Electricity Report

AUSTRALIAN ENERGY REGULATOR

8 – 14 August 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $19/MWh in Tasmania to $65/MWh in New South Wales. High wind generation during the middle of the week saw South Australian spot prices drop below -$100/MWh, breaching our reporting thresholds (see detailed analysis section).

Purpose

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 8 to 14 August 2021.

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

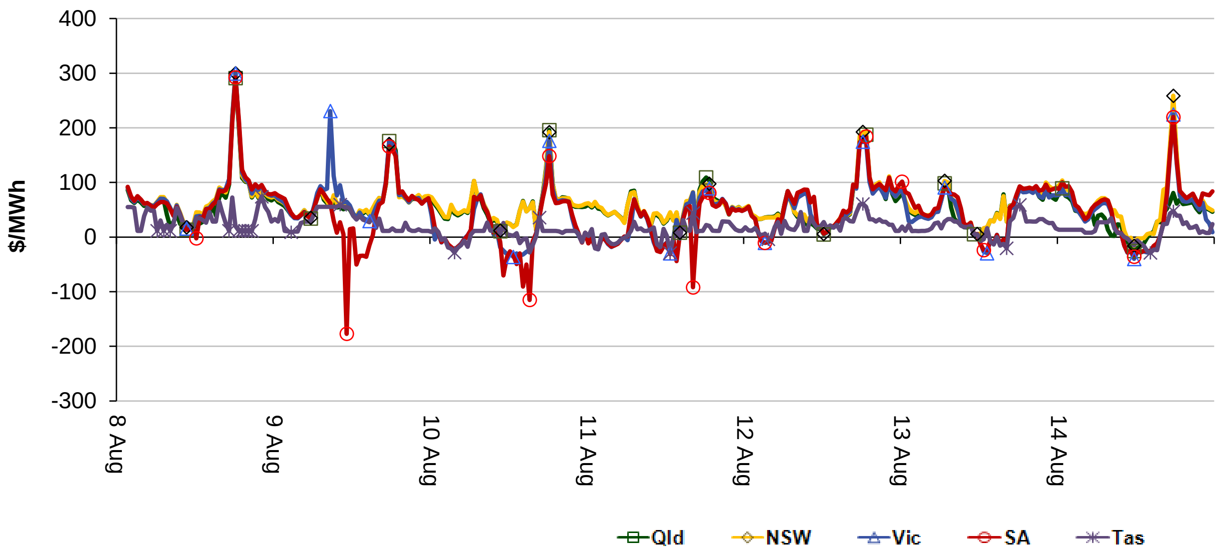


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

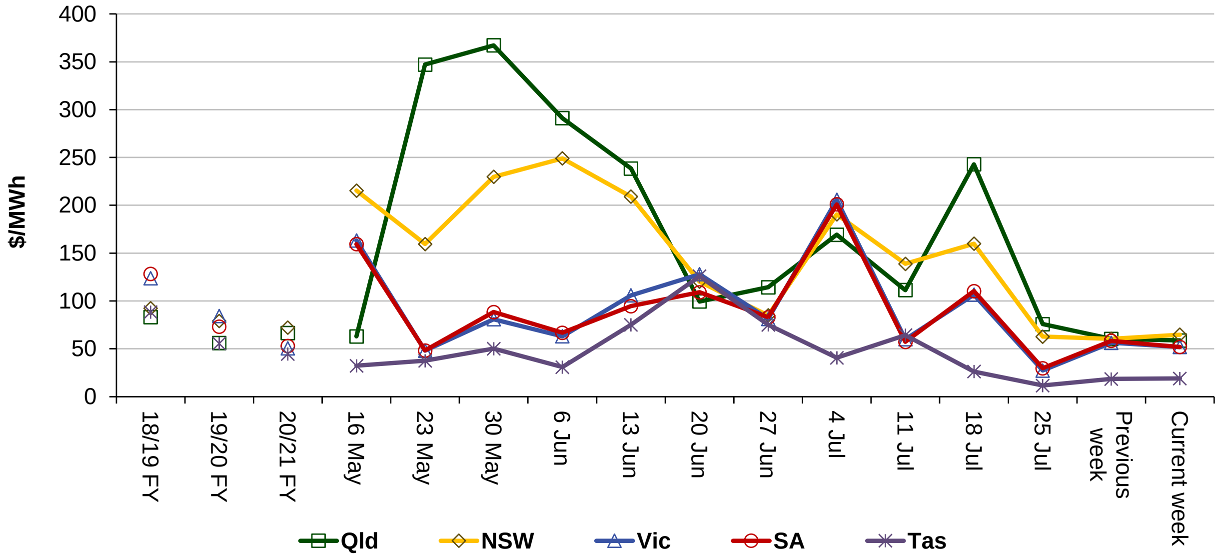


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	59	65	52	52	19
Q3 2020 (QTD)	38	49	62	58	56
Q3 2021 (QTD)	123	115	86	86	32
20-21 financial YTD	38	49	62	58	56
21-22 financial YTD	123	115	86	86	32

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 296 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2020 of 233 counts and the average in 2019 of 204. 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	13	0	2
% of total below forecast	12	51	0	15

