Electricity Report

AUSTRALIAN ENERGY REGULATOR

23 – 29 February 2020

Weekly Summary

Average prices for the week ranged from $41/MWh in Tasmania to $61/MWh in South Australia. Multiple lines were reclassified due to voltage control, unplanned outages, and severe weather conditions in Queensland, Victoria and New South Wales, however these reclassifications did not have a significant impact on prices.

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 23 to 29 February 2020.

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

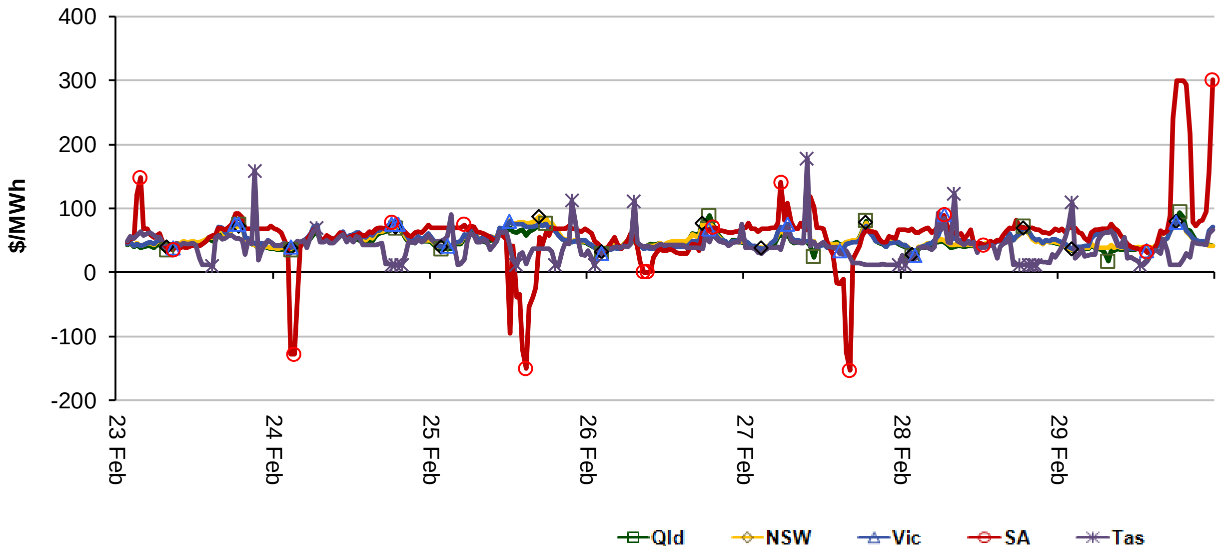


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

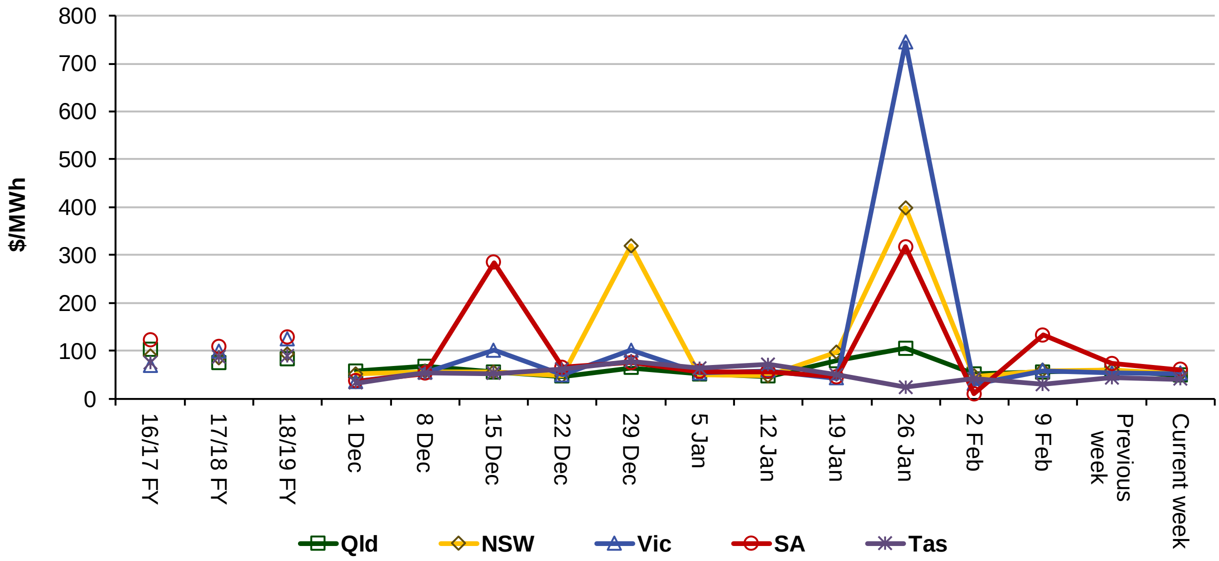


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	49	51	52	61	41
18-19 financial YTD	85	95	128	137	80
19-20 financial YTD	65	95	105	88	67

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 190 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	17	0	1
% of total below forecast	11	51	0	14

