Electricity Report

AUSTRALIAN ENERGY REGULATOR

28 February– 6 March 2021

Weekly Summary

Volume weighted average (VWA) prices for the week ranged from $22/MWh in Victoria to $53/MWh in Queensland. Queensland spot prices reached over $2,500/MWh on 5 March, driven by a 5-minute increase in demand.

Planned line outages in Victoria which affected the Heywood interconnector were completed on 3 March.

On Thursday 4 March Hydro Tasmania changed its offer profile with capacity previously priced between $100/MWh to $500/MWh to around $900/MWh (Figure 7).

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 28 February to 6 March 2021.

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

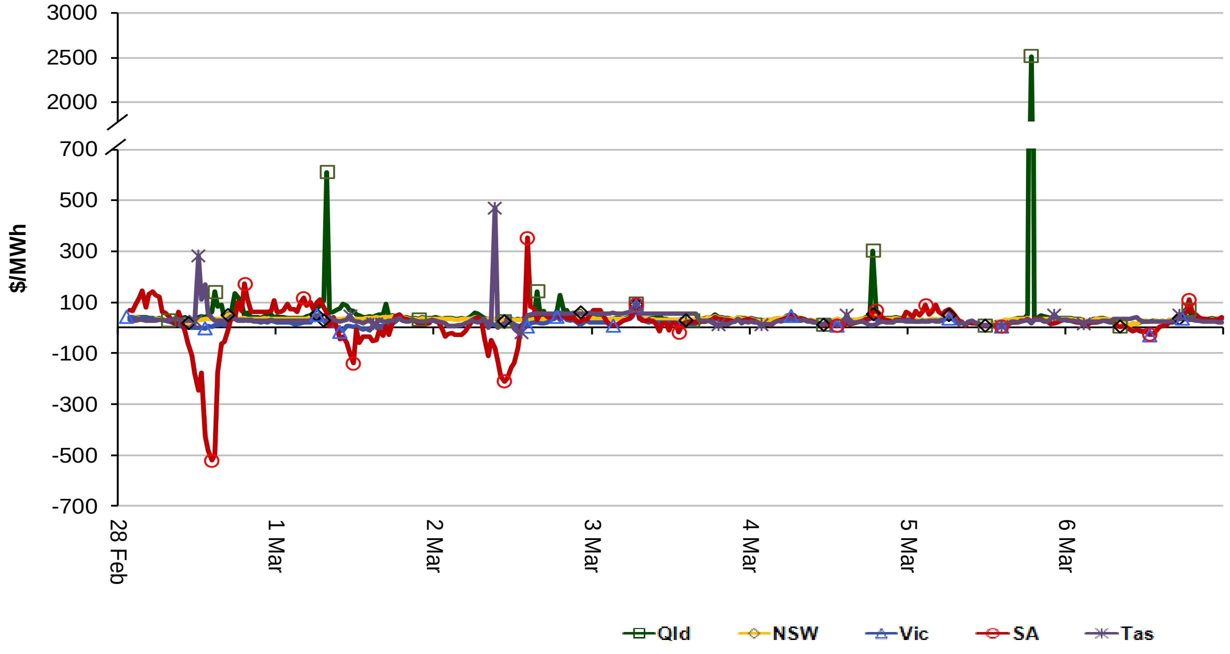


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

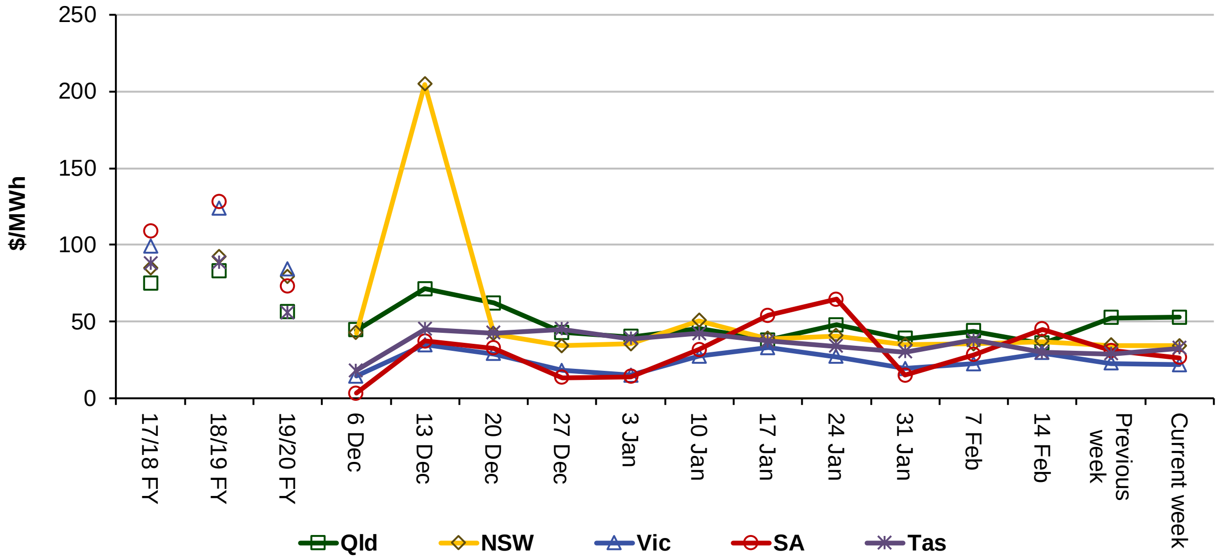


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	53	34	22	27	33
Q1 2020 (QTD)	63	129	133	95	47
Q1 2021 (QTD)	44	38	24	35	35
19-20 financial YTD	65	94	103	87	66
20-21 financial YTD	42	54	42	39	45

