Electricity Report

AUSTRALIAN ENERGY REGULATOR

19 – 25 January 2020

Weekly Summary

Market outcomes for this week were largely impacted by abnormal weather conditions including extreme temperatures, bushfires impacting network elements, and heavy rain and wind. This resulted in a number of reclassifications of lines and declarations of actual Lack of Reserve (levels 1 and 2) during the week.

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 19 to 25 January 2020.

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

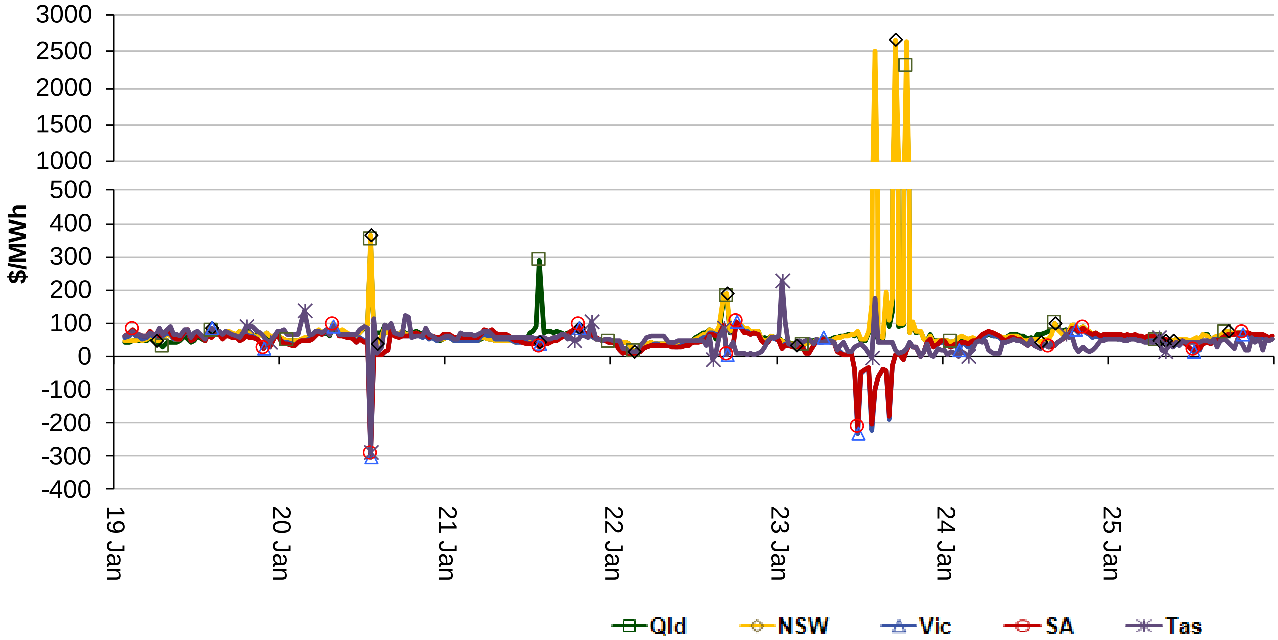


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

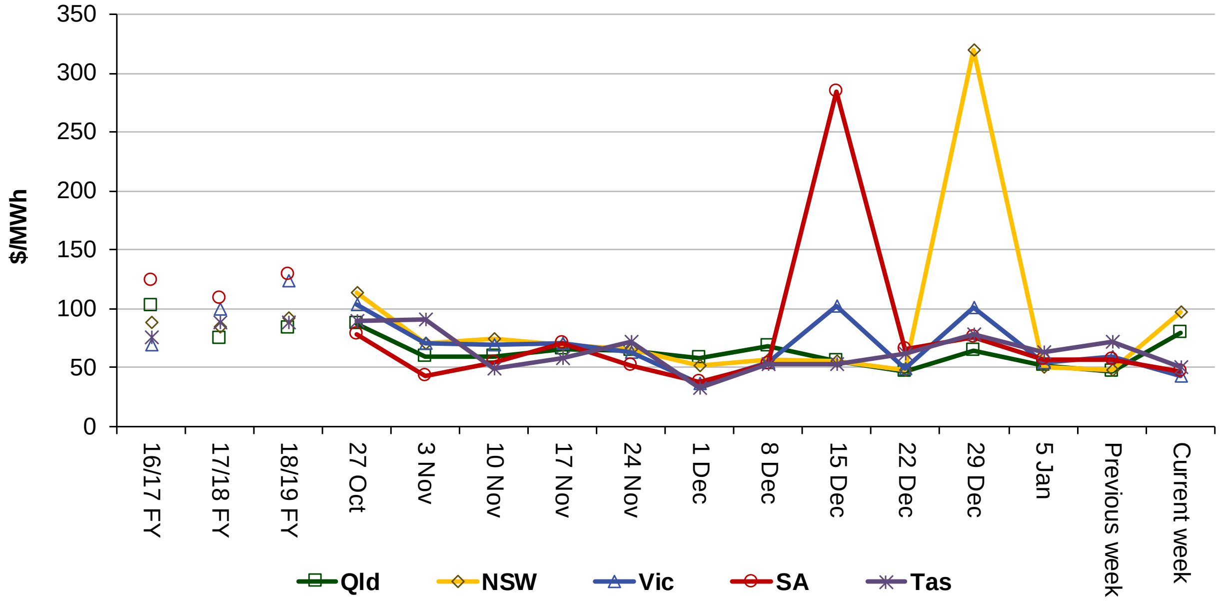


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	79	98	43	46	50
18-19 financial YTD	84	93	129	140	71
19-20 financial YTD	65	88	88	81	72