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

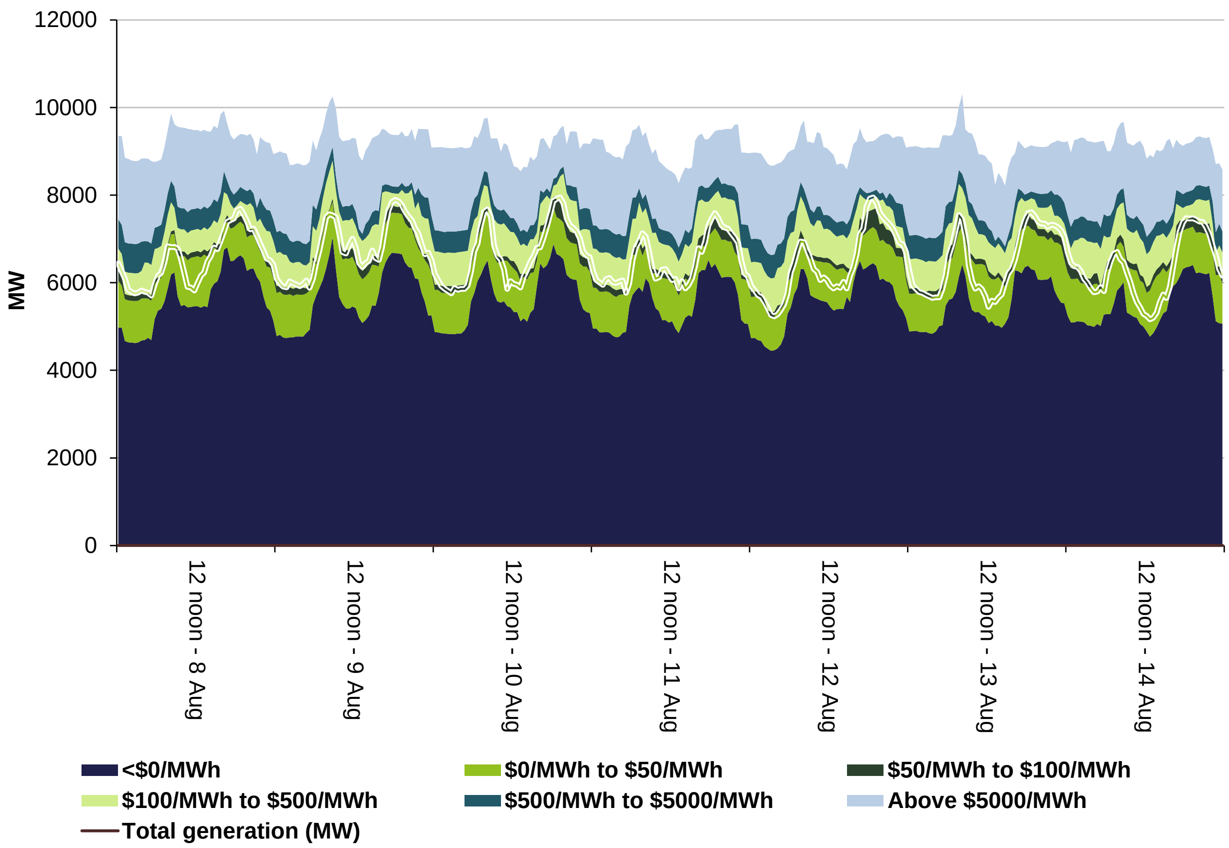


