22 – 28 September 2019

Introduction

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 22 to 28 September 2019.

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

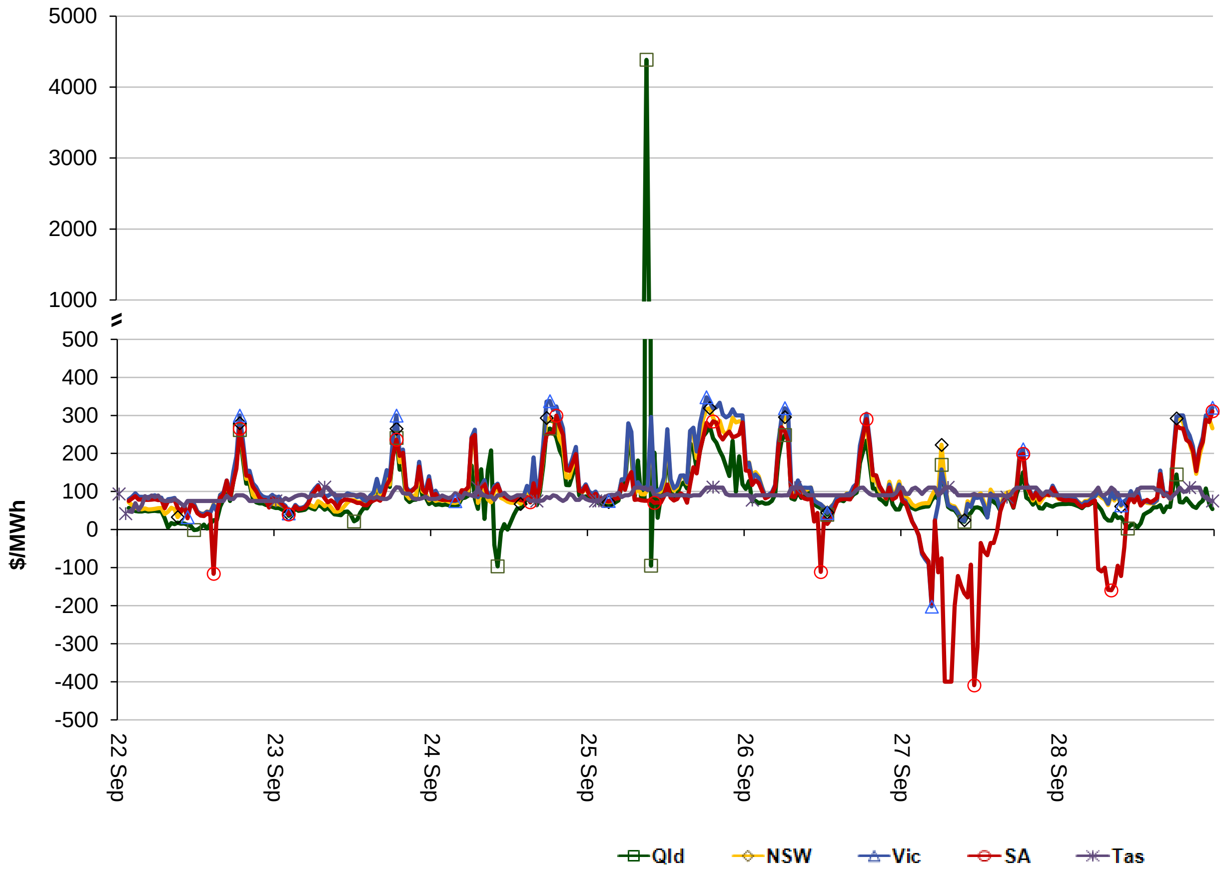


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

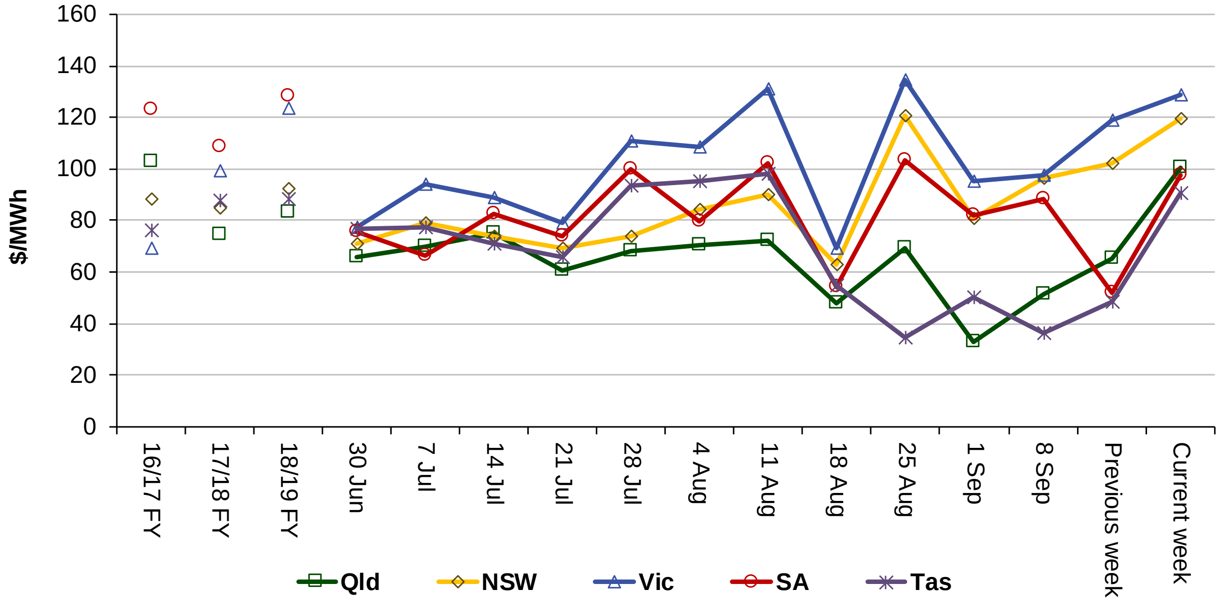


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	101	119	129	98	91
18-19 financial YTD	80	91	84	95	42
19-20 financial YTD	66	86	103	82	69

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 249 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	10	20	0	1
% of total below forecast	7	57	0	5

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 **Error! Reference source not found.** 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

