Electricity Report

AUSTRALIAN ENERGY REGULATOR

3 – 9 January 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $15/MWh in Victoria to $40/MWh in Queensland. Quarter to date VWA prices are between $23/MWh and $43/MWh lower in all regions except NSW. NSW quarter to date VWA prices are down by $227/MWh, driven by high VWA prices on 4 January 2020.

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 3 to 9 January 2021.

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

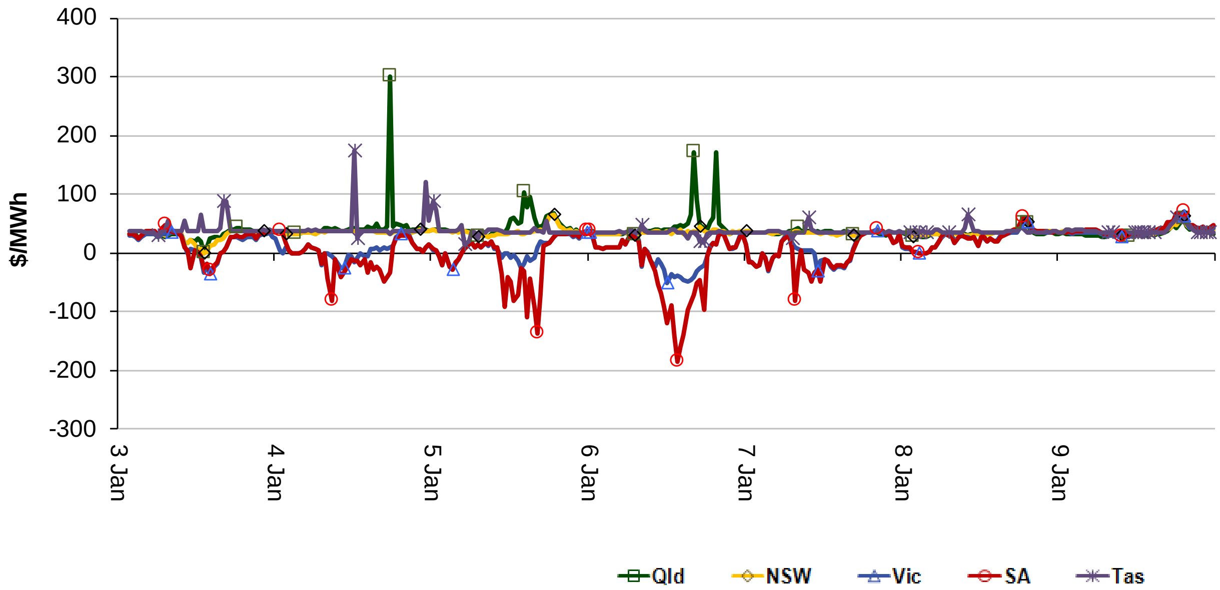


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

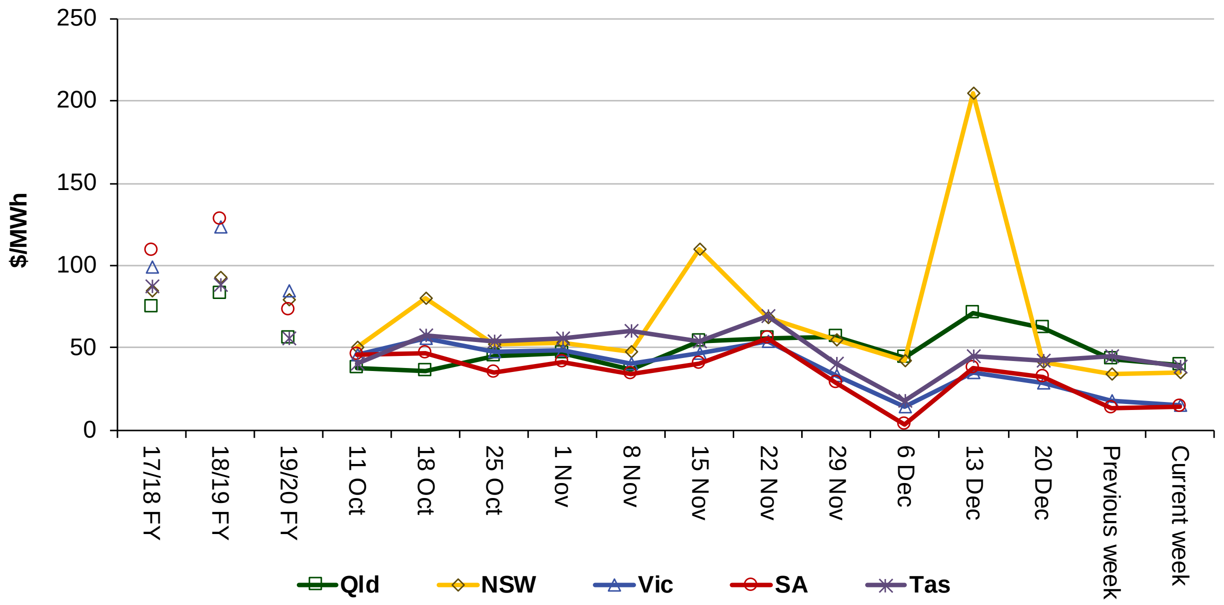


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	40	35	15	14	39
Q1 2020 (QTD)	61	262	55	58	72
Q1 2021 (QTD)	38	35	16	15	39
19-20 financial YTD	65	90	91	83	73
20-21 financial YTD	41	58	46	40	48

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 208 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	34	56	0	0
% of total below forecast	2	8	0	0

