Electricity Report

AUSTRALIAN ENERGY REGULATOR

24 - 30 December 2017

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 24 - 30 December 2017.

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

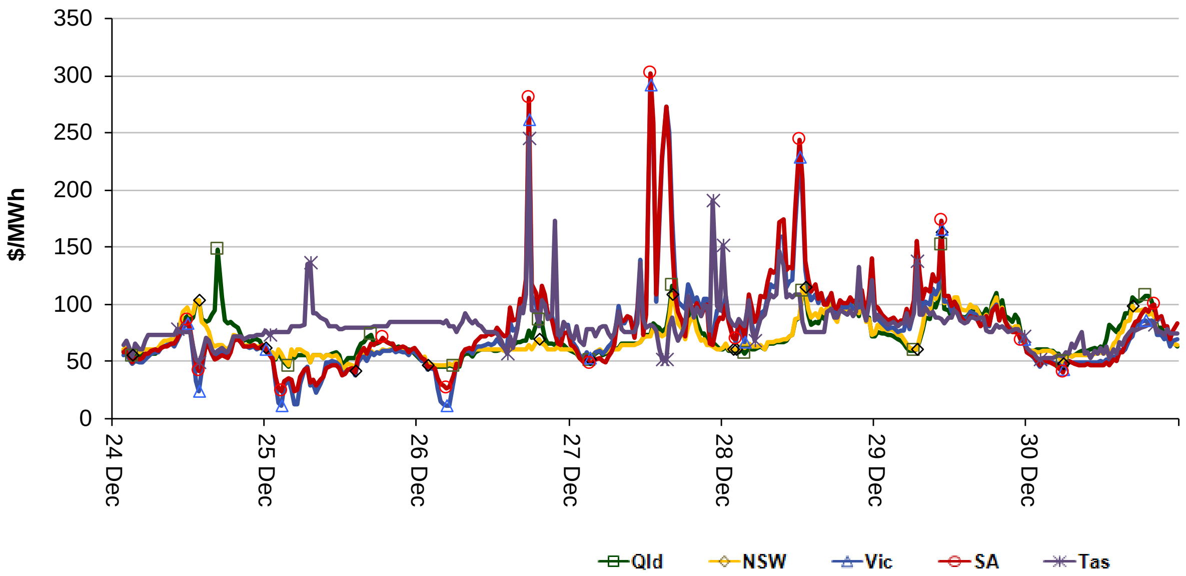


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

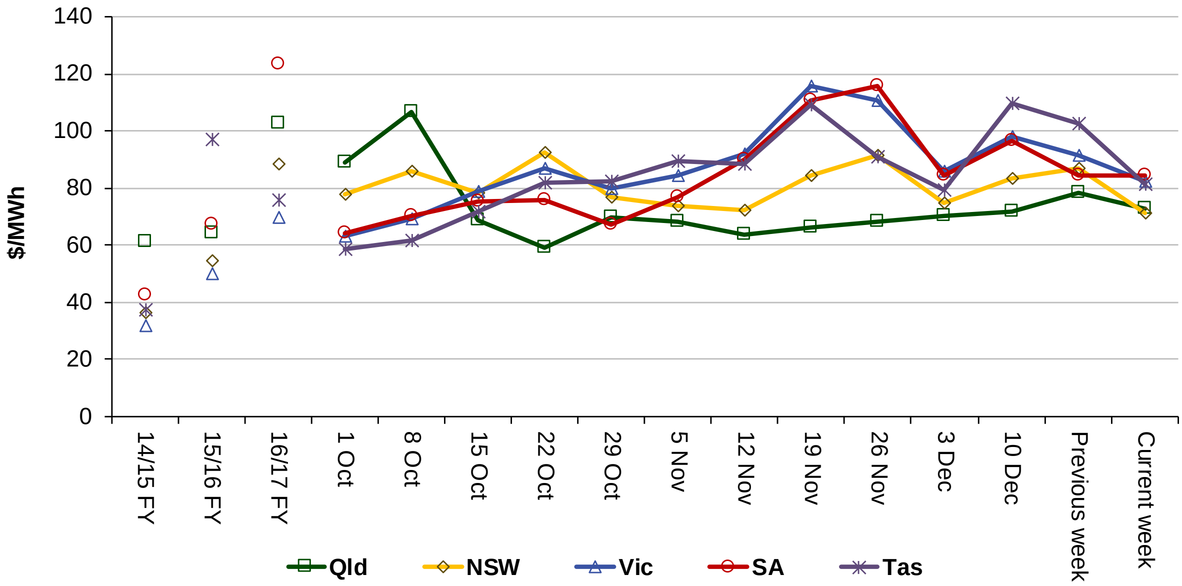


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	73	71	82	84	81
16-17 financial YTD	60	61	44	107	47
17-18 financial YTD	77	88	96	95	91

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 142 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2016 of 273 counts and the average in 2015 of 133. 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	1	33	0	4
% of total below forecast	40	15	0	6