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 2018 of 199 counts and the average in 2017 of 185. 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	6	33	0	3
% of total below forecast	11	40	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

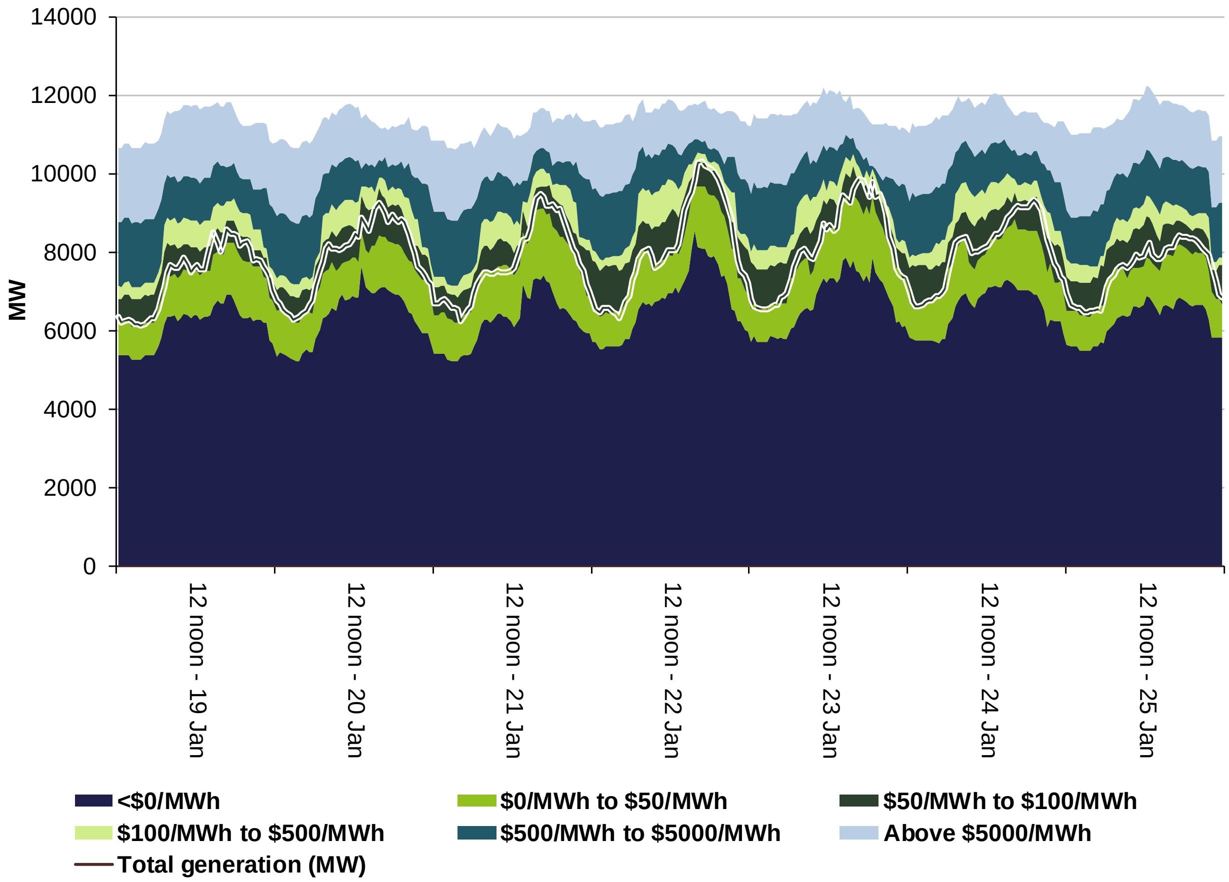


Figure 4: New South Wales generation and bidding patterns

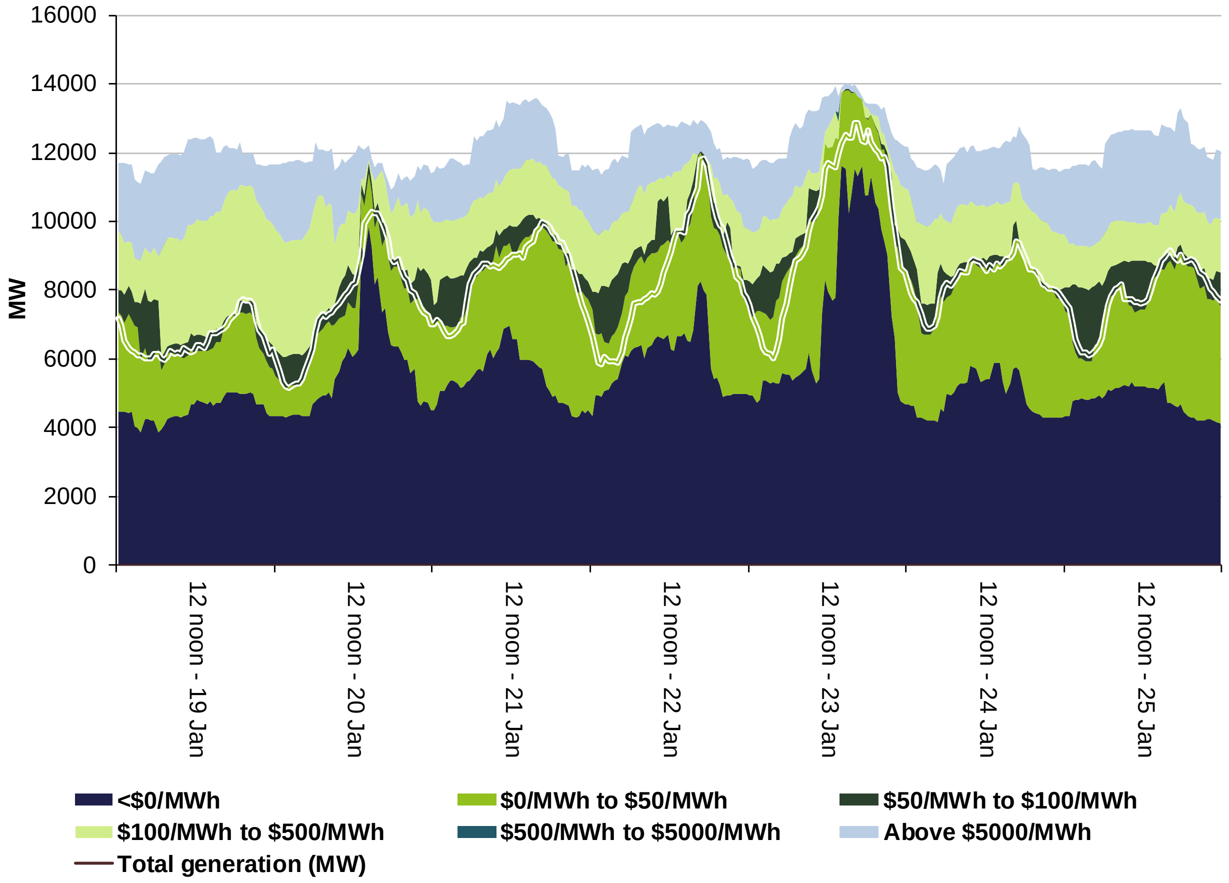


