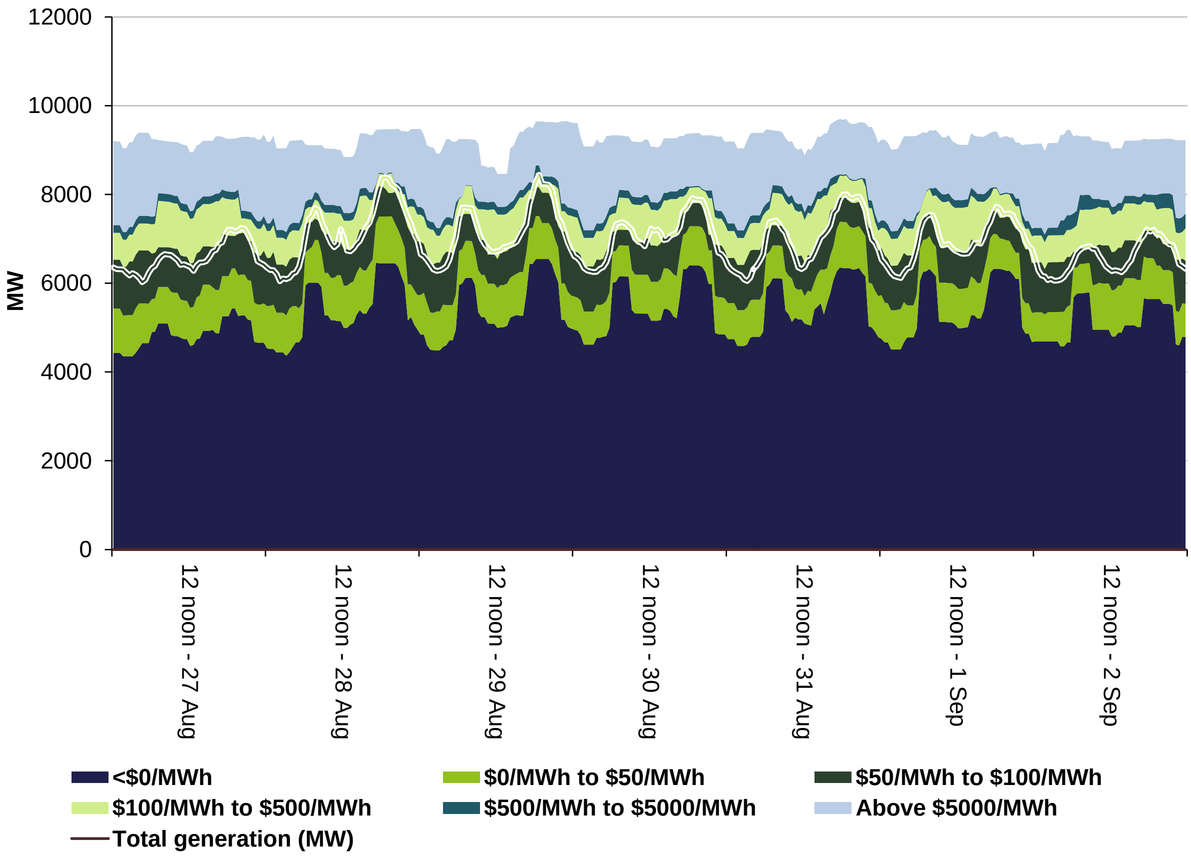


Figure 4: New South Wales generation and bidding patterns

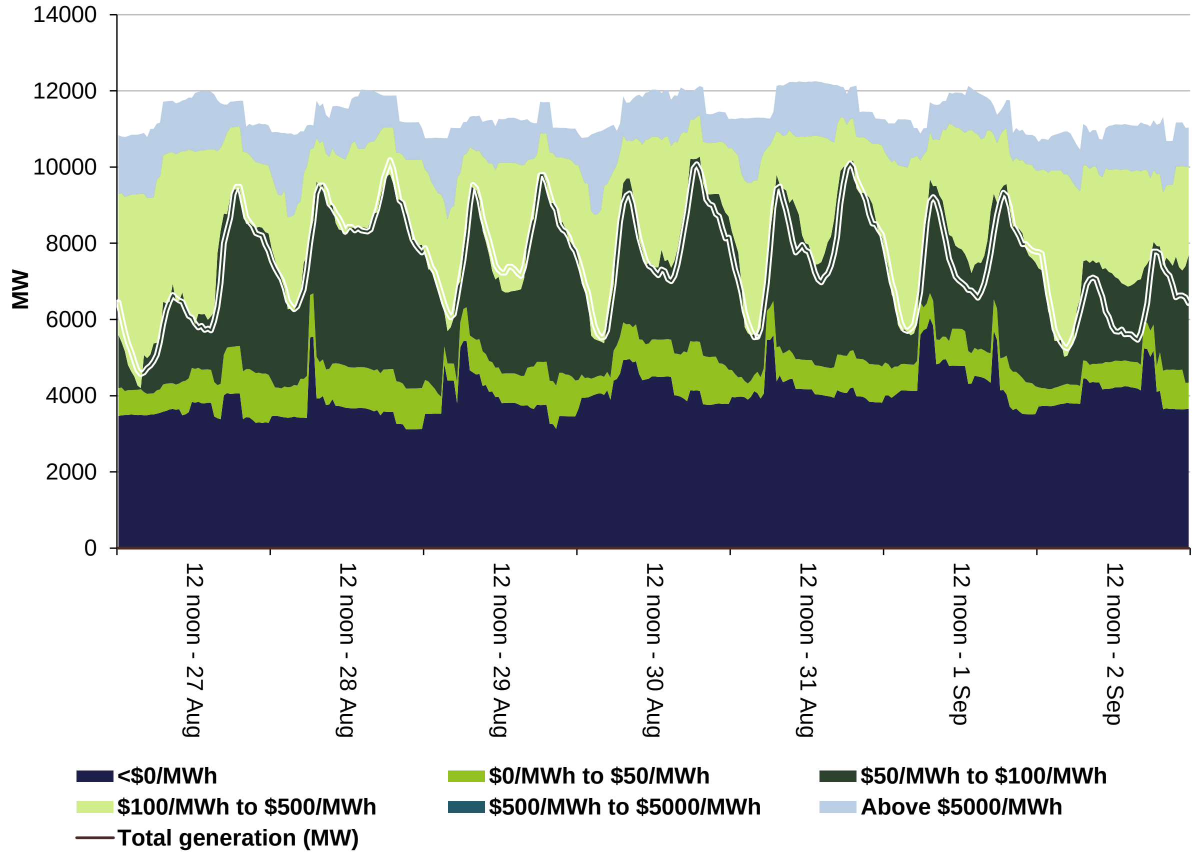