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

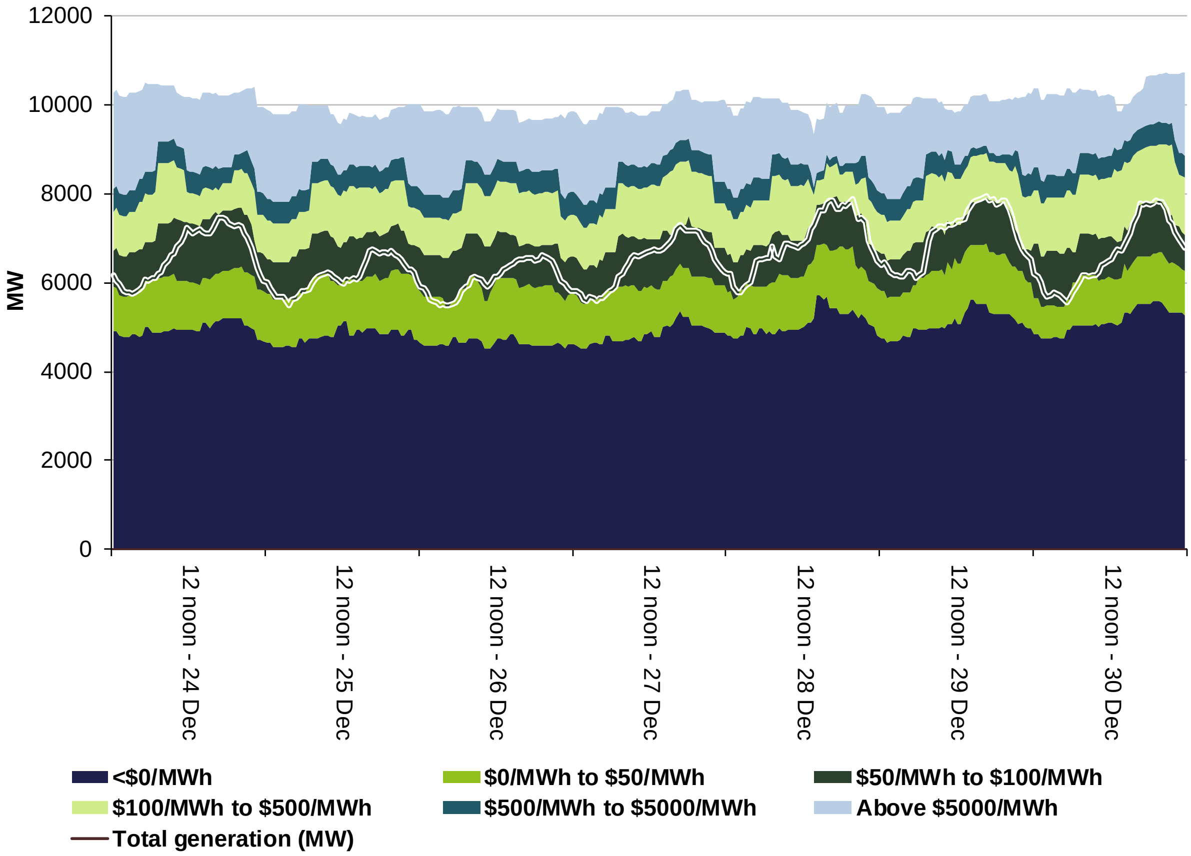


