Electricity Report

AUSTRALIAN ENERGY REGULATOR

4 – 10 April 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged between $25/MWh in Tasmania to $63/MWh in Queensland. This week saw Queensland's highest VWA price over the last 10 weeks, driven by 6 prices above $290/MWh.

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 4 to 10 April 2021.

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

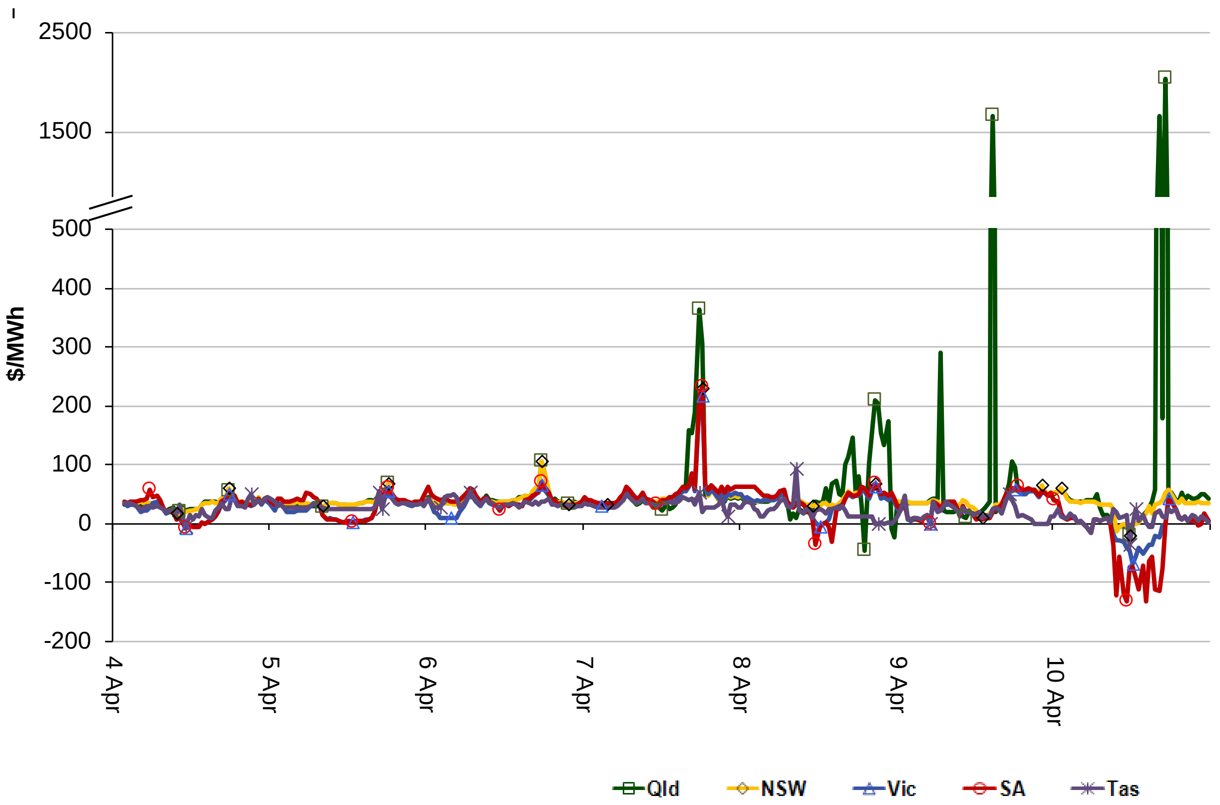


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

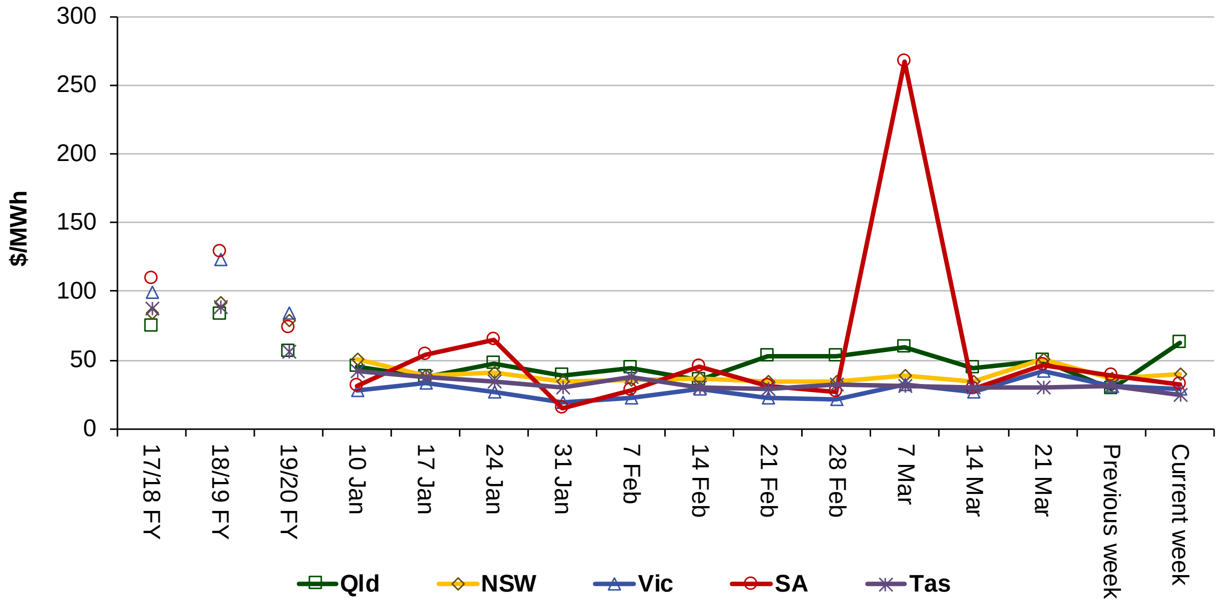


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	63	40	29	33	25
Q2 2020 QTD	42	49	48	44	35
Q2 2021 QTD	52	37	27	33	26
19-20 financial YTD	62	89	97	82	63
20-21 financial YTD	43	52	41	44	43

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 186 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	2	21	0	3
% of total below forecast	13	38	0	24

