Electricity Report

AUSTRALIAN ENERGY REGULATOR

5 – 11 April 2020

Weekly Summary

Spot prices ranged from -$168/MWh in South Australia to $427/MWh in Tasmania.

On 11 April, there was a non-credible contingency event in Victoria when three units at Yallourn and Macarthur Wind Farm unit 4 tripped just before 1.30 pm. However, with low weekend demand there were no significant market impacts.

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 5 to 11 April 2020.

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

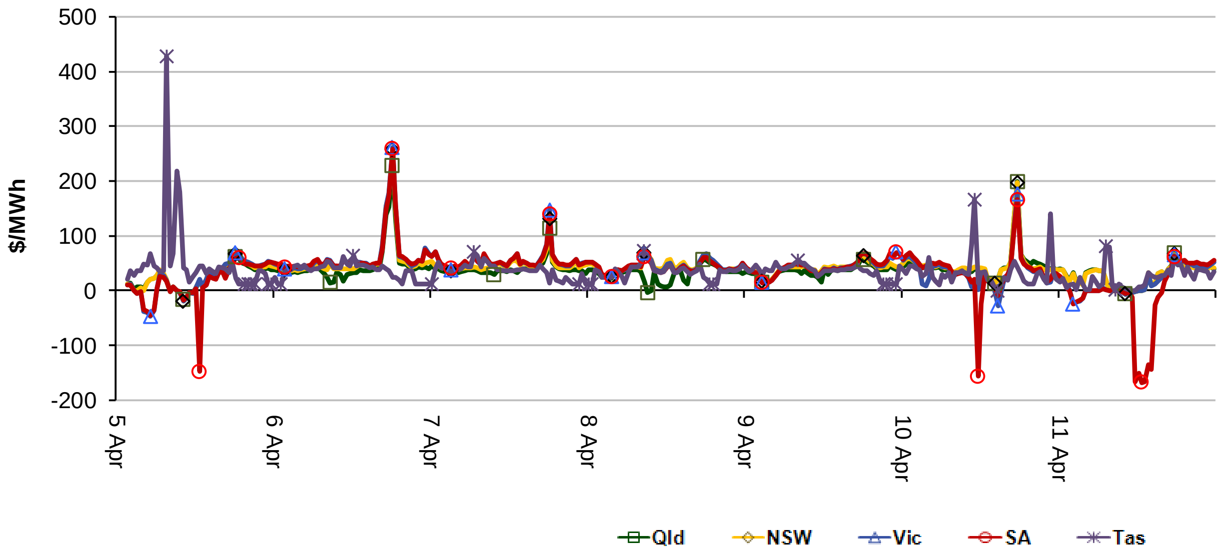


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

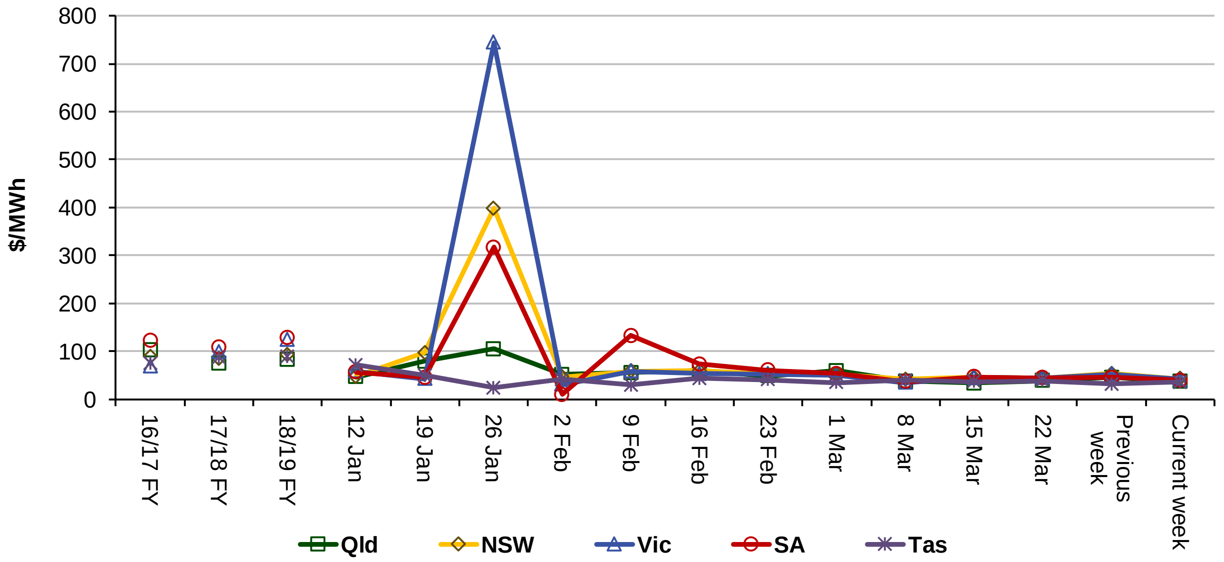


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	37	43	42	39	36
18-19 financial YTD	84	94	131	138	86
19-20 financial YTD	62	89	96	82	63