Figure 4: New South Wales generation and bidding patterns

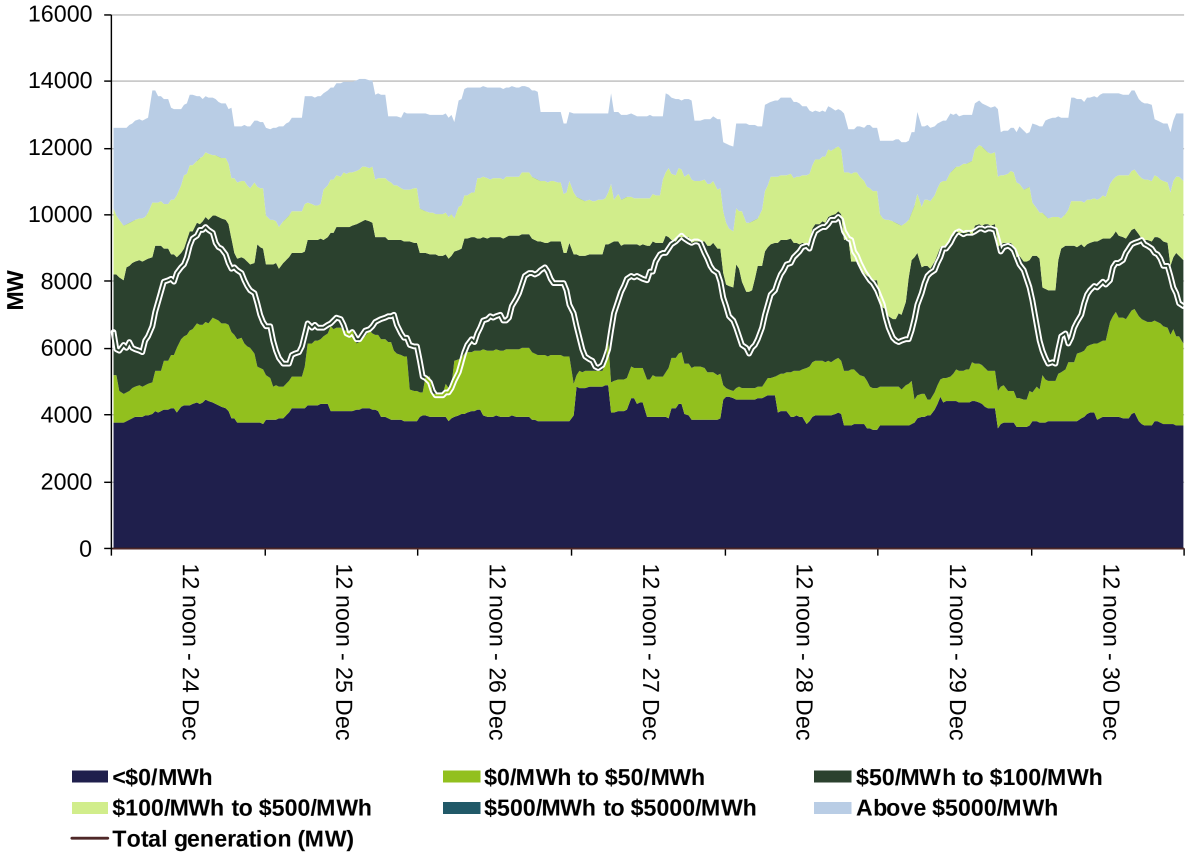


Figure 5: Victoria