Figure 5: Victoria generation and bidding patterns

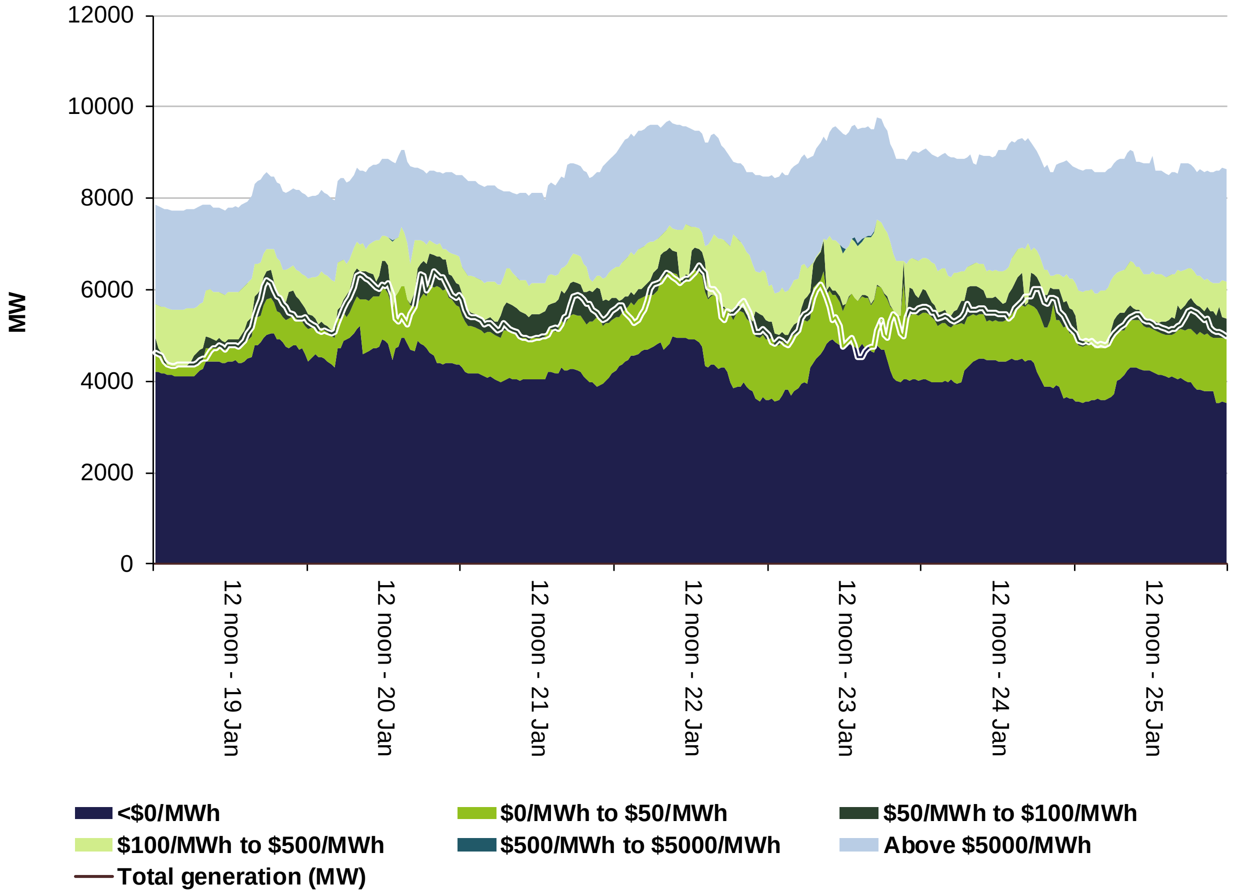


Figure 6: South Australia generation and bidding patterns

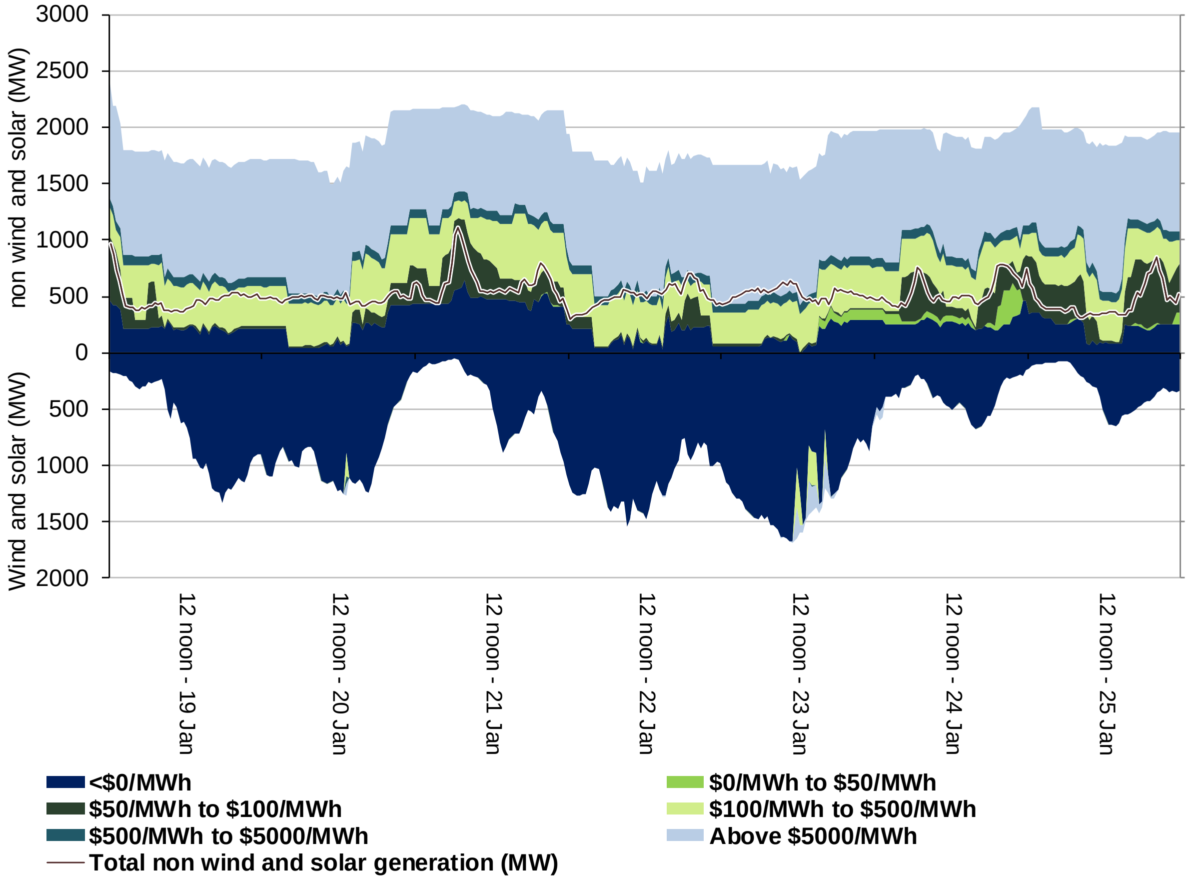
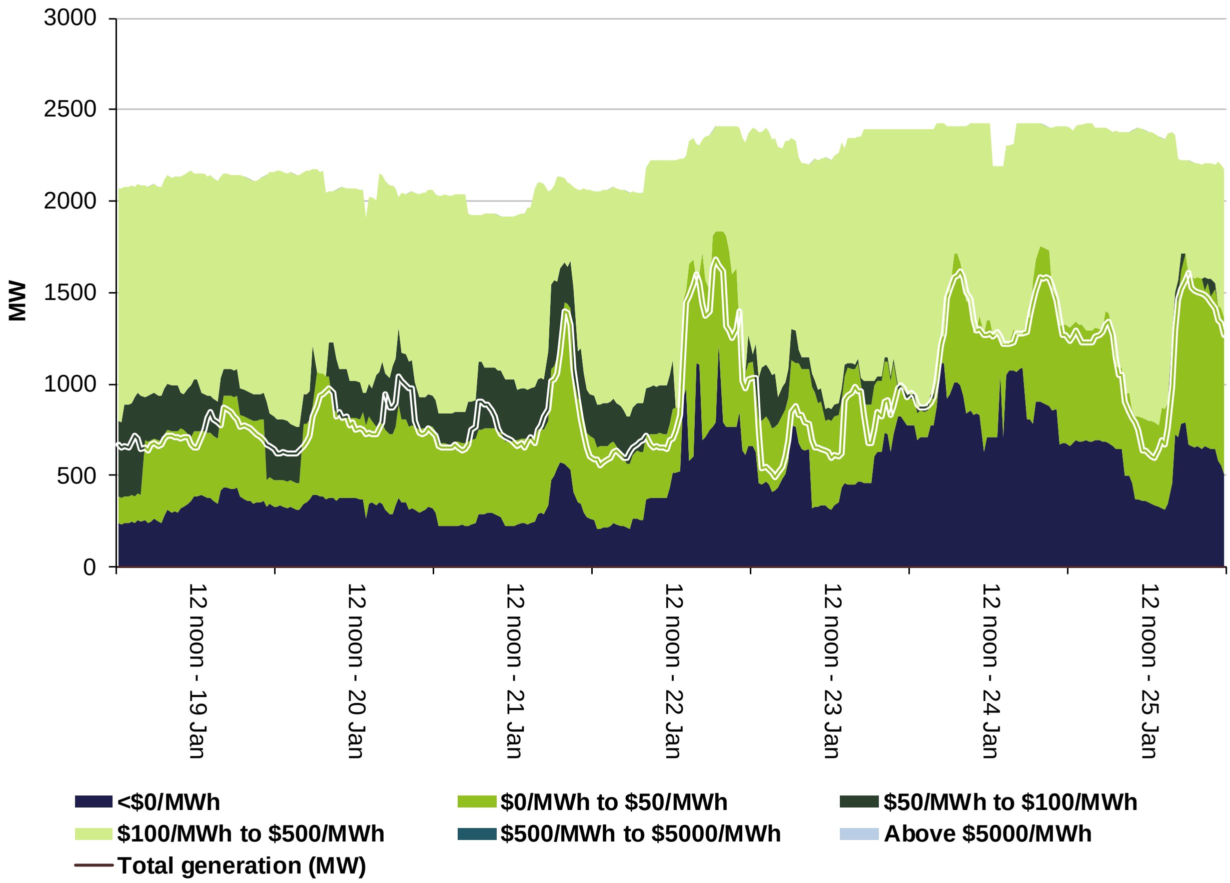


