Electricity Report

AUSTRALIAN ENERGY REGULATOR

27 December 2020 – 2 January 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $13/MWh in South Australia to $45/MWh in Tasmania. Quarter to date VWA prices are between $21/MWh to $45/MWh lower than the same time last year.

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 27 December 2020 to 2 January 2021.

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

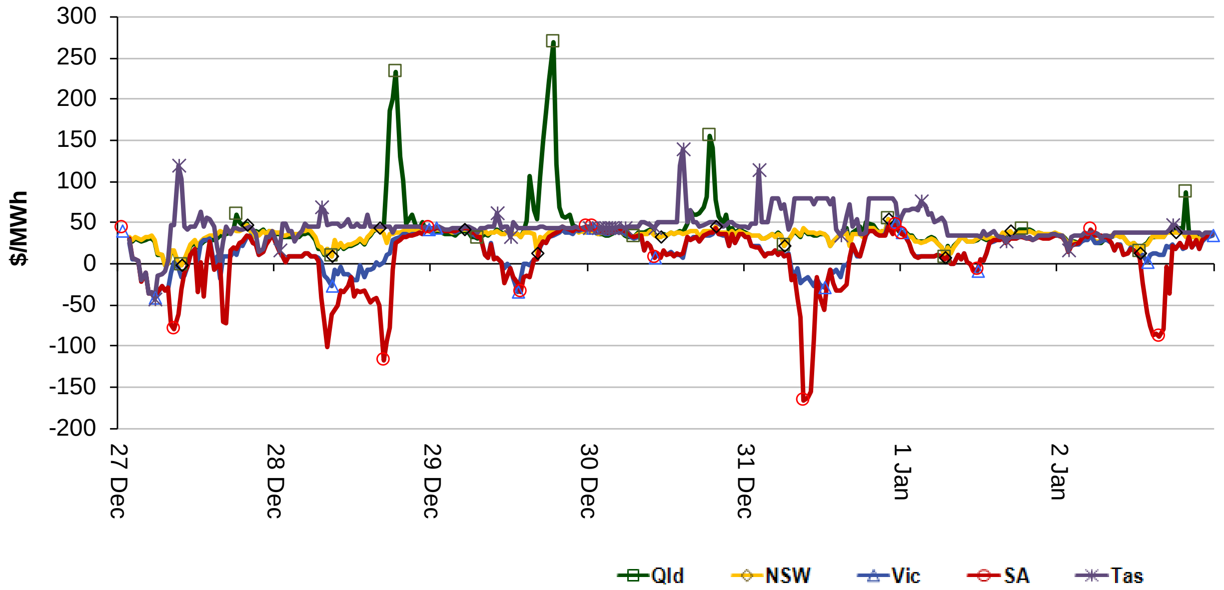


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

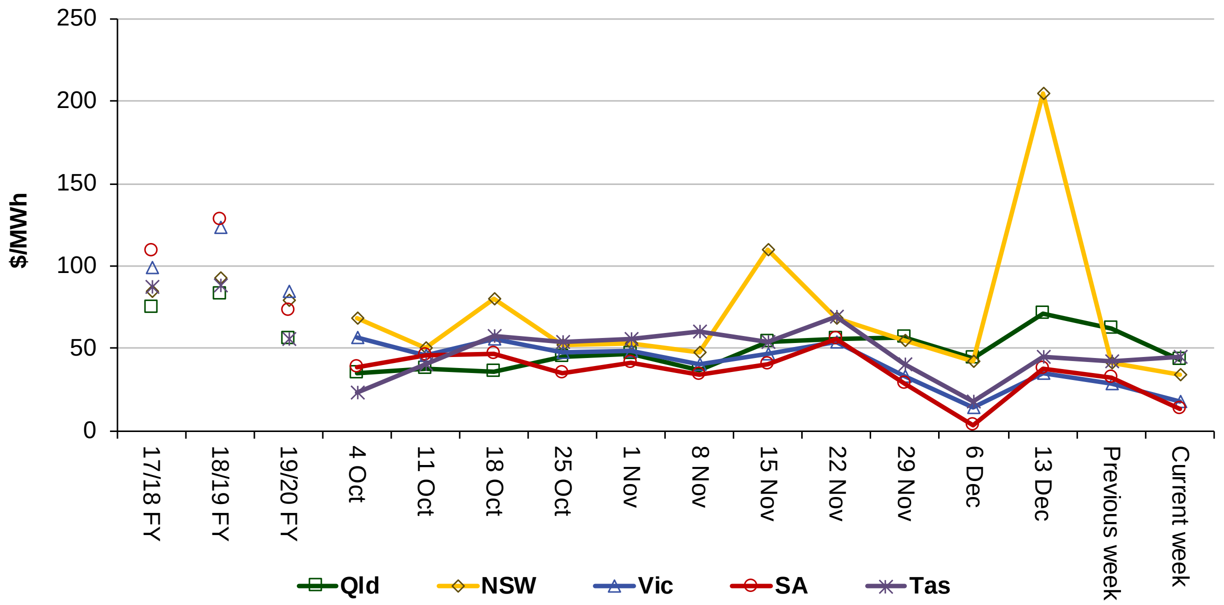


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	43	34	18	13	45
Q1 2020 QTD	57	53	61	63	80
Q1 2021 QTD	33	32	21	18	39
19-20 financial YTD	65	81	93	84	73
20-21 financial YTD	41	59	47	41	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 248 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2019 of 204 counts and the average in 2018 of 199. 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 4 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	32	0	0
% of total below forecast	29	31	0	5