generation and bidding patterns

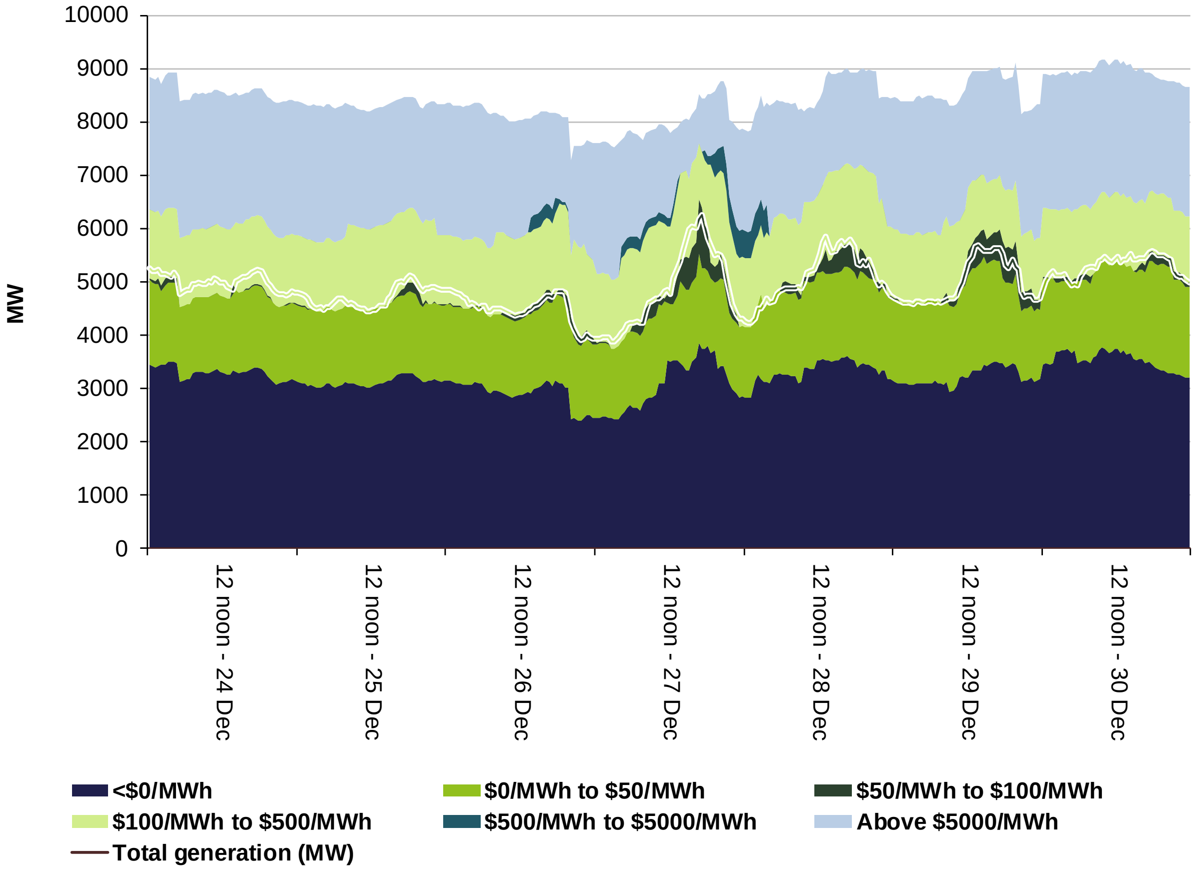


Figure 6: South Australia generation