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

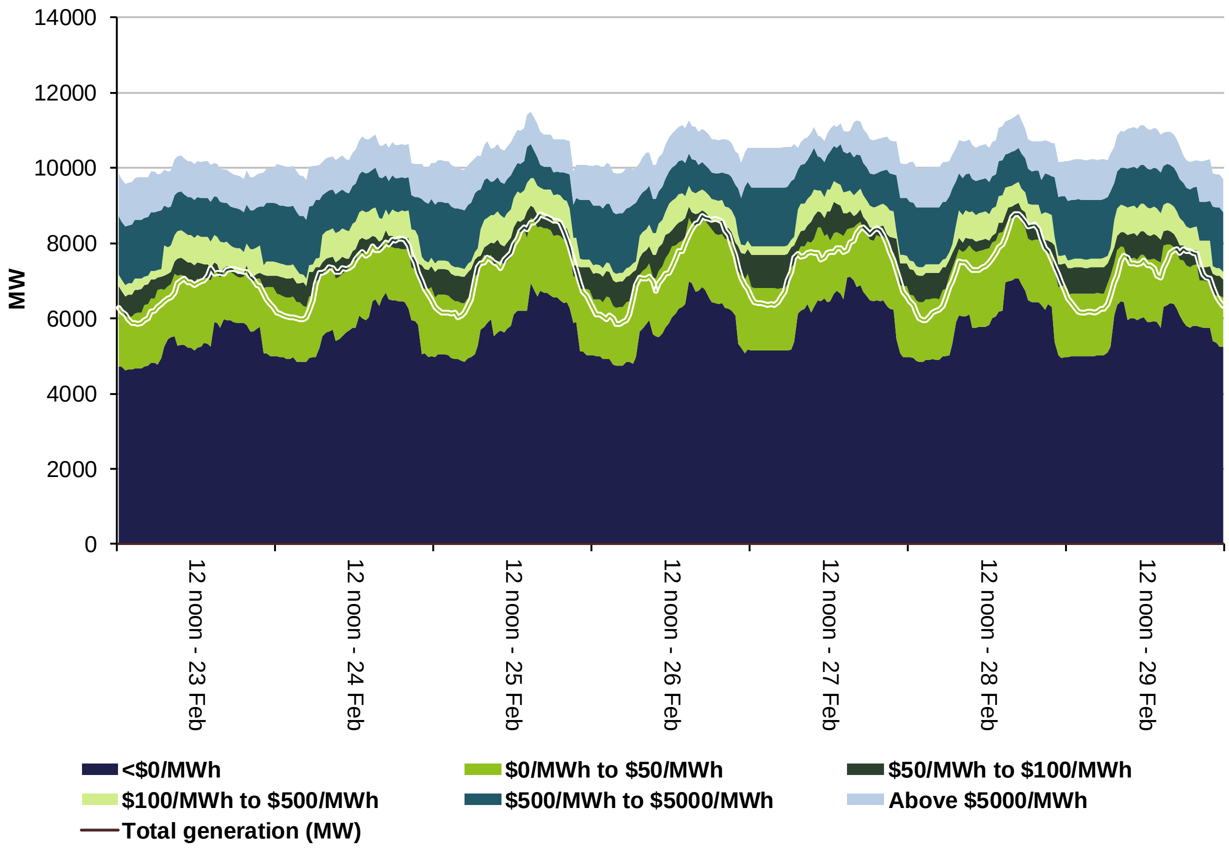