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

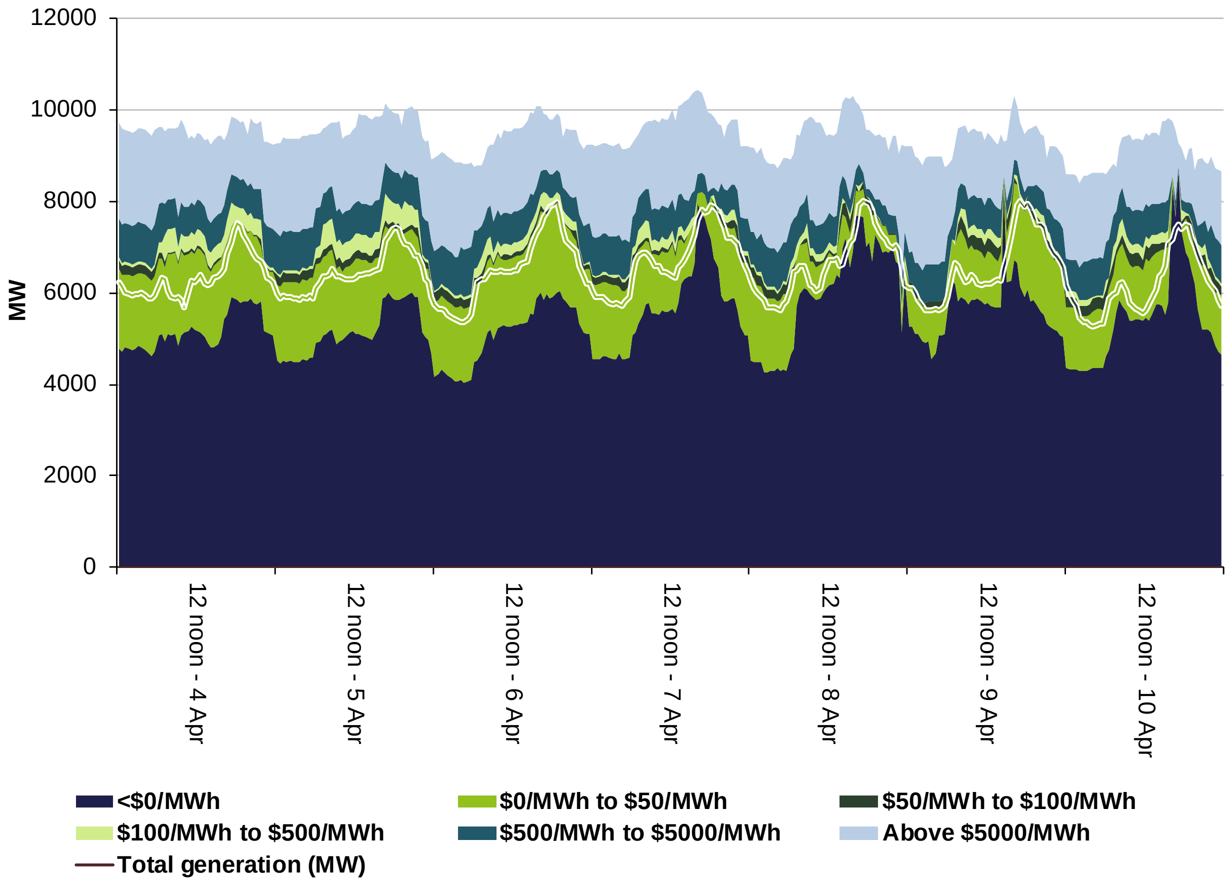


Figure 4: New South Wales generation and bidding patterns

