Electricity Report

AUSTRALIAN ENERGY REGULATOR

2 – 8 September 2018

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 2 – 8 September 2018.

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

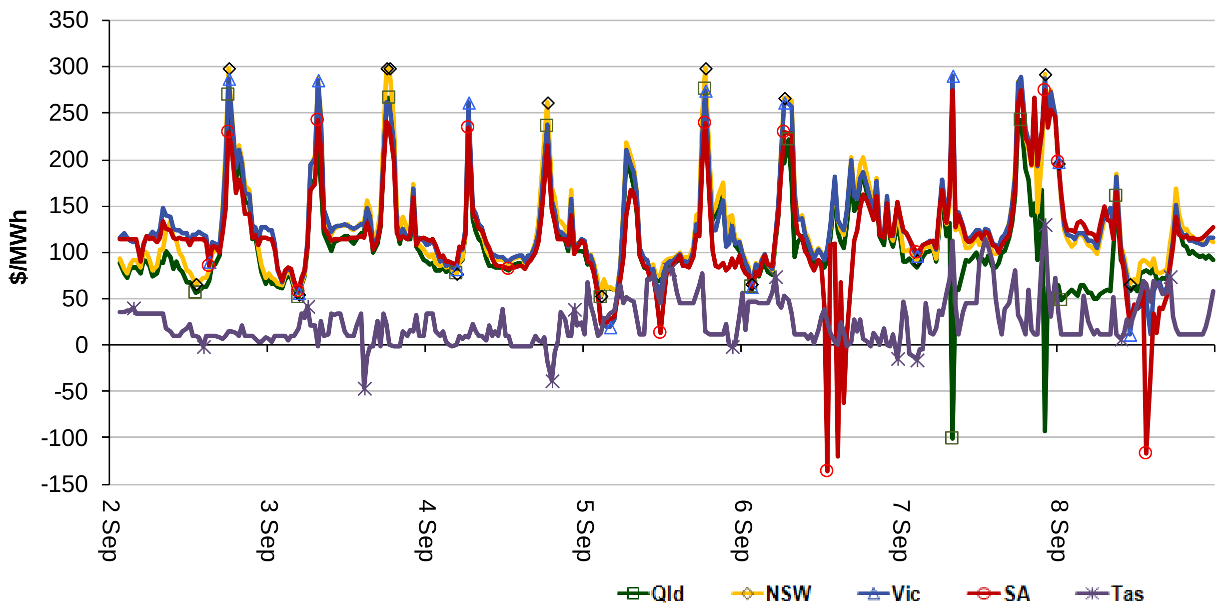


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

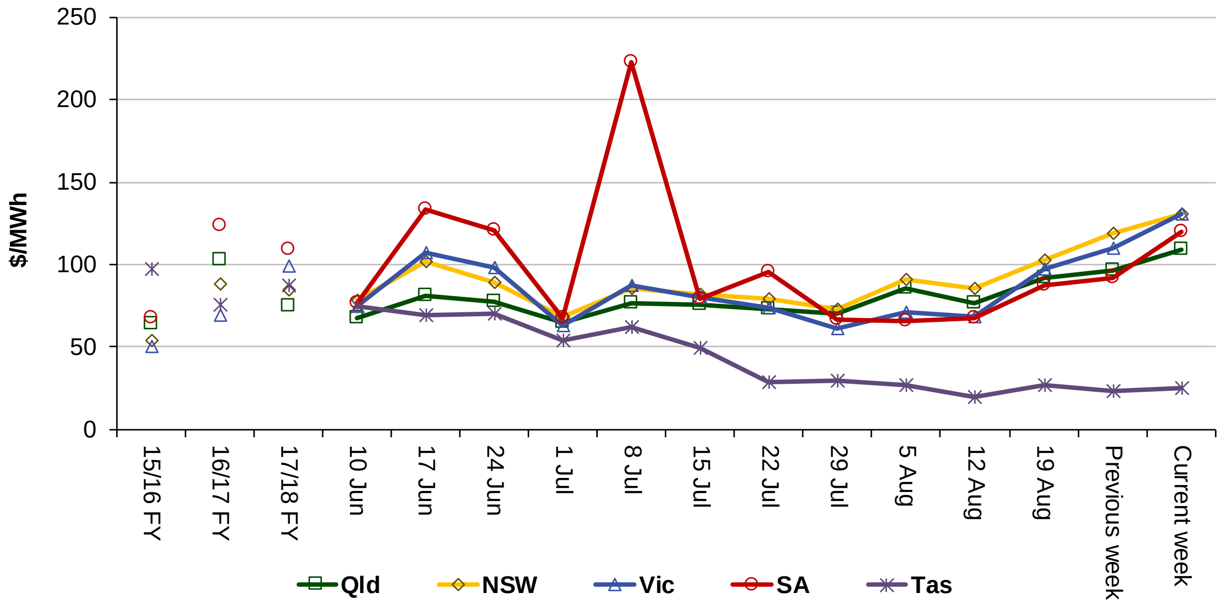


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	109	131	131	120	25
17-18 financial YTD	82	98	111	111	106
18-19 financial YTD	82	92	84	97	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 281 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. 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	7	24	0	1
% of total below forecast	11	38	0	20