Figure 4: New South Wales generation and bidding patterns

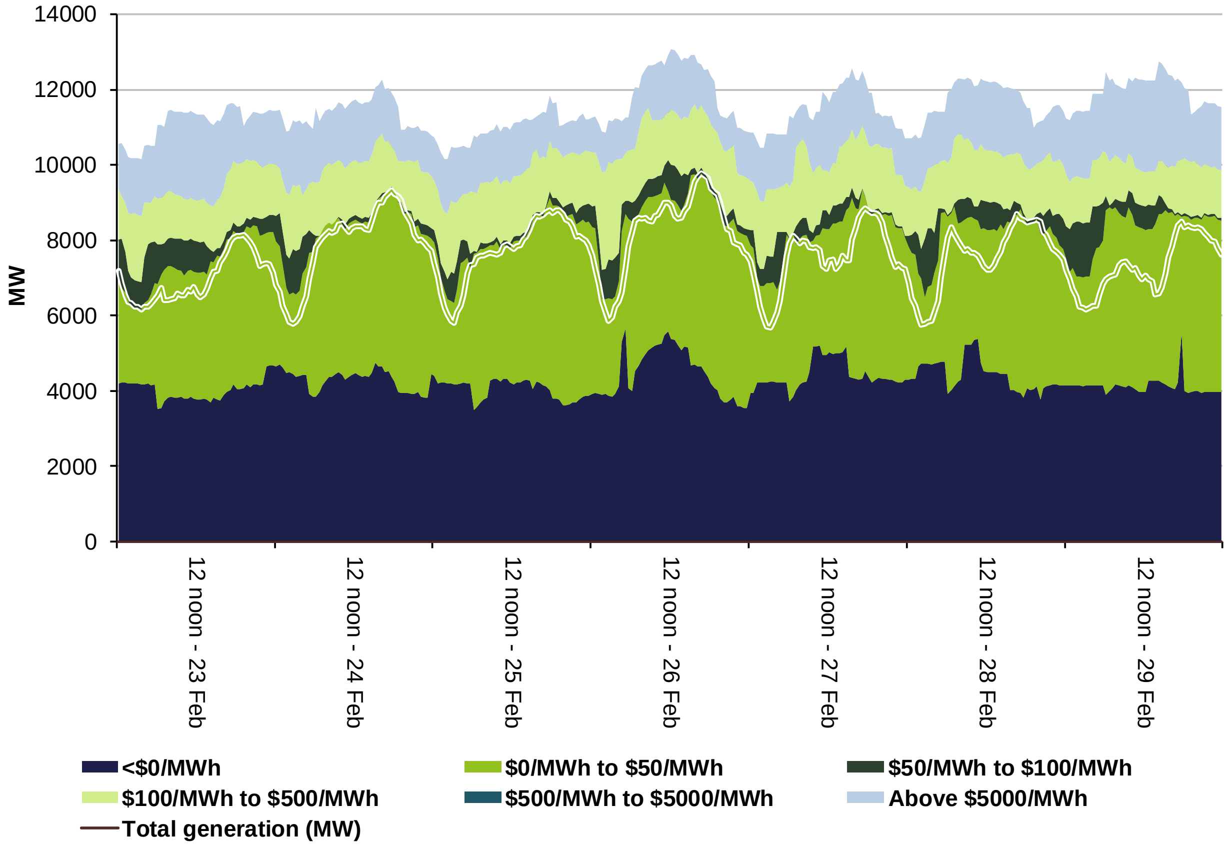


Figure 5: Victoria