Electricity Report

AUSTRALIAN ENERGY REGULATOR

12 – 18 April 2020

Weekly Summary

Average spot prices ranged from $22/MWh in Tasmania to $41/MWh in New South Wales. Prices breached our weekly reporting threshold in five trading intervals, two of which saw price alignment across all mainland regions early in the week.

Multiple lines were reclassified due to voltage control, unplanned outages and severe weather in Victoria and Queensland, however these reclassifications did not significantly impact 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 12 to 18 April 2020.

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

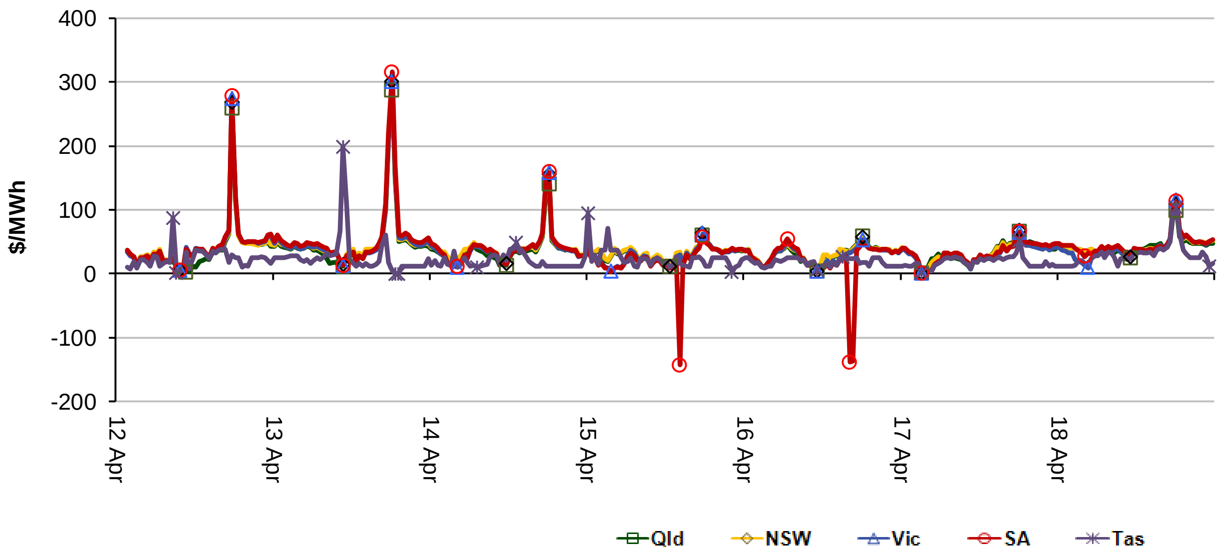


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

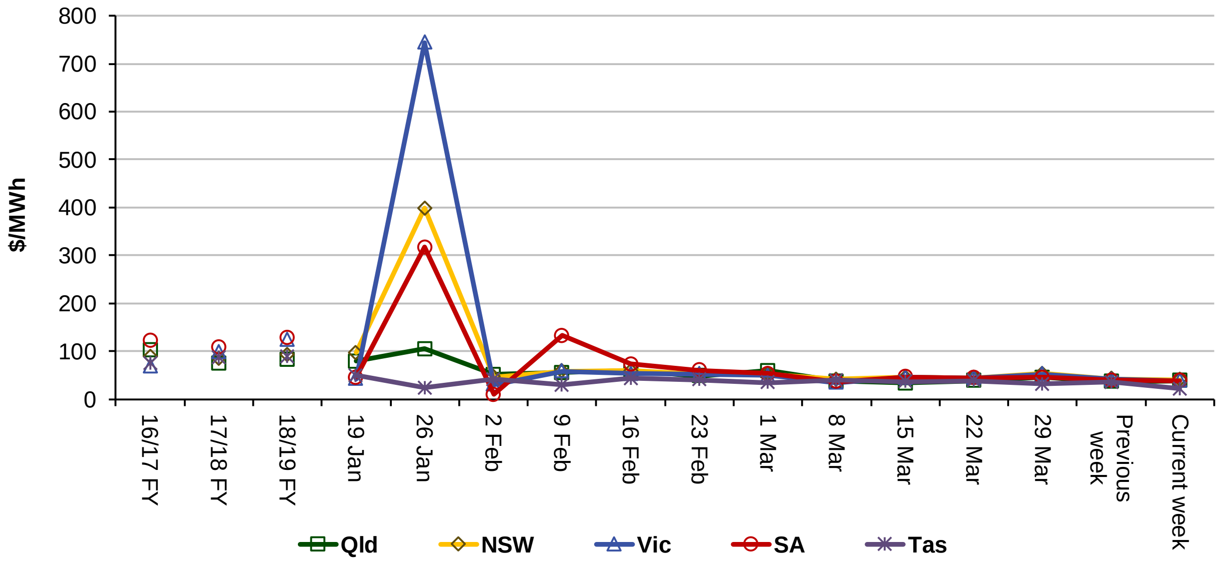


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	39	41	39	39	22
18-19 financial YTD	84	94	130	137	87
19-20 financial YTD	61	88	95	81	62

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 209 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	11	36	0	1
% of total below forecast	12	29	0	11