and bidding patterns

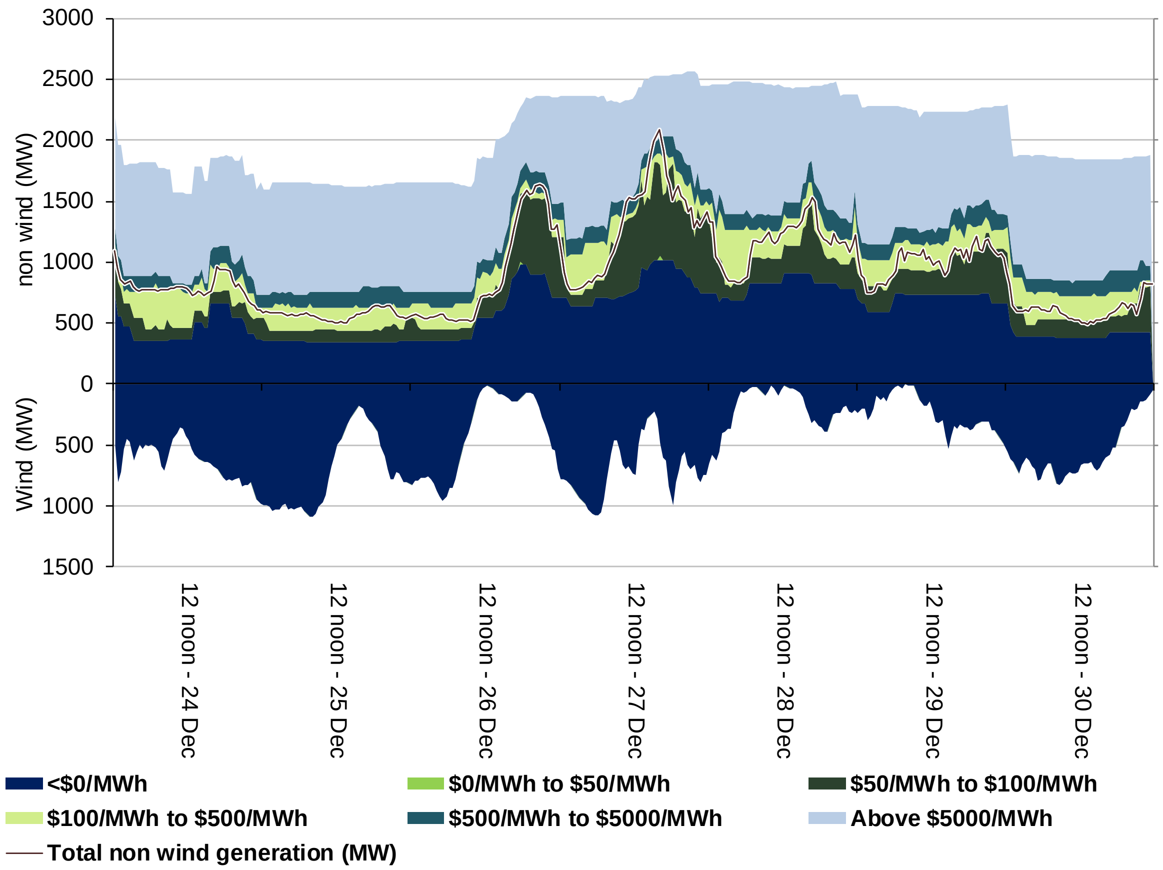
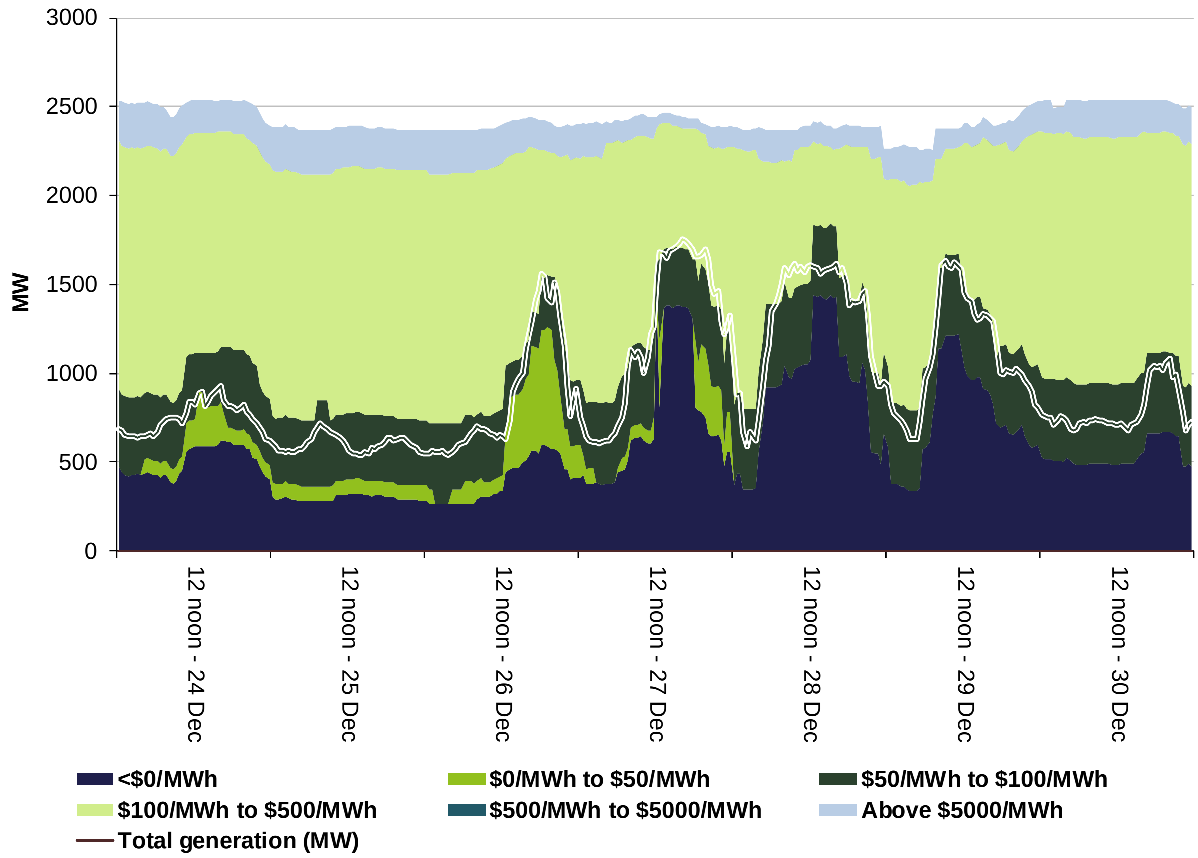