generation and bidding patterns

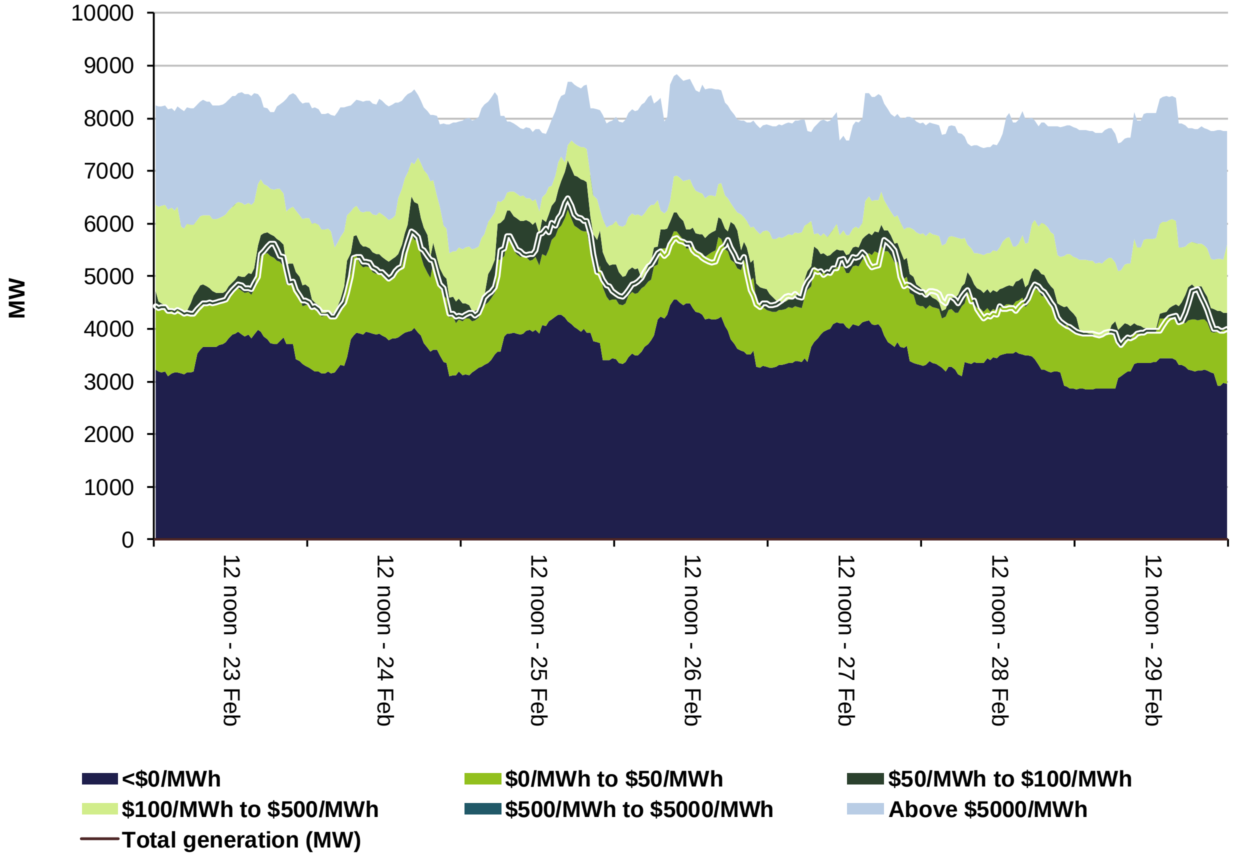


Figure 6: South Australia generation