Electricity Report

1 – 7 March 2020

Weekly Summary

Average prices for the week ranged from $35/MWh in Tasmania up to $60/MWh in Queensland. In South Australia the weekly average price was $53/MWh, despite two spot prices exceeding $5000/MWh.

On Monday 2 March, South Australia separated from the rest of the NEM again from midday till 8.05 pm and had to provide its own energy and FCAS. For energy, this led to the energy price exceeding $5000/MWh for two trading intervals in the afternoon. For FCAS, the separation caused constraints to be invoked that increased the requirement for local FCAS and led to high prices across most services throughout the afternoon.

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 1 to 7 March 2020.

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

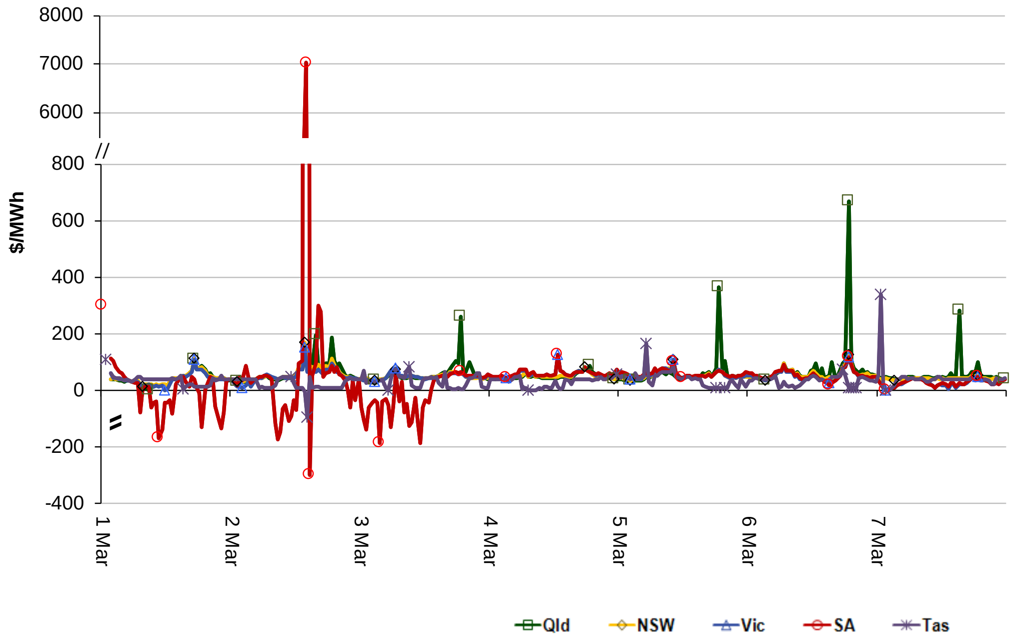


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

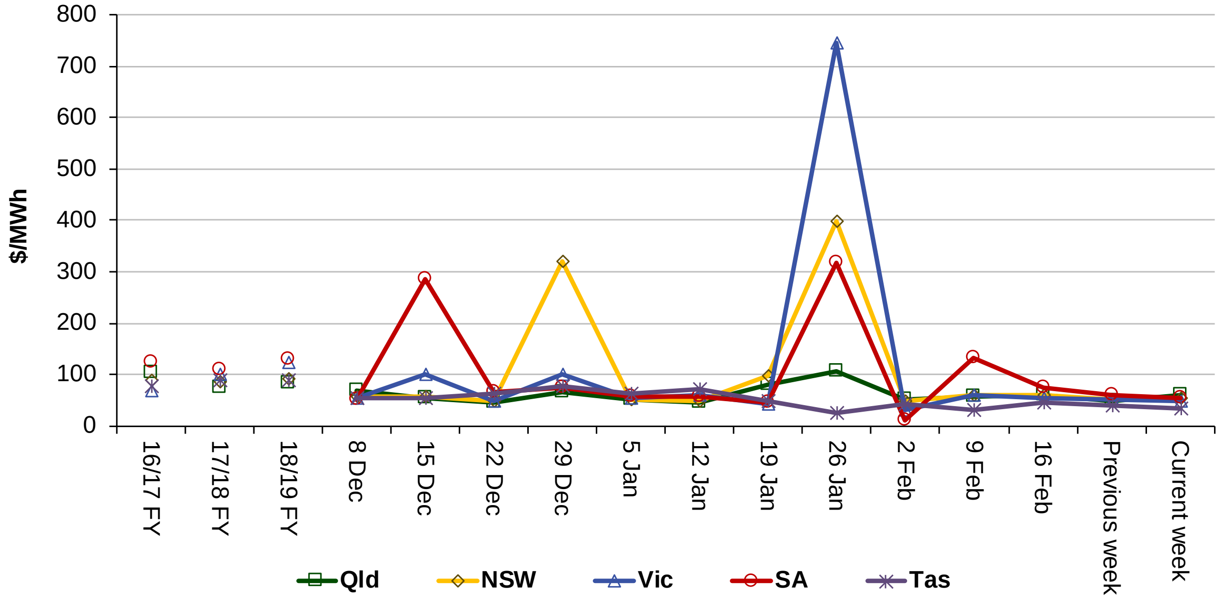


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	60	53	49	53	35
18-19 financial YTD	85	95	134	143	81
19-20 financial YTD	65	94	103	87	66

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 230 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	8	27	0	1
% of total below forecast	15	38	0	12

