Electricity Report

10 – 16 November 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 10 to 16 November 2019.

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

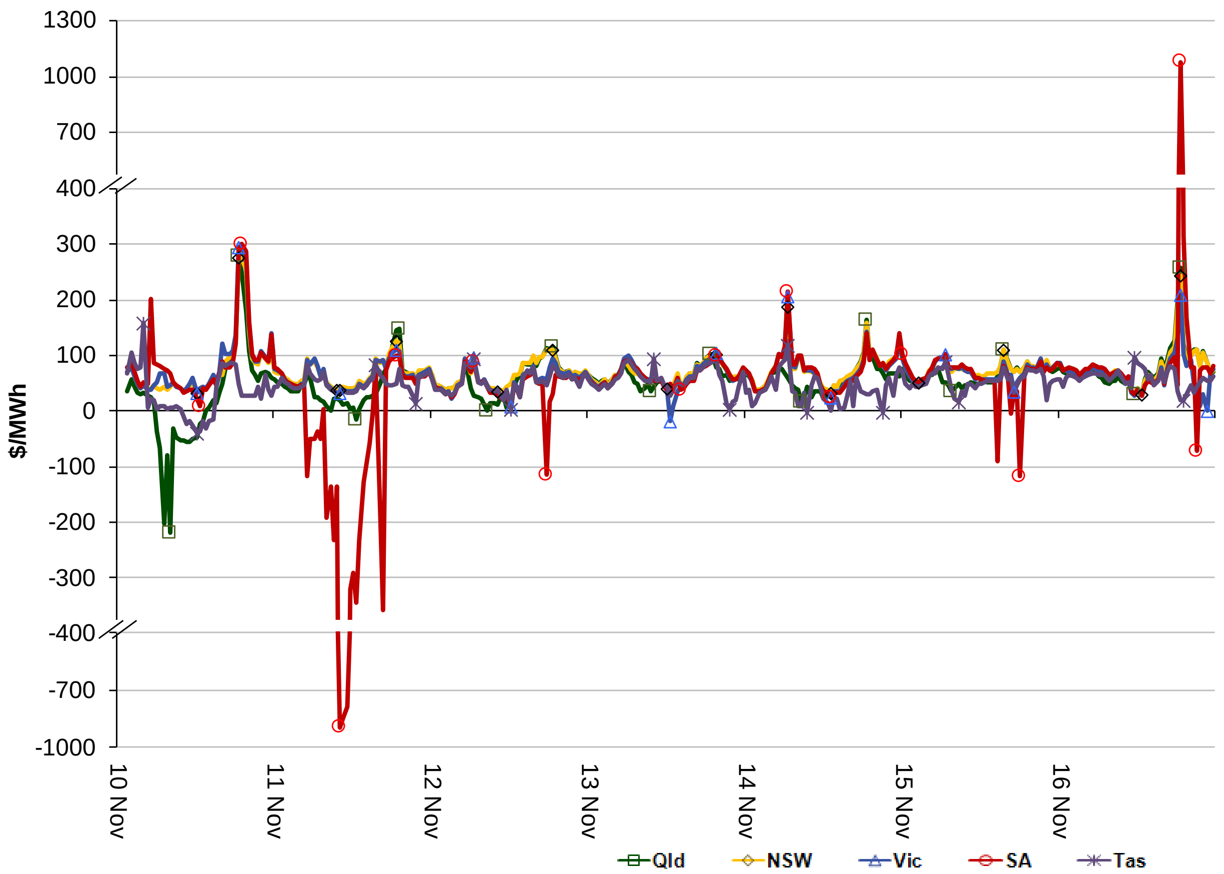


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

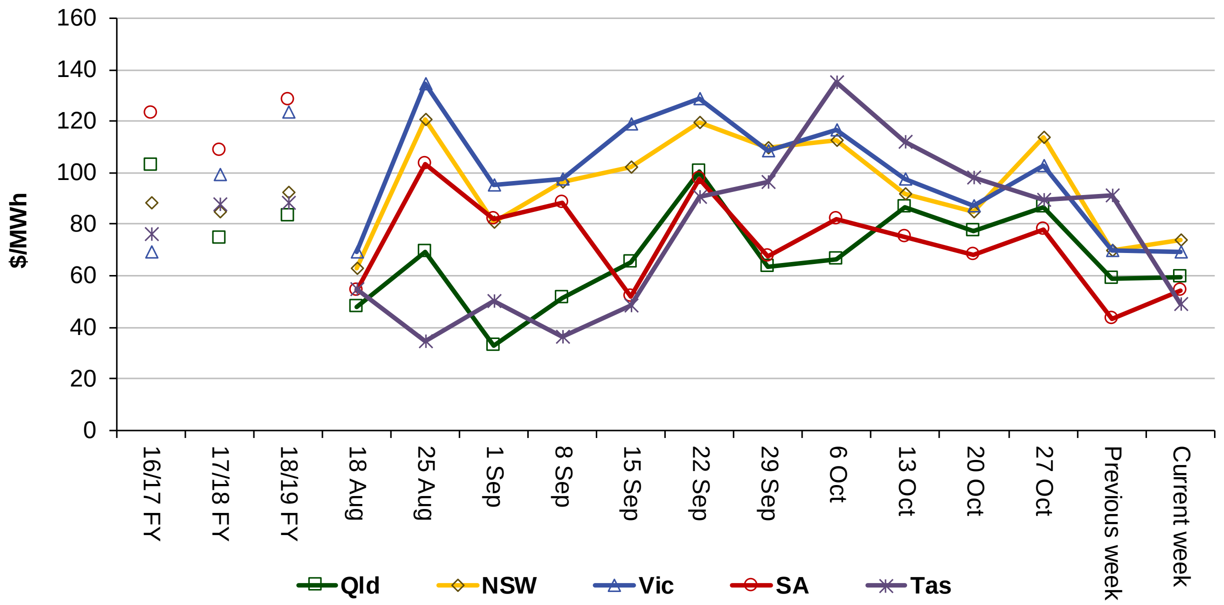


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	59	74	69	54	49
18-19 financial YTD	82	90	89	97	58
19-20 financial YTD	68	89	100	77	78