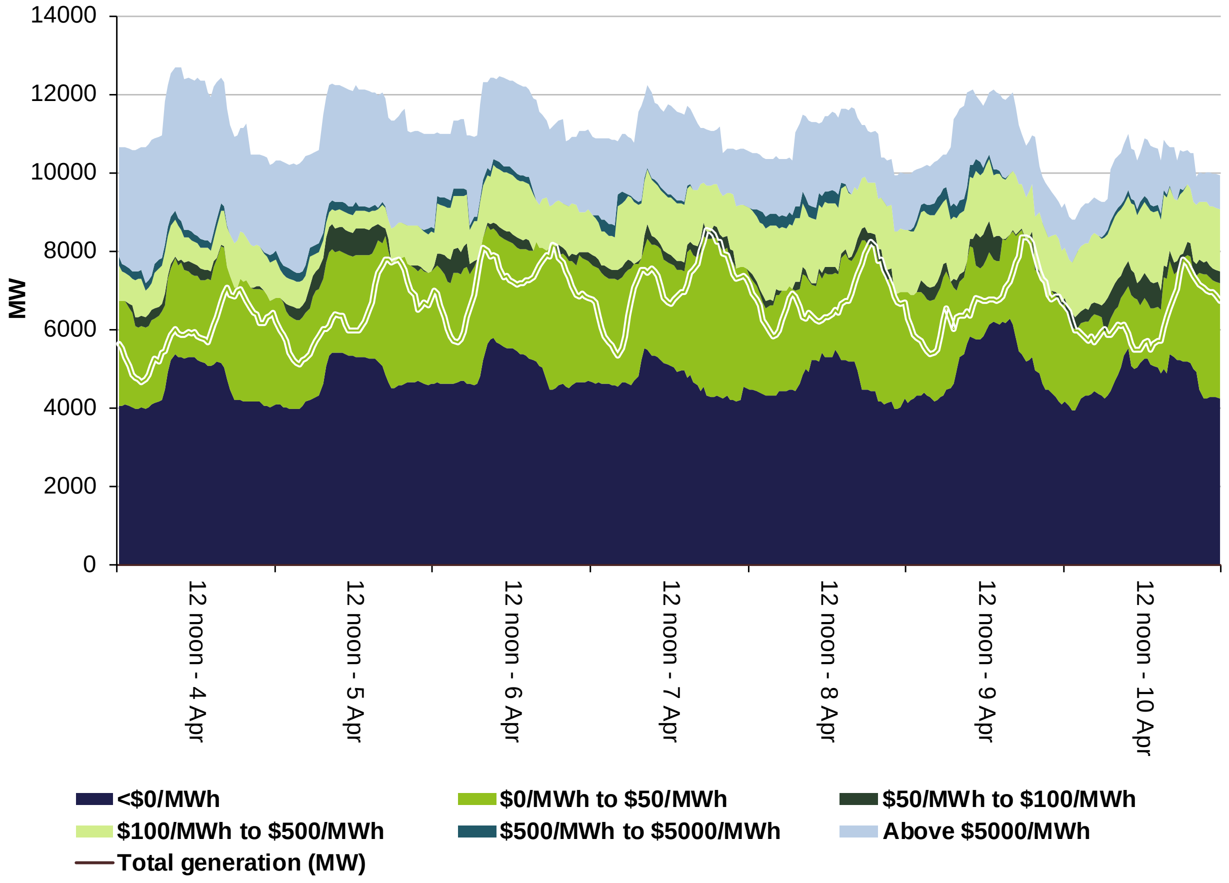


Figure 5: Victoria generation and bidding patterns

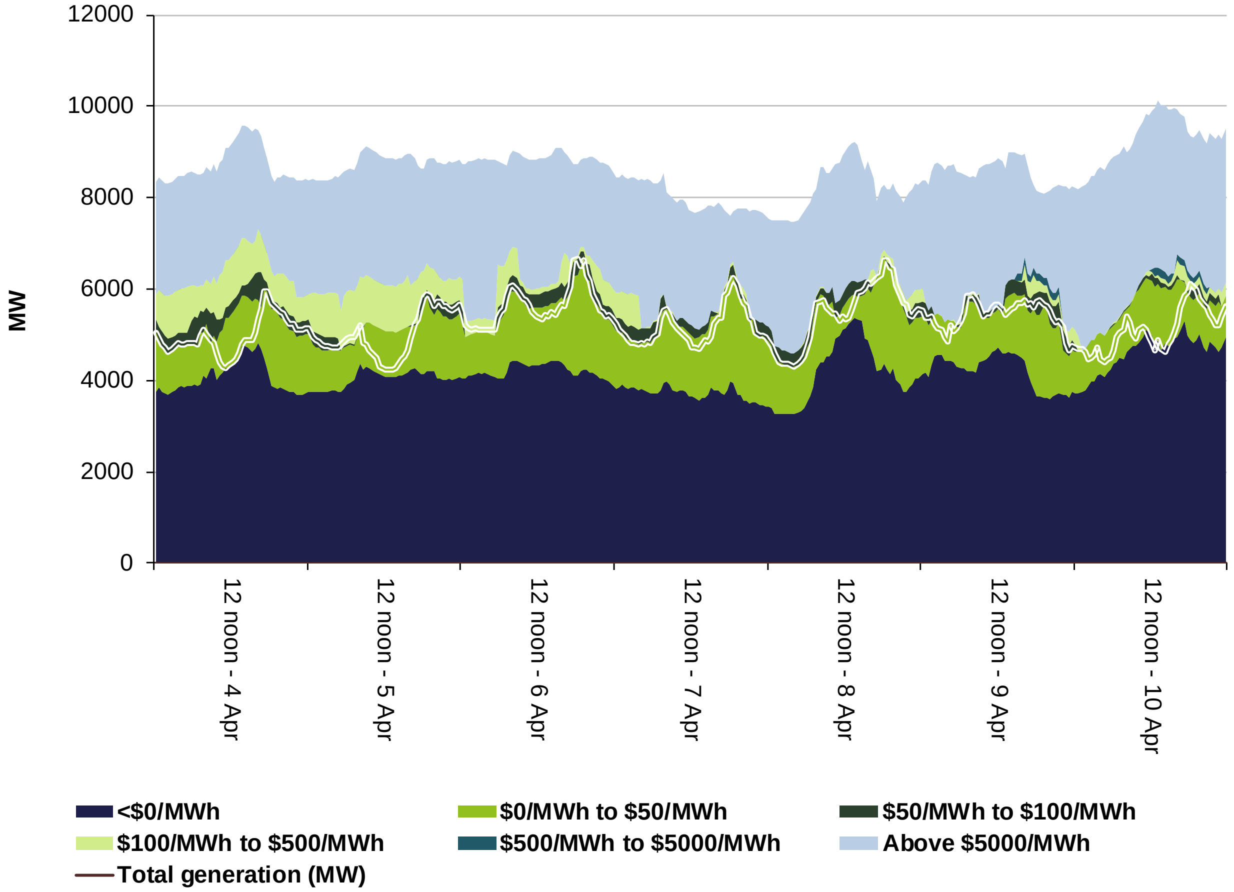