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

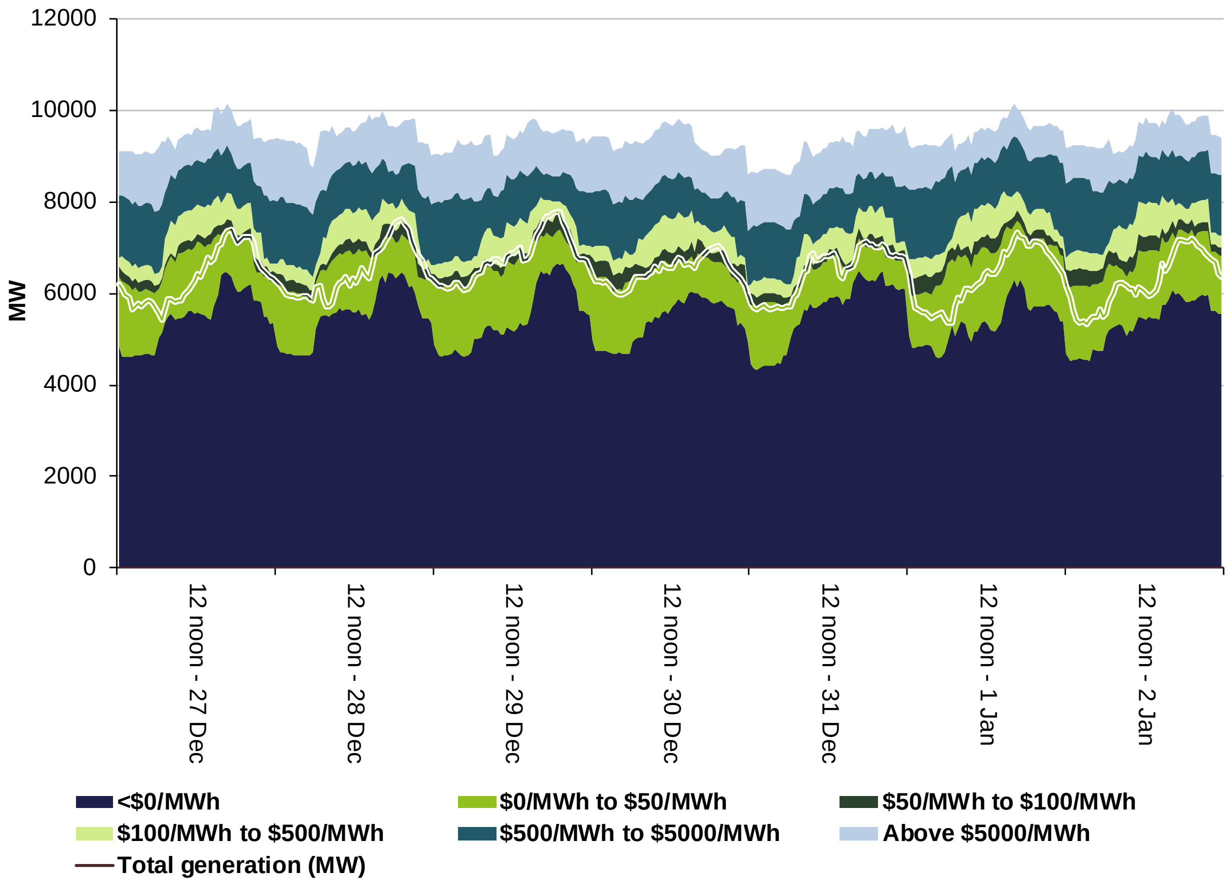