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

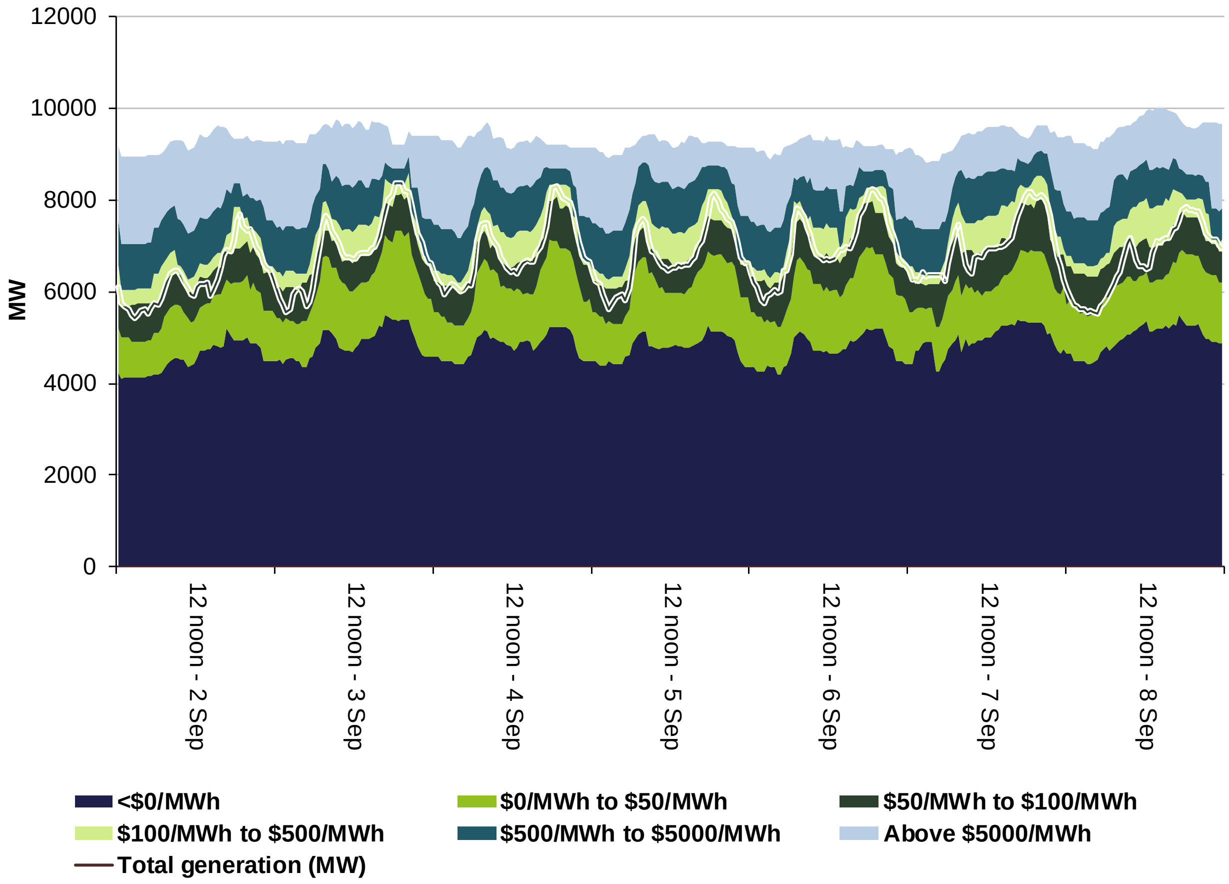


Figure 4: New South Wales generation and bidding patterns

