Electricity Report

AUSTRALIAN ENERGY REGULATOR

19 – 25 August 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 19 – 25 August 2018.

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

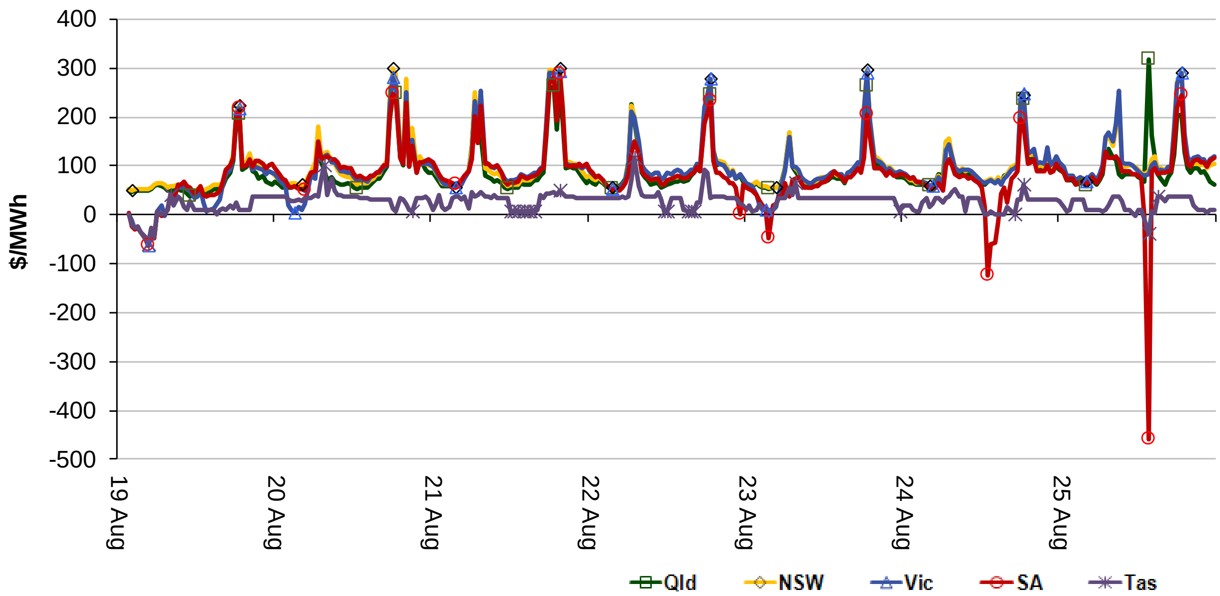


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

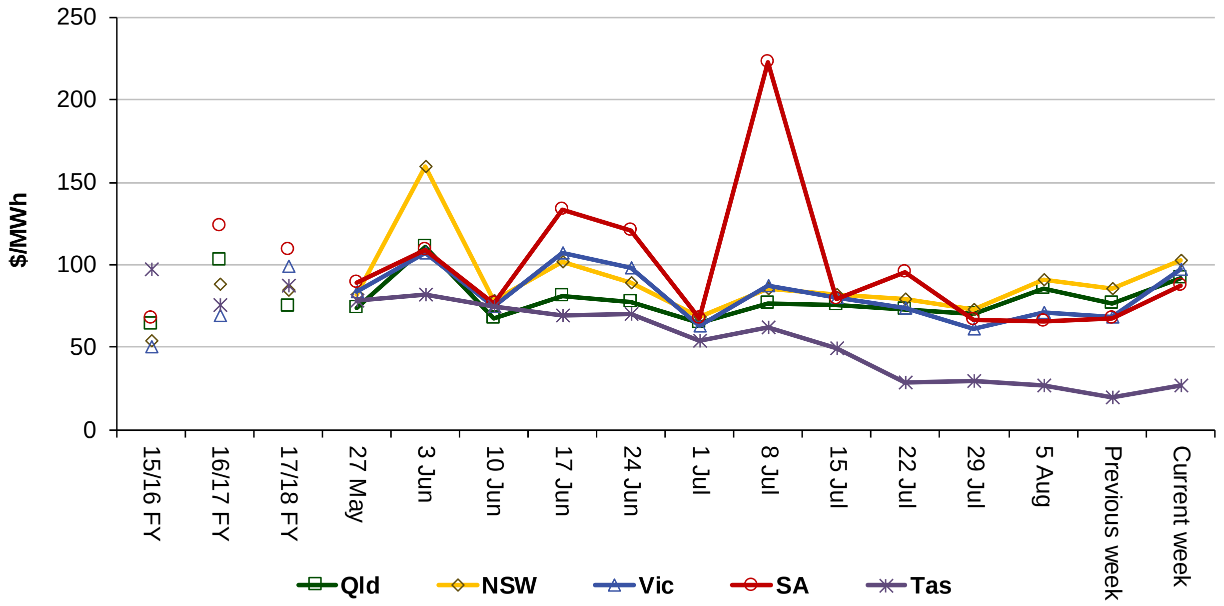


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	92	103	98	88	27
17-18 financial YTD	80	96	112	109	108
18-19 financial YTD	77	84	75	95	37

