Electricity Report

AUSTRALIAN ENERGY REGULATOR

27 September – 3 October 2020

Weekly Summary

Weekly volume weighted average (VWA) prices were between $23/MWh in South Australia and $44/MWh in New South Wales. 2020-2021 financial year to date VWA prices are between $20/MWh to $50/MWh lower than the same time last year.

High wind generation in South Australia throughout the week led to a series of negative prices, which are detailed in our market analysis section below.

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 27 September to 3 October 2020.

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

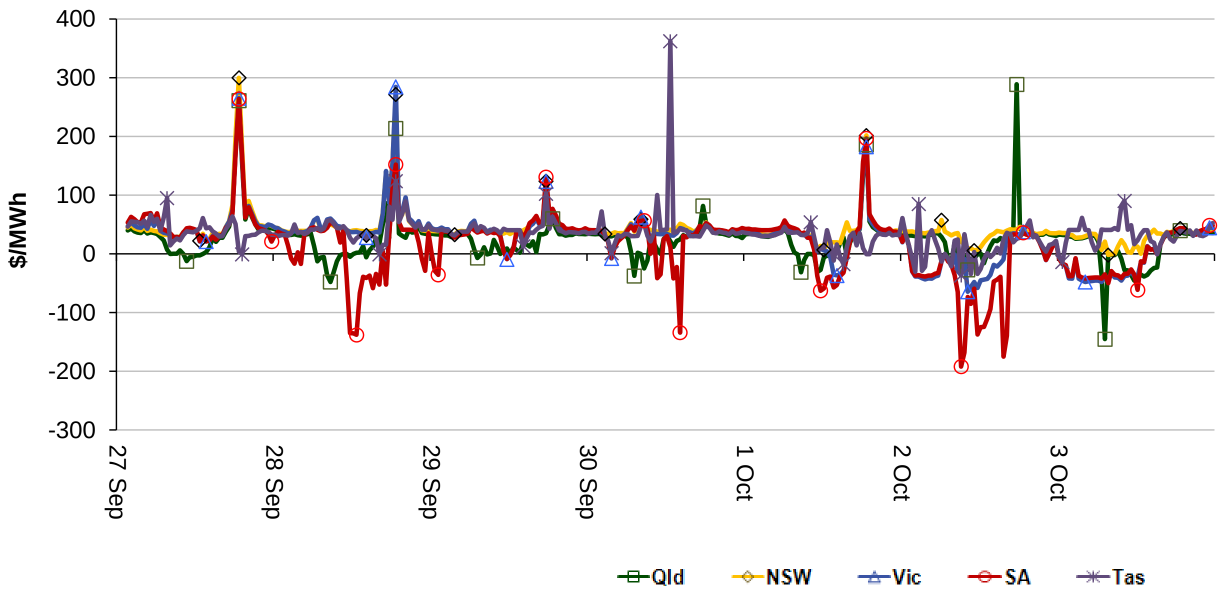


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous three financial years.

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

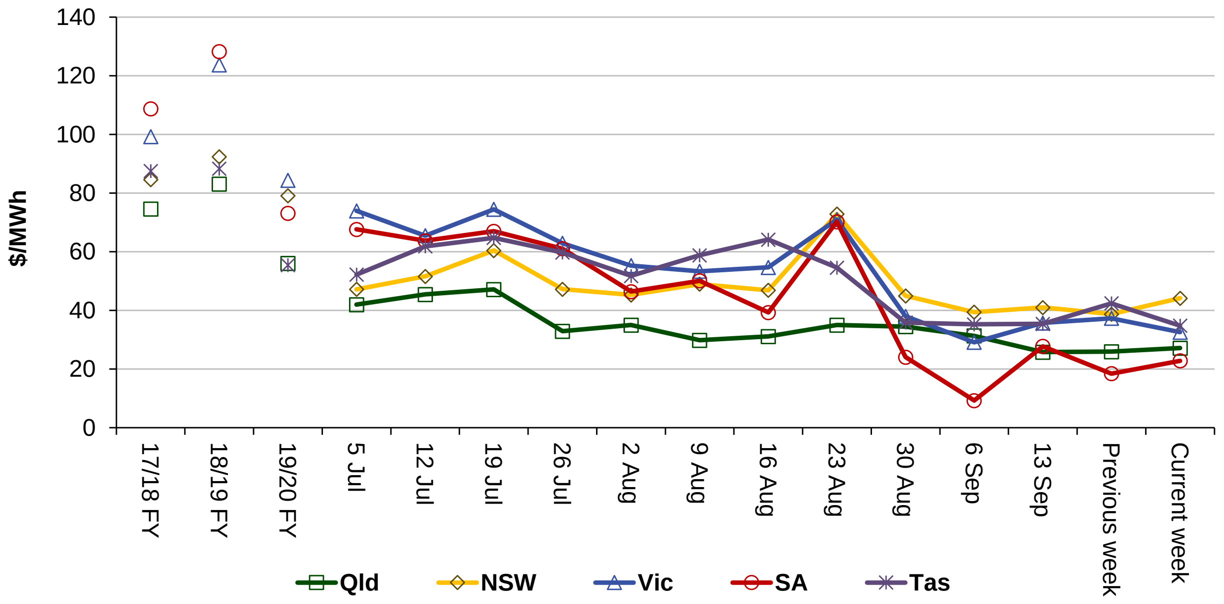


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	27	44	33	23	35
Q4 2019 QTD	70	118	113	64	95
Q4 2020 QTD	23	35	9	4	24
19-20 financial YTD	66	87	103	82	70
20-21 financial YTD	34	48	53	45	50