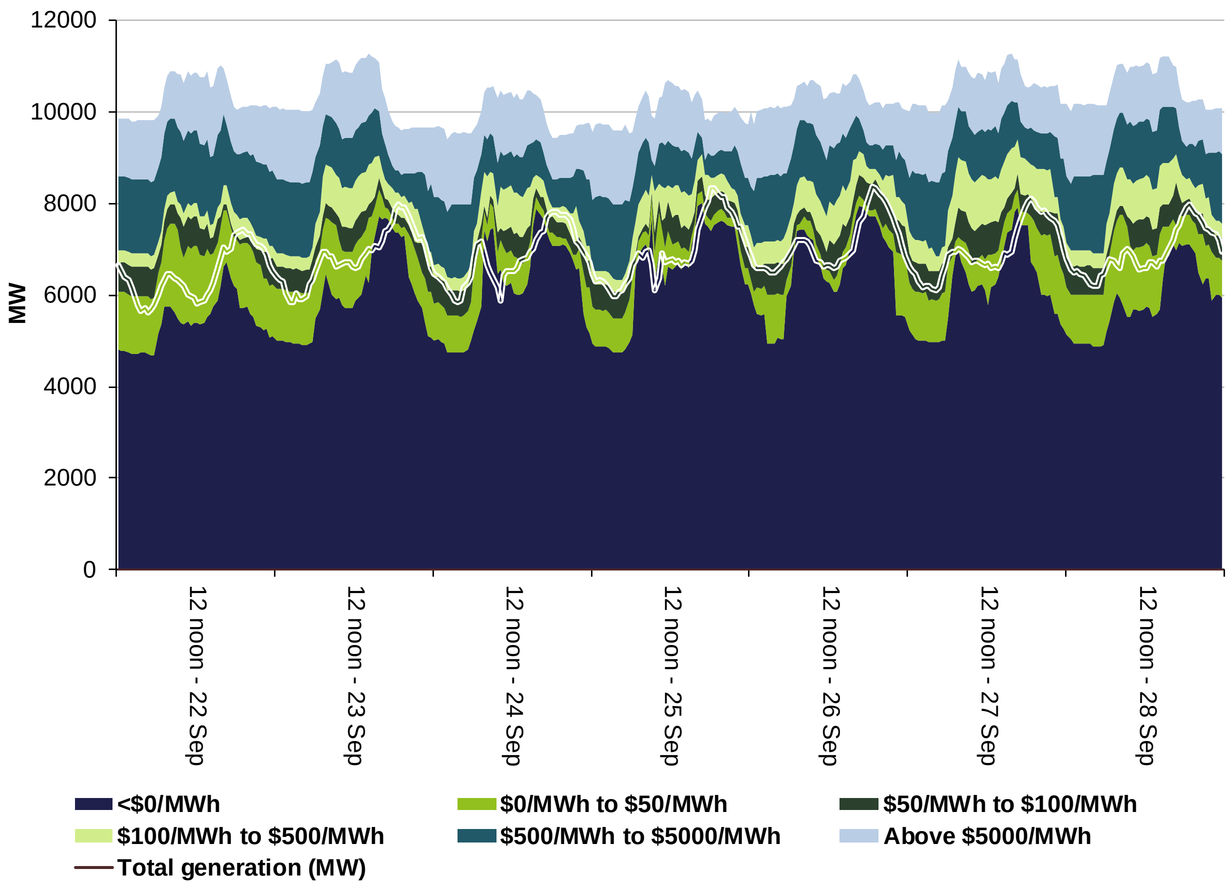


Figure 4: New South Wales generation and bidding patterns

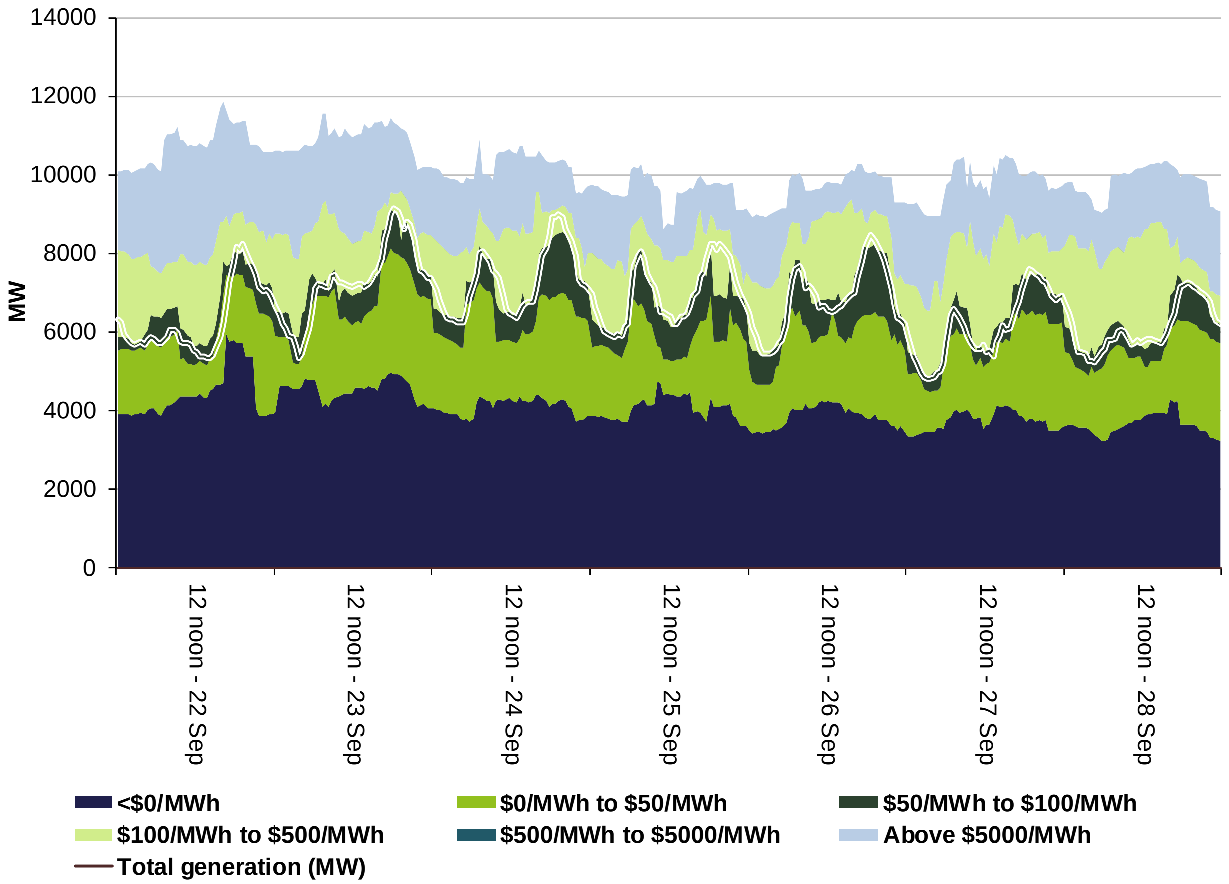