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 234 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	3	25	1	0
% of total below forecast	9	49	1	11

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

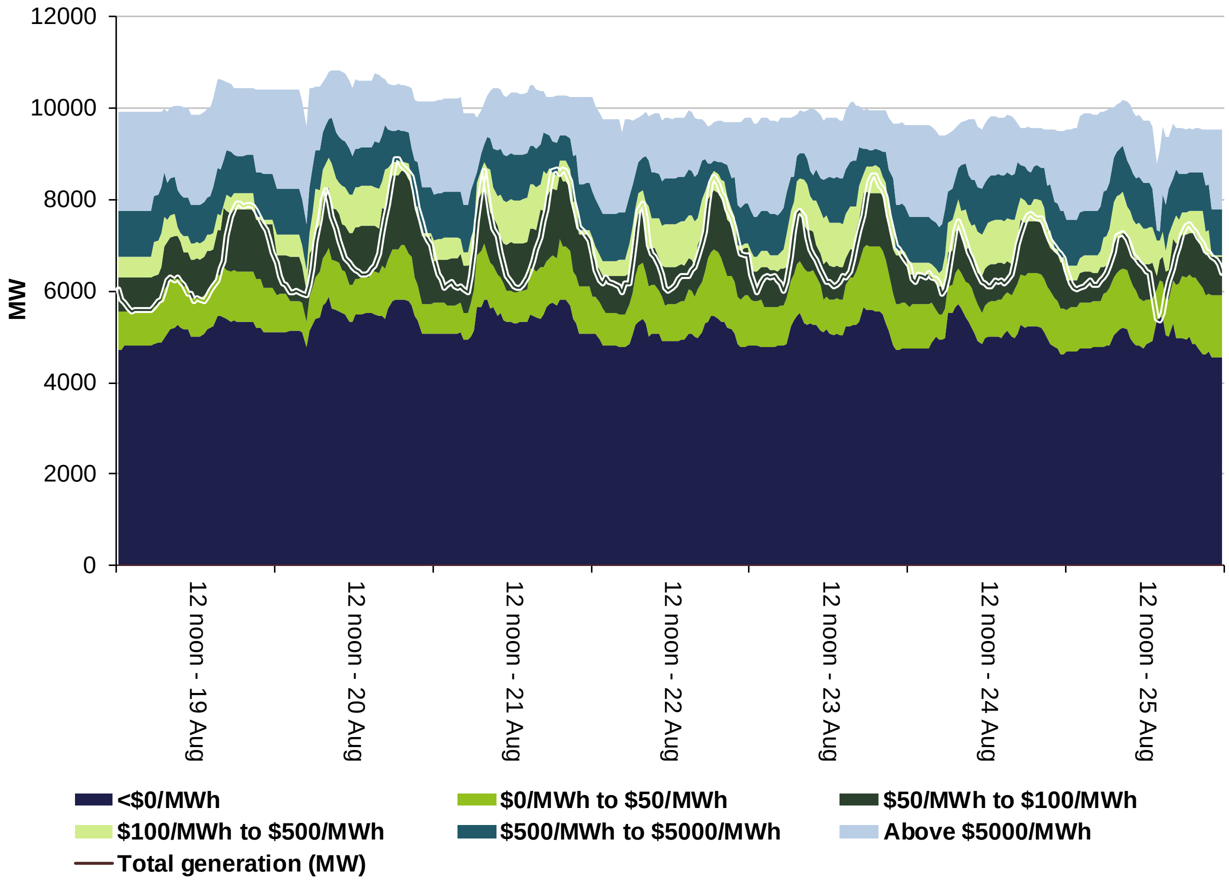


Figure 4: New South Wales generation and bidding patterns

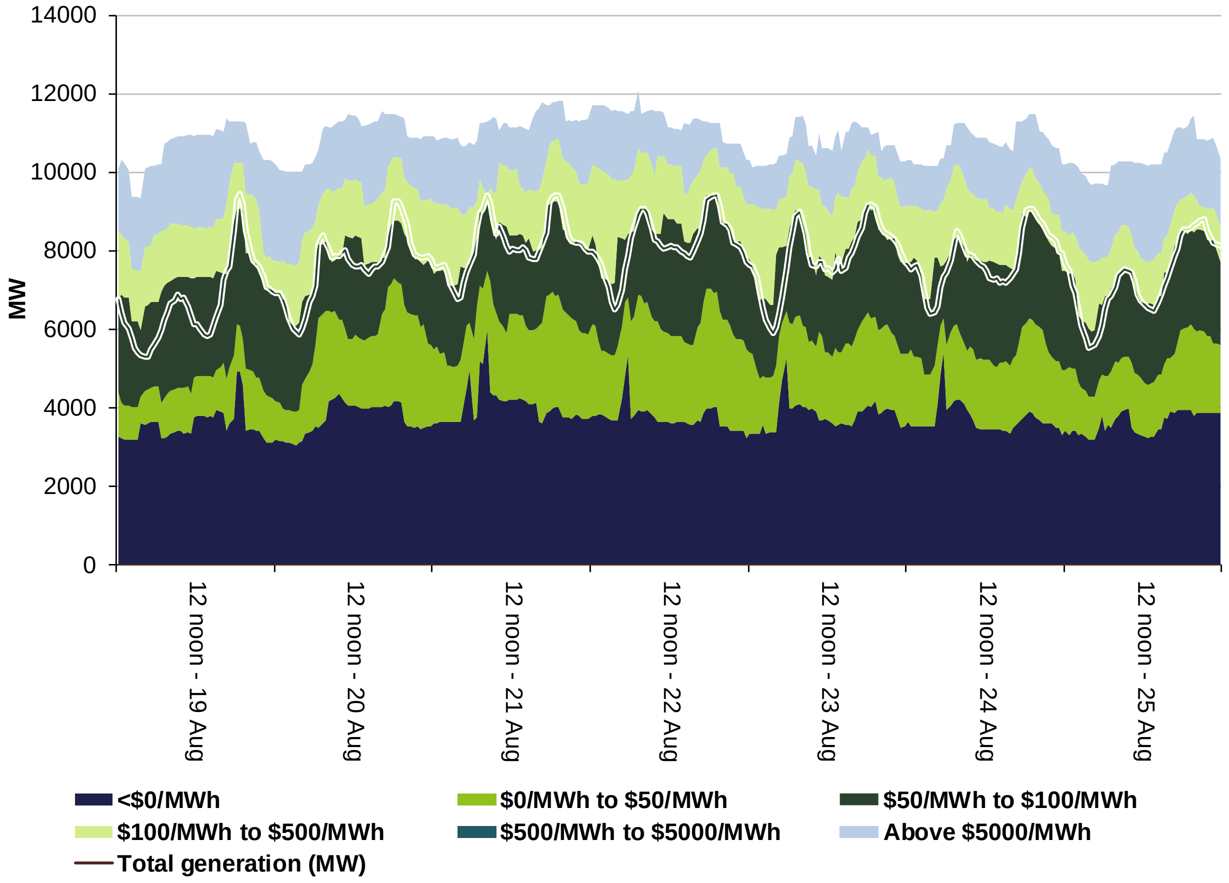