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

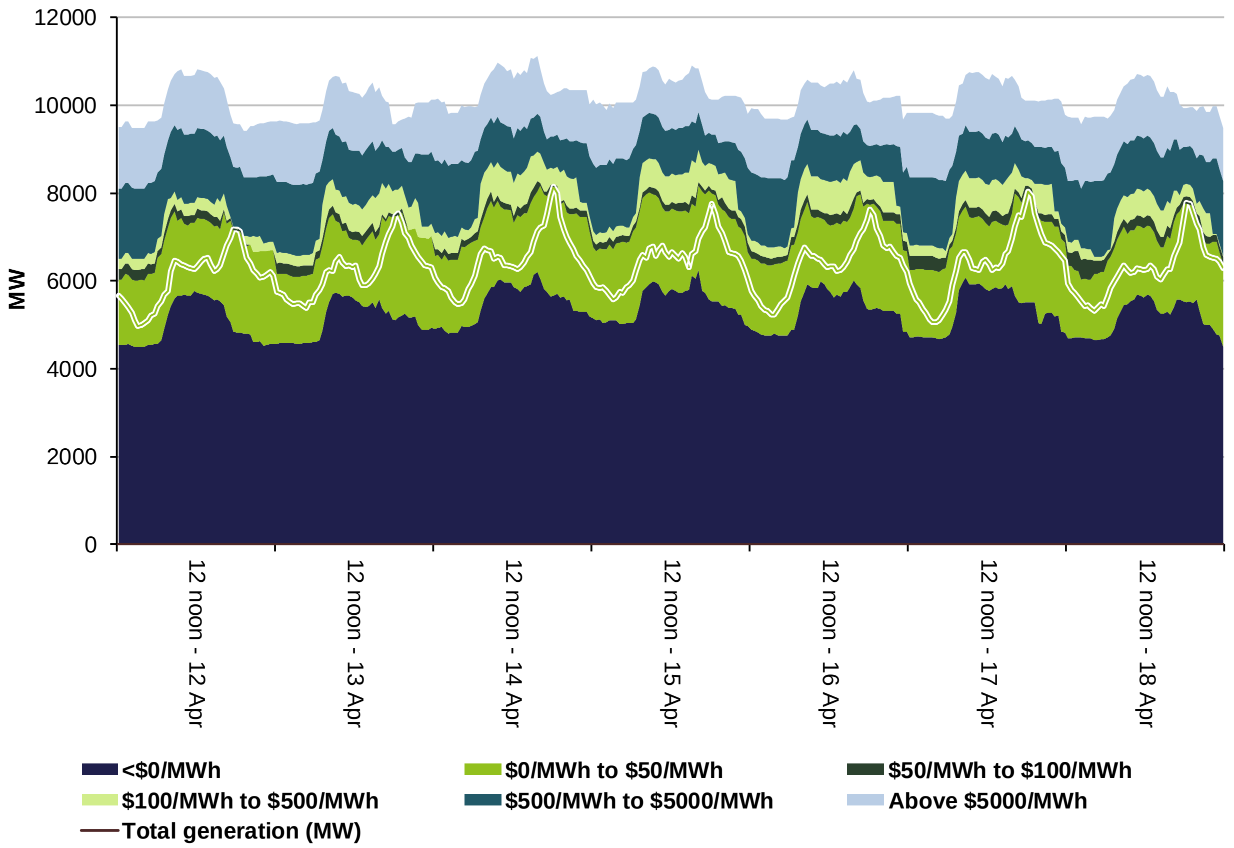