Figure 7: Tasmania generation and bidding patterns



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.

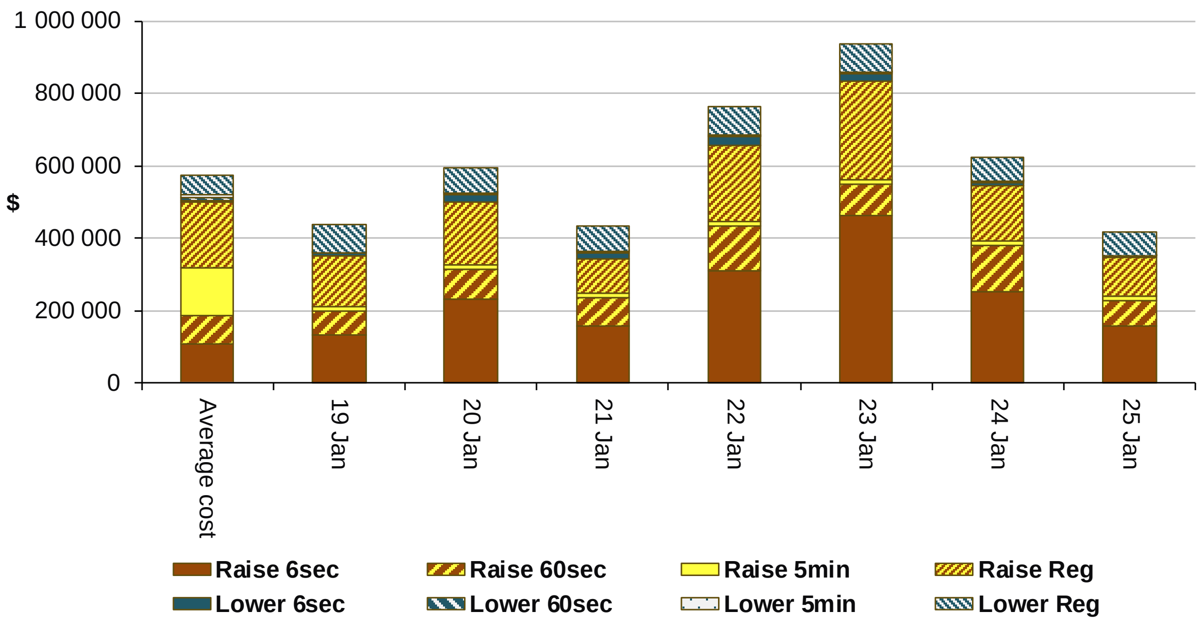
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3539000 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $670500 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