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 232 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	8	33	0	1
% of total below forecast	14	32	0	11

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

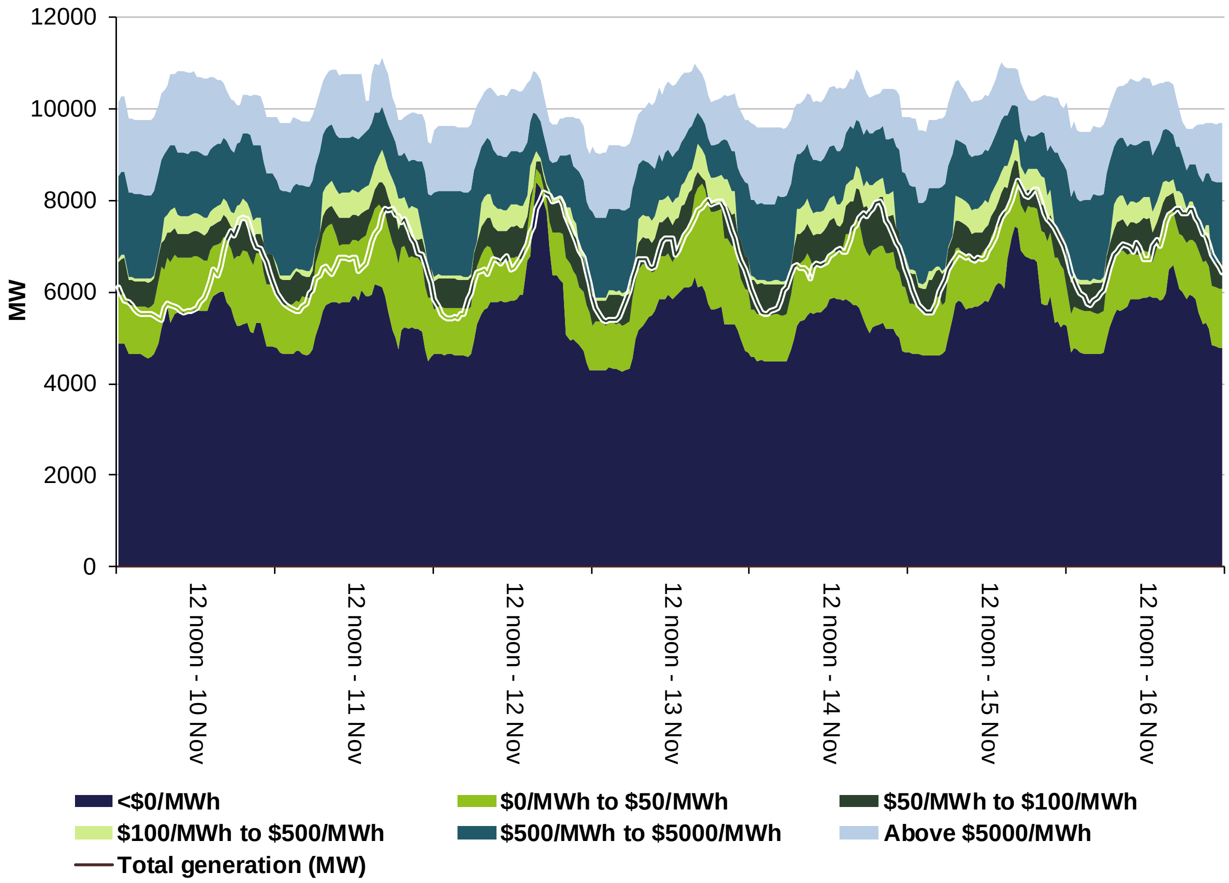


Figure 4: New South Wales generation and bidding patterns

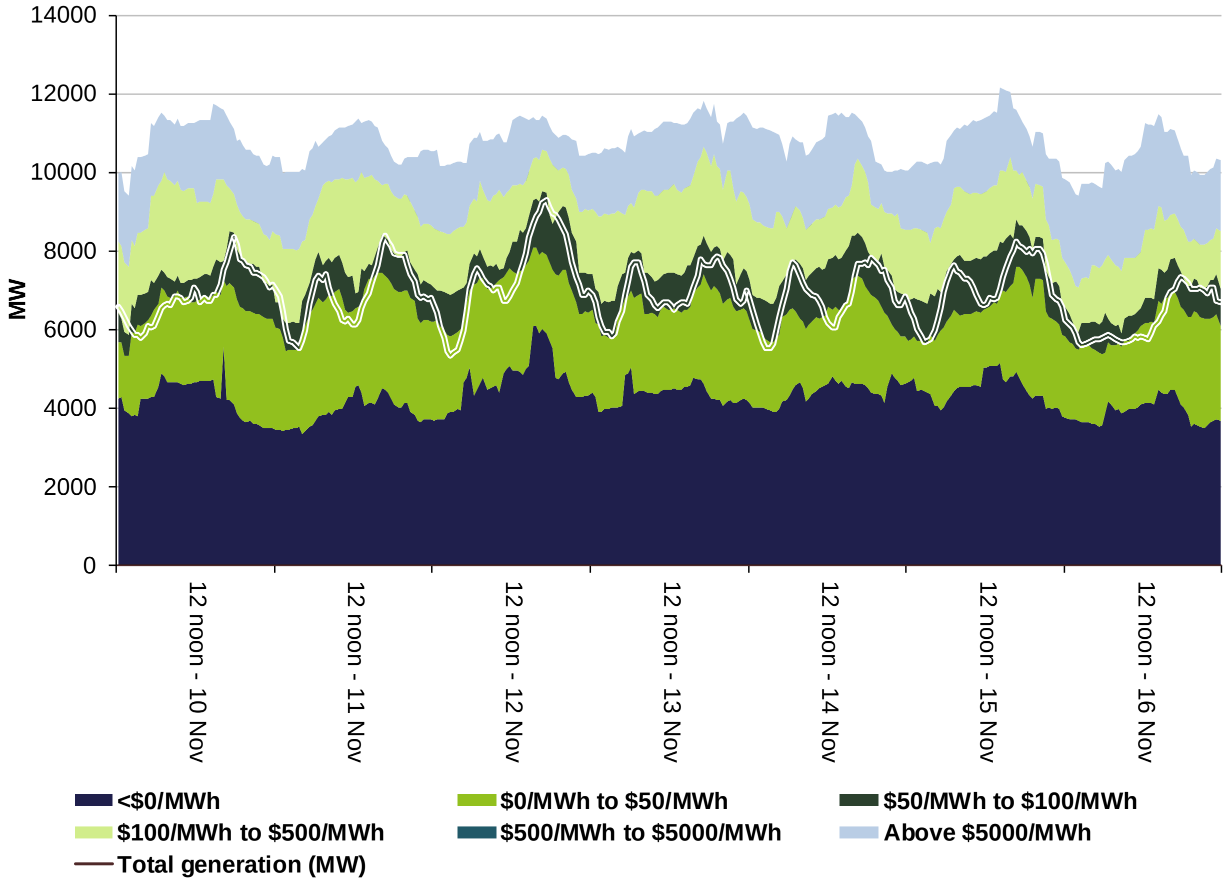


Figure 5: Victoria generation and bidding patterns