Figure 4: New South Wales generation and bidding patterns

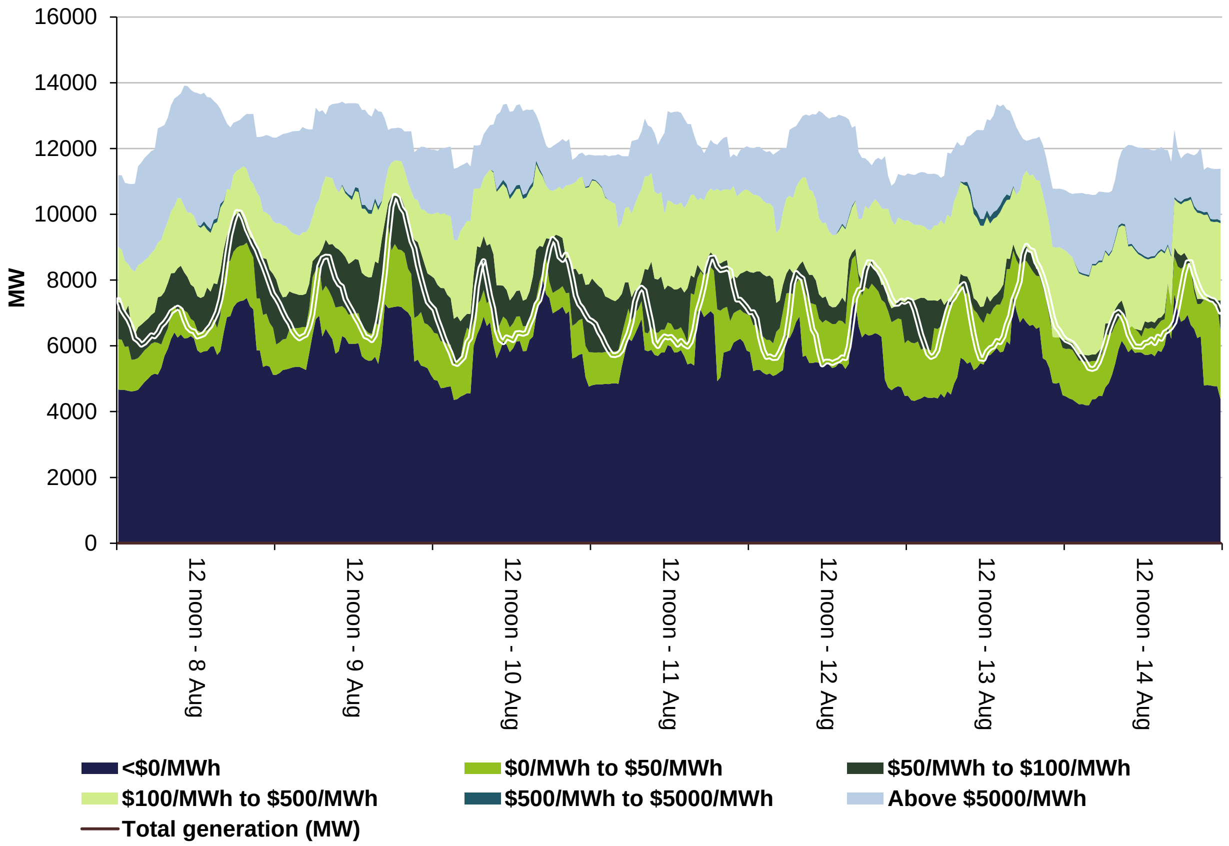


Figure 5: Victoria