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

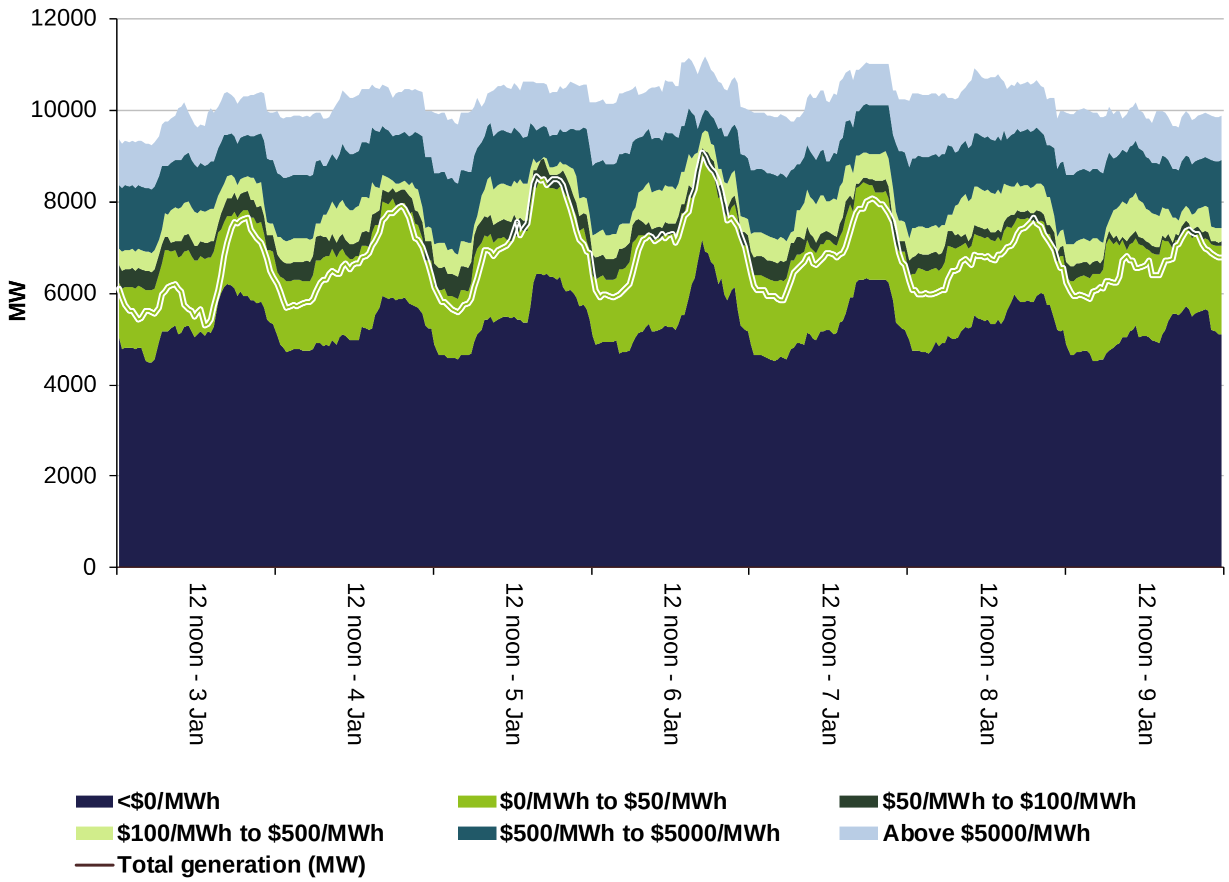


Figure 4: New South Wales generation and bidding patterns