Figure 4: New South Wales generation and bidding patterns

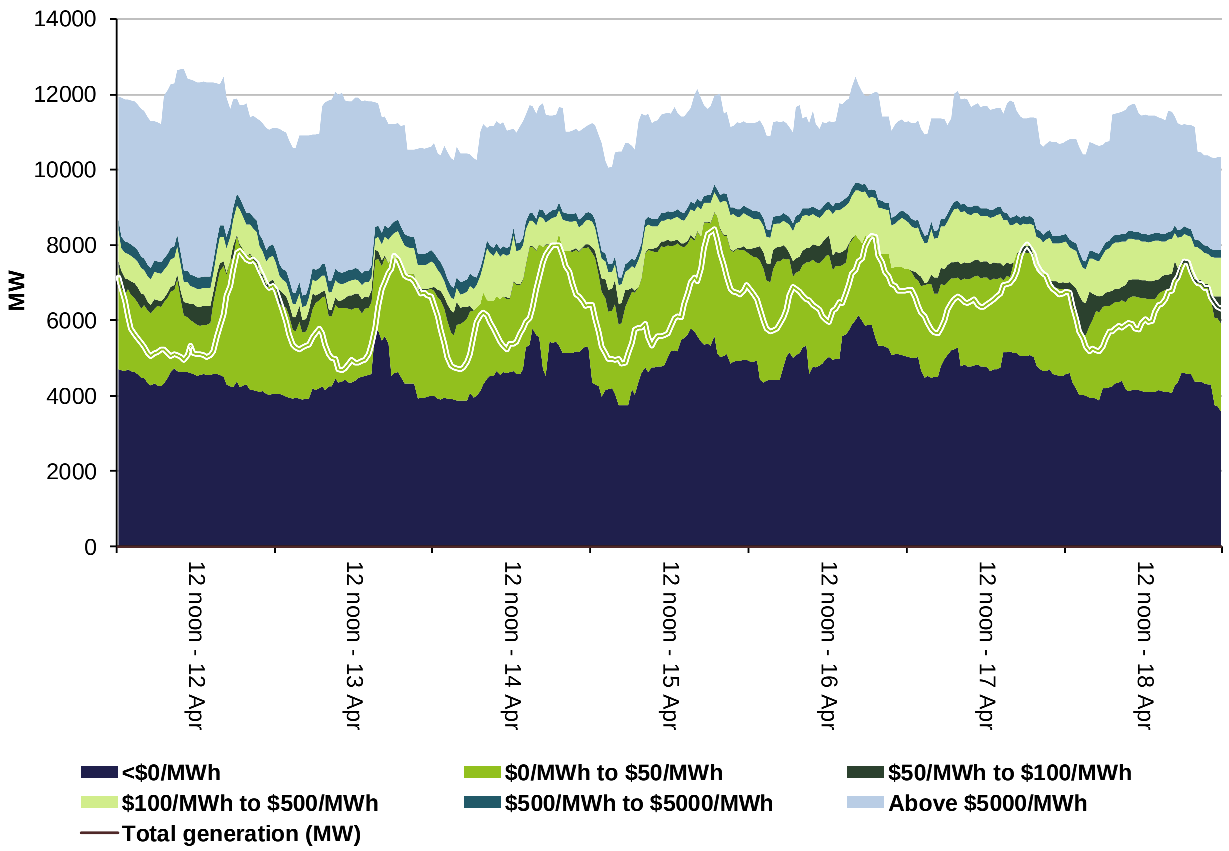


Figure 5: Victoria