Electricity Report

AUSTRALIAN ENERGY REGULATOR

6 – 12 October 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 6 to 12 October 2019.

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

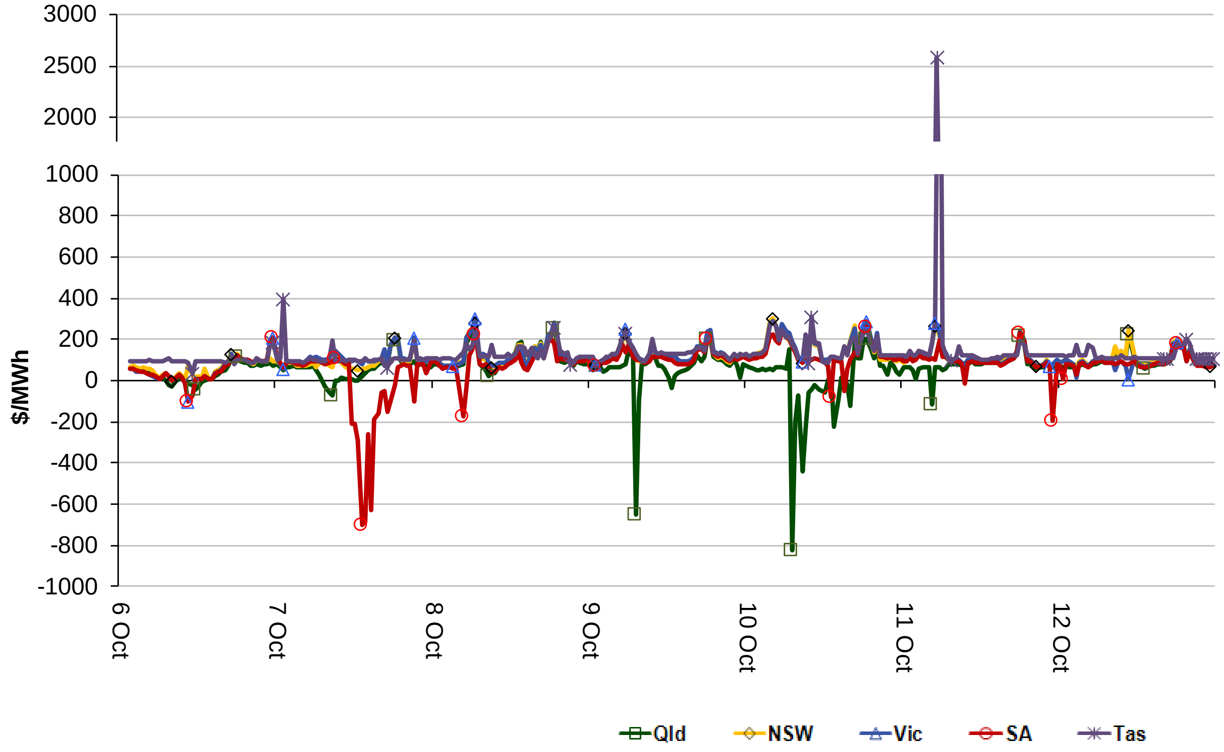


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

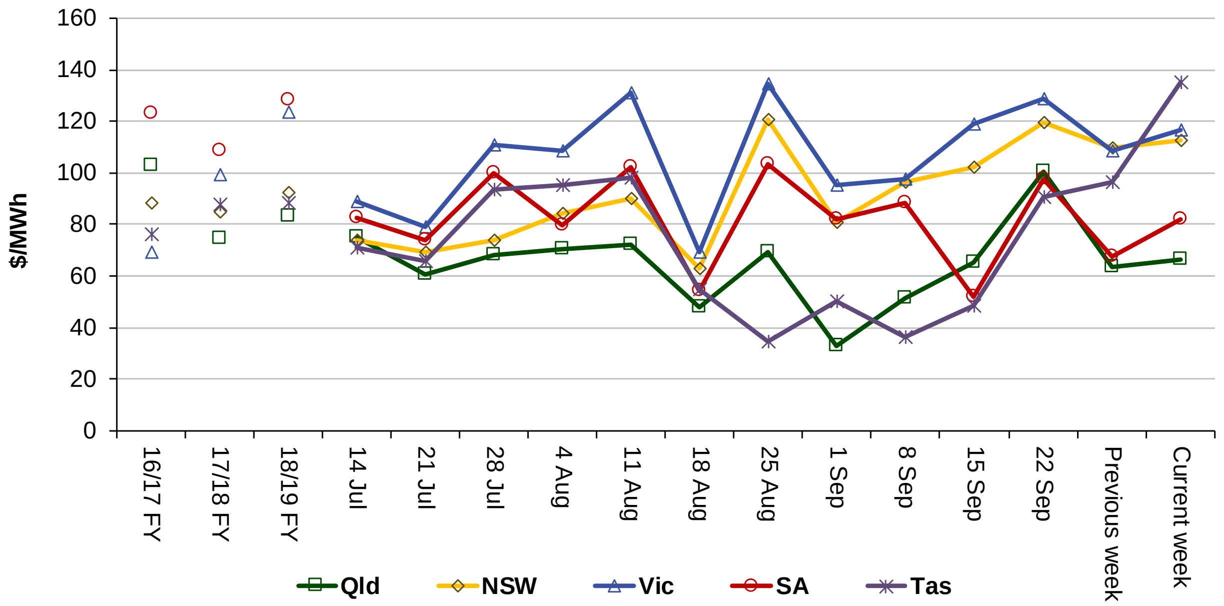


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	66	113	117	82	135
18-19 financial YTD	80	89	86	95	49
19-20 financial YTD	65	89	104	81	75