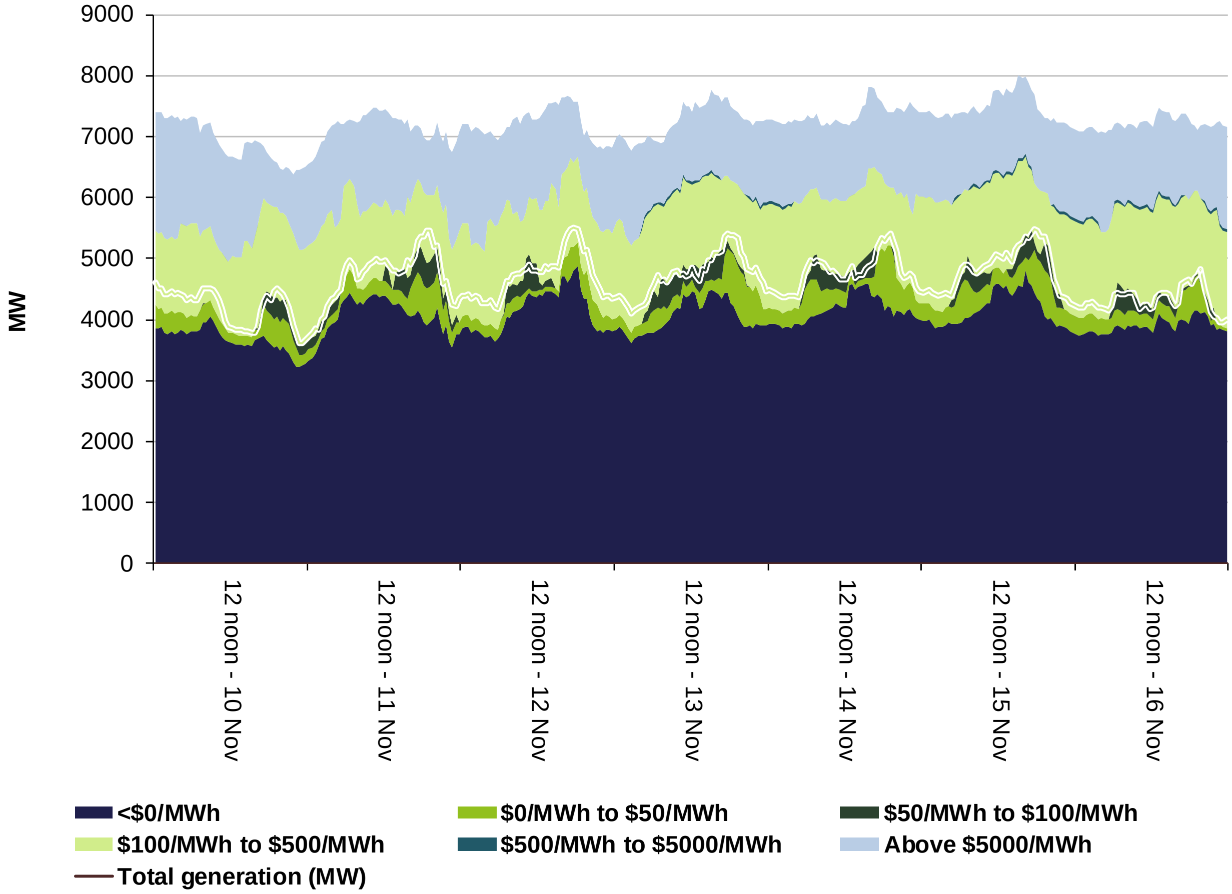


Figure 6: South Australia generation and bidding patterns

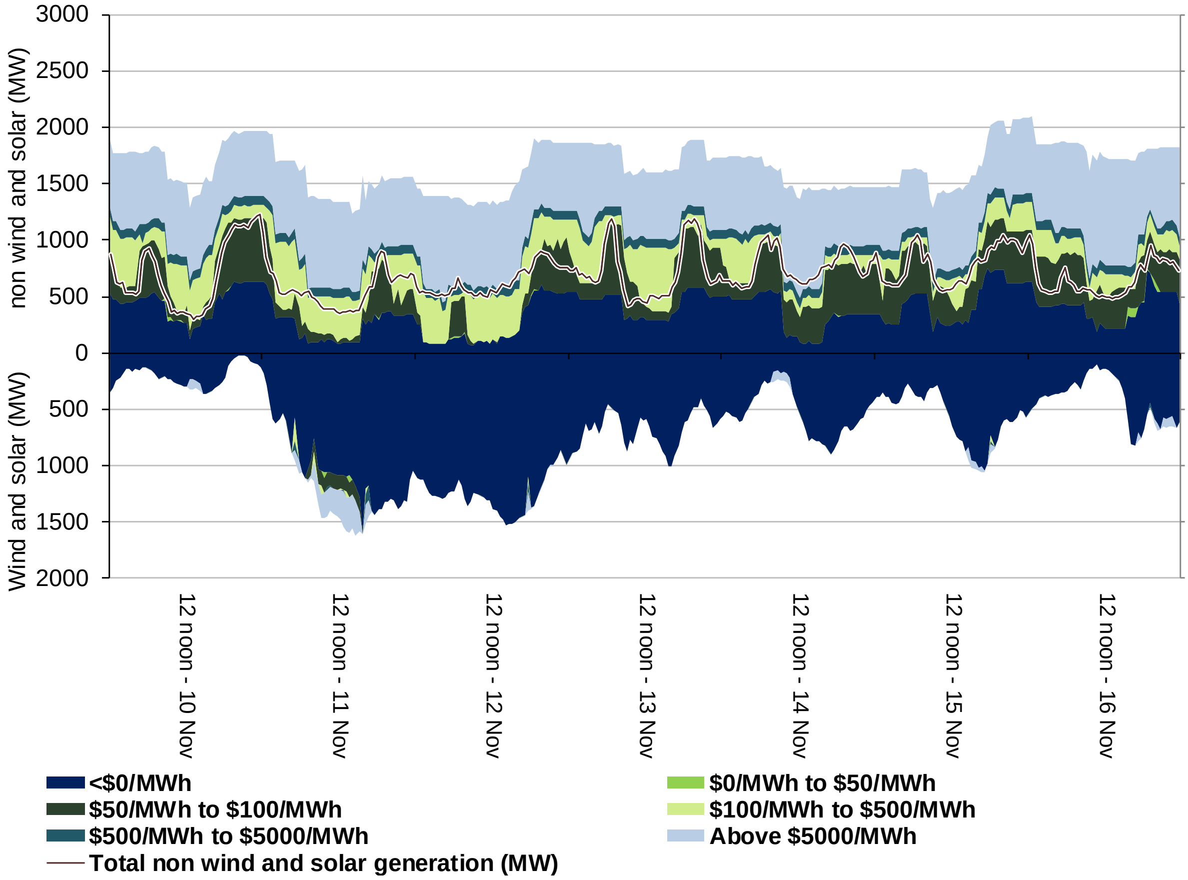
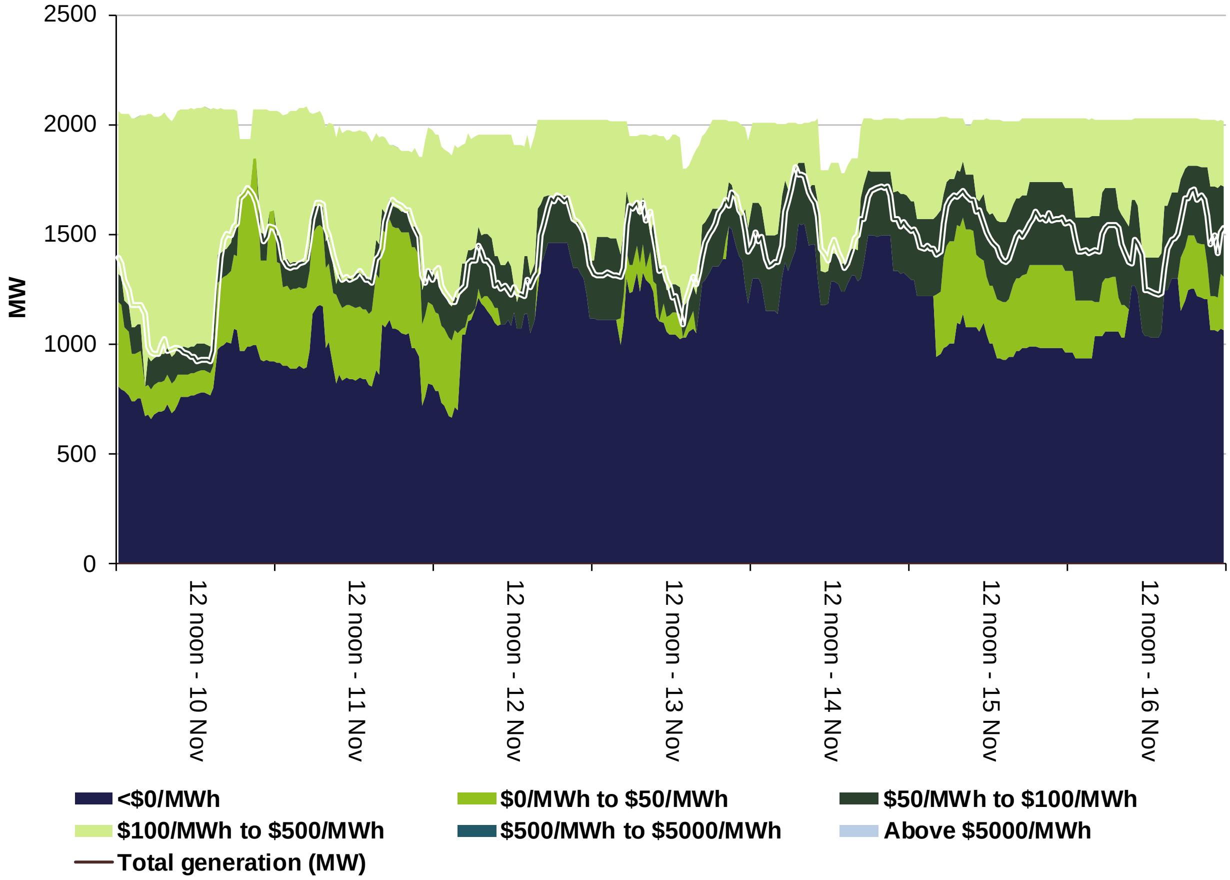