generation and bidding patterns

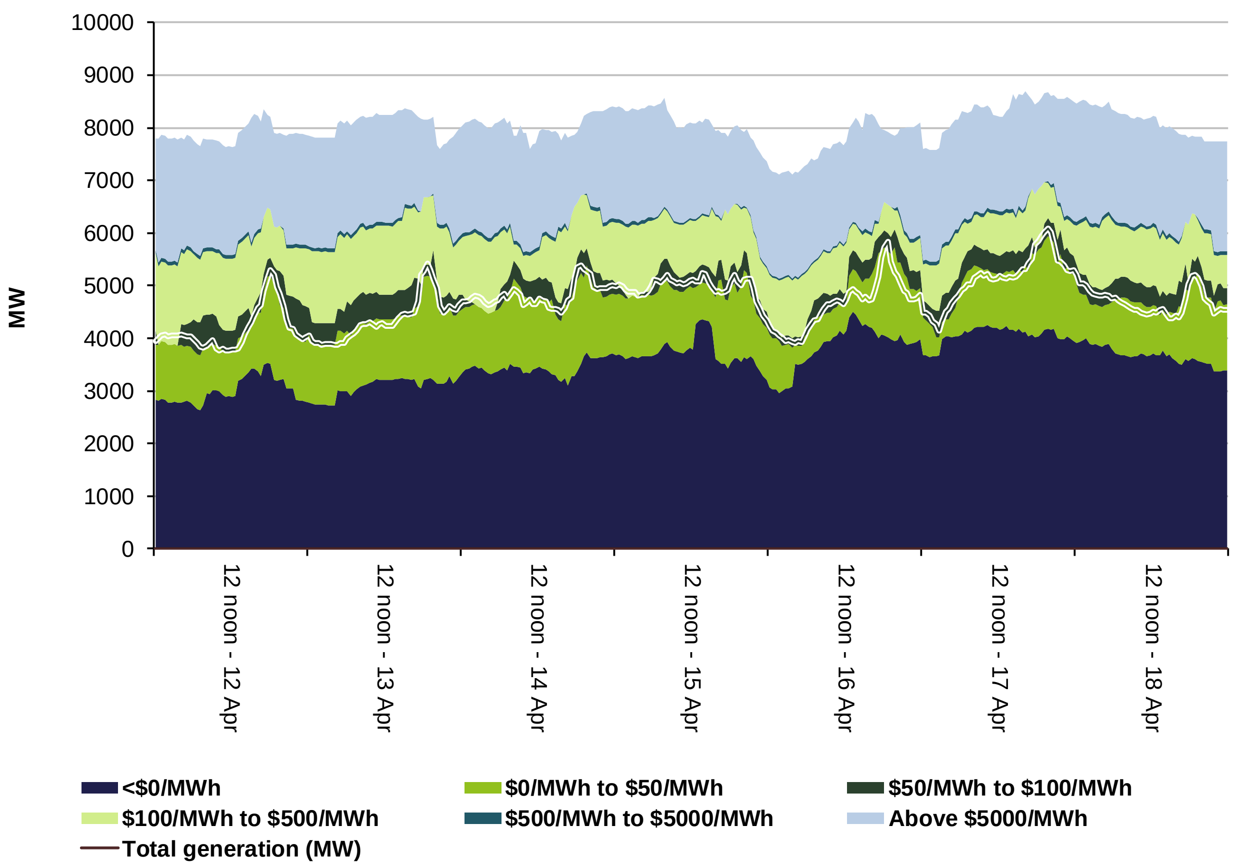


Figure 6: South Australia generation