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 234 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	11	28	0	2
% of total below forecast	8	44	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

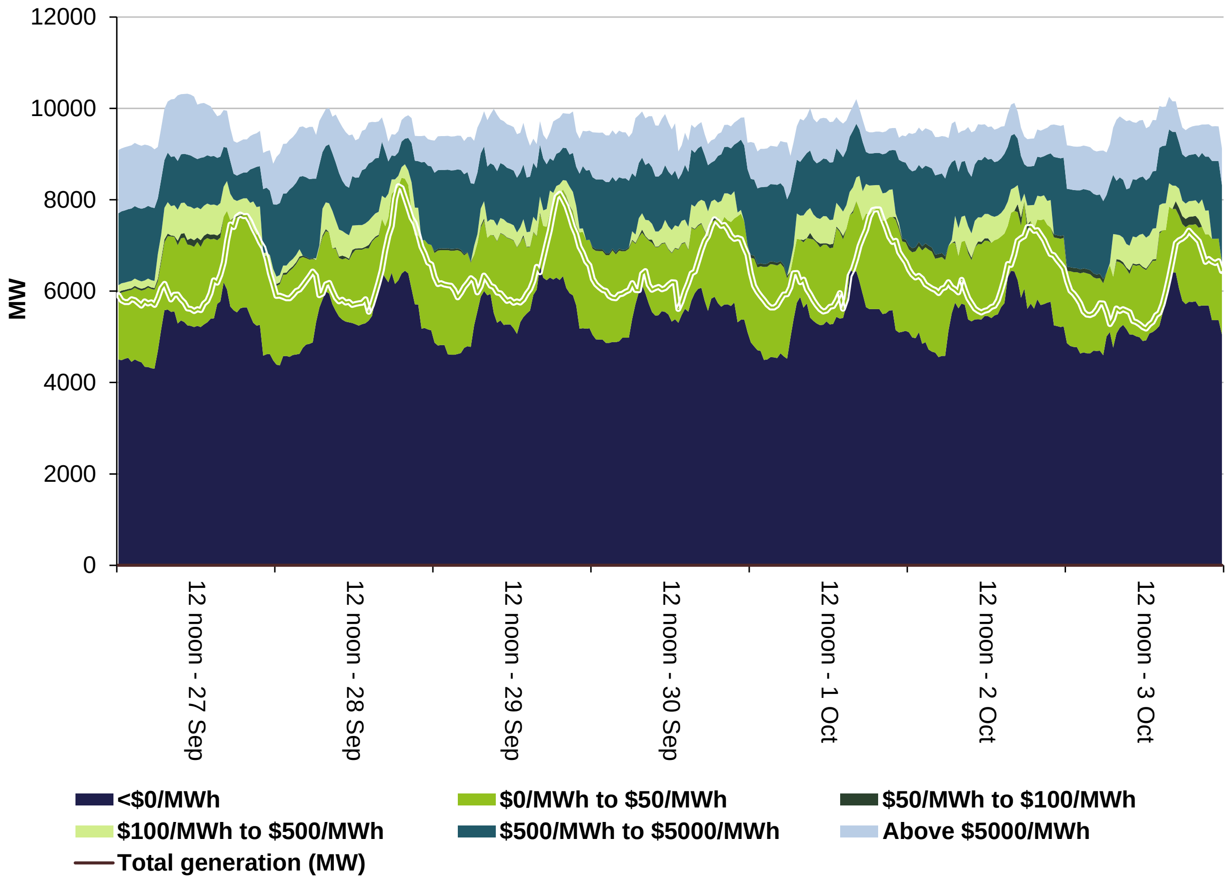


Figure 4: New South Wales generation and bidding patterns

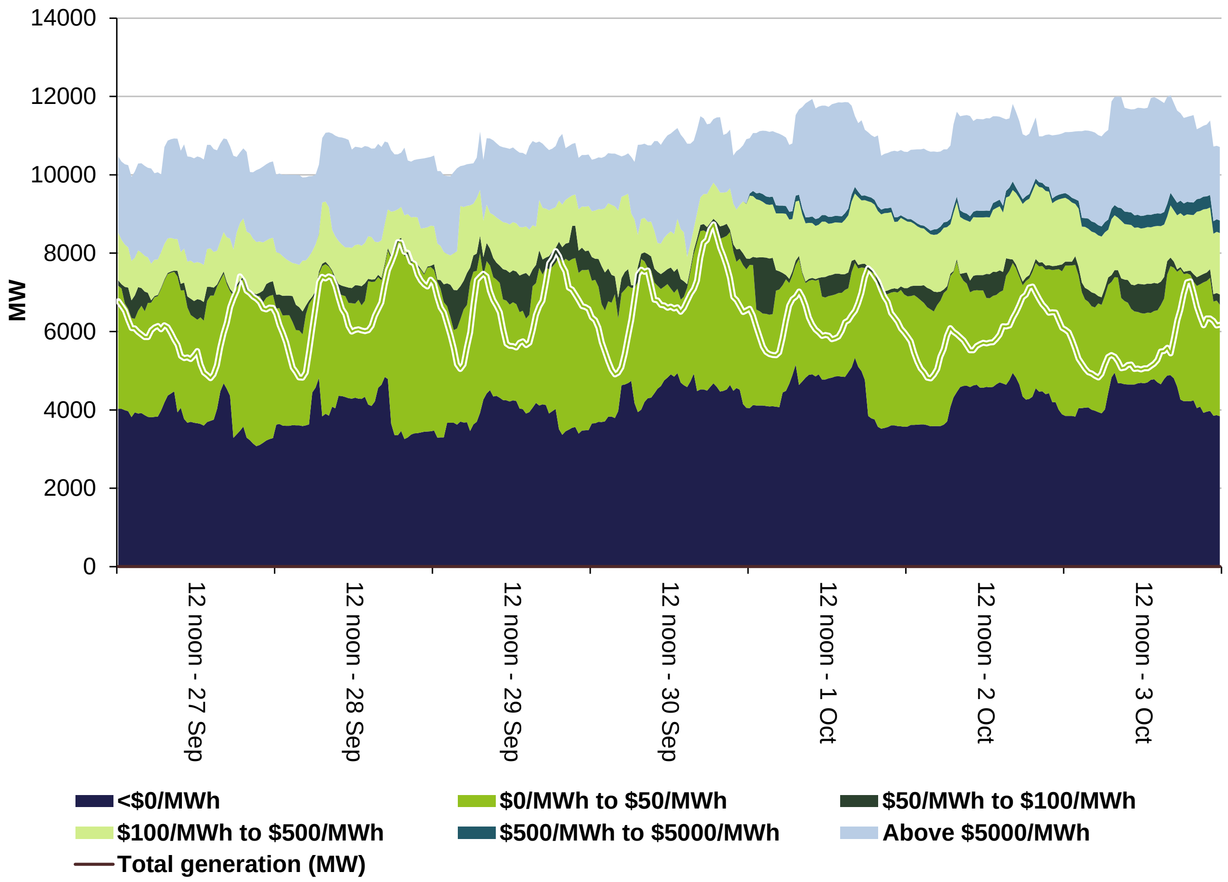


Figure 5: Victoria generation and bidding patterns