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

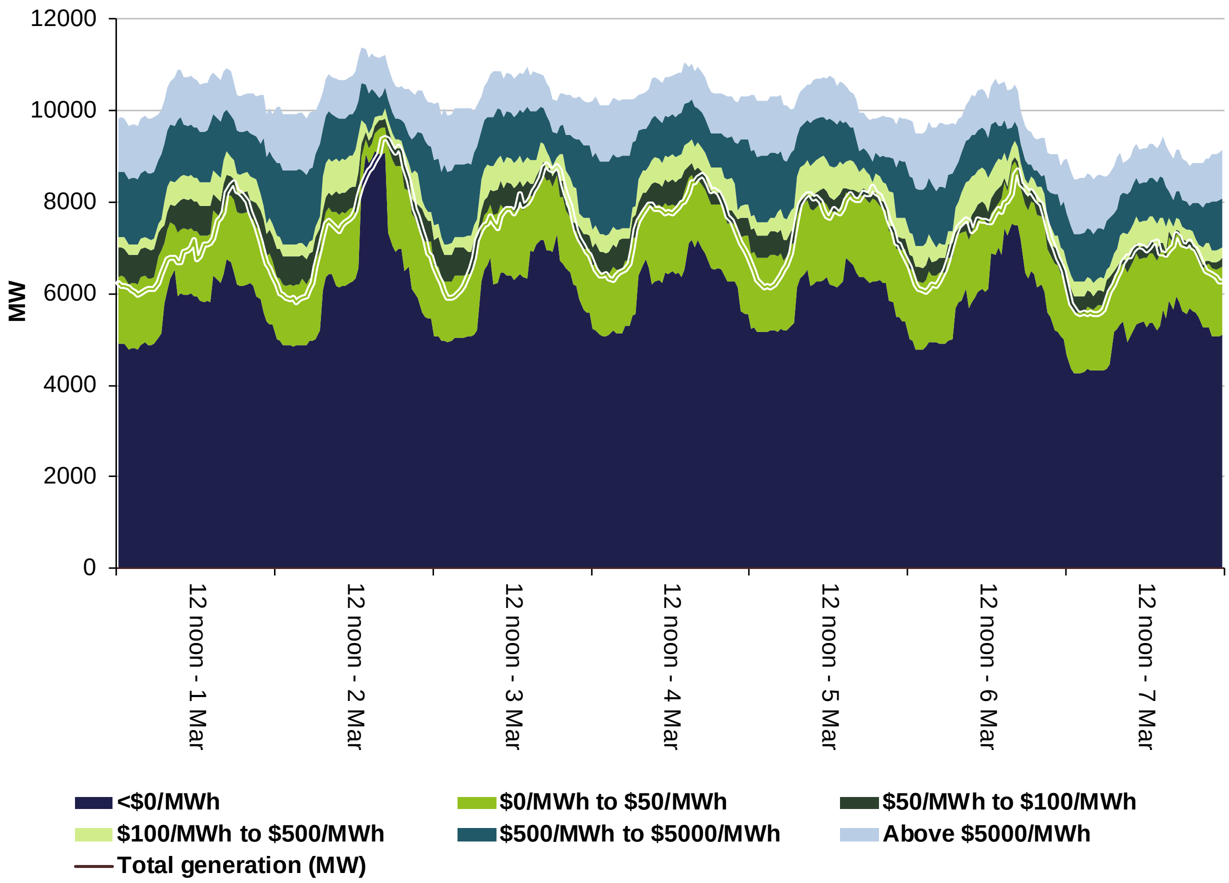


Figure 4: New South Wales generation and bidding patterns