Figure 5: Victoria generation and bidding patterns

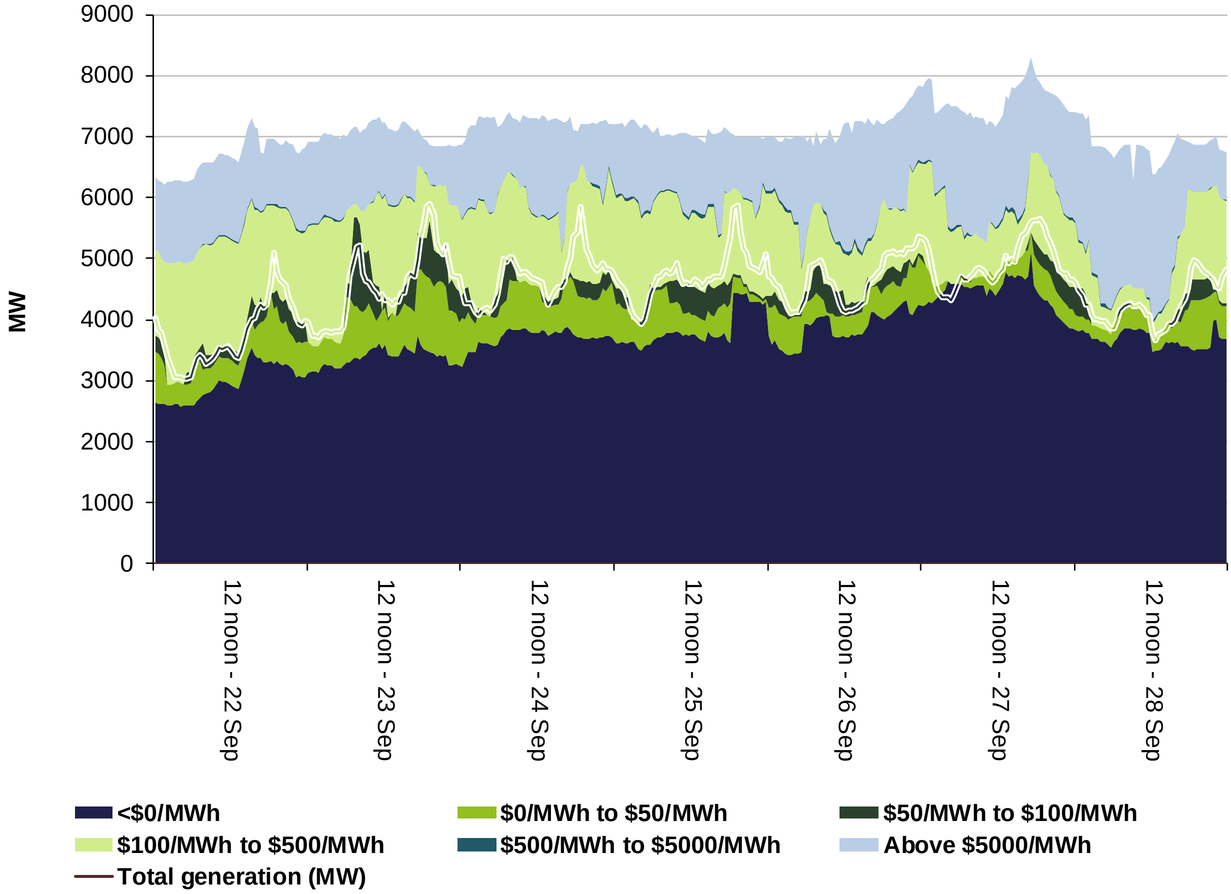