Figure 7: Tasmania generation and bidding patterns



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.

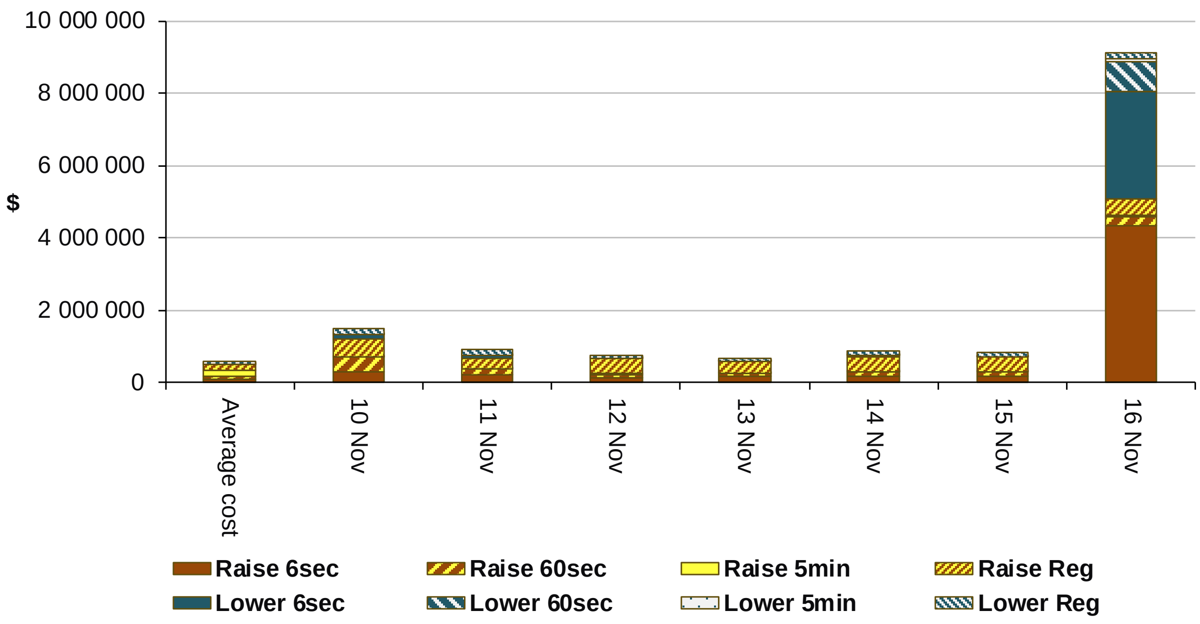
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $14 044 500 or less than 7 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $610 500 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



On 16 November at around 6 pm an unplanned outage of the Heywood interconnector saw South Australia electrically isolated from the rest of the NEM. This meant South Australia had to supply its own FCAS and capacity priced above $5000/MW needed to be dispatched to meet local requirements. Raise 6 sec and lower 6 sec services went to the price cap for a few hours. The AER will conduct a detailed analysis of this FCAS event and publish it as a FCAS $5000/MW report.

Detailed market analysis of significant price events

Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $59/MWh and above $250/MWh and there were two occasions where the spot price was below -$100/MWh.

