Electricity Report

AUSTRALIAN ENERGY REGULATOR

9 – 15 February 2020

Weekly Summary

Average prices for the week ranged from $30/MWh in Tasmania up to $133/MWh in South Australia. Higher weekly average prices in South Australia were driven by three instances where the spot price exceeded $1000/MWh.

South Australia remained separated from the rest of the NEM following six 500 kV transmission towers in south western Victoria being blown over on 31 January. Due to the separation of South Australia from the rest of the NEM, there were some instances of local FCAS prices above $5000/MW in South Australia.

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 9 to 15 February 2020.

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

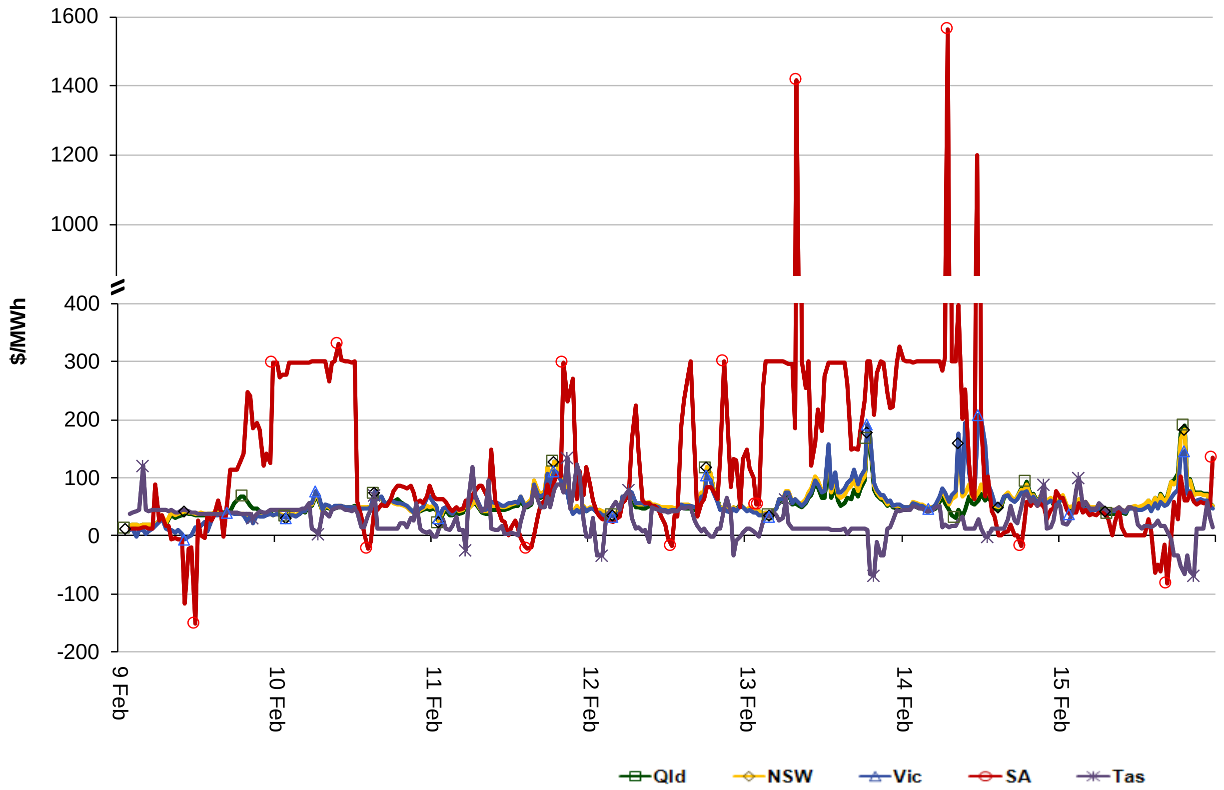


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

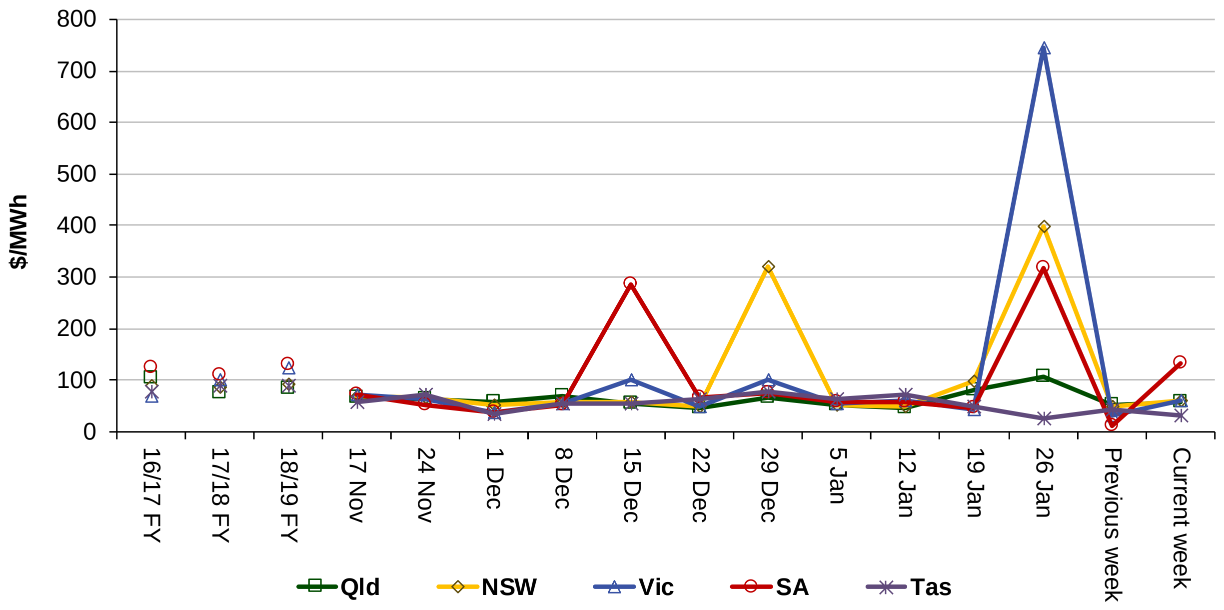


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	56	59	59	133	30
18-19 financial YTD	85	96	129	138	78
19-20 financial YTD	65	98	108	89	68

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 293 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	20	22	0	1
% of total below forecast	6	46	0	6