generation and bidding patterns

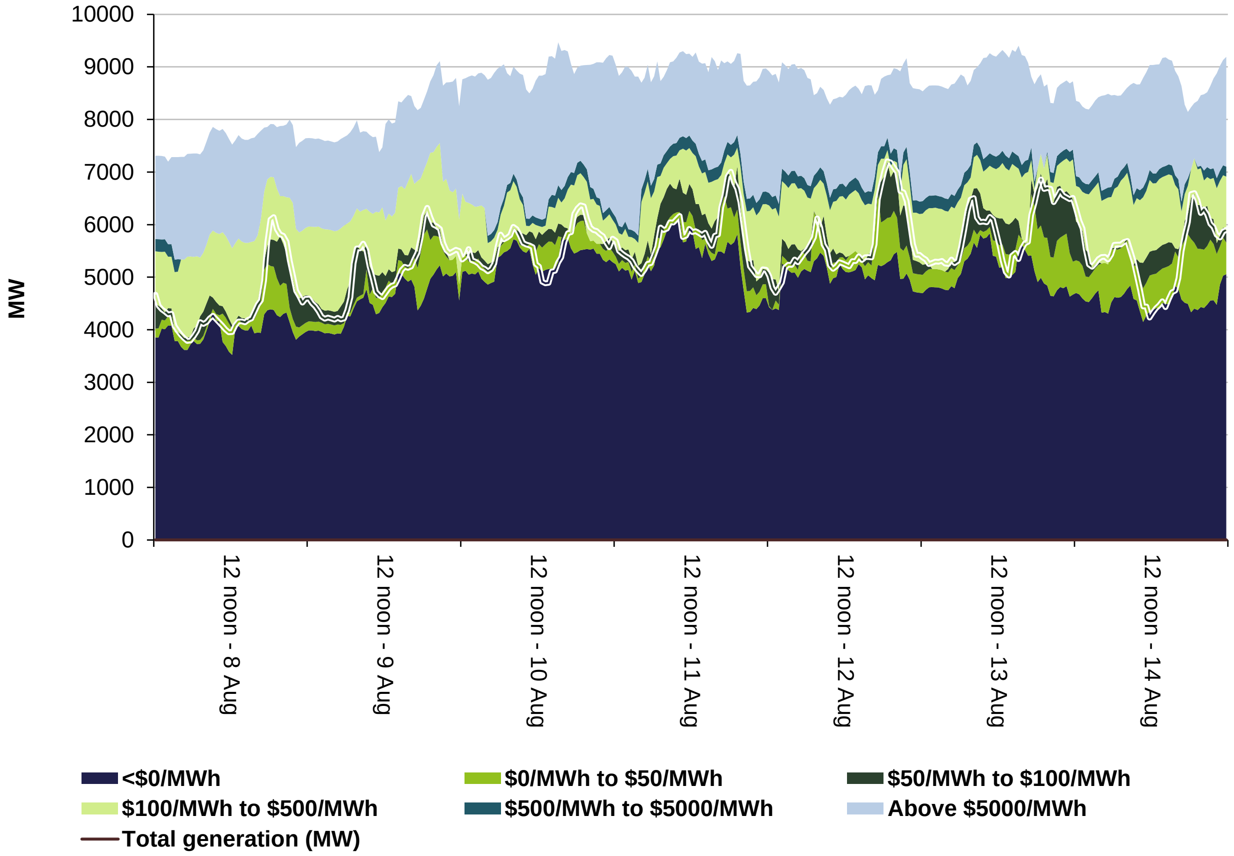


Figure 6: South Australia generation