Electricity Report

AUSTRALIAN ENERGY REGULATOR

8 – 14 November 2020

Weekly Summary

Volume weighted average (VWA) prices for the week ranged from $34/MWh in South Australia to $60/MWh in Tasmania. Quarter to date VWA prices were at least $27/MWh lower in all regions 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 8 to 14 November 2020.

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

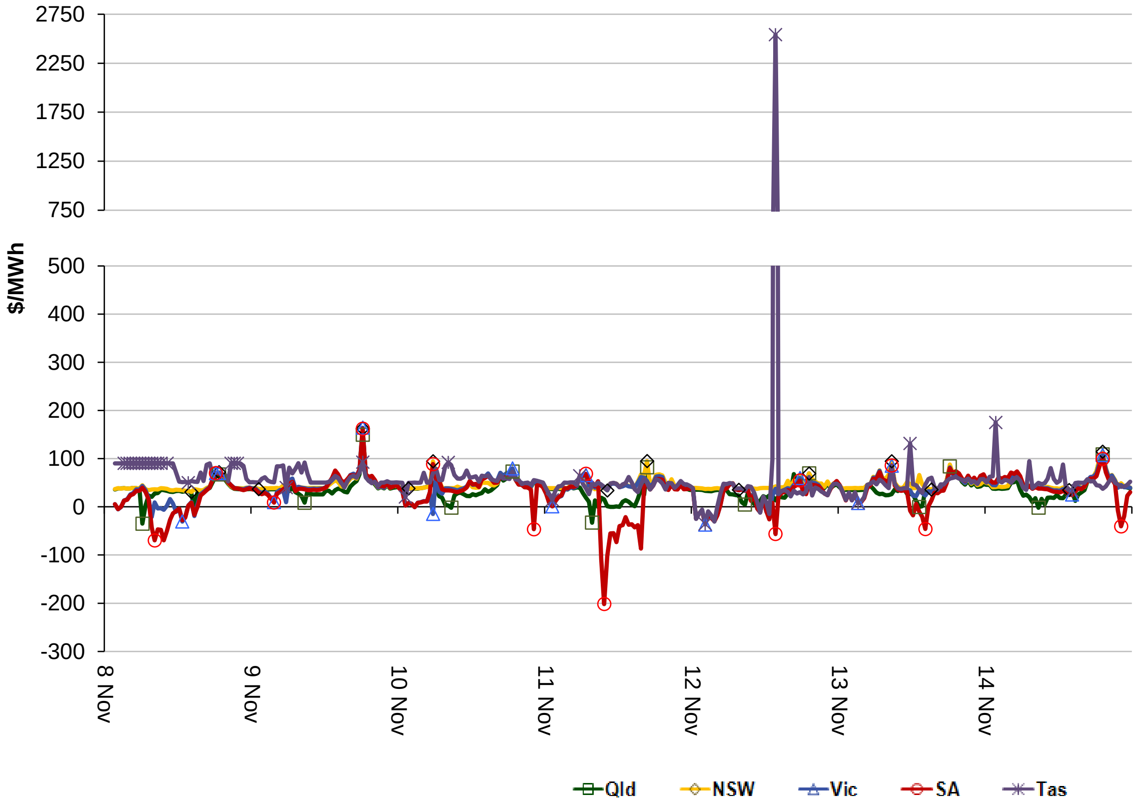


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

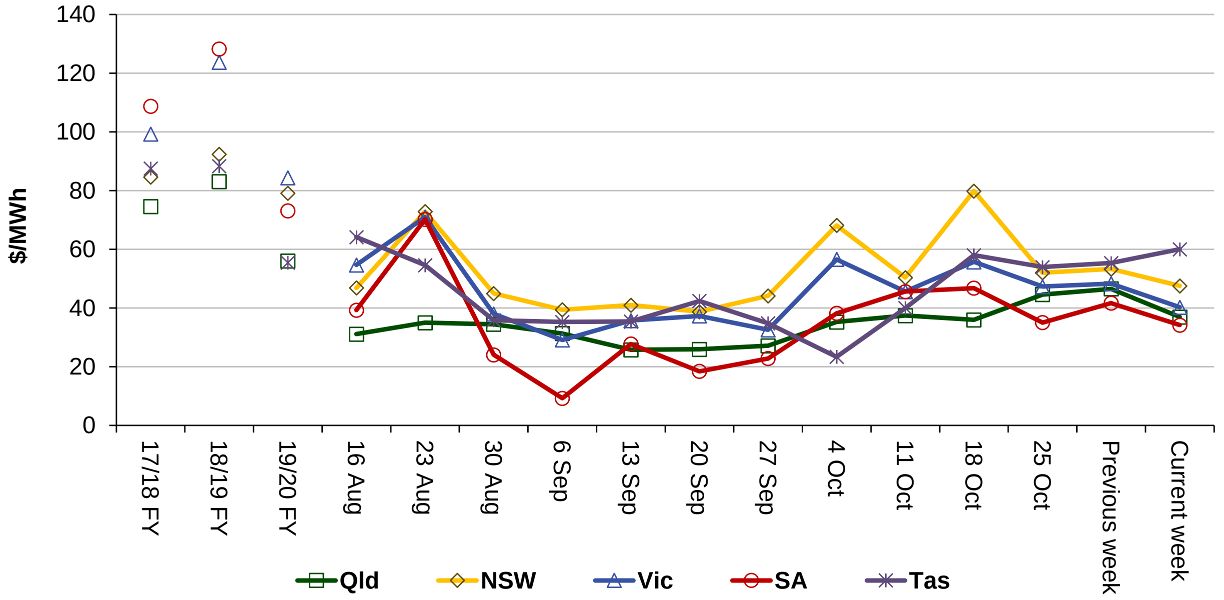


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	37	48	40	34	60
Q4 2019 QTD	71	94	94	65	97
Q4 2020 QTD	38	57	46	38	46
19-20 financial YTD	67	89	100	77	78
20-21 financial YTD	36	51	52	44	49

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 271 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 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	6	24	0	1
% of total below forecast	14	45	0	11

Note: Due to rounding, the total may not be 100%.

