Electricity Report

AUSTRALIAN ENERGY REGULATOR

15 - 21 December 2019

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $53/MWh in Tasmania and $285/MWh South Australia. The high prices in South Australia were mainly a result of extreme temperatures exceeding 45 degrees Celsius which resulted in spot prices above $5000/MWh on two occasions even though more were forecast.

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 15 to 21 December 2019.

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

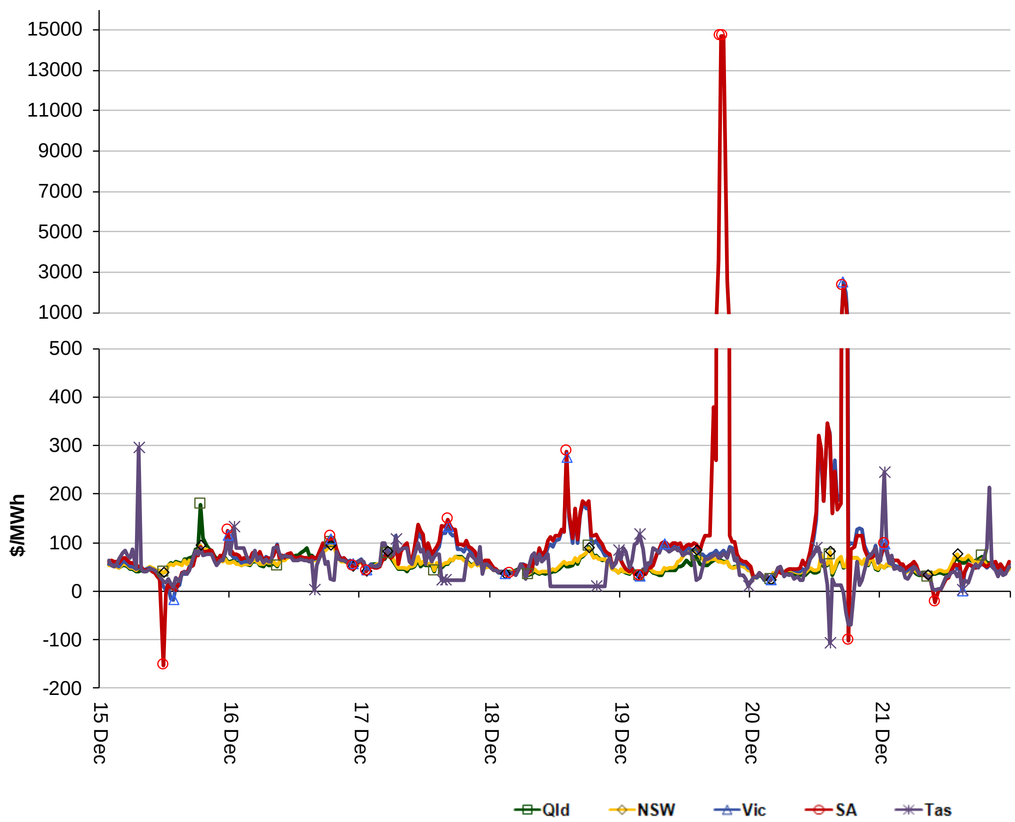


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

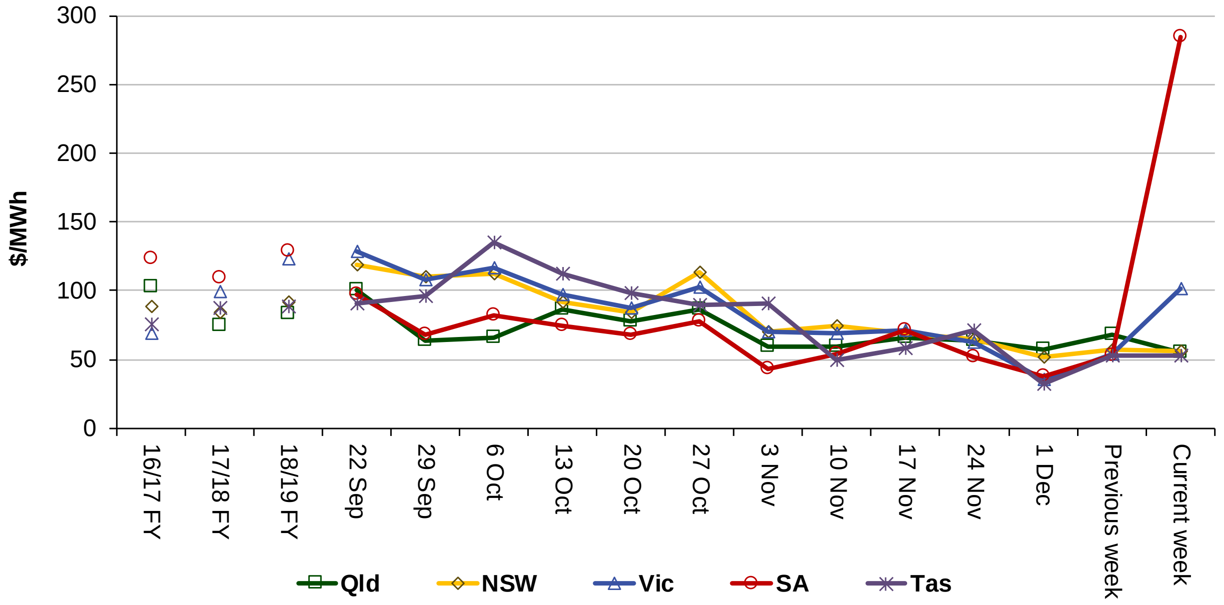


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	56	56	102	285	53
18-19 financial YTD	84	90	92	97	62
19-20 financial YTD	66	83	93	85	73

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 260 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2018 of 199 counts and the average in 2017 of 185. 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	8	27	0	2
% of total below forecast	8	49	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

