Electricity Report

AUSTRALIAN ENERGY REGULATOR

2 – 8 December 2018

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 1 - 2 December 2018.

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

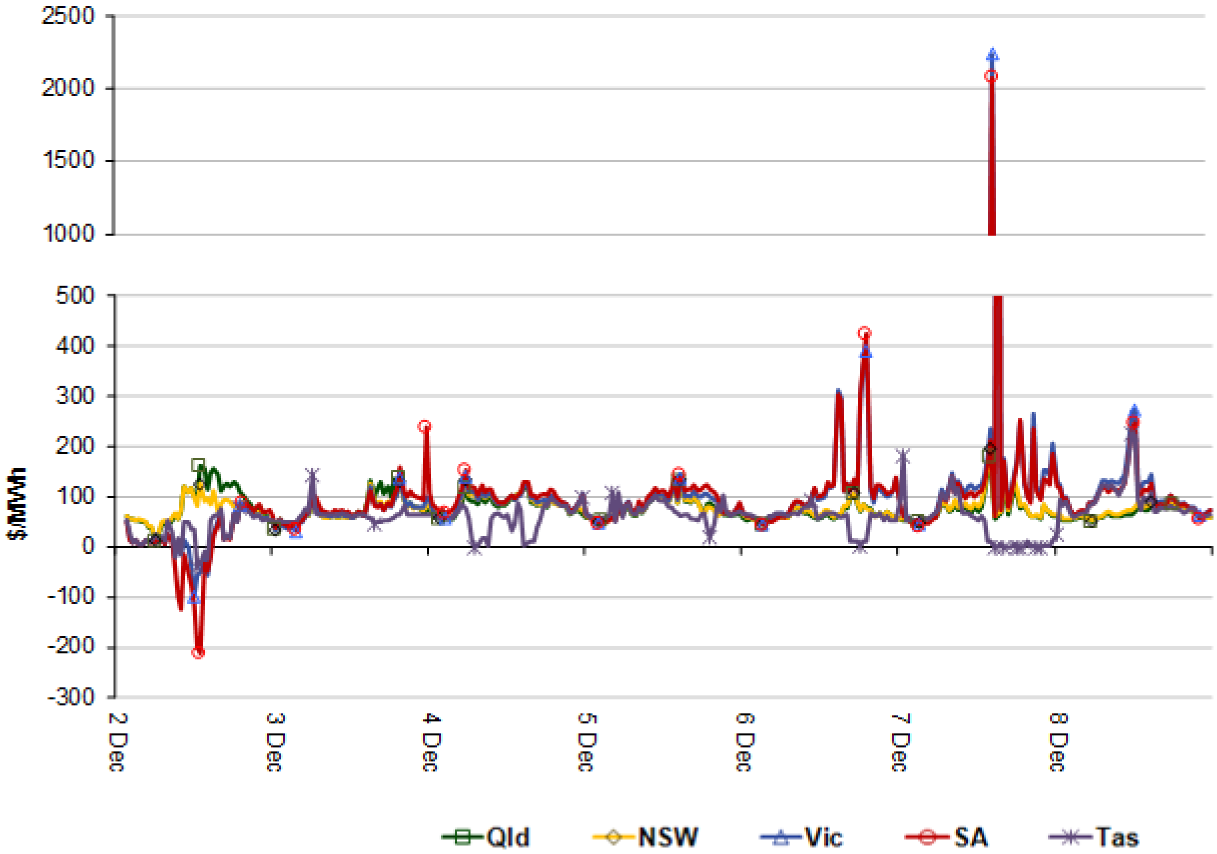


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

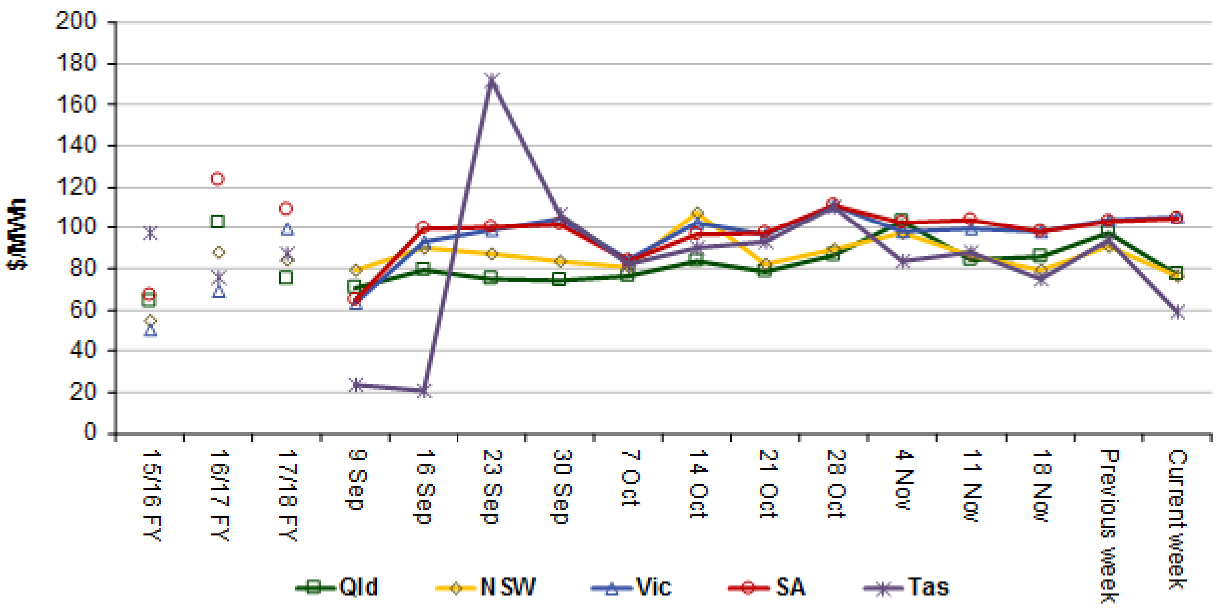


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	77	77	105	104	59
17-18 financial YTD	78	90	97	95	91
18-19 financial YTD	82	89	91	97	61

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 214 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. 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	19	0	0
% of total below forecast	14	46	0	15