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

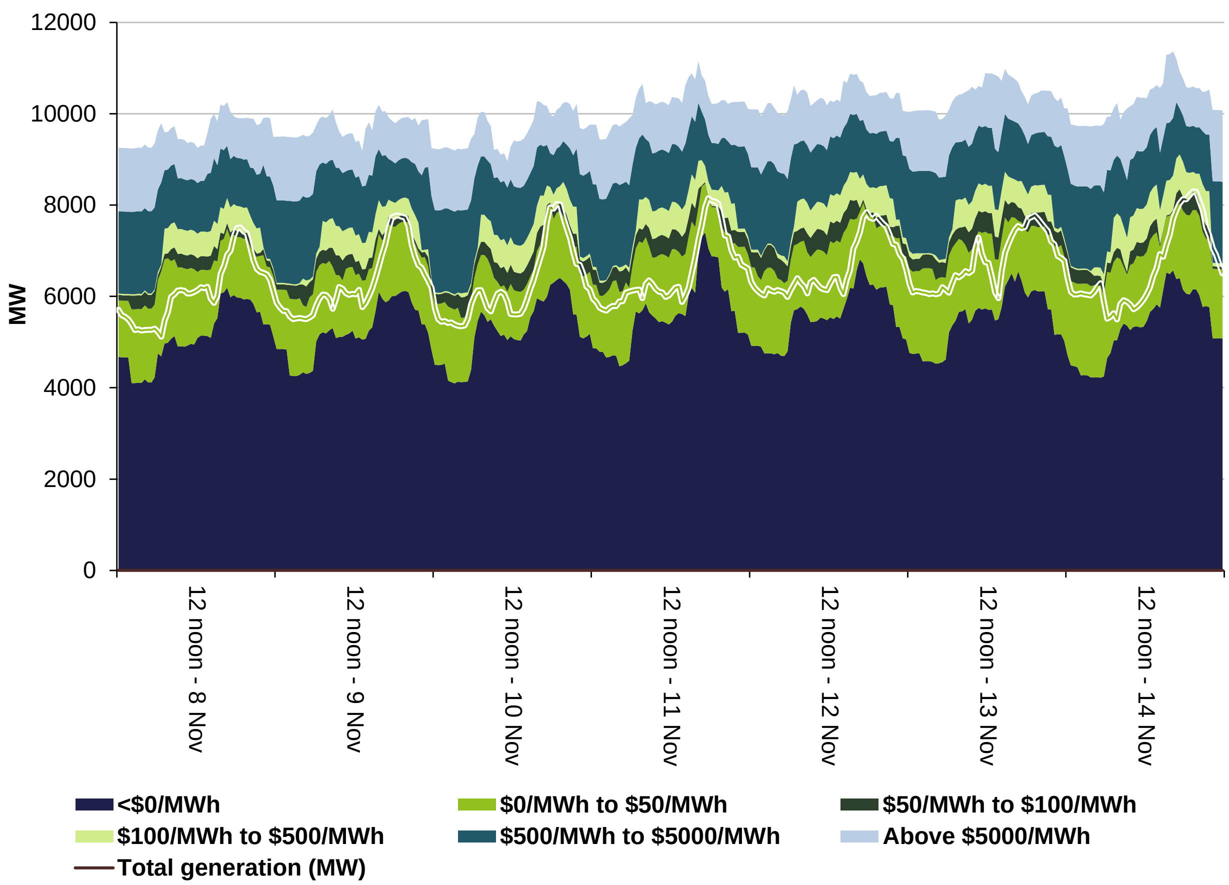