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 288 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	27	0	1
% of total below forecast	11	52	0	4

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

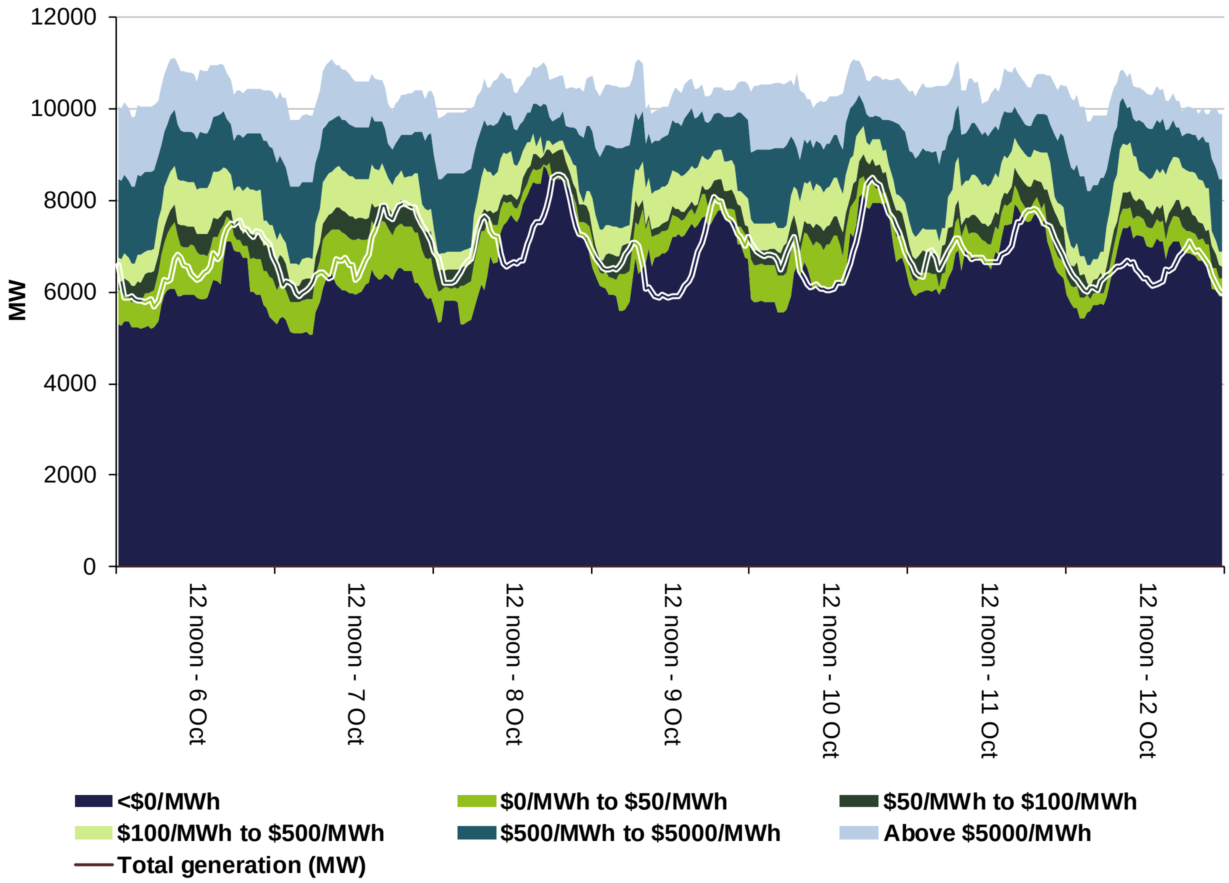


Figure 4: New South Wales generation and bidding patterns

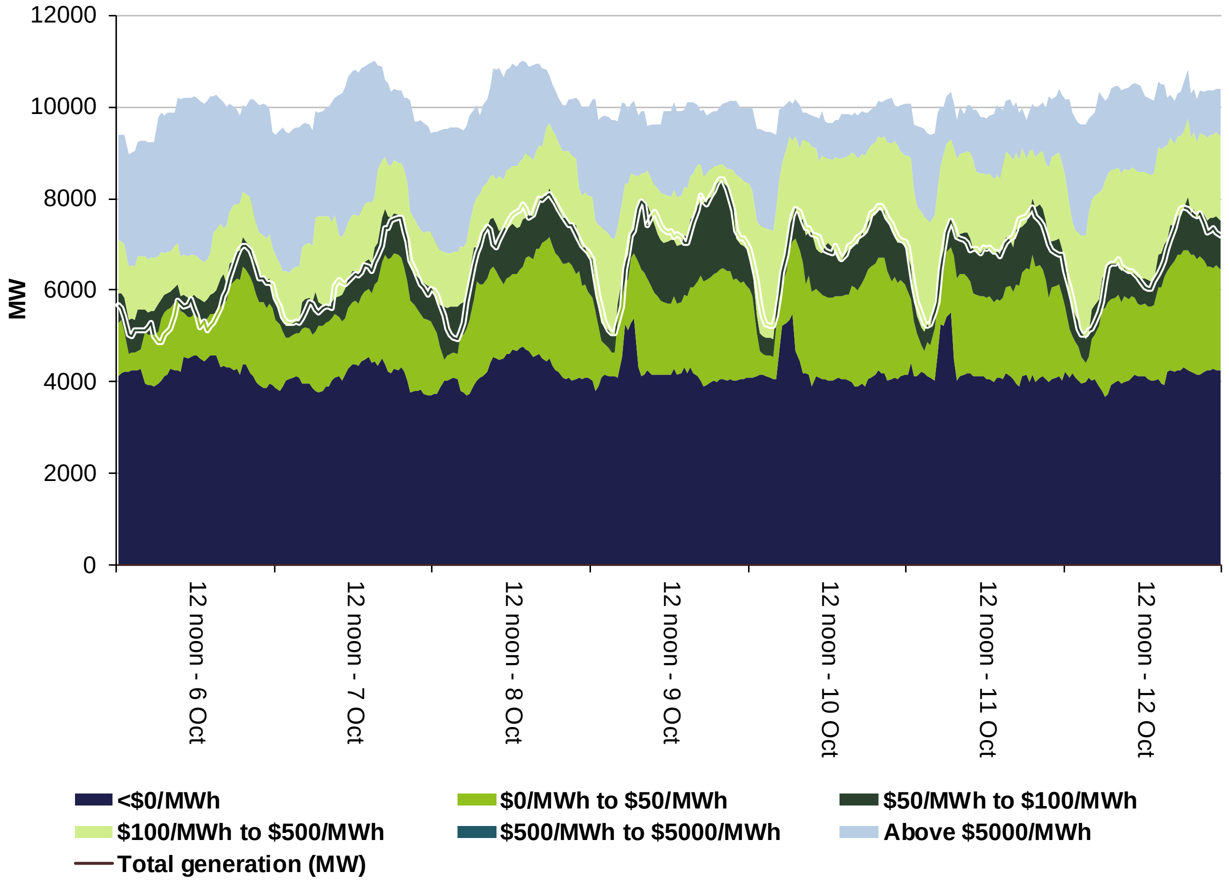


Figure 5: Victoria generation and bidding patterns