Figure 6: South Australia generation and bidding patterns

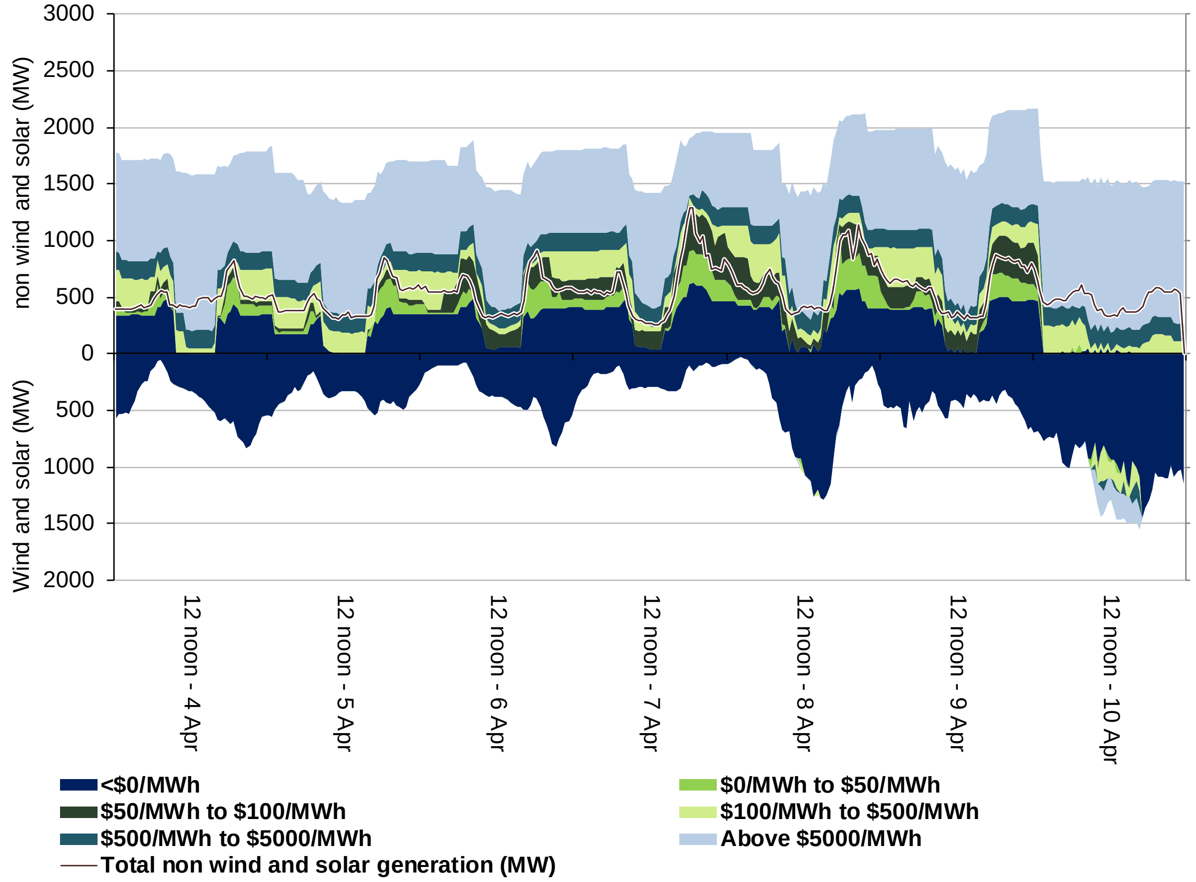