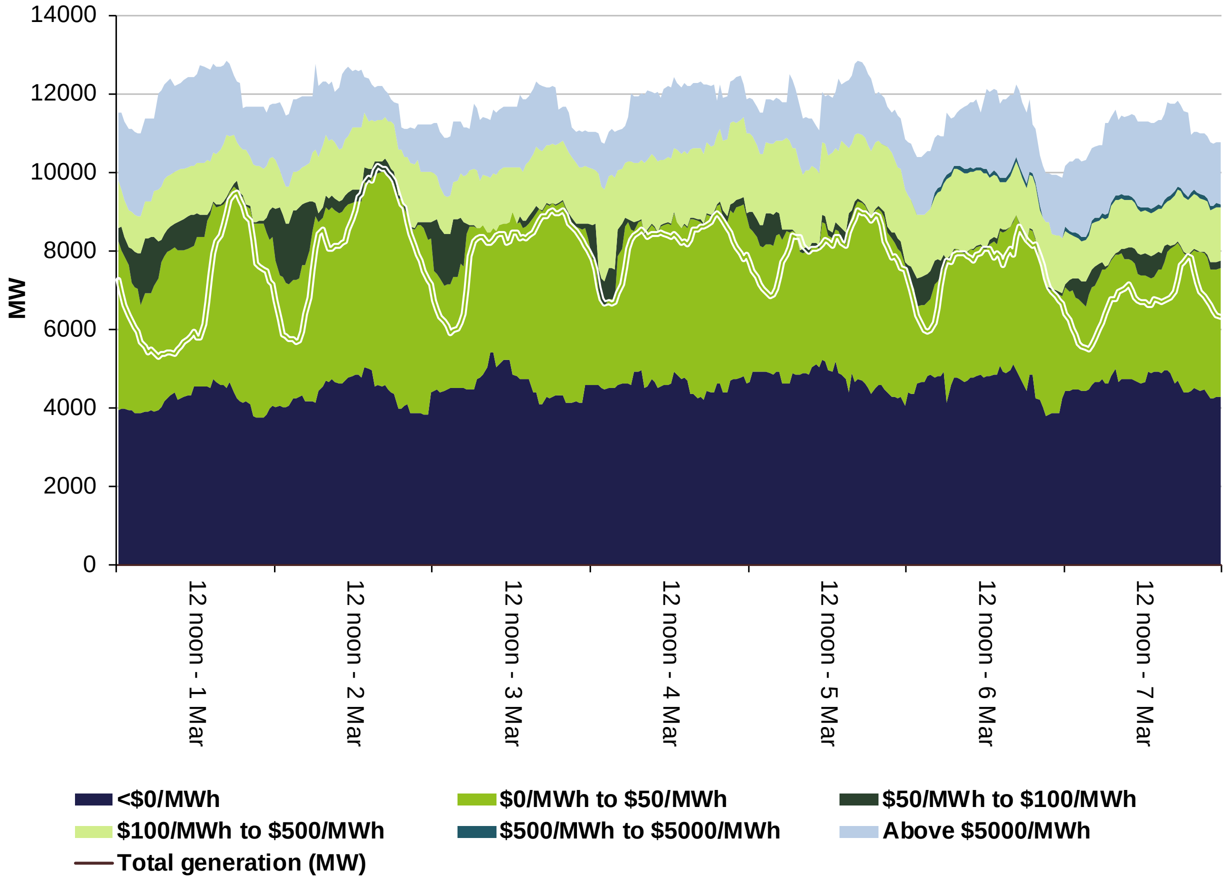


Figure 5: Victoria generation and bidding patterns

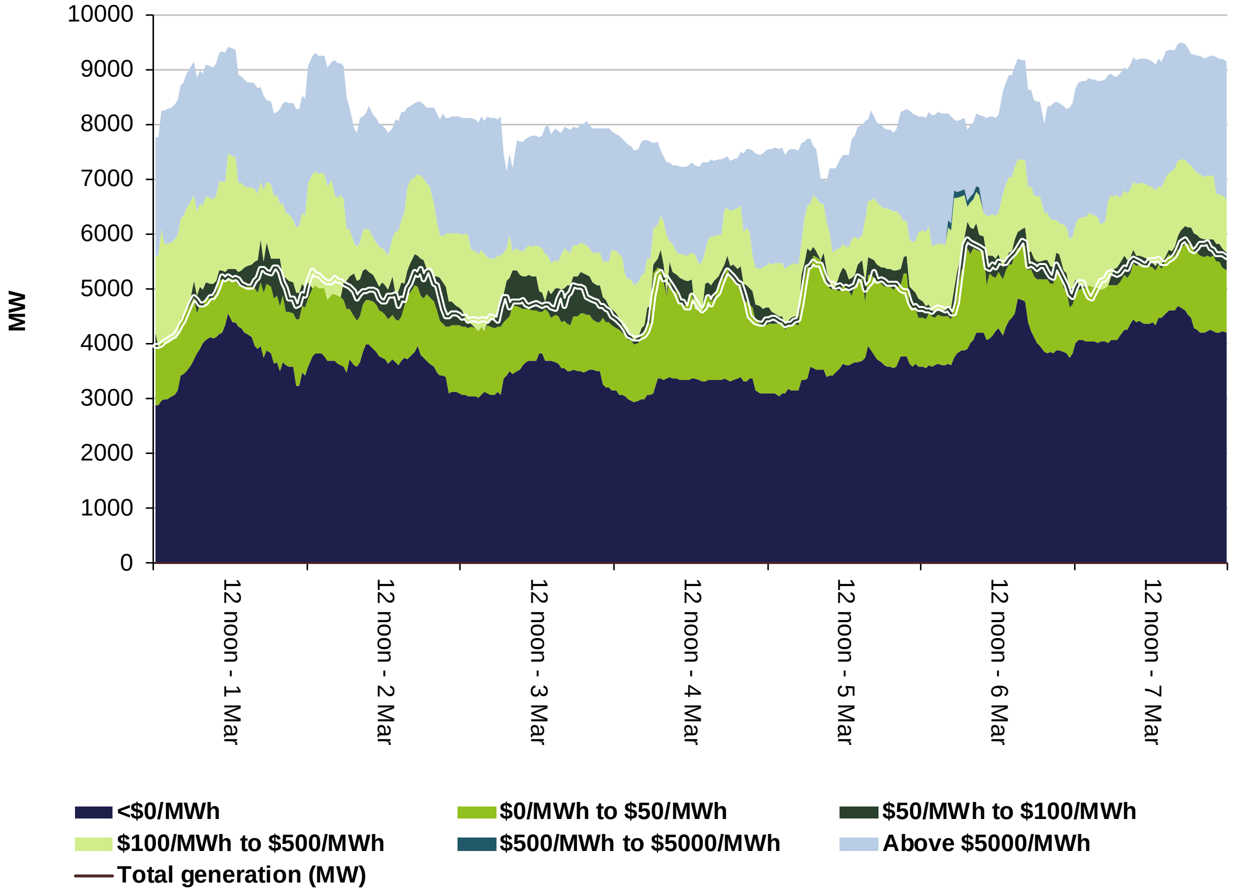