and bidding patterns

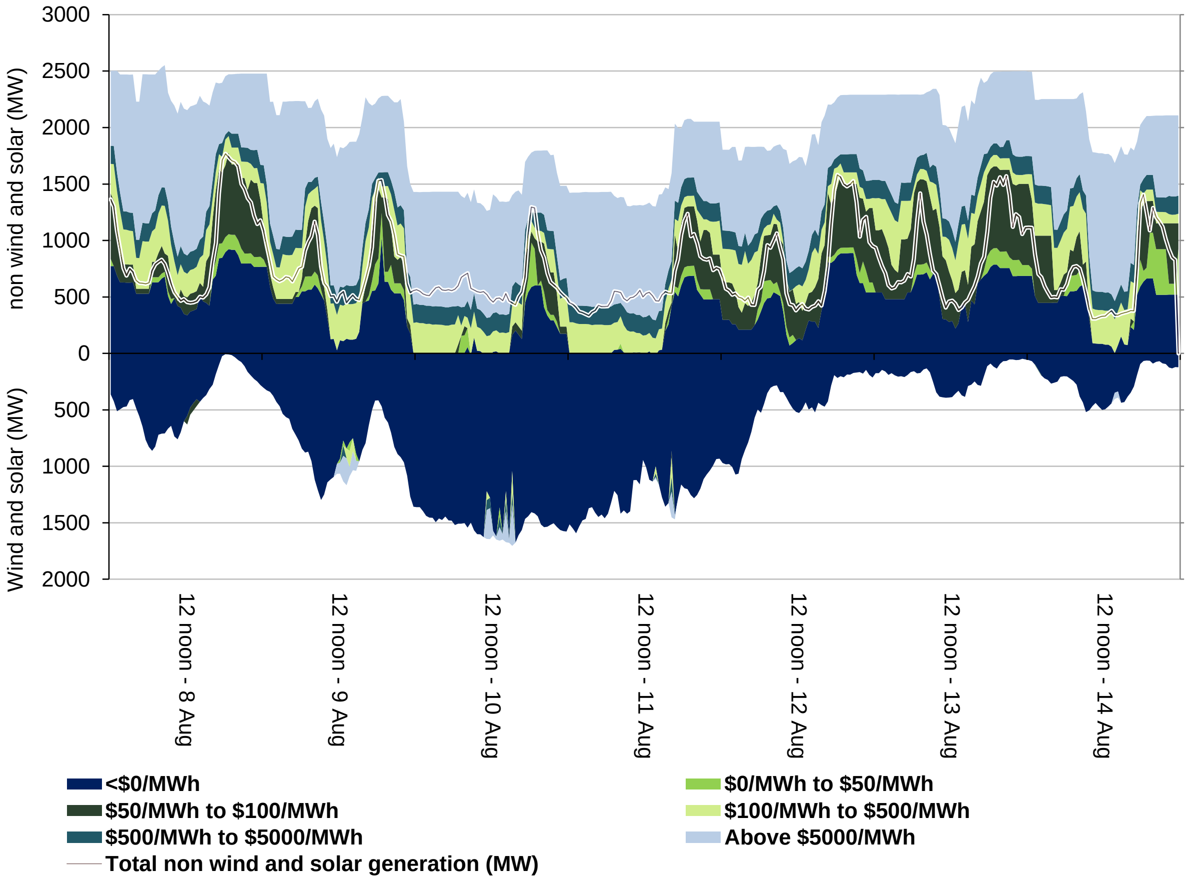
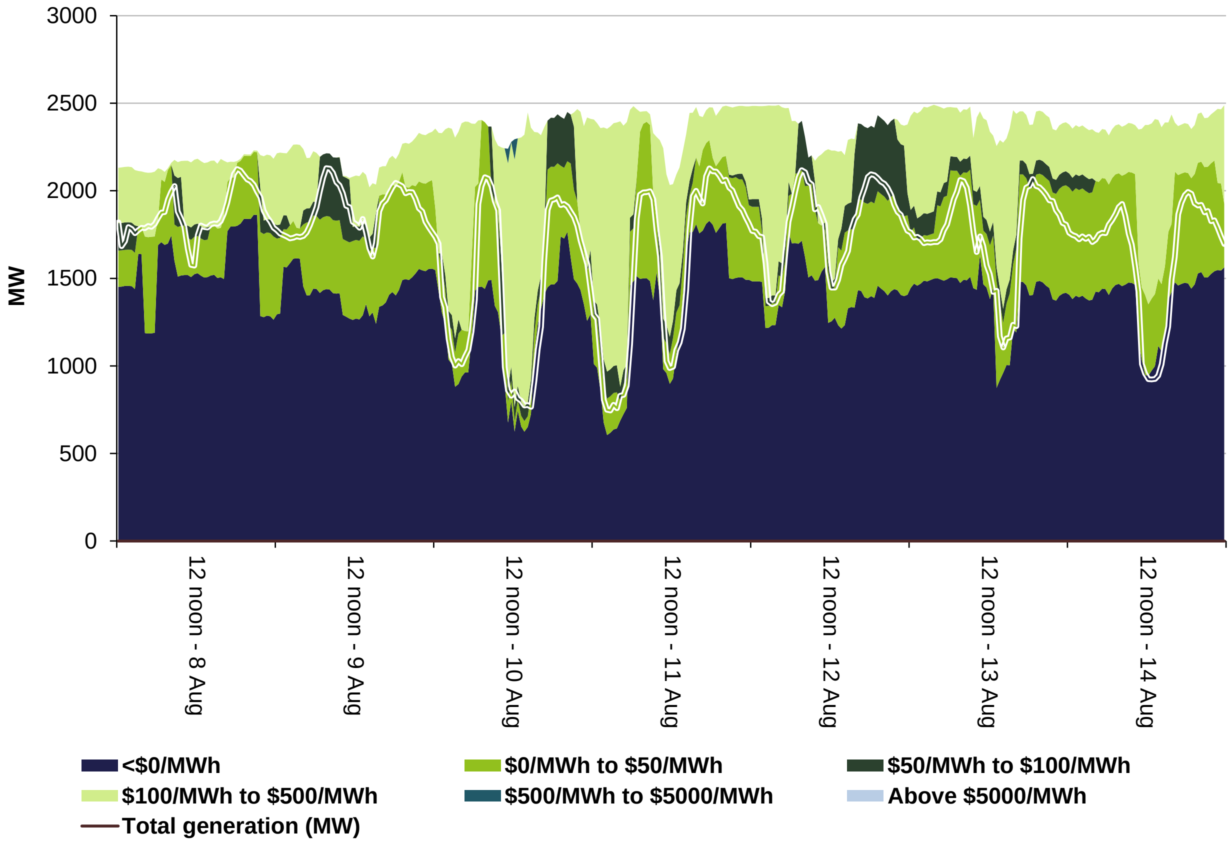