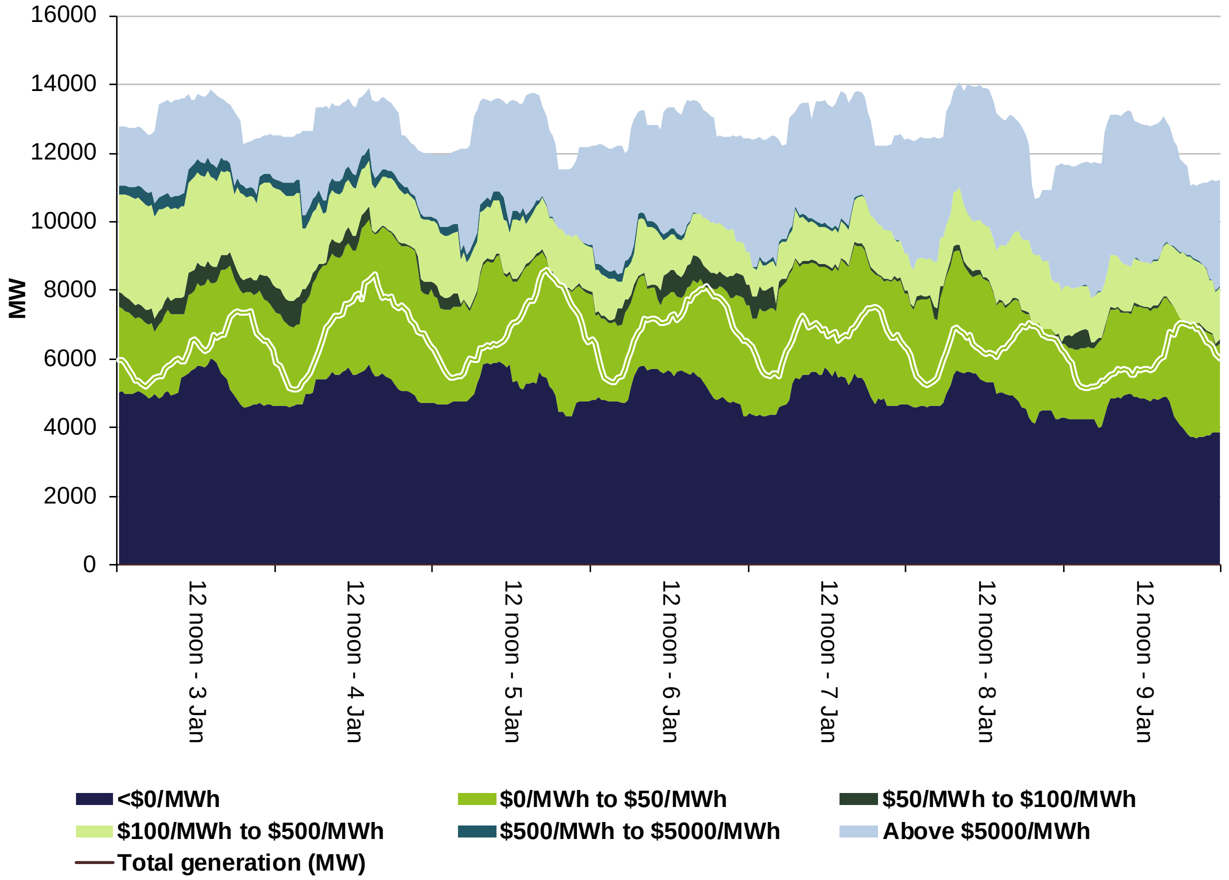


Figure 5: Victoria generation and bidding patterns

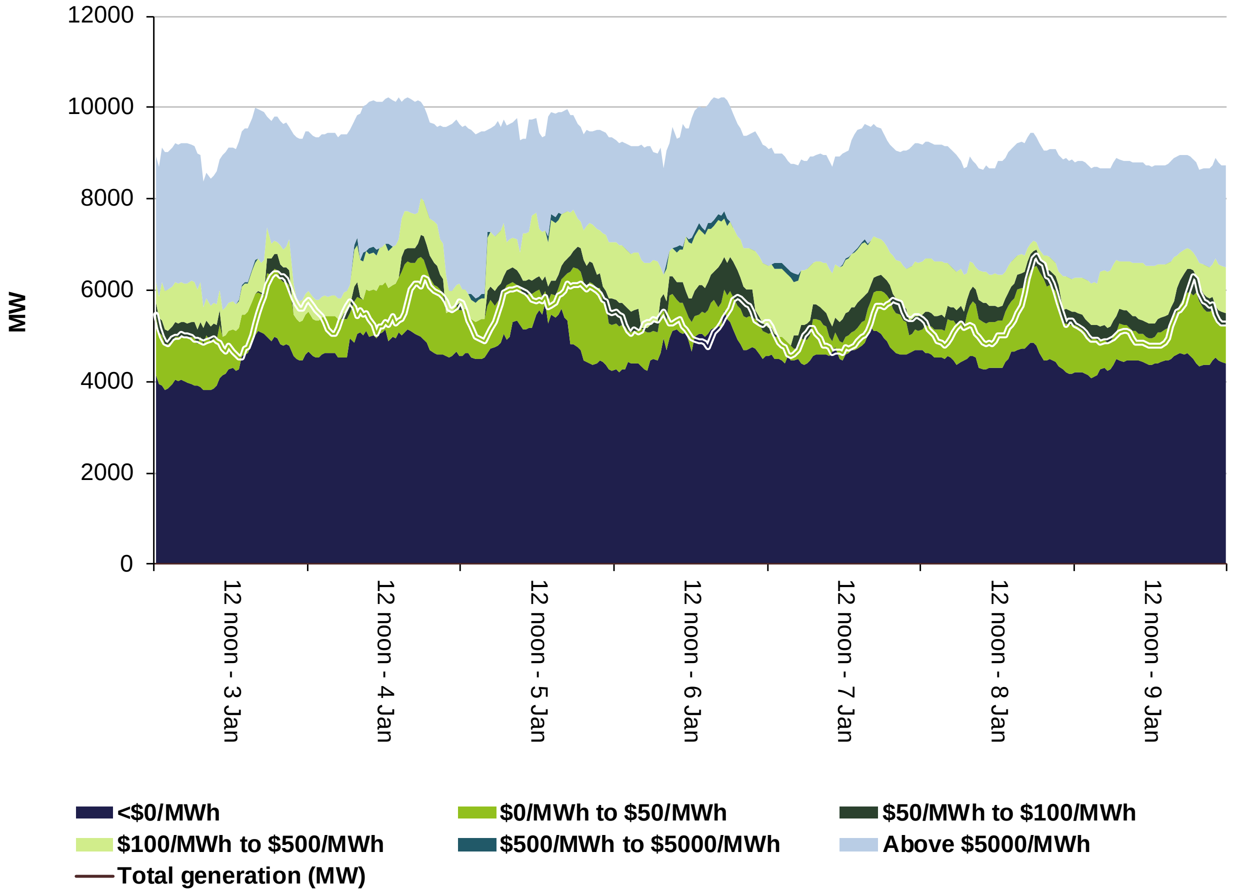