Figure 7: Tasmania generation and bidding patterns



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.

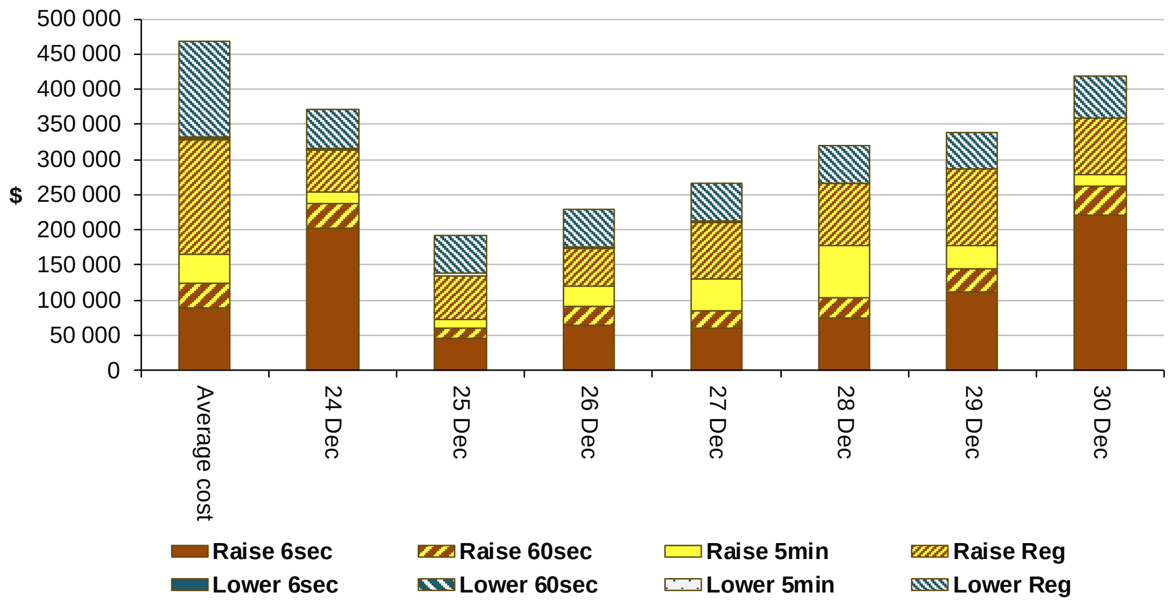
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 271 000 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $866 500 or around six 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

Victoria

There were four occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $82/MWh and above $250/MWh.

Tuesday, 26 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
6 pm	261.87	151.03	77.68	5317	5279	4976	8168	8134	8155

Conditions at the time saw demand and availability close to that forecast four hours ahead. Victoria and South Australia prices were aligned and acting as one region.