and bidding patterns

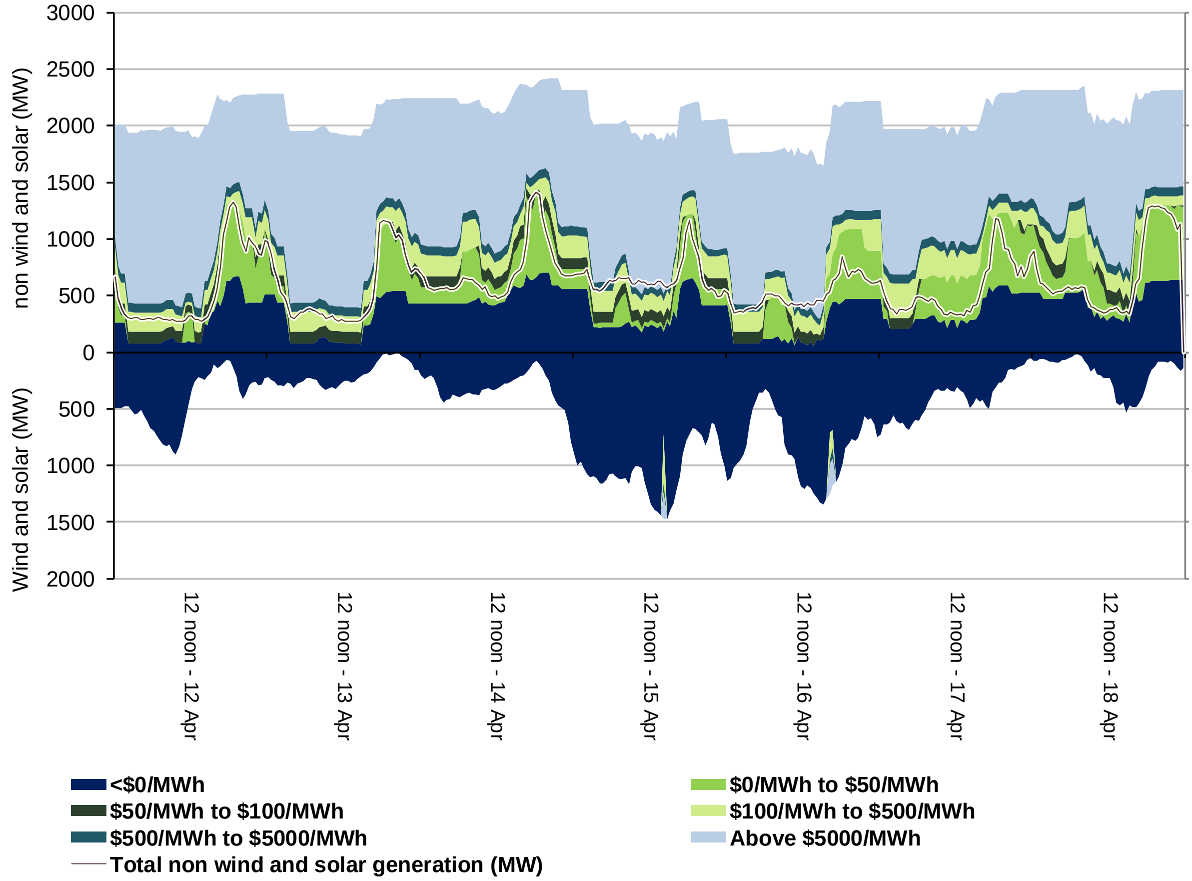
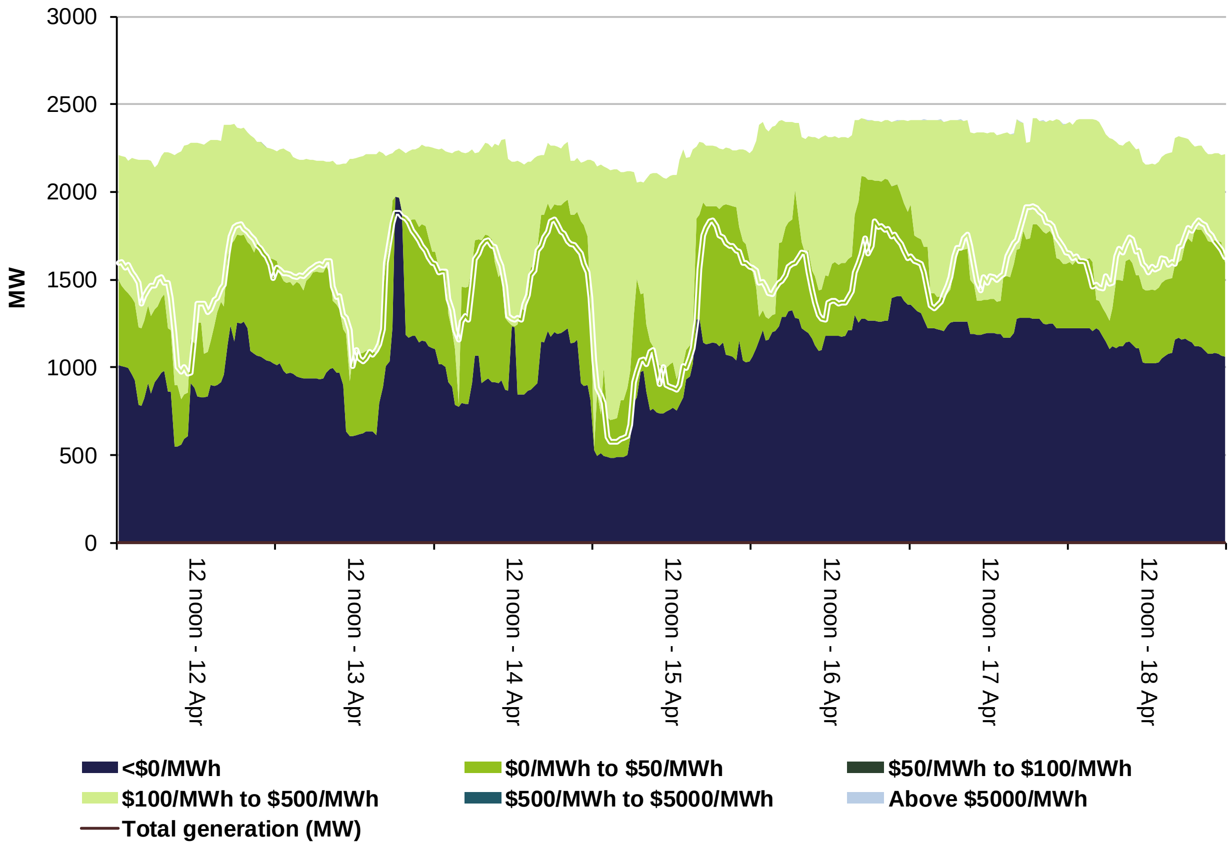


