02 – 08 February 2020

Weekly Summary

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 a high count of negative spot prices in South Australia and high local Frequency Control Ancillary Services (FCAS) costs.

On 1 February, the cumulative price threshold for FCAS was breached due to high local prices for FCAS in South Australia. AEMO declared that an administered price period would commence and prices of FCAS were capped at $300/MWh.

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 2 to 8 February 2020.

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

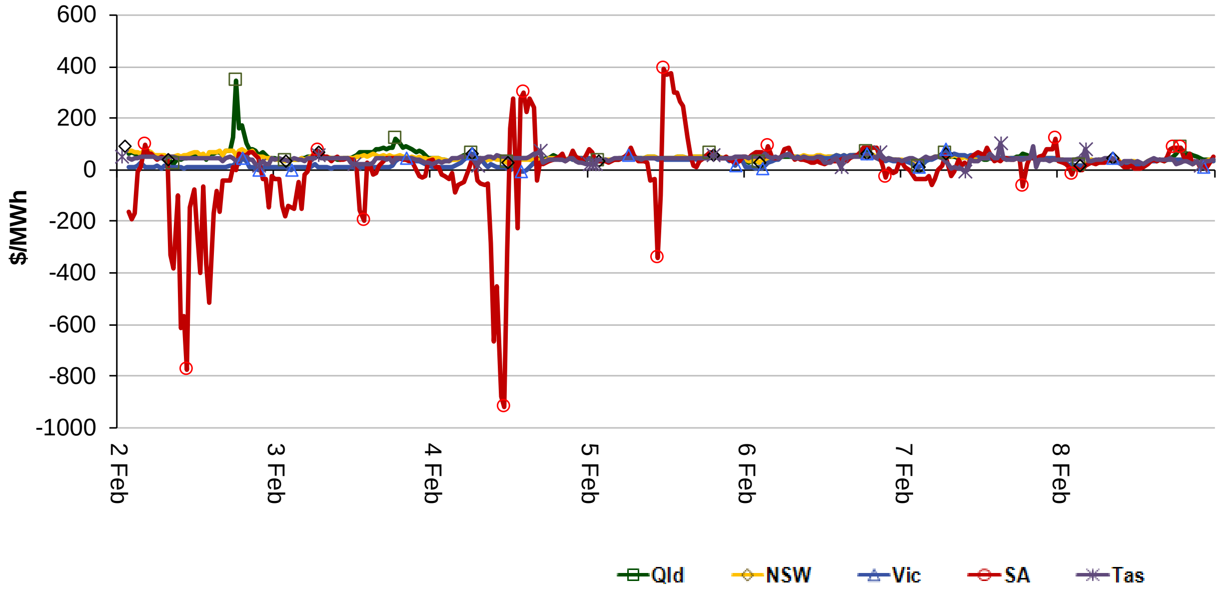


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

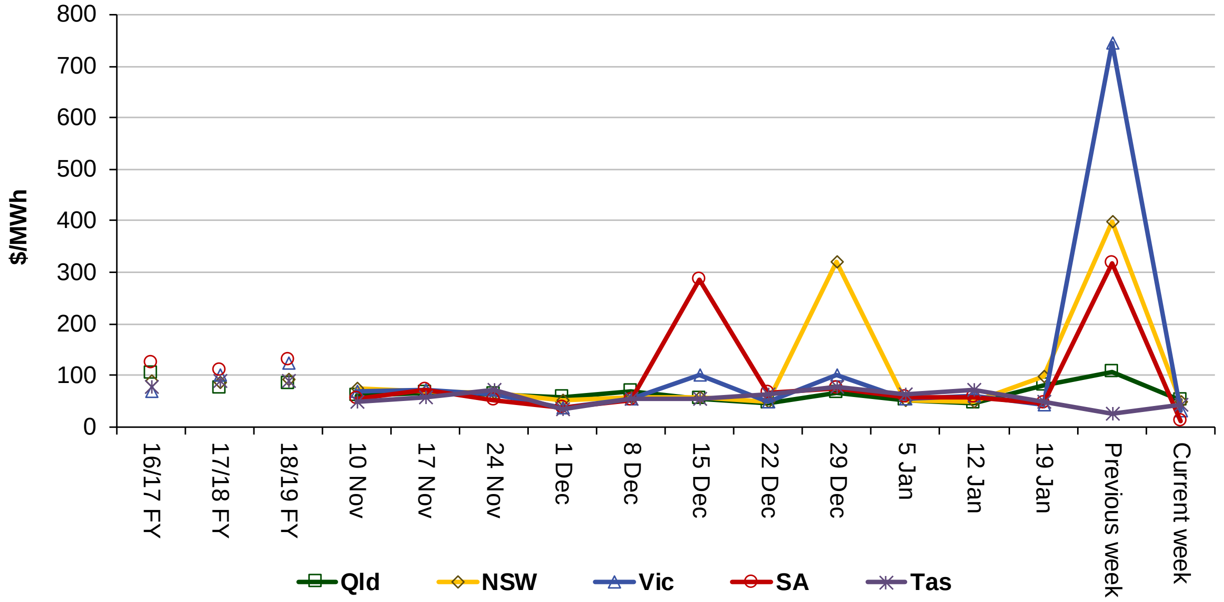


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	51	47	31	10	42
18-19 financial YTD	85	96	130	139	77
19-20 financial YTD	66	99	109	87	70