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

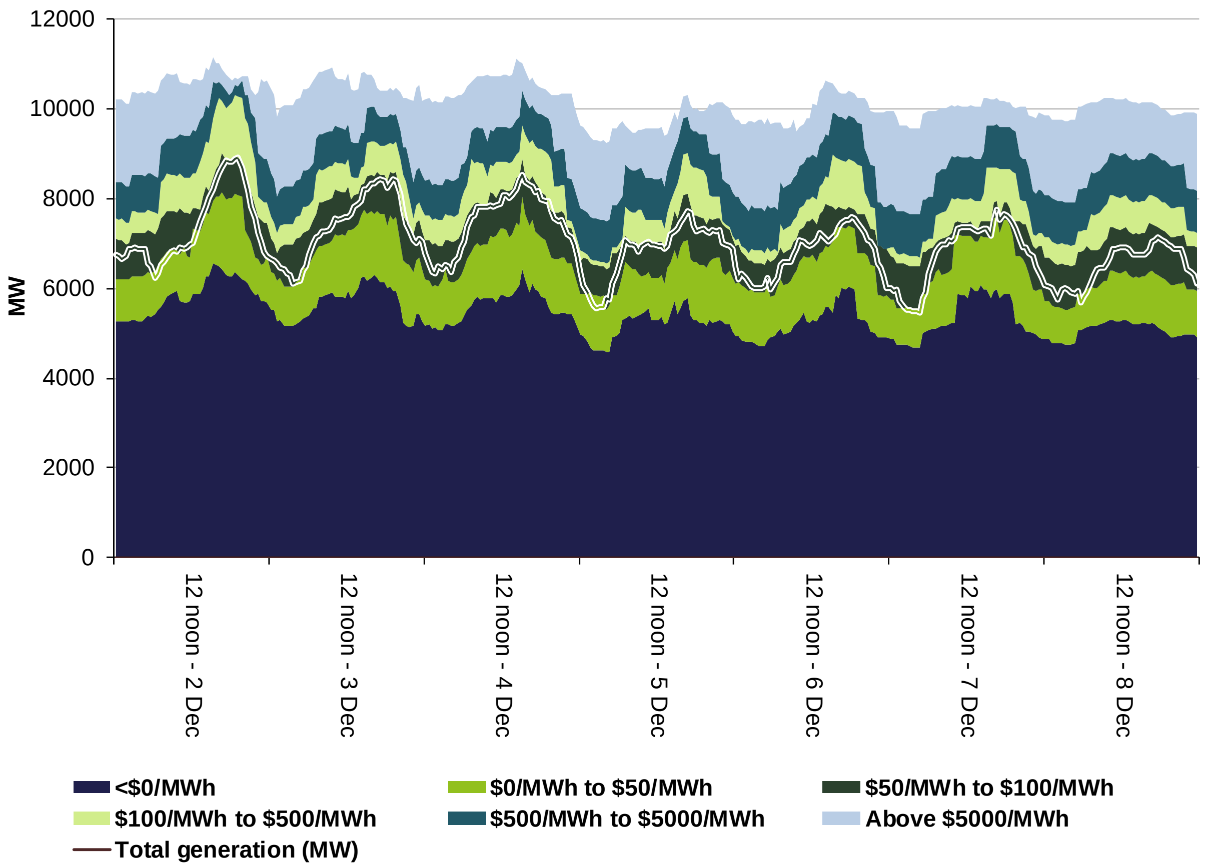


Figure 4: New South Wales generation and bidding patterns