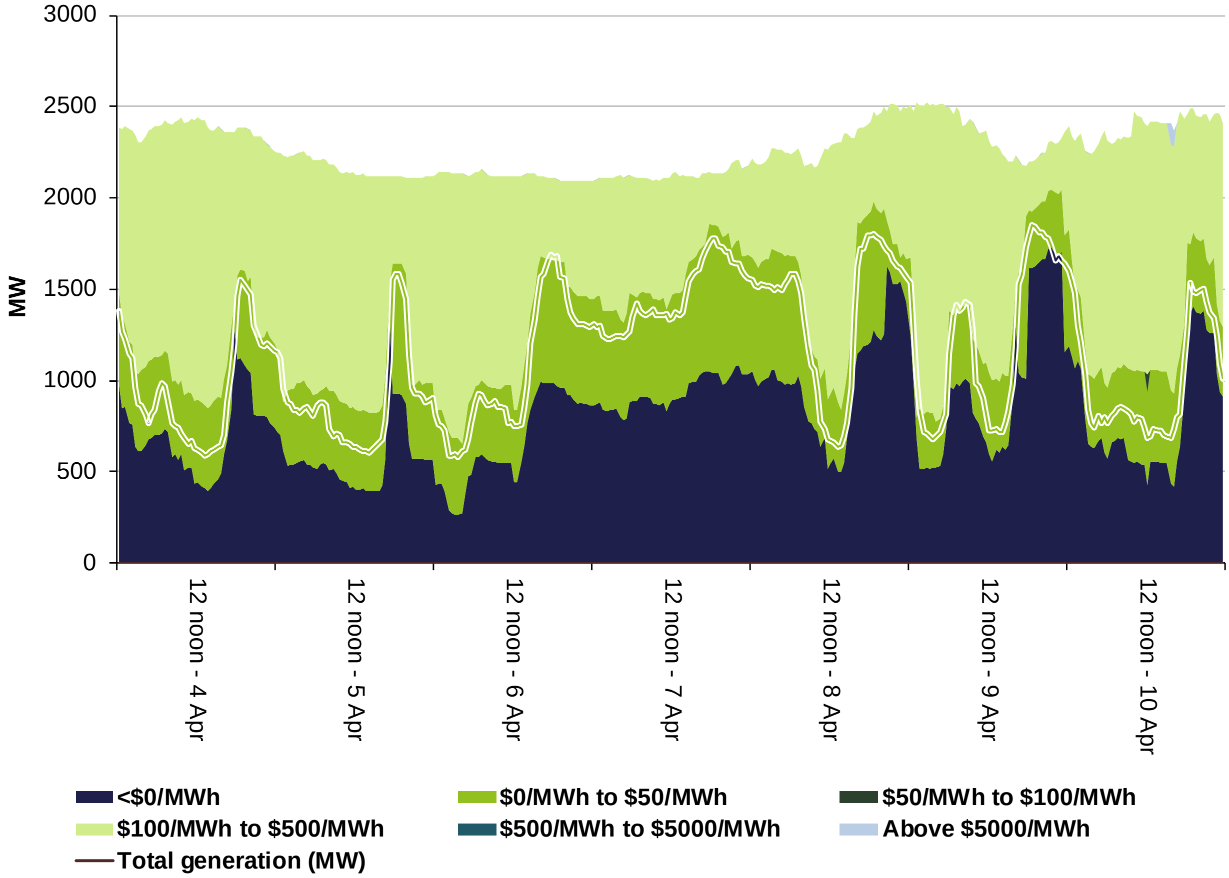


Figure 7: Tasmania generation and bidding patterns



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.