Figure 7: Tasmania generation and bidding patterns



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.

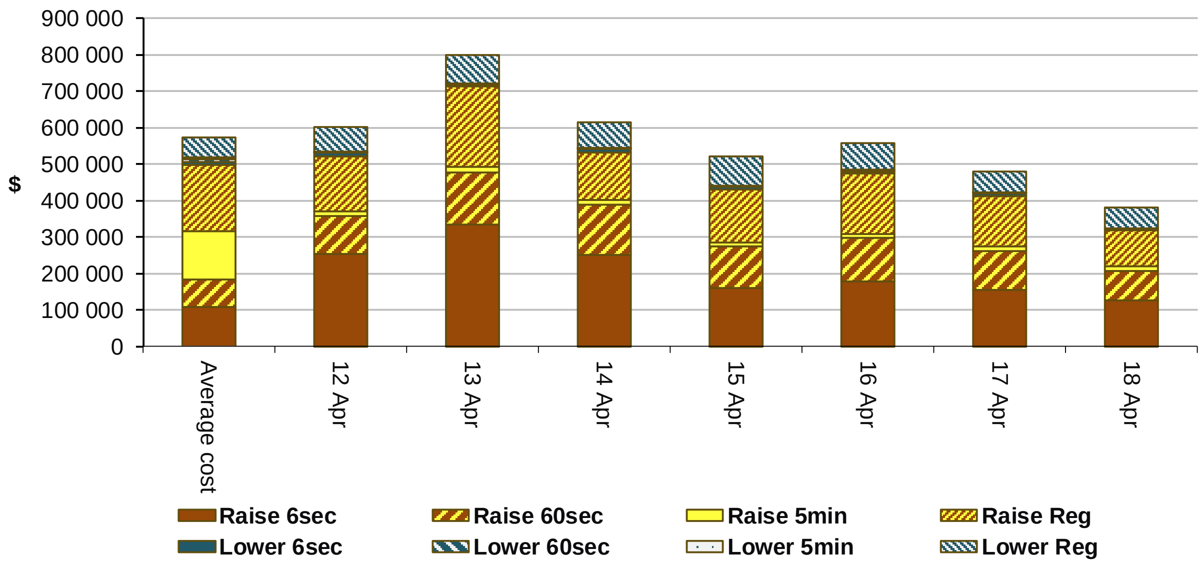
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 683 000 or around 3 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $273 000 or less than 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

Mainland

There were two occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $41/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Sunday, 12 April

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	268.37	66.47	49	21 318	20 254	20 014	31 732	31 656	31 739

Prices were aligned across the mainland and will be treated as one region. Demand was collectively 1064 MW higher than forecast, and availability close to forecast, four hours prior. The higher than forecast demand resulted in prices around $290/MWh for a majority of the trading interval.

Monday, 13 April

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
6.30 pm	300.78	66.99	112.42	22 060	21 397	21 513	31 157	32 078	31 607

Prices were aligned across the mainland and will be treated as one region. Demand was collectively 663MW higher than forecast, and availability was collectively 921 MW lower than forecast, four hours prior. Lower availability was mainly due to removal of capacity from generators in Queensland and New South Wales due to technical reasons and changes in forecast demand:

- 50 MW from Tarong priced below $45/MWh;
- 105 MW from Millmerran priced below $12/MWh;
- 285 MW from Wivenhoe priced at the cap;
- 400 MW from Eraring – 380 MW priced below $50/MWh and 20 MW priced at $12 000/MWh

At 5.52 pm, Snowy Hydro rebid 325 MW from prices below $68/MWh to $300/MWh. Combined with the higher than forecast demand and lower than forecast availability; prices were set above $283/MWh for the trading interval.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $39/MWh and above $250/MWh and there were three occasions where the spot price was below -$100/MWh.