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 282 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	14	14	0	2
% of total below forecast	4	59	0	7

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

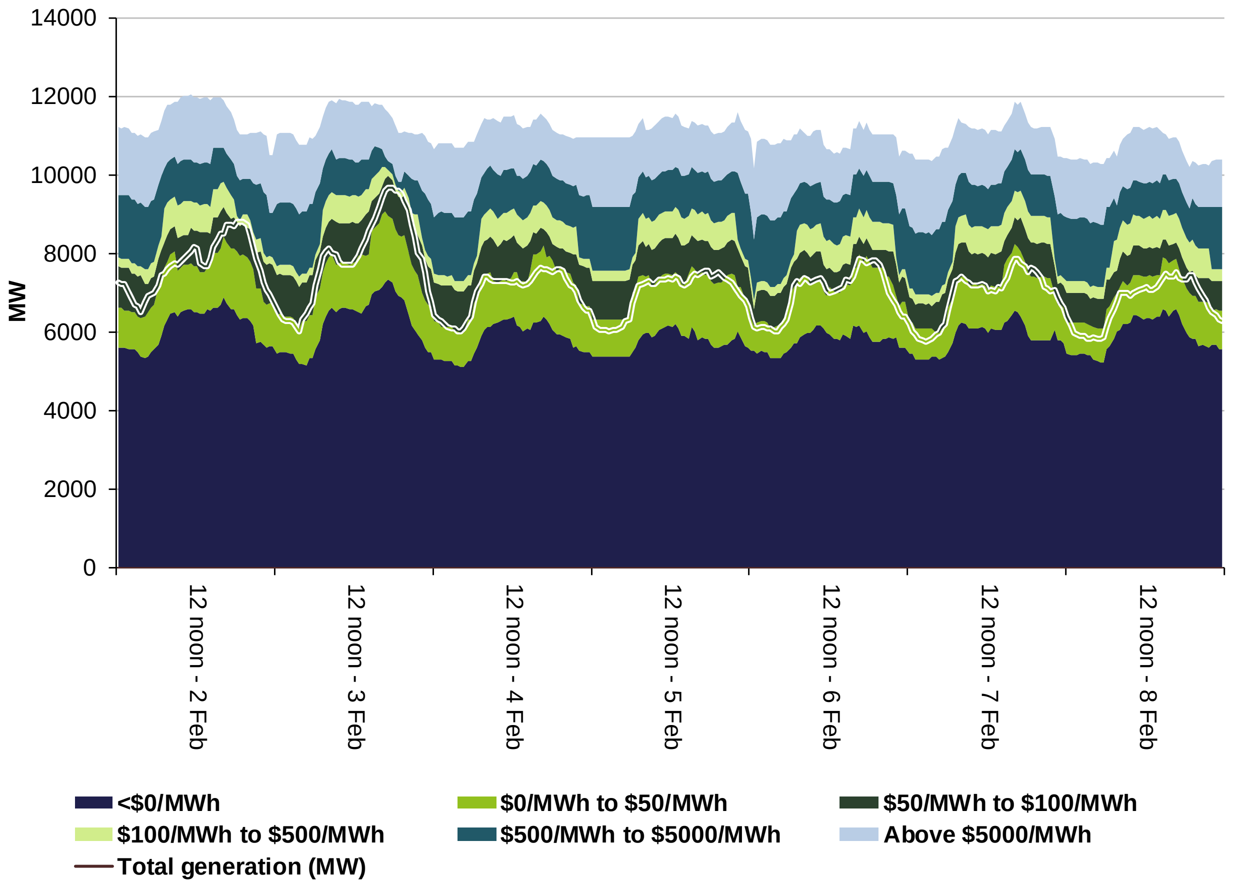


Figure 4: New South Wales generation and bidding patterns

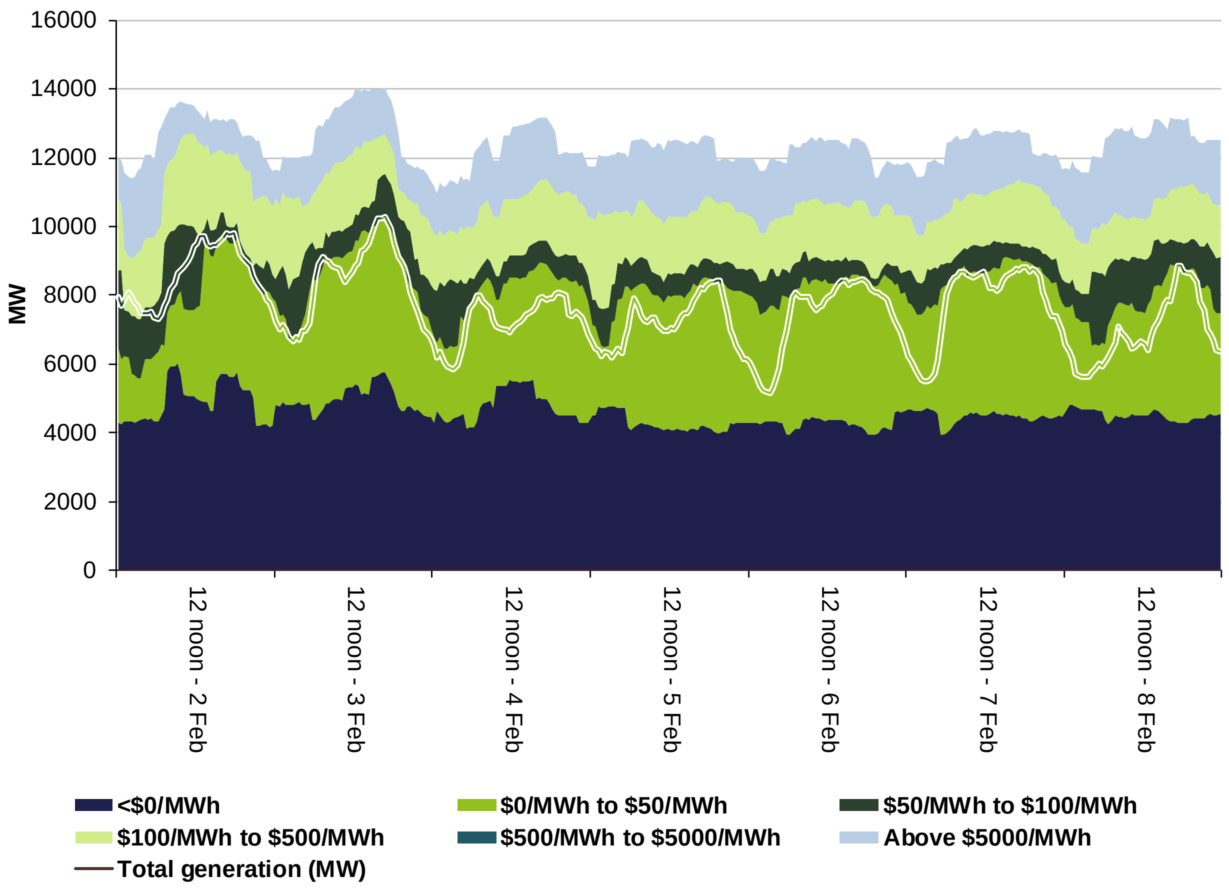


Figure 5: Victoria generation and bidding patterns