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 217 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	2	58	0	0
% of total below forecast	6	25	0	8

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

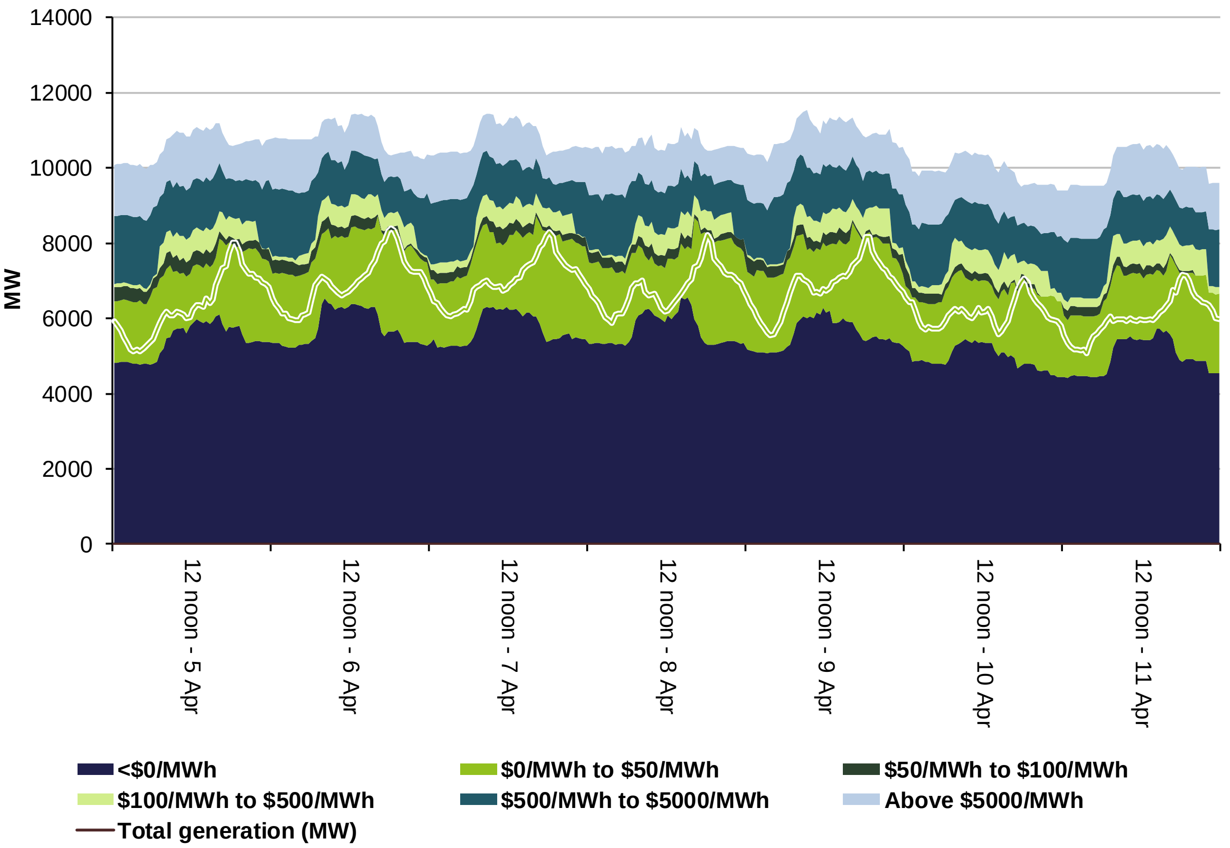


Figure 4: New South Wales generation and bidding patterns

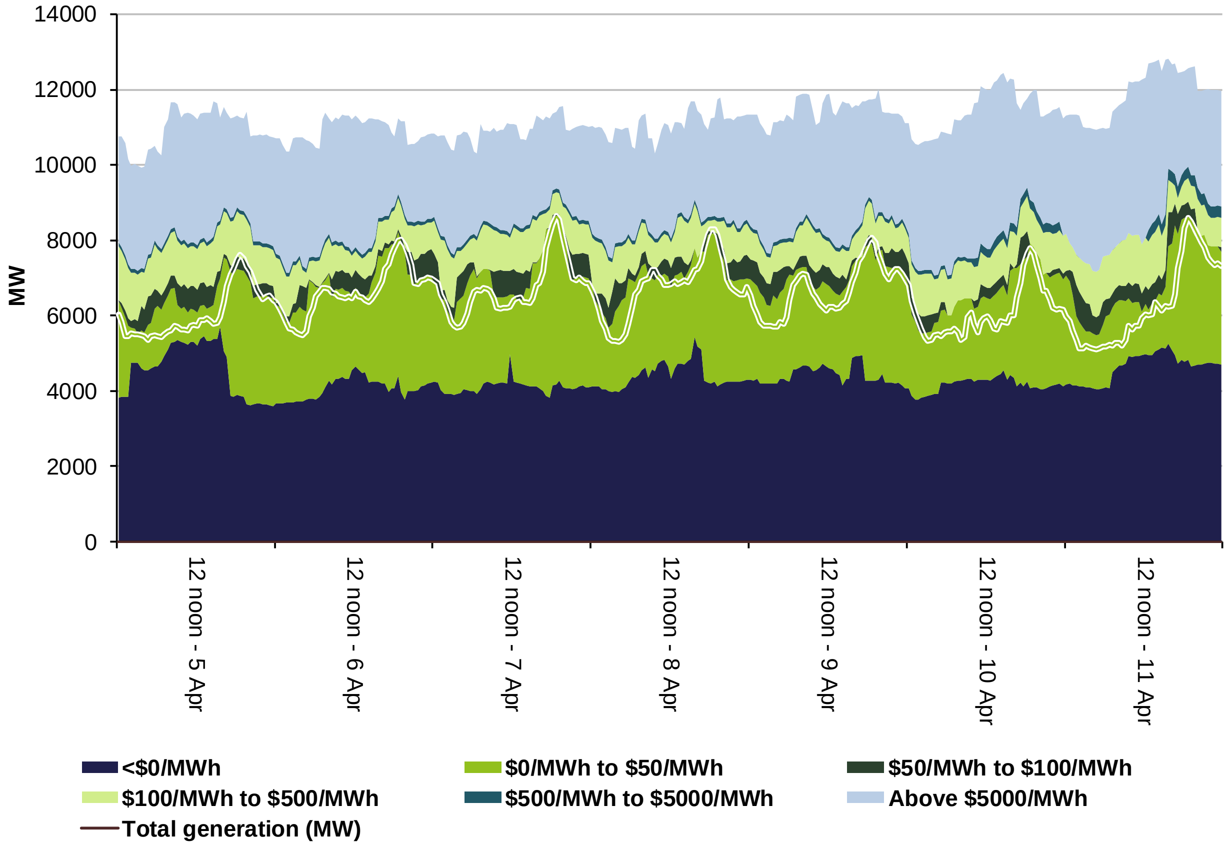