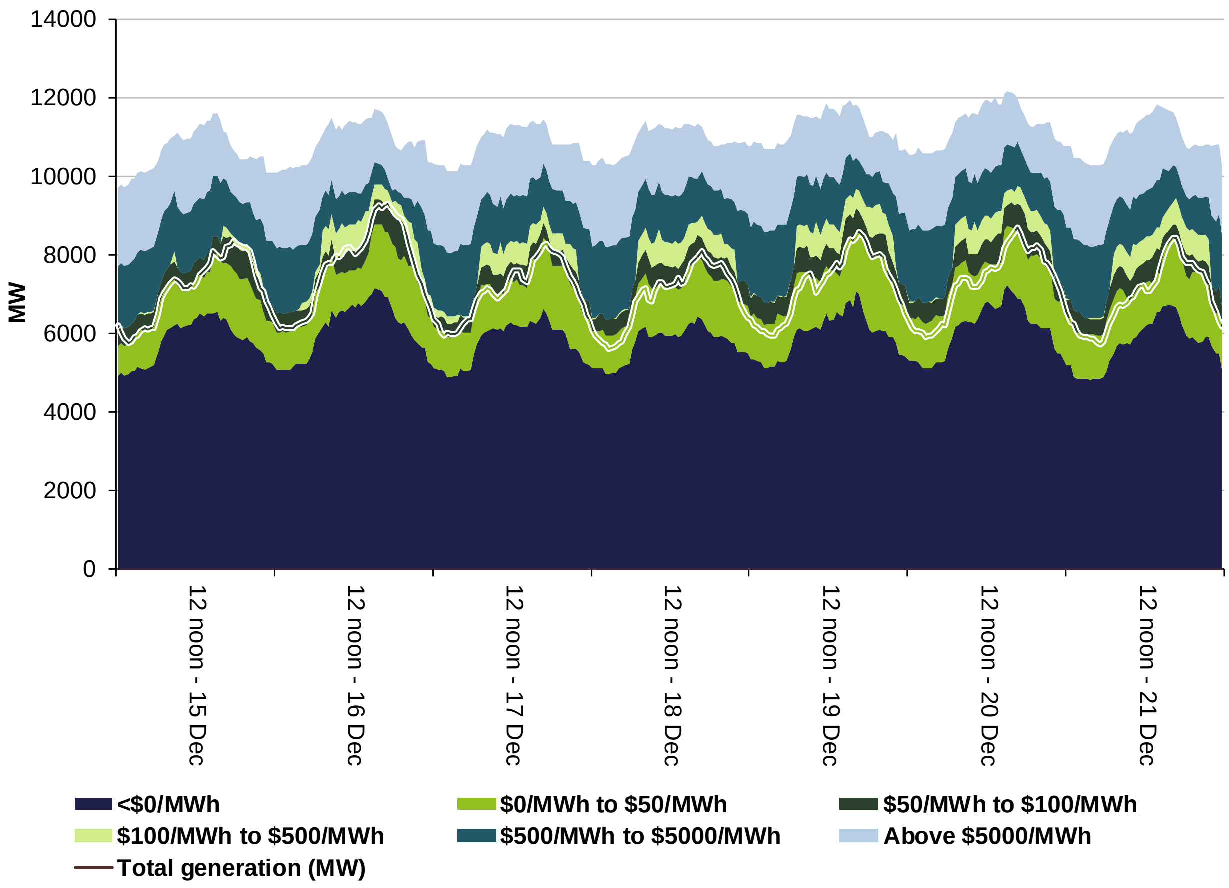


Figure 4: New South Wales generation and bidding patterns

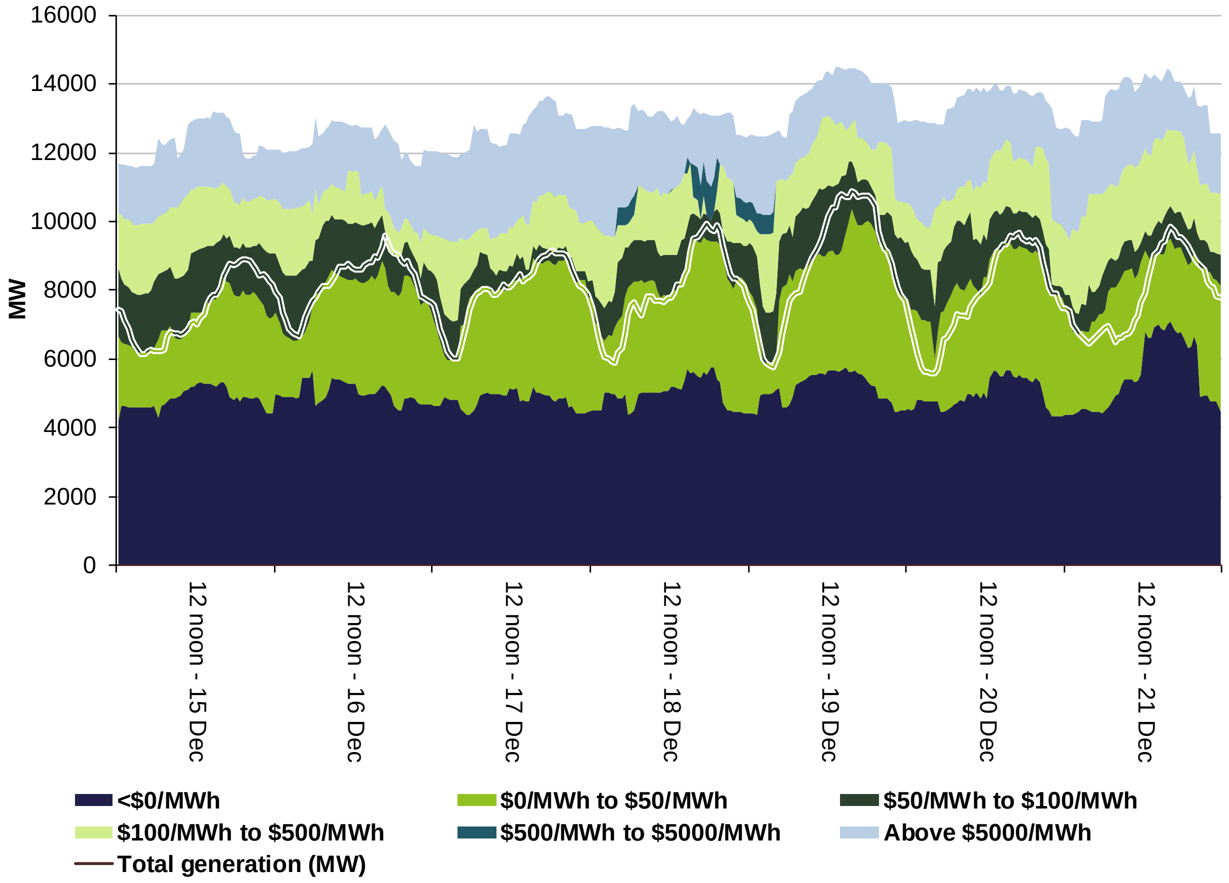