Figure 4: New South Wales generation and bidding patterns

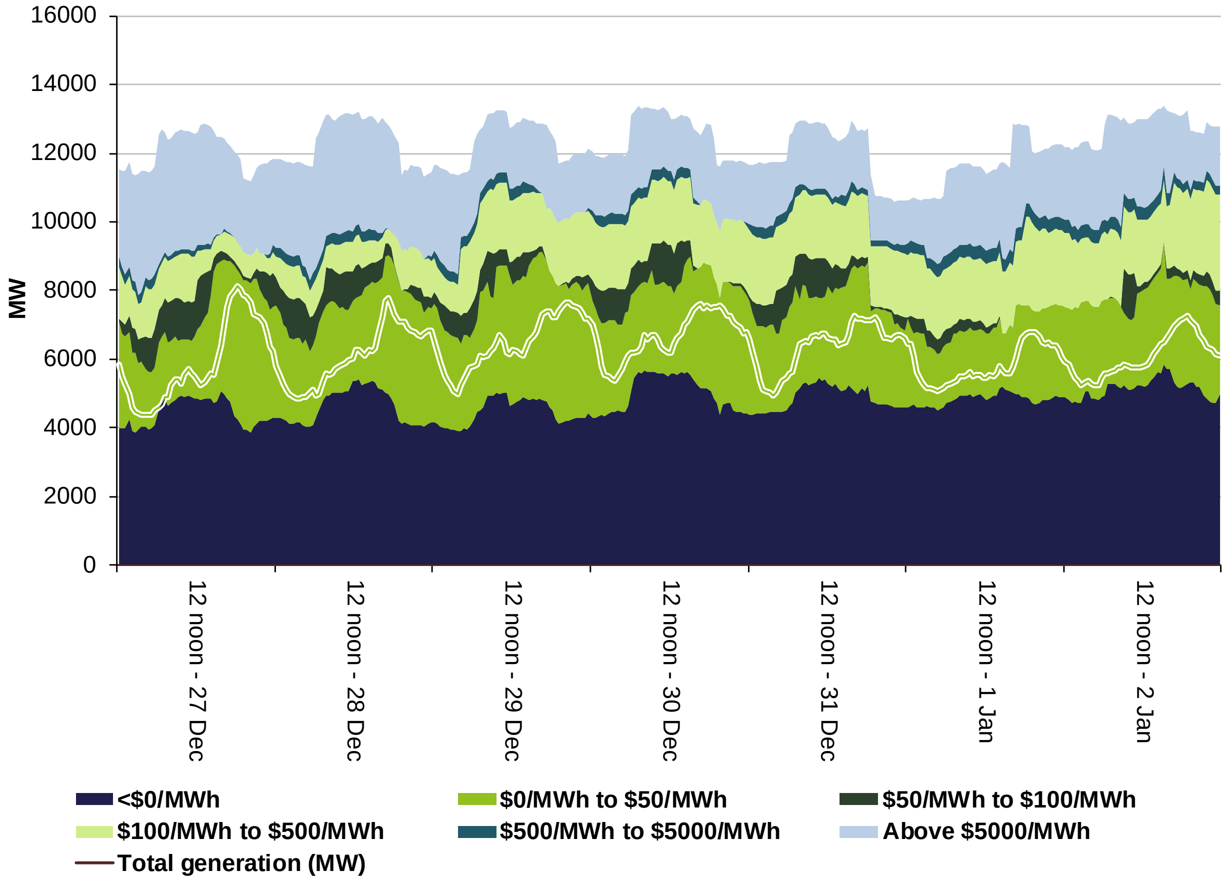


Figure 5: Victoria