Figure 6: South Australia generation and bidding patterns

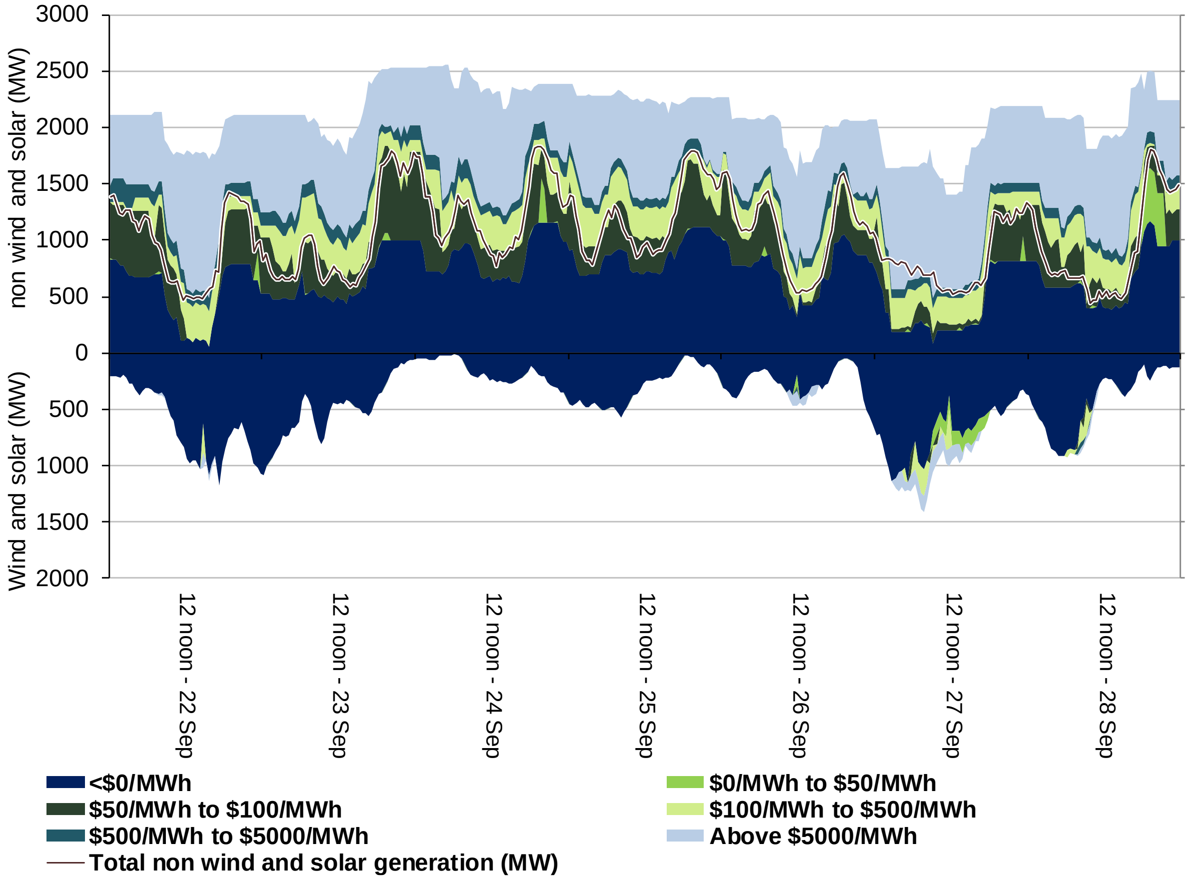
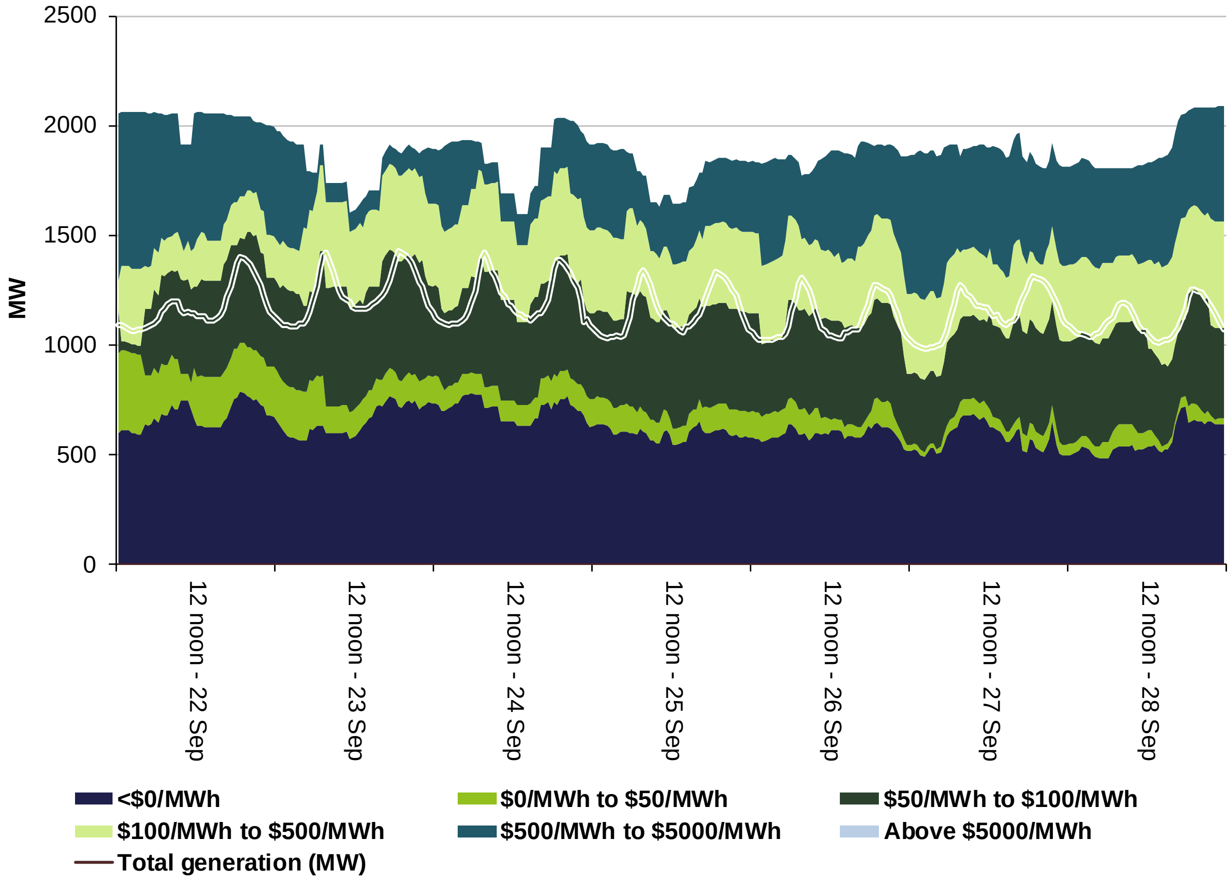