Figure 6: South Australia generation and bidding patterns

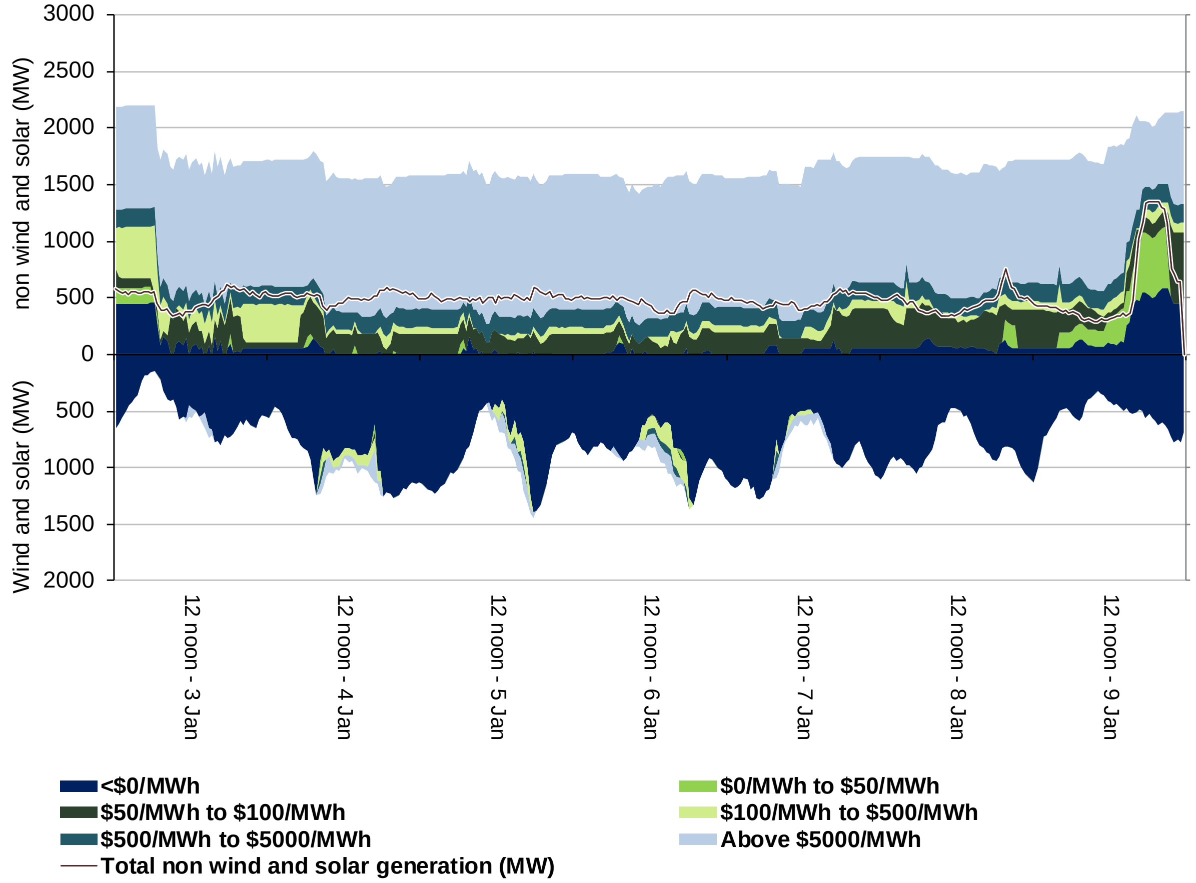