Figure 5: Victoria generation and bidding patterns

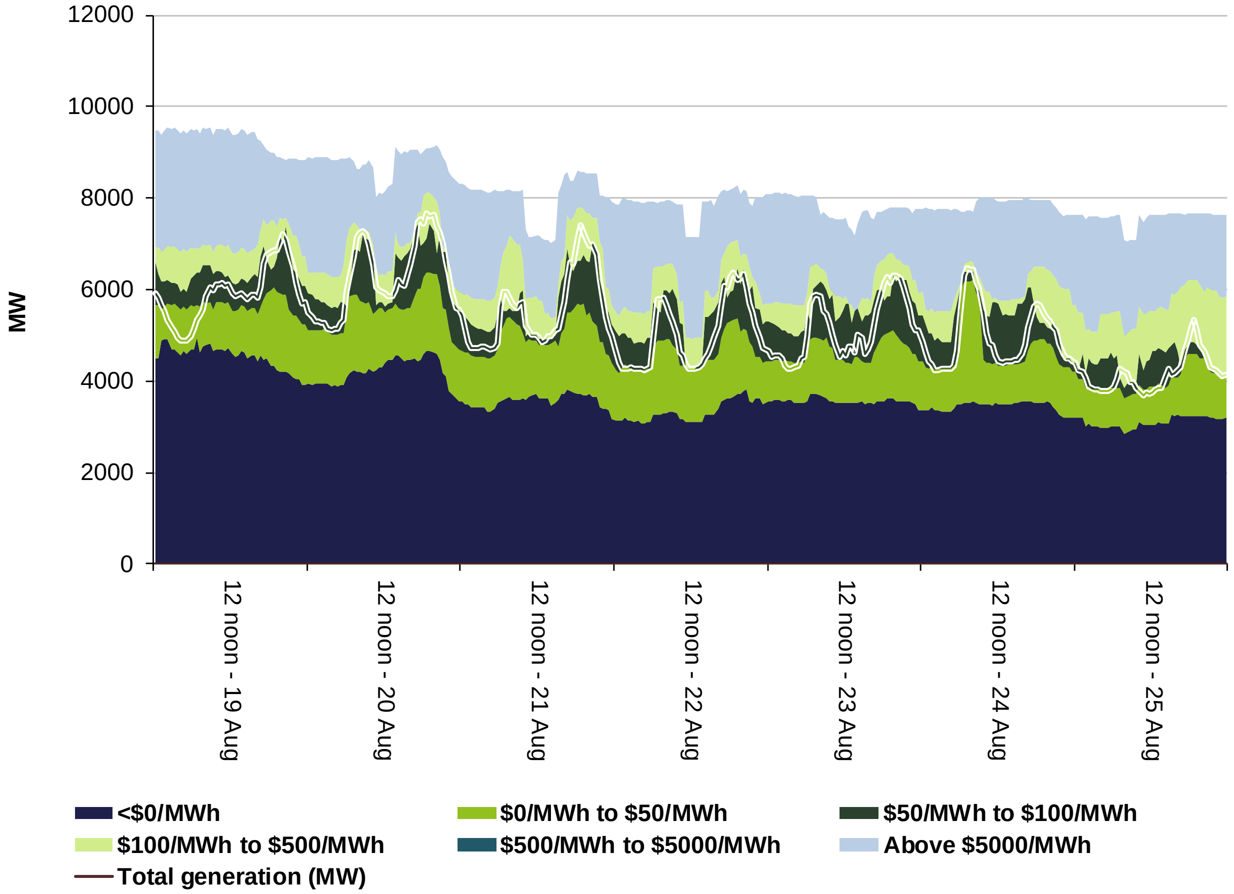


Figure 6: South Australia generation and bidding patterns