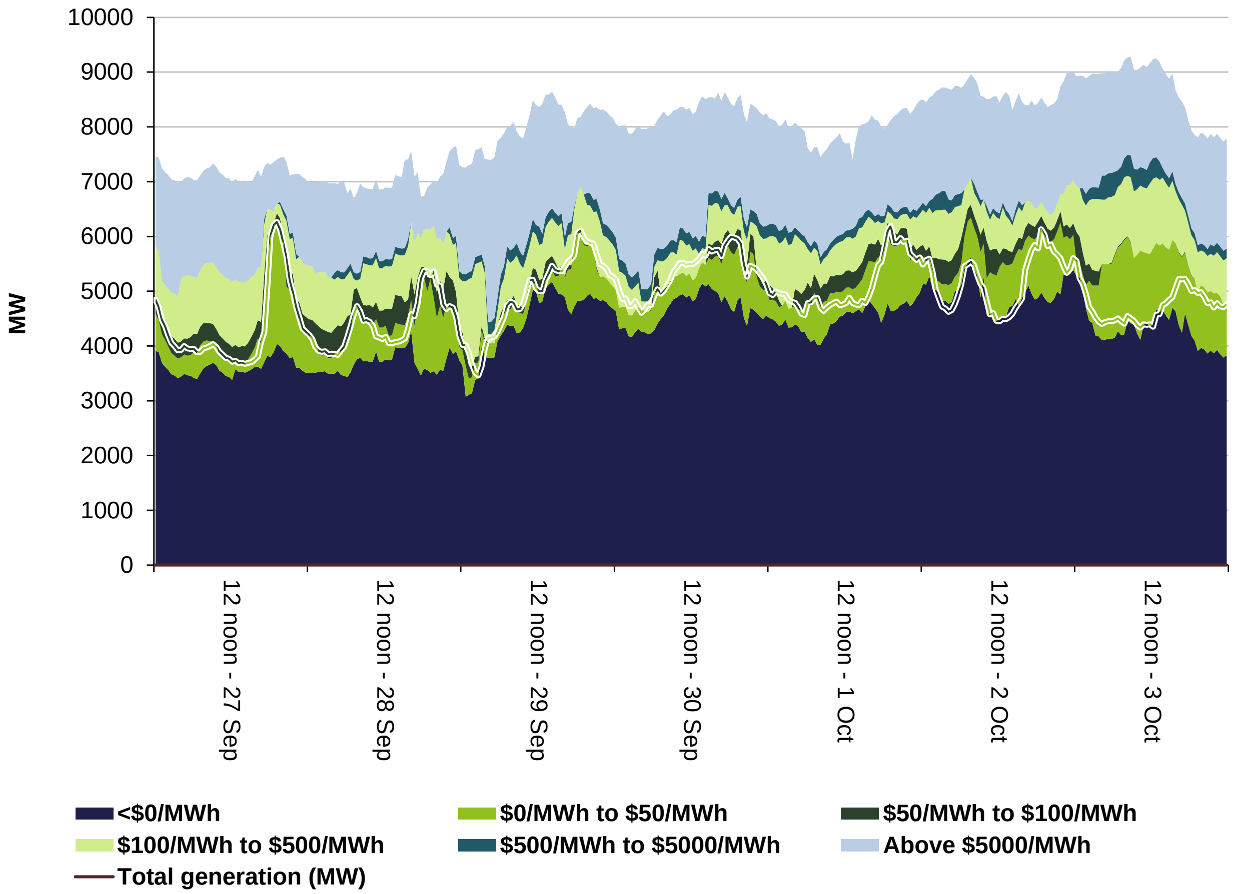


Figure 6: South Australia generation and bidding patterns

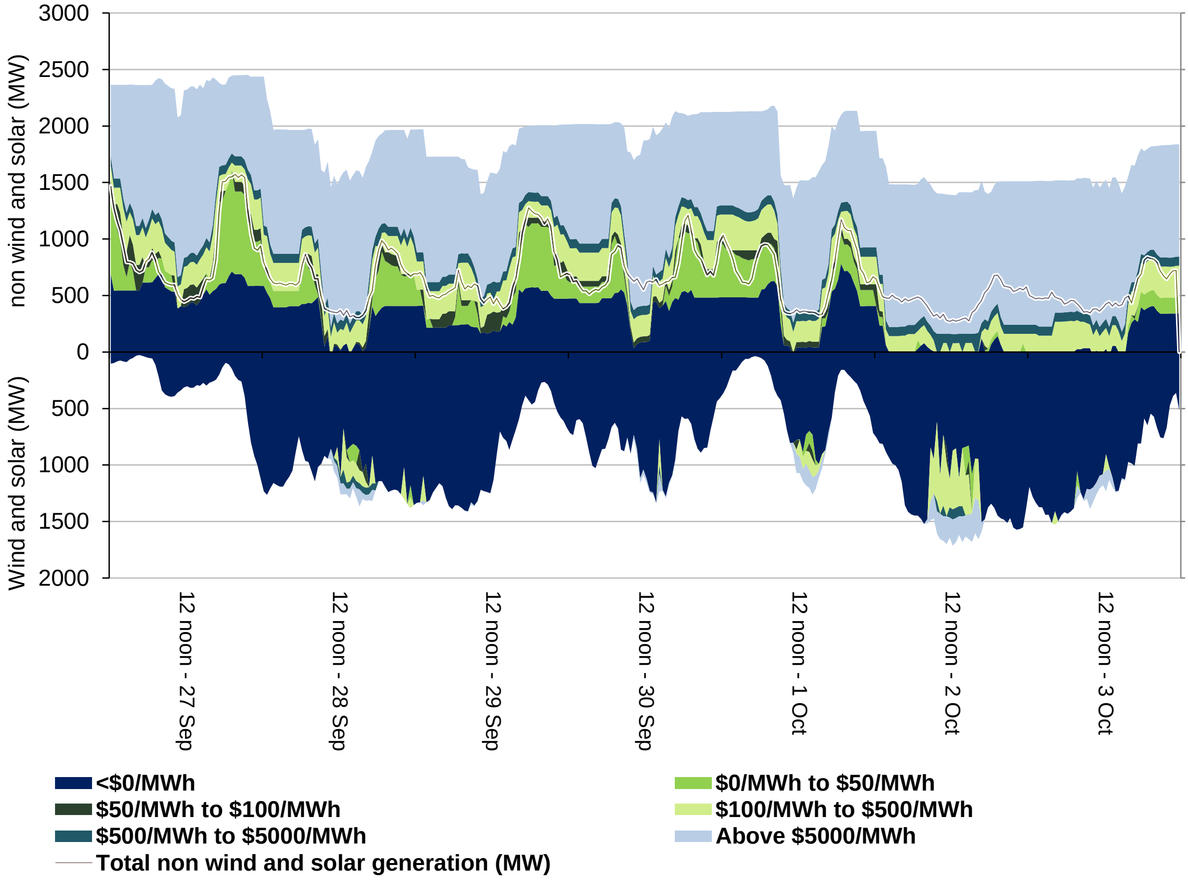
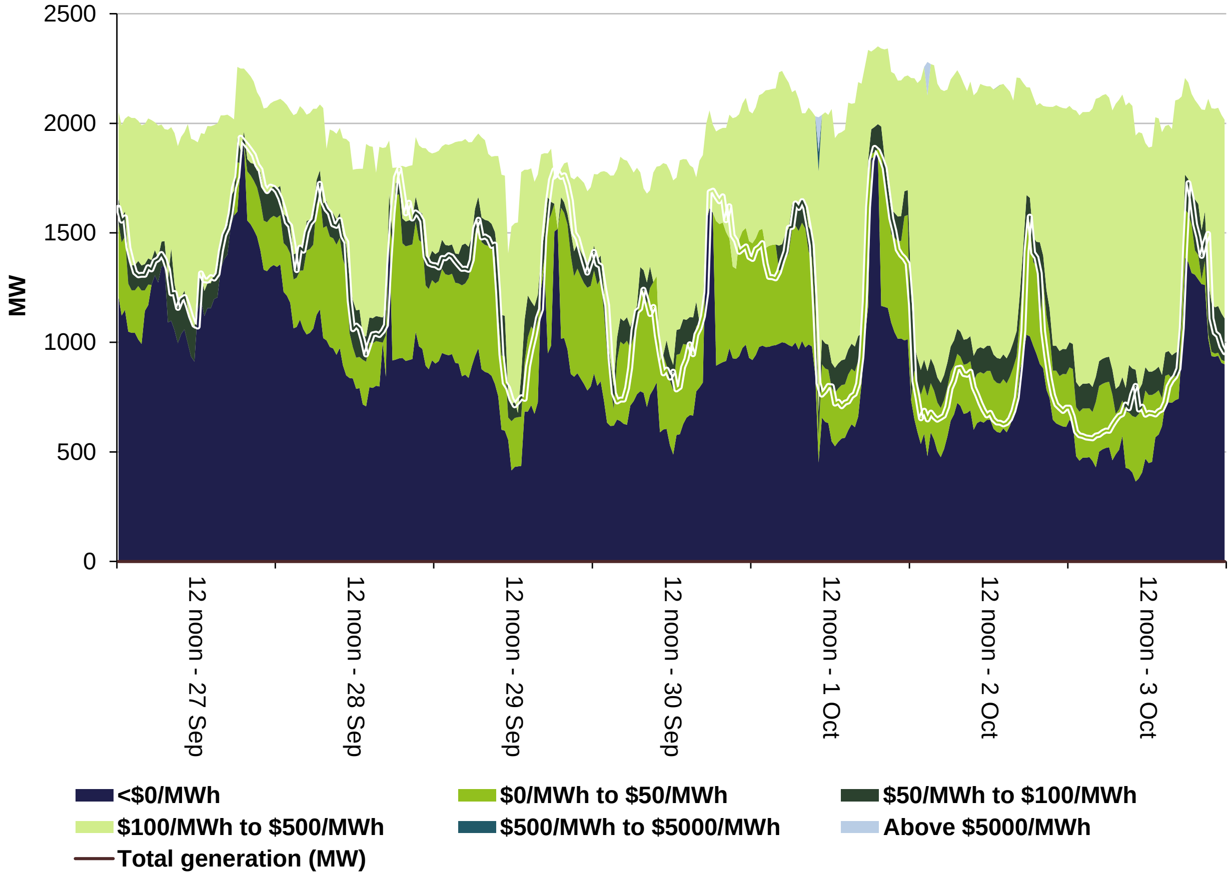