generation and bidding patterns

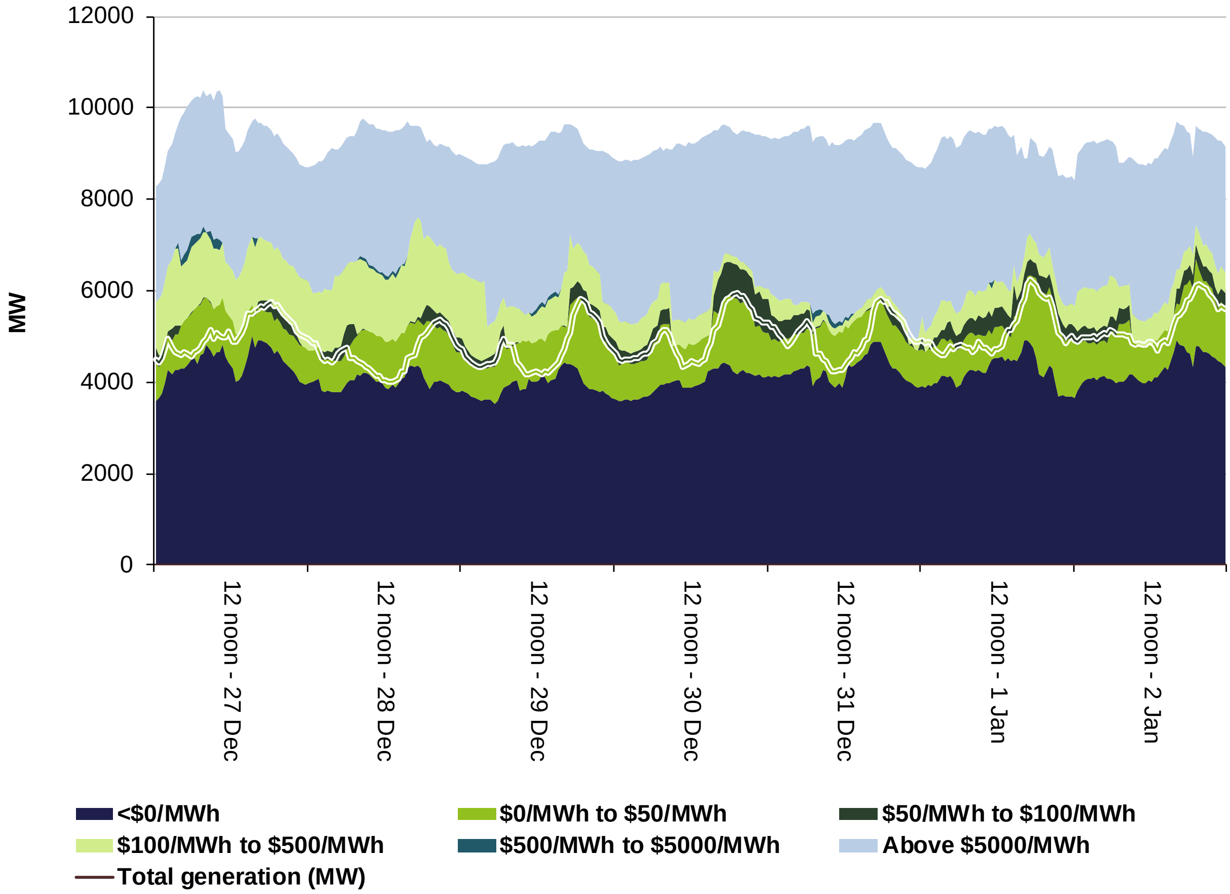


Figure 6: South Australia generation