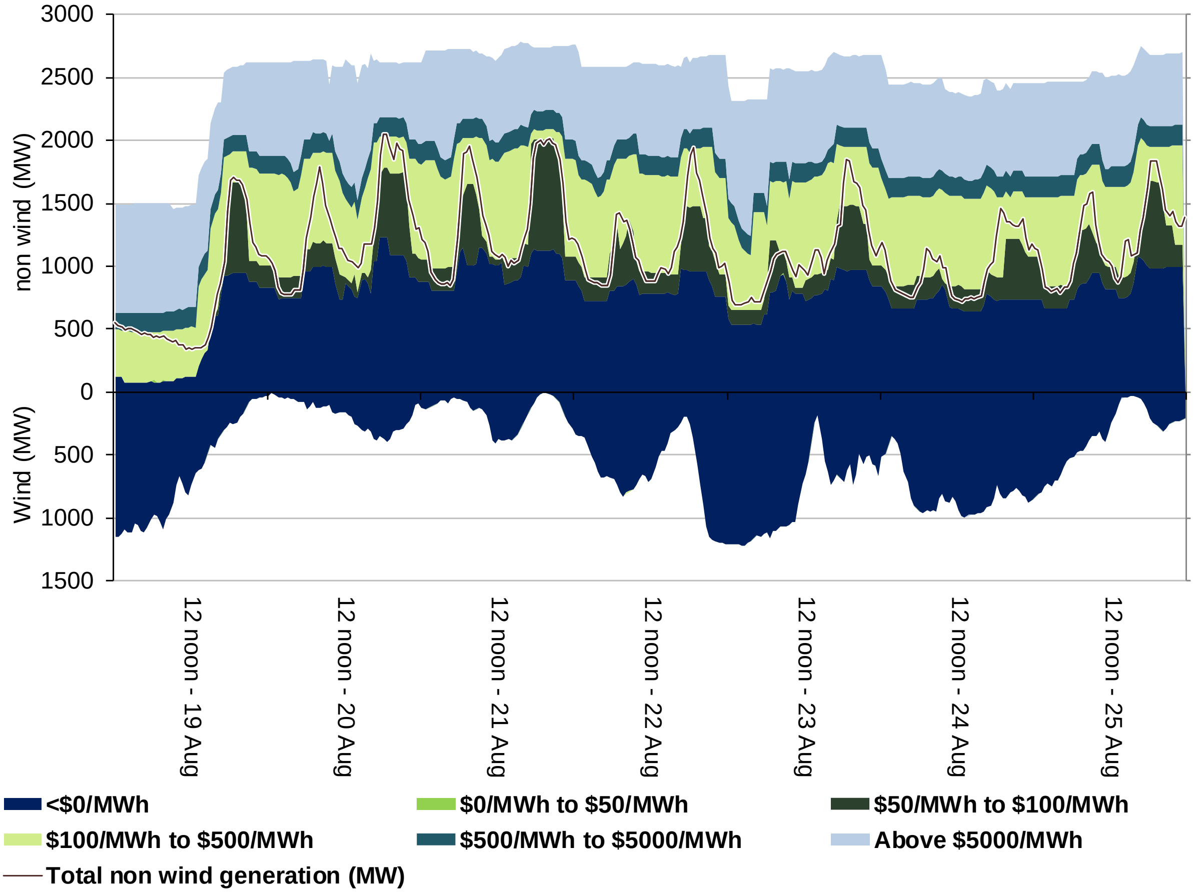
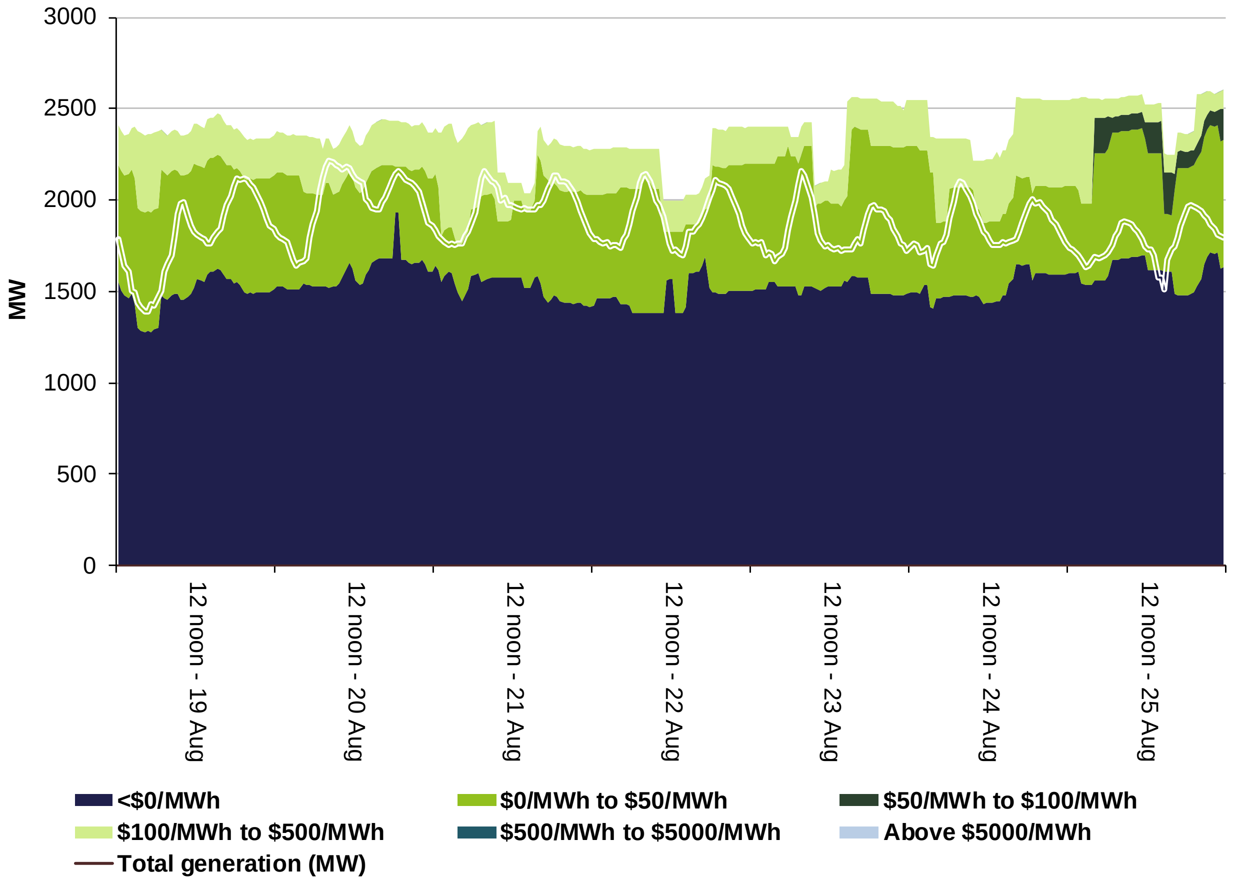


Figure 7: Tasmania generation and bidding patterns



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.