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 255 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2020 of 233 counts and the average in 2019 of 204. 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	4	17	0	2
% of total below forecast	18	51	0	8

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

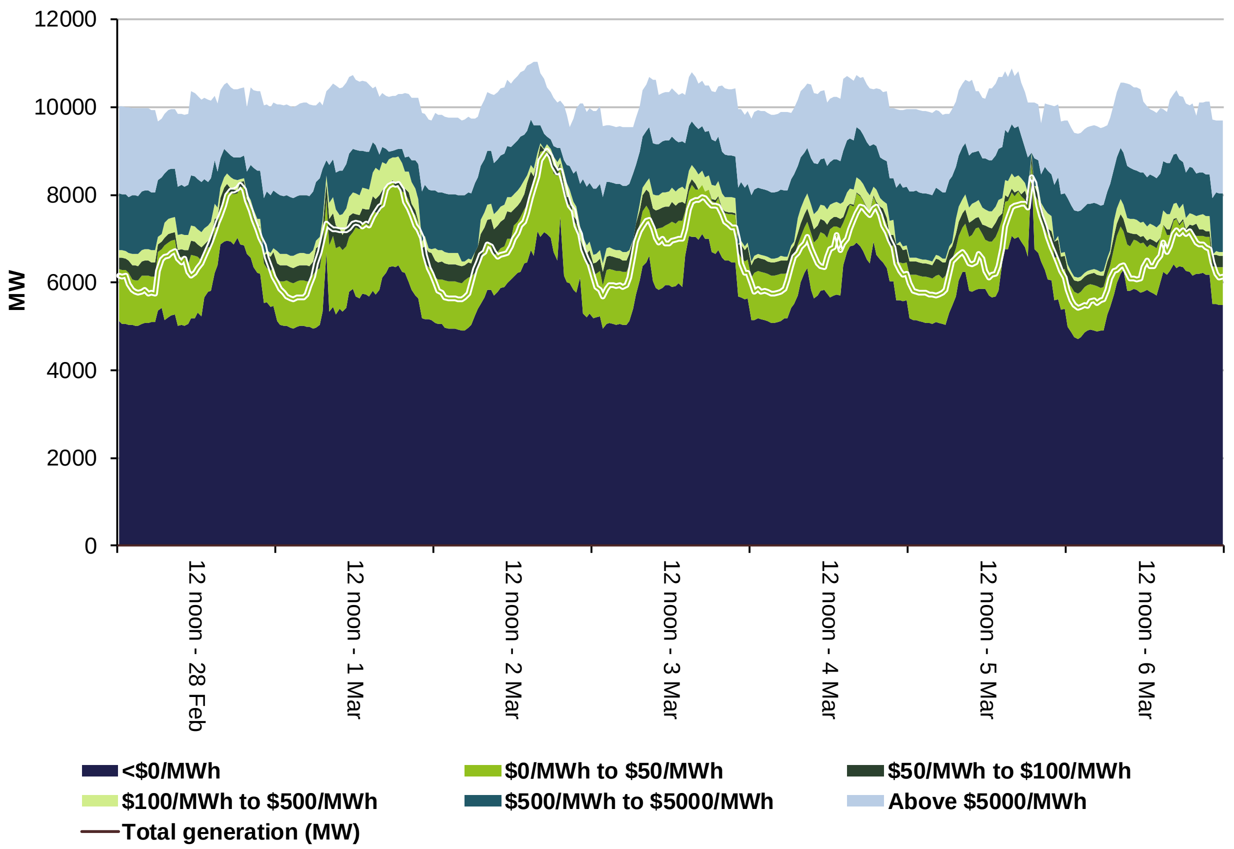


Figure 4: New South Wales generation and bidding patterns

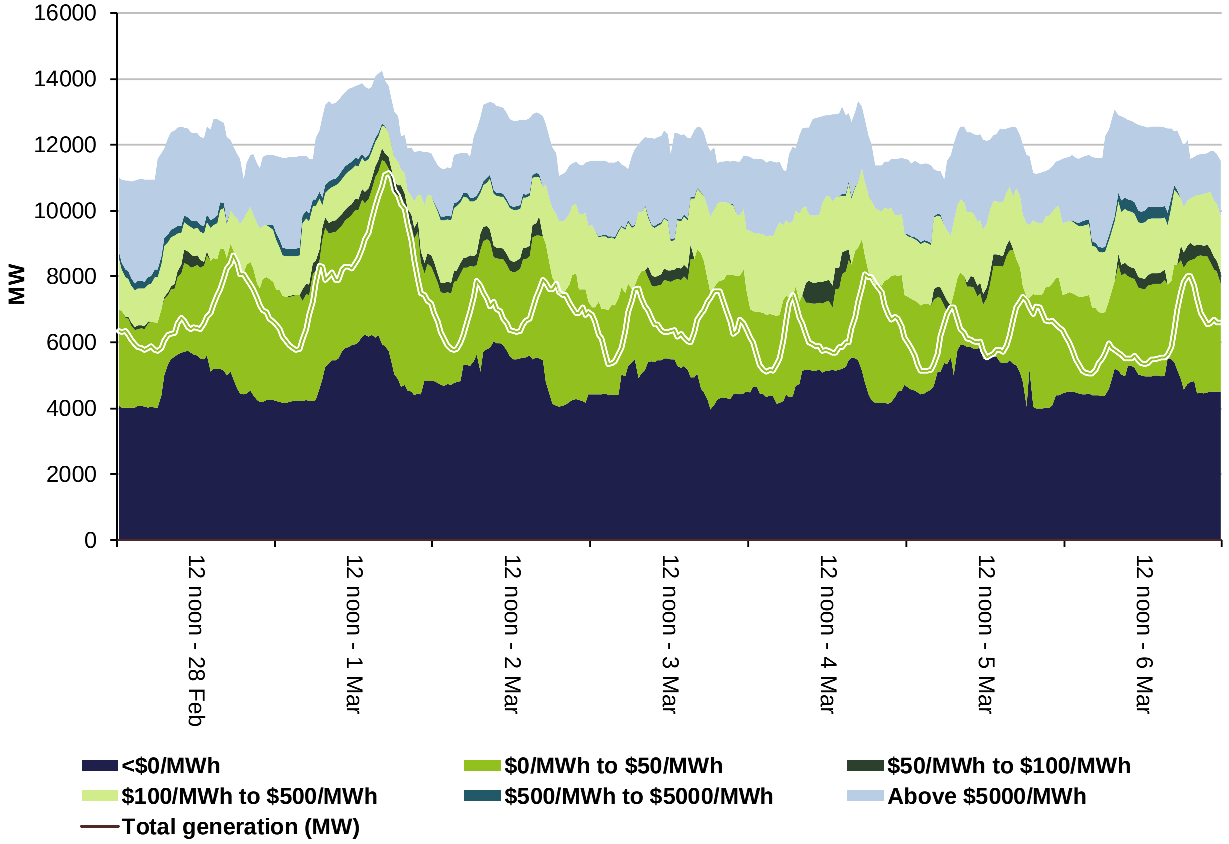