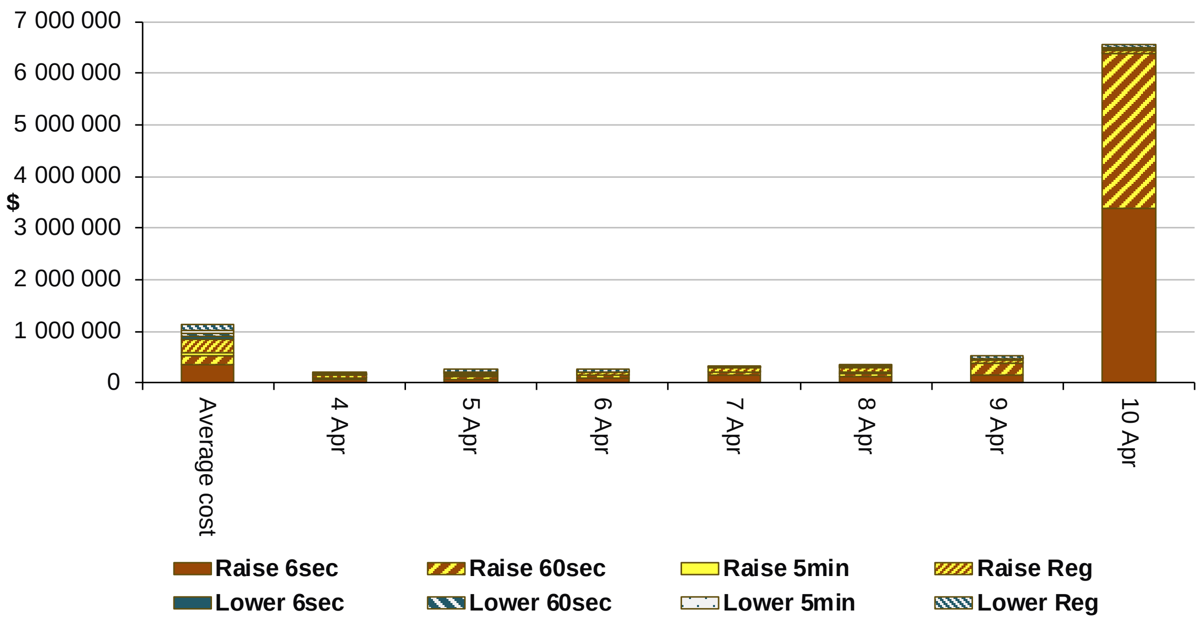
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $8,049,000 or less than 6% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $451,000 or around 10% 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 10 April 2021, Queensland local raise 6 second and raise 60 second services exceeded $5,000/MW in the afternoon. Between 4.05 pm and 5.15 pm (inclusive) the price for raise 6 second and raise 60 second services reached between $7,500/MW and the price cap of $15,000/MW for the majority of the dispatch intervals as the requirement for both services increased to a maximum of around 270 MW. Analysis into the drivers for FCAS prices above $5,000/MW will be included in the AER's Wholesale Markets Quarterly, Q2 2021.

Detailed market analysis of significant price events

Queensland

There were 6 occasions where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $63/MWh and above $250/MWh.

Wednesday, 7 April

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 pm	364.09	70.73	70.73	7,533	7,482	7,515	9,956	9,944	9,947
6.30 pm	305.83	273.21	278.67	7,634	7,576	7,596	9,914	9,938	9,845

Demand and availability were both close to forecast, 4 hours prior.

Rebids by CS Energy from 5.22 pm shifted over 400 MW of capacity at Gladstone from prices below $71/MWh to prices above $1,560/MWh due to a constraint invoked because of a planned outage of the Bouldercombe to Stanwell 275 kV line. The same constraint forced exports from Queensland into New South Wales throughout the trading intervals, requiring more generation in Queensland to be dispatched and resulting in price being set above forecast for both trading intervals.

Friday, 9 April

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
7 am	291.12	39.90	37.10	5,997	6,003	6,020	8,911	9,133	9,153
3 pm	1,665.83	35.74	45.42	6,172	6,235	6,307	9,311	9,699	9,870

For the 7 am trading interval, demand was close to forecast and availability was 222 MW lower than forecast, 4 hours prior. Lower than forecast availability was mostly due to lower than forecast solar generation.

Similar to 7 April, a planned outage of the Bouldercombe to Stanwell 275 kV line saw forced exports from Queensland into New South Wales as morning peak demand started to increase. With other generation either trapped or stranded in FCAS or unable to start in 5 minutes, the price increased to $1,602/MWh for one dispatch interval. In response, nearly 400 MW of capacity was rebid from prices above $1,602/MWh to at or below $0/MWh and prices returned to below $30/MWh for the remainder of the trading interval.

For the 3 pm trading interval, demand was 63 MW lower than forecast and availability was 388 MW lower than forecast, 4 hours prior. Lower than forecast availability was mostly due to lower than forecast solar generation.

At 2.35 pm, solar availability fell by 117 MW and with other generation ramp up-constrained, trapped or stranded in FCAS or unable to start in 5 minutes, the price increased to $14,995/MWh for 5 minutes. In response, effective 2.40 pm, more than 1,800 MW of capacity was rebid to the price floor with more than 640 MW of this from prices above $14,900/MWh. As a result, prices fell to -$1,000/MWh for the remainder of the trading interval.

Saturday, 10 April

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
4.30 pm	1,665.50	50.73	50.73	6,937	6,978	6,980	9,743	9,812	9,771
5.30 pm	2,037.24	70.73	70.73	7,341	7,465	7,464	9,270	9,510	9,346

For the 4.30 pm trading interval, demand and availability were both close to forecast, 4 hours prior.

At 4.05 pm, demand increased by over 130 MW and with lower-priced generation unable to turn on in 5 minutes or ramp-constrained and unable to set price, price was set at $14,993/MWh for the first dispatch interval. In response to the high price, participants rebid over 1,100 MW of capacity from prices above $51/MWh to the floor. Prices remained at the price floor for the remainder of the trading interval.