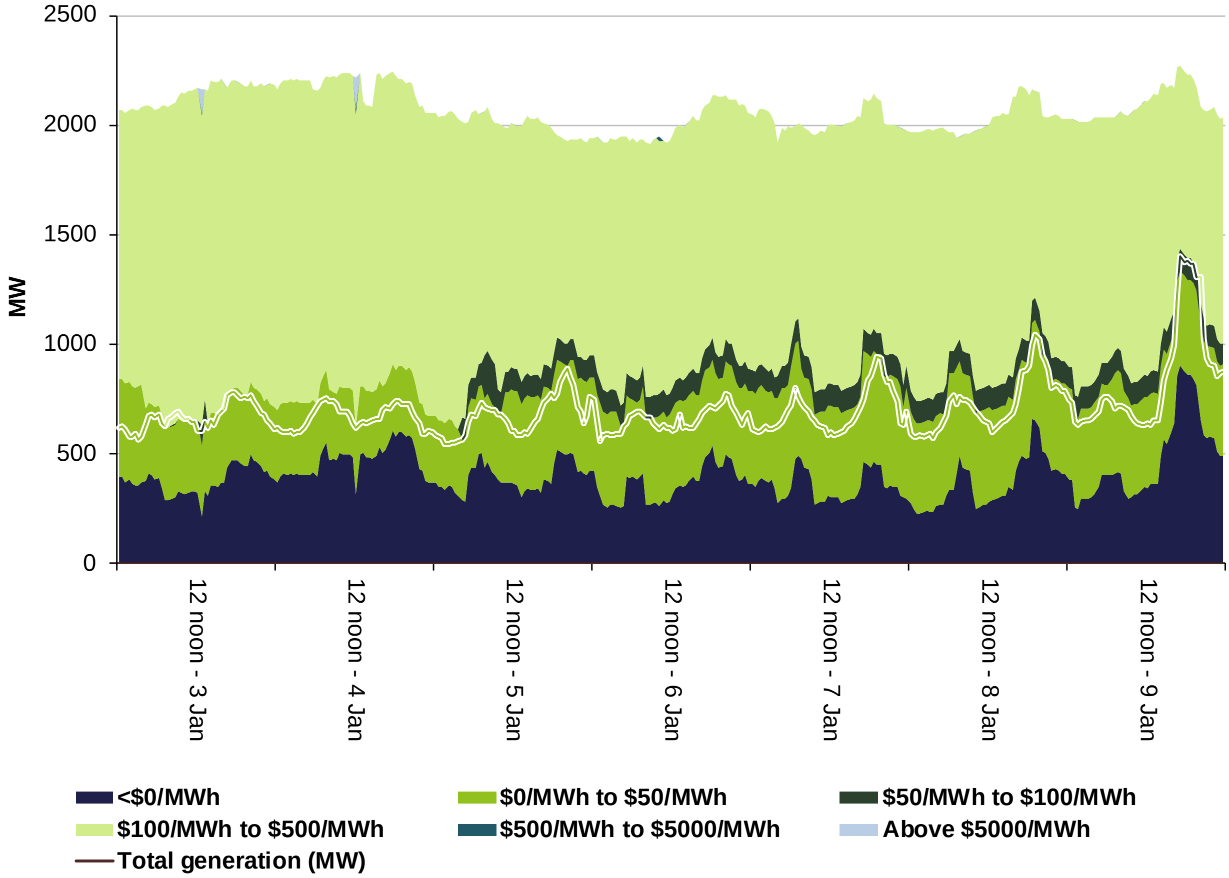


Figure 7: Tasmania generation and bidding patterns



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.