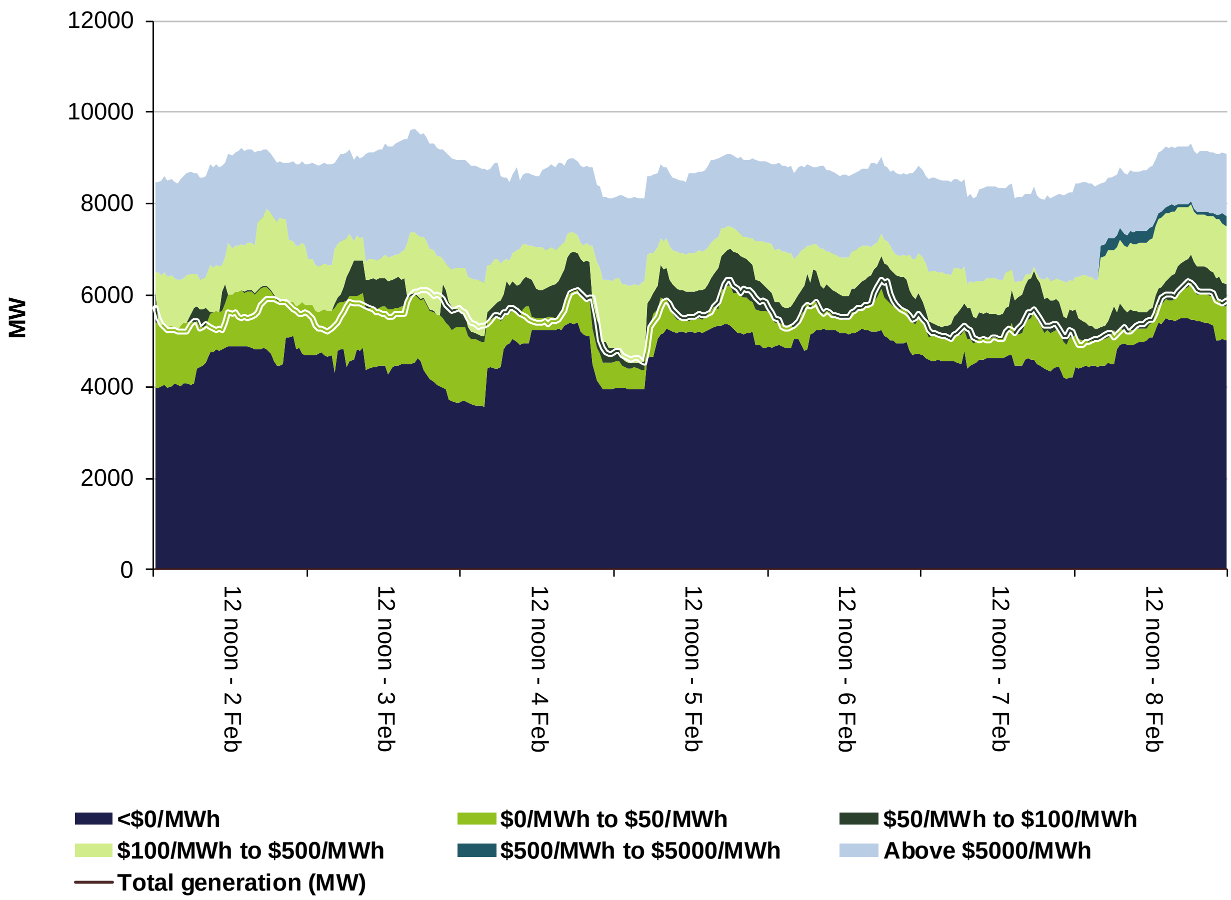


Figure 6: South Australia generation and bidding patterns

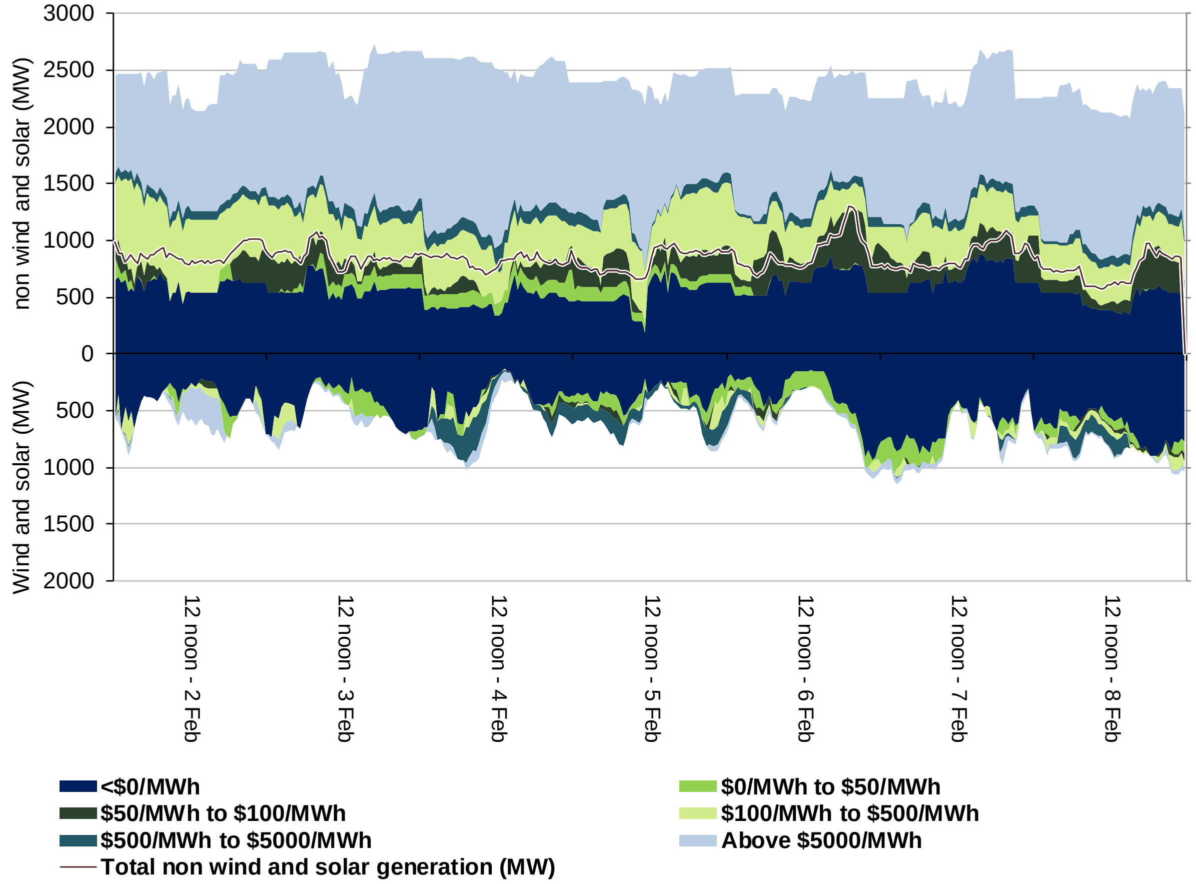
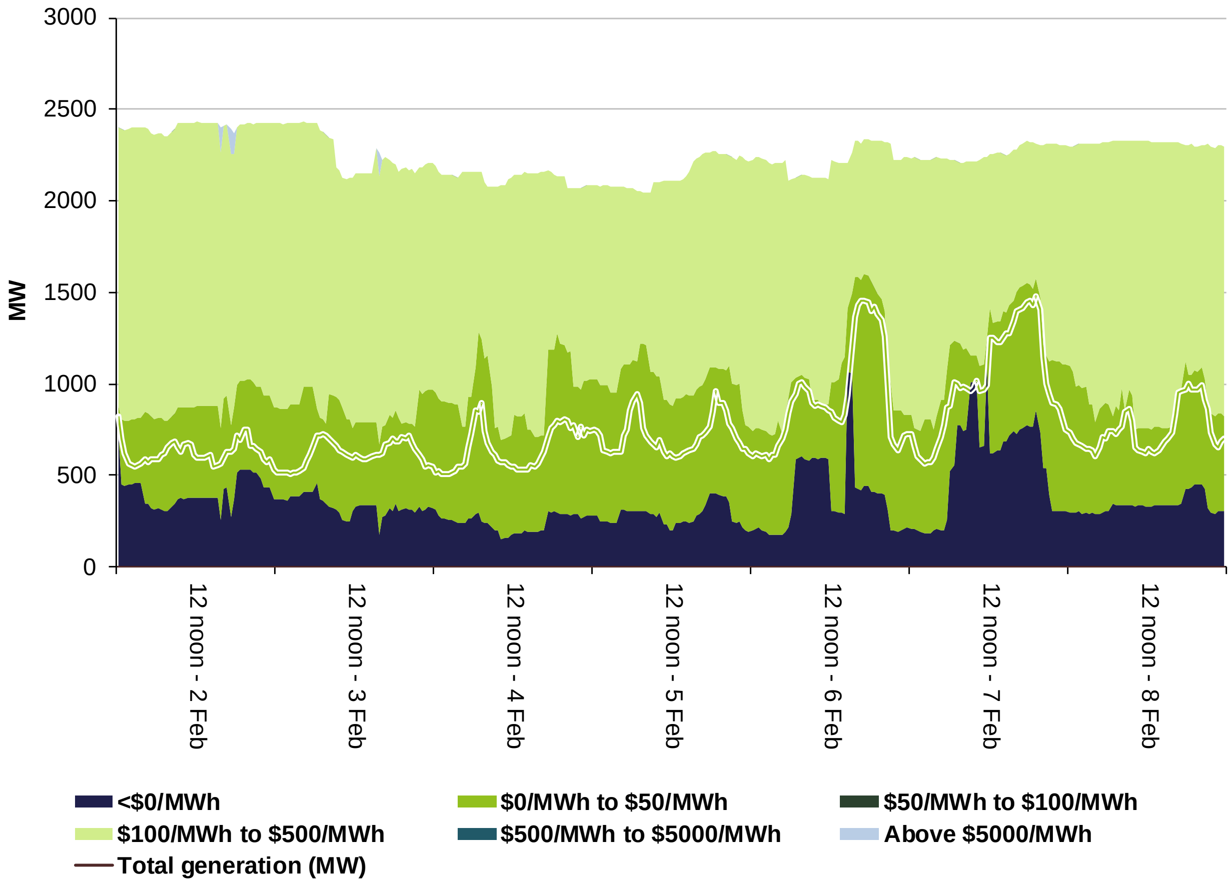