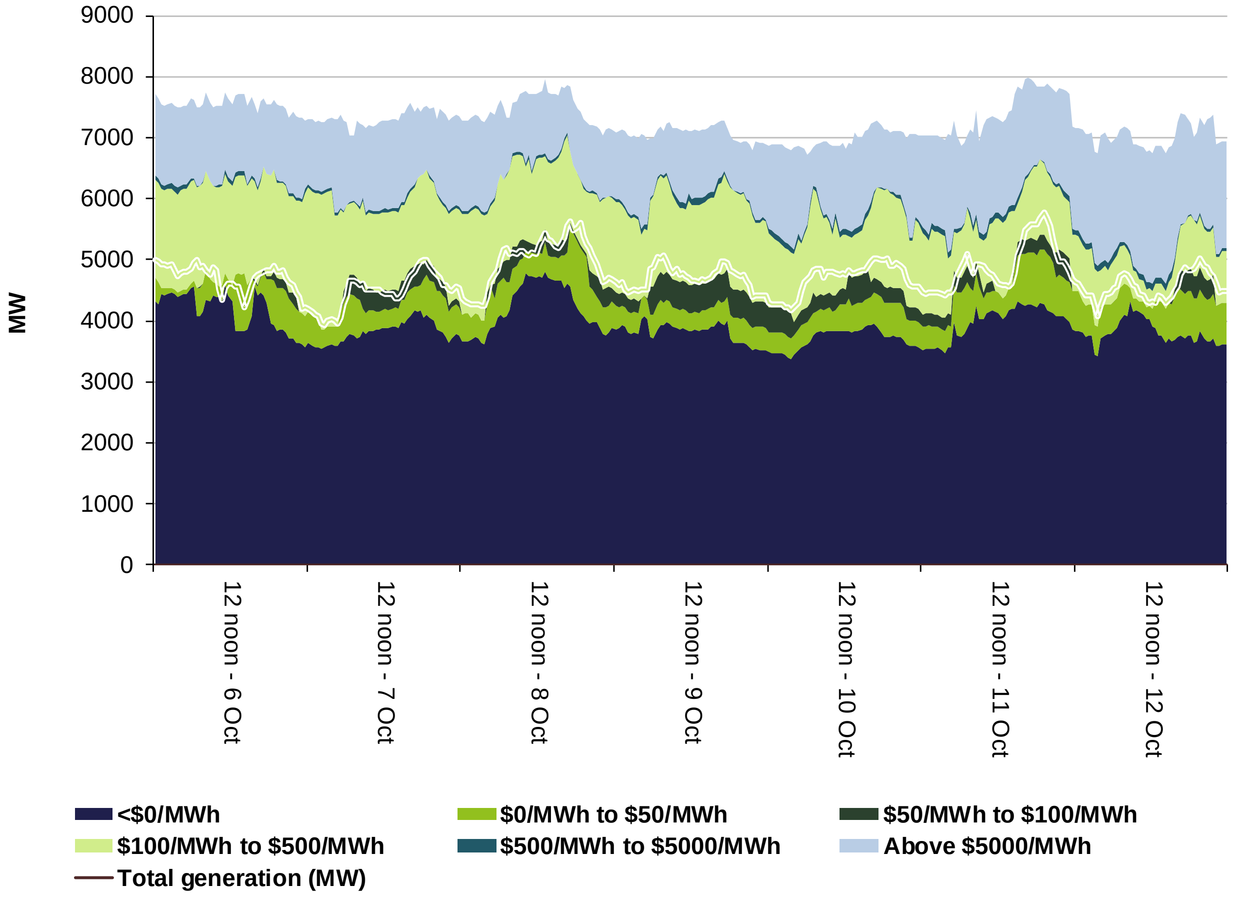


Figure 6: South Australia generation and bidding patterns

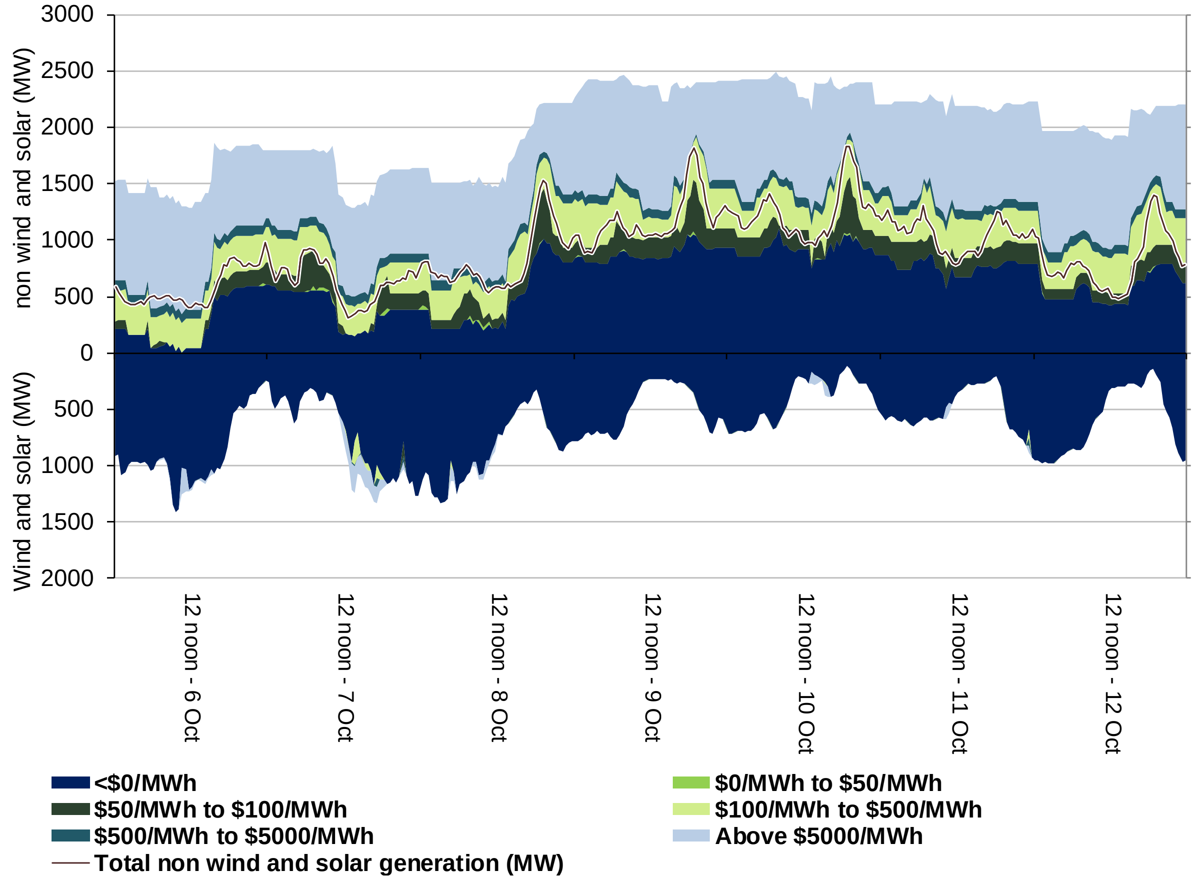
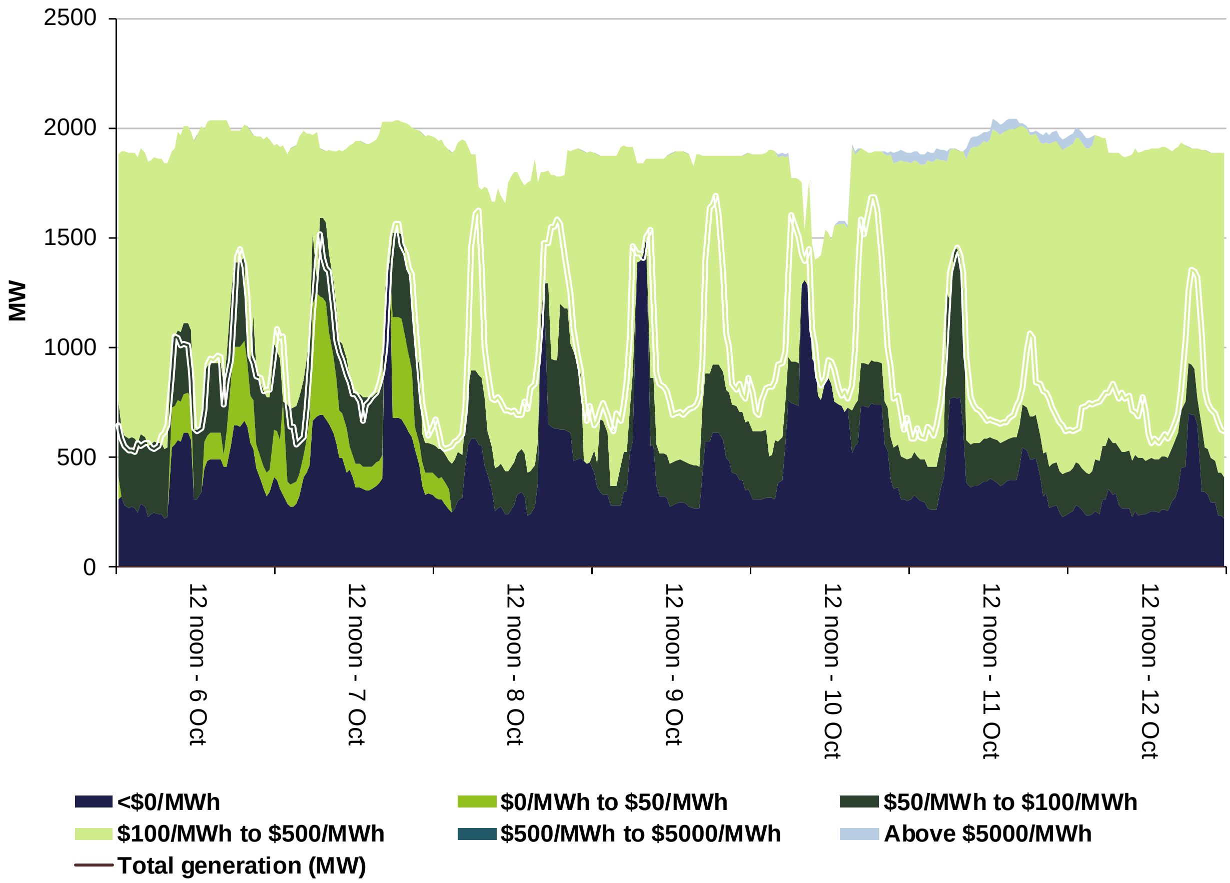