For the 5.30 pm trading interval, demand was 124 MW lower than forecast and availability was 240 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to removal of capacity by CS Energy (170 MW at Gladstone at various prices due to a unit trip) and Origin Energy (62 MW at Darling Downs Power Station priced below $47/MWh due to technical reasons).

Effective 5.15 pm, participants rebid over 700 MW from prices below $300/MWh to the cap to avoid high FCAS prices. With lower-priced generation unable to provide any further capacity, price was set at $14,994/MWh for 5 minutes. In response to the high price, participants rebid over 830 MW from prices above $14,993/MWh to the floor. As a result, prices remained at the price floor for the remainder of the trading interval.

South Australia

There were 7 occasions where the spot price in South Australia was below -$100/MWh.

Saturday, 10 April

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
10 am	-122.49	-35.95	-190	903	835	834	2,738	2,540	2,522
11 am	-121	-117.48	-649.33	813	738	734	2,949	2,580	2,629
11.30 am	-131.68	-190	-977.87	787	667	670	2,928	2,617	2,645

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	-111.16	-200	-947.35	852	521	595	2,969	2,722	2,701
2.30 pm	-131.41	-944.46	-1000	783	541	578	2,951	2,779	2,746
4 pm	-111.20	-200	-890.80	850	717	700	2,994	2,858	2,802
4.30 pm	-115.83	-190	-649.33	974	746	766	3,017	2,838	2,795

For the 10 am trading interval, demand was 68 MW higher than forecast and availability was 198 MW higher than forecast, 4 hours prior. Higher than forecast availability was mostly due to higher than forecast wind and solar generation which was mostly offered at low prices. This increased the amount of low-priced capacity and as a result the price was lower than forecast.

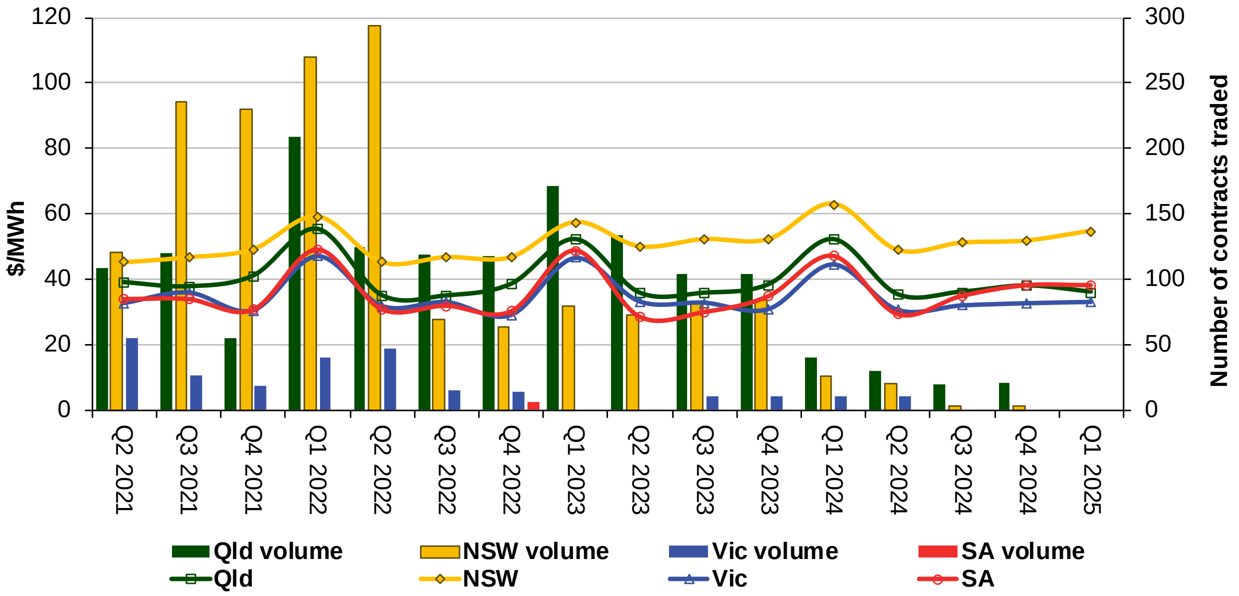
For the 11 am trading interval, prices were close to forecast, 4 hours prior.

For the remaining trading intervals demand was up to 331 MW higher than forecast and availability was up to 311 MW higher than forecast, 4 hours prior. Higher than forecast availability was mostly due to higher than forecast wind and solar generation which was mostly offered at low prices. There was rebidding of capacity from prices less than -$190/MWh to above $43/MWh for all but the 1.30 pm trading interval. The higher than forecast demand and rebidding resulted in prices higher than forecast.