Figure 7: Tasmania generation and bidding patterns



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.

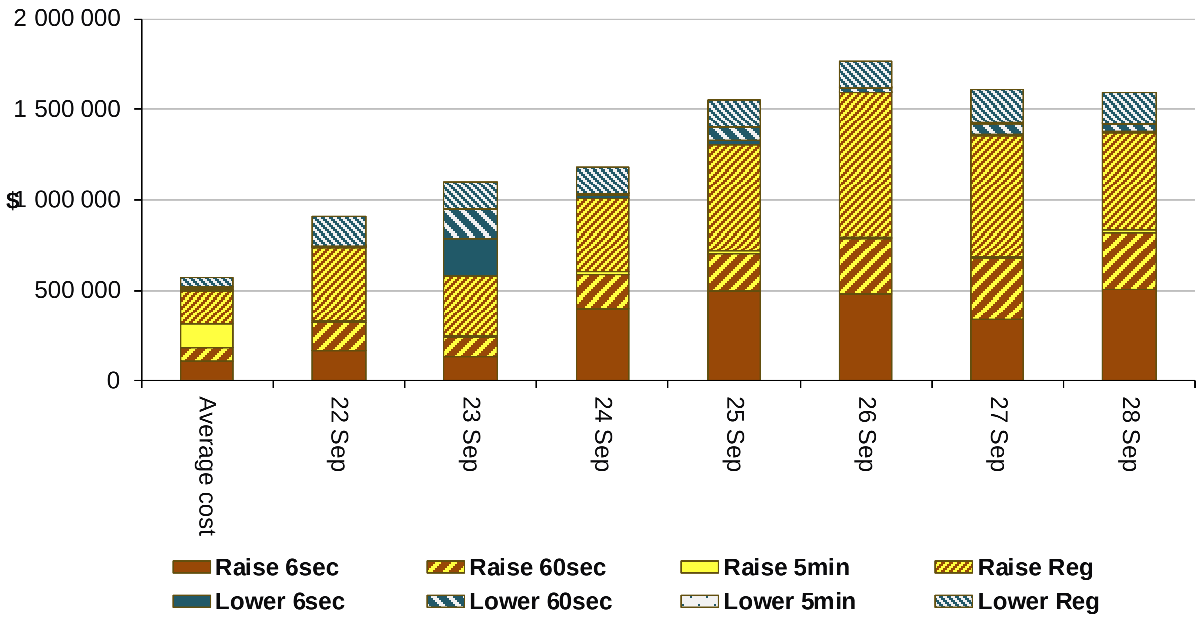
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $9 129 000 or less than 3 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $584 000 or less than 4 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 was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $101/MWh and above $250/MWh.