Figure 5: Victoria generation and bidding patterns

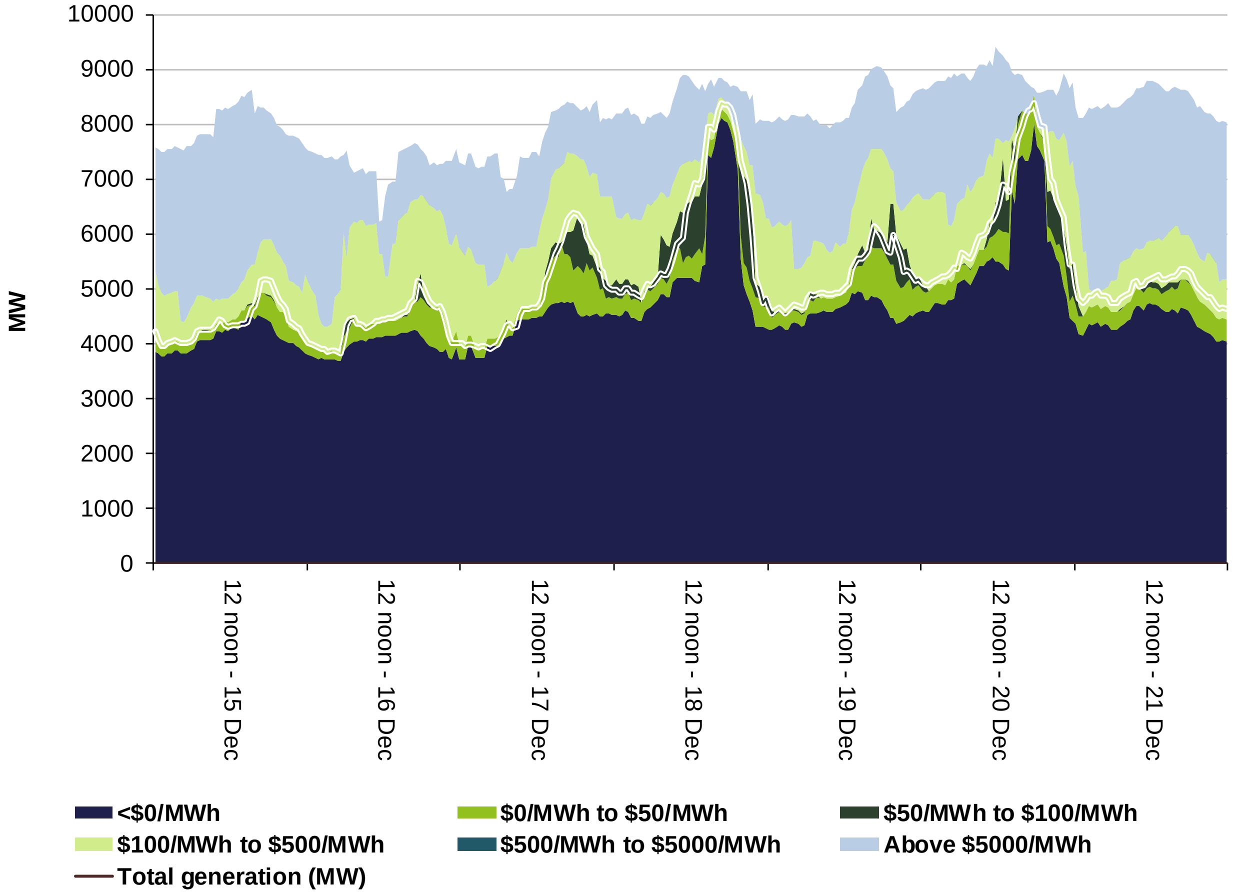