Figure 5: Victoria generation and bidding patterns

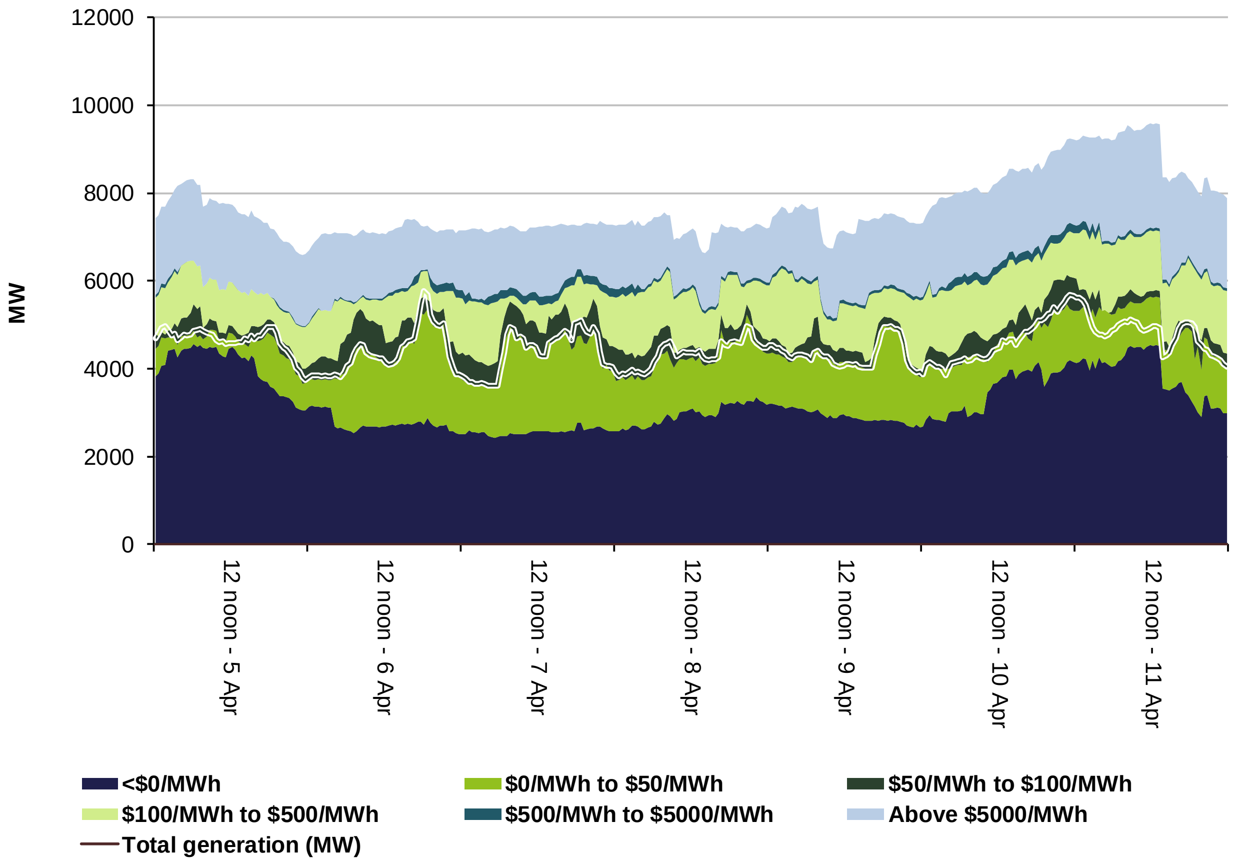


Figure 6: South Australia generation and bidding patterns