Figure 7: Tasmania generation and bidding patterns



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.

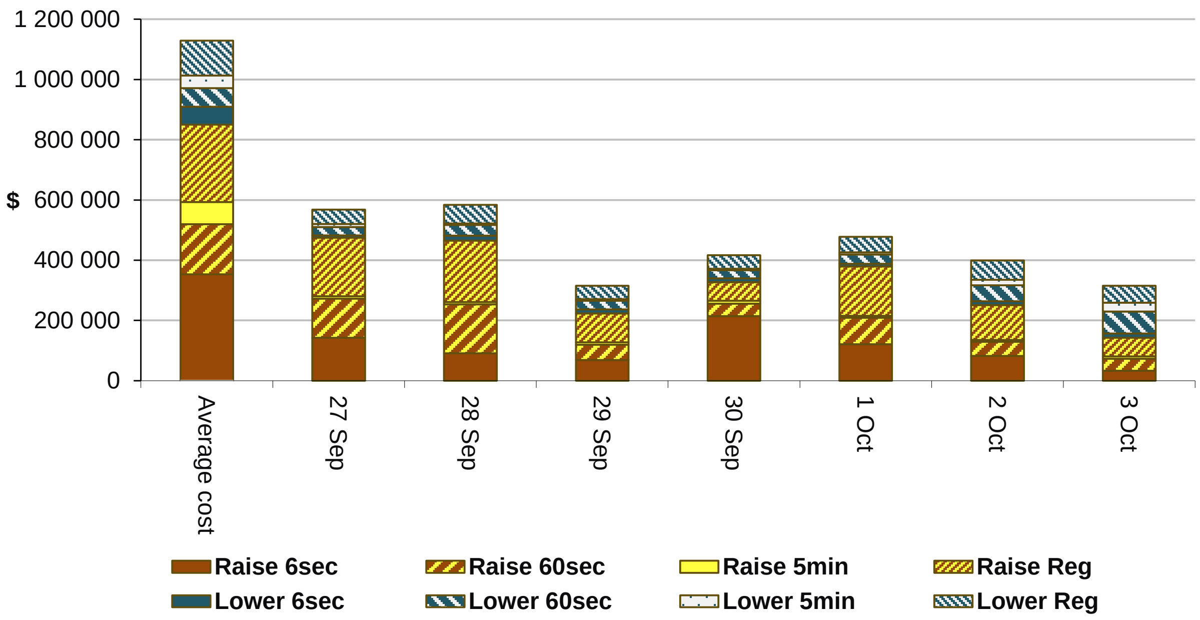
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 582 000 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $493 500 or less than 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 on the mainland was greater than three times the New South Wales weekly average price of $44/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Sunday, 27 September