Figure 7: Tasmania generation and bidding patterns



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.

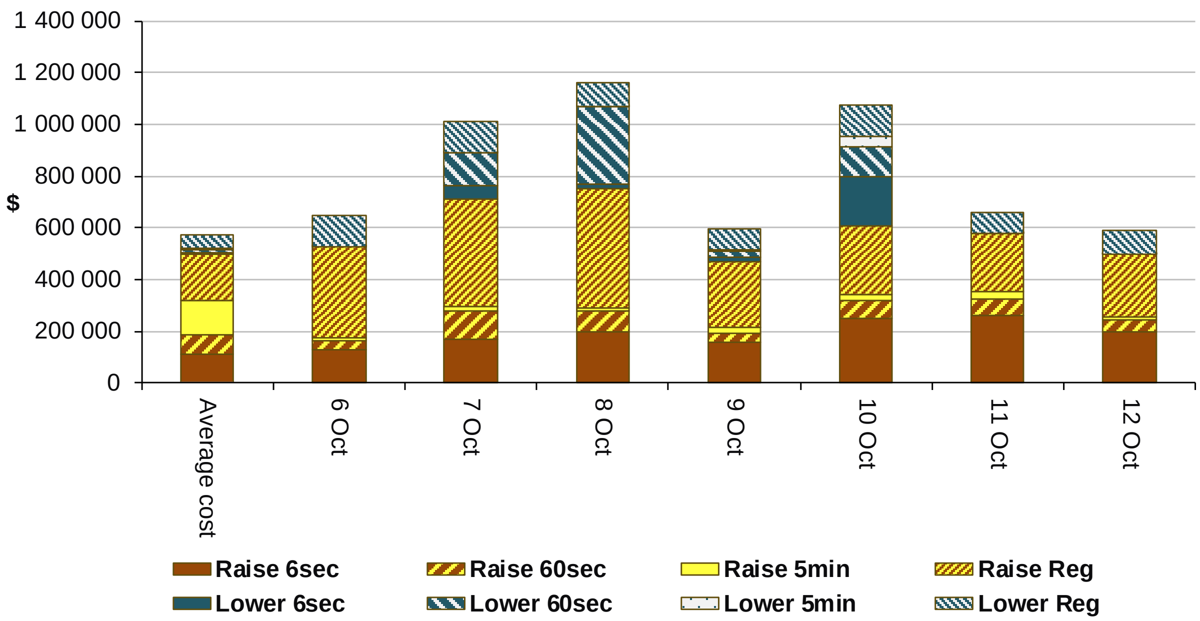
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $4 831 000 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $910 500 or around 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 $66/MWh and above $250/MWh and there were eight occasions where the spot price was below -$100/MWh.