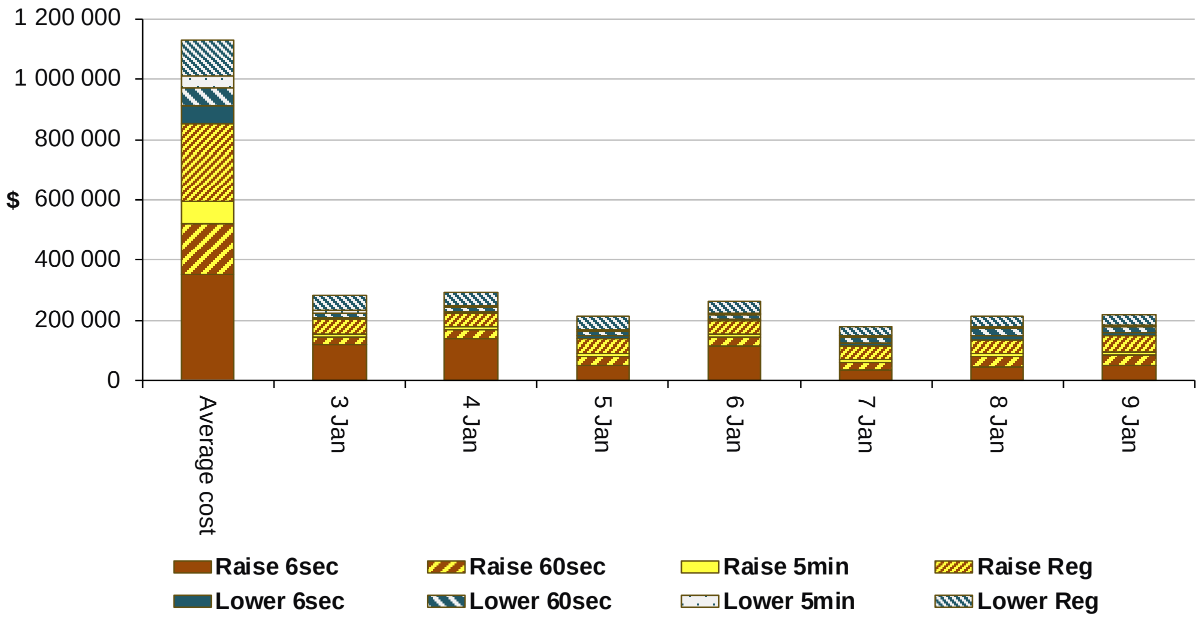
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1,152,500 or less than 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $509,500 or less than 8 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



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 $40/MWh and above $250/MWh.

Monday, 4 January

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	300.74	49.73	49.95	7933	7988	8113	10336	10438	10414

Demand was 55 MW lower than forecast and availability was 102 MW lower than forecast, four hours prior. Lower than forecast availability was due to lower than forecast solar generation, and rebids at Millmerran which removed 55 MW of capacity priced at the floor due to plant issues.

The dispatch price remained close to forecast between 5.35 pm to 5.45 pm. Effective 5.50 pm, a rebid from Callide C removed 86 MW of low-priced capacity due to a mill trip. With several generators unable to come on in 5 minutes, the dispatch price increased to $1,552/MWh for one dispatch interval. In response, participants rebid 435 MW of capacity from above $32/MWh to below $1/MWh, resulting in prices below $45/MWh for the rest of the trading interval.

South Australia

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

Tuesday, 5 January

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
3 pm	-109.28	-16.93	-1000	438	360	400	2488	2435	2629
4.30 pm	-136.26	-35.95	-542.24	671	560	593	2767	2556	2687

For the 3 pm trading interval, demand was 78 MW higher than forecast and availability was 53 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh.