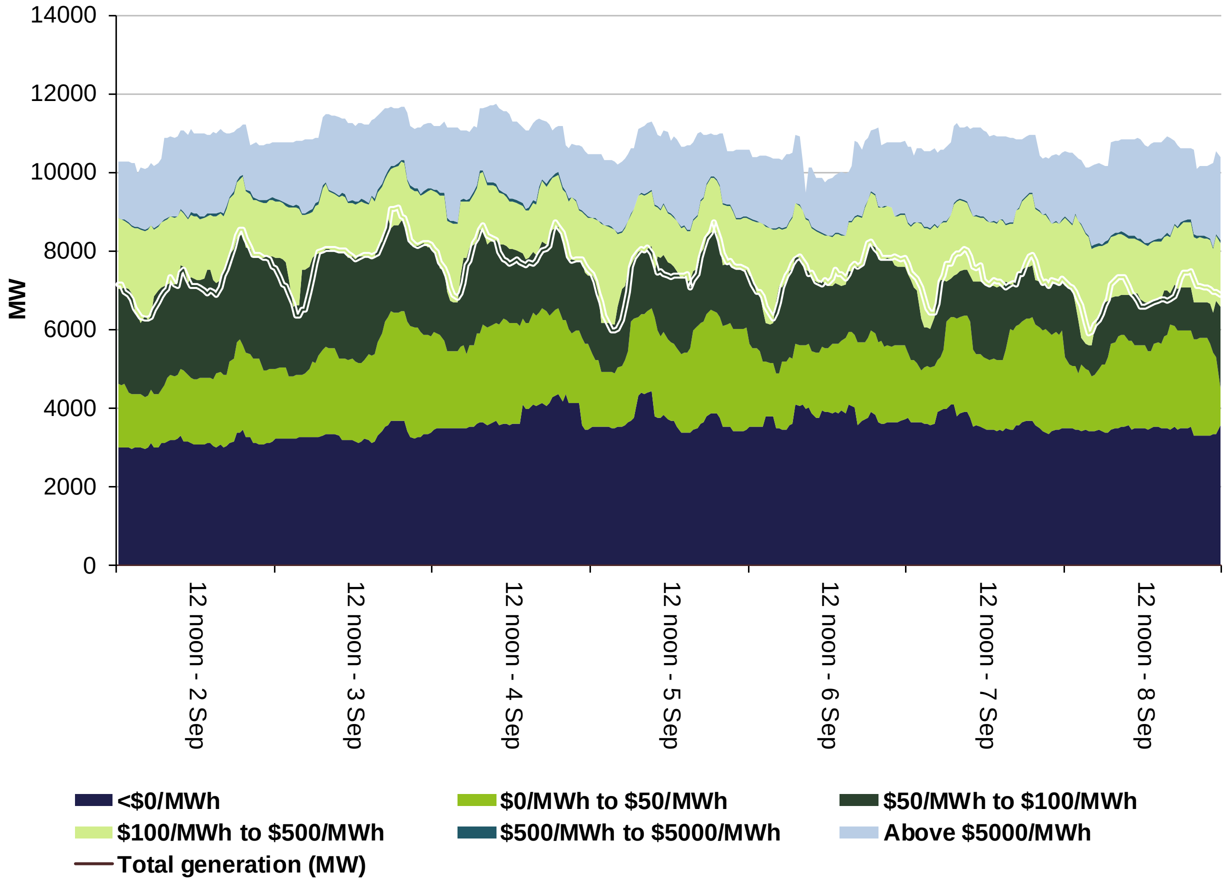


Figure 5: Victoria generation and bidding patterns

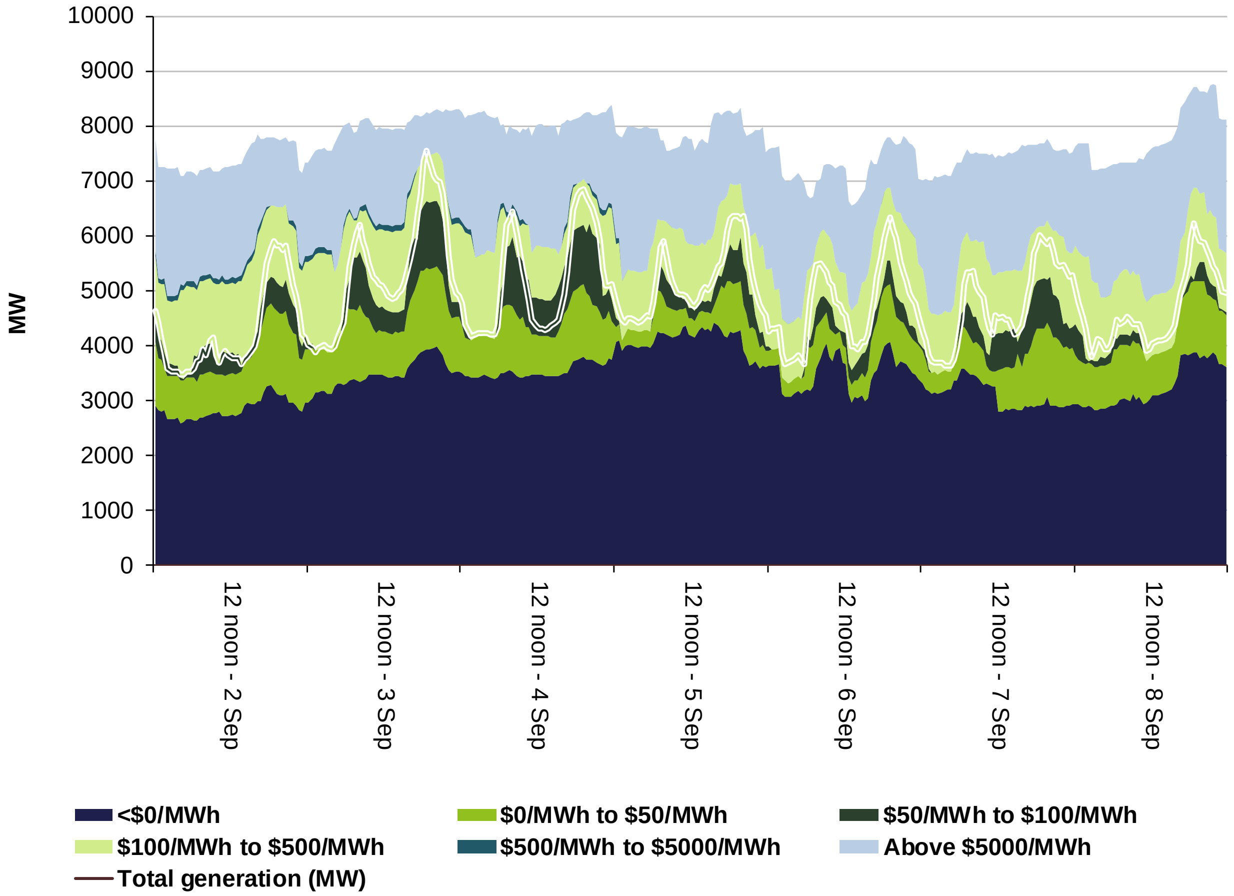