Figure 5: Victoria generation and bidding patterns

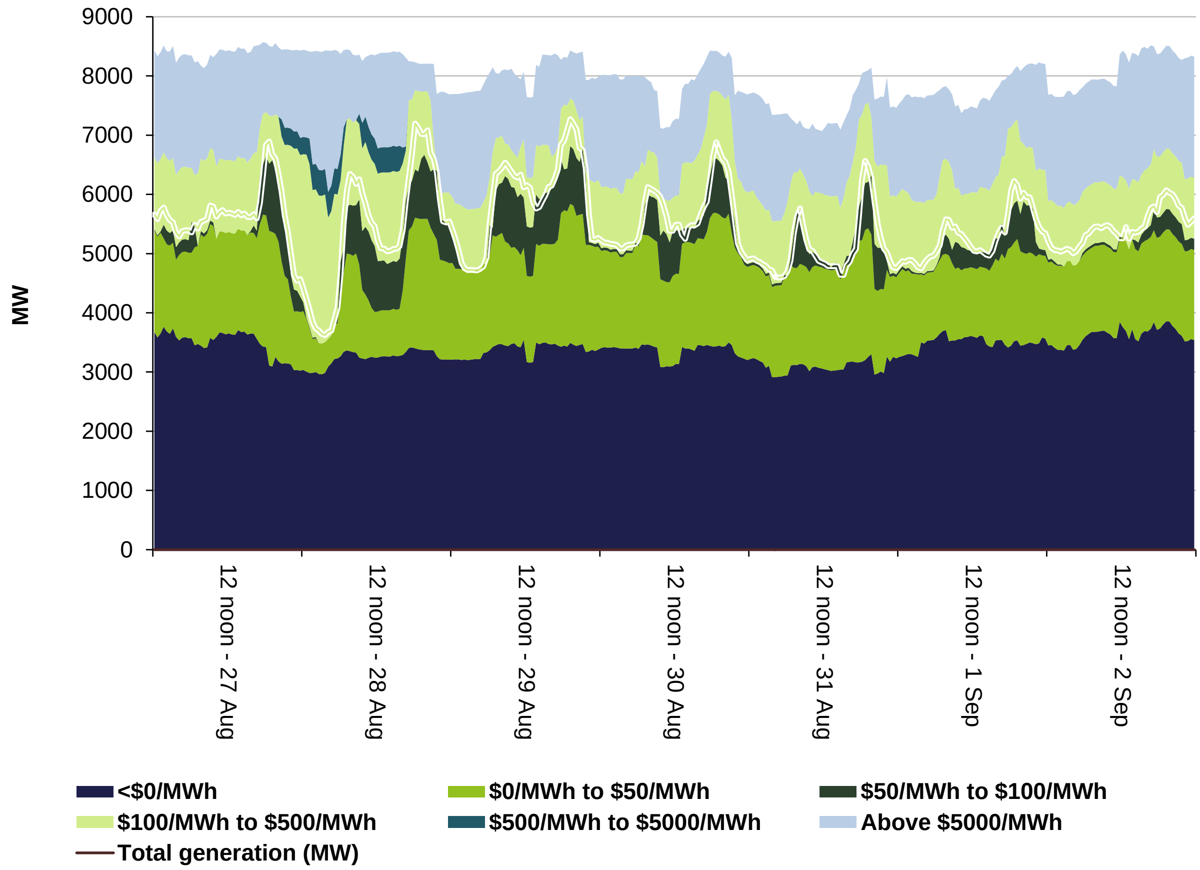