and bidding patterns

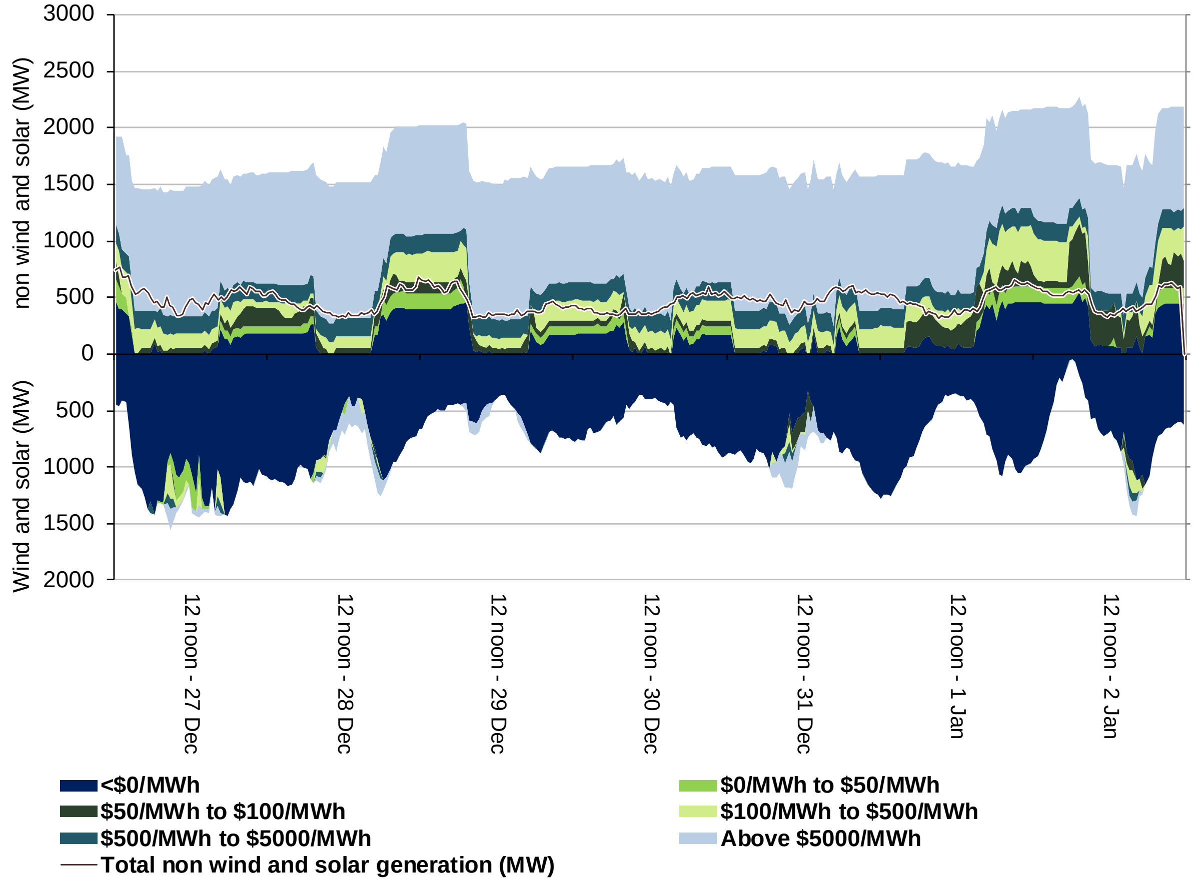
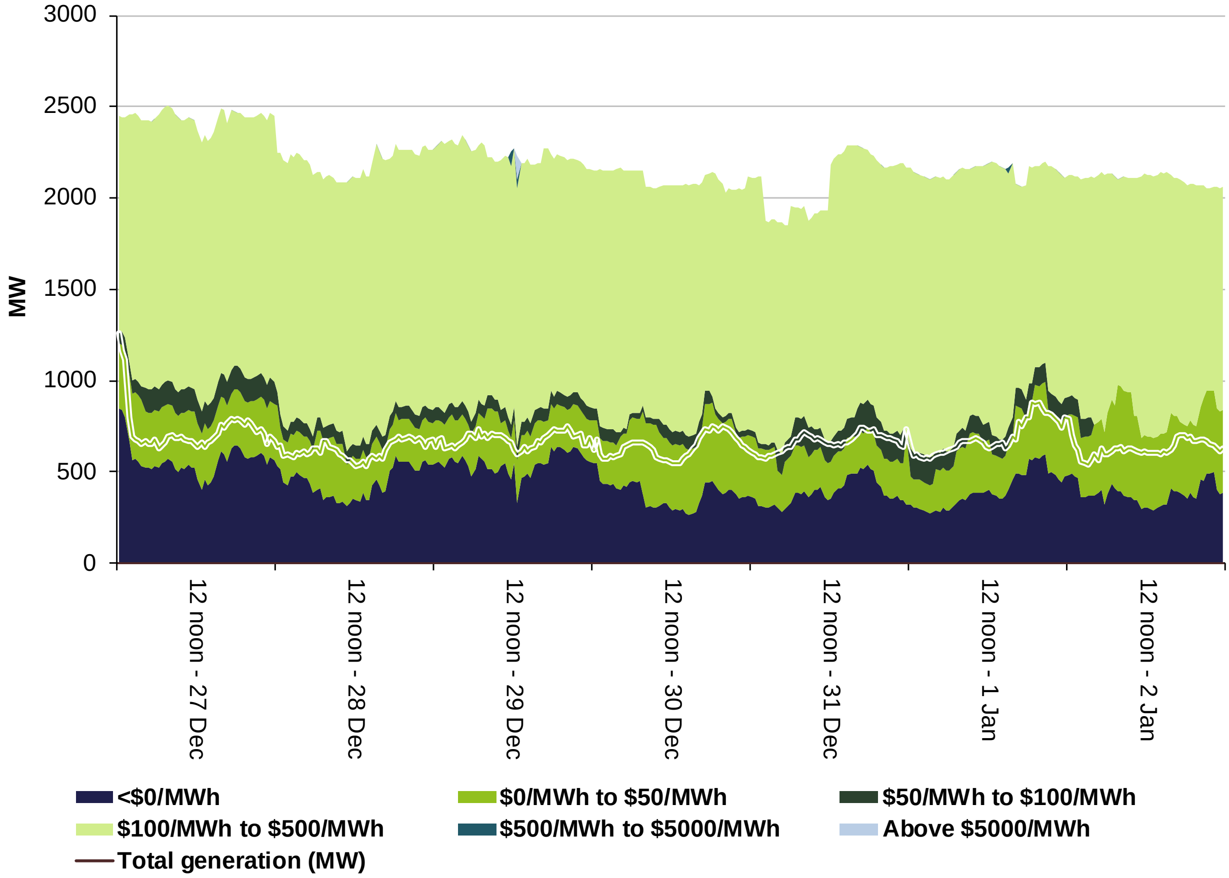