Figure 6: South Australia generation and bidding patterns

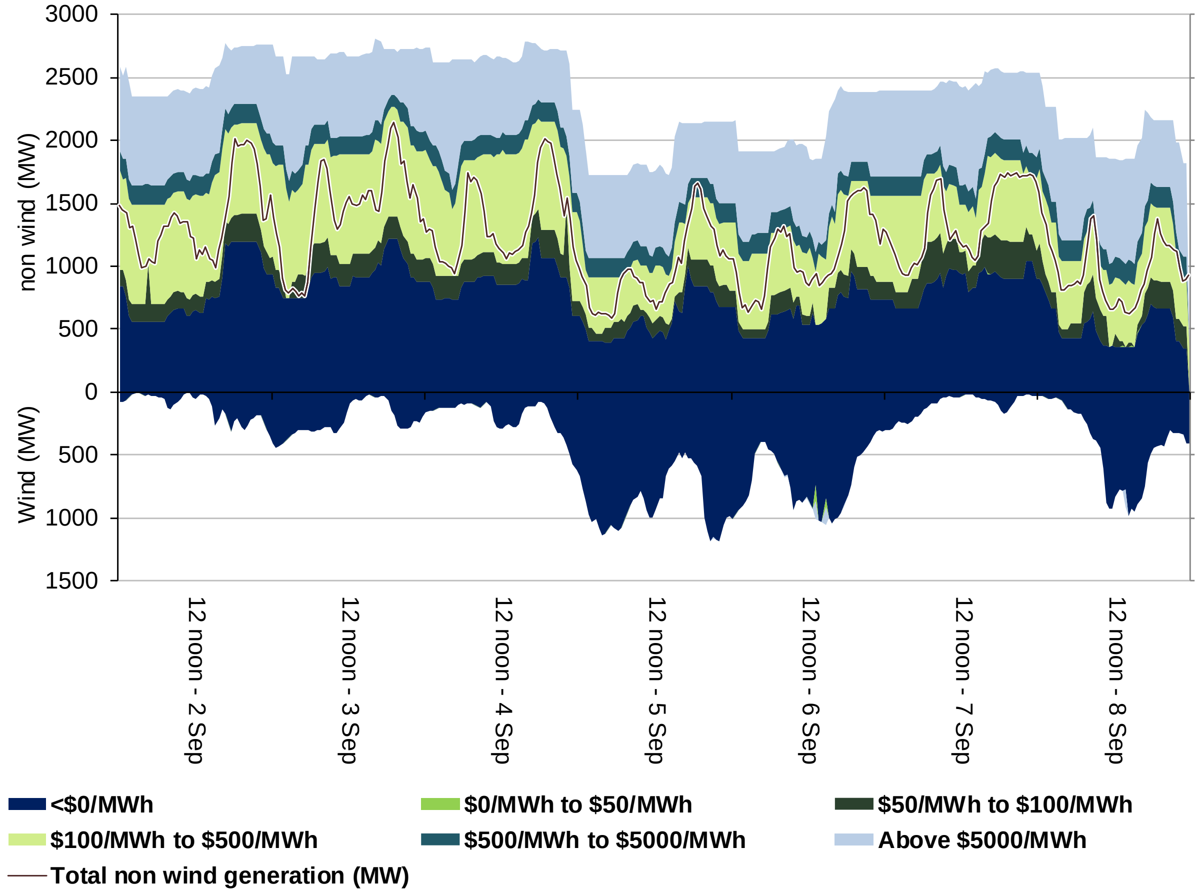