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

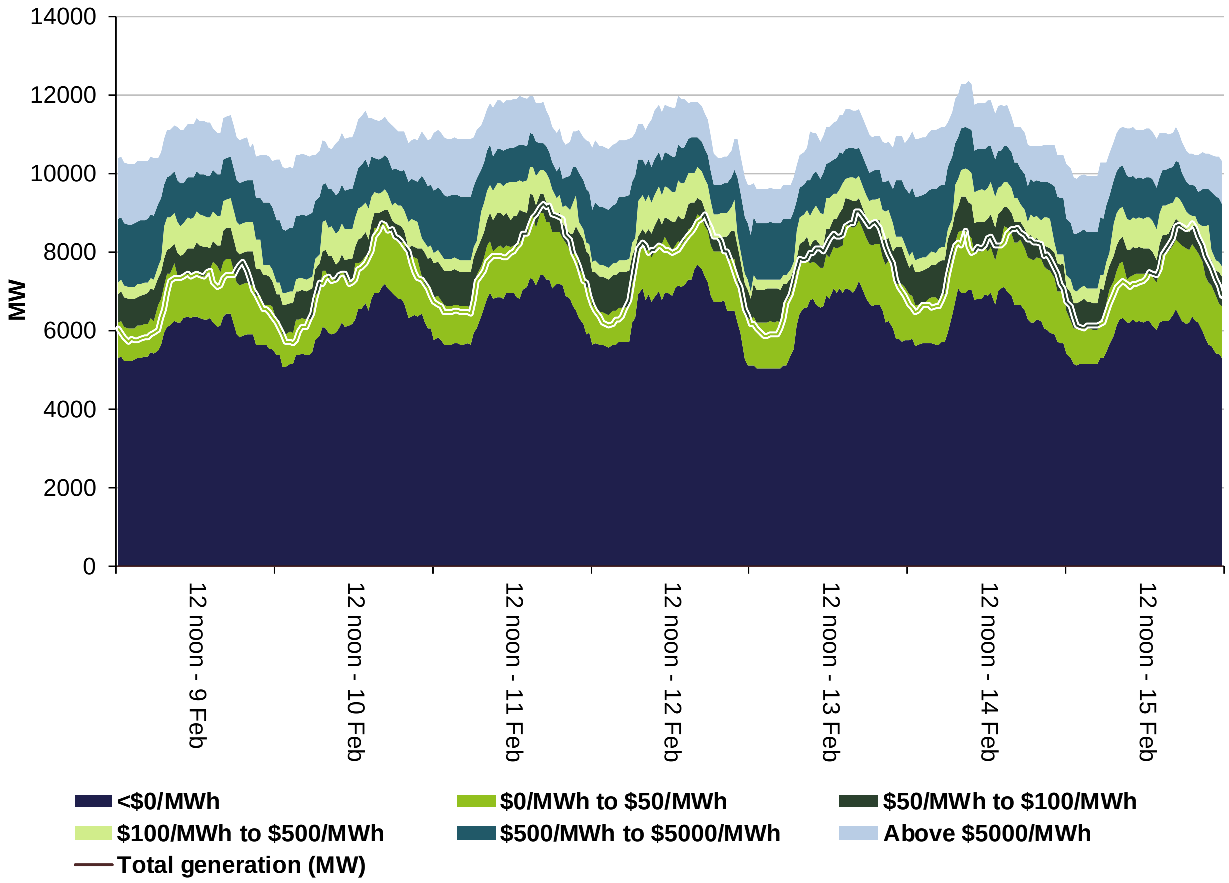