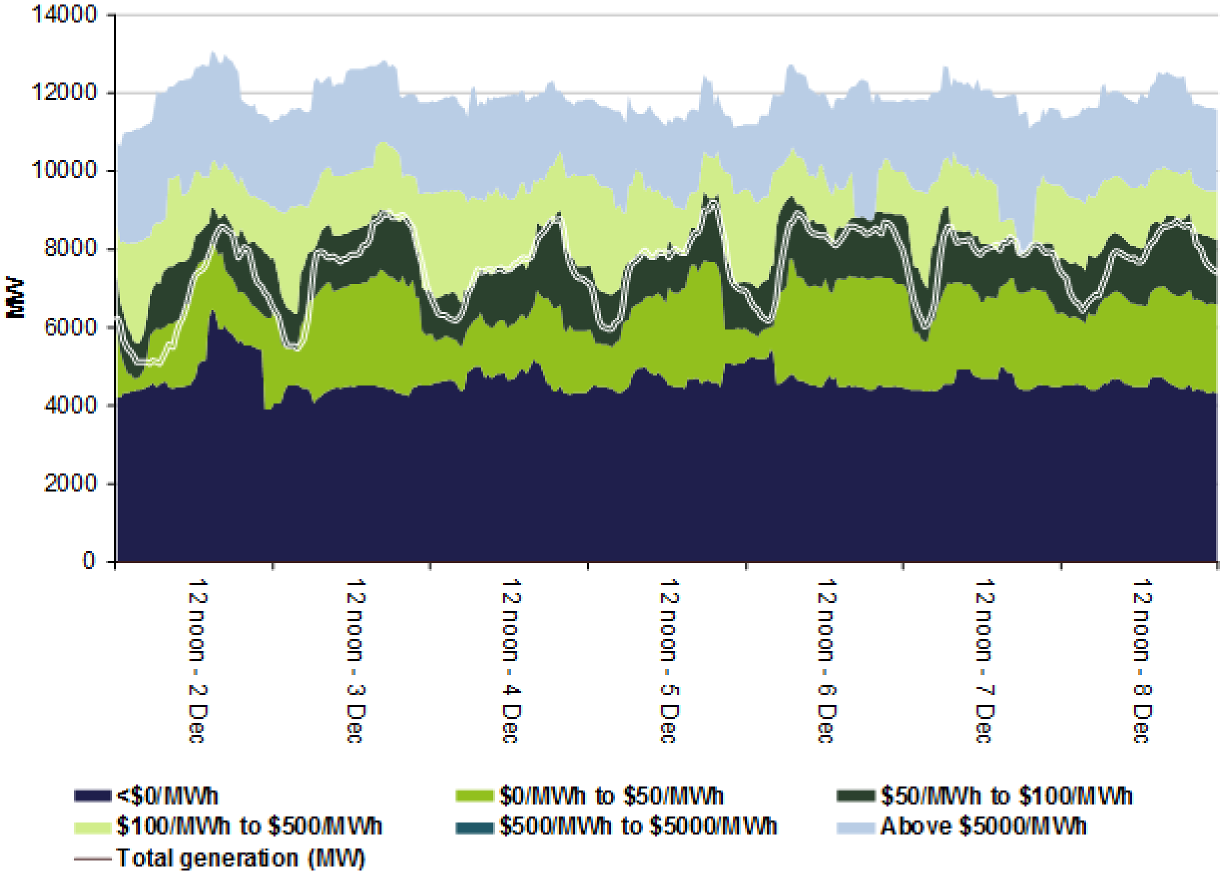


Figure 5: Victoria generation and bidding patterns

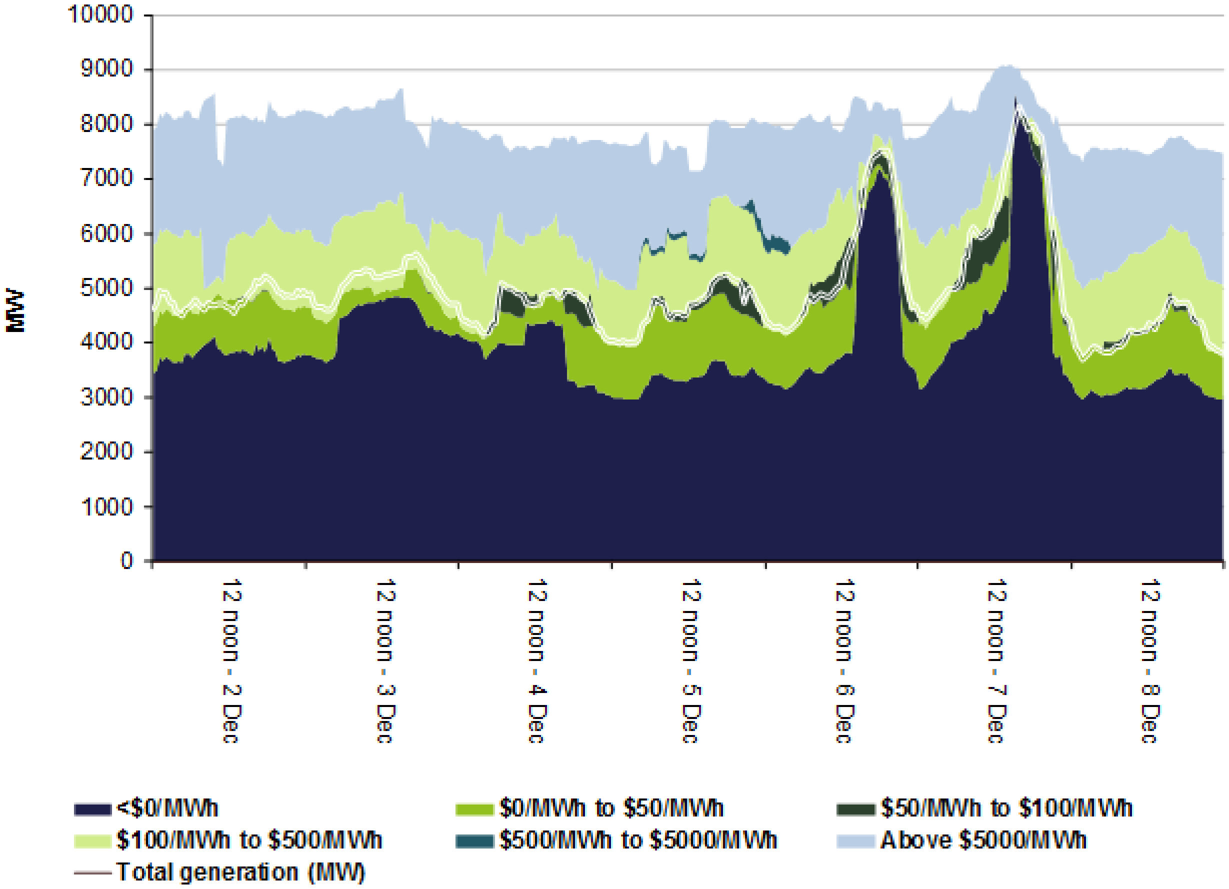