Figure 7: Tasmania generation and bidding patterns



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.

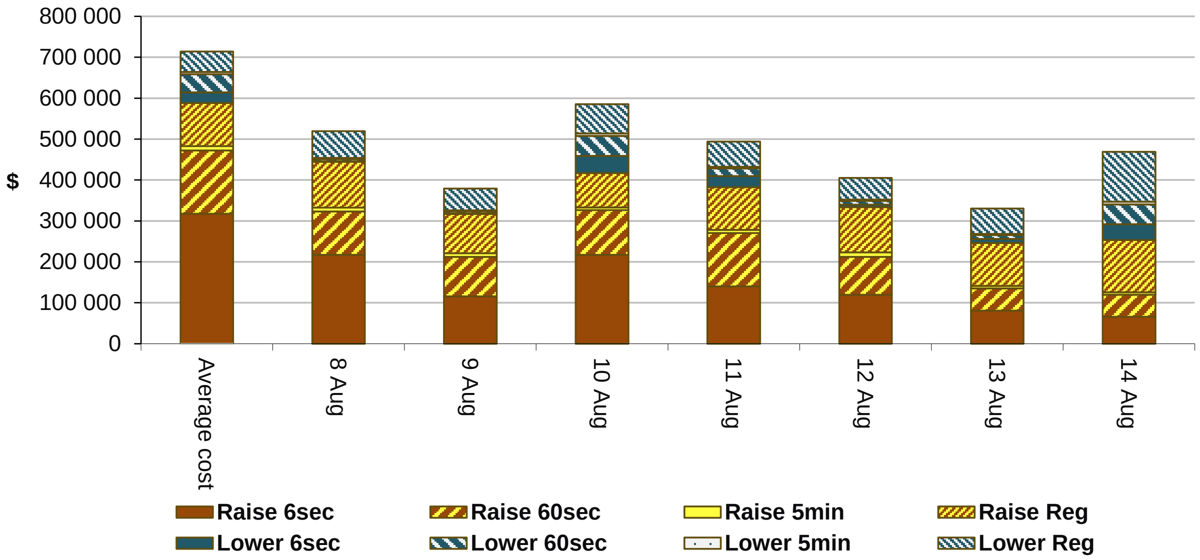
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2,749,000 or around 1% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $432,500 or less than 11% 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



Detailed market analysis of significant price events

Mainland

There was 1 occasion where prices across the mainland were greater than 3 times the New South Wales weekly average price of $65/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Sunday, 8 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	299.7	385.09	300	26,012	26,070	25,821	32,535	32,727	32,647

Prices were aligned across the mainland and will be analysed as 1 region. Demand was 59 MW lower than forecast while availability was 192 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind generation, which mostly offers at low prices, and participants removing capacity, mostly offered below $279/MWh, due to plant reasons and forecast prices.

In the 4 hours prior to the start of the trading interval, participants rebid over 1,400 MW of capacity from the price cap to prices below $0/MWh due to forecast prices, forecast demand and plant reasons. As a result, prices remained below forecast throughout the trading interval.

New South Wales

There was 1 occasion where the spot price in New South Wales was greater than 3 times the New South Wales weekly average price of $65/MWh and above $250/MWh.