Queensland

There were four occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $79/MWh and above $250/MWh.

Monday, 20 January

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
1.30 pm	351.52	77.41	63.43	8365	8111	8177	11 630	11 906	11 802

Prices were aligned across Queensland and New South Wales and will be analysed as one region. Demand was collectively around 680 MW higher than forecast while availability was collectively 800 MW lower than forecast, four hours earlier.

Within four hours of dispatch, Stanwell withdrew over 110 MW of capacity from Tarong priced at $93/MWh. With a number of plants in New South Wales and Queensland trapped/stranded in FCAS, the dispatch reached around $1500/MWh for one dispatch interval.

Tuesday, 21 January

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
2 pm	287.03	92.89	92.73	8456	8245	8590	11 414	11 355	11 819

Demand was 200 MW higher than forecast and availability was 60 MW lower than forecast, four hours prior.

At 1.35 pm, demand increased by 130 MW and with little capacity priced between $92/MWh and $1500/MWh, the dispatch price reached around $1500/MWh for one dispatch interval.

Thursday, 23 January

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
5.30 pm	2286.08	98.00	201.00	8786	8866	9040	11 591	11 689	11 828
7 pm	2295.63	68.73	143.32	8936	8823	9022	11 304	11 709	11 647

Prices in Queensland were aligned with New South Wales and will be treated as one region. There was little capacity available priced between $100/MWh and $13 000/MWh in both regions combined. This meant small changes in conditions could lead to high prices.

For the 5.30 pm and 7 pm trading intervals demand was in total 260 MW and 636 MW higher than forecast four hours ahead, respectively. Available capacity was lower than forecast four hours ahead mainly due to CS Energy delaying the return to service of Callide B 1, which had all of its 330 MW of capacity priced below $20/MWh.

There was also rebidding of capacity from low to high prices by Millmerran Energy Trading at Millmerran and Callide power trading at Callide from below $26/MWh to the price cap because of a change in Queensland prices. These resulted in one dispatch price in each trading interval above $12 500/MWh.

New South Wales

There were four occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $98/MWh and above $250/MWh.

Monday, 20 January

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
1.30 pm	364.81	84.27	59.97	9613	9189	9488	12 060	12 579	12 635

Prices aligned with Queensland and are analysed in the Queensland section.

Thursday, 23 January

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
2.30 pm	2508.45	14 700.00	170.12	12 674	12 734	12 332	13 772	13 937	13 799
5.30 pm	2652.08	108.12	229.03	13 166	12 826	12 546	13 678	13 728	13 610
7 pm	2634.57	70.93	149.61	12 531	12 008	11 888	13 410	13 253	13 333

For the 2.30 pm trading interval, demand was close to forecast and availability was 165 MW lower than forecast. Lower availability was due to de-rating of generators across New South Wales due to extreme temperature and wind conditions.

In response to forecast and actual high prices, over 1000 MW of capacity was rebid from high prices to the price floor in the lead up and during the trading interval. This saw prices under $100/MWh for all but one dispatch interval when it reached $14 700/MWh.

The 5.30 pm and 7 pm prices aligned with Queensland and are analysed in the Queensland section.

Victoria

Monday, 20 January

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
1.30 pm	-304.15	45.76	48.58	5226	4984	5078	8820	9034	9003

Prices across Victoria, South Australia and Tasmania were aligned and will be treated as one region. Demand was 242 MW higher than forecast and availability was 214 MW lower than forecast, both four hours prior.

At 1.20 pm a constraint controlling flows across the VIC-NSW interconnector became binding and forced the interconnector to flow counter-price – an 880 MW swing. This caused almost 800 MW of generation in Victoria to be backed down and become ramp down constrained. With this generation unable to set price, the dispatch price dropped to the price floor for two dispatch intervals.

Thursday, 23 January

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
Midday	-231.21	8.95	30.01	4650	4852	4578	9430	9539	9490
2 pm	-222.10	-96.42	9.18	4630	4666	4505	9615	9563	9532
2.30 pm	-100.52	-184.78	14.75	4600	4612	4527	9507	9527	9513
4.30 pm	-188.82	-40.01	-96.42	4796	4847	4778	9544	9656	9712

Victoria and South Australia were price aligned during all the above trading intervals and will be treated as one region. At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed a gas plant in South Australia and activated RERT in New South Wales, triggering an intervention event. Special pricing arrangements apply for the 4.30 pm trading interval in all regions following an intervention in the market.