Figure 6: South Australia generation and bidding patterns

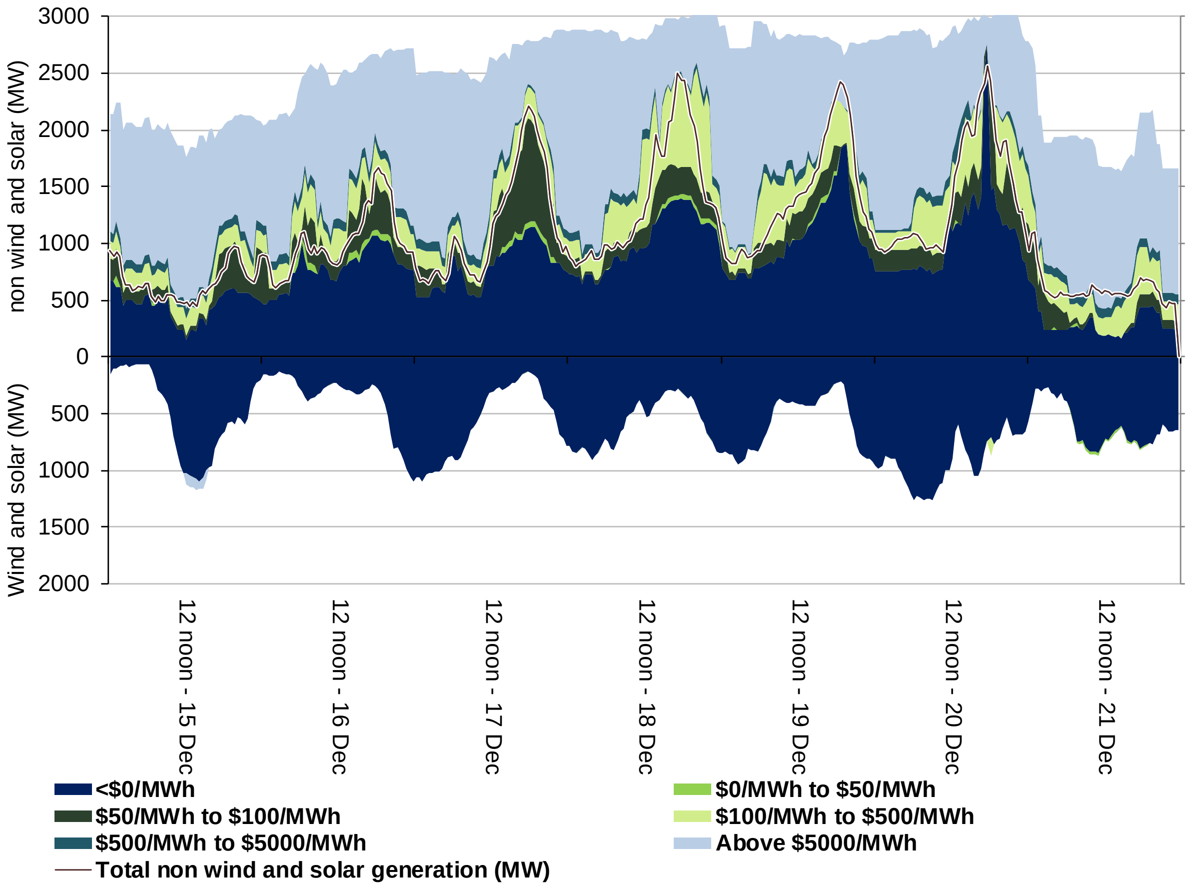
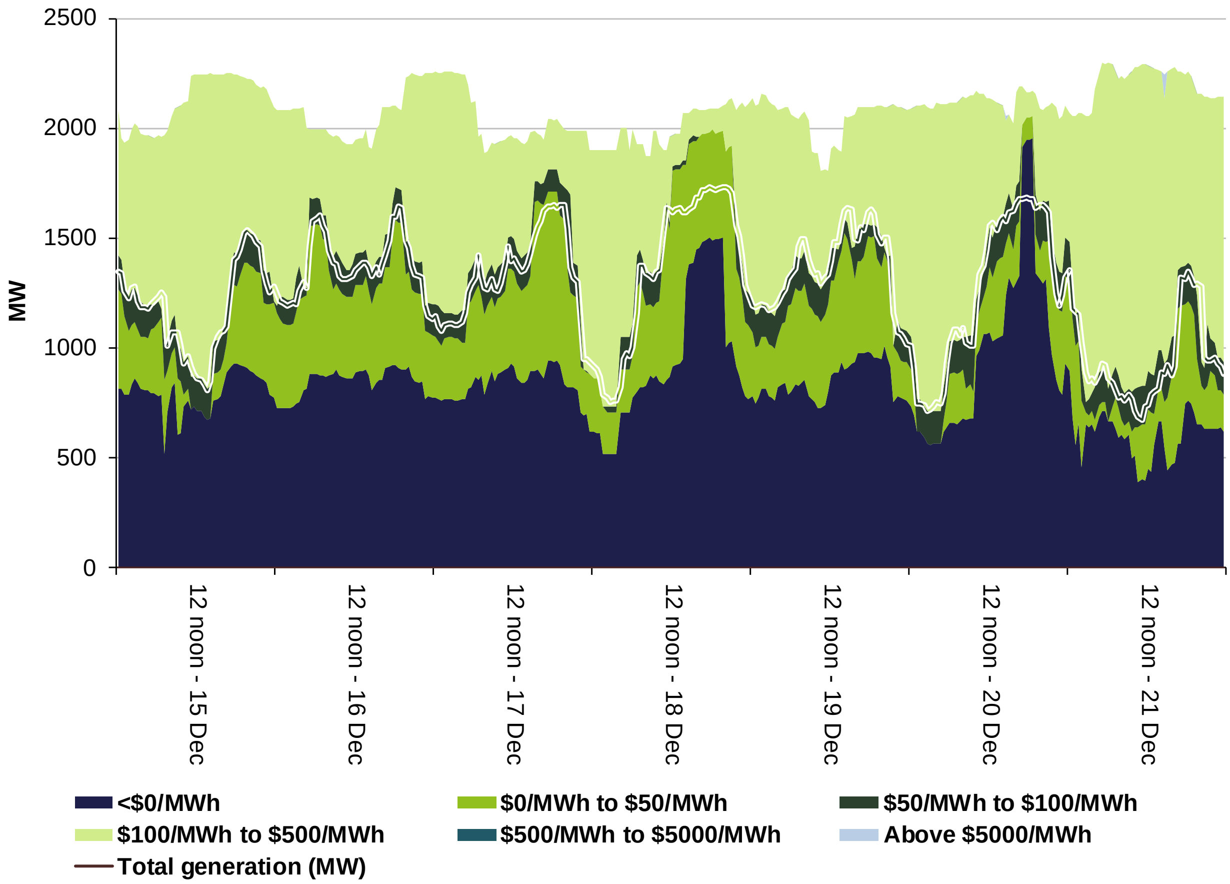


Figure 7: Tasmania generation and bidding patterns



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.