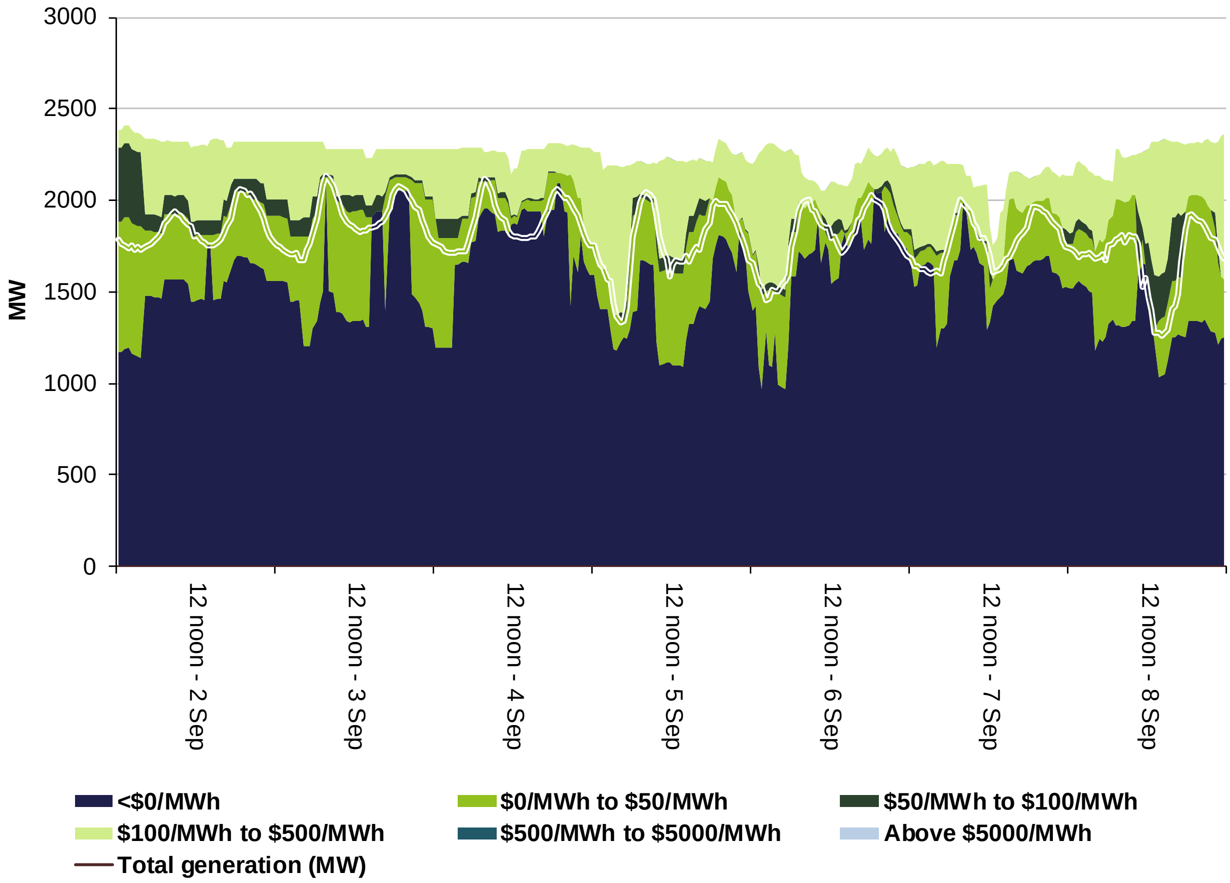


Figure 7: Tasmania generation and bidding patterns



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.