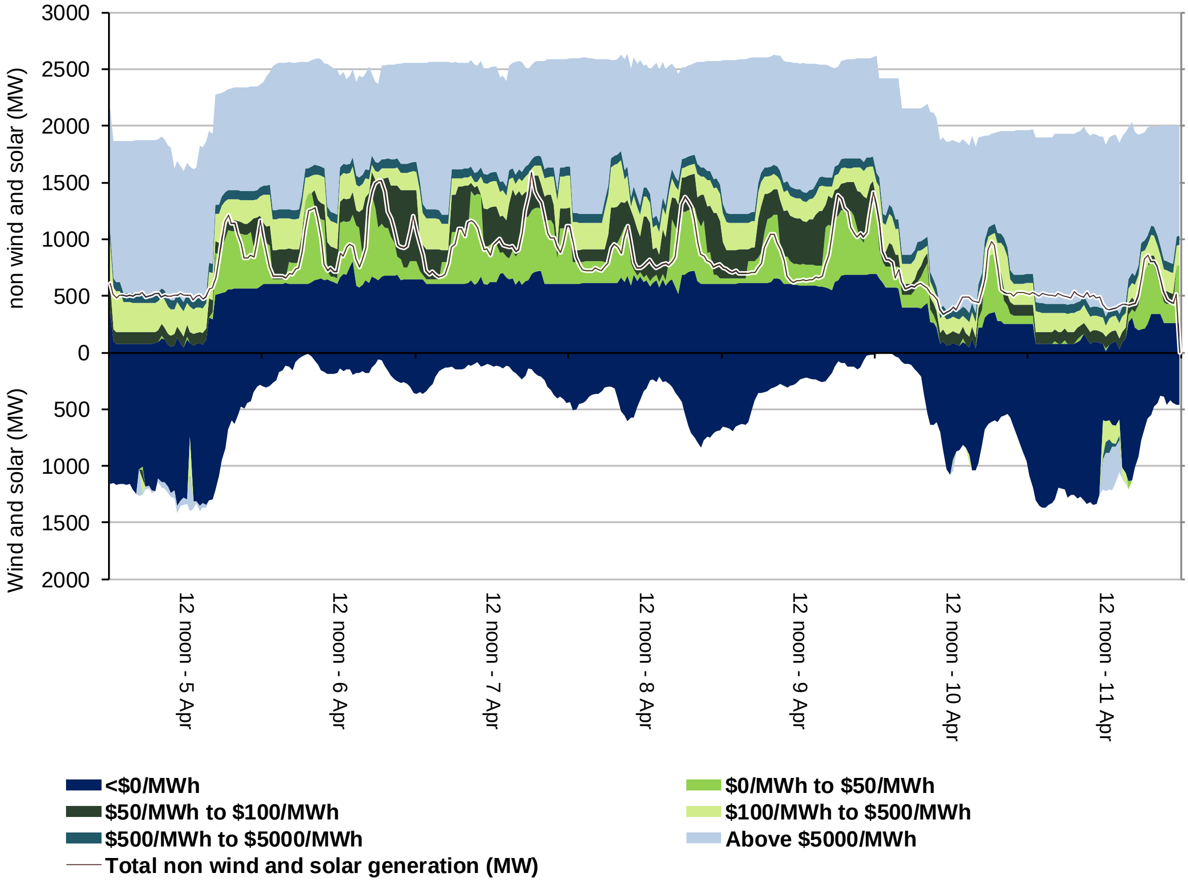
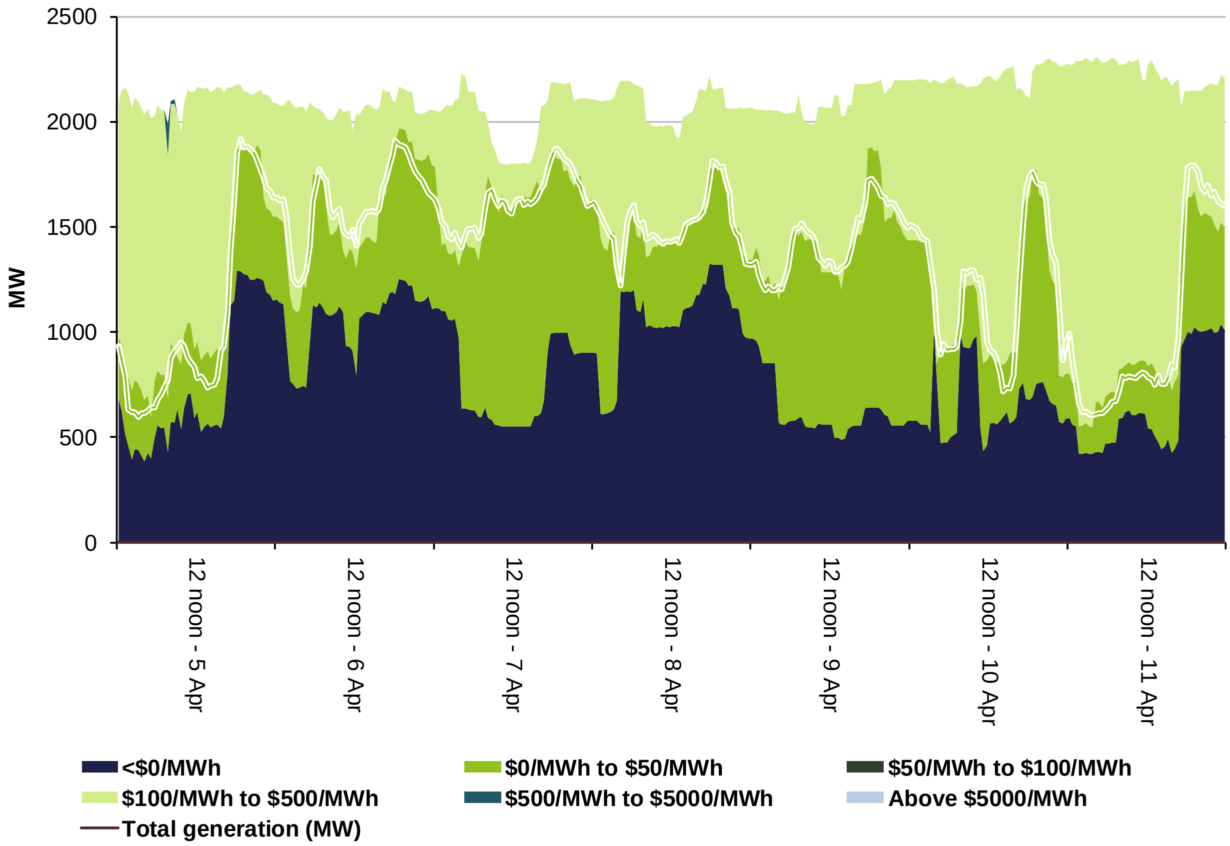


Figure 7: Tasmania generation and bidding patterns



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.