Figure 7: Tasmania generation and bidding patterns



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.

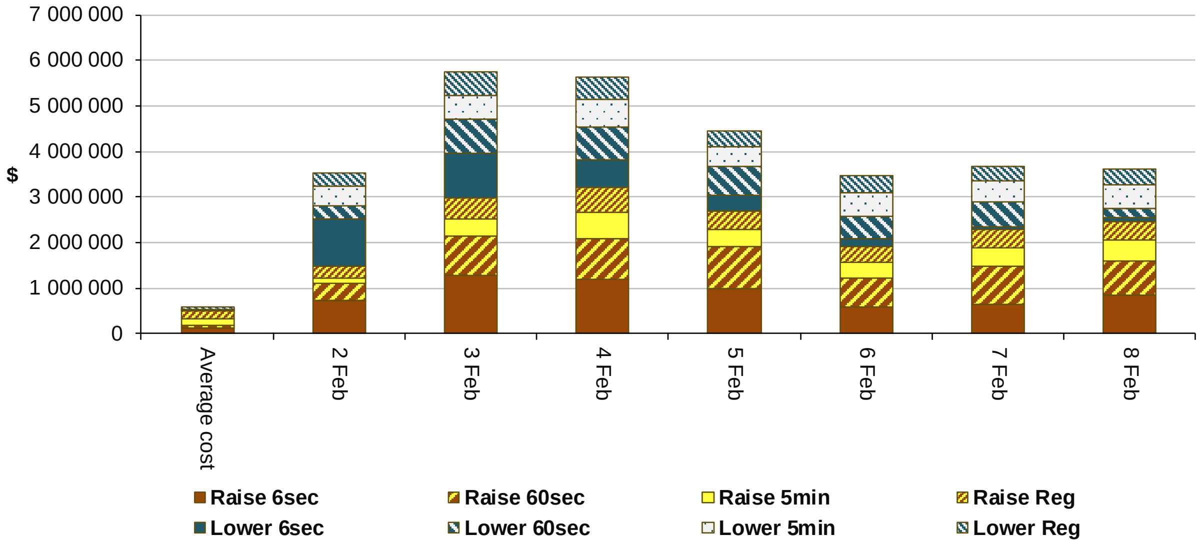
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $29 200 000 or less than 20 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $949 000 or around less than 14 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 separation from the rest of the NEM on 31 January. South Australia was required to provide its own FCAS services locally which lead to high FCAS prices.