Saturday, 14 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 pm	258.67	108.37	92.80	9,072	9,111	9,000	11,640	11,808	12,145

Demand was close to forecast while availability was 168 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind generation, which mostly offers at low prices. From 5.14 pm AGL Energy at Bayswater and EnergyAustralia at Mount Piper removed a total of 200 MW of capacity priced below $36/MWh due to plant reasons. This coupled with a 131 MW increase in demand at 5.40 pm saw prices at $300/MWh for most of the trading interval.

South Australia

There were 2 occasions where the spot price was below -$100/MWh.

Monday, 9 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
11.30 am	-177.11	33.58	43.09	746	814	812	2,944	2,823	2,834

Demand was 68 MW lower than forecast while availability was 121 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was offered below $0/MWh.

There was no capacity offered between -$36/MWh and -$1,000/MWh. At 11.30 am wind generation increased by over 60 MW while demand fell by nearly 20 MW as a result price fell to the price floor.

Tuesday, 10 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
3.30 pm	-115.07	-27.73	-8.57	1,154	1,102	1,017	3,111	2,674	2,655

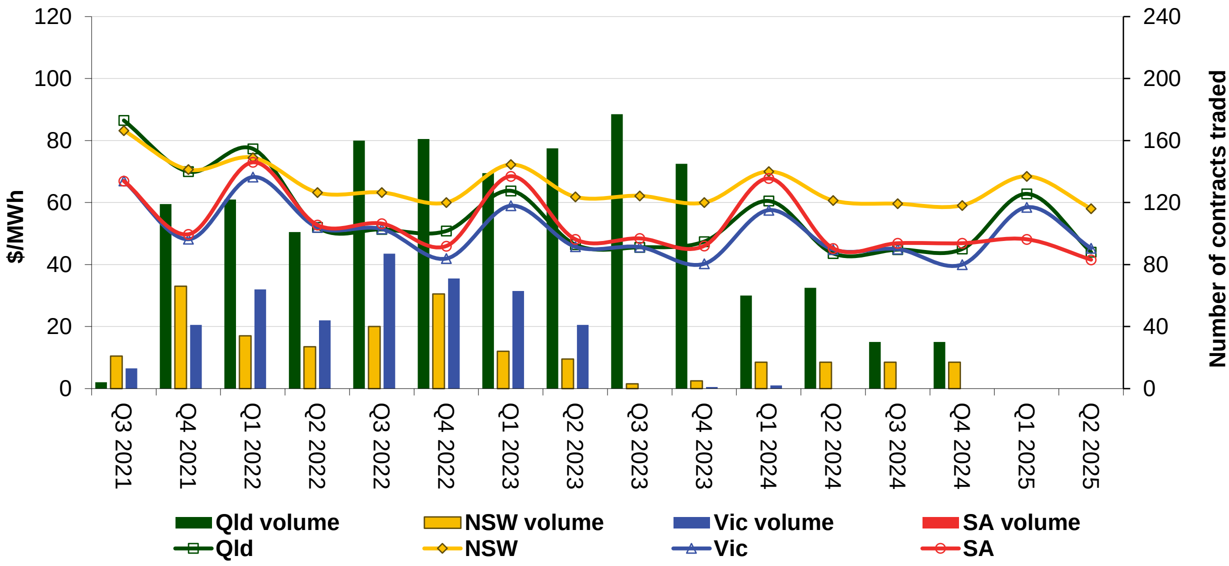
Demand was 52 MW higher than forecast while availability was 437 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was offered below $0/MWh.

With no capacity offered between $72/MWh and -$1,000/MWh, at 3.10 pm a 20 MW fall in wind generation meant low-priced generation had to come from other regions. There was co-optimisation between energy and contingency services from other regions that resulted in the price falling to nearly -$600/MWh. In response, participants rebid over 650 MW from the price floor to prices above $21/MWh.

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.