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 Q2 2021 – Q1 2025

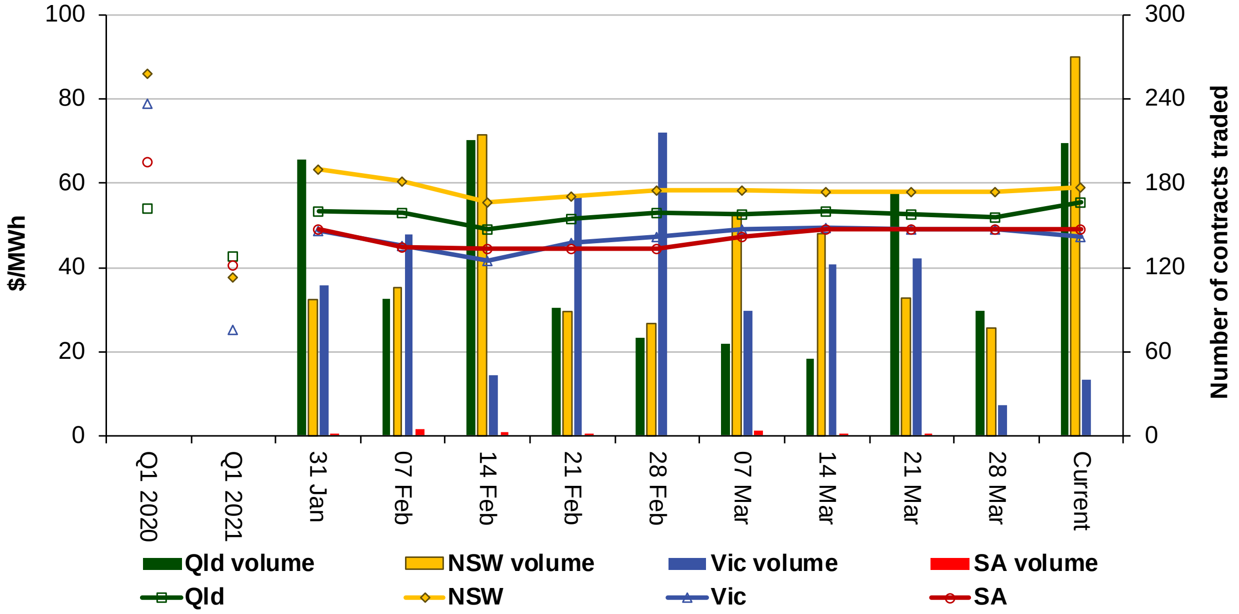


Source. ASXEnergy.com.au

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)



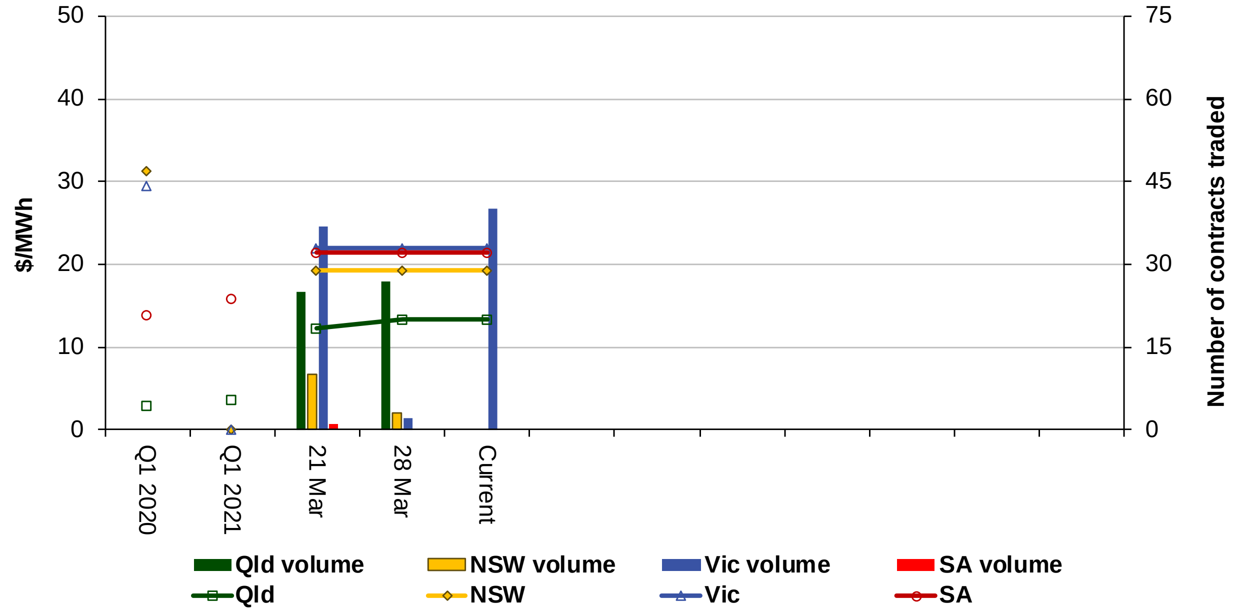
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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.

Cap contracts for 5 minute settlement (due to commence from Q4 2021) were listed on 22 March 2021. As a result, there's only been 3 weeks of Q1 2022 cap contract trading so far.

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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