Figure 6: South Australia generation and bidding patterns

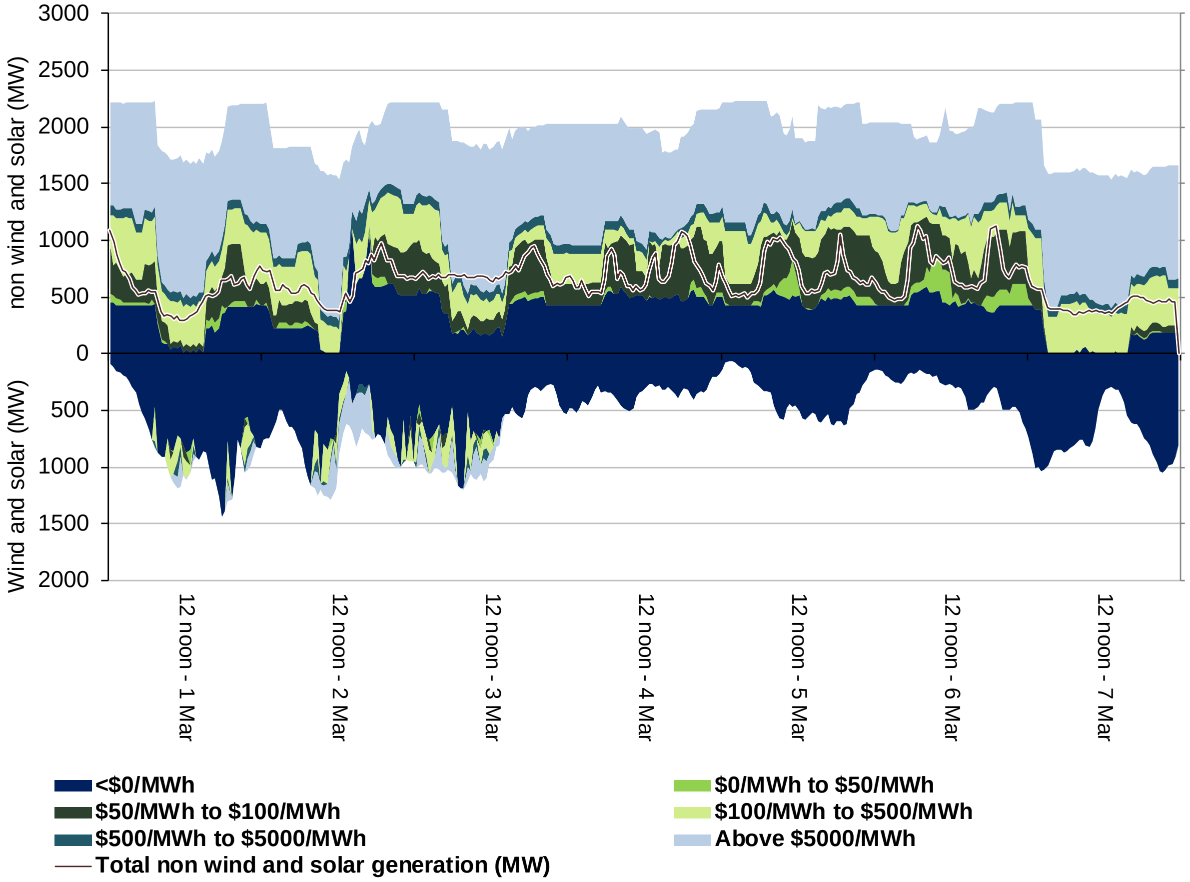
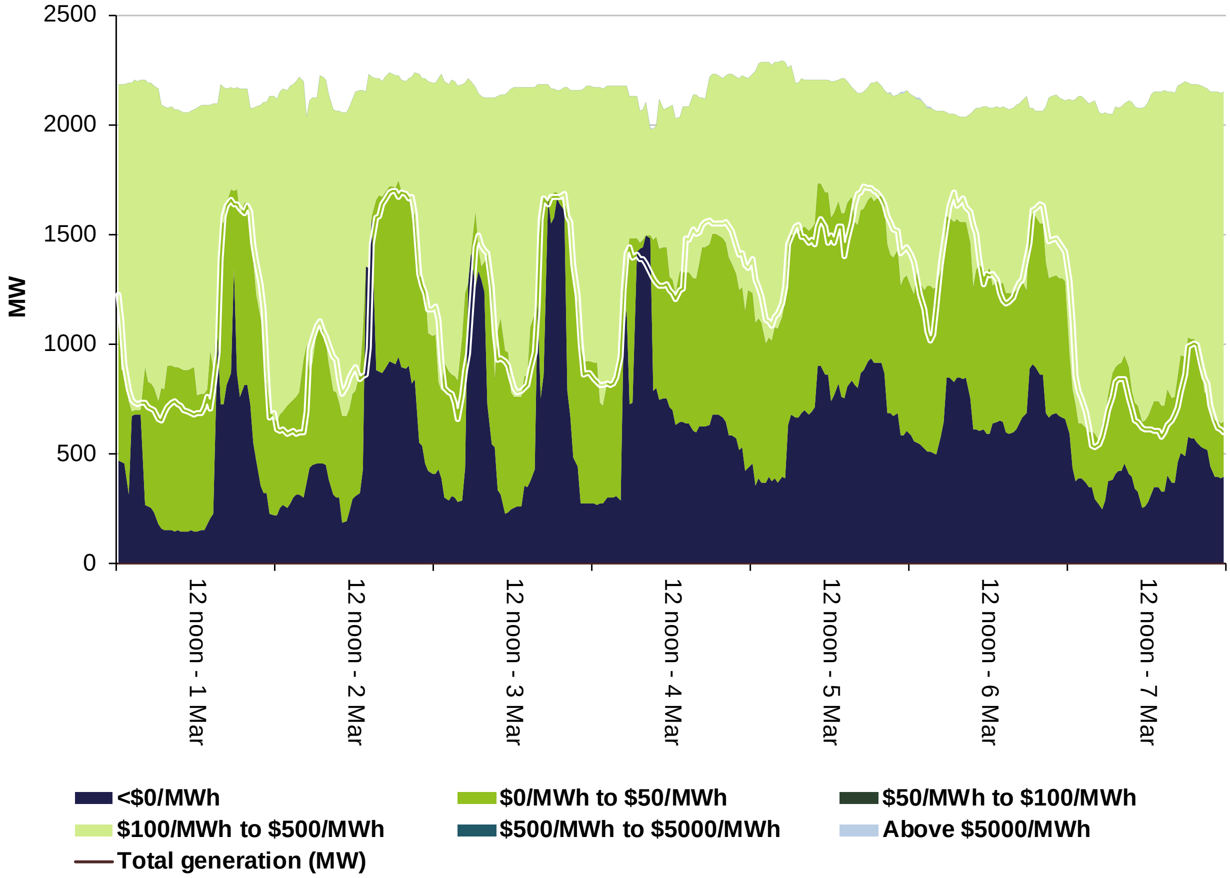