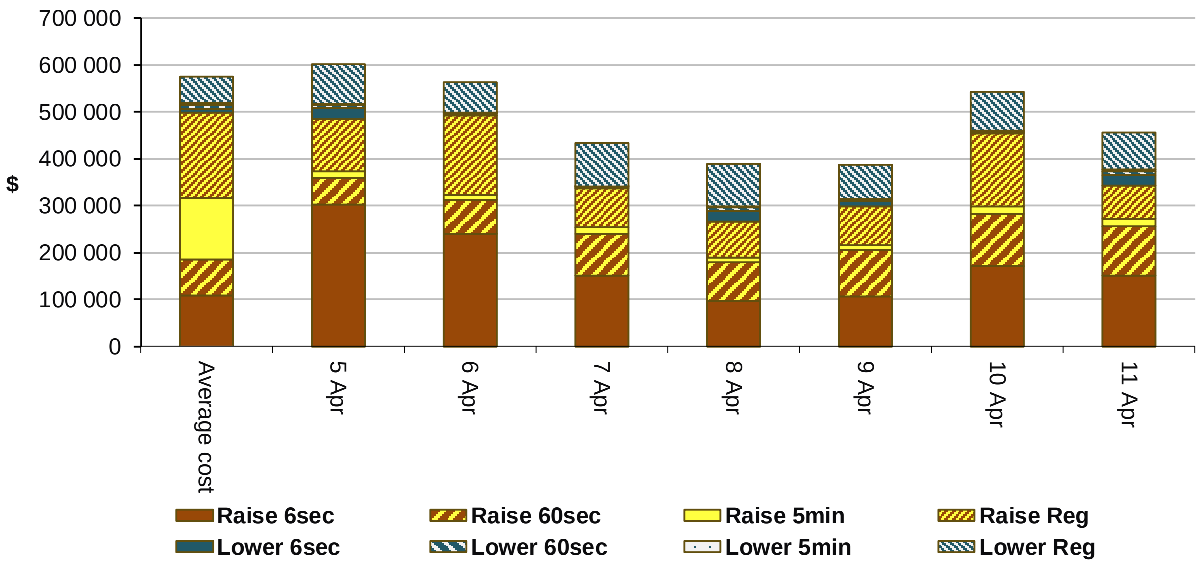
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 813 000 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $562 000 or around 8 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 was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $43/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Monday, 6 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
6.30 pm	256.77	62.32	85.76	23 832	23 541	23 640	30 895	31 597	31 412

Prices were aligned across the mainland and will be treated as one region, though Queensland did not breach our reporting thresholds. Demand was collectively 291 MW higher than forecast and availability was collectively 702 MW lower than forecast. Lower availability was mainly due to removal of capacity from generators in New South Wales and South Australia due to technical reasons:

- 245 MW from Bayswater priced at the floor;
- 130 MW from Eraring half priced at the floor and half at the cap;
- 80 MW from Uranquinty priced at the floor and 82 MW priced at the cap; and
- 123 MW from Quarantine priced below $59/MWh.

At 6.10 pm, demand increased across the mainland by around 300 MW causing the dispatch price to be set at around $295/MWh. At 6.08 pm and effective 6.15 pm, Snowy Hydro rebid 205 MW at Murray from prices below $81/MWh to $300/MWh in response to a higher than forecast price in Victoria at 6.10 pm. With a number of generators in New South Wales and Victoria trapped/stranded in FCAS or ramp constrained and unable to set price, the dispatch price was set just under $300/MWh for the remainder of the trading interval.

South Australia

There was one occasion 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 (covered in the mainland section) and there were eight occasions where the spot price was below -$100/MWh.

Sunday, 5 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
1 pm	-147.49	-50.53	-157.81	708	775	772	3033	2884	2854

Demand was 67 MW less than forecast, while availability was 149 MW higher than forecast, four hours prior. Higher availability was due to higher than forecast wind generation, most of which was priced below $0/MWh.

There was no capacity offered between -$40/MWh and the price floor, so small fluctuations in demand and availability could cause large changes in price. At 12.45 pm, demand fell by 67 MW and resulted in the dispatch price falling to the floor for one dispatch interval, before participants rebid over 1000 MW of capacity from the floor to prices above $249/MWh.