Figure 6: South Australia generation and bidding patterns

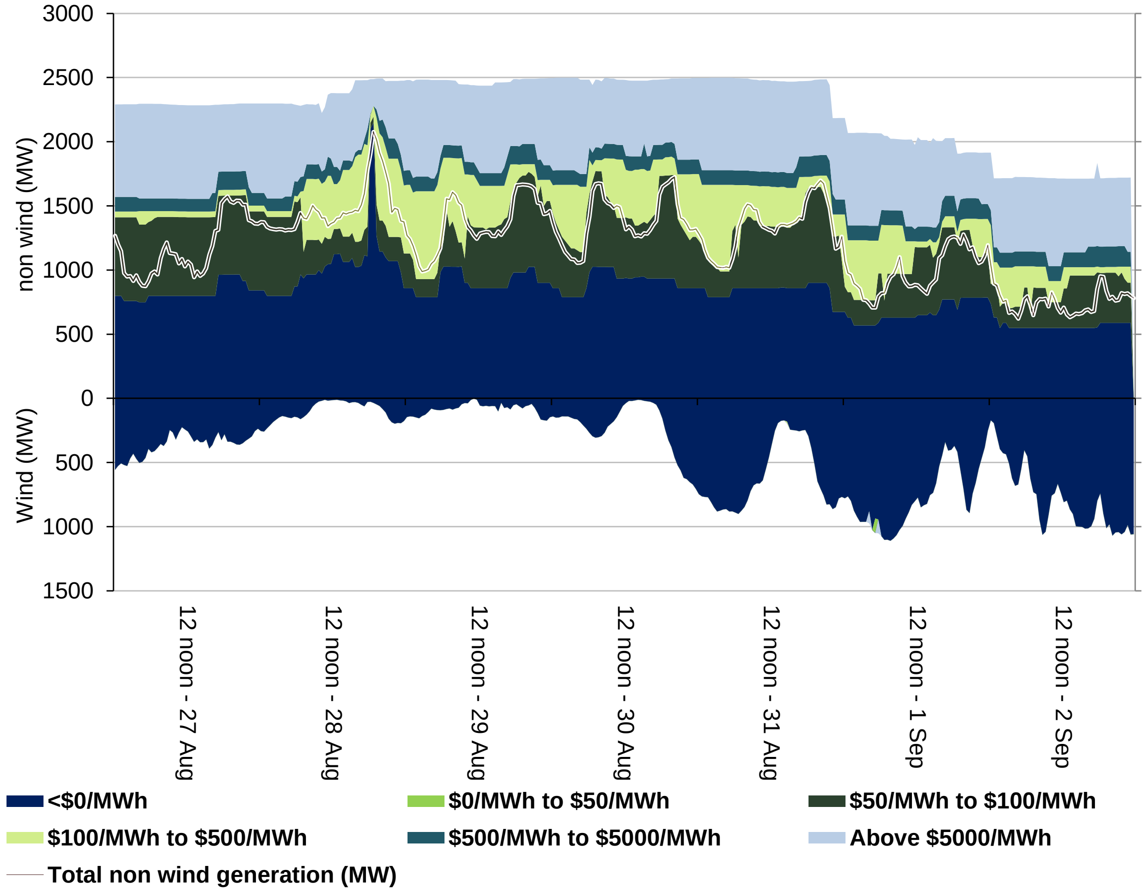
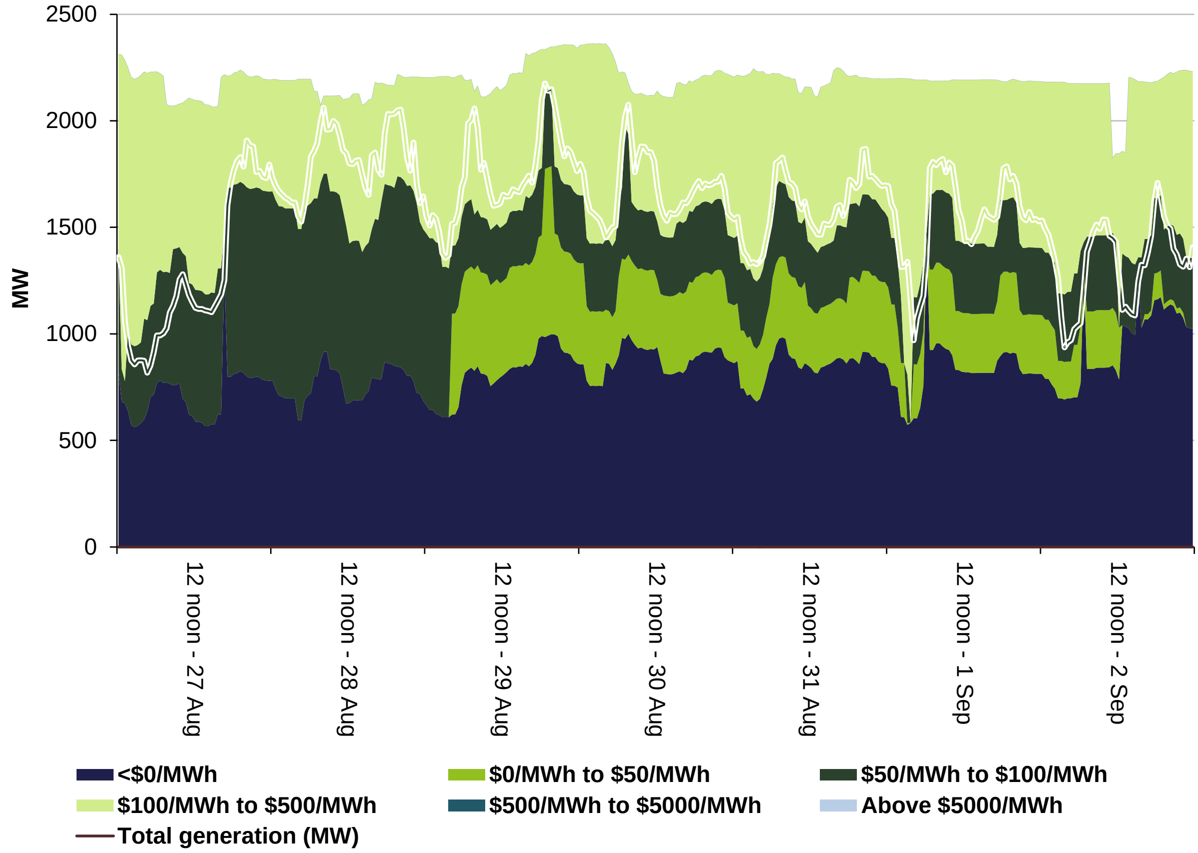


Figure 7: Tasmania generation and bidding patterns



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.