Figure 7: Tasmania generation and bidding patterns



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.

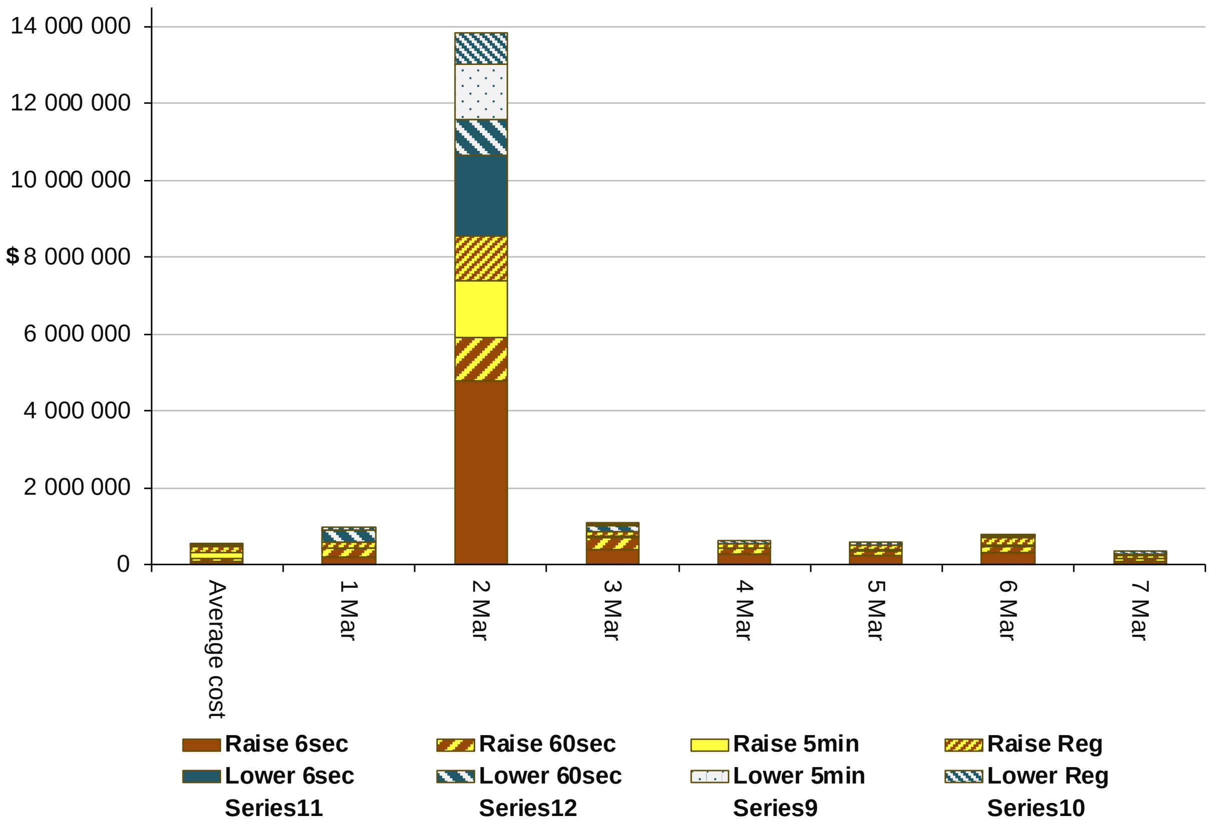
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $17 814 500 or less than 10 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $490 500 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



Following an unplanned outage of the Heywood interconnector on 2 March, South Australia had to supply its own FCAS. Constraints were invoked that increased the requirement for local FCAS and led to high prices across most services throughout the afternoon.

Detailed market analysis of significant price events

Queensland

There were four occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $60/MWh and above $250/MWh.

Tuesday, 3 March

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
7 pm	262.23	400.00	201.00	8959	8793	8616	10 202	10 321	10 283

Demand was 166 MW higher than forecast while availability was 119 MW lower than forecast, four hours prior. Lower than forecast availability was due to rebids at Gladstone that removed 115 MW of capacity priced less than $111/MWh due to technical issues.

In response to higher than forecast prices at the start of the trading interval, Arrow rebid 155 MW of capacity at Braemar 2 from prices above $591/MWh to the price floor (effective 6.45 pm), and CleanCo rebid a further 83 MW at Kareeya from $2657/MWh to the price floor (effective 6.50 pm). At 6.50 pm demand dropped by almost 130 MW and continued to drop for the rest of the trading interval, causing the price to be set below $73/MWh for the remainder of the trading interval.