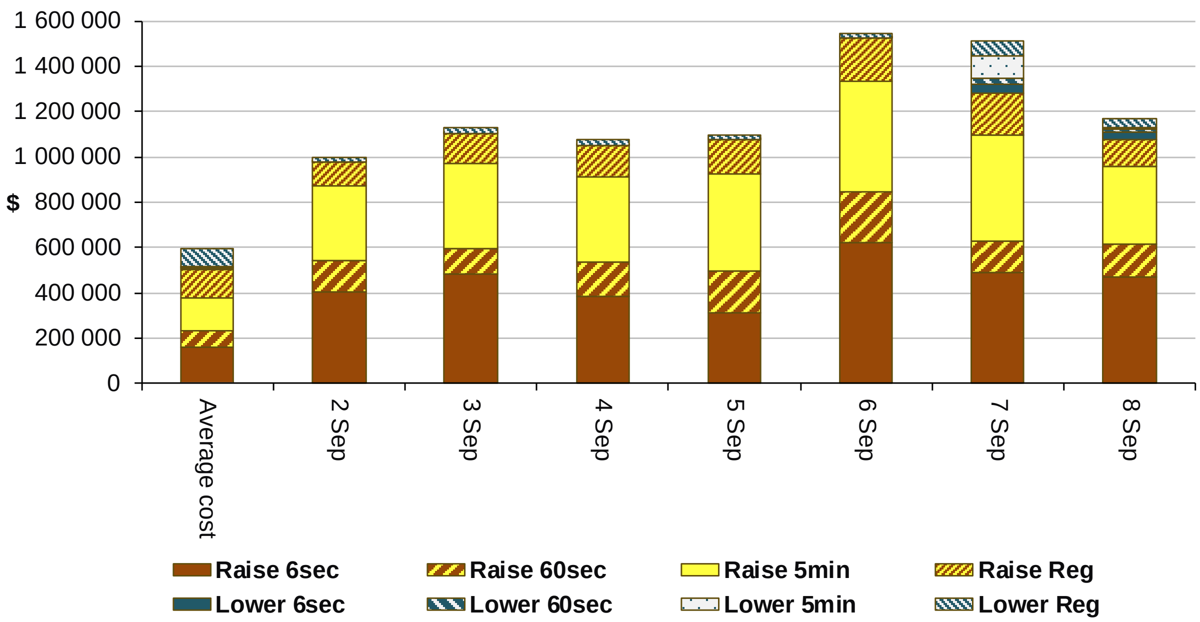
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $8 376 000 or around two per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $158 000 or around three 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 higher than average costs across the week for Raise 6 second and Raise 5 minute services was caused by a reduction in low priced capacity from coal power stations in New South Wales and Queensland due to plant and technical issues.

Detailed market analysis of significant price events

Queensland

There was one occasion where the spot price in Queensland was below -$100/MWh.

Friday, 7 September

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
8:30 am	-100.80	160.16	159.73	6189	6295	6252	9421	9421	9658

Demand was 106 MW lower than forecast and availability was as forecast, four hours ahead.

For the 8.10 am dispatch interval, an unforecast FCAS constraint (used to manage the loss of the Dumaresq to Bulli Creek 330 kV lines) reduced exports from Queensland on the QNI interconnector by 642 MW. The sudden drop in exported generation saw a number of units either ramp down constrained or stranded in FCAS and could not set price. As a result, the dispatch price was set at the price floor and at –$1/MWh for the 8.10 am and 8.15 am dispatch intervals respectively.

In response to the negative prices, participants shifted around 500 MW of capacity priced at the price floor into price bands greater than $150/MWh. These rebids combined with falling demand caused the dispatch price to set at $60/MWh for the remaining three dispatch intervals.

South Australia

There were three occasions where the spot price in South Australia was below -$100/MWh.

Thursday, 6 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
1:30 pm	-136.44	96.28	82.66	860	908	930	2856	2853	2714
3 pm	-120.51	91.34	94.10	936	970	961	3055	3108	2761

Demand was around 50 MW lower than forecast and availability was close to forecast, four hours ahead.

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO issued a direction to a participant in South Australia triggering an intervention event and special pricing arrangements applied in all regions following the intervention.

At the start of the 1.30 pm trading interval, there was only 71 MW of capacity priced between -$152/MWh and $148/MWh, so small increases in negatively priced solar, wind generation or decreases in demand or exports could lead to negative prices. The 1.10 pm dispatch price fell to -$152/MWh because wind generation increased by 27 MW and demand fell by 3 MW. The 1.25 pm dispatch price fell to -$984/MWh when solar generation increased by 20 MW. For both the 1.10 pm and 1.25 pm intervals, more expensive generation was dispatched but could not set price as they were either trapped or stranded in FCAS or ramp down constrained. These two dispatch intervals led to a negative spot price.