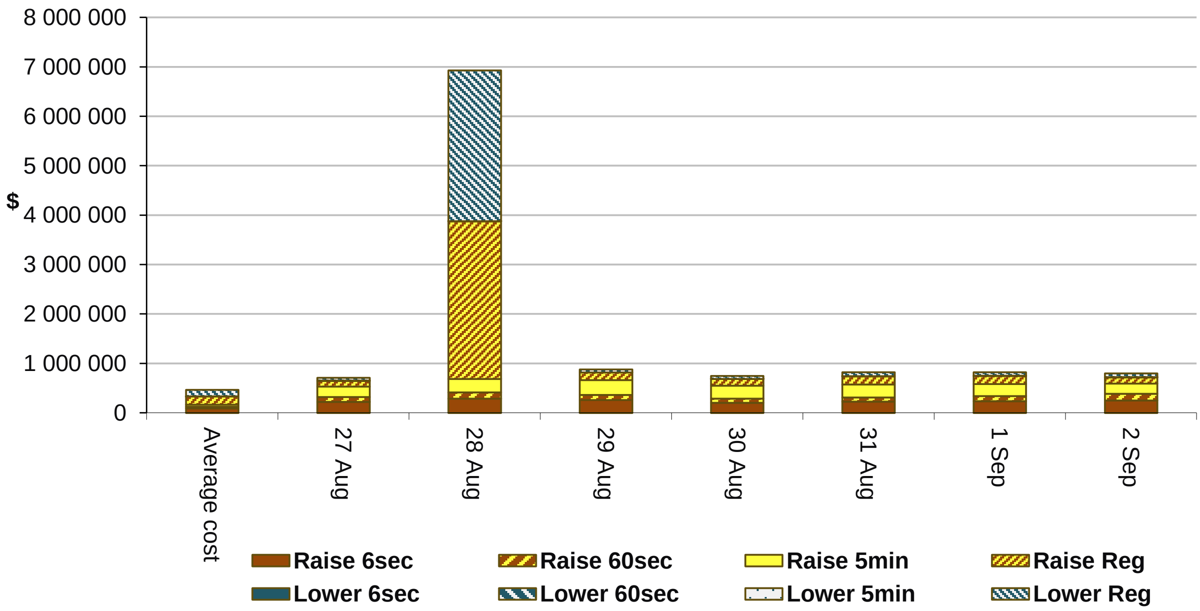
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $10 778 500 or around three per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $942 500 or around four 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



On 28 August a planned outage on the Moorabool to Mortlake PS 500kV line in Victoria left Heywood on a single contingency which if it occurs separates South Australia from the rest of the NEM. AEMO invoked constraints requiring 35 MW of local regulation services. The price of regulation services in South Australia exceeded $5000/MW for 17 trading intervals in both services. The total cost was around $6 million.

As required under the Electricity Rules, staff will prepare a FCAS Prices above $5000/MW report into the reasons for the high prices.

Detailed market analysis of significant price events

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 $146/MWh and above $250/MWh and there were two occasions where the spot price was below -$100/MWh.

Monday, 28 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
6.30 pm	2653.94	380.55	351.58	2111	2162	2038	2405	2442	2420
7 pm	2027.09	388.54	374.09	2232	2277	2156	2422	2457	2431

Conditions at the time saw demand and availability close to that forecast four hours ahead. With a planned outage in Victoria, the Heywood interconnector was on a single contingency and AEMO invoked constraints to limit imports into South Australia to 50 MW, the nominal import limit is 650 MW. The outage was scheduled to finish at 5.30 pm but was extended on several occasions from 5 pm to eventually finish at 7 pm, meaning the 50 MW import constraint remained in place for longer than what was forecast. The four hour forecasts had imports into South Australia on the Heywood interconnector between 500 MW and 550 MW.

Imports across Murraylink were being limited to around 140 MW but this was higher than forecast four hours ahead.

For the 6.20 pm dispatch interval, demand increased by around 30 MW with only 20 MW of capacity available between $360/MWh and $13 999/MWh (another 110 MW was also offered, but by peaking generators taking longer than five minutes to start), the remainder of the demand increase was met by local high priced generation and the price reached $13 999/MWh for one dispatch interval.

For the 6.35 pm dispatch interval, imports were 510 MW lower than forecast and around 80 MW of capacity priced less than $1750/MWh was rebid to higher prices. As a result the dispatch price reached $10 579/MWh for one dispatch interval. Prices stayed around $300/MWh for the remainder of the trading interval due to rebidding of capacity from high to low prices.