Tuesday, 8 October

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	253.76	213.71	302.58	7874	7762	7807	10 695	10 566	10 570

The spot price was close to forecast.

Wednesday, 9 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
7.30 am	-649.51	101.27	67.80	6162	6087	6017	11 104	11 128	11 166

Demand and availability were both close to forecast four hours prior.

In preparation for planned maintenance work on the QNI interconnector, a ramping constraint reduced exports out of Queensland during the 7.30 am trading interval by around 440 MW. This meant that any excess low priced generation in Queensland could not reach neighbouring regions. As a result, there were four dispatch prices set between -$979/MWh and the price floor.

Thursday, 10 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	-821.84	111.11	111.11	6112	6059	5942	10 824	10 773	10 776
8 am	-203.59	12.43	12.43	5962	5962	5852	10 418	10 425	10 419
9 am	-438.42	12.43	0.84	5693	5657	5561	10 247	10 578	10 585
9.30 am	-229.88	-77.90	-1000	5622	5515	5421	10 286	10 639	10 645
2 pm	-225.43	-154.54	12.43	5701	5541	5526	10 372	10 277	10 365
4.30 pm	-124.71	91.02	264.97	6585	6432	6339	11 118	10 926	10 508

Across the day demand was up to 160 MW greater than forecast. Availability was largely close to forecast, other than the 9 am and 9.30 am trading intervals where availability was up to 353 MW lower than forecast due to participants removing capacity relating to plant issues.

Planned maintenance work on the QNI interconnector was undertaken between 7 am and 4.40 pm. During this time the export limit out of Queensland was reduced by around 700 MW. This meant any excess low priced generation in Queensland could not reach neighbouring regions.

For the 7.30 am trading interval, a ramping constraint reduced exports out of Queensland by around 650 MW. At 5.23 am CS Energy shifted 400 MW of capacity at Gladstone power station from prices above $54 MW to the floor, the reason related to intra-regional constraint management. As a result of reduced exports and rebidding the trading interval had five dispatch prices between -$945/MWh and the floor.

The remaining trading intervals continued to be priced lower than forecast due to reduced exports out of Queensland, participants briefly shifting capacity into lower price bands and co-optimisation between the FCAS and energy markets.

Friday, 11 October

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
5 am	-115.71	62.75	53.73	5355	5285	5229	10 501	10 625	10 634

Demand and availability were both close to forecast.

At the start of the trading interval, Queensland was exporting over QNI at the export limit. For the 4.45 am dispatch interval the QNI interconnector was de-rated due to lightening in the area which increased the risk of QNI tripping. The export limit was reduced by 251 MW. As low priced generation could not reach neighbouring regions, the dispatch price was set at -$1000/MWh which led to the lower than forecast spot price.

Victoria

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

Sunday, 6 October

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
11 am	-102.24	-35.41	28.95	3088	3361	3455	7521	7866	7895

Victoria and South Australia were price aligned during the trading interval, however the South Australian price did and not trigger our reporting threshold.

Demand was 273 MW lower than forecast and availability was 345 MW lower than forecast, both four hours prior. Lower than forecast availability was due to AGL removing 150 MW of capacity at Loy Yang A due to testing and wind generation was 170 MW lower than expected.

At 2 am AEMO de-energised the Hazelwood to South Morang line to manage voltages in the region. A set of constraints was invoked that affected local generation and flows on all four interconnectors into Victoria. These constraints forced generation from South Australia into Victoria on both interconnectors. Low priced wind generation in South Australia was higher than expected. The spot price was lower than forecast due to the lower than forecast demand and increased wind generation from South Australia.

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 $82/MWh and above $250/MWh and there were fourteen occasions where the spot price was below -$100/MWh.

Monday, 7 October

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	-207.34	5.42	-520.14	663	861	802	2159	2144	2272
12.30 pm	-211.00	-273.56	-560.17	607	840	773	2177	2117	2242
1 pm	-291.67	-521.21	-590.08	681	848	770	2291	2195	2315
1.30 pm	-700.00	-522.70	-589.08	782	844	769	2519	2229	2336
2 pm	-686.78	-555.76	-586.82	713	805	745	2541	2228	2355
2.30 pm	-258.65	-587.89	-586.22	621	759	713	2375	2373	2375
3 pm	-633.33	-588.64	-1000	662	721	698	2382	2379	2393
3.30 pm	-192.38	-590.07	-584.23	772	730	733	2495	2408	2410
4 pm	-159.99	-585.02	-581.98	819	741	759	2511	2430	2419
5.30 pm	-151.73	-550.26	-495.50	1055	998	1045	2833	2604	2549
6 pm	-104.38	-546.23	-151.85	1120	1100	1127	2851	2704	2658
9.30 pm	-105.23	84.18	78.32	1198	1133	1112	2668	2699	2780

At 1.25 am AEMO de-energised the Hazelwood to South Morang line to manage voltages in the region. A set of constraints was invoked that can affect flows on both interconnectors into South Australia. The constraints were in place until 6.20 pm.