Sunday, 10 November

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
7.30 am	-203.46	0	0.62	4773	4937	4872	10 593	10 686	11 153
8.30 am	-217.84	-52.21	0.62	4688	4811	4753	10 775	10 818	11 014
7 pm	280.03	72.89	86.65	7212	7062	6970	10 103	10 273	10 300

For the 7.30 am trading interval, demand was 164 MW lower than forecast while availability was 93 MW lower than forecast. The lower availability was due to a reduction of capacity priced at the floor from Yarwun and Stanwell stations because of technical limitations. At 7.05 am, there were little capacity priced between -$70/MWh and the price floor. With capacity priced above the price floor either trapped in FCAS or ramp down-constrained and unable to set price, small reduction in demand resulted in the price dropping to the floor for one dispatch interval.

Similar conditions saw the price dropping to the floor for one dispatch interval during the 8.30 am trading interval.

The 7 pm trading interval price was aligned with the mainland regions and is discussed in the New South Wales section for analysis.

Saturday, 16 November

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	257.27	165.32	201	7799	7796	7677	9547	9580	9677

The price was aligned with New South Wales and will be analysed as one region. Demand was 247 MW higher than forecast, while availability was 407 MW less than forecast across both regions, four hours prior. The lower availability was mostly a result of 300 MW of capacity, priced below $80/MWh, being withdrawn by EnergyAustralia at Mt Piper station due to plant issues. These conditions resulted in prices rising to between $240/MWh and $320/MWh for much of this trading interval.

New South Wales

There were three occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $74/MWh and above $250/MWh.

Sunday, 10 November

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	277.62	98.20	97.98	7653	7549	7604	10 779	10 833	10 944
7.30 pm	273.57	123.58	97.98	7695	7586	7634	10 748	10 782	10 901
8 pm	255.75	148	89.65	7652	7517	7533	10 598	10 744	10 860

For the 7 pm trading interval, prices were aligned across mainland regions of the NEM and the high price event will be discussed here collectively.

Demand was 388 MW higher than forecast while availability was 331 MW lower than forecast, four hours prior. The lower availability was due to low priced capacity being withdrawn at Eraring, Bayswater and Gladstone due to plant issues. Rebidding prior and during the trading interval saw over 500 MW of capacity, priced below $152/MWh, either withdrawn or shifted to over $300/MWh, see Table 6 for detailsTable 6: Significant rebids, 7pm. With little capacity priced between the forecast price and $300/MWh across the mainland regions of the NEM, these conditions resulted in prices settling around $300/MWh for most of the trading interval.

Table 6: Significant rebids, 7pm

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.01 pm		Daydream Solar Farm Pty Ltd	Daydream Solar Farm	150	14 700	-1000	0820 rebid price lower than predispatch forecasts
4.21 pm		Origin Energy	Eraring	-20	38	N/A	1617P change in avail – steam backpressure issue
4.35 pm		Origin Energy	Eraring	-40	38	N/A	1632P change in avail – mill limitation
4.37 pm		Origin Energy	Eraring	-10	38	N/A	1632P change in avail – steam backpressure issue revised
4.38 pm		CS Energy	Gladstone	-150	<77	N/A	1637P updated unit ramp up schedule
5.39 pm		Snowy Hydro	Upper Tumut	130	98	299	17:02:00 A nsw 30min pd price $49.21 higher than 30min pd 19:30@16:32 ($148.00)
6.17 pm		AGL Energy	Bayswater	-50	38	N/A	1815~P~010 unexpected/plant limits~101 milling limits
6.27 pm	6.35 pm	Alinta Energy	Braemar A	168	152	305	1825~F~avoid uneconomic start

Similar conditions, with the exception of a few different rebids, resulted in prices across New South Wales, Victoria and South Australia settling above $250/MWh during the 7.30 pm and 8 pm trading intervals.

Victoria

There were three occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $69/MWh and above $250/MWh.

Sunday, 10 November

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	294.53	105.45	105.03	4965	4844	4863	6588	6664	7017
7.30 pm	293.93	133.72	108.47	5006	4900	4893	6570	6617	6978
8 pm	277.47	161.79	105.03	5031	4880	4868	6489	6592	6971

Prices were aligned across the mainland, see New South Wales section for analysis.

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $54/MWh and above $250/MWh and there were seventeen occasions where the spot price was below -$100/MWh.

Sunday, 10 November

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
7 pm	287.55	107.10	106.69	1304	1291	1297	2062	2093	2084
7.30 pm	301.81	137.60	111.61	1342	1320	1322	2030	2017	2019
8 pm	287.33	167.89	108.99	1363	1342	1343	2008	1997	2010

Prices were aligned across the mainland, see New South Wales section for analysis.

Monday, 11 November

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
5.30 am	-115.94	65.51	67.87	1034	960	939	2655	2447	2523
8.30 am	-192.37	-1000	-1000	989	955	954	2541	2442	2520
9 am	-136.67	-1000	-1000	904	864	866	2719	2496	2560
9.30 am	-233.33	-1000	-1000	885	778	779	2816	2561	2607
10 am	-136.67	-1000	-1000	842	714	708	2826	2570	2620
10.30 am	-900.47	-1000	-1000	796	671	668	2815	2628	2629
11 am	-846.81	-1000	-1000	764	634	633	2761	2615	2631
11.30 am	-786.90	-1000	-1000	793	631	628	2768	2634	2628
midday	-320.00	-1000	-1000	790	664	667	2783	2640	2628
12.30 pm	-290.24	-1000	-1000	833	657	661	2818	2682	2664
1 pm	-343.33	-1000	-1000	818	725	690	2874	2648	2658
1.30 pm	-233.33	-1000	-1000	884	775	732	2928	2656	2667
2 pm	-128.48	-1000	-1000	923	830	780	2934	2656	2674
4.30 pm	-172.60	-1000	83.01	1437	1262	1210	2923	2575	2534
5 pm	-358.93	73.48	77.50	1439	1342	1287	2982	2725	2621

At 5.05 am, a network constraint was invoked to prevent overloading transmission lines in South Australia. The constraint caused flows from South Australia to Victoria to reduce by 120 MW and consequently generation in South Australia was backed off by more than 120 MW. With capacity offered around the forecast price being either backed off or ramp down-constrained, the price fell to around -$500/MWh for two dispatch intervals during the 5.30 am trading interval.