Thursday, 5 March

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
7 pm	364.33	300.23	105.00	8447	8417	8338	9809	10 006	10 346

Demand was 30 MW higher than forecast while availability was almost 200 MW lower than forecast, four hours prior. Lower than forecast availability was mainly due to rebids that removed around 170 MW of capacity at Braemar 2 (priced above $590/MWh) and 25 MW at Millmerran (priced at the floor) due to technical issues.

At 6.35 pm there was a 160 MW increase in demand. With 380 MW of capacity priced between $300/MWh and $1400/MWh constrained, the dispatch price increased to $1494/MWh for one dispatch interval.

Friday, 6 March

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 pm	669.17	151.50	151.50	8425	8302	8305	9647	9770	10 278

Demand was 123 MW higher than forecast while availability was 123 MW lower than forecast, four hours prior. Rebids in the lead up to the start of the trading interval removed net 160 MW of capacity (priced at the floor) from Millmerran and 50 MW at Gladstone due to technical issues.

Effective 7 pm, rebids by Arrow removed 173 MW of capacity at Braemar 2 that (priced at $591/MWh) to avoid an uneconomic start. With all capacity priced between $591/MWh and $2657/MWh either ramp constrained or trapped/stranded in FCAS, the dispatch price increased to $2657/MWh for one dispatch interval.

Saturday, 7 March

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
3.30 pm	282.65	46.06	39.12	7331	7225	6999	9243	9718	10 168

Demand was 106 MW higher than forecast and availability was 475 MW lower than forecast, four hours prior. Lower than forecast availability was due to lower than forecast solar generation and rebids that removed 250 MW of capacity from Millmerran due to technical issues (most priced at the floor), and around 55 MW from other generators due to technical issues.

At 3.30 pm, demand increased by 44 MW. With capacity priced between $66/MWh and $1387/MWh constrained, the dispatch price increased to $1387/MWh for one dispatch interval.

South Australia

There were six occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $53/MWh and above $250/MWh and there were eighteen occasions where the spot price was below -$100/MWh.

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
12.30 am	300.50	69.70	192.00	1330	1346	1340	2306	2451	2439
1am	263.67	73.13	114.00	1262	1292	1287	2339	2492	2463
11am	-168.58	-1000.00	-3.10	988	818	901	2912	2599	2571

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
11.30 am	-138.59	-1000.00	-0.39	944	874	926	2890	2593	2570
7 pm	-129.57	67.81	72.53	1376	1357	1332	3489	2804	2561
10 pm	-101.51	53.50	41.09	1239	1186	1079	3228	2854	2427
10.30 pm	-132.64	53.50	41.16	1184	1137	1044	3197	2857	2372

For the 12.30 am and 1 am trading intervals, demand was close to forecast while availability was between 145 MW and 153 MW lower than forecast, four hours prior. Lower than forecast availability was due to lower wind generation which reduced the amount of low priced energy available. As a result, the spot price was higher than forecast.

For the 11 am trading interval, demand was 170 MW higher than forecast while availability was 313 MW higher than forecast, four hours prior. Rebids in the lead up to the trading interval shifted around 270 MW of capacity from low to high prices. As a result, the dispatch price settled around $15/MWh for half of the trading interval.

For the 11.30 am trading interval, demand was 70 MW higher than forecast while availability was 297 MW higher than forecast four hours prior. In response to the dispatch price falling to -$900/MWh at 11.15 am, rebids shifted 736 MW of capacity from the price floor to more than $150/MWh (effective 11.20 am). As a result, prices settled around $20/MWh for the rest of the trading interval.

For the 7 pm, 10 pm and 10.30 pm trading intervals, demand was close to forecast while availability was between 340 MW and 685 MW higher than forecast four hours prior. Higher than forecast availability was largely driven by higher than forecast wind generation, which increased the amount of low priced energy available. With no capacity priced between -$3/MWh and the price floor, minor changes in demand or availability could result in large fluctuations in price. In each trading interval, the dispatch price fell to the price floor for one dispatch interval due to either an increase in wind generation or decrease in demand.

Monday, 2 March

Table 8: 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	-115.41	35.05	49.71	1148	1080	1108	2835	2524	2486
9 am	-171.01	-50.86	36.25	1130	992	1031	2898	2557	2511
9.30 am	-144.68	-1000	47.93	1055	900	953	2766	2505	2297
11 am	-107.90	-1000	-1000	891	706	731	2862	2532	2464
2 pm	5063.20	-3.10	-1000	693	618	629	2318	2277	2260
2.30 pm	7026.84	31.94	-1000	586	619	631	2376	2158	2291

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 pm	-299.93	35.22	-1000	637	657	643	2684	2321	2483
4.30 pm	300.00	69.00	0.00	997	826	808	2586	2346	2448
5 pm	279.66	279.57	61.02	1044	923	901	2678	2252	2557

For the 8.30 am and 9 am trading intervals, demand was between 68 MW and 138 MW higher than forecast, and availability was between 311 MW and 341 MW higher than forecast, four hours prior. The higher than forecast availability was largely due to higher than forecast wind generation which increased the amount of low priced energy available. With little capacity priced between $54/MWh and the price floor, minor changes in demand or availability could result in large fluctuations in price. Due to decreases in demand, the dispatch price fell to -$990/MWh and the price floor at 8.25 am and 8.55 am respectively, resulting in lower than forecast spot prices.

For the 9.30 am trading interval, demand was 155 MW higher than forecast and availability was 261 MW higher than forecast. A sudden drop in wind generation for the first two dispatch intervals caused the dispatch price to be set at $43/MWh and $192/MWh.