Demand was up to 233 MW lower than forecast up until 3 pm, it was close to forecast for the rest of the day. Availability was up to 313 MW greater than forecast due to greater than forecast wind generation.

For the midday trading interval there was only around 100 MW of capacity offered between the floor and $30/MWh. This meant small changes in demand, generator availability or rebidding capacity could lead to unexpected price outcomes. While there were multiple rebids across the trading interval, for the last dispatch interval EnergyAustralia shifted 130 MW of capacity at Waterloo wind farm from -$350/MWh to the floor. The dispatch price was set at -$1000/MWh and resulted in a lower than forecast spot price.

The 12.30 pm trading interval had one dispatch interval at the floor due to forced exports falling by 17 MW at 12.15 pm and participants shifting capacity into lower price bands.

In the fours leading up to each trading interval participants had shifted capacity into higher price bands so forecast prices were no longer negative. However a pattern continued throughout the afternoon, each trading interval contained one or more dispatch intervals priced between -$900/MWh and the floor. These low priced dispatch intervals were due to a drop in demand, an increase of low priced wind generation, a reduction of forced exports or participants briefly shifting capacity into lower price bands.

Tuesday, 8 October

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
5 am	-173.75	59.39	49.48	1043	986	948	2651	2600	2466

Demand and availability were both close to forecast.

In preparation for planned maintenance of the Heywood interconnector a ramping constraint reduced exports by over 150 MW during the trading interval. This meant excess low priced generation from South Australia could not reach neighbouring regions. The dispatch was set between -$234/MWh and -$530/MWh for the first half of the trading interval before participants shifted capacity into higher price bands, resulting the remaining dispatch intervals being set above $77/MWh.

Thursday, 10 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
7 pm	257.72	207.87	198.57	1454	1348	1339	2519	2577	2553

Demand was 106 MW greater than forecast and availability was close to forecast, both four hours prior.

Higher than forecast demand meant higher priced generation was required to meet demand.

Friday, 11 October

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
11.30 pm	-193.53	81.00	83.50	1137	1155	1133	3111	2995	3031

Demand was close to forecast and availability was 116 MW higher than forecast. Higher than forecast availability was due to increased low priced wind generation.

The 11.25 pm dispatch interval was priced at the floor because there was an increase in low priced wind generation, exports on Heywood were reduced by 25 MW and demand fell by 12 MW. As a result the spot price was lower than forecast.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $135/MWh and above $250/MWh.

Friday, 11 October

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
6 am	2587.22	119.14	119.13	1137	1107	1099	1893	1901	1902

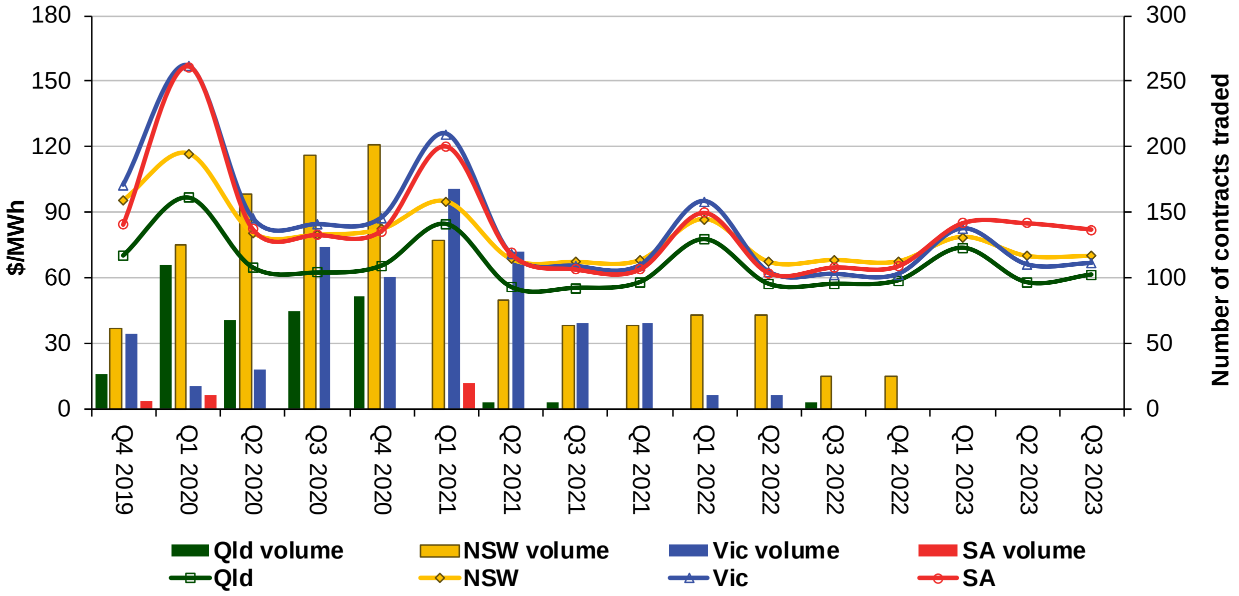
Demand and availability were both close to forecast four hours prior.

The last dispatch interval was priced at the cap. FCAS constraints forced exports across Basslink into Victoria. All low priced capacity was either trapped or stranded in FCAS or ramp constrained, so could not set price. As a result the spot price was higher than 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.