On 1 February the rolling sum of uncapped market ancillary raise 6 sec service prices exceeded 6 times the cumulative price threshold of $221 100. As a result, AEMO declared that an administered price period would commence in South Australia, resulting in an administered price floor of $0/MWh and an administered price cap of $300/MWh for local FCAS services.

For the week 2 February to 8 February, local FCAS services in South Australia reached the administered price cap for 88 per cent of the week. Detailed analysis of these days will be covered in our *FCAS prices above $5000/MW report*.

Detailed market analysis of significant price events

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $51/MWh and above $250/MWh.

Sunday, 2 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
6.30 pm	348.38	151.90	151.50	8824	8549	8582	11 173	11 109	11 175

Demand was 275 MW higher than forecast and availability was 64 MW higher than forecast, four hours prior.

At 6.20 pm demand increased by 100 MW. With generators either trapped/stranded in FCAS or shut down/off, the dispatch price reached around $1494/MWh for one dispatch interval.

South Australia

There were ten occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $10/MWh and above $250/MWh and there were thirty-four occasions where the spot price was below -$100/MWh.

Sunday, 2 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
1 am	-131.50	101.72	-1000.00	1230	1318	1279	3076	2913	3133
2 am	-161.56	70.50	56.74	1137	1181	1169	3256	2854	2593
2.30 am	-192.06	80.92	54.12	1120	1146	1141	3363	2841	2556
3 am	-171.59	64.21	56.90	1122	1129	1127	3288	2832	2534
8.30 am	-332.92	-1000.00	-1000.00	886	983	935	2837	2844	2756
9 am	-383.33	-1000.00	-1000.00	838	927	885	2732	2625	2885
9.30 am	-100.14	-1000.00	-1000.00	810	853	815	2776	2879	2941

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 am	-612.43	-1000.00	-1000.00	777	769	750	2865	2935	2807
10.30 am	-566.42	-1000.00	-1000.00	773	723	724	2922	2951	2780
11 am	-773.31	-1000.00	-1000.00	749	691	677	2766	2956	2541
11.30 am	-144.59	-1000.00	-1000.00	827	671	655	2808	2955	2549
12.30 pm	-250.00	-1000.00	-1000.00	806	624	607	2733	2939	2742
1 pm	-400.00	-1000.00	-1000.00	796	626	600	2806	2949	2746
2 pm	-365.64	-1000.00	-1000.00	720	625	654	2703	2980	2875
2.30 pm	-517.51	-1000.00	-1000.00	718	640	653	2760	2983	2888
3 pm	-171.82	-1000.00	-1000.00	726	685	676	2788	2987	2905
4 pm	-163.69	-1000.00	-1000.00	793	816	787	2919	3023	2924
11.30 pm	-145.95	38.72	44.35	1147	1179	1209	3111	3019	2756

For the 1 am, 2 am, 2.30 pm and 3 pm trading intervals, demand was between 7 MW and 88 MW less than forecast and availability was between 163 MW and 522 MW higher than forecast, four hours prior. The increase in availability was largely due to wind generation being between 166 MW and 220 MW higher than forecast, four hours prior. Most of this capacity was negatively priced and resulted in lower than forecast prices.

For the trading intervals between 8.30 am and 4 pm the spot price was forecast to be at the price floor four hours ahead. The dispatch price fell to or close to the price floor early in the trading interval, then in response participants rebid capacity into higher prices and the dispatch price generally increased to around -$100/MWh for the remainder of the trading interval.

For the 11.30 pm trading interval, demand was 32 MW less than forecast, and availability was 92 MW higher than forecast, four hours prior. During the 11.10 pm dispatch interval the spot price fell to the floor, largely driven by an increase in wind generation which was price at the floor.

Monday, 3 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
1.30 am	-140.81	46.98	87	1210	1222	1274	3389	2898	2553
2 am	-178.95	41.17	131.73	1171	1173	1234	3448	2900	2556
2.30 am	-141.44	42.66	62.72	1153	1154	1211	3382	2943	2566

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	-147.68	40.94	62.72	1124	1150	1207	3363	2952	2577
3.30 am	-149.69	42.08	47.61	1119	1143	1194	3342	2953	2587
4.30 am	-148.94	40.64	42.35	1119	1142	1185	3348	3030	3042
1.30 pm	-158.85	-35	-1000	938	941	937	2856	3097	3344
2 pm	-195.29	-35	-1000	917	937	931	2925	3097	3345

Between 1.30 am to 4.30 am, availability was between 318 MW and 548 MW higher than forecast, four hours prior, largely driven by higher than forecast wind generation most of which was priced negatively. In the early part of each trading interval the price fell to the price floor for one dispatch interval before participants rebid capacity to higher prices in response.

Each of the 1.30 pm and 2 pm trading intervals had one dispatch interval where the spot price fell to the price floor, largely driven by decreases in demand.