Figure 4: New South Wales generation and bidding patterns

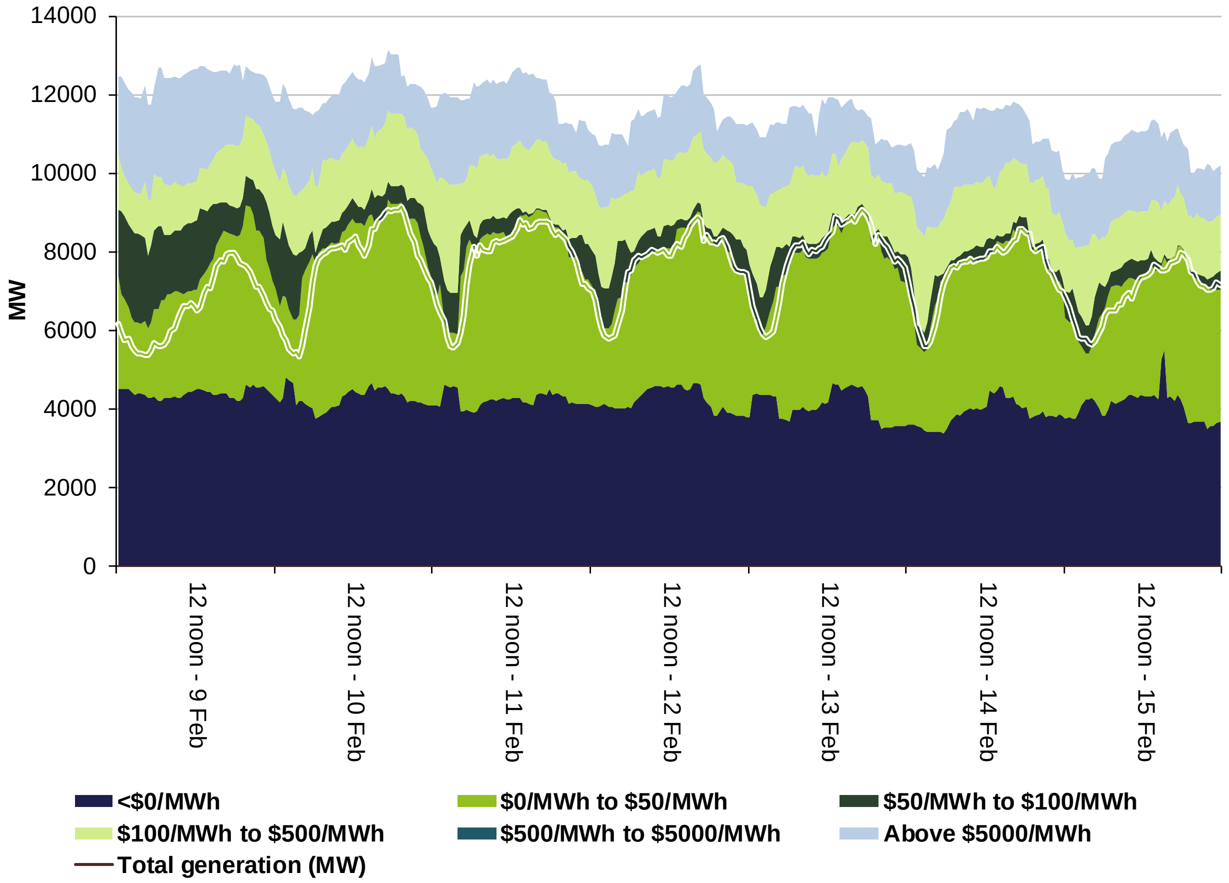


Figure 5: Victoria