Wednesday, 25 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
9.30 am	4385.62	299.73	95.99	5841	5799	5773	10 283	10 482	10 472

Conditions at the time saw demand and availability close to forecast.

At 9.05 am a planned network outage of the Woolooga to South Pine 275kV line commenced. This constraint can affect the generation of around 60 units in Queensland. At 9.10 am the constraint reduced the output of 20 units by a total of around 740 MW, all of which had capacity priced below $70/MWh. With cheaper generation constrained the price was set at $14 000/MWh for the 9.10 am and 9.15 am dispatch intervals. In response to the high prices, participants rebid capacity to the floor, resulting in the last two dispatch intervals priced at the floor.

Victoria

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

Friday, 27 September

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
5 am	-202.08	56.73	43.67	3598	3586	3523	7504	7318	7413

Prices were aligned between Victoria and South Australia and will be discussed as one region. Demand for both regions was close to forecast and availability was approximately 580 MW higher than forecast, four hours prior. Higher availability was mostly due to higher than forecast wind generation, most of which was offered at the floor.

Higher than forecast wind availability meant all dispatch intervals were priced lower than forecast. At 4.50 pm, demand dropped collectively by 70 MW. This resulted in one dispatch interval priced below -$870/MWh.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australian weekly average price of $98/MWh and above $250/MWh and there were 20 occasions where the spot price was below -$100/MWh.

Sunday, 22 September

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
3 pm	-116.23	47.26	-35.01	677	714	675	2804	2769	2836

Conditions at the time saw demand 37 MW lower than forecast and availability 35 MW higher than forecast, both four hours prior.

At the time, there was little or no capacity offered between the price floor and $100/MWh. This meant that small changes in demand or supply could result in large changes in price. System strength constraints reduced exports on the Heywood interconnector into Victoria by around 50 MW. At 2.50 pm, demand dropped by 55 MW. With both interconnectors already exporting at their limits, further low priced generation could not be exported. As a result the dispatch price dropped to the price floor for one dispatch interval.

Tuesday, 24 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
7.30 pm	299.47	346.94	318.92	1799	1738	1747	2579	2683	2831

Demand was 61 MW higher than forecast and availability was around 100 MW lower than forecast, four hours prior. Lower availability was due to lower than forecast wind generation.

Prior to commencement of the trading interval, Origin Energy shifted over 310 MW of capacity from prices above $319/MWh to prices below $78/MWh. This led to the dispatch price settling at about $280/MWh for the majority of the trading interval.

Thursday, 26 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
Midday	-111.26	-1000.00	-1000.00	689	648	651	2139	2088	2181

Demand was 41 MW higher than forecast and availability was 51 MW higher than forecast, four hours prior. In response to a negative dispatch price at 11.35 am, approximately 230 MW of capacity was rebid from the price floor to prices above $73/MWh by Energy Australia’s Waterloo Wind Farm and Trustpower’s Snowtown Wind Farm. This saw prices around $60/MWh for the remainder of the trading interval.

Friday, 27 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
5 am	-193.80	54.28	43.09	1007	974	1019	2886	2489	2450
6 am	-112.47	75.70	56.21	1107	1044	1083	2882	2623	2542
7 am	-400.00	78.00	57.09	1196	1162	1173	2919	2679	2616
7.30 am	-400.00	78.00	78.00	1239	1187	1190	3037	2702	2596
8 am	-400.00	78.00	78.00	1207	1170	1173	3071	2692	2569
8.30 am	-200.82	38.60	78.00	1179	1123	1123	2958	2694	2534
9 am	-122.27	39.42	78.00	1101	1049	1049	2882	2564	2483
9.30 am	-148.51	.00	68.80	990	960	973	2844	2515	2440
10 am	-167.70	-3.09	41.84	923	878	895	2561	2479	2408
10.30 am	-178.62	-1000.00	-7.52	822	806	824	2483	2445	2426
11.30 am	-409.17	-1000.00	-1000.00	700	717	721	2389	2469	2412
Midday	-308.80	-1000.00	-151.85	696	728	734	2404	2487	2400

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed gas plant in South Australia, triggering an intervention event. Special pricing arrangements apply for all the intervals discussed here, following the intervention event.

Prices aligned between Victoria and South Australia for the 5 am trading interval, see the analysis under the Victorian section.

Demand was close to forecast for all intervals. Availability was up to 379 MW greater than forecast for the 6 am to 10.30 am trading intervals, this was due to greater than forecast wind availability. Availability was around 80 MW lower than forecast for the 11.30 am and midday intervals because some solar generation was constrained.

A planned network outage in Victoria reduced exports from South Australia on the Heywood interconnector from 6 am until around 3 pm. This meant that excess low priced generation from South Australia could not always be exported to neighbouring regions.

There was little capacity offered between the floor and around $80/MWh for the morning. This meant that small changes in demand or supply could lead to large fluctuations in price outcomes.