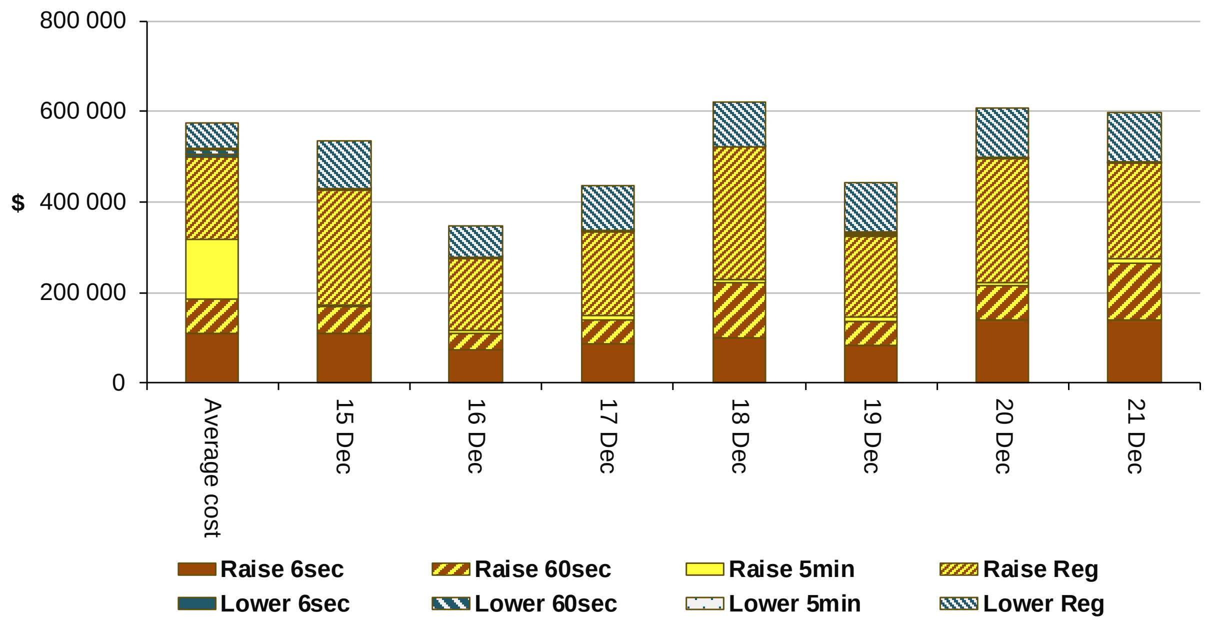
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 916 500 or 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $671 500 or around 7 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

Victoria

There were four occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $102/MWh and above $250/MWh.

Friday, 20 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
2.30 pm	343.10	269.72	154.73	7887	8013	7969	8976	9461	9474
3 pm	324.91	411.95	147.82	8184	8142	8127	8914	9499	9513
5.30 pm	2518.98	114.28	524.66	9060	8924	8971	8687	9334	9400
6 pm	1964.52	115.57	519.36	9113	8987	9005	8662	9247	9326

For the 2.30 pm and 3 pm trading intervals prices were close to forecast four hours ahead.

For the 5.30 pm and 6 pm trading intervals, prices were aligned with South Australia and will be treated as one region. Demand was collectively around 200 MW higher than forecast and availability was collectively around 450 MW to 500 MW lower than forecast, four hours prior. Wind generation was around 700 MW lower than forecast, most of which was negatively priced. This combined with no capacity in Victoria priced between $0/MWh and $11 500/MWh saw the price at or above $11 5000/MWh at 5.20 pm and 5.35 pm.

South Australia

There were six occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $285/MWh and above $250/MWh and there were two occasions where the spot price was below -$100/MWh.

Sunday, 15 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
Midday	-152.04	25.03	20.50	669	511	535	2888	2482	2563

Demand was 158 MW and availability was 406 MW higher than forecast four hours ahead. The higher than forecast availability was due to higher than forecast wind generation, all of which was priced negatively. As a result prices were lower than forecast.

Thursday, 19 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
6.30 pm	3594.91	12 919.81	13 100.02	3089	3059	3055	3039	3090	3038
7 pm	14 700.00	3577.47	13 100.02	3108	3038	3036	3011	3105	3016
7.30 pm	14 700.00	379.95	13 072.35	3082	2985	2975	2997	3115	3075
8 pm	2590.00	177.18	379.95	3001	2882	2898	3077	3152	3125

Maximum temperatures in Adelaide exceeded 45°C, leading to close to record demand. With imports from Victoria limited across the Murraylink interconnector and despite 83 per cent of capacity in South Australia being priced below $5000/MWh, capacity priced above $5000/MWh was dispatched to meet demand. We have written a $5000/MWh report on the day.

Price sensitivity reports published throughout the day by AEMO, the market operator, indicated that less than a one percent error in forecast demand, supply or network capacity from neighbouring regions could lead to significant swings in price outcomes of between $115/MWh and the market cap. A number of factors varied from those forecast four hours ahead. Imports from Victoria were as much as 210 MW lower than forecast, demand was up to 120 MW greater than forecast and low priced wind generation was at times more than 110 MW lower than forecast. These factors combined resulted in actual prices being higher than those forecast.