Figure 4: New South Wales generation and bidding patterns

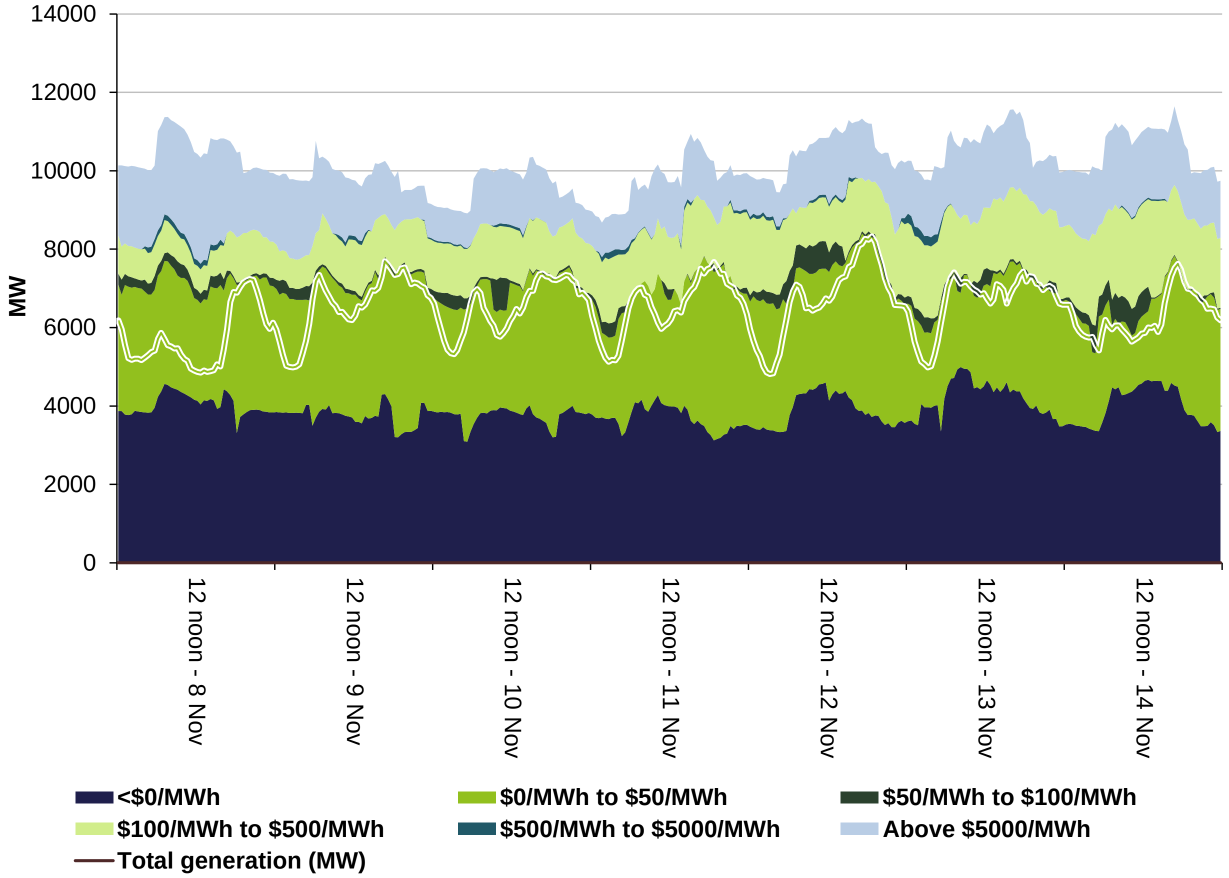


Figure 5: Victoria