Wednesday, 15 April

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
2.30 pm	-143.78	25.13	31.12	903	1071	1125	3371	3084	3212

Demand was 168 MW less than forecast, while availability was 287 MW higher than forecast, four hours prior. Higher availability was largely due to higher than forecast wind generation, which generally offers capacity below $0/MWh.

At 2.10 pm, demand fell by 87 MW. With no capacity priced between $38/MWh and the floor, the dispatch price fell to the floor for one dispatch interval. Participants responded by rebidding capacity from the floor to higher price bands, resulting in the price remaining above $18/MWh for the rest of the trading interval.

Thursday, 16 April

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
4.30 pm	-139.13	7.33	22.97	1029	994	991	3259	3112	3031
5 pm	-136.39	23.02	29.43	1122	1086	1097	3378	3232	3134

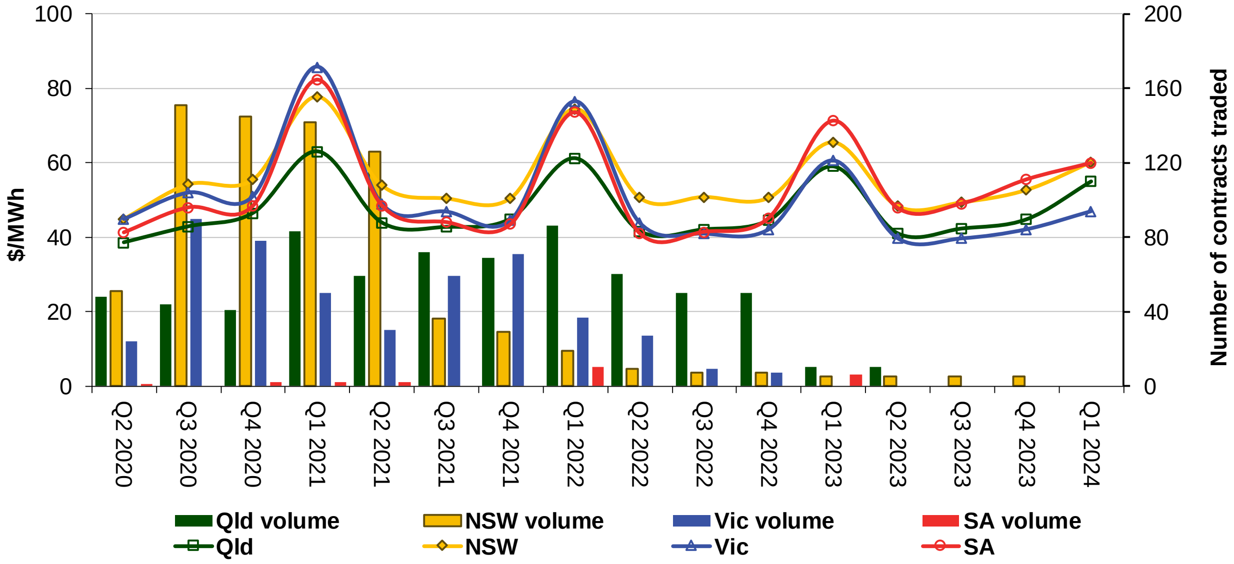
Demand was around 35 MW higher than forecast, while availability was around 145 MW higher than forecast, four hours prior. Higher availability was largely due to higher than forecast wind generation, which generally offers capacity below $0/MWh.

Both trading intervals saw a 5-minute increase in available capacity from either gas or wind, most of which was priced at the floor. As a result, the dispatch price fell to the floor in both trading intervals for one dispatch interval. Participants responded by rebidding capacity from the floor to higher price bands, resulting in prices remaining above $25/MWh for the rest of both 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.