and bidding patterns

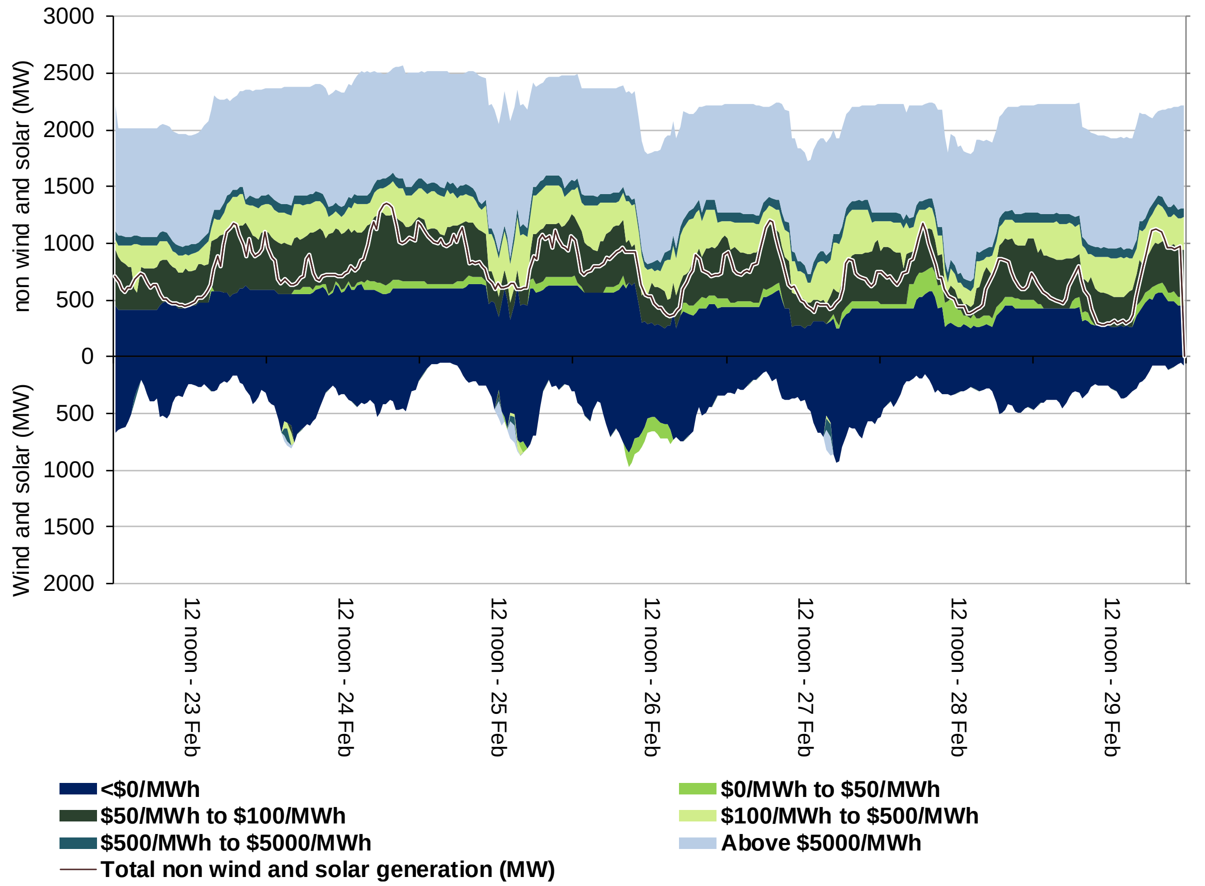
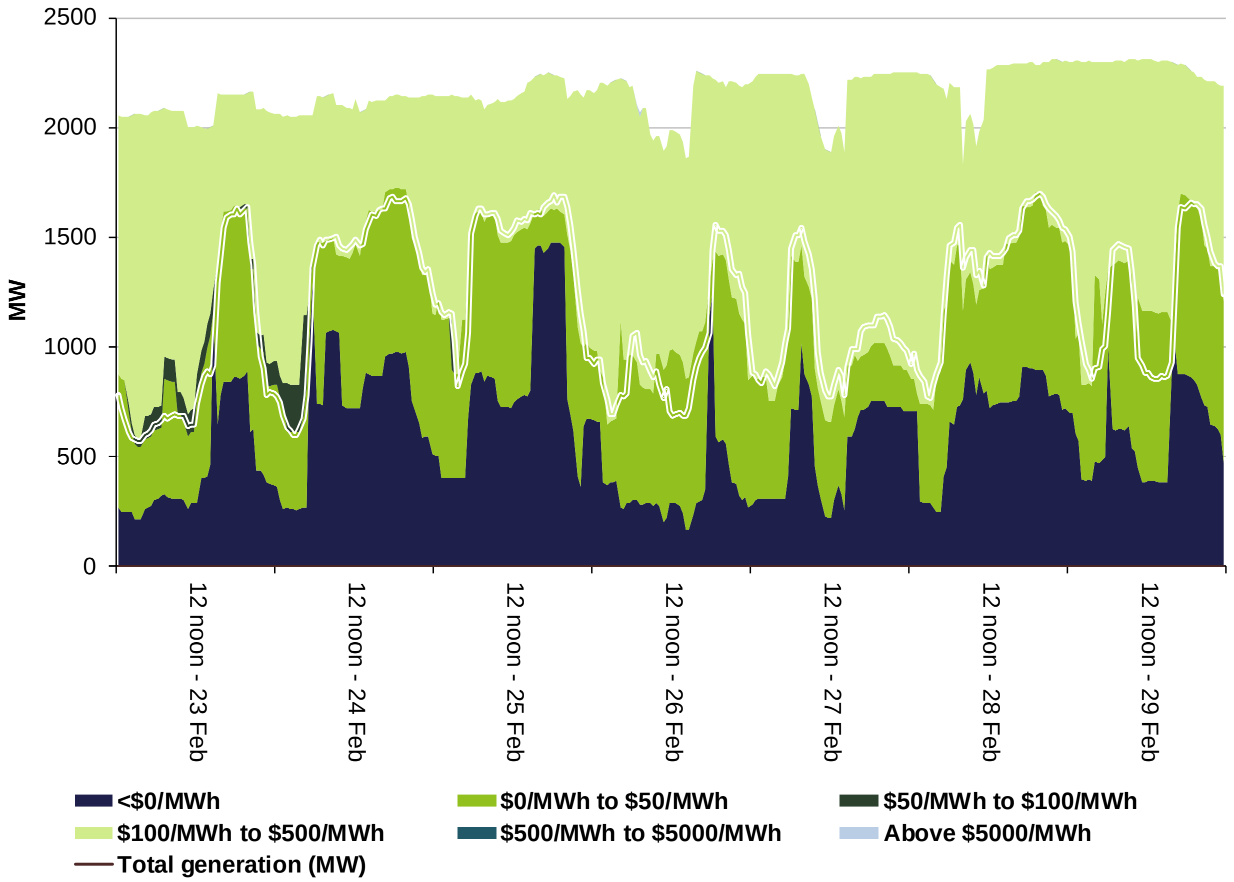