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	299.99	318.69	363.11	23 021	23 875	24 025	19 189	19 441	19 385

Prices were aligned across mainland regions and will be treated as one region. Prices were close to forecast.

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $27/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Friday, 2 October

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
6 pm	288.86	38.47	36.06	6789	6675	6633	9376	9165	9218

Demand was 114 MW higher than forecast and availability was 211 MW higher than forecast, four hours prior. Higher availability was mainly due to Origin Energy adding in around 140 MW of capacity at the cap, when a unit at Mount Stuart returned to service at 3.15 pm.

Network constraints relating to the upgrade of the QNI interconnector forced flows into New South Wales. At 5.50 pm demand increased by over 40 MW, with flows forced into New South Wales, lower-priced generation was either fully dispatched or ramp-constrained. As a result, the price was set at $1536/MWh for one dispatch interval.

Saturday, 3 October

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	-145.21	16.00	0.00	4872	5007	4946	9733	9759	9740

Demand was 135 MW lower than forecast and availability was close to forecast, four hours prior. At 7.05 am demand dropped by almost 50 MW and with a number of plants ramp-constrained or trapped/stranded in FCAS and unable to set price, the price dropped to the floor for five minutes.

New South Wales

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 $44/MWh and above $250/MWh.

Monday, 28 September

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
7 pm	271.64	107.14	299.99	9272	9407	9490	10 523	10 734	10 727

Prices were aligned across New South Wales and Victoria and will be treated as one region. Demand was collectively 135 MW lower than forecast and availability was collectively around 1270 MW lower than forecast, four hours prior. Lower than forecast availability was mainly due to the trip of EnergyAustralia's Yallourn unit 4 (396 MW) and Alinta Energy's LoyYang B unit 2 (580 MW) all priced below $9/MWh. There was also lower than forecast wind generation in New South Wales (mostly priced below $0/MWh).

The lower than forecast availability resulted in the dispatch price settling around $300/MWh for the majority of the trading interval.

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $33/MWh and above $250/MWh.

Monday, 28 September

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
7 pm	284.66	105.66	299.50	6109	6109	6033	6914	7971	7754

Prices were aligned across New South Wales and Victoria. See the New South Wales section for analysis.

South Australia

There were 12 occasions where the spot price was below -$100/MWh.

Monday, 28 September

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
Midday	-134.99	-200.00	-1000.00	712	671	715	2649	2698	2713
12.30 pm	-135.18	-649.33	-1000.00	795	639	661	2820	2728	2738
1 pm	-137.88	-999.00	-1000.00	683	624	650	2833	2767	2759

For the midday trading interval demand was 41 MW higher than forecast and availability was 49 MW lower than forecast, four hours prior. Lower than forecast availability was due to lower than forecast solar generation, most of which was priced below $0/MWh. Continuous rebidding of capacity up and down in the four hours prior to dispatch resulted in 99 MW less capacity offered at the floor at the time of dispatch. This resulted in dispatch prices between -$650/MWh and $33/MWh.

For the 12.30 pm trading interval demand was 156 MW higher than forecast and availability was 92 MW higher than forecast. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh. Continuous rebidding of capacity up and down in the four hours prior to dispatch resulted in 64 MW less offered at the floor at the time of dispatch. Co-optimisation between the FCAS and energy markets, higher than forecast demand and rebidding capacity resulted in dispatch prices above -$123/MWh for all but the last dispatch interval where the price fell to -$649/MWh.

For the 1 pm trading interval demand was 59 MW higher than forecast and availability was 66 MW higher than forecast. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh. The price dropped to the floor at 12.35 pm as forecast and in response participants rebid over 210 MW from the floor to prices above $300/MWh. This resulted in dispatch prices above $30/MWh for the remainder of the trading interval.

Wednesday, 30 September

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
2.30 pm	-134.02	-183.00	9.98	1223	906	987	3253	2988	3071

Demand was 317 MW and availability was 265 MW greater than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was offered below $0/MWh.