Figure 5: Victoria generation and bidding patterns

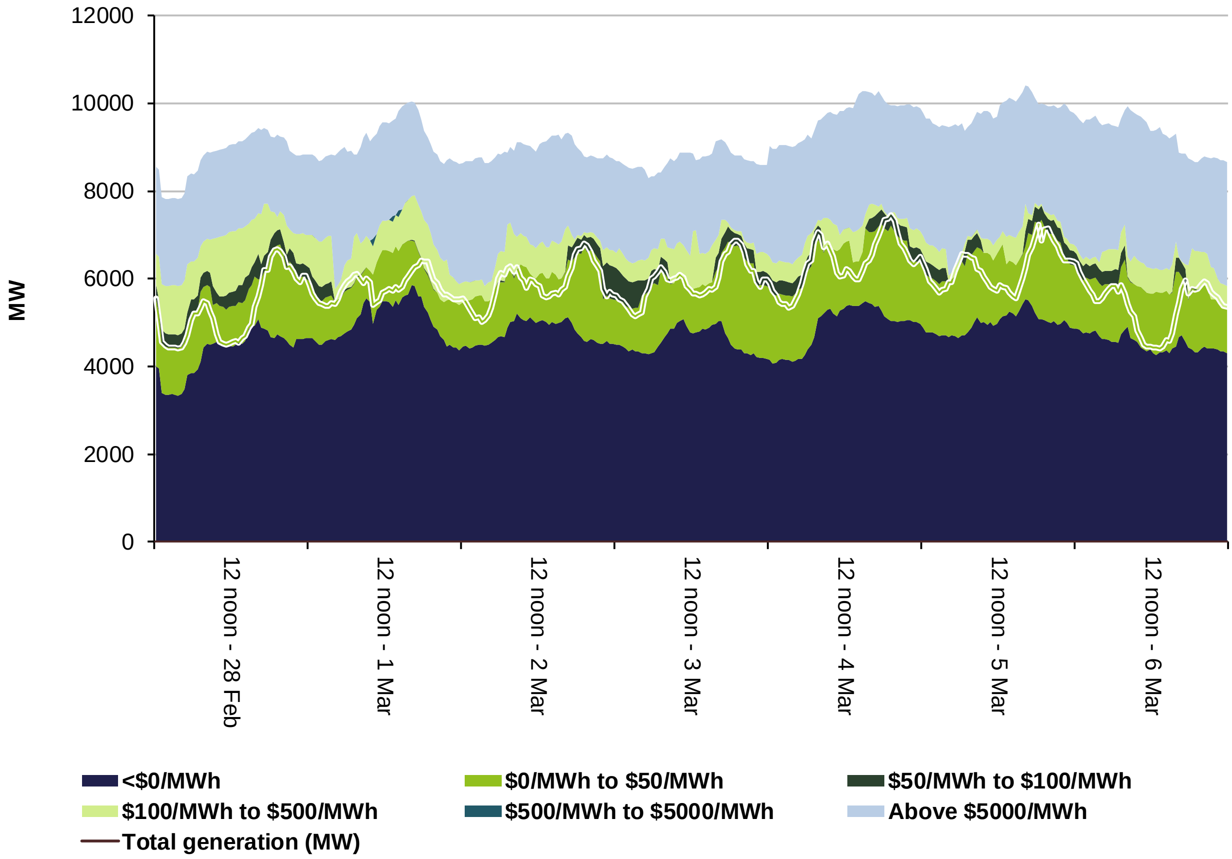


Figure 6: South Australia generation and bidding patterns

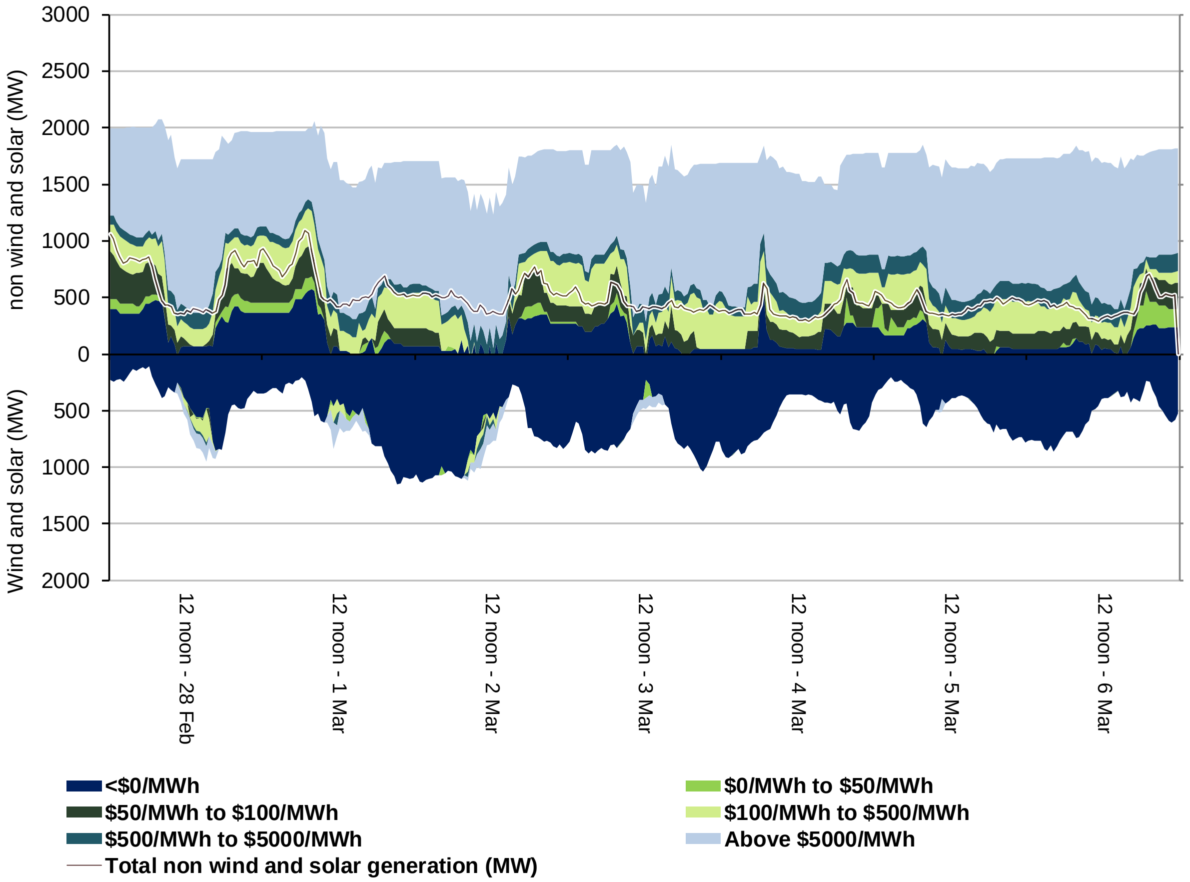
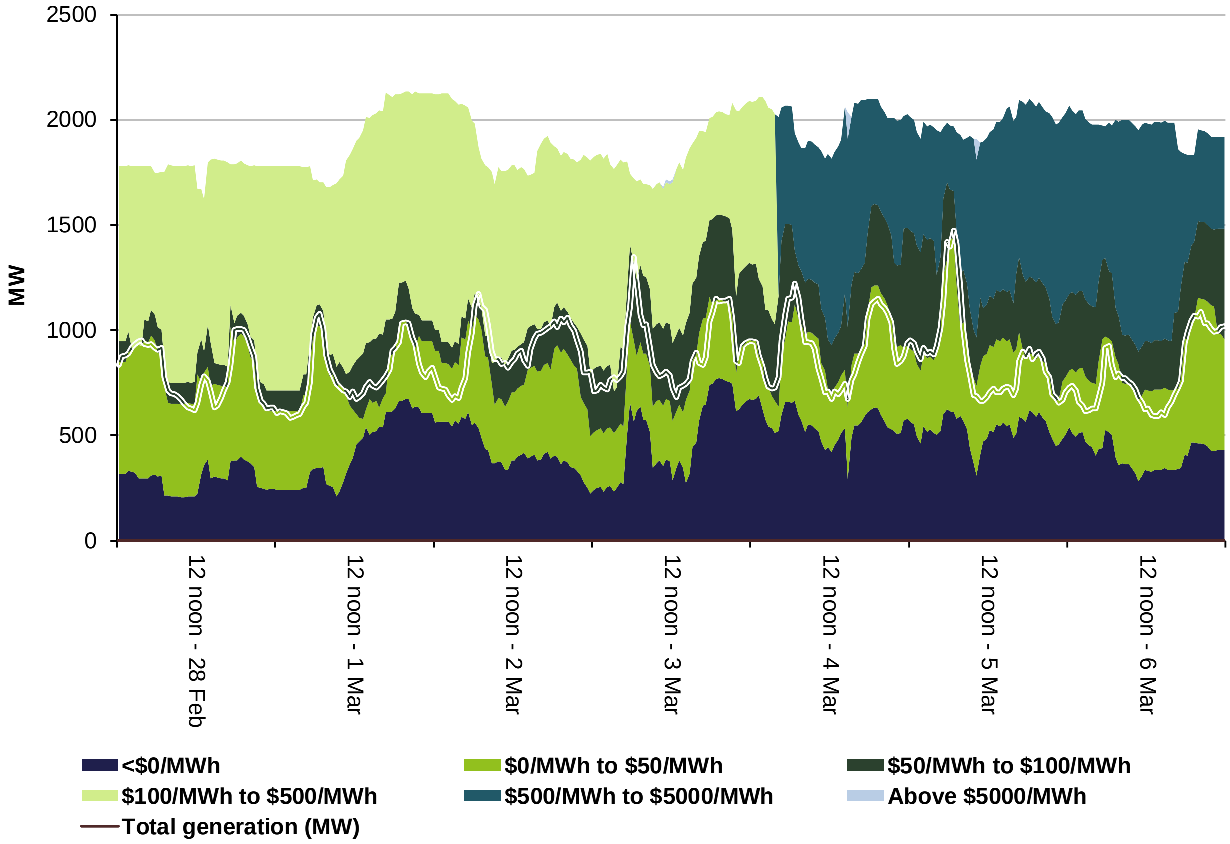