Figure 6: South Australia generation and bidding patterns

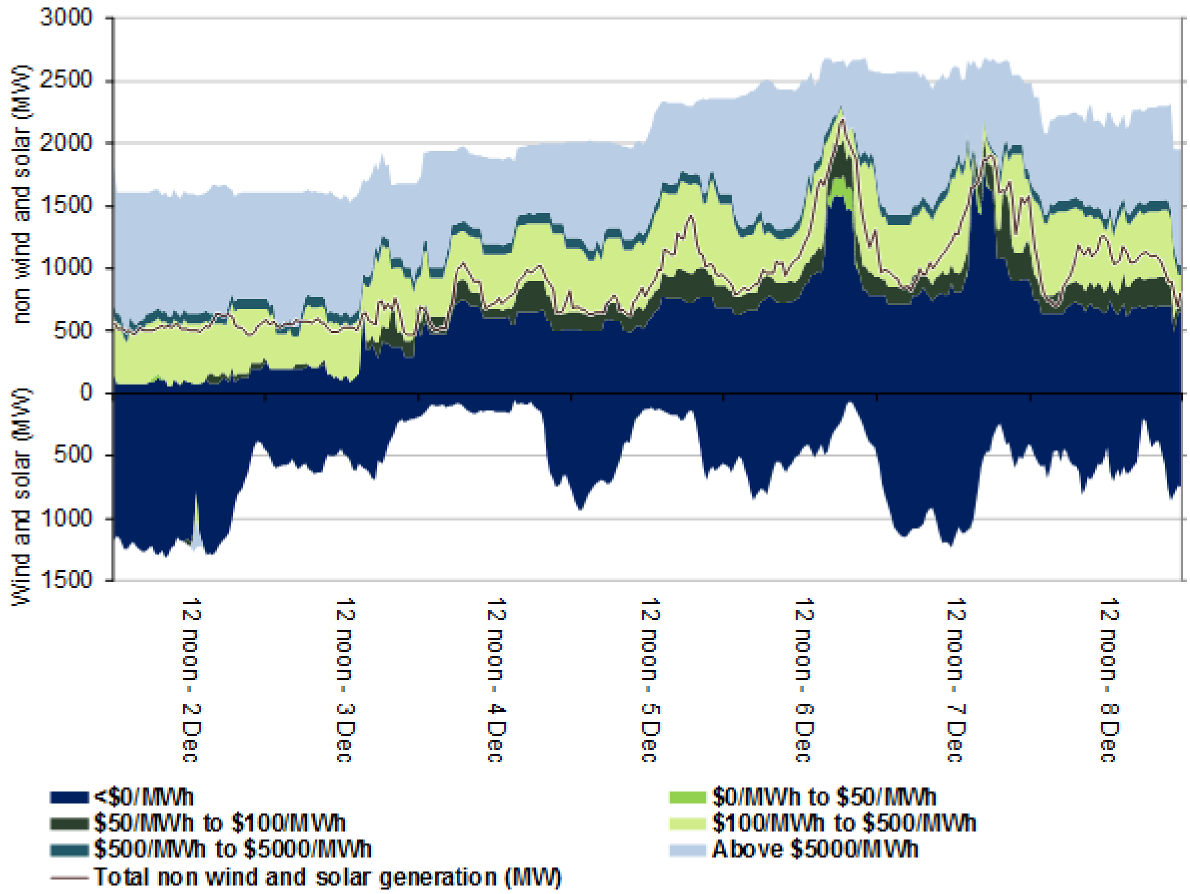