generation and bidding patterns

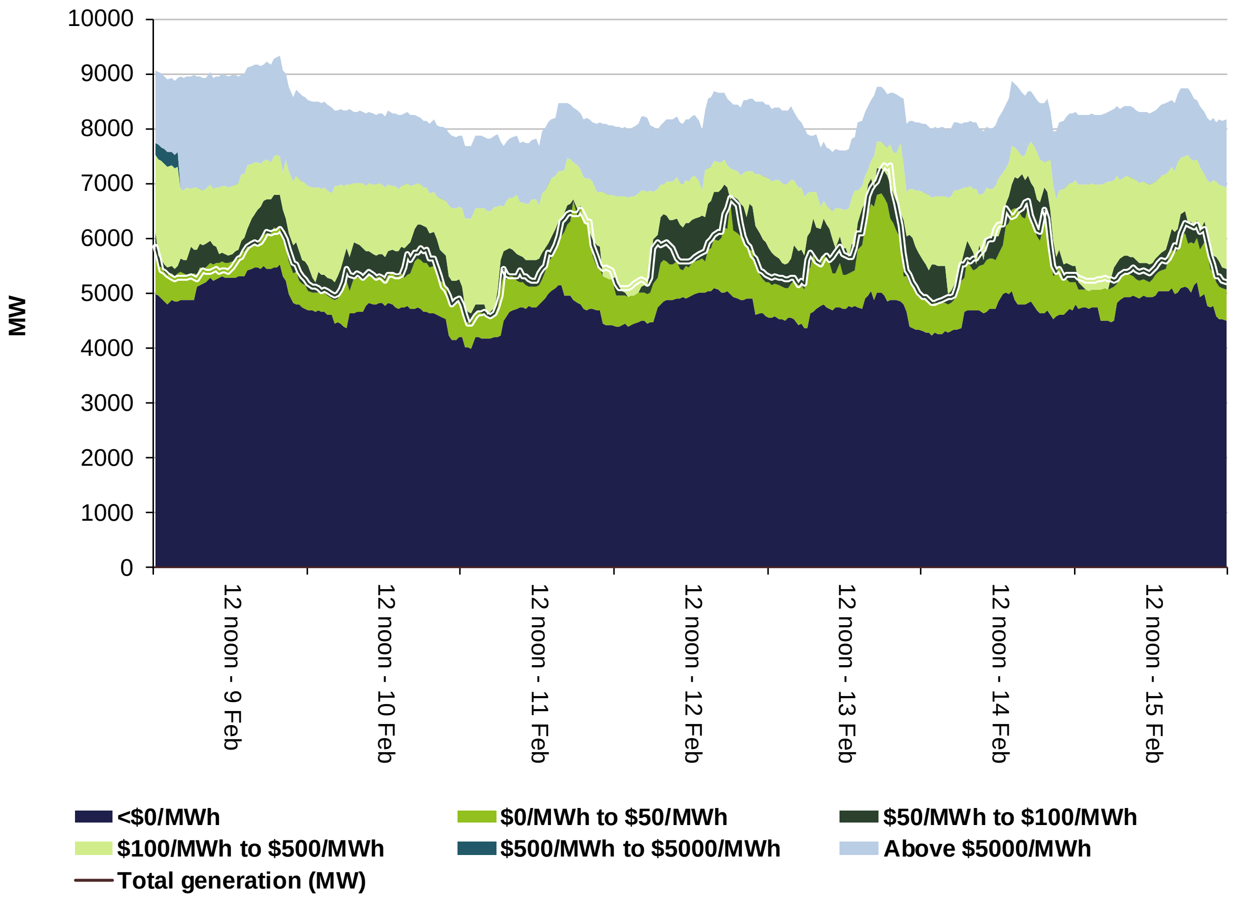


Figure 6: South Australia generation