Demand was around 160 MW higher than forecast in South Australia and imports from New South Wales were around 100 MW less than forecast. This combined with a system normal constraint which avoids voltage collapse for loss of the largest Victorian generating unit or Basslink, limiting low priced generation in Victoria saw the dispatch price increase to $397/MWh at 5.55 pm and $529/MWh at 6 pm.

Wednesday, 27 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
1 pm	292.00	84.82	89.15	5911	5352	5665	7854	7997	7980
3.30 pm	272.99	534.68	134.51	6995	6478	6402	8039	8602	8639
4 pm	250.16	300.24	134.62	7224	6678	6552	8032	8589	8630

Conditions at the time saw demand around 550 MW higher than forecast while availability was between 150 MW and 560 MW lower than forecast four hours prior.

For the 1 pm and 3.30 pm trading intervals Victoria and South Australia prices were aligned and acting as one region.

The reduction in available capacity in the four hours leading up to the start of the 1 pm trading interval was mainly due to AGL removing 540 MW of capacity priced at the floor from its Loy Yang A power station due to delays in returning a unit to service.

The higher than forecast price was a result of the reduction in low priced capacity, higher than forecast demand and a system normal constraint was limiting import into Victoria from New South Wales.

The lower than forecast price for the 3.30 pm trading interval was a result of higher than forecast imports (around 700 MW) from South Australia and New South Wales and over 500 MW of capacity rebid in South Australia and 450 MW in Victoria from the prices near the cap to less than $105/MWh. The rebids are shown in Table 5 below.

Table 5: Rebidding

Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.10 am	AGL Energy	Somerton	160	13 988	0	1101~A~050 chg in aemo pd~51 pd demand increase vic cumulative 193mw pe16:00 (pd10:30-11:00)
11.13 am	Alinta Energy	Bairnsdale	72	14 411	<68	1102A price different from forecast: vic
12.43 pm	Origin Energy	Mortlake	224	14200	<78	1242A inc nem dem 5pd 23637 mw > 30pd 23179 mw @1330 sl
1.04 pm	Origin Energy	Ladbroke Grove	74	14 200	-1000	1302A inc vic dem 5pd 6120 mw > 30pd 5931 mw @1330sl
1.04 pm	Origin Energy	Quarantine	112	14 200	<80	1302A inc vic dem 5pd 6120 mw > 30pd 5931 mw @1330sl
1.14 pm	AGL Energy	Torrens Island	260	14 200	<105	1310~P~010 unexpected/plant limits~108 load variation during rts
2.43 pm	Origin Energy	Quarantine	72	14 200	-1000	1440A constraint management - n^^v_nil_1 sl

The 4 pm trading interval was close to that forecast four hours prior.

South Australia

There were four occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $84/MWh and above $250/MWh.

Tuesday, 26 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
6 pm	280.00	165.00	91.36	1745	1581	1536	2381	2392	2453

The higher than forecast price is discussed in the Victorian section under Table 3 above.

Wednesday, 27 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
1 pm	302.56	89.00	89.56	1903	1812	1645	2931	2939	2968
1.30 pm	259.53	105.00	113.79	1943	1868	1702	2806	2952	2977
3.30 pm	272.85	600.80	145.50	1912	2165	1914	2750	3004	3029