Figure 7: Tasmania generation and bidding patterns



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.

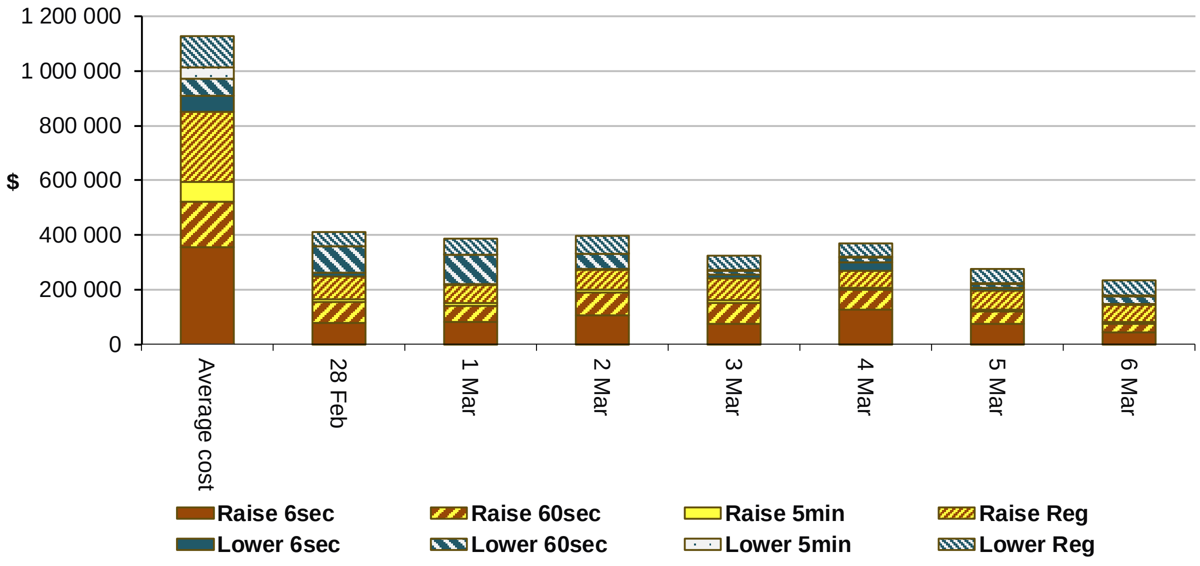
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1,726,000 or around 1% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $669,000 or less than 12% 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 three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $53/MWh and above $250/MWh.