Figure 7: Tasmania generation and bidding patterns



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.

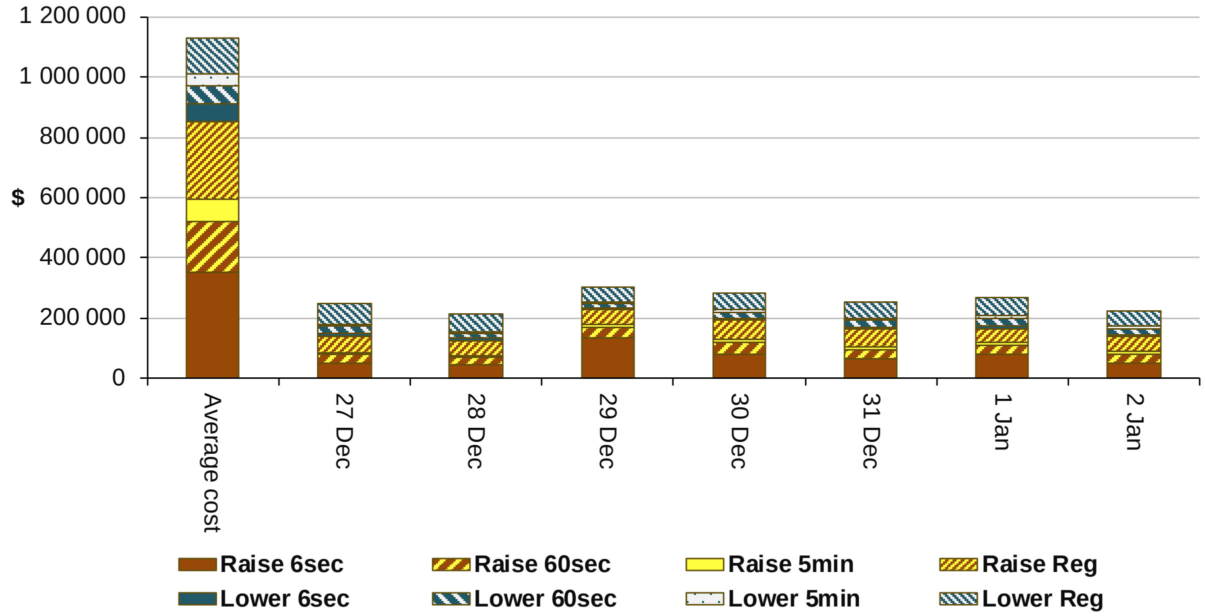
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1,366,500 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $422,000 or around 5 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 $43/MWh and above $250/MWh.

Tuesday, 29 December

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
7 pm	268.82	200.11	200.11	7,960	7,772	7,663	9,526	9,530	9,570

Demand was 188 MW higher than forecast and availability was close to forecast, 4 hours prior. At 6.15 pm, Arrow withdrew 155 MW of capacity priced at $0/MWh at Yabulu due to plant failure. The higher than forecast demand combined with the removal of lower-priced capacity resulted in the price being slightly higher than forecast.

South Australia

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

Monday, 28 December

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
8.30 am	-101.08	7.91	-3.10	863	846	854	2,682	2,450	2,511
5 pm	-116.60	15.99	-200.00	681	713	718	2,696	2,439	2,572

For the 8.30 am trading interval, demand was close to forecast and availability was 232 MW higher than forecast, 4 hours prior. Higher than forecast availability was mainly due to higher than forecast wind generation, most of which was priced below $0/MWh. This resulted in prices between -$30.99/MWh and -$200/MWh during the trading interval.