Demand combined across both regions was 200 MW lower or close to forecast for the midday and 2 pm trading intervals, respectively. Availability combined across both regions for both trading intervals was approximately 180 MW higher than forecast, four hours prior.

In both trading intervals, a constraint relating to line outages in New South Wales forced the VIC-NSW interconnector to flow counter-price and increase imports into Victoria by around 180 MW to 200 MW. This resulted in generation being ramped down constrained and unable to set price, and the price fell close to the price floor for one dispatch period during each trading interval.

For the 2.30 pm trading interval, demand was collectively 123 MW higher than forecast while availability was 127 MW higher than forecast, four hours prior. Higher availability was due to higher than forecast wind generation in Victoria, most of which was priced below $0/MWh.

There was over 1500 MW of capacity bid from lower prices to prices above $-100/MWh, causing the dispatch price to settle above $-100/MWh for the majority of the trading interval.

For the 4.30 pm trading interval, demand and availability collectively across both regions were close to forecast, four hours prior. A constraint managing the requirement for raise 6 second services on the mainland was binding. At 4.05 pm there was co-optimisation of raise 6 and 60 second services and the Energy market, resulting in the price falling to the floor for one dispatch interval.

South Australia

There were five occasions where the spot price in South Australia was below -$100/MWh.

Monday, 20 January

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
1.30 pm	-292.43	40.24	42.13	1046	887	863	2919	2891	2910

Prices were aligned with Victoria and are analysed in the Victorian section.

Thursday, 23 January

Table 11: 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	-212.43	7.41	25.90	788	791	816	3264	2978	2963
2 pm	-201.76	-83.41	8.05	758	651	719	3050	2930	2967
2.30 pm	-100.92	-162.83	12.81	808	673	743	3059	2912	2967
4.30 pm	-179.51	-38.03	-88.37	916	915	885	2986	2861	2953

Prices were aligned with Victoria and are analysed in the Victorian section.

Tasmania

There was one occasion where the spot price in Tasmania was below -$100/MWh.

Monday, 20 January

Table 12: Price, Demand and Availability

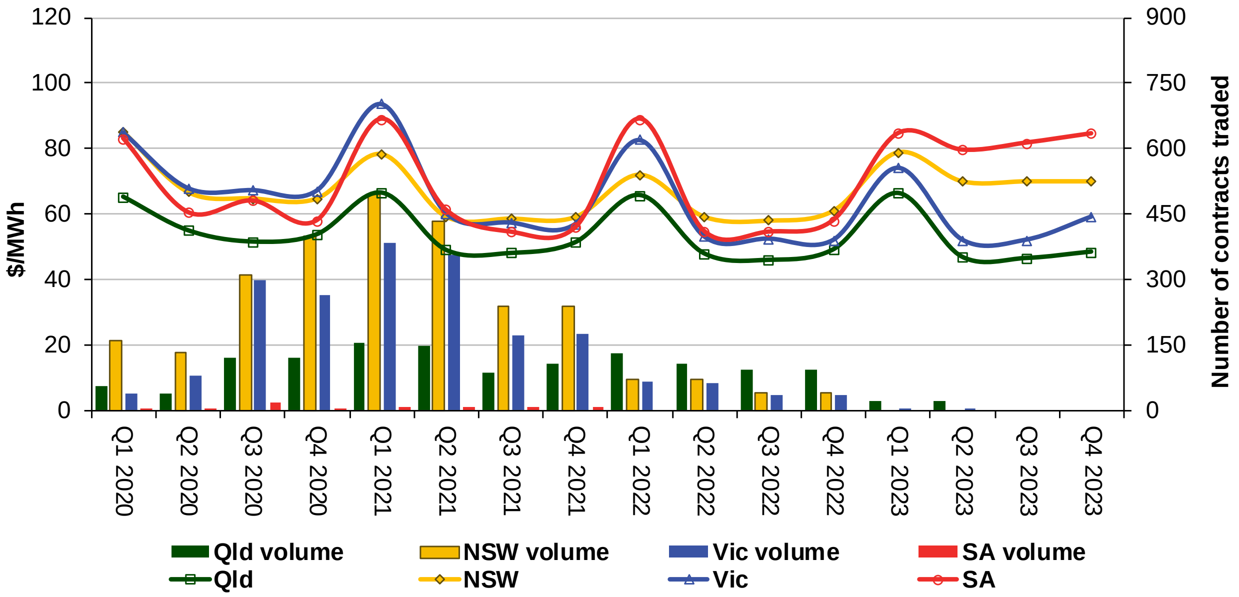
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
1.30 pm	-290.50	401.99	65.34	1116	1129	1054	1920	1904	1897

Prices were aligned with Victoria and are explained in the Victorian section.