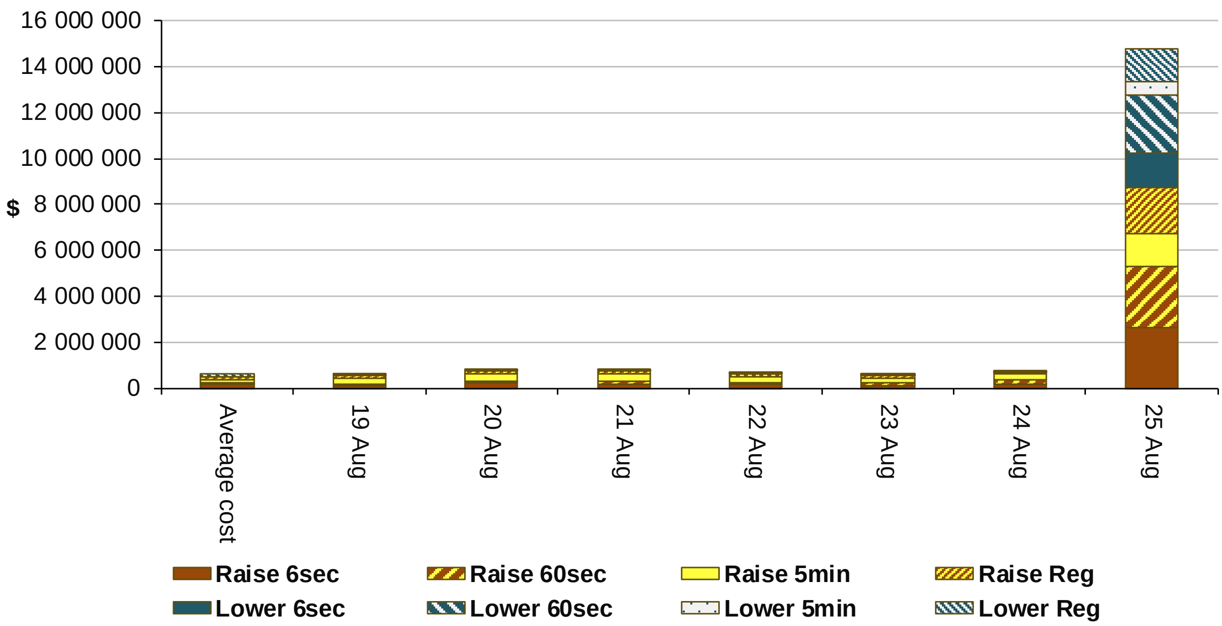
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $18 842 500 or around five per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $64 500 or around one 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 ancillary service costs on 25 August were caused by the trip of the QNI and Heywood interconnectors, islanding Queensland and South Australia from the rest of the NEM. Initial reports indicate that a lightning strike caused the QNI interconnector to trip. This led to a frequency drop in the power system, and combined with a change in flow, Heywood tripped when its emergency control scheme activated.[1] 800 MW of load was shed in New South Wales,

[1] AEMO - Queensland and South Australia system separation on 25 August 2018 - Preliminary Report

280 MW was shed in Victoria and 80 MW was shed in Tasmania. The price for all eight frequency control ancillary services exceeded $5000/MW in Queensland for most of the dispatch intervals between 1.25 pm and 2.45 pm. In South Australia all services, with the exception of raise 60 second, experienced one dispatch interval above $5000/MW between 1.25 pm and 1.45 pm. In both regions the higher FCAS prices only occurred while they were islanded.

As required under the Electricity Rules, an FCAS Prices above $5000/MW report will be prepared.

Detailed market analysis of significant price events

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $92/MWh and above $250/MWh.

Saturday, 25 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
2 pm	317.63	53.83	60.34	5220	5160	5106	8972	9740	9646

Demand was close to forecast and availability was around 770 MW lower than that forecast four hours prior.

The QNI interconnector tripped as a result of lightning at 1.17 pm. Just before it tripped Queensland was exporting around 820 MW into New South Wales. When the interconnector tripped the frequency of the whole power system fluctuated. Since Queensland was exporting power to New South Wales immediately prior to the QNI trip an over frequency situation occurred in that region. Conversely the loss of that 820 MW to the rest of the NEM resulted in a material variation in supply and frequency, contributing to the trip of the Heywood interconnector.

A number of units either tripped or reduced their output because of the over frequency. Effective for the 1.35 pm dispatch interval, CS Energy withdrew 419 MW of capacity at Gladstone power station due to boiler control issues following the QNI trip, 384 MW of this was priced below $85/MWh. Stanwell's Barron gorge power station tripped, removing 33 MW of capacity, of which 31 MW was priced at -$1/MWh.

Effective for the 1.40 pm dispatch interval, Stanwell withdrew 23 MW of capacity priced at $16/MWh from Tarong North power station.

With all other available low priced capacity either ramp constrained or stranded in FCAS, the dispatch price reached $1412/MWh for the 1.40 pm dispatch interval. Unsurprisingly, given the QNI trip, this was higher than forecast spot price.