Similarly for the 3 pm trading interval, two negatively dispatch prices led to the lower than forecast spot price. Effective from 2.50 pm, Engie increased the capacity at Pelican Point by 60 MW (priced at the price floor) as well as shifted a 60 MW from $351/MWh to the price floor, the reason related to its return to service profile. Wind generation increased by around 70 MW and the dispatch price fell to -$149/MWh. For the 2.55 pm dispatch interval, demand fell by 53 MW and although more expensive generation was dispatched it was either trapped or stranded in FCAS and could not set price. As a result, the dispatch price was set at -$984/MWh. These two dispatch intervals led to the negative spot price.

Saturday, 8 September

Table 5: 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
2 pm	-117.39	53.99	47.65	627	585	648	2764	2512	2489

Demand was around 40 MW higher than forecast and availability was around 250 MW higher than forecast, four hours ahead. The increased availability was partly because semi-scheduled wind was around 170 MW higher than forecast four hours ahead.

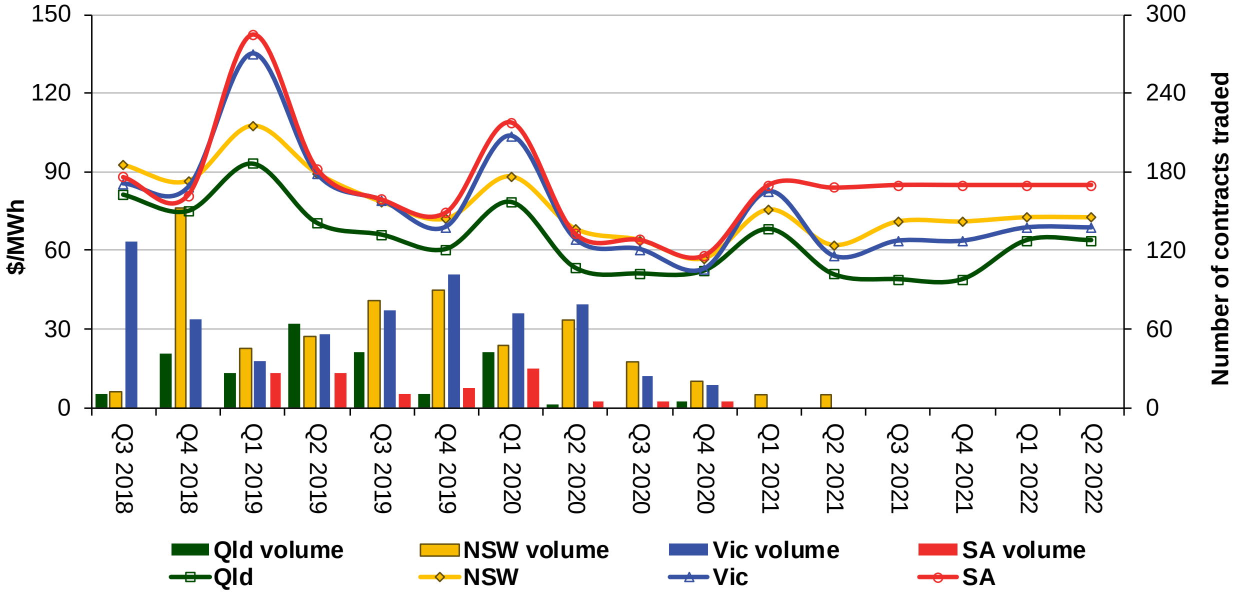
At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO issued a direction to a gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following the intervention in the market.

At 1.40 pm, demand dropped by 5 MW and semi-scheduled wind and solar generation increased by around 50 MW. Although higher priced generation was dispatched, it could not set price as it was either trapped or stranded in FCAS. As a result the dispatch price fell to -$984/MWh for one dispatch interval, resulting in a negative spot price.

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.