Friday, 10 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
Midday	-156.74	0.01	0.00	617	565	607	2952	2589	2630

Demand was 52 MW higher than forecast and availability was 363 MW higher than forecast. Higher availability was due to higher than forecast wind generation, most of which was priced below $0/MWh.

There was little capacity offered between $68/MWh and the price floor so small fluctuations in demand or availability could cause large changes in price. At 12 pm demand dropped by 43 MW, and with higher priced generation ramp constrained and unable to set price the price was set at the floor for one dispatch interval.

Saturday, 11 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
Midday	-166.67	-1000.00	-1000.00	655	502	491	3120	3045	3088
12.30 pm	-150.52	-1000.00	-1000.00	611	493	485	3127	3036	3062
1 pm	-167.70	-1000.00	-1000.00	564	476	461	3118	3064	3046
1.30 pm	-166.25	-998.19	-1000.00	541	466	456	3122	3075	3063
2 pm	-135.50	-994.96	-1000.00	516	484	472	3049	3065	3074
2.30 pm	-143.20	-1000.00	-1000.00	504	491	491	2956	3074	3075

For the above trading intervals, demand was between 13 MW to 153 MW higher than forecast while availability was between 118 MW lower to 91 MW higher than forecast, four hours prior. Changes in availability were due to fluctuations in wind generation, about half of which was priced below $0/MWh.

The price dropped to below -$900/MWh (as forecast) once during each trading interval. In response to the drop in price, generators rebid between 600 MW to 850 MW of capacity priced at the floor to prices above $71/MWh.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $36/MWh and above $250/MWh.

Sunday, 5 April

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
8 am	427.40	36.74	44.82	1189	1087	1118	2038	2033	2073

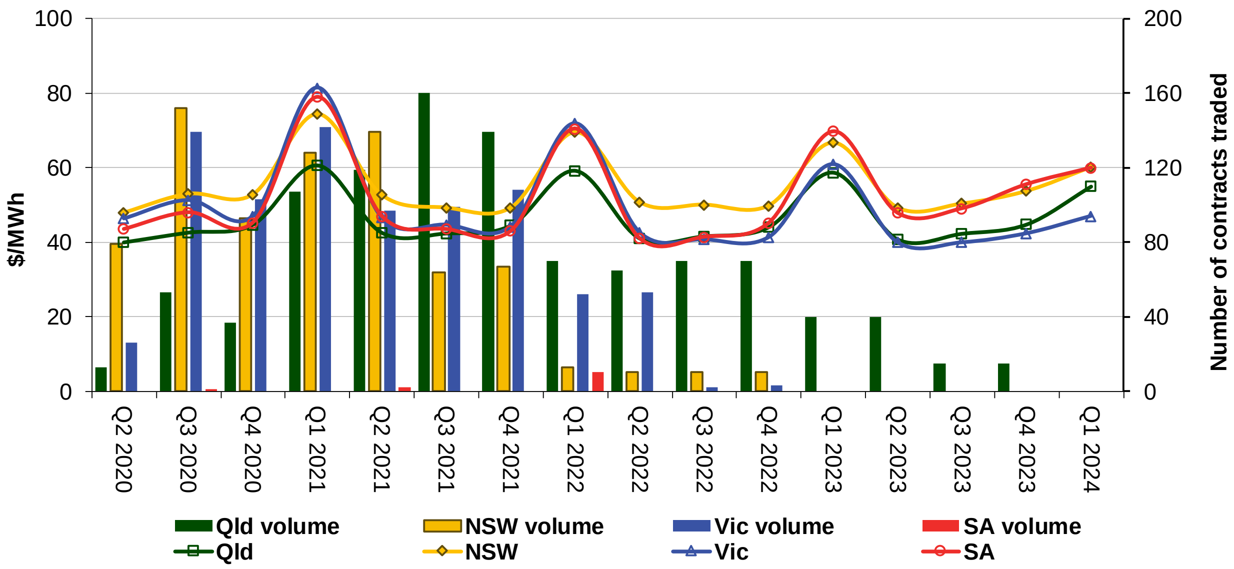
Demand was 102 MW higher than forecast while availability was close to forecast, four hours prior.

At 7.19 am, Hydro Tasmania shifted 83 MW from prices below $140/MWh to $402/MWh. With no capacity offered between $44/MWh and $402/MWh the dispatch price was set between $402/MWh to $551/MWh for the whole 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.