Tuesday, 4 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
9.30 am	-284.33	-1000	-1000	985	979	1019	3495	3450	3451
10 am	-666.67	-1000	-1000	901	895	930	3399	3410	3402
10.30 am	-453.17	-1000	-1000	842	827	866	3282	3321	3273
11 am	-878.78	-1000	-1000	771	783	816	3159	3242	3186
11.30 am	-919.78	-1000	-1000	739	759	791	3005	3167	3102
Midday	-316.28	-1000	-1000	709	725	770	2913	3094	3024
1 pm	275.5	-1000	-1000	676	700	738	2743	2964	2901
1.30 pm	-226	-1000	-1000	644	705	733	2739	2960	2899
2 pm	275.5	-1000	-1000	694	699	737	2668	2954	2896
2.30 pm	301	-1000	-1000	698	702	738	2642	2927	2899
3.30 pm	275.5	-1000	-1000	754	758	798	2648	2852	2907

Between 9.30 am and midday, and 1.30 pm, the spot price was below -$100/MWh and was forecast to be at the price floor, four hours prior. Within each trading interval, the dispatch price would typically fall to the price floor, as forecast, and in response participants rebid capacity into higher price bands. The dispatch price would then increase to above $0/MWh.

For the 1 pm, 2 pm, 2.30 pm, and 3.30 pm trading intervals, the price was above $275/MWh despite being forecast at the price floor, four hours prior. This was largely driven by wind generation being between 101 MW and 128 MW less than forecast four hours prior, most of which is generally priced at the floor.

Wednesday, 5 February

Table 7: Price, Demand and Availability

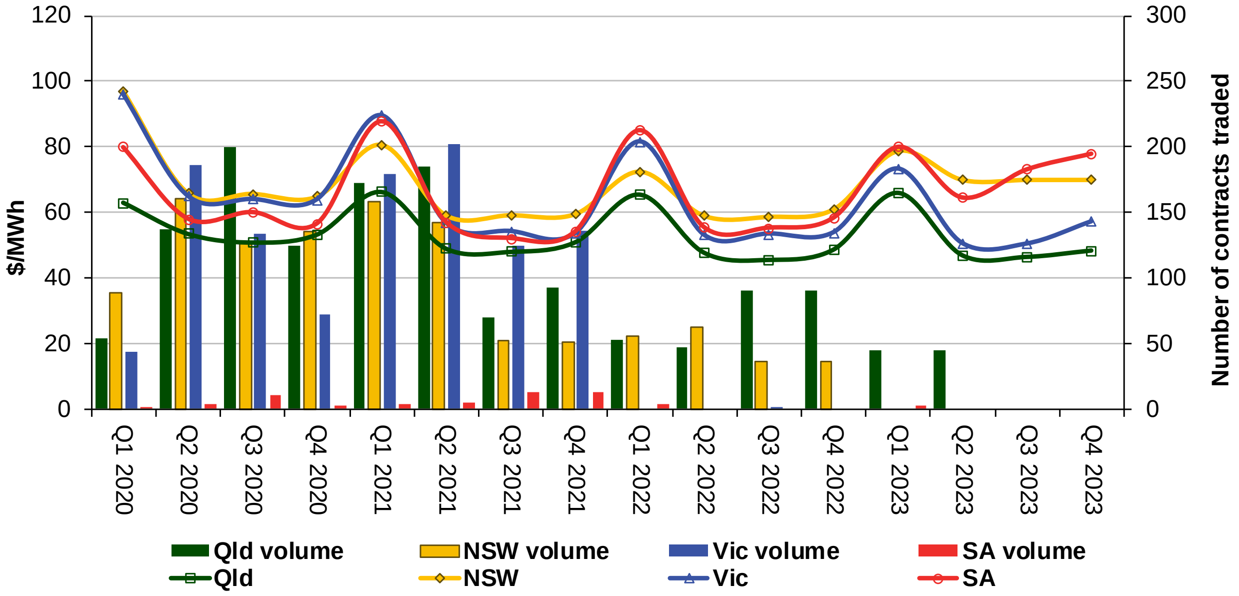
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
11 am	-343.40	-1000.00	-1000.00	797	762	782	2881	2799	2993
Midday	391.51	-1000.00	-1000.00	791	734	765	2676	2927	2905
12.30 pm	366.84	-1000.00	-1000.00	785	715	752	2690	2891	2866
1 pm	376.46	-1000.00	-1000.00	794	722	751	2641	2857	2826
1.30 pm	301.00	-1000.00	-1000.00	807	736	766	2560	2643	2827
2 pm	301.00	-1000.00	-1000.00	829	755	785	2500	2617	2827
2.30 pm	266.83	-1000.00	-1000.00	824	775	791	2558	2659	2836

Between 11 am and 2.30 pm, demand was between 35 MW and 74 MW higher than forecast and availability was between 82 MW higher and 251 MW lower than forecast. Wind and grid-solar generation were lower than forecast, reducing the amount of cheap energy available. This resulted in spot prices higher than forecast four hours prior.

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.