For the 5 pm trading interval, demand was slightly lower than forecast and availability was 257 MW higher than forecast, 4 hours prior. Higher than forecast availability was mainly due to higher than forecast renewable generation, most of which was priced below $0/MWh. The higher than forecast availability resulted in prices at -$50/MWh for the first four dispatch intervals. Origin rebid 110 MW of capacity at Bungala One Solar Farm, effective 4.55 pm, to the price floor in response to forecast demand, resulting in the price falling to -$512.46/MWh for the dispatch interval. In the next dispatch interval, wind generation dropped 88 MW while demand increased by 23 MW, resulting in a dispatch price of $12.92/MWh.

Thursday, 31 December

Table 5: Price, Demand and Availability

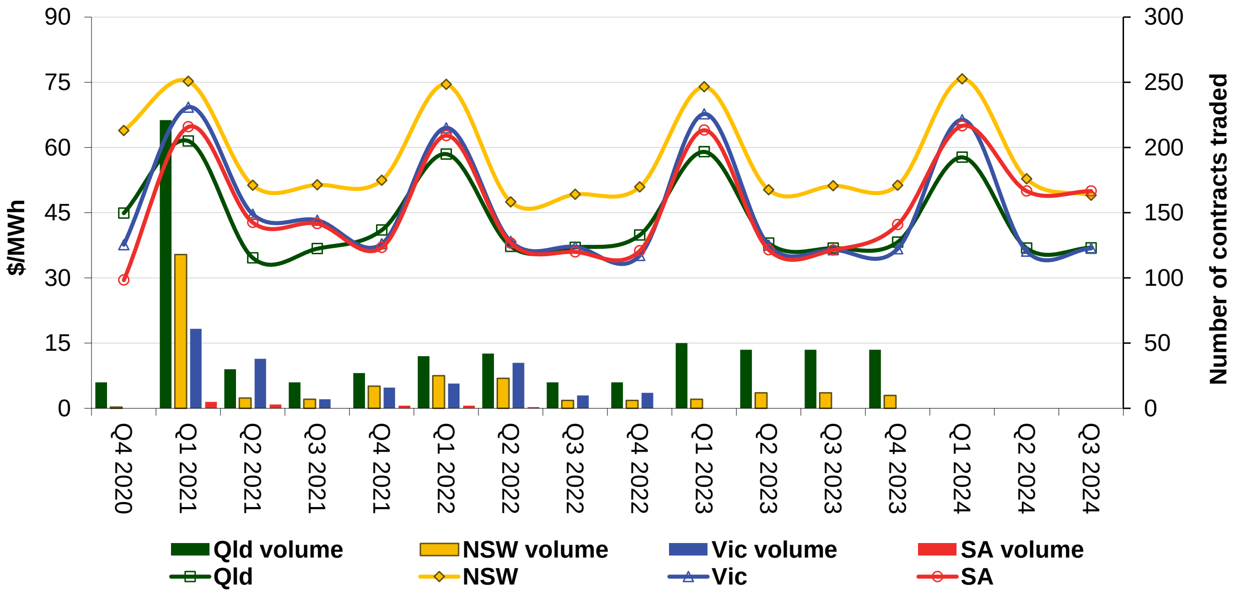
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
9.30 am	-165.60	-630.11	-928.22	734	614	635	2,739	2,630	2,612
10 am	-162.64	-586.94	-872.87	683	504	528	2,745	2,616	2,573
10.30 am	-155.83	-542.59	-858.17	635	411	434	2,748	2,556	2,609

Demand was between 120 MW to 224 MW higher than forecast, while availability was between 109 MW to 192 MW higher than forecast, 4 hours prior. Higher than forecast availability was mainly due to higher than forecast renewable generation, much of which was offered below $0/MWh. In response to the forecast low price, participants rebid up to around 825 MW of capacity from lower to higher prices from 7 am. This resulted in prices above forecast for the majority of the trading intervals.