Monday, 1 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
8 am	610.35	90.73	55.73	7,298	7,043	6,958	10,232	10,382	10,413

Demand was 255 MW higher than forecast, while availability was 150 MW less than forecast, 4 hours prior. Less than forecast availability was due to lower than forecast renewable generation, all of which was priced below $0/MWh.

At 7.35 am, a step change in availability saw higher priced generation required to meet demand. With several generators unable to come on in 5 minutes or ramp constrained, the dispatch price increased to $3,500/MWh for one dispatch interval. In response, participants rebid 140 MW of capacity from the price cap to the price floor. Prices remained below $34/MWh for the remainder of the trading interval.

Thursday, 4 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	301.98	59.50	301.12	7,779	7,713	7,772	10,410	10,200	10,203

Demand was close to forecast while availability was 210 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation and rebids at Darling Downs Power Station which added 120 MW at $0/MWh due to plant reasons.

At 6.45 pm, demand increased by nearly 90 MW. With several generators unable to come on in 5 minutes, the dispatch price was set at $1,552/MWh. In response, participants rebid 162 MW from prices above $1,500/MWh to the price floor. Prices remained below $47/MWh for the remainder of the quarter.

Friday, 5 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	2,512.61	301.12	301.12	7,927	7,931	7,812	10,100	10,030	9,956

Demand and availability were close to forecast, 4 hours prior.

At 6.35 pm, demand increased by nearly 150 MW. With several generators unable to come on in 5 minutes or ramp up-constrained and unable to set price, the dispatch price was set at $14,999/MWh. In response, participants rebid over 850 MW of capacity from prices above $591/MWh to prices below $0/MWh. Prices remained below $23/MWh for the remainder of the trading interval.

South Australia

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

Sunday, 28 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
11.30 am	-107.18	-180.20	-510.17	492	535	552	2,152	2,074	2,176
Midday	-179.53	-566.10	-492.20	479	502	525	2,245	2,128	2,210
12.30 pm	-245.42	-549.37	-1,000	459	496	514	2,305	2,191	2,256
1 pm	-178.75	-521.08	-1,000	484	468	499	2,425	2,243	2,312
1.30 pm	-426.74	-500.45	-1,000	473	466	502	2,481	2,268	2,348
2 pm	-480.84	-502.66	-1,000	484	452	510	2,546	2,284	2,382
2.30 pm	-520.47	-520.44	-1,000	508	529	545	2,558	2,319	2,416
3 pm	-500.02	-506.54	-1,000	568	567	578	2,587	2,369	2,450
3.30 pm	-175.30	-516.65	-1,000	608	619	644	2,663	2,426	2,485

For the 11.30 am to 1.30 pm, and 3.30 pm trading intervals, demand was close to forecast, and availability was between 78 MW and 237 MW higher than forecast, 4 hours prior. Higher than forecast availability was mainly due to higher than forecast renewable generation, most of which was priced below $0/MWh.

Up to 4 hours prior to the start of each trading interval, participants rebid at least around 299 MW from prices below -$649/MWh to prices above -$89/MWh, due to forecast prices or plant reasons. Additionally, rebids throughout the trading intervals shifted capacity from low to high prices in response to forecast prices. In each trading interval there was little capacity priced between -$33/MWh and the price floor, so small changes in demand or availability could result in large fluctuations in price. As a result, spot prices were set higher than forecast.

For the 2 pm, 2.30 pm and 3 pm trading intervals, prices were close to forecast, 4 hours prior.

Monday, 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
Midday	-140.01	-200	-870.02	724	686	655	2,426	2,245	2,278

Demand was 38 MW higher than forecast and availability was 181 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh.

A rebid by Vena Energy Services at Tailem Bend Solar Farm at 10.28 am shifted 95 MW from the price floor to the price cap due to forecast prices. Throughout the trading interval, due to a combination of participants rebidding capacity to higher prices, and a sudden drop in wind generation, prices were set higher than forecast.

Tuesday, 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	-111.71	-190	-572.19	1,260	1,151	1,157	2,480	2,379	2,394
10 am	-132.61	-510.69	-830.34	951	874	881	2,326	2,358	2,256
10.30 am	-190	-506.11	-1000	826	803	806	2,342	2,308	2,335
11 am	-210.63	-649.33	-1000	755	745	746	2,240	2,242	2,259
11.30 am	-198.33	-498.47	-998.99	727	712	704	2,125	2,166	2,173
Midday	-154.77	-509.07	-649.33	657	681	671	2,112	2,072	2,083
12.30 pm	-138.33	-190	-334.67	665	658	652	2,109	1,988	2,011
2.30 pm	351.91	-190	-190	787	689	681	1,820	1,830	1,871

For the 8.30 am and 10 am to 12.30 pm trading intervals, demand was close to and up 109 MW higher than forecast, while availability was between 41 MW lower than forecast and 121 MW higher than forecast, 4 hours prior. Variations in forecast availability was due to variations in wind generation, most of which was priced below $0/MWh, and rebids by Origin Energy at Quarantine which removed 29 MW, mostly priced at the floor, due to plant reasons.