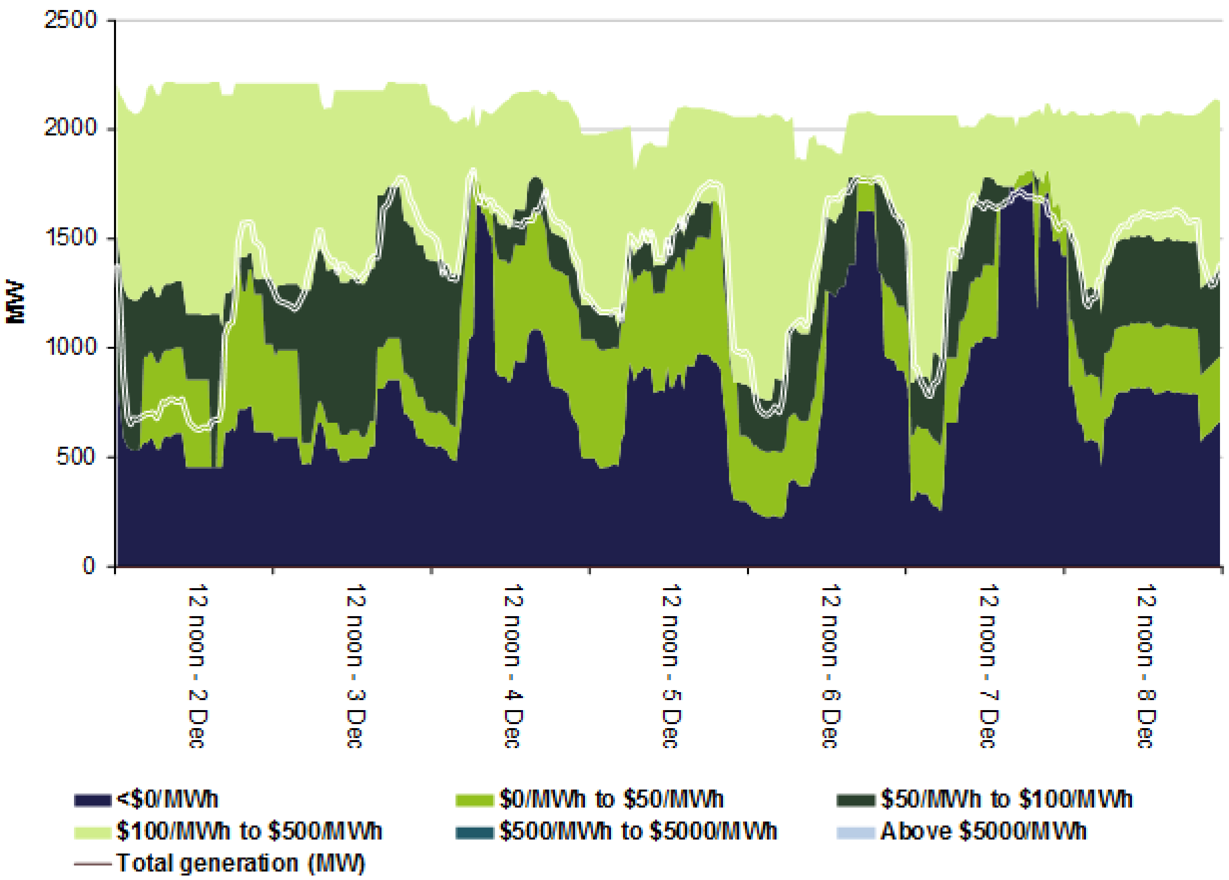


Figure 7: Tasmania generation and bidding patterns



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.