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 Q4 2020 – Q3 2024

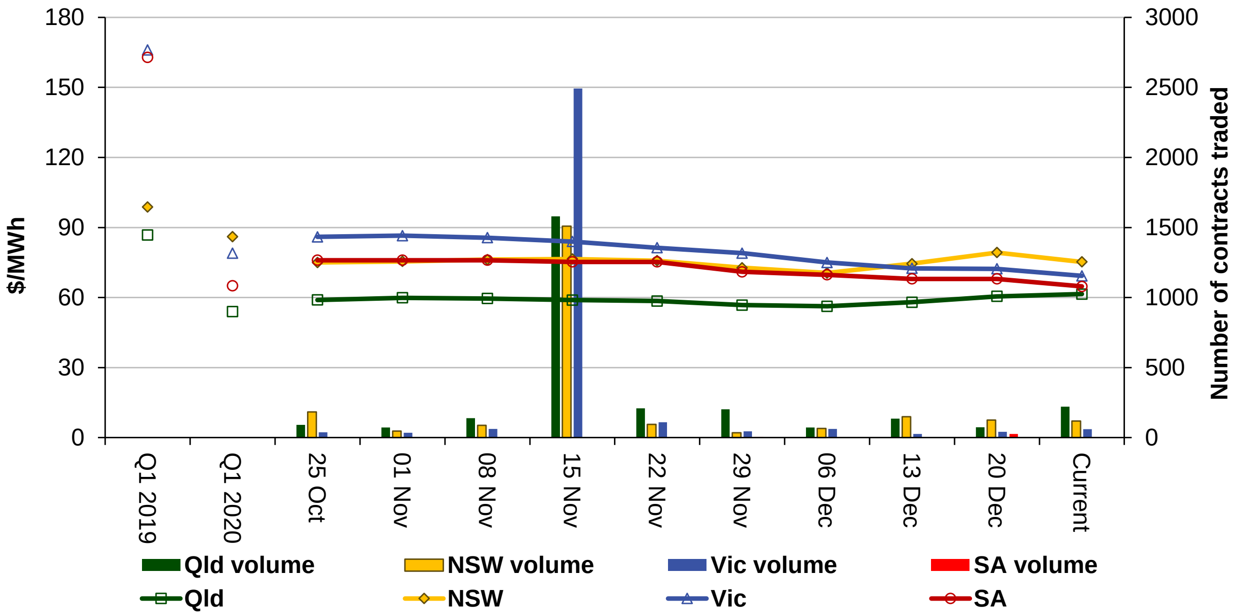


Source. ASXEnergy.com.au

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 Q1 2020 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on 19 November 2020.

Figure 10: Price of Q1 2021 base contracts over the past 10 weeks (and the past 2 years)

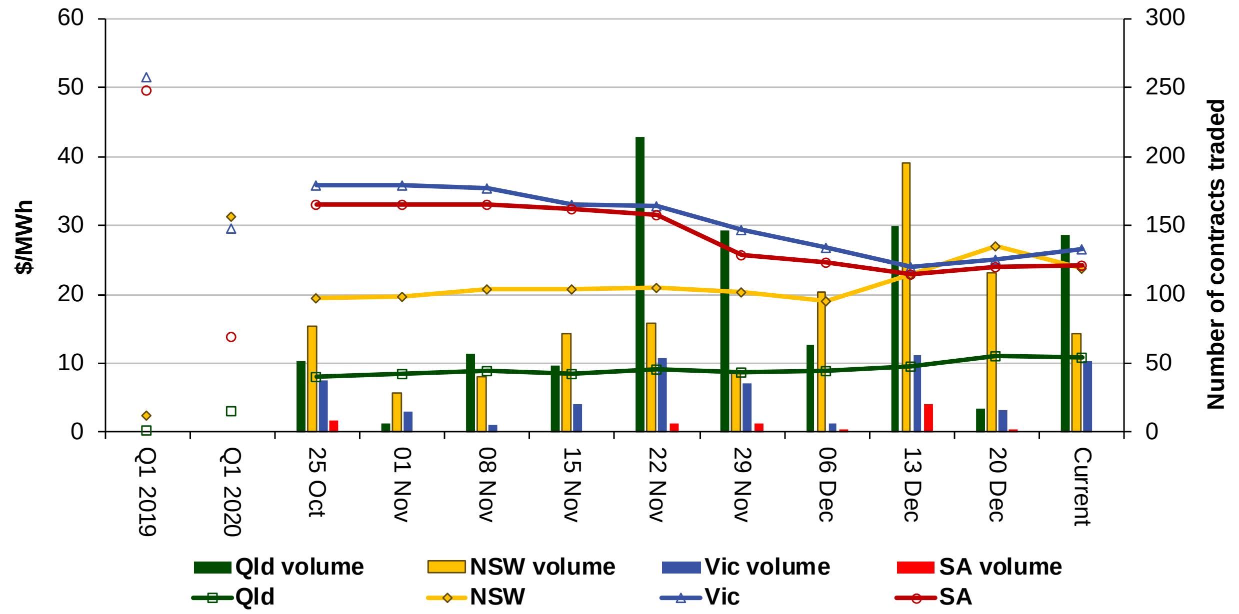


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
January 2021