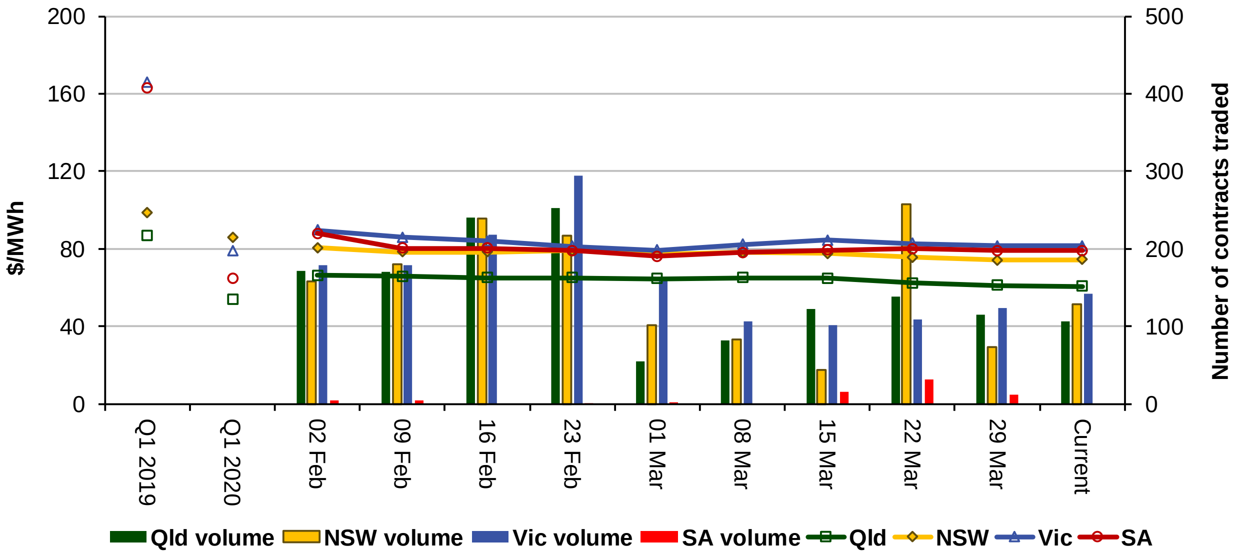
Figure 9: Quarterly base future prices Q2 2020 – Q1 2024



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)

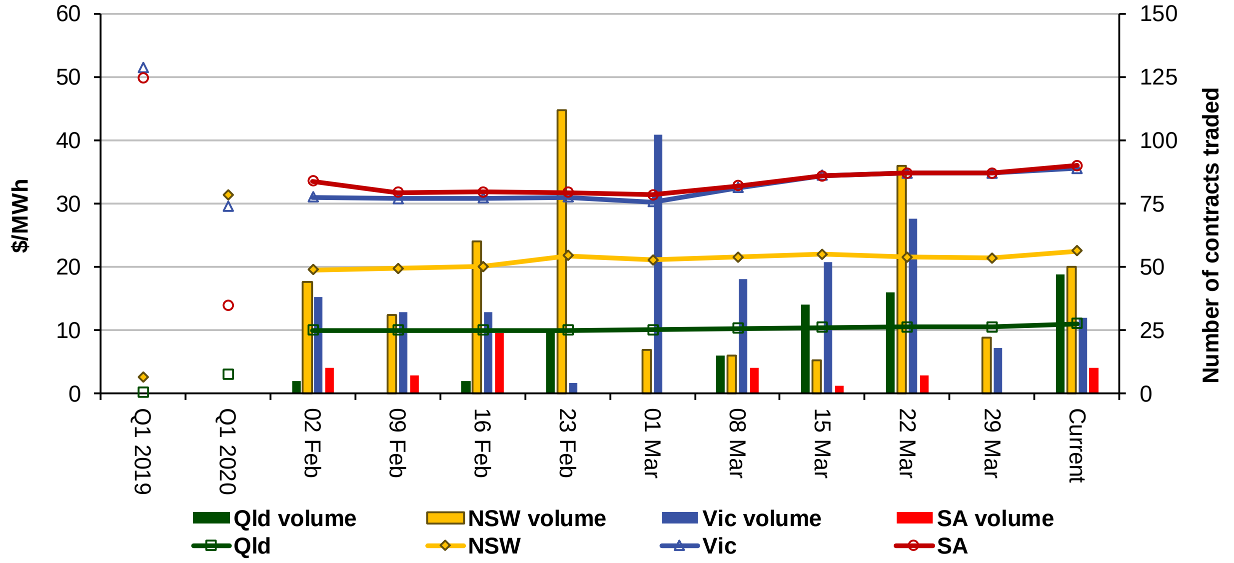


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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