Figure 7: Tasmania generation and bidding patterns



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.

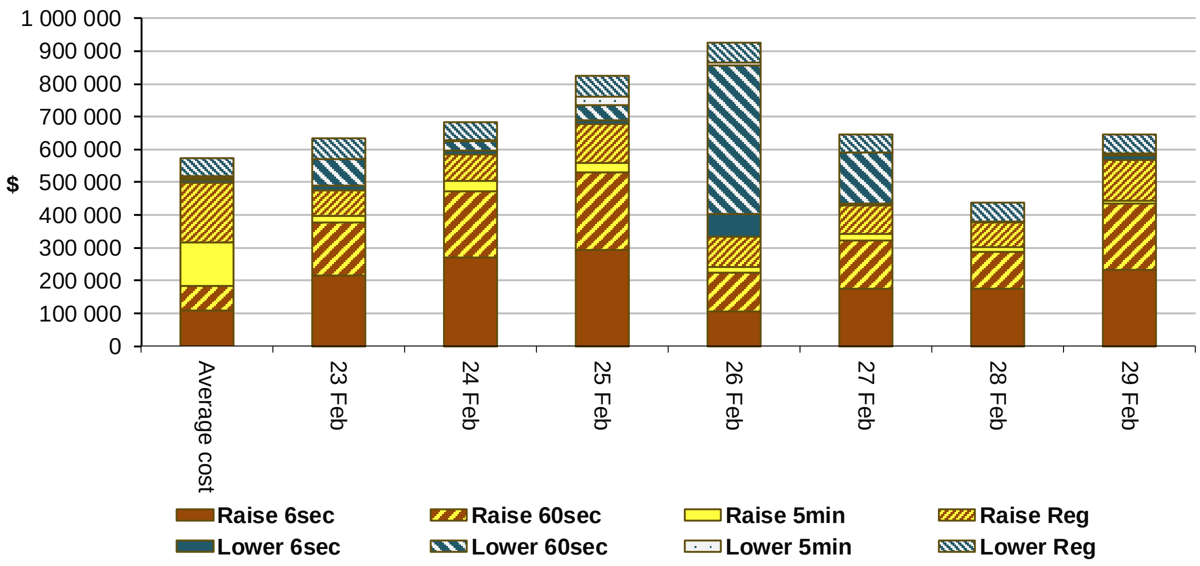
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $4 372 500 or less than 3 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $425 500 or less than 6 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

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $61/MWh and above $250/MWh and there were six occasions where the spot price was below -$100/MWh.

Monday, 24 February

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
3 am	-127.77	62.70	48.24	1218	1231	1187	3129	2735	2703
3.30 am	-128.84	62.70	53.06	1230	1213	1163	3163	2723	2674

For the 3 pm and 3.30 pm trading intervals, demand was close to forecast while availability was between 394 MW and 440 MW higher than forecast, four hours prior. Higher availability was due to between 268 MW and 300 MW higher than forecast wind generation, with most capacity priced at the floor.

Tuesday, 25 February

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
2.30 pm	-120.92	-183.00	-3.10	1055	1030	1110	2927	2906	3258
3 pm	-150.74	-3.10	-3.10	1095	1062	1124	2969	2932	3278

For the 2.30 pm trading interval, demand and availability were both close to forecast four hours prior. With no capacity priced between $33/MWh and the price floor, little changes in demand or availability could cause large fluctuations in price, and as a result, the dispatch price fell to the floor at 2.05 pm. Market participants responded to the 2.05 pm dispatch price by rebidding capacity into higher price bands, resulting in the dispatch price remaining between $53/MWh and $59/MWh for the remainder of the trading interval.