and bidding patterns

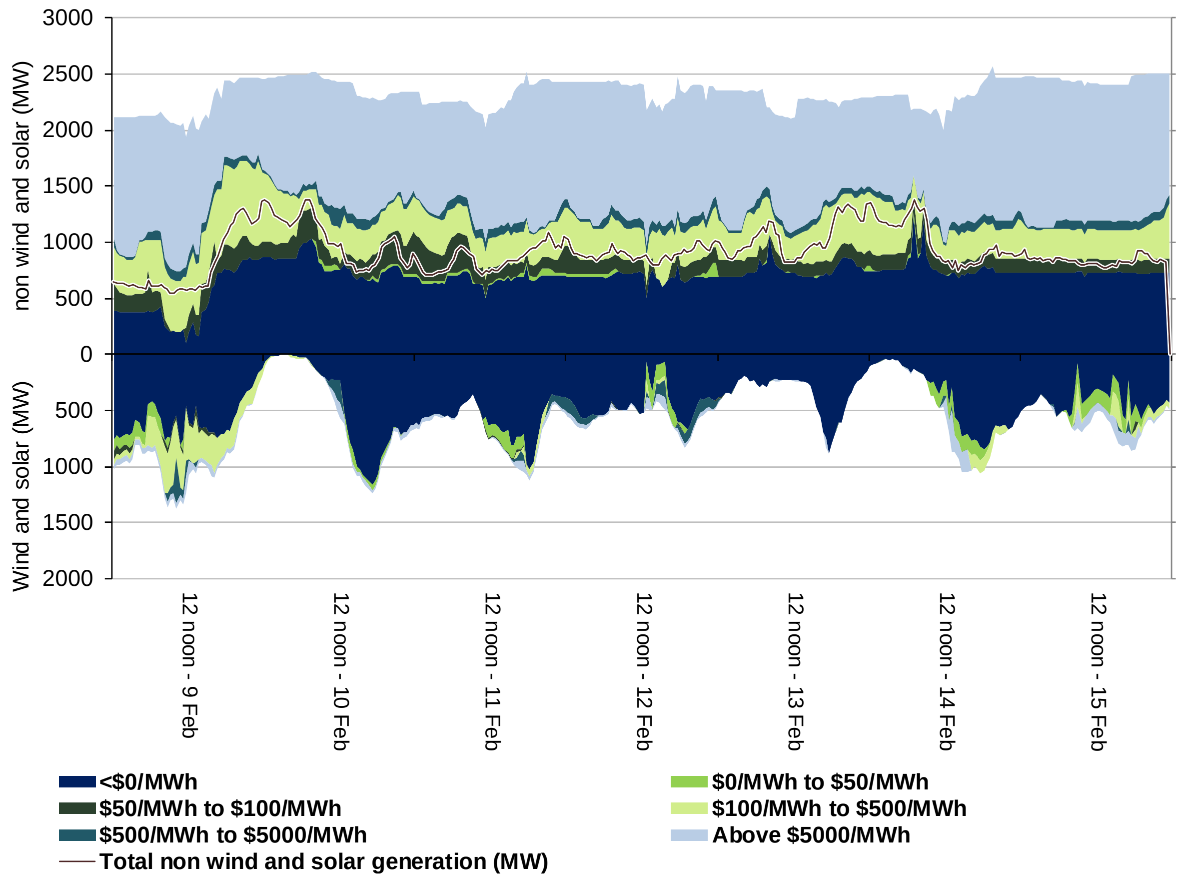
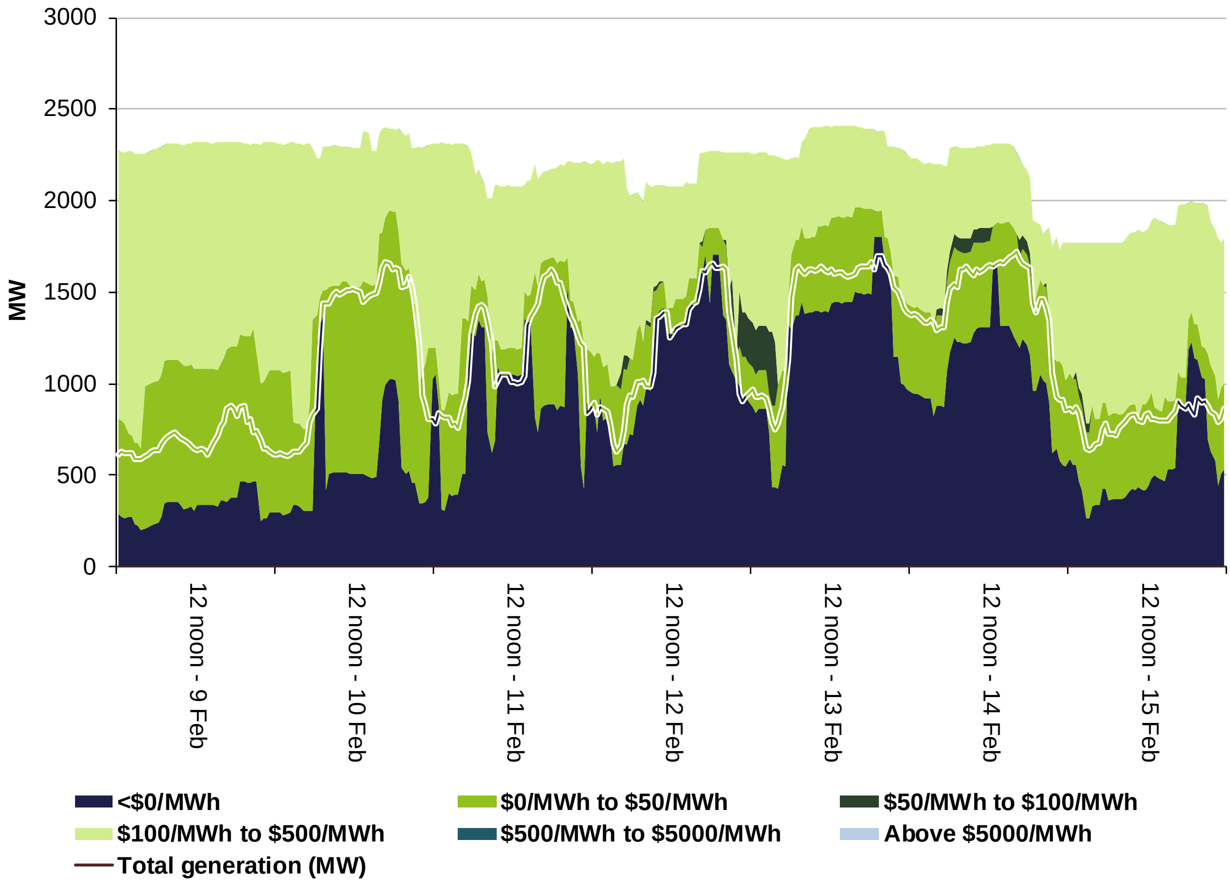