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

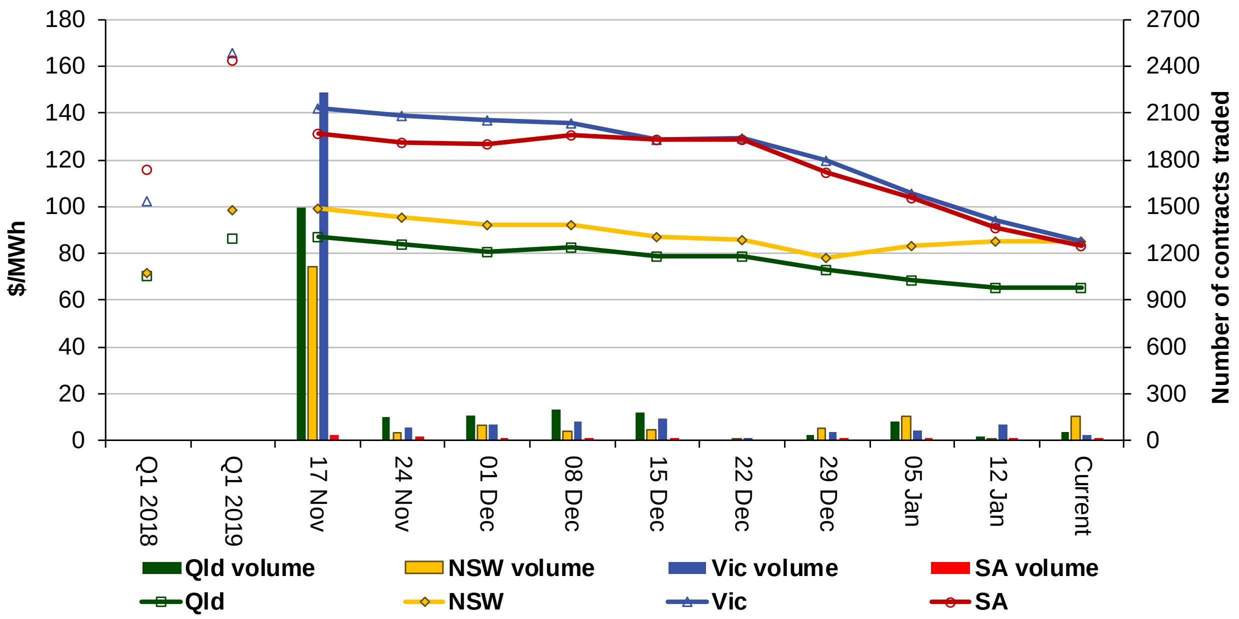


Source. ASXEnergy.com.au

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.

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on 19 November 2019.

Figure 10: Price of Q1 2020 base contracts over the past 10 weeks (and the past 2 years)



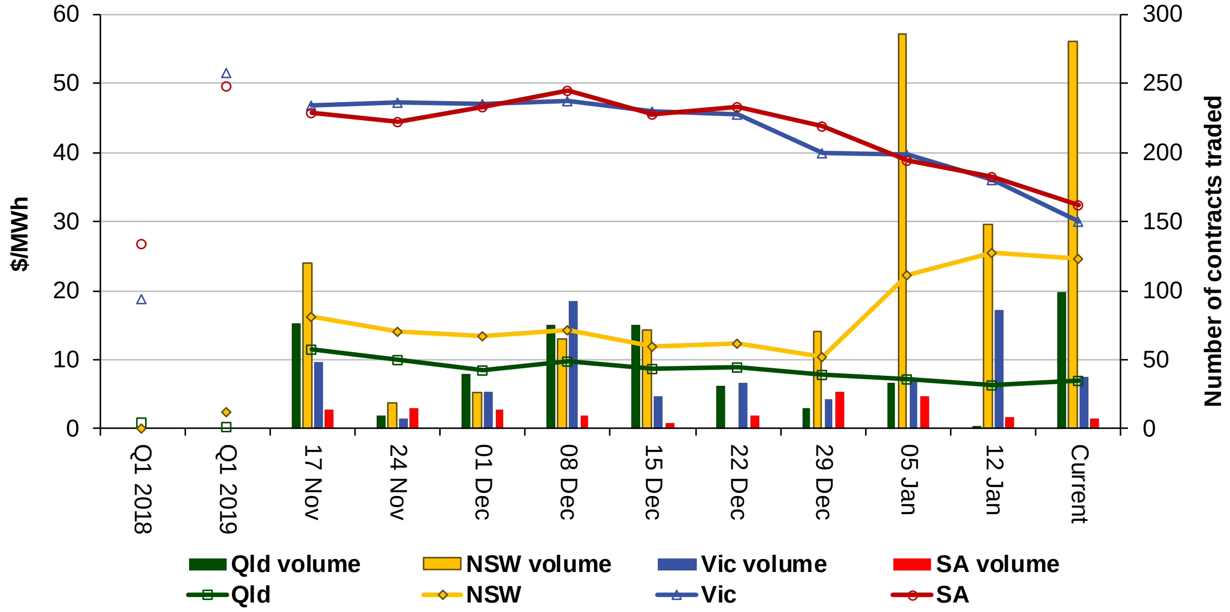
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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.

The high volume of trades and the doubling of prices for New South Wales cap contracts for the week starting 5 January 2020 is possibly due to market responses to high price events at the start of quarter 1 2020.

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