Friday, 1 September

Table 4: 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
4.30 am	-134.21	63.69	71.62	958	902	849	2962	2909	2917

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 am	-104.82	63.69	64.52	1099	931	892	3043	2922	2956

For the 4.30 am trading interval, both demand and availability were around 55 MW higher than that forecast four hours ahead. Around 3 am there was an unplanned outage of the Murraylink interconnector. It was forecast to be exporting into Victoria at around 180 MW.

For the 4.25 am dispatch interval, demand decreased by 12 MW and exports on the Heywood interconnector also reduced by 20 MW. With higher priced generation ramp down limited and unable to set price the price fell -$1000/MWh for one dispatch interval.

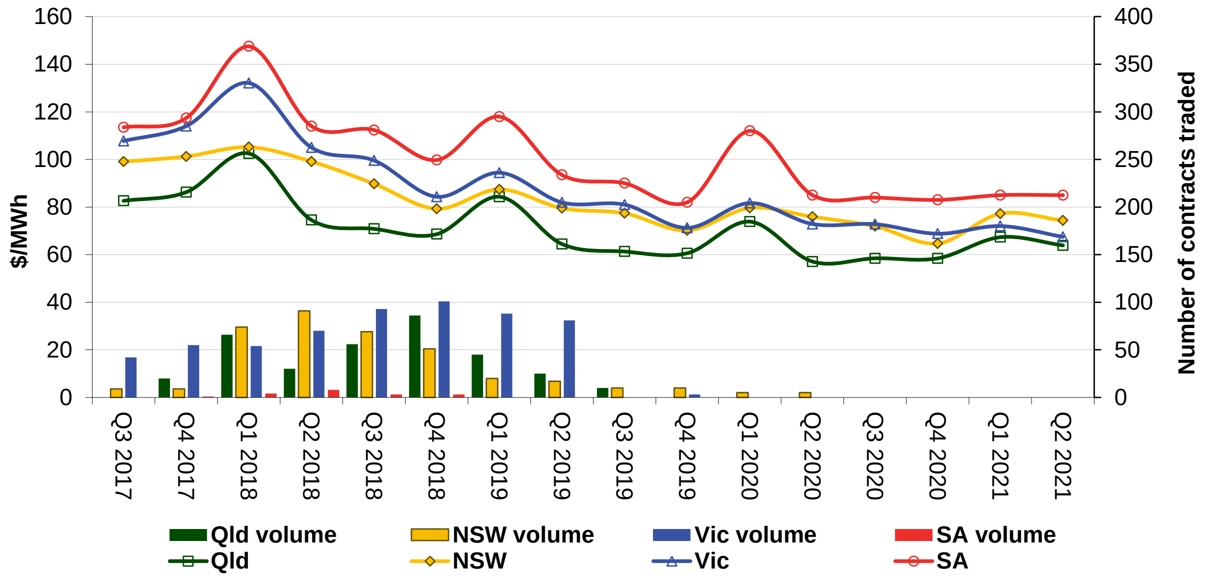
For the 6 am trading interval, demand was around 170 MW higher than forecast and availability was around 120 MW greater than that forecast four hours ahead due to higher than forecast wind. Murraylink was still out and was forecast to be exporting into Victoria at 125 MW four hours prior.

Reduced net exports and higher than forecast wind generation saw the dispatch price fall to the floor at 5.35 am. In response to the negative price, AGL rebid 40 MW of capacity at Torrens Island from the floor to $90/MWh. This coupled with a 68 MW increase in demand saw the price increase to $64/MWh at 5.40 pm and stay under $90/MWh for the remainder of the trading interval.

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.