Figure 7: Tasmania generation and bidding patterns



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.

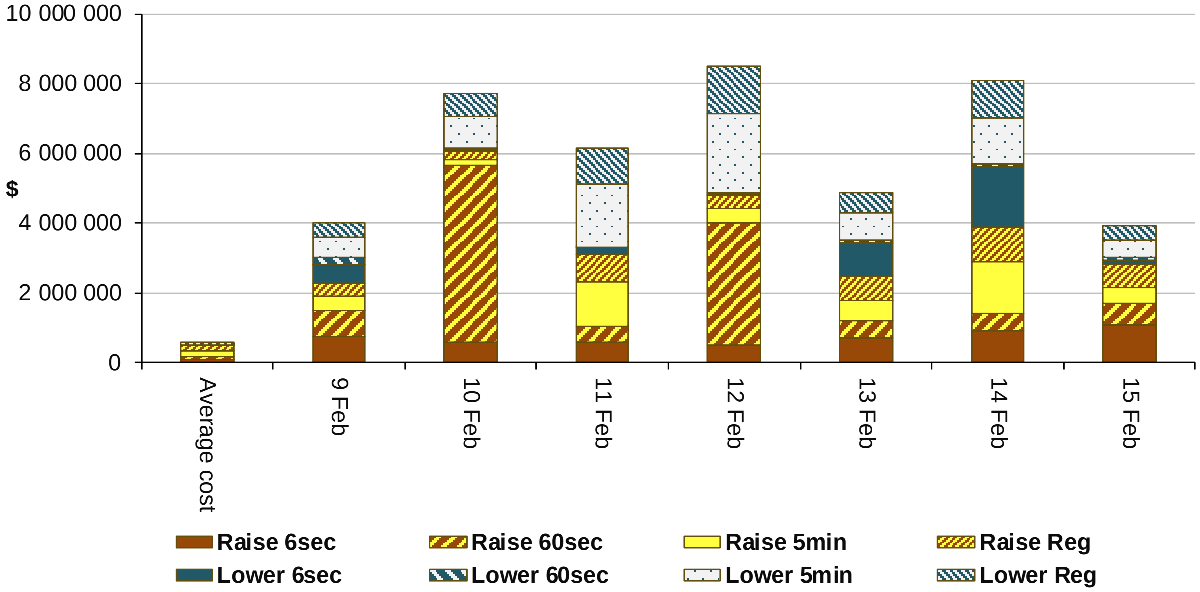
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $42 173 500 or less than 19 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 134 500 or less than 22 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



Most of the high FCAS costs occurred in South Australia due to its continued separation from the rest of the NEM on 31 January. South Australia was required to provide its own FCAS services locally which led to high FCAS prices.

The administrative price cap on FCAS (applied since 1 February) was lifted on 10 February. On both 10 and 12 February, prices for FCAS exceeded $5000/MW for a number of trading intervals across local services in South Australia. Detailed analysis of these days will be covered in our *FCAS prices above $5000/MW report*.

High total FCAS costs in Tasmania were related to Tasmania being required to supply more FCAS for mainland requirements due to the separation of South Australia from the eastern states.

Detailed market analysis of significant price events

South Australia

There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $133/MWh and above $250/MWh and there were two occasions where the spot price was below -$100/MWh.

For all trading intervals in this section, the Heywood interconnector was offline causing South Australia to be isolated from the rest of the NEM. As a result, South Australia was required to source its own FCAS.

Sunday, 9 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
10.30 am	-117.73	-1000.00	-1000.00	1030	979	959	3418	3060	3054
Midday	-152.04	-559.25	-1000.00	943	1066	1036	3272	3054	3024

For the 10.30 am and midday trading intervals respectively, demand was 51 MW higher and 123 MW lower than forecast and availability was 358 MW and 218 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast renewable generation mainly priced below $0/MWh.