Each trading interval had one or two dispatch intervals priced between -$840/MWh and the floor because either demand fell, exports on Heywood were reduced further or low priced generation output increased.

In response to the negative priced dispatch intervals, participants rebid some capacity into higher price bands, leading to the trading interval prices settling to between -$112/MWh and -$400/MWh.

Saturday, 28 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
6.30 am	-103.61	78.70	78.00	1206	1124	1143	2997	2789	2750
7 am	-110.00	77.50	78.00	1209	1146	1164	2964	2775	2733
8 am	-158.51	78.00	82.02	1144	1130	1142	2985	2558	2598
8.30 am	-159.67	78.00	79.58	1102	1096	1101	2952	2471	2549
9 am	-145.17	78.00	78.00	1001	1039	1036	2905	2430	2520
10 am	-122.16	78.00	77.50	834	904	890	2529	2356	2475

Between 6.30 am and 8.30 am actual demand was between 6 MW and 82 MW greater than forecast. For the 9 am and 10 am intervals demand was up to 70 MW lower than forecast, compared to four hours prior. For all intervals discussed here, availability was between 173 MW and 483 MW greater than forecast due to greater than forecast low priced wind availability.

A planned network outage in Victoria reduced exports from South Australia on the Heywood interconnector from around 6 am until 4.30 pm. This meant that excess low priced generation from South Australia could not always be exported to neighbouring regions.

There was little capacity available priced between $77/MWh and -150/MWh. This meant minor fluctuations in demand, exports or supply could lead to price outcomes different than forecast.

Across the 6.30 am trading interval, flows across the Heywood interconnector continued to ramp down in preparation for the maintenance work. With falling exports, increased low priced wind generation and co-optimisation between the FCAS and energy markets, lower than forecast prices were set for each dispatch interval. Once the interconnector was ramped down to its required limit, the trend of lower priced generation setting price continued across the morning.

Sunday, 29 September

Table 10: Price, Demand and Availability

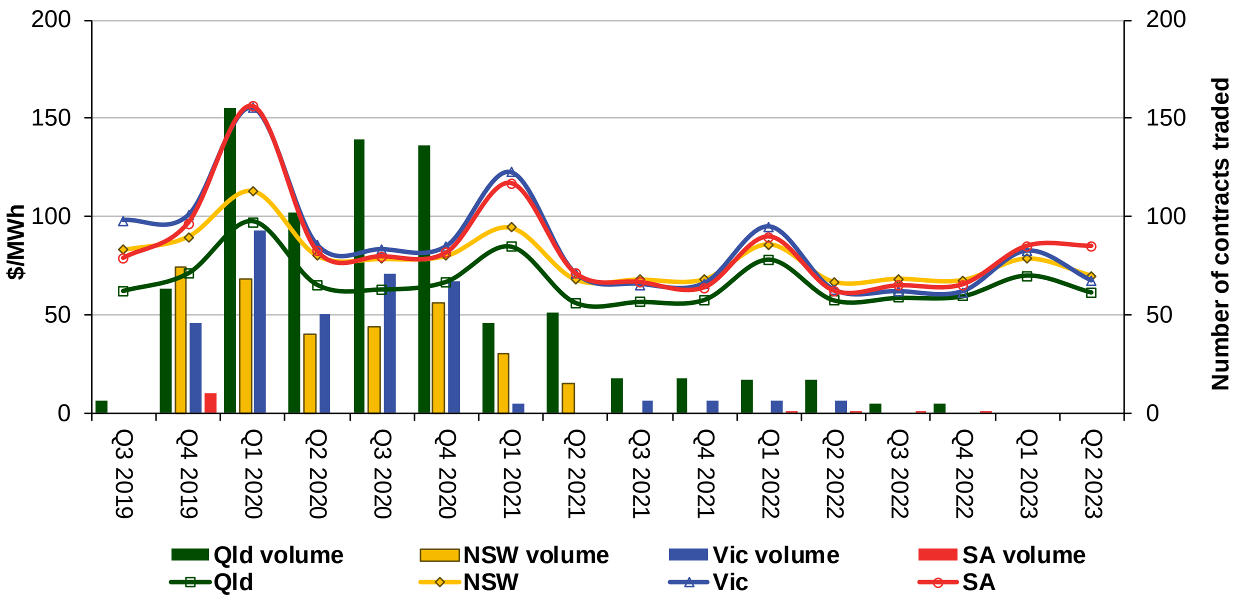
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
Midnight	310.99	111.63	318.83	1519	1519	1500	2368	2392	2391

At the time, South Australia was aligned with Victoria which meant that events in those regions could impact on price outcomes in South Australia. However, only prices in South Australia breached our reporting thresholds. Demand was as forecast and availability was close to forecast, four hours prior in South Australia. However, Victorian demand was 93 MW higher than forecast. At 10.25 pm, Loy Yang B tripped in Victoria, removing 583 MW of capacity priced at the floor. The loss of low priced capacity and higher than forecast demand in Victoria led the prices around $300/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.