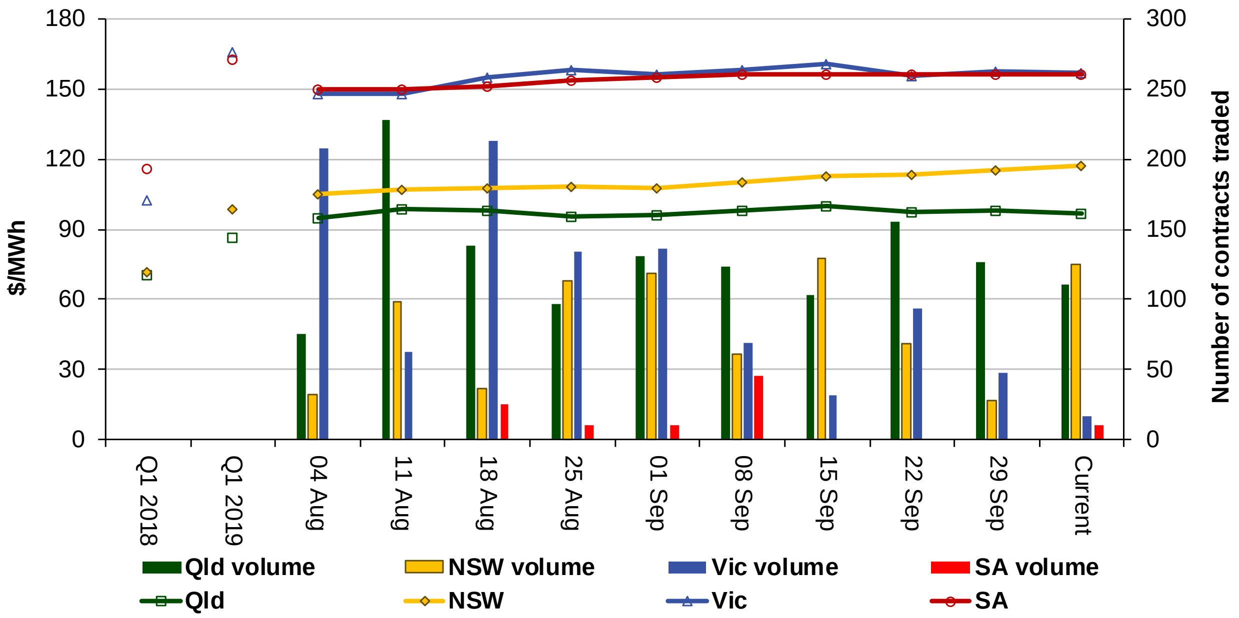
Figure 9: Quarterly base future prices Q4 2019 – Q3 2023



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 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)

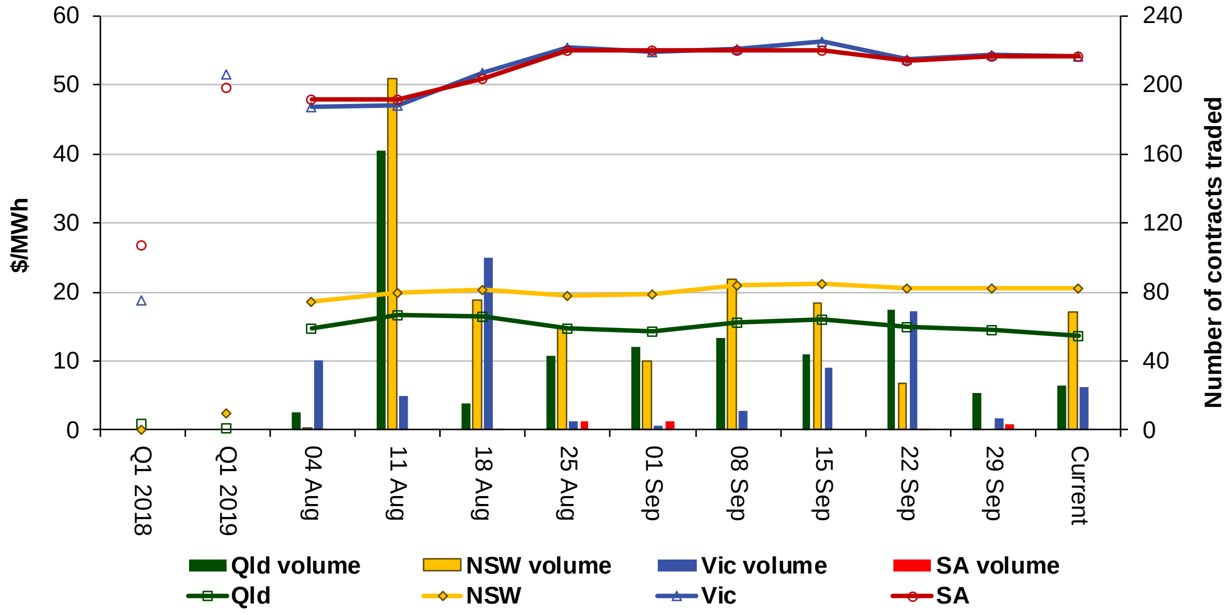


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
November 2020