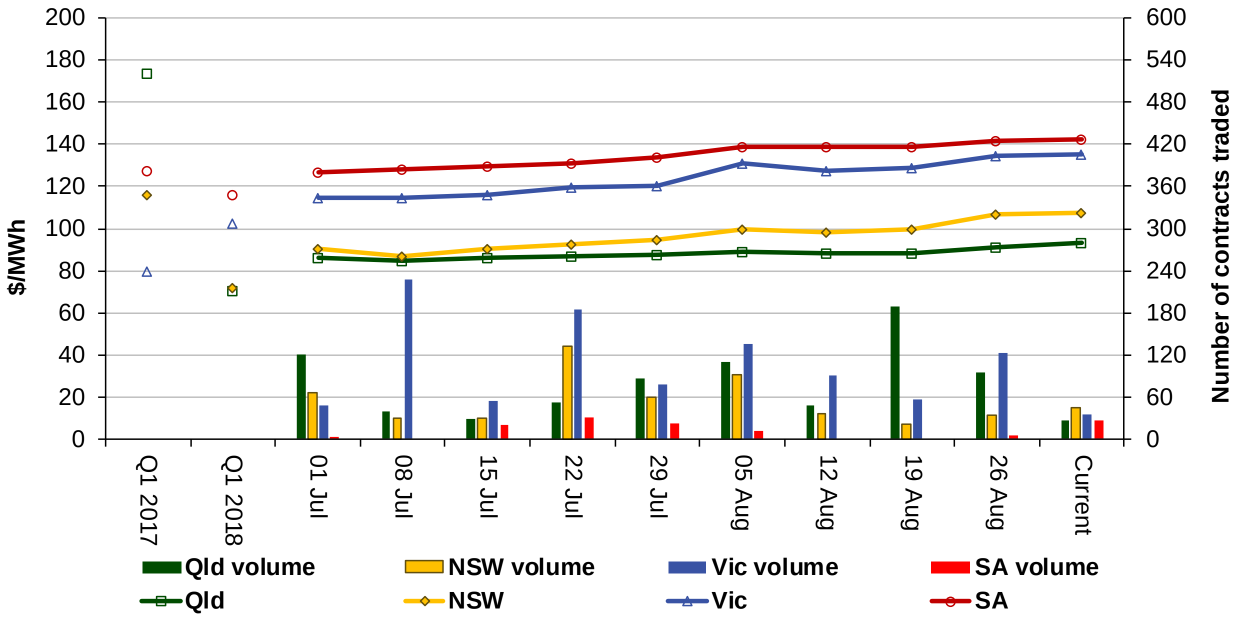
Figure 9: Quarterly base future prices Q3 2018 – Q2 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 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 2019 base contracts over the past 10 weeks (and the past 2 years)



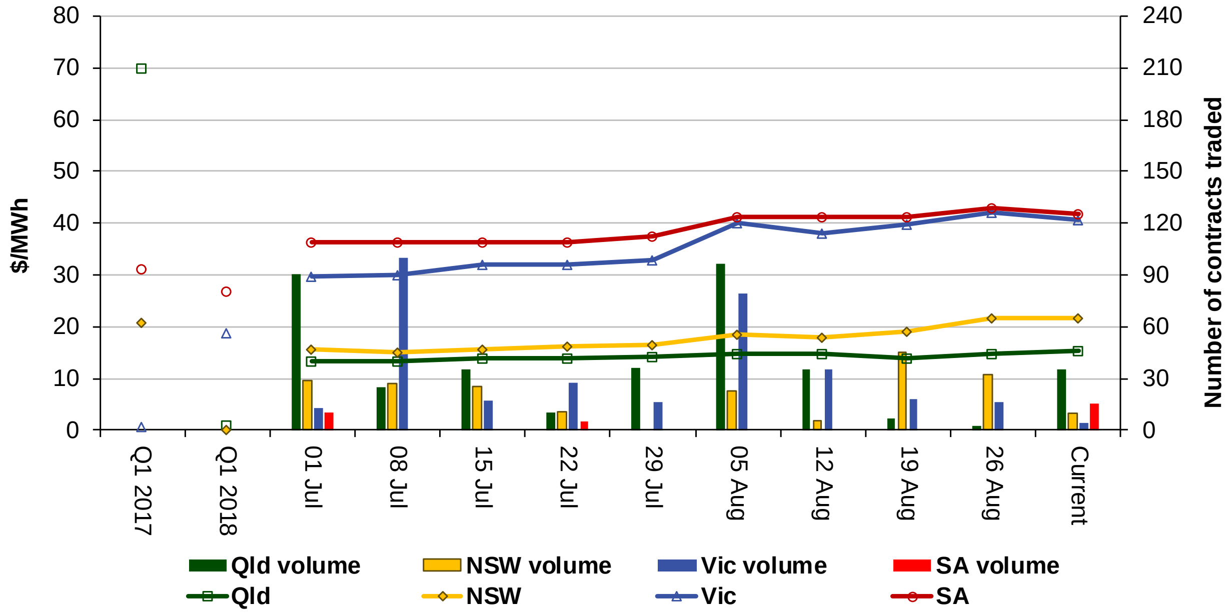
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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