generation and bidding patterns

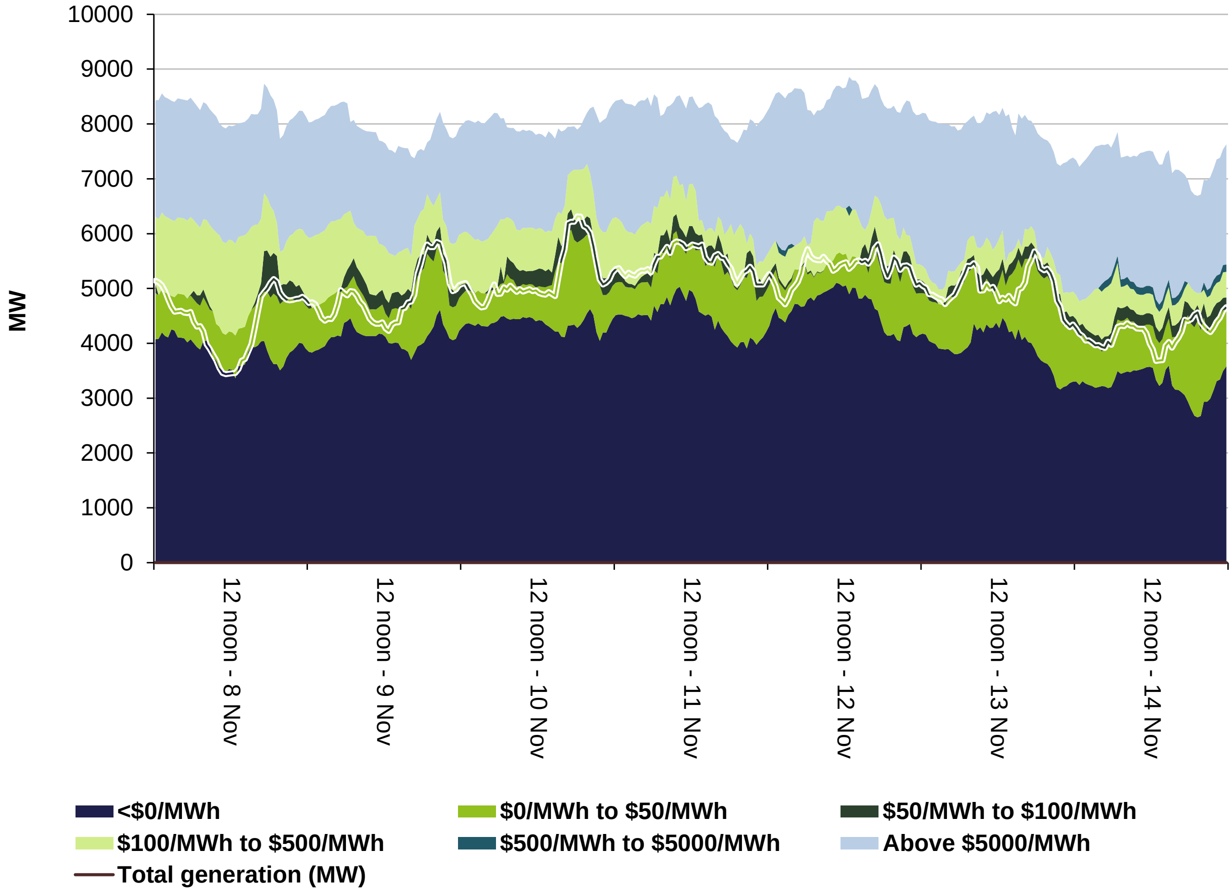


Figure 6: South Australia generation