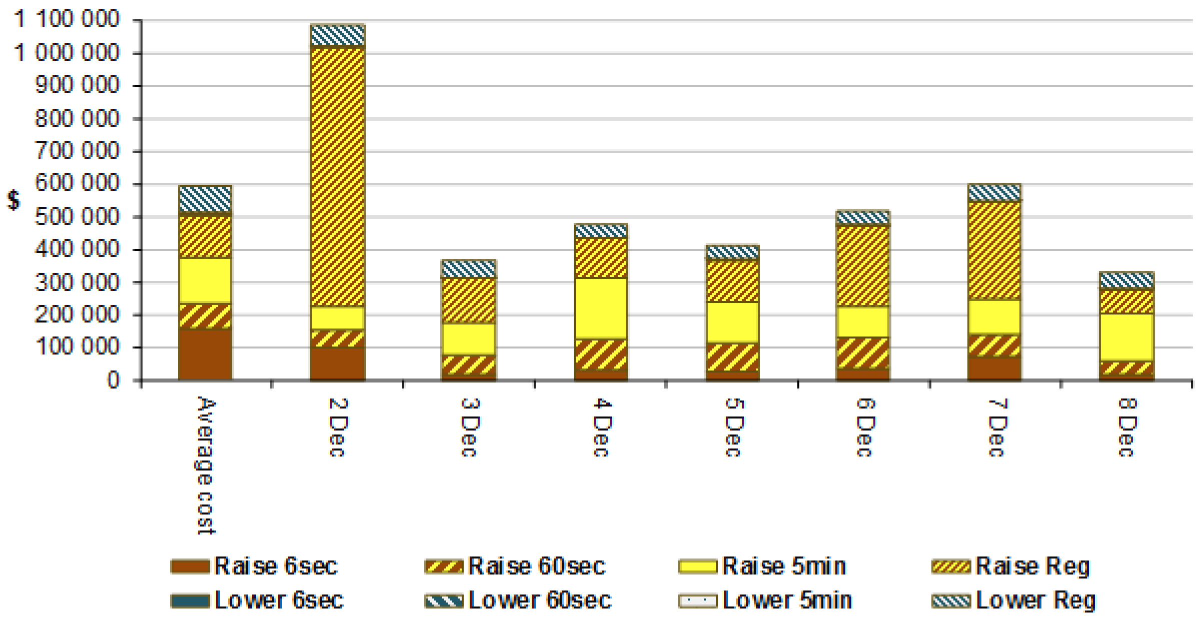
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 399 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $393 000 or around four 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



For the majority of the afternoon on 2 December a constraint which manages raise regulation requirements on the mainland bound. The price, which was co-optimised with energy and other FCAS markets, ranged from $20/MW to $515/MW from 8:55 am to 7:20 pm with a number of prices around $450/MW.

Detailed market analysis of significant price events

Victoria

There were three occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $105/MWh and above $250/MWh.

Thursday, 6 December

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	359.37	299.30	560.22	7631	7392	7386	8174	8198	8166
7.30 pm	391.36	157.43	317.07	7417	7221	7232	8172	8235	8172

The price was aligned with South Australia and will be discussed as one region.

For the 7 pm trading interval, across both regions demand was 142 MW higher than forecast while availability was close to forecast.

The higher than forecast demand saw dispatch prices range from $247/MWh to $517/MWh for the entire trading interval.

For the 7:30 pm trading interval, across both regions demand was 112 MW higher than forecast while availability was 153 MW lower than forecast, four hours prior.

The lower than forecast availability is mainly attributed to lower than forecast wind generation. This combined with the higher than forecast demand saw dispatch prices range between $251/MWh and $592/MWh for the entire trading interval.

Friday, 7 December

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
3.30 pm	2237.41	10 000	11 053	8448	8408	8179	8924	8620	8570

The price was aligned with South Australia and will be discussed as one region.

Conditions at the time saw net demand around 160 MW lower than forecast while net availability was approximately around 590 MW higher than forecast four hours prior, mainly due to higher than forecast wind generation.

In the lead up to the start of the trading interval around (net) 340 MW was rebid from more than $12 100/MWh to less than $0. This saw the first two dispatch intervals between $73/MWh and $116/MWh.

At 1.15 pm there was a 200 MW drop in wind generation and a 136 MW increase in demand. With cheaper priced generation ramp up-constrained, the dispatch price increased to $13 071/MWh in Victoria and $12 094/MWh in South Australia.

Prices then decreased to between $77/MWh and $10/MWh for the remainder of the trading interval after participants rebid around 830 MW of capacity from prices above $10 000/MWh to the price floor.

South Australia

There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $104/MWh and above $250/MWh and there were four occasions where the spot price was below -$100/MWh.

Sunday, 2 December

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
10.30 am	-124.68	-1000	-149	578	576	564	2745	2724	2644
12.30 pm	-115.33	-1000	-150	544	507	496	2812	2746	2622
1 pm	-198.81	-1000	-150	520	478	490	2860	2741	2621
1.30 pm	-213.08	-1000	-150	524	478	477	2822	2734	2680

At times, AEMO override the normal dispatch process to maintain system security. On this day AEMO directed a gas plant in South Australia, triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

For all trading intervals, demand and availability was close or slightly above forecast, four hours prior.