There was little capacity offered between the floor and -$3/MWh so small changes in demand or availability could cause large fluctuations in price. At 2.25 pm demand dropped by 24 MW and with capacity priced above the floor ramp-constrained and unable to set price, the price dropped to the floor for one dispatch interval.

Friday, 2 October

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
9.30 am	-191.91	-649.33	-1000.00	935	809	827	2901	2790	2768
10 am	-168.24	-1000.00	-1000.00	870	729	740	3011	2829	2774
Midday	-137.17	-1000.00	-1000.00	729	547	578	3036	2867	2826
12.30 pm	-124.95	-1000.00	-1000.00	716	564	589	3106	2874	2834
1 pm	-124.55	-1000.00	-1000.00	718	578	586	3072	2853	2838
1.30 pm	-110.14	-1000.00	-1000.00	748	621	606	3013	2877	2837
4 pm	-175.19	-40.00	-649.33	1024	991	885	3039	2876	2802
4.30 pm	-139.29	18.58	-2.37	1098	1044	978	3093	2849	2807

Conditions saw demand between 33 MW and 182 MW higher than forecast, while availability was between 111 MW to 244 MW higher than forecast, both four hours prior. Higher availability was due to higher than forecast renewable generation, most of which was offered below $0/MWh.

For the 9.30 am trading interval higher than forecast demand and ramp-rated generators that were unable to set price resulted in prices around -$40/MWh for the first four dispatch intervals.

For the 10 am trading interval three wind farms rebid 400 MW of capacity from greater than - $190/MWh to the floor. As a result, the price hit the floor for one dispatch interval. In response participants rebid 515 MW of capacity from the floor to prices above -$37/MWh. Prices were set above -$30/MWh for the remainder of the trading interval.

For the midday to 1.30 pm trading intervals, during the morning participants shifted around 500 MW of capacity from the floor to prices above -$100/MWh in response to forecast prices. This resulted in price settling around -$110/MWh to - $125/MWh for all trading intervals.

For the 4 pm and 4.30 pm trading intervals, the price fell to the floor once during each trading interval due to multiple windfarms rebidding up to 400 MW of capacity priced above -$190/MWh to the floor. In response, participants rebid up to 600 MW of capacity in each trading interval to prices above -$100/MWh.

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.

Wednesday, 30 September

Table 11: Price, Demand and Availability

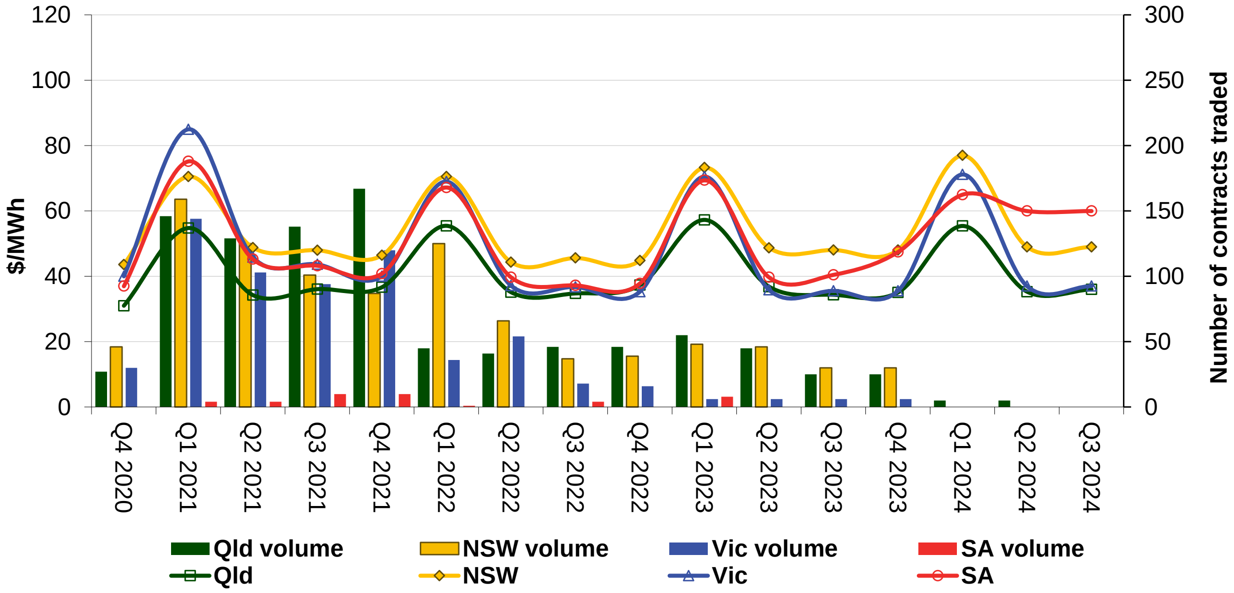
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
1 pm	362.48	400.02	400.02	1052	1089	1078	1778	1776	1788

Prices were close to forecast.

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.