and bidding patterns

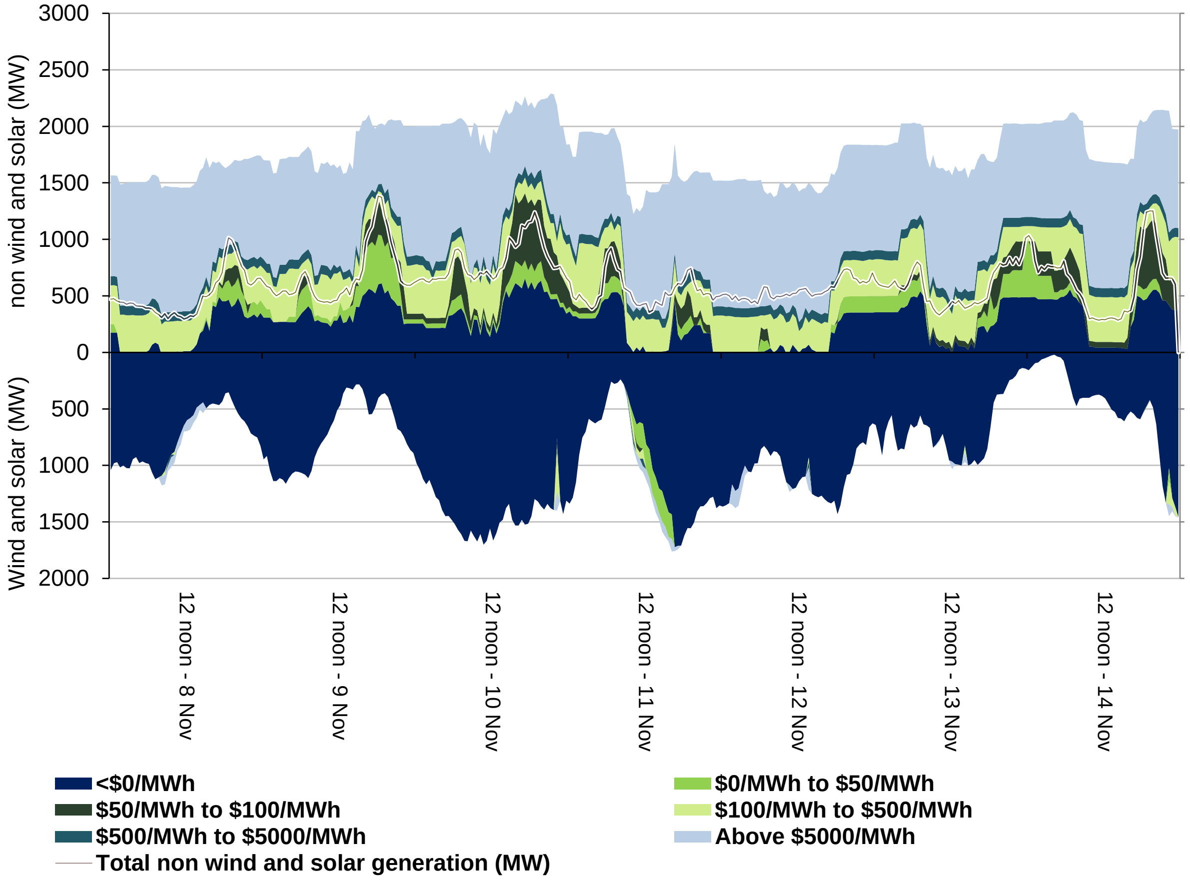
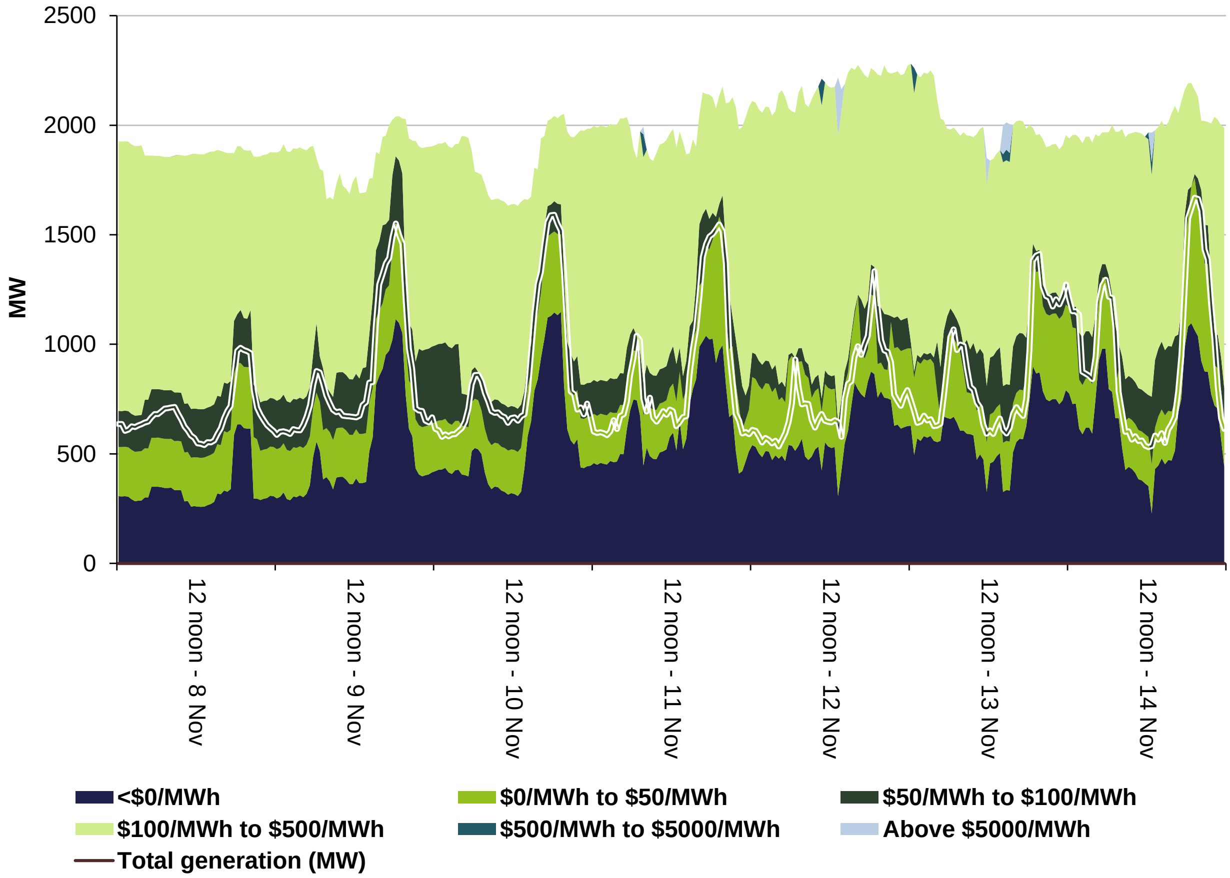