South Australia

There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $88/MWh and above $250/MWh and there were two occasions where the spot price was below -$100/MWh**.**

Tuesday, 21 August

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
6:30 pm	269.80	303.28	348.92	1834	1890	2005	2782	2788	2780
7 pm	281.99	316.46	379.95	1993	1994	2110	2752	2791	2771
8 pm	287.53	292.88	342.85	2018	1984	2090	2753	2826	2813

The actual price was close to forecast for all three trading intervals.

Friday, 24 August

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
1:30 pm	-125.28	54.74	50.98	906	1013	938	3361	3328	3323

Demand was around 110 MW lower than forecast and availability was close to forecast, both 12 and four hours prior.

Semi scheduled, low priced wind generation was 124 MW greater than forecast four hours prior. High levels of wind generation and low local demand meant both interconnectors were exporting at their limits into Victoria for the entire trading interval which was around 100 MW higher than forecast.

Higher than forecast wind generation and lower than forecast demand meant that more expensive generation was not needed to meet demand. The dispatch price between -$152/MWh and $0/MWh for the entire trading interval.

Saturday, 25 August

Table 6: 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	-458.59	53.94	64.62	758	807	724	2565	2655	2646

Demand was around 50 MW lower than forecast and availability was 90 MW lower than forecast, both four hours prior.

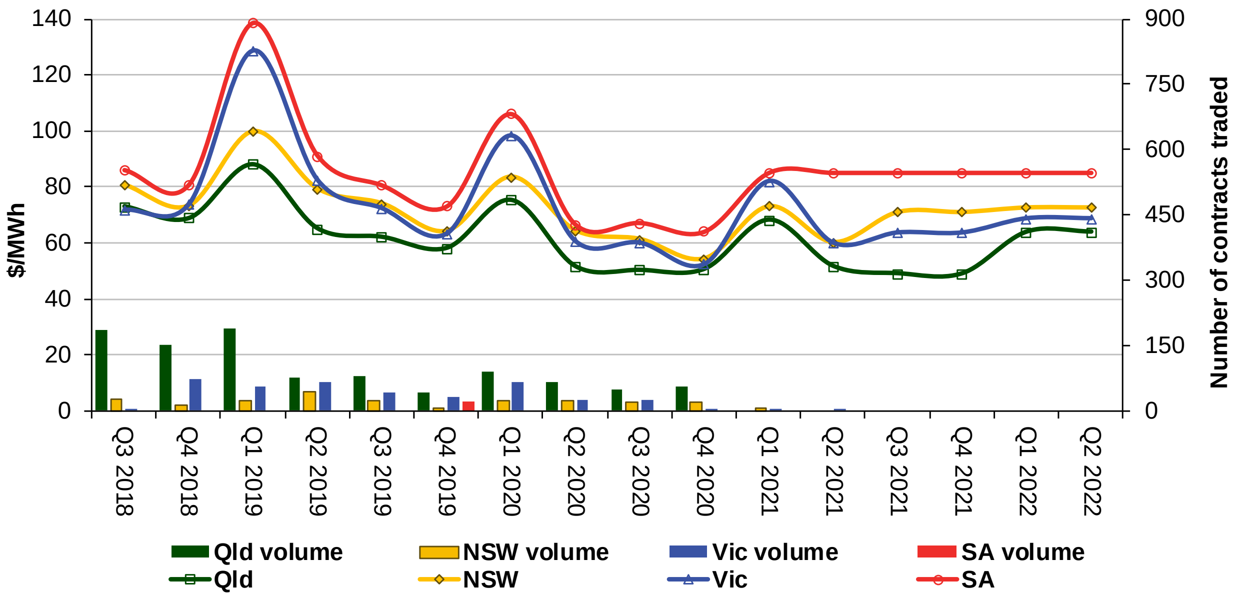
As discussed in the Queensland section, the Heywood interconnector tripped following frequency fluctuations that followed from QNI tripping. The sudden trip of the Heywood interconnector islanded South Australia from the rest of the NEM and, as power was flowing into Victoria immediately prior, the frequency in South Australia increased and local FCAS requirements increased.

As output from the generators in South Australia reduced, the price for the first two dispatch intervals dropped to the price floor. Even though higher priced capacity at Torrens power station was dispatched, it could not set price as it was heavily dispatched in all ancillary services.

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.