Up to 4 hours prior to the start of each trading interval, participants rebid at least 300 MW of capacity from prices from the price floor to price above -$80/MWh due to forecast prices. Additionally, rebids throughout the trading intervals shifted capacity from low to high prices in response to forecast prices. As a result, prices were set higher than forecast in each trading interval.

For the 2.30 pm trading interval, demand was 98 MW higher than forecast while availability was close to forecast, 4 hours prior. Wind generation fell by nearly 90 MW throughout the trading interval. Constraints related to system strength requirements when South Australia is at risk of separation saw Bungala Solar Farm generation limited. With little capacity priced between -$33/MWh and $1,000/MWh, small changes in demand or availability could result in large fluctuations in price. As a result, the dispatch price reached above $1,000/MWh for the last two dispatch intervals.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $33/MWh and above $250/MWh.

Sunday, 28 February

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
12.30 pm	281.29	25.45	25.64	974	987	984	1,768	1,786	1,787

Demand and availability were close to forecast, 4 hours prior.

Constraints related to an outage of the Hadspen to George Town 220 kV line violated at 12.15 pm which reduced imports into Tasmania from Victoria over Basslink. Generators with capacity priced between $53/MWh and $390/MWh were trapped in FCAS and unable to set price, the dispatch price was above $398/MWh for the remainder of the interval.

Sunday, 2 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
9.30 am	470.42	55.38	-0.54	1,028	988	1,025	1,717	1,822	1,819

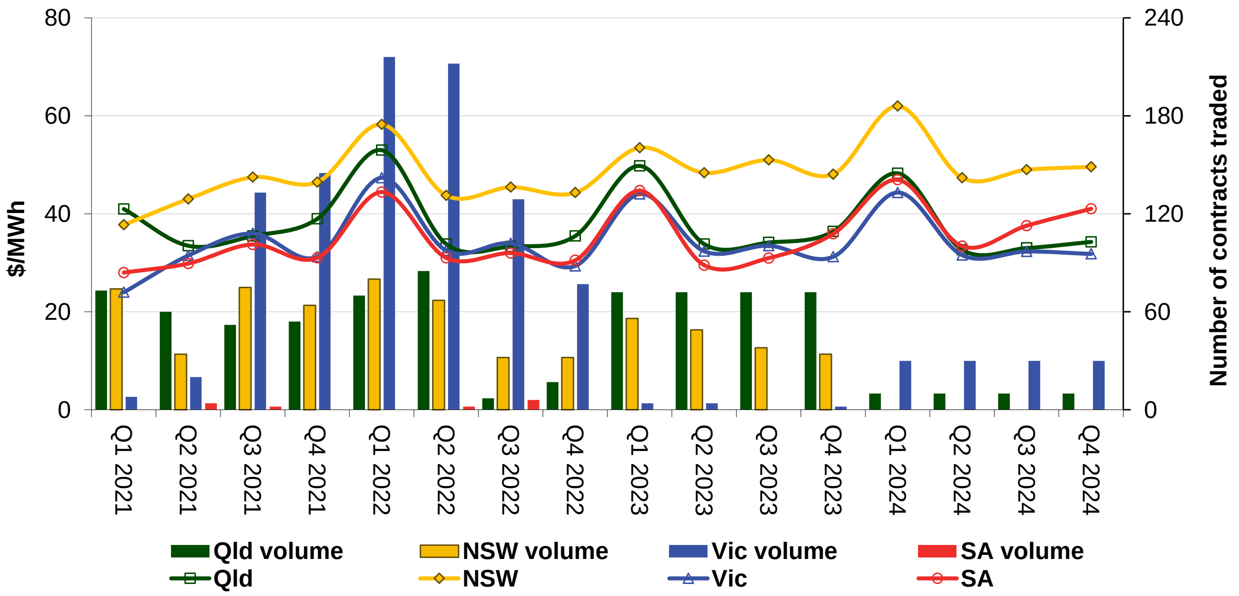
Demand was close to forecast while availability was 105 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind generation, nearly half of which was below $0/MWh and rebids throughout the trading interval by Hydro Tasmania at Tamar Valley GT which removed 65 MW of capacity due to plant reasons and forecast prices..

A constraint related to an outage to the Palmerston to Sheffield 220 kV line bound at 9.15 am, constraining several Tasmanian generators. Effective 9.15 am, Hydro Tasmania's rebid at Tamar Valley GT removed 40 MW of capacity from $398/MWh due to plant reasons, while a rebid by Wild Cattle Hill at Cattle Hill Wind Farm shifted 144 MW from the price floor to price cap due to the co-optimisation of energy revenues and FCAS costs. As a result, the dispatch priced reached $2,446/MWh for 5 minutes.

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.