Figure 7: Tasmania generation and bidding patterns



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.

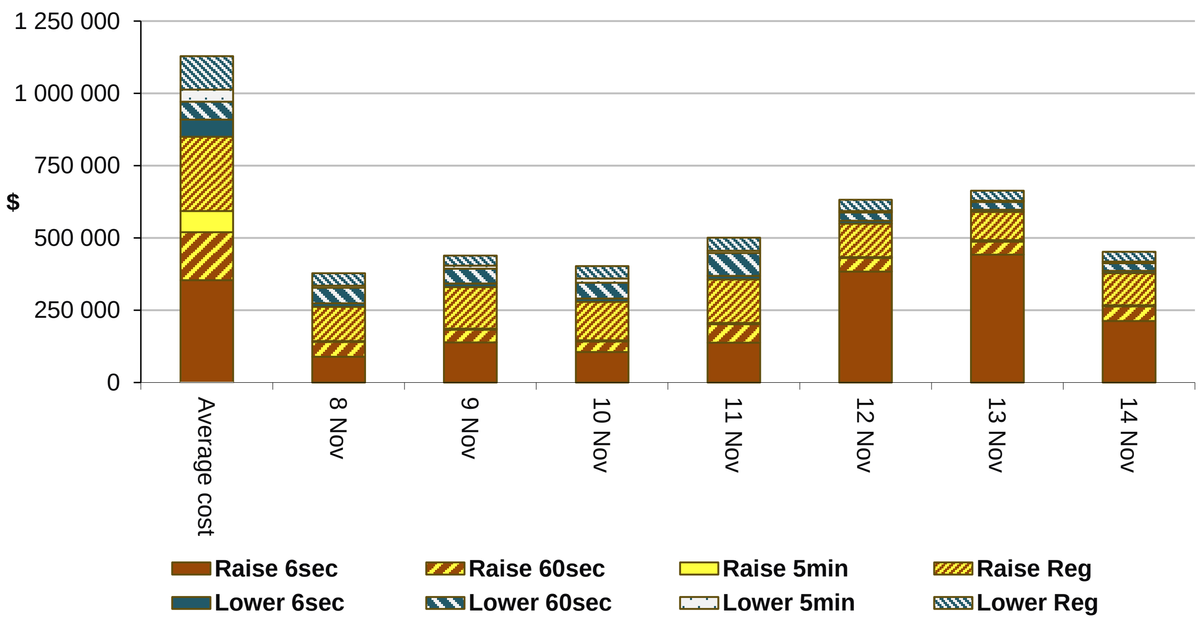
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2,178,500 or less than 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1,290,000 or less than 13% 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

South Australia

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

Wednesday, 11 November

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
9.30 am	-108.67	33.25	38.32	851	956	1017	1836	2390	2537
10 am	-201.76	-190.00	35.11	754	815	885	2040	2434	2593
10.30 am	-101.93	-200.00	33.89	727	697	787	2184	2291	2644

For the 9.30 am trading interval demand was 105 MW lower than forecast and availability was 554 MW lower than forecast, four hours prior. Lower than forecast availability was mainly due to rebids that removed more than 280 MW of low priced capacity by AGL at Torrens Island for unexpected plant limits and Origin at Osborne for 'constraint management' as well as lower than forecast wind generation. There was little capacity offered between -$649/MWh and $119/MWh so small fluctuations in demand or availability could cause large changes in price. At 9.25 am demand dropped by 29 MW and the price fell to -$615/MWh for 5 minutes. In response, participants rebid over 230 MW from the floor to prices above $100/MWh.