Across all four trading intervals there was no capacity priced between -$150/MWh and the floor. This meant reductions in capacity at the floor, decrease in wind generation or increases in demand could cause large movements in price.

For the 10:30 am interval, across 2 rebids around 10 am, Infigen rebid 159 MW at Lake Bonney 2 wind farm from the price floor to -$3/MWh, due to constraint management. The decrease in capacity saw prices stay at approximately -$150/MWh for the entire trading interval.

The rebid at Lake Bonney 2 was still in place for the 12.30 pm trading interval. Effective from 12.05 pm, Hornsdale wind farm 2 rebid 50 MW from the floor to -$150 and above. The rebid reason related to constraint management. Effective from 12.15 pm Energy Australia rebid 130 MW from the floor to $60/MWh at its Waterloo wind farm with the rebid reason '12:07 ~ A ~ BAND ADJ TO 5MIN NEGATIVE DP ~ SL'.

The reduction in cheaper priced capacity saw dispatch prices between -$81/MWh to -$150/MWh.

For the 1 pm interval the rebids from Lake Bonney 2 and Waterloo wind farm were still in place. Again the reduction in cheaper priced capacity saw dispatch prices between -$79/MWh to -$656/MWh.

For the 1:30 pm interval the rebid from Lake Bonney 2 was still in place. After the dispatch price fell to the floor at 1.10 pm, a number of wind farms rebid around 240 MW from the floor to $60/MWh. The price then increased to between -$79/MWh and $8/MWh for the remainder of the trading interval.

Thursday, 6 December

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	367.50	348.91	658.44	2526	2623	2624	2864	2868	2743
7.30 pm	423.86	192.39	373.87	2474	2558	2565	2760	2850	2728

Prices were aligned with Victoria, see analysis from Victorian section.

Friday, 7 December

Table 7: Price, Demand and Availability

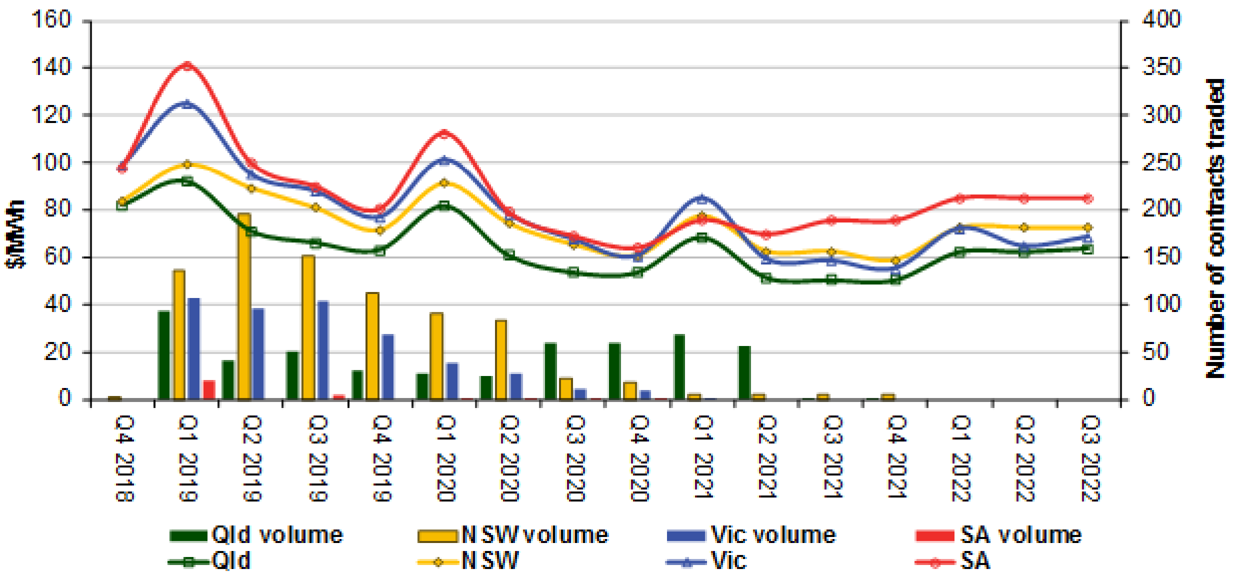
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
3.30 pm	2068.88	8855.38	10 046	2354	2235	2354	3652	3365	3101

Prices were aligned with Victoria, see analysis from Victorian section.

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.