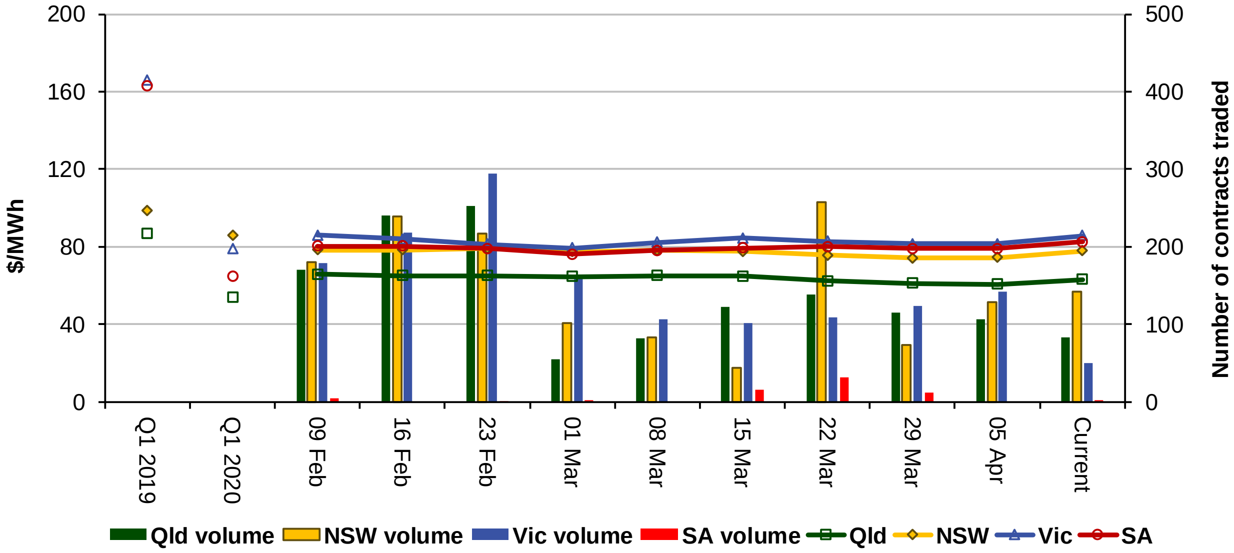
Figure 9: Quarterly base future prices Q2 2020 – Q1 2024



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 quarter 1 2019 and quarter 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)

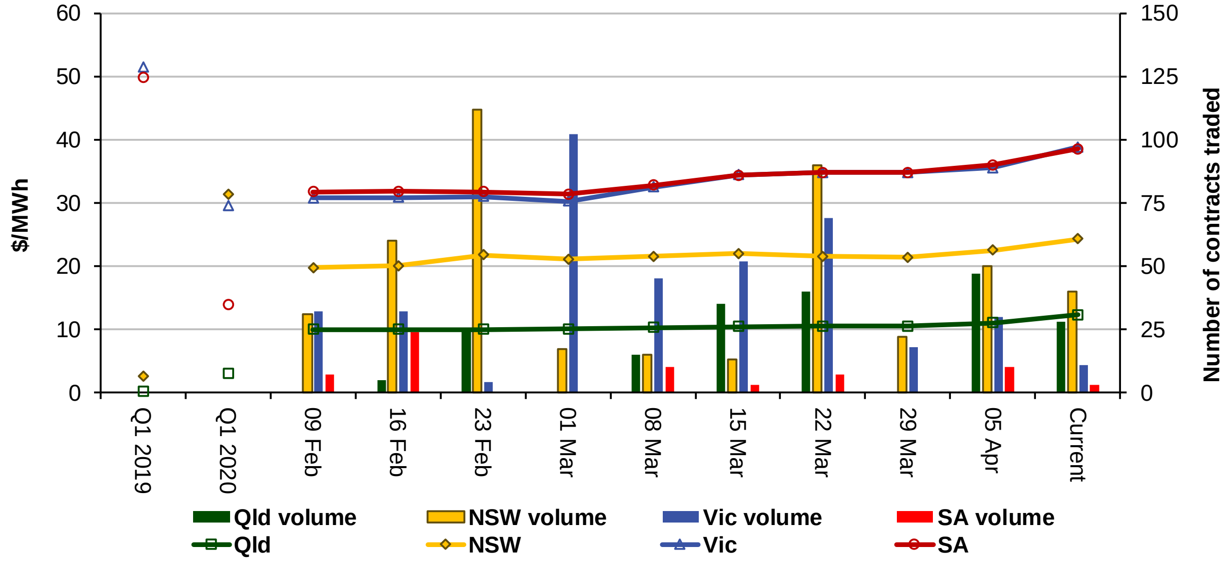


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional quarter 1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2019 and quarter 1 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
April 2020