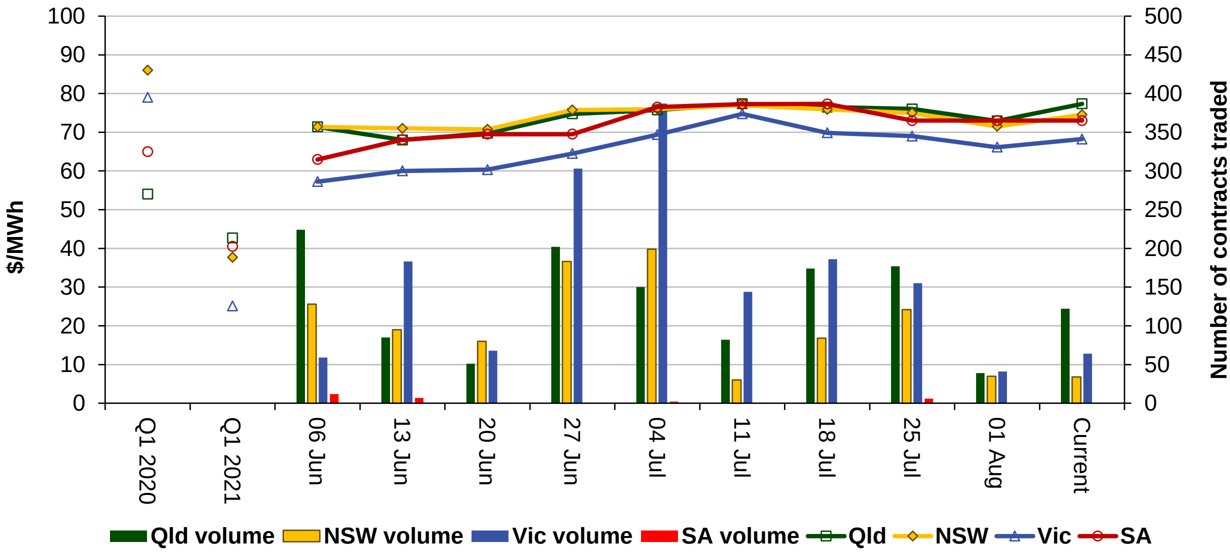
Figure 9: Quarterly base future prices Q3 2021 – Q2 2025



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2022 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 2020 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 2022 base contracts over the past 10 weeks (and the past 2 years)

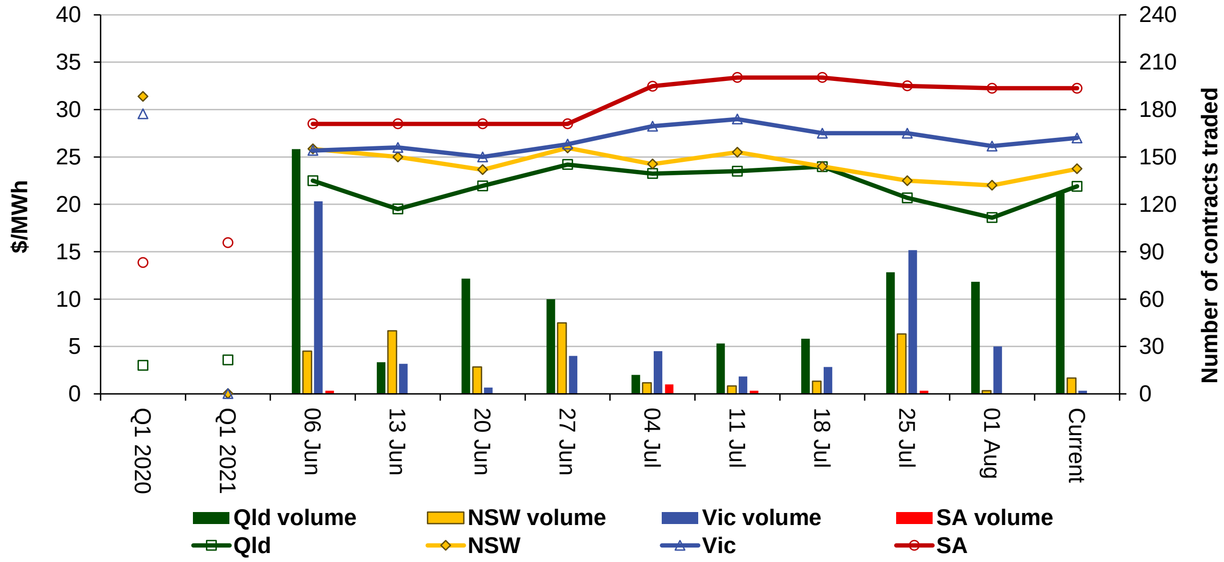


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2022 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 2020 prices are also shown.

Figure 11: Price of Q1 2022 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

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

Australian Energy Regulator
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