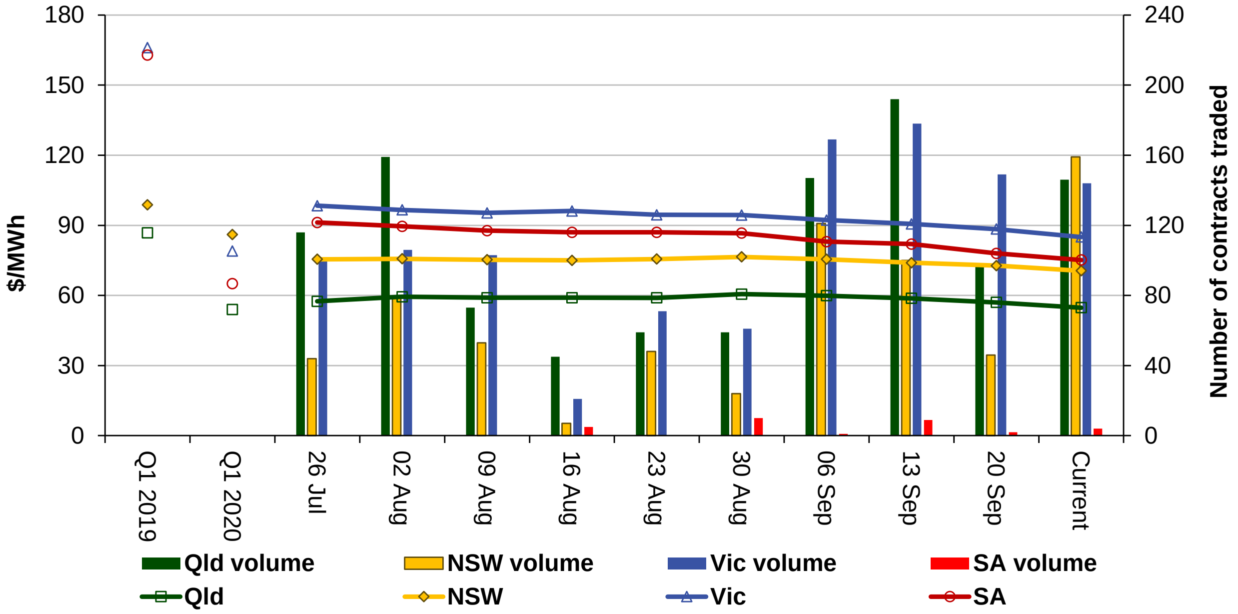
Figure 9: Quarterly base future prices Q4 2020 – Q3 2024



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 Q1 2019 and Q1 2020 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

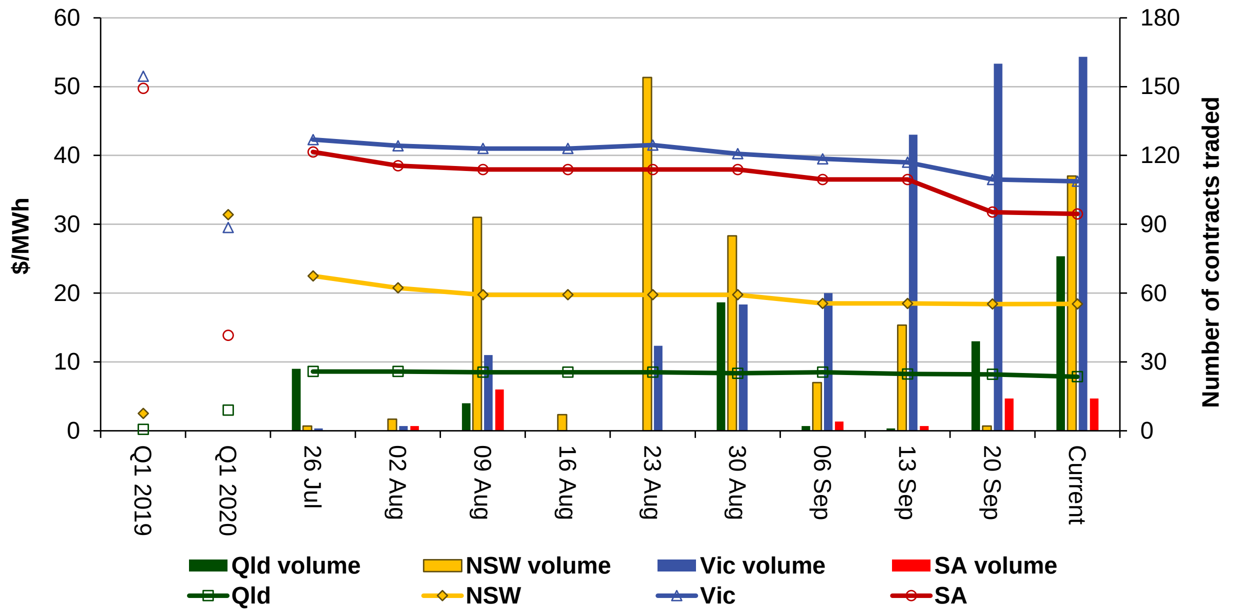
Figure 10: Price of Q1 2021 base contracts over the past 10 weeks (and the past 2 years)



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 Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q1 2020 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
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