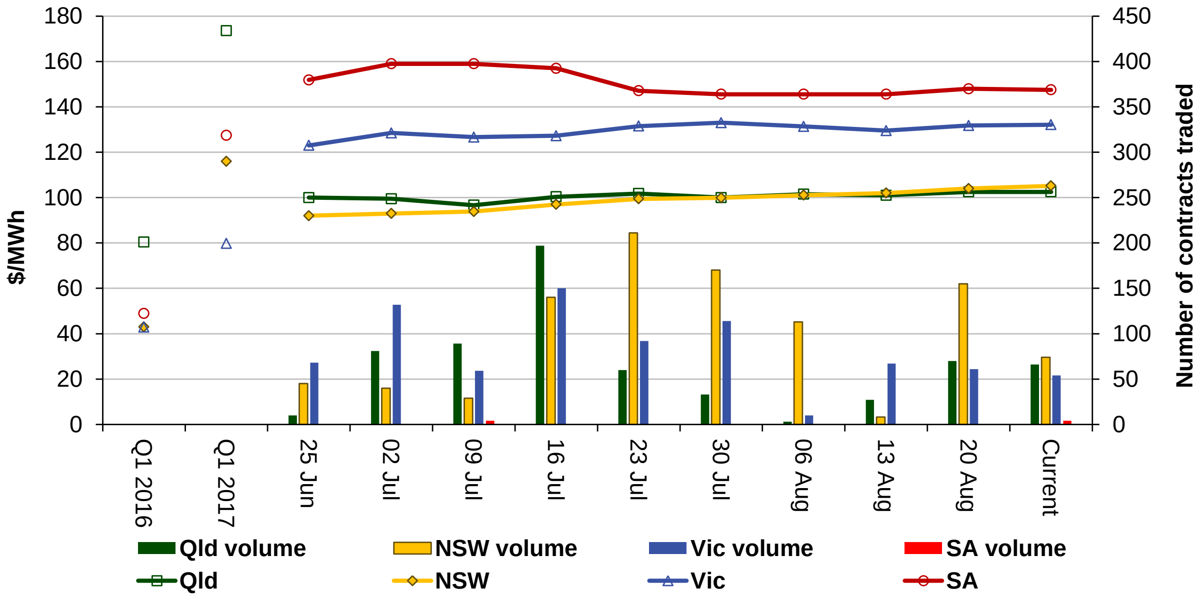
Figure 9: Quarterly base future prices Q3 2017 – Q2 2021



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2018 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 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 2018 base contracts over the past 10 weeks (and the past 2 years)



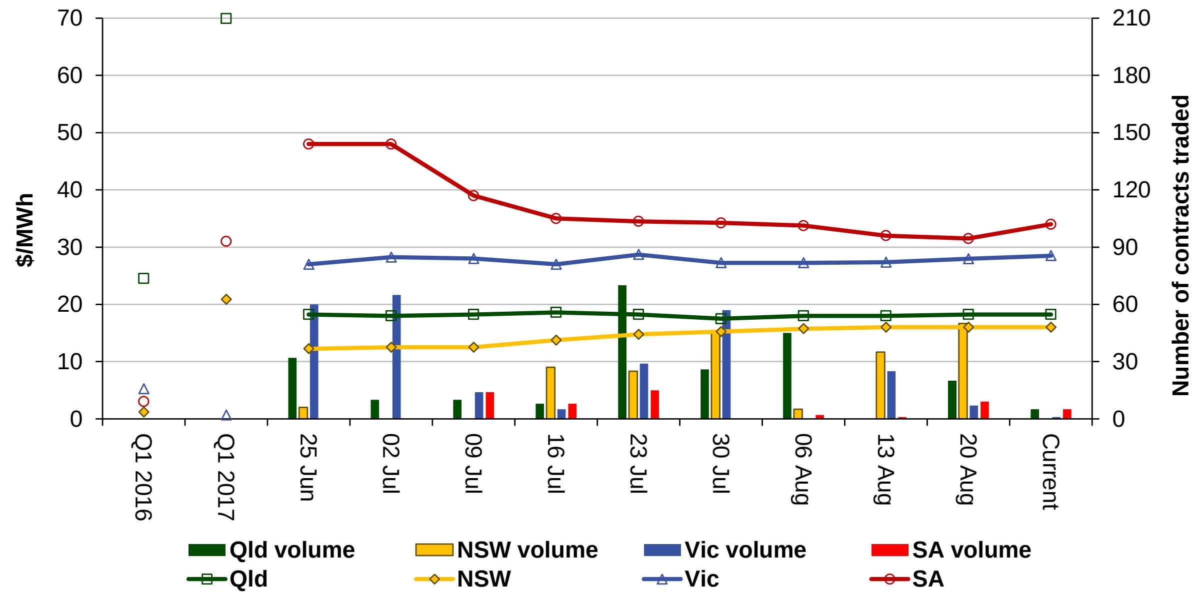
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics section of our website.

Figure 11 shows how the price for each regional quarter 1 2018 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 prices are also shown.

Figure 11: Price of Q1 2018 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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