For the 11 am trading interval, demand was 185 MW higher than forecast while availability was 330 MW higher than forecast four hours prior. For the majority of the trading interval, prices were between $30/MWh and $46/MWh. This was mostly driven by rebids during the trading interval that shifted nearly 500 MW of capacity at numerous wind farms from the price floor to more than $50/MWh (effective 10.50 am) due to negative or lower than forecast prices.

Analysis of the 2 pm and 2.30 pm trading intervals will be discussed in Electricity spot prices above $5000/MWh, South Australia – 2 March 2020 report.

For the 3 pm trading interval, demand was close to forecast while availability was 363 MW higher than forecast, four hours prior. Higher than forecast availability was mainly driven by rebids in the lead up to the trading interval that added capacity. With no capacity priced between -$3/MWh and the price floor, minor changes in demand or availability could result in large fluctuations in price. As a result, the price fell to the price floor for two dispatch intervals.

For the 4.30 pm trading interval, demand was 171 MW higher than forecast and availability was 240 MW higher than forecast four hours prior some of this capacity was priced high. Due to higher than forecast demand and lower than forecast wind generation, reducing the amount of cheap-energy available, prices settled at $300/MWh throughout the trading interval.

The 5 pm trading interval spot price was close to forecast four hours prior.

Tuesday, 3 March

Table 9: 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	-101.06	34.47	43.32	1265	1224	1208	3209	3009	2604
1.30 am	-137.04	37.70	42.62	1193	1144	1136	3194	2752	2608

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 am	-186.53	29.34	40.12	1065	1064	1040	3240	2823	2810
6 am	-130.12	28.39	38.17	1235	1204	1210	2924	2821	2656
9.30 am	-123.63	-1000.00	36.82	1280	976	1023	2923	2836	2547
10 am	-112.39	-1000.00	31.74	1193	894	942	2936	2834	2521
11 am	-113.90	-1000.00	-663.99	1099	786	807	2963	2762	2613
11.30 am	-184.28	-1000.00	3.63	1109	798	784	2940	2680	2522

For the 1 am, 1.30 am, 4 am, and 6 am trading intervals, demand was close to forecast while availability was between 103 MW and 442 MW higher than forecast, four hours prior, most of this capacity was priced low. The dispatch price fell to less than -$700/MWh once in each trading interval followed by rebidding into high prices band because of the low price.

For the 9.30 am, 10 am, 11 am and 11.30 am trading intervals, demand was around 300 MW higher than forecast while availability was up to 260 MW higher than forecast four hours prior. The higher than forecast availability was largely due to higher than forecast wind generation which increased the amount of low priced energy available. Rebids in response to forecast prices leading up to the start of each trading interval shifted up to 627 MW of capacity from the price floor to more than -$150/MWh. As a result, prices settled around $50/MWh for most the time in each of the trading intervals.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $35/MWh and above $250/MWh

Saturday, 7 March

Table 10: 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	339.37	41.99	39.52	880	928	924	2108	2111	2112

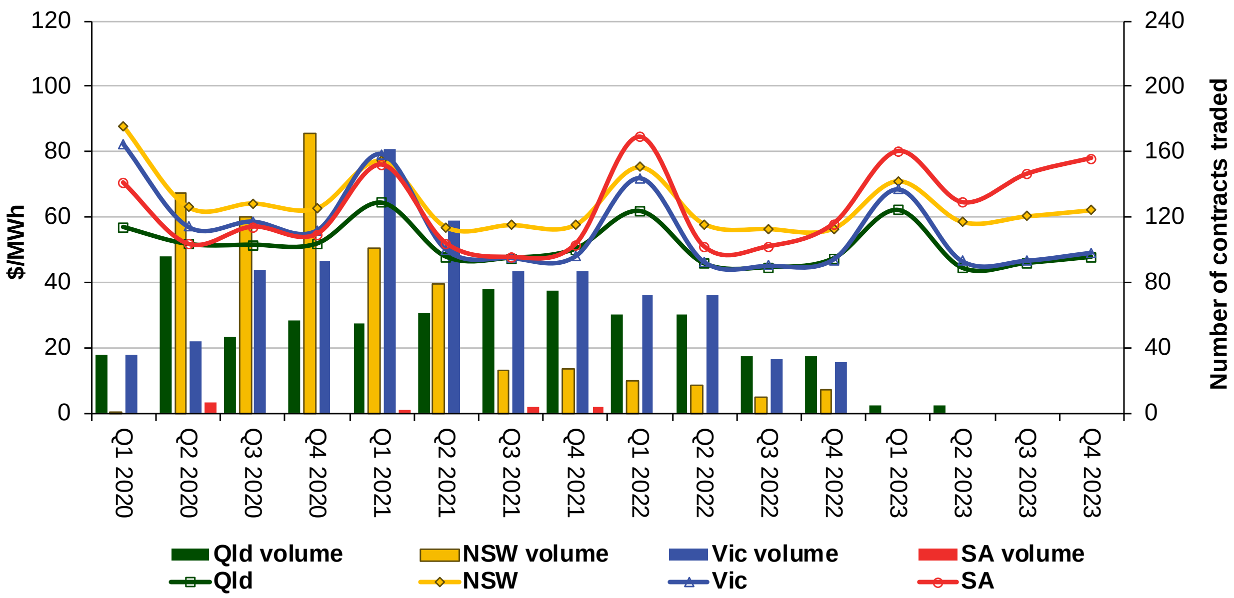
Demand was 48 MW lower than forecast and availability was close to forecast, four and 12 hours prior.