Friday, 20 December

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
5.30 pm	2300.87	115.00	484.04	2838	2758	2850	3870	3720	3999
6 pm	1454.79	115.00	477.39	2710	2608	2788	3774	3643	3924
6.30 pm	-101.56	115.00	485.67	2523	2562	2721	3831	3553	3799

The 5.30 pm and 6 pm prices were aligned with those in Victoria and are detailed in the Victorian section.

For the 6.30 pm trading interval, demand was 40 MW lower than forecast and availability was around 280 MW higher than forecast. Higher availability was due to higher than forecast wind generation, most of which was priced negatively. There was no capacity priced between $69/MWh and the floor so small changes in demand or rebidding could cause large movements in price. At 6.20 pm there was a 46 MW fall in demand and the price went to the price floor. In response participants rebid over 600 MW of capacity to higher prices and the price went to $87/MWh for the remainder 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 $53/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Sunday, 15 December

Table 7: 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
7.30 am	293.98	49.56	38.91	1048	1032	1019	1966	2053	2157

Conditions at the time saw demand higher and availability close to forecast.

At 7.05 am there was a step change in offers below $0/MWh and with cheaper generation trapped or stranded in FCAS the price was set at $402/MWh for the first four dispatch intervals.

Friday, 20 December

Table 8: 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	-106.52	89.76	129.46	950	840	958	2085	2130	2120

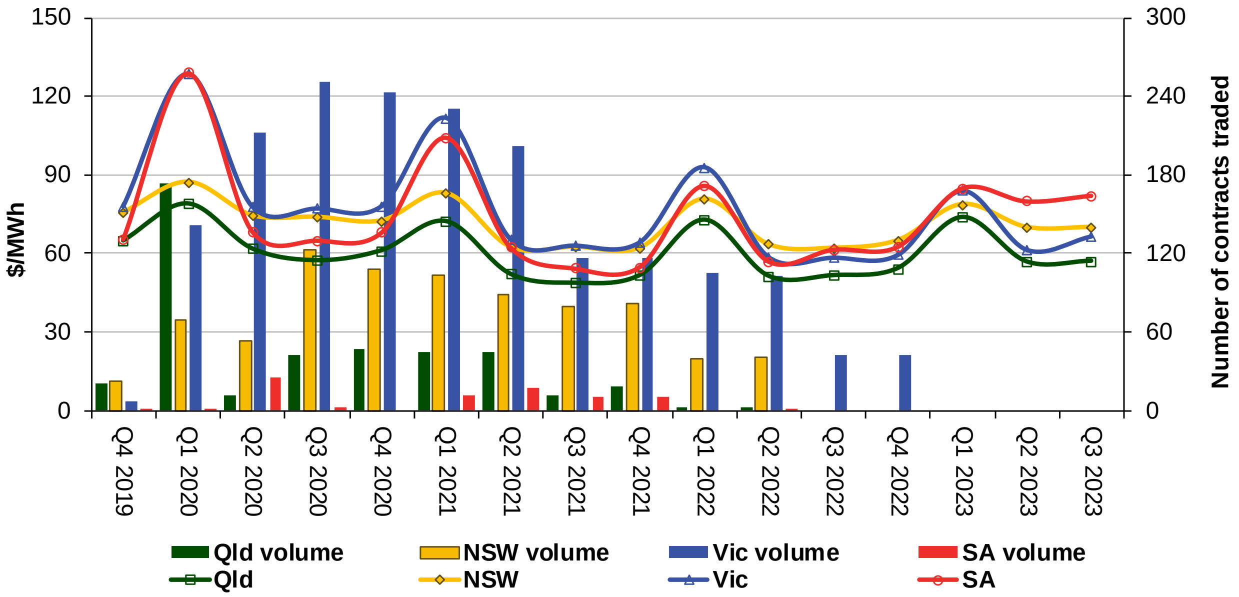
Conditions at the time saw demand 110 MW higher than forecast and availability 45 MW lower than forecast four hours ahead.

At 2.35 pm there was a 1100 MW step change increase in capacity priced at or close to the price floor. As a result of higher priced capacity being constrained down the price went almost to the floor at 2.40 pm. At 2.45 pm most units were no longer ramp rate limited and the price went to around $90/MWh for the rest 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.