For the 3 pm trading interval, demand and availability were both close to forecast four hours prior. From 2.08 pm, around 460 MW of capacity was rebid from prices above $12/MWh to prices below -$35/MWh due to changes in forecast prices. There was little capacity priced between -$35/MWh and the price floor, resulting in the dispatch price falling to the floor at 4.45 pm.

Thursday, 27 February

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 pm	-124.71	38.60	23.74	819	840	759	2754	2531	2623
4.30 pm	-153.67	44.52	31.89	892	928	847	2812	2557	2549

For the 4 pm and 4.30 pm trading intervals, demand was close to forecast and availability was between 223 MW and 255 MW greater than forecast, four hours prior. Higher availability was due to higher than forecast wind generation for both trading intervals, most of which was priced below $0/MWh.

Saturday, 29 February

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
6.30 pm	300.50	301.00	301.00	1374	1358	1338	2309	2315	2290
7 pm	300.50	301.00	301.00	1409	1396	1374	2249	2272	2251
7.30 pm	299.77	301.00	301.00	1396	1406	1388	2245	2258	2231
8 pm	293.26	301.00	301.00	1404	1411	1388	2243	2290	2263

Prices were close to forecast four and twelve hours prior.

Sunday, 1 March

Table 7: Price, Demand and Availability

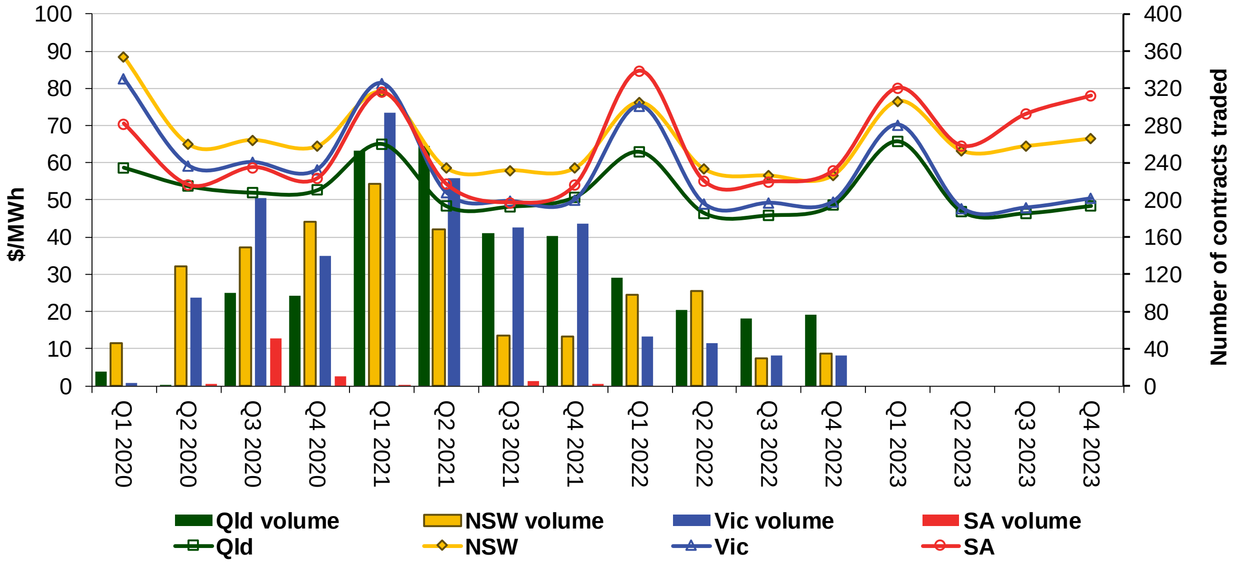
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
Midnight	301.00	87.00	249.00	1378	1382	1359	2294	2455	2459

Demand was close to forecast while availability was 161 MW less than forecast four hours prior. Lower availability was due to actual wind generation being 200 MW lower than forecast, most of which was priced below $0/MWh. With little capacity priced between $87/MWh and $300/MWh, the dispatch price remained at $301/MWh for the entire 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.