Between midnight and the start of the trading interval, Hydro Tasmania rebid almost 350 MW of capacity across several generators from prices below $140/MWh to $402/MWh. The reasons given were related to forecast lake levels and forecast price differences. As a result, the dispatch price was set at $402/MWh for the majority of the 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.

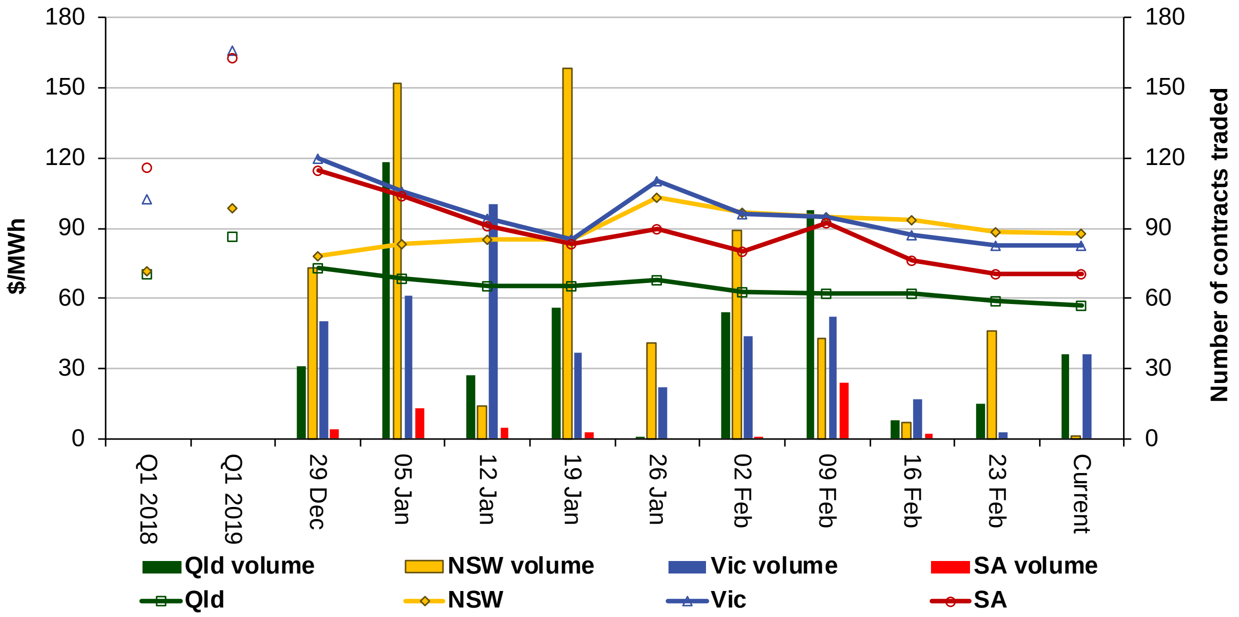
Figure 9: Quarterly base future prices Q1 2020 – Q4 2023



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)

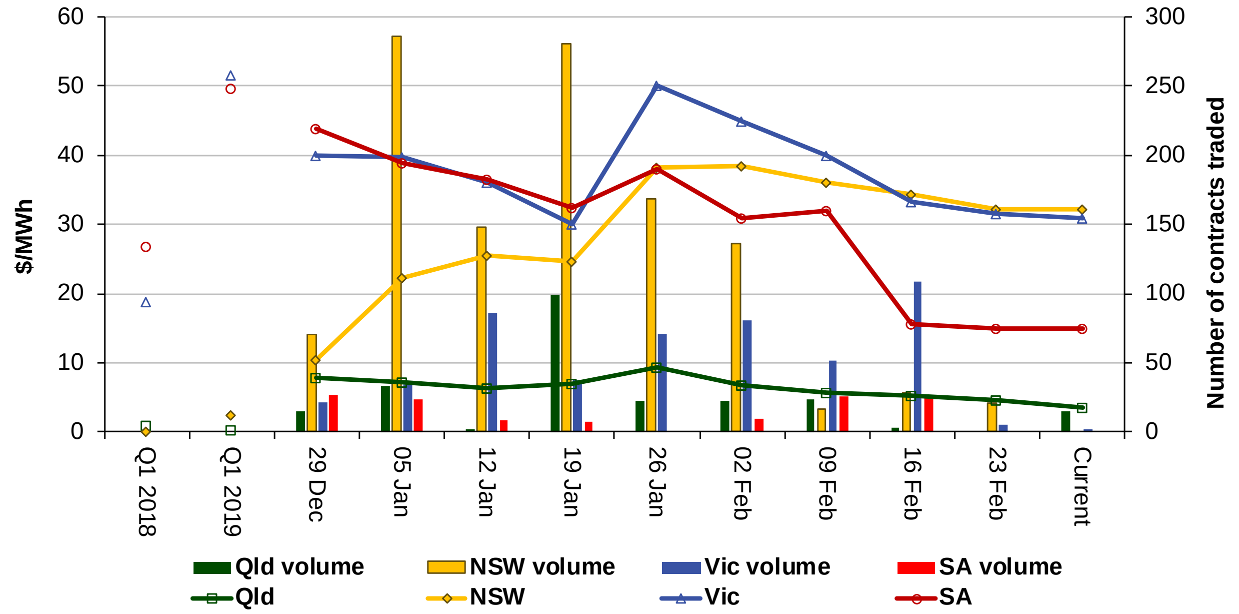


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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