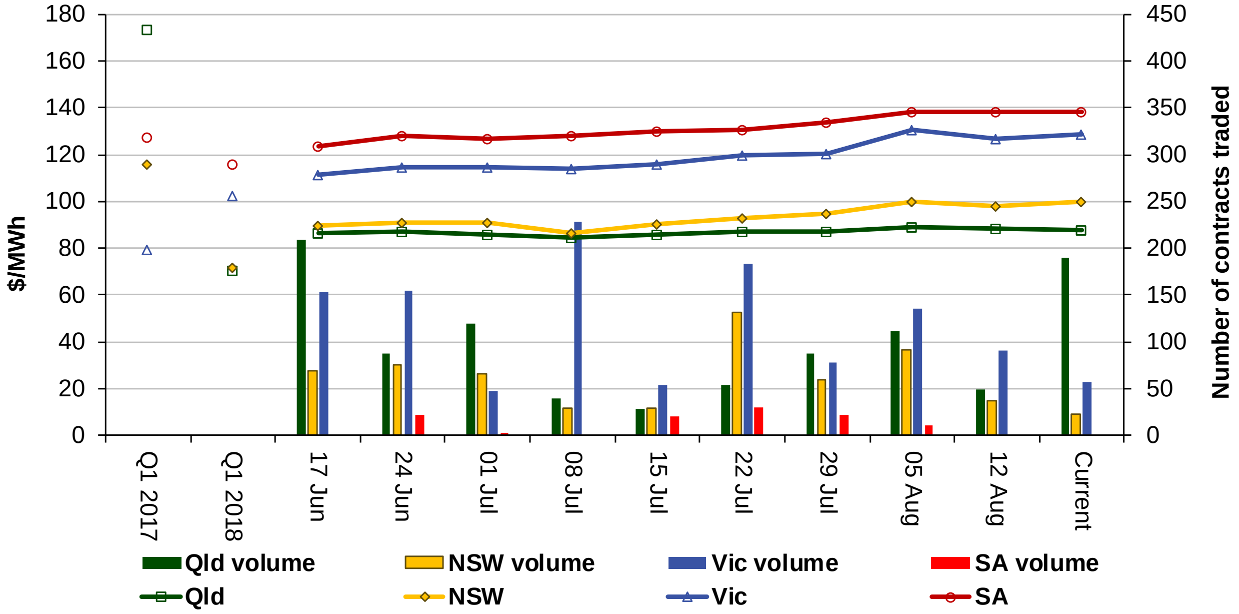
Figure 9: Quarterly base future prices Q3 2018 – Q2 2022



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 and no buy or sell prices have been recorded for South Australia for the period after Q2 2021.

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



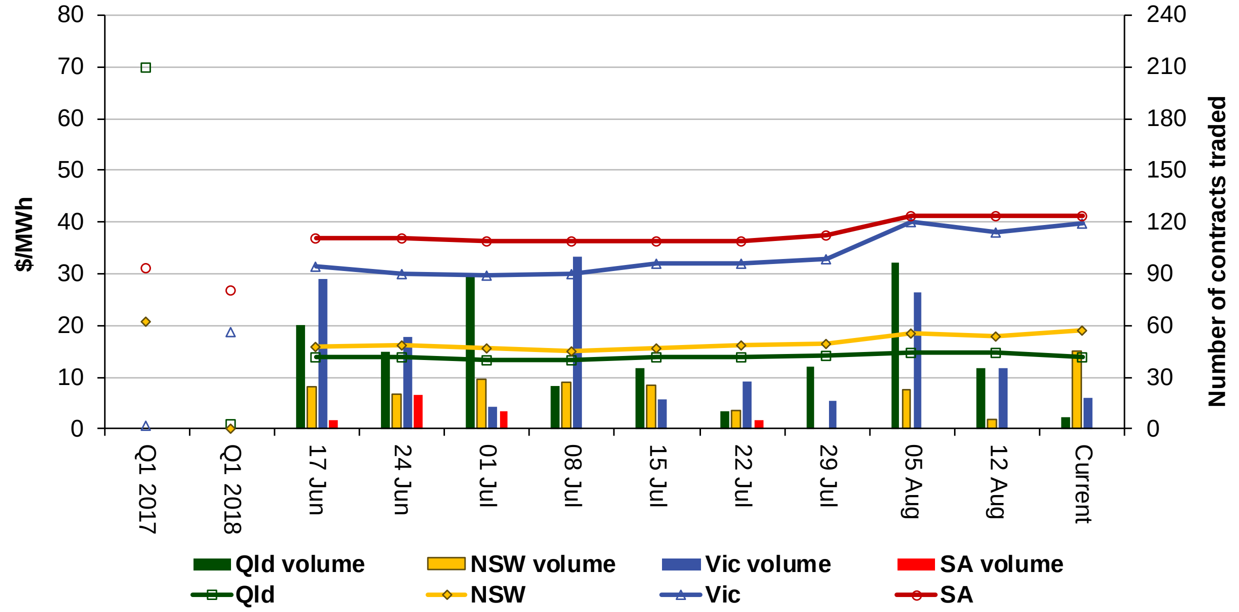
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
September 2018