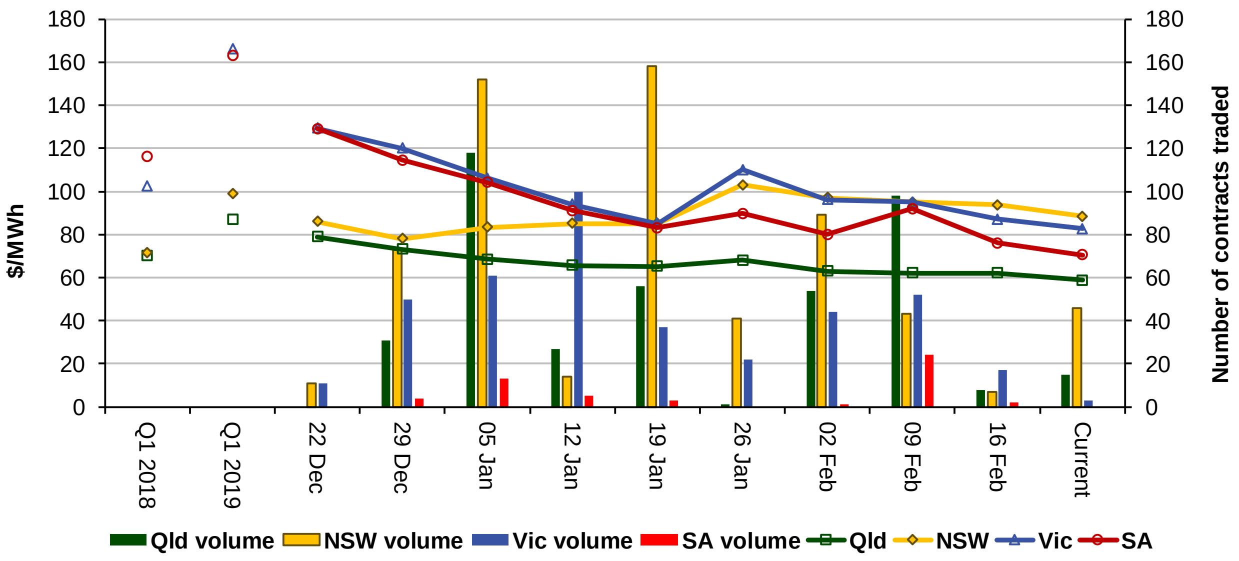
Figure 9: Quarterly base future prices Q1 2020 – Q4 2023



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 quarter 1 2018 and quarter 1 2019 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 2020 base contracts over the past 10 weeks (and the past 2 years)

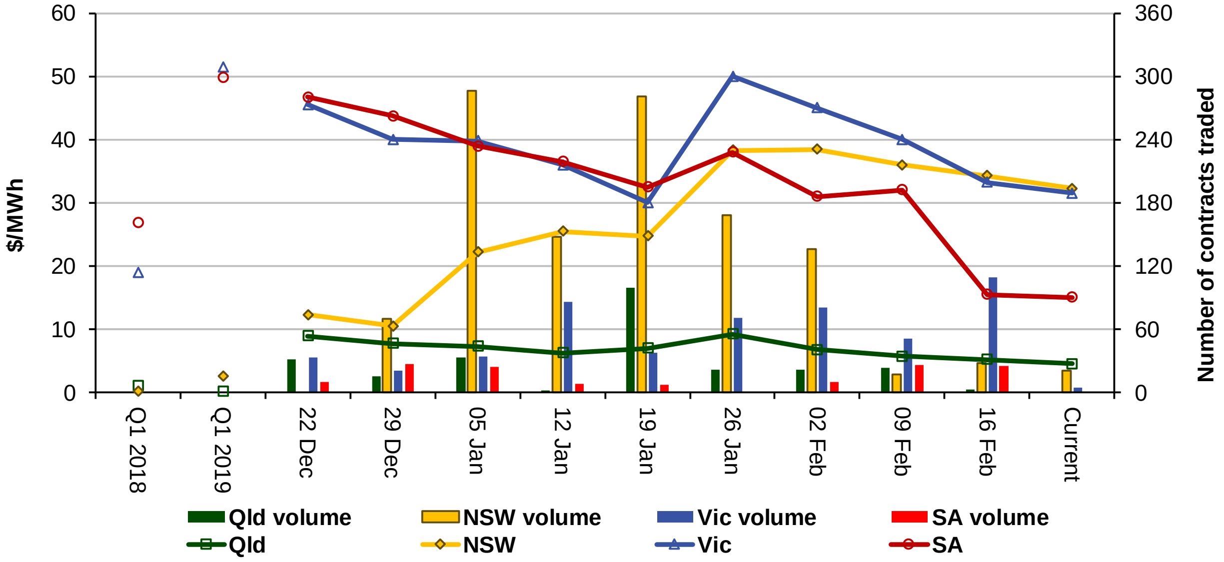


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional quarter 1 2020 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 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
March 2020