In response to the dispatch price falling to the floor in the middle of both trading intervals, participants rebid up to 470 MW of capacity into higher prices and the dispatch price increased to around $30/MWh for the remainder of each trading interval.

Thursday, 13 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
8.30 am	1417.20	301.00	301.00	1409	1393	1370	2398	2384	2455

Demand and availability were close to forecast, both four hours prior. At 8.15 am, a number of local FCAS constraints became binding and resulted in co-optimisation between the FCAS and energy markets. This resulted in the dispatch price increasing to $7000/MWh for one dispatch interval.

Friday, 14 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
7.30 am	1563.50	329.14	321.39	1604	1550	1569	2304	2460	2603
Midday	1200.67	301.00	84.41	1243	1127	1114	2410	2458	2487

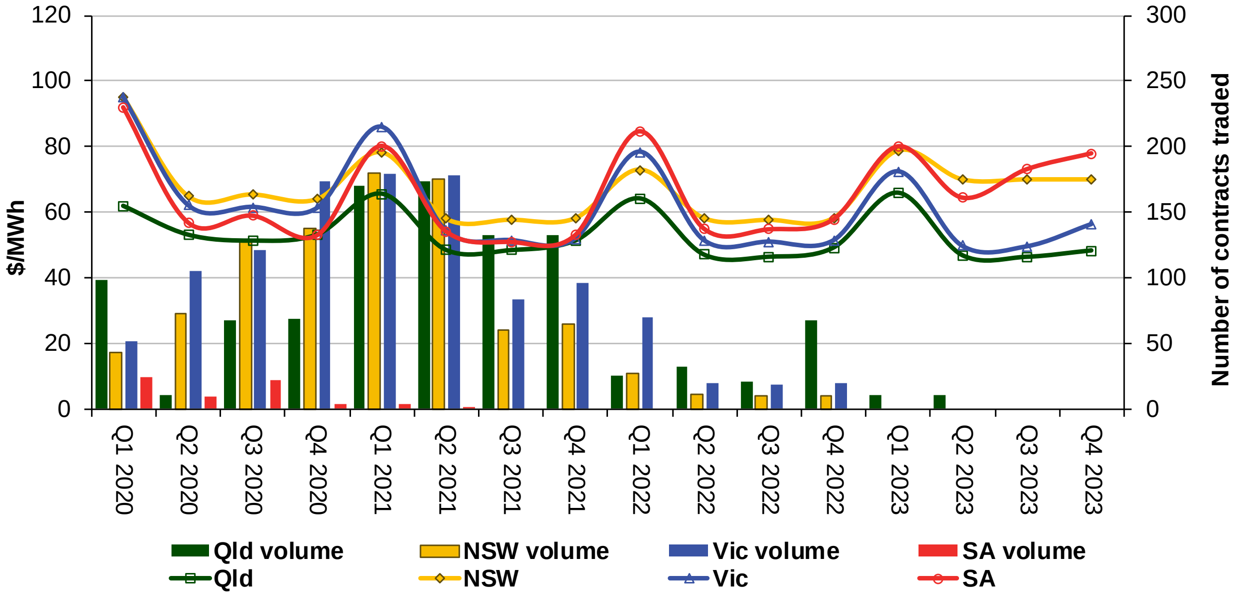
For the 7.30 am trading interval, demand was close to forecast and availability was 156 MW lower than forecast. Lower availability was due to AGL removing 140 MW of capacity at Barker Inlet power station which was priced at the market price cap. At 7.15 am, a number of local FCAS constraints became binding and resulted in co-optimisation between the FCAS and energy markets. This resulted in a dispatch price increasing to $7000/MWh for one dispatch interval.

For the midday trading interval, demand was 116 MW higher than forecast and availability was 48 MW lower than forecast. In the four hours before the trading interval, around 580 MW of capacity was rebid from prices below $30/MWh to more than $3000/MWh. During the trading interval, Neoen rebid 313 MW of capacity at Hornsdale wind farm from less than $30/MWh to the market price cap. A majority of these rebids reasons related to higher than forecast or actual FCAS prices. With little capacity priced between $300/MWh and $3000/MWh, the dispatch price increased to $3000/MWh for two dispatch 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.