For the 10 am trading interval, prices were close to forecast, four hours prior.

For the 10.30 am trading interval demand was 30 MW higher than forecast and availability was 107 MW lower than forecast, four hours prior. Lower than forecast availability was due to rebids by Origin that removed 176 MW of low priced capacity at Osborne. Effective 10.15 am, rebids by Engie and Neoen shifted more than 150 MW of capacity from -$1000/MWh to more than $100/MWh in response to changes in forecast prices. As a result, prices remained above -$87/MWh for the rest of the trading interval.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $60/MWh and above $250/MWh.

Thursday, 12 November

Table 4: Price, Demand and Availability

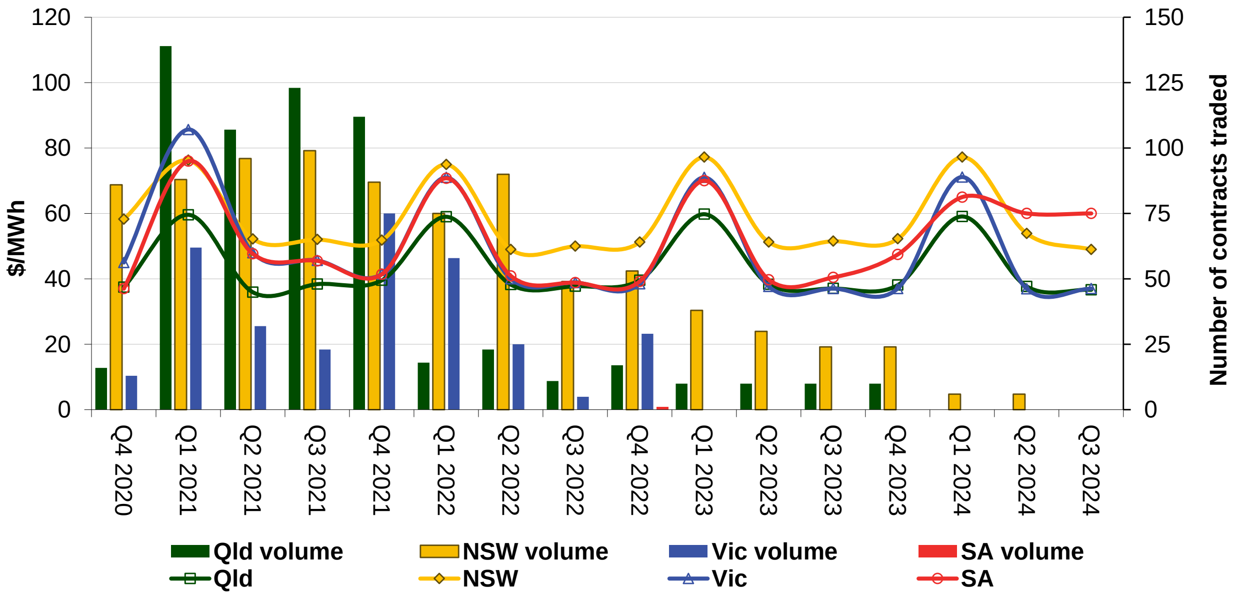
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
2 pm	2541.95	52.56	50.34	988	900	951	2184	2206	2125

Demand was 88 MW higher than forecast and availability was close to forecast, four hours prior. Effective 1.35 pm, Hydro Tasmania rebid 168 MW at Musselroe from -$277/MWh to the price cap in response to high forecast FCAS prices. At the same time, demand increased by 45 MW and with the majority of generators in the region ramp constrained or trapped in FCAS and unable to set price, the price increased to $15,000/MWh for five minutes. From 1.40 pm, cheaper priced generation was no longer ramp constrained and price returned close to forecast for the remainder of the 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.