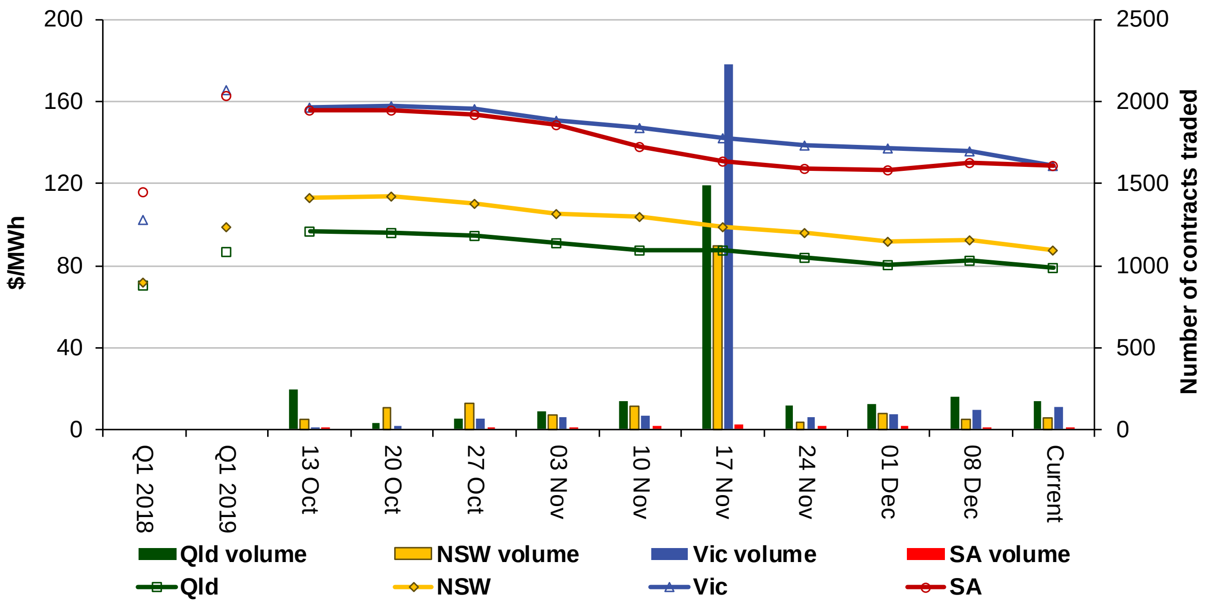
Figure 9: Quarterly base future prices Q4 2019 – Q3 2023



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2020 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2018 and Q1 2019 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 2019.

Figure 10: Price of Q1 2020 base contracts over the past 10 weeks (and the past 2 years)

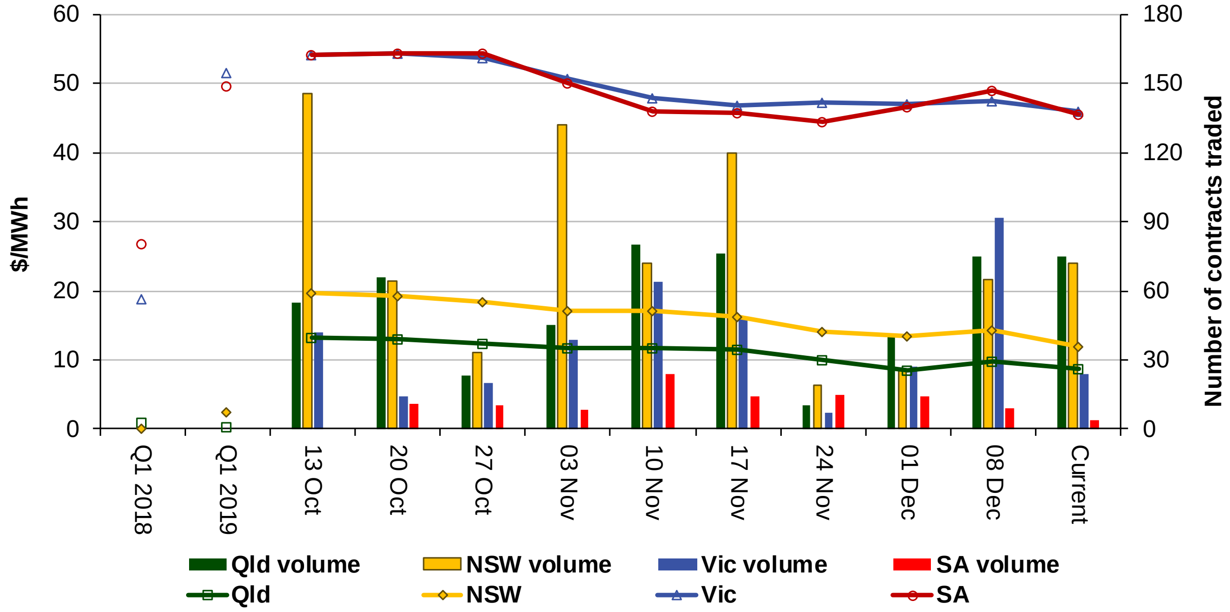


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2020 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2018 and Q1 2019 prices are also shown.

Figure 11: Price of Q1 2020 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
October 2020