From 8.30 am to 4.30 pm, negative prices occurred during a period of low demand and high wind generation availability. The actual spot prices were higher than forecast because wind and solar generators in South Australia rebid large amounts of capacity from the price floor to higher prices to avoid being dispatched when the price is at or close to the floor.

For the 5 pm trading interval, demand was 97 MW higher than forecast, while availability was 257 MW higher than forecast, four hours prior. Higher availability was from Engie's Pelican Point station due to revised tolling nomination as well as higher than forecast wind generation, mostly priced at the floor. As a result, price fell to the price floor for the first and second dispatch intervals before participants responded and rebid capacity at the floor to above zero and prices increased for the remainder of the trading interval.

Tuesday, 12 November

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
6 pm	-114.77	91.58	78	1183	1145	1133	3110	2915	2870

Demand was 38 MW higher than forecast and availability was 195 MW higher than forecast, four hours prior. At 5.35 pm, a constraint managing system strength in South Australia stopped binding and limiting the dispatch of wind farms. This resulted in an additional 281 MW of wind capacity priced at floor being made available. As a result, the price fell to the floor and in response participants rebid over 400 MW of renewable capacity from the price floor to above $80/MWh.

Friday, 15 November

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
6.30 pm	-118.23	77.50	77.50	1258	1170	1141	2917	2400	2376

Demand was 88 MW higher than forecast while availability was 517 MW higher than forecast, four hours prior. The higher availability was due to Origin rebidding around 270 MW of capacity at Quarantine and Osborne stations into the market (priced at the floor), either due to plant reasons or in response to market conditions. Higher than forecast wind generation also contributed to the additional availability. At 3.37 pm, Infigen also rebid 136 MW of capacity at Lake Bonney 2 wind farm from -$3/MWh to the price floor due to price changes. As a result, the dispatch price fell to the price floor in the first dispatch interval. In response, a number of participants in South Australia rebid capacity at wind farms from the price floor to higher prices to avoid uneconomic dispatch and the dispatch price remained around $50/MWh for the remainder of the trading interval.

Saturday, 16 November

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
7 pm	1078.17	78.71	85.23	1259	1222	1241	2355	2399	2298
7.30 pm	314.70	78	87.76	1261	1246	1257	2233	2436	2301

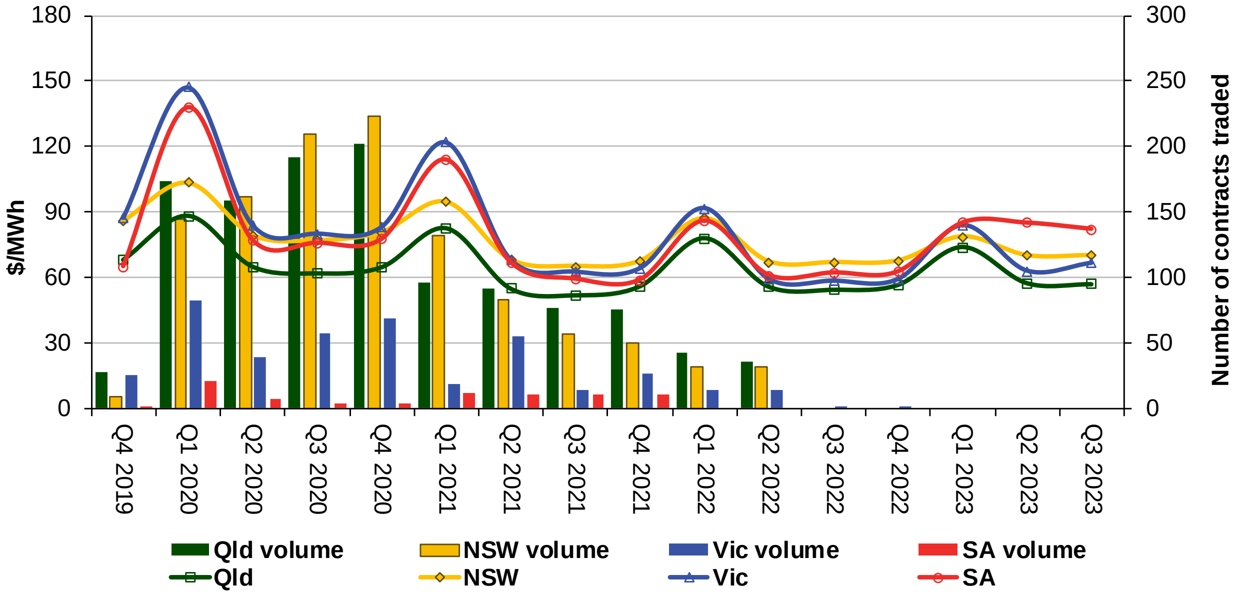
For both trading intervals, demand was close to forecast and availability was between 44 MW and 203 MW lower than forecast, four hours prior.