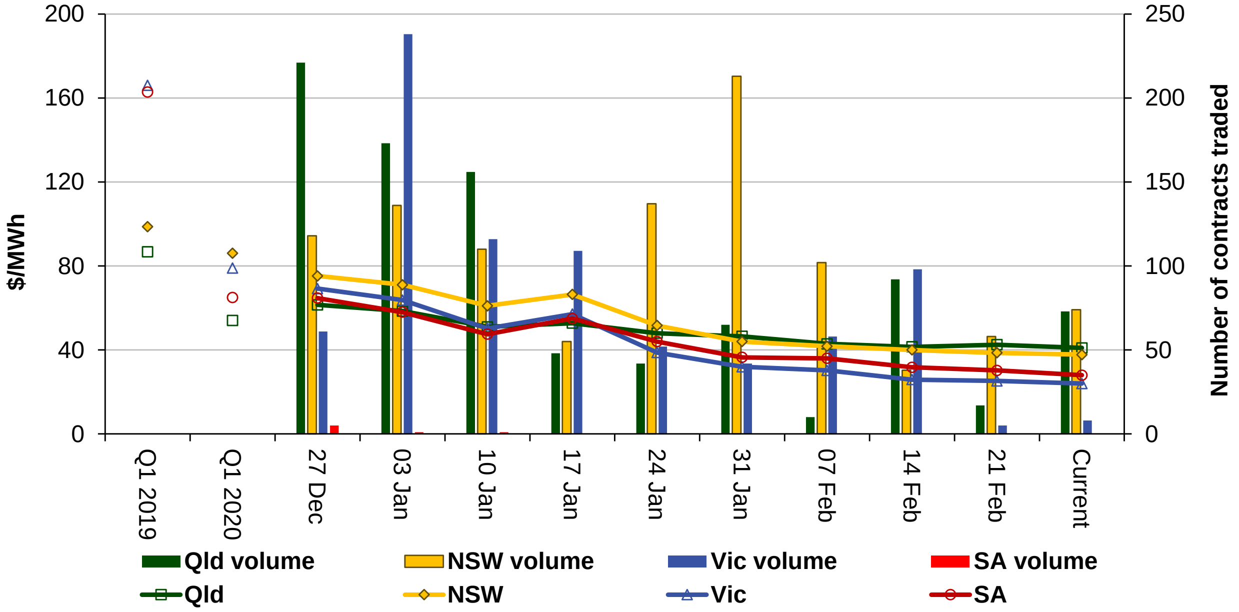
Figure 9: Quarterly base future prices Q1 2021 – Q4 2024



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 2020 and Q1 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 2021 base contracts over the past 10 weeks (and the past 2 years)

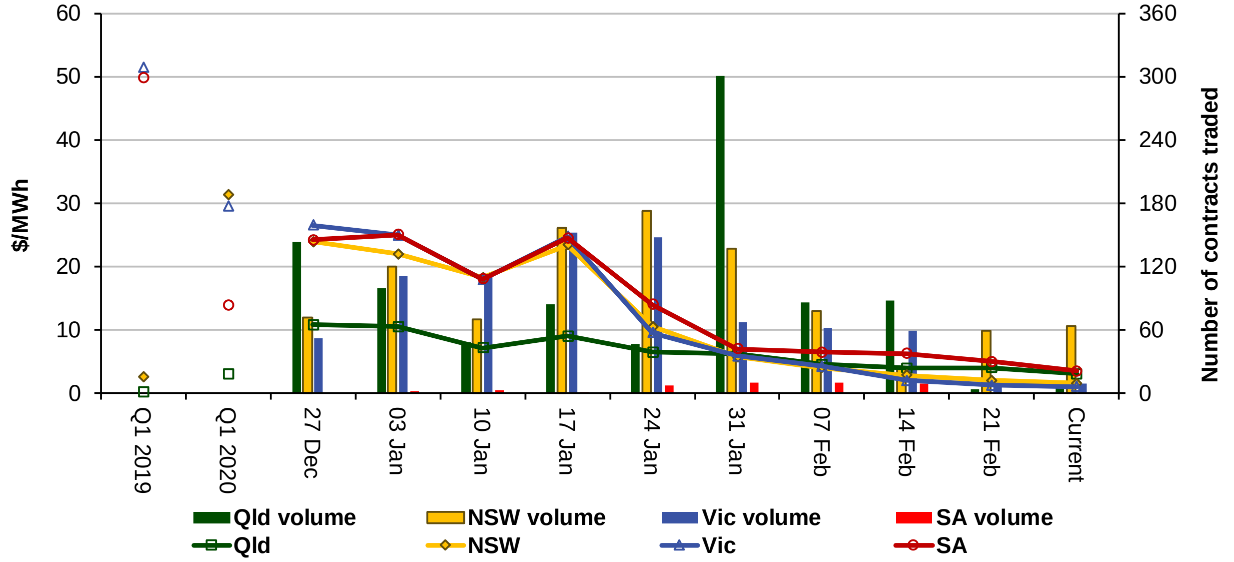


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2020 and Q1 2019 prices are also shown.

Figure 11: Price of Q1 2021 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 2021