Effective from 2.40 pm, rebids by Trustpower at Snowtown Wind Farm and Pacific Hydro at Clements Gap Wind Farm, in response to forecast prices, shifted over 150 MW of capacity to the price floor. As a result the dispatch price fell to -$517/MWh. In response to negative prices, participants rebid capacity from low to high prices, resulting in the 2.45 pm dispatch price reaching $10/MWh. Effective 2.50 pm, participants' rebids shifted nearly 200 MW of capacity to prices below -$649/MWh and the dispatch price fell to -$190/MWh. In response, rebids by participants shifted nearly 300 MW of capacity from negative prices to prices above $2/MWh, resulting in prices for the rest of the trading interval above $15/MWh.

For the 4.30 pm trading interval, demand was 111 MW higher than forecast and availability was 211 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast renewable generation, most of which was price below $0/MWh. Throughout most of the trading interval prices were around -$200/MWh as a result of the higher than forecast renewable generation.

Wednesday, 6 January

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
12.30 pm	-119.57	-200	-897.17	489	407	425	2332	2306	2356
1.30 pm	-142.71	-680.88	-874.93	548	351	408	2395	2334	2430
2 pm	-185.85	-1000	-859.51	532	362	409	2437	2365	2472
2.30 pm	-160.53	-649.33	-1000	554	344	374	2474	2441	2514
3 pm	-139.2	-633.31	-1000	581	353	378	2626	2500	2575

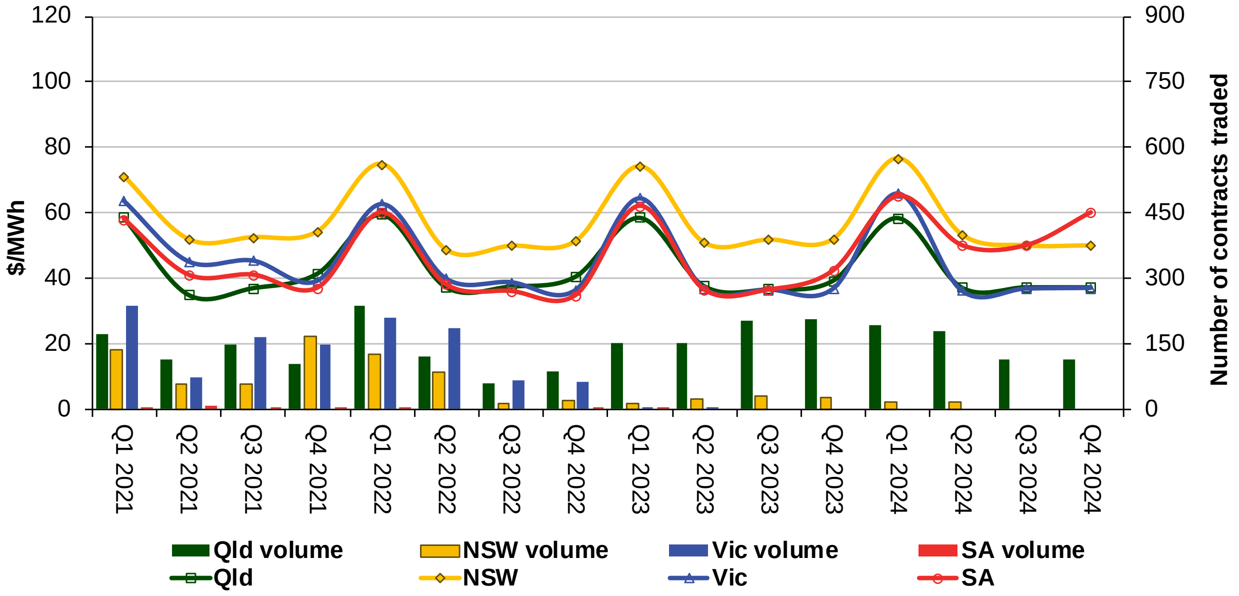
For the 12.30 pm trading interval, demand was 82 MW higher than forecast while availability was close to forecast, four hours prior. Effective from 12.15 pm, participants in response to forecast prices rebid 260 MW of capacity from prices below -$110/MWh to above -$27/MWh, resulting in prices above -$45/MWh for the remainder of the trading interval.

For the 1.30 pm to 3 pm trading intervals, demand was between 170 MW and 228 MW higher than forecast, while availability was up to 126 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh. Higher than forecast demand saw prices set higher than forecast throughout each 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.