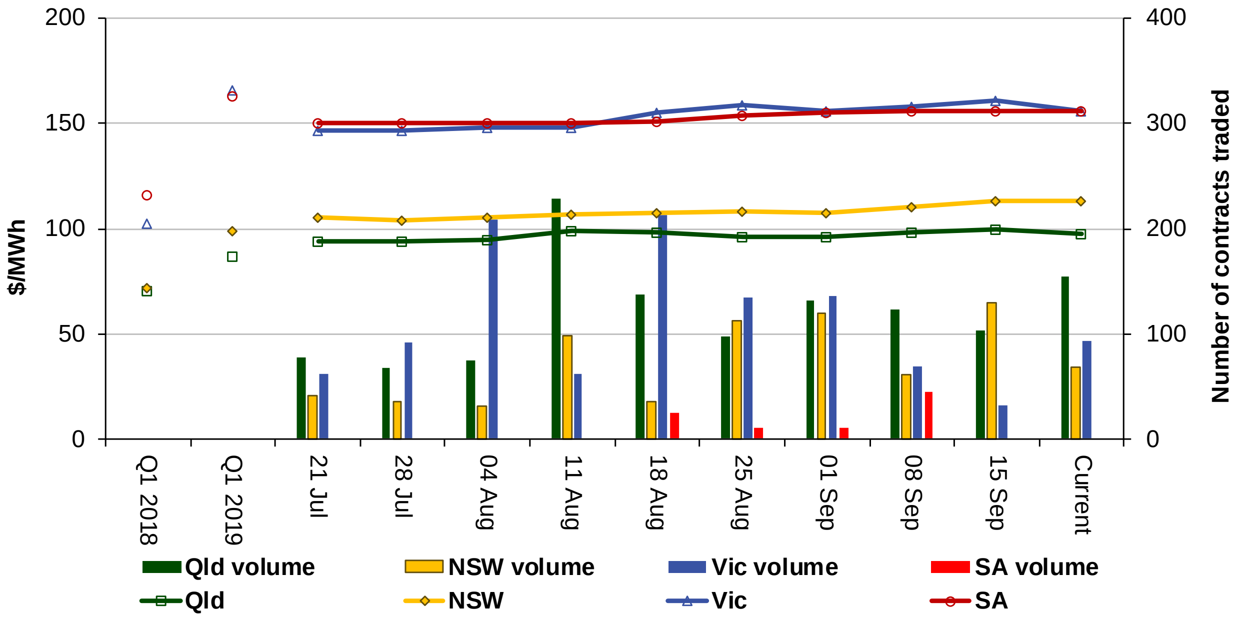
Figure 9: Quarterly base future prices Q3 2019 – Q2 2023



Source. ASXEnergy.com.au

Error! Reference source not found. 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: Q1 2020 base contract prices over past 10 weeks (and past two years)



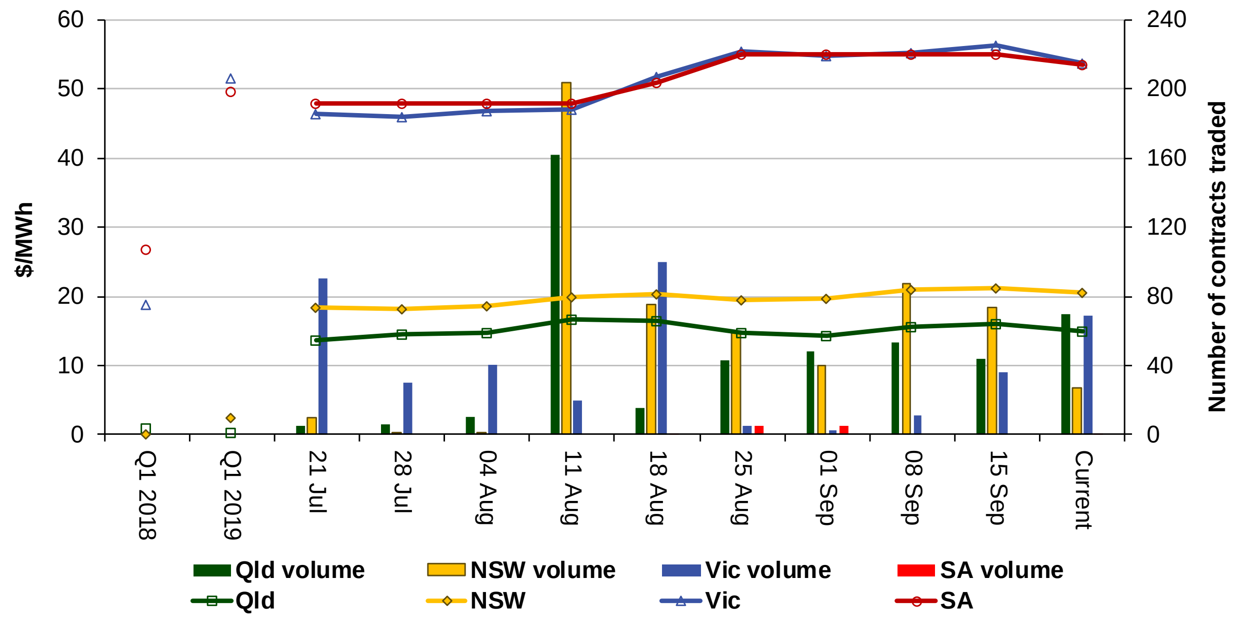
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics section of our website.

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: Q1 2019 cap contracts prices over past 10 weeks (and past two years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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