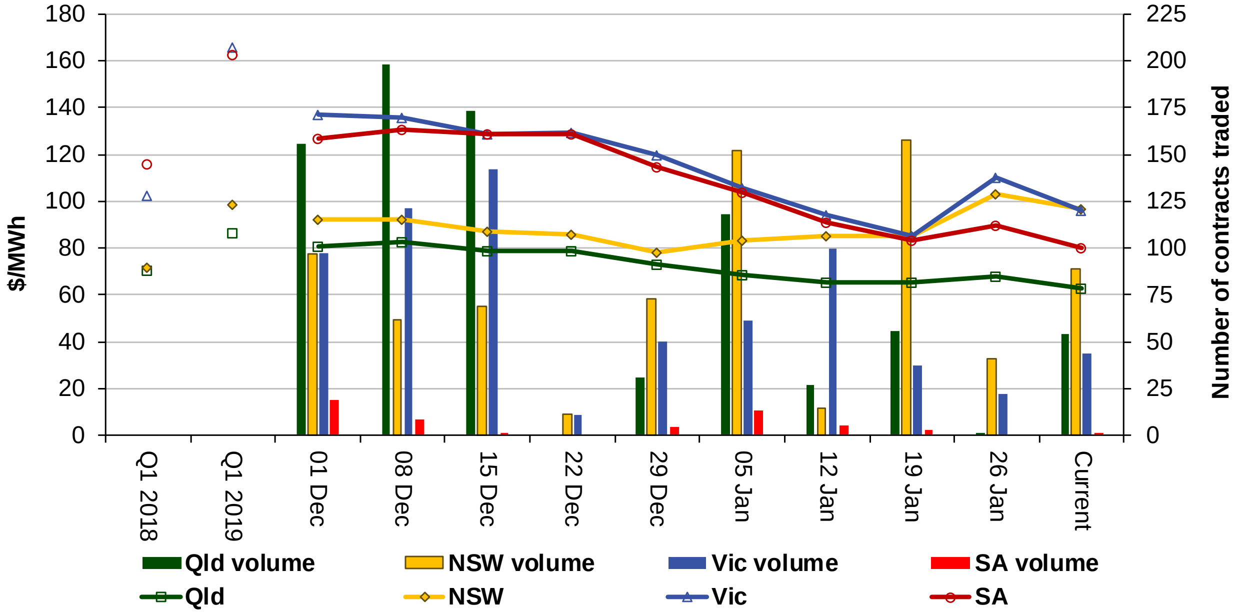
Figure 9: Quarterly base future prices Q1 2020 – Q4 2023



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)

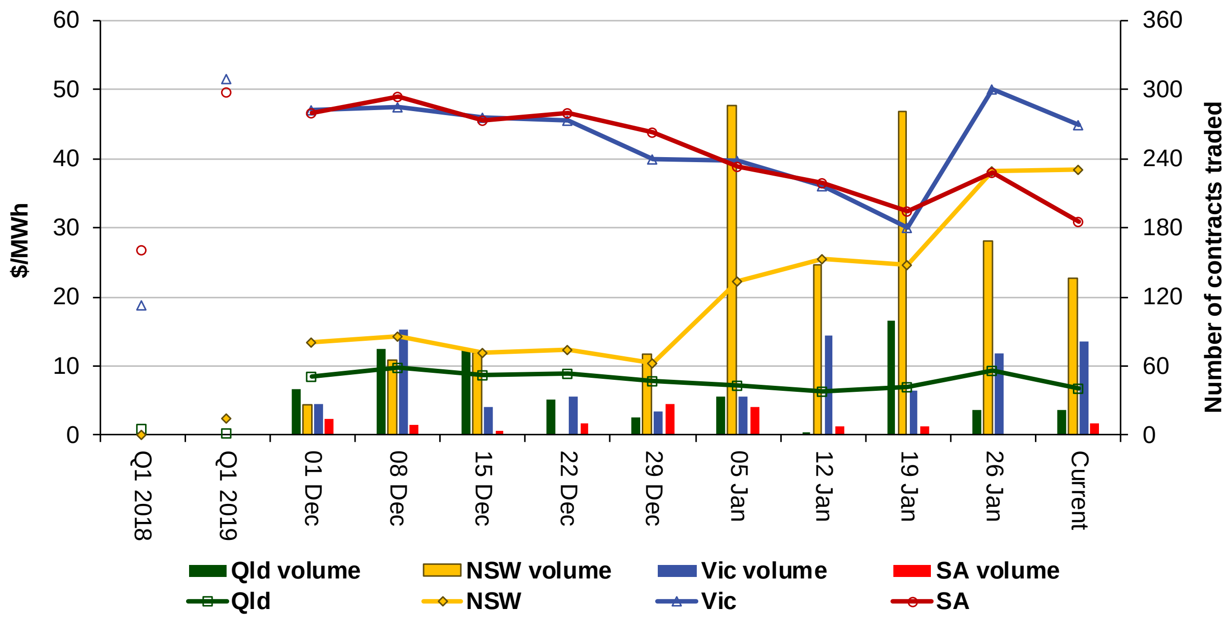


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional quarter 1 2019 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
February 2020