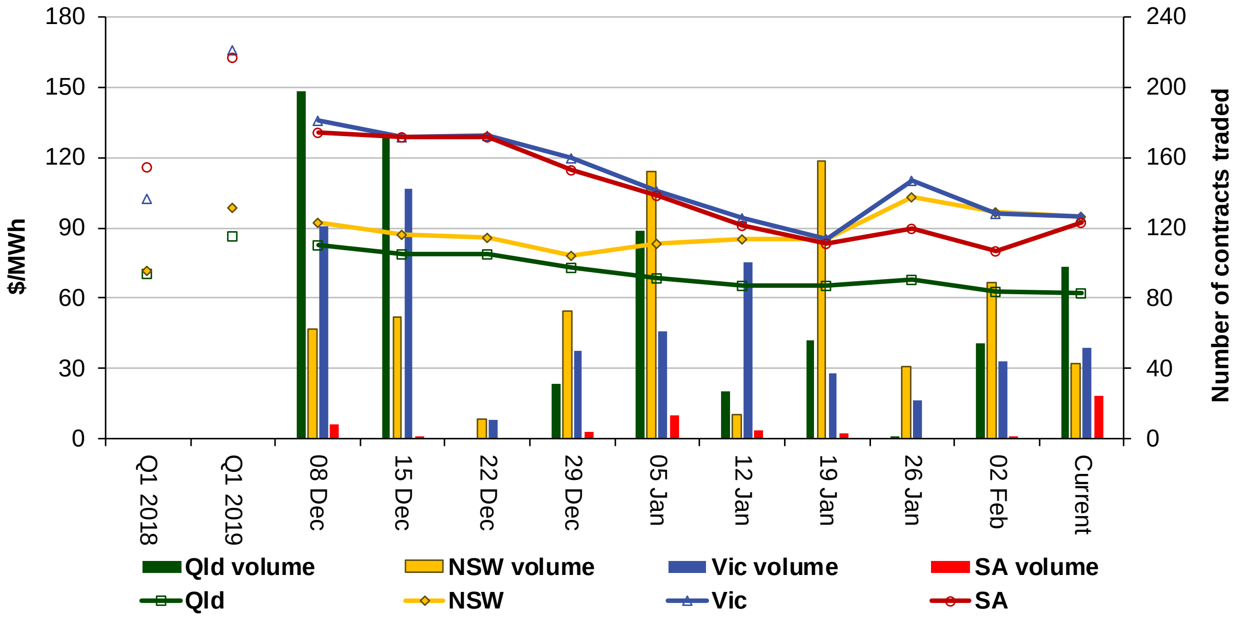
Figure 9: Quarterly base future prices Q1 2020 – Q4 2023



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)

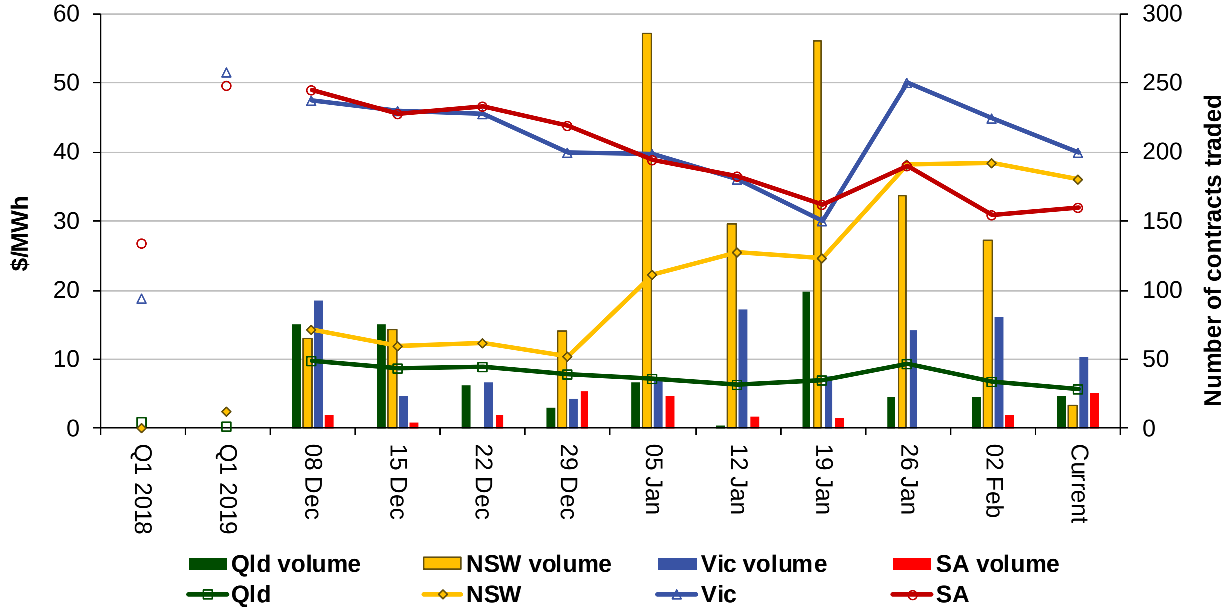


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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