At around 6 pm, the Heywood interconnector tripped due to failure of equipment around the smelter in Victoria. With the Murraylink interconnector already out, South Australia was separated from the rest of the NEM. This meant both energy and FCAS services in South Australia had to be supplied locally during the outage. There were periods of co-optimisation between the FCAS and Energy markets which saw prices around $500/MWh. At 6.50 pm, the dispatch price reached $5000/MWh when cheaper priced generation was trapped in FCAS and unable to set price. Approximately 8 MW of capacity priced at $5000/MWh was required.

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.

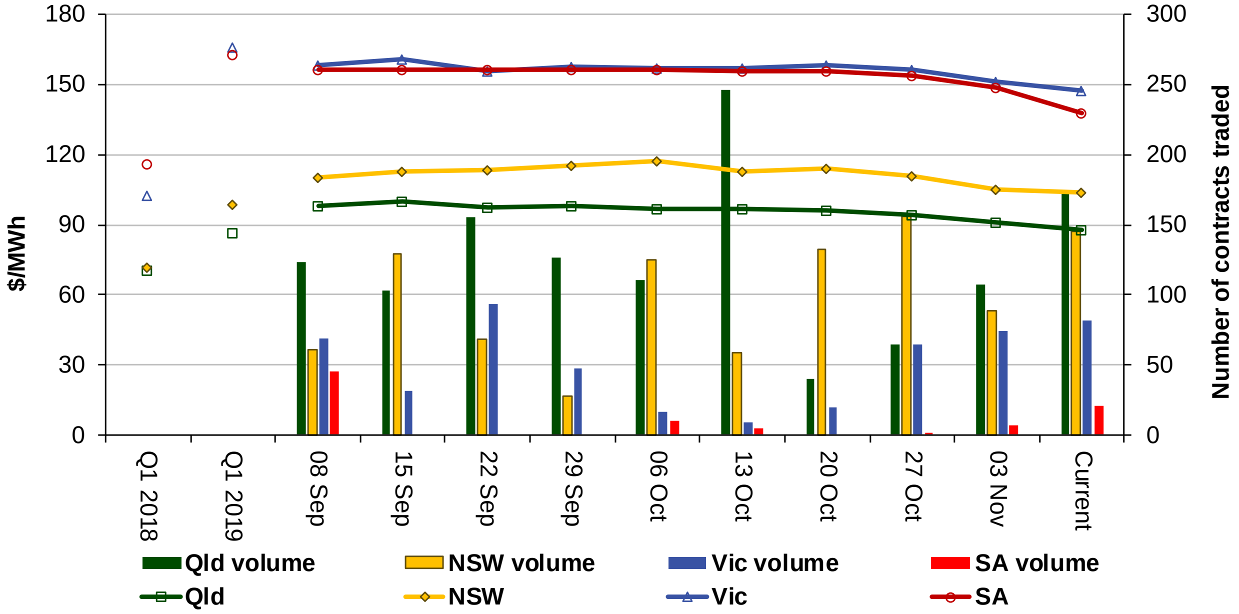
Figure 9: Quarterly base future prices Q4 2019 – Q3 2023



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)

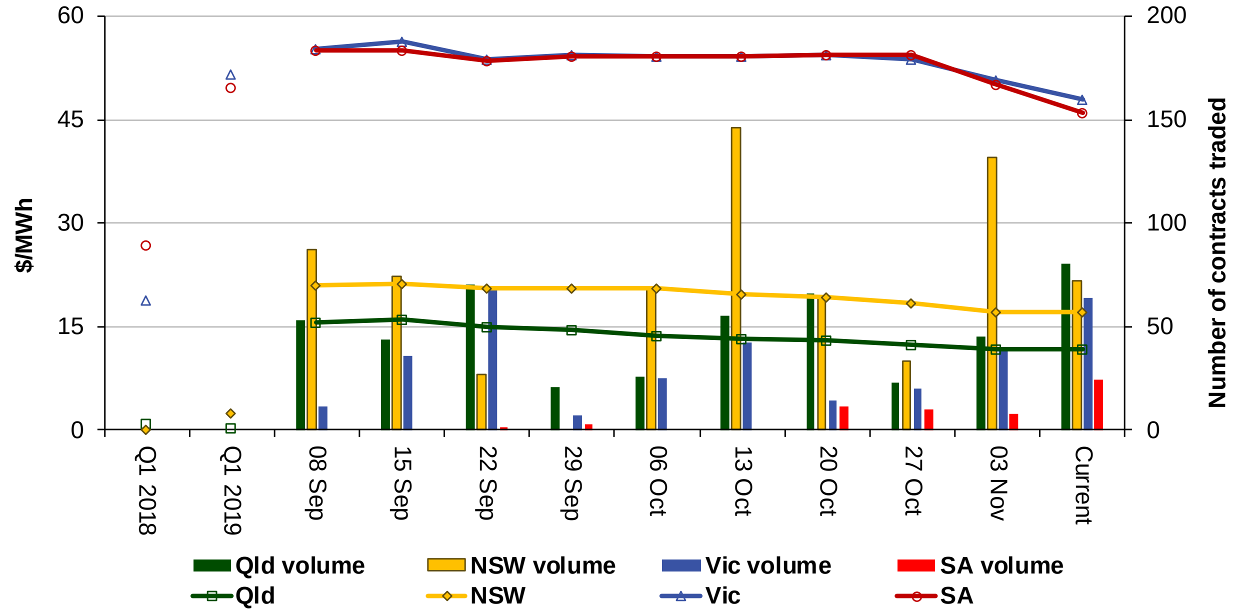


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
December 2019