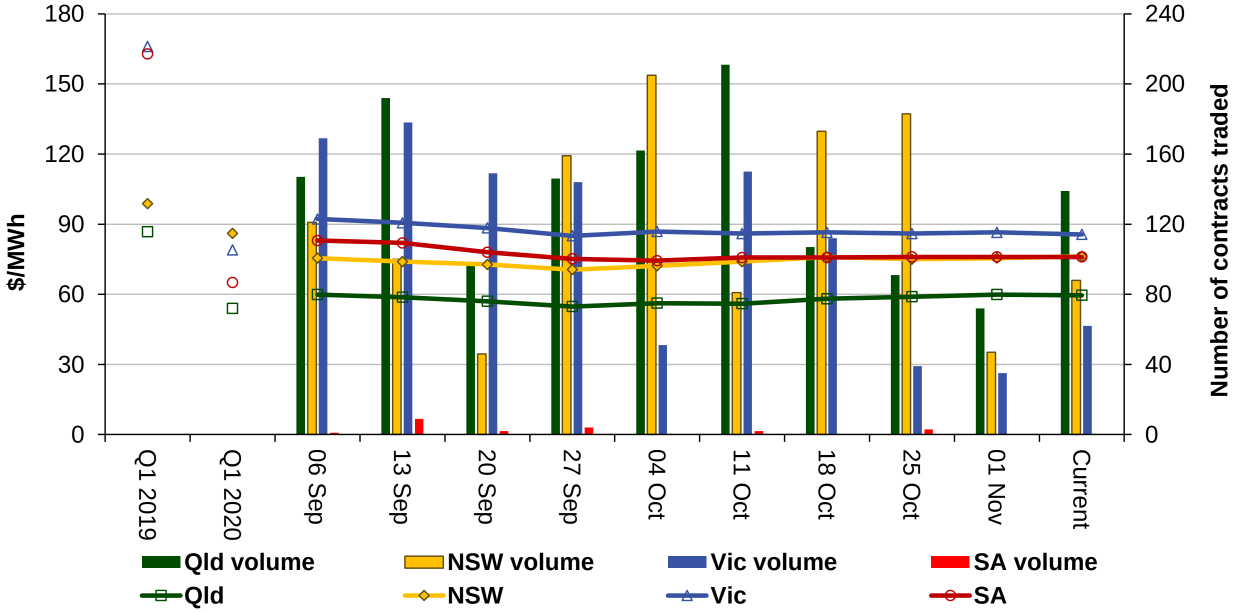
Figure 9: Quarterly base future prices Q4 2020 – Q3 2024



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.

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

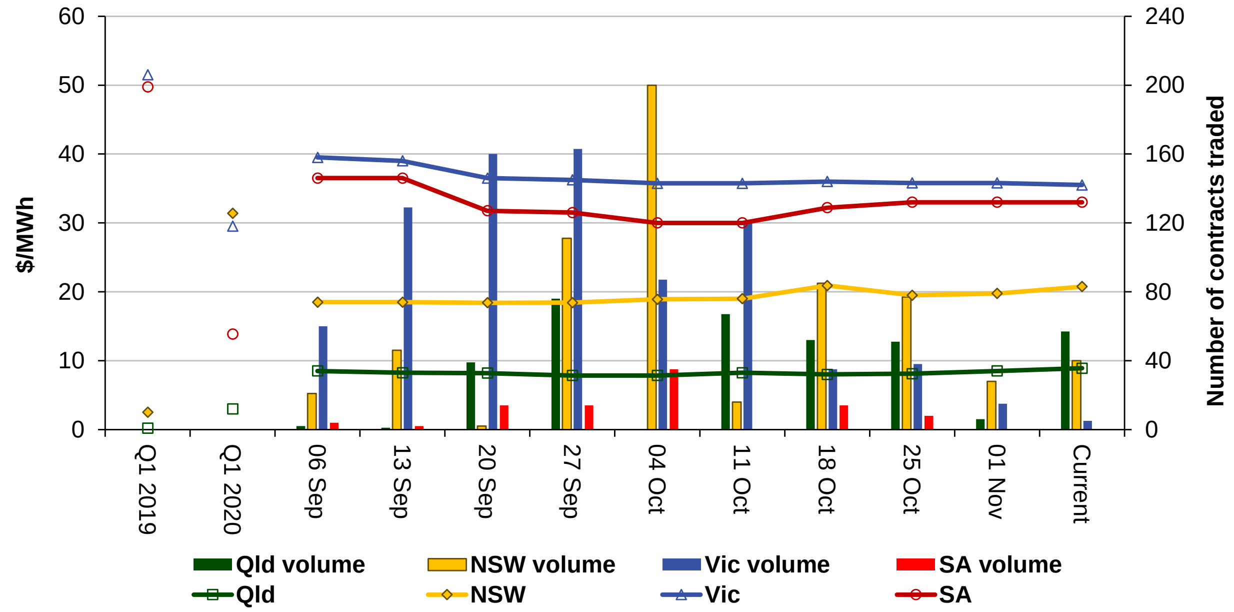


Source: ASXEnergy.com.au

Notes: 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.

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
December 2020