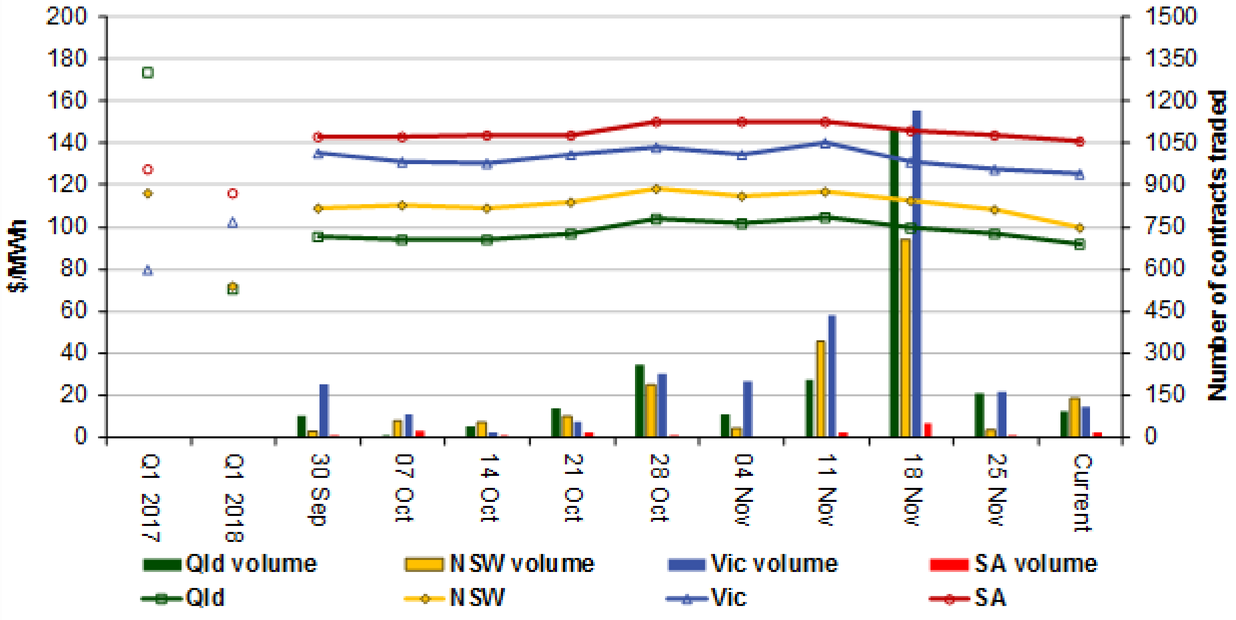
Figure 9: Quarterly base future prices Q4 2018 – Q3 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 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 2019 base contracts over the past 10 weeks (and the past 2 years)



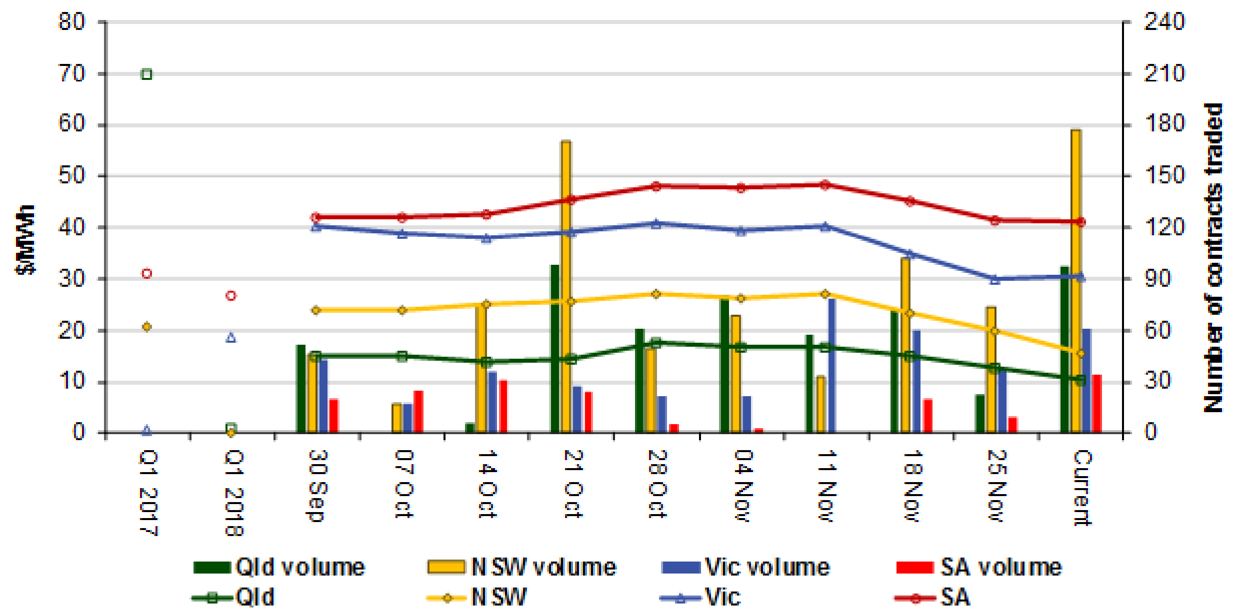
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

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 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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