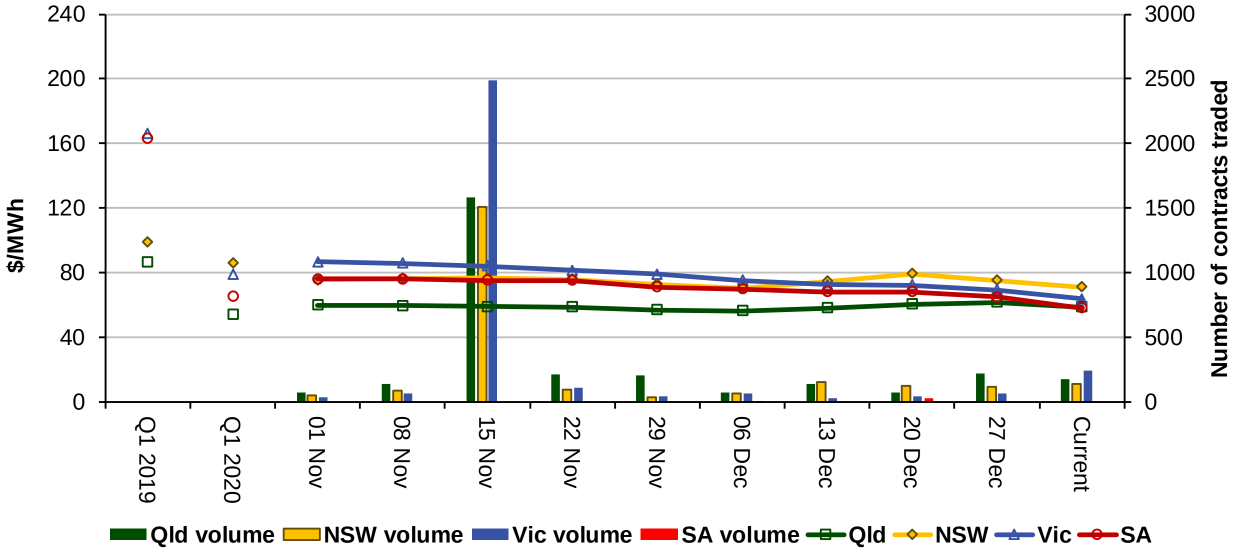
Figure 9: Quarterly base future prices Q1 2021 – Q4 2024



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2021 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q 1 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 2021 base contracts over the past 10 weeks (and the past 2 years)

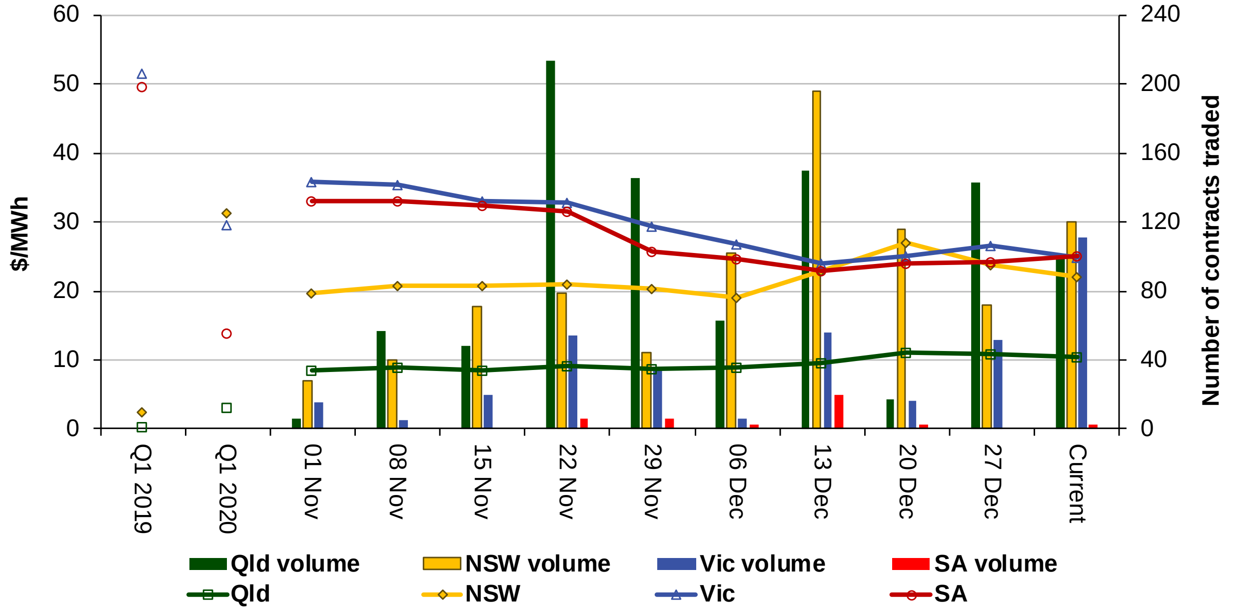


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q1 2020 prices are also shown.

Figure 11: Price of Q1 2021 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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