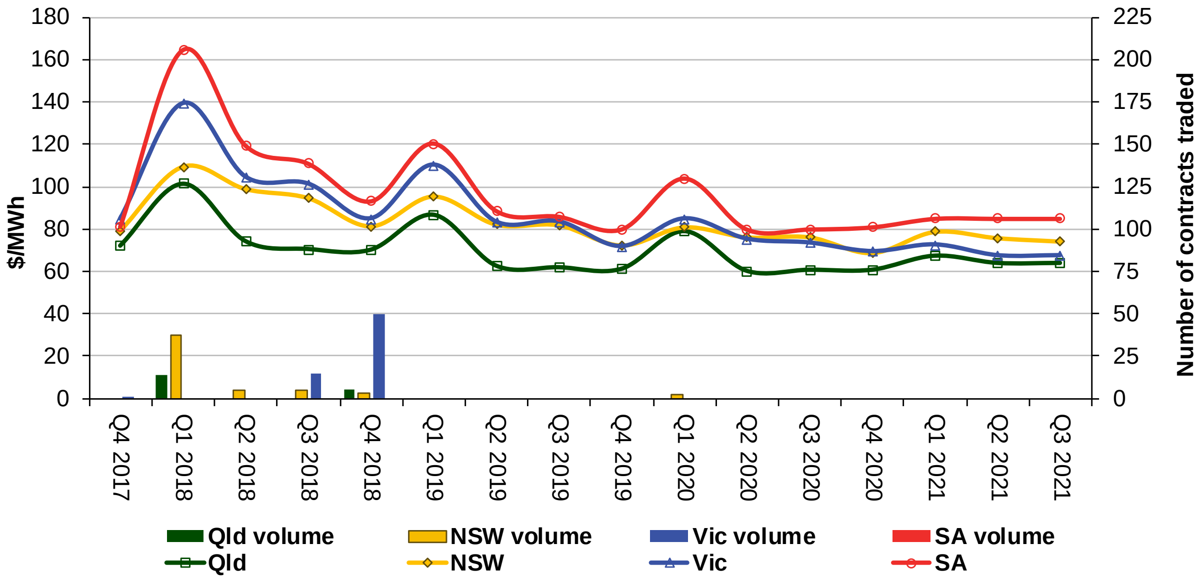
The 1 pm and 3.30 prices are discussed in the Victorian section under Table 4 above.

For the 1.30 pm trading interval demand was 75 MW higher than forecast while availability was 146 MW lower than forecast four hours prior, due to lower than forecast wind generation. This combined with a reduction in imports saw the dispatch price range from $123/MWh and $522/MWh for 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.

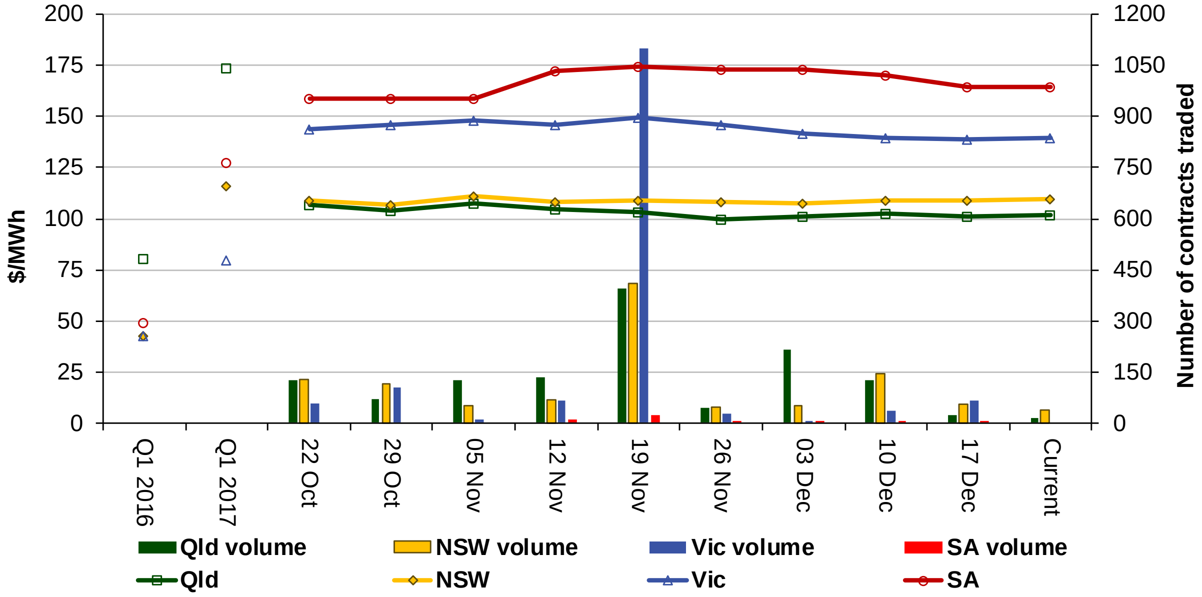
Figure 9: Quarterly base future prices Q4 2017 – Q3 2021



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2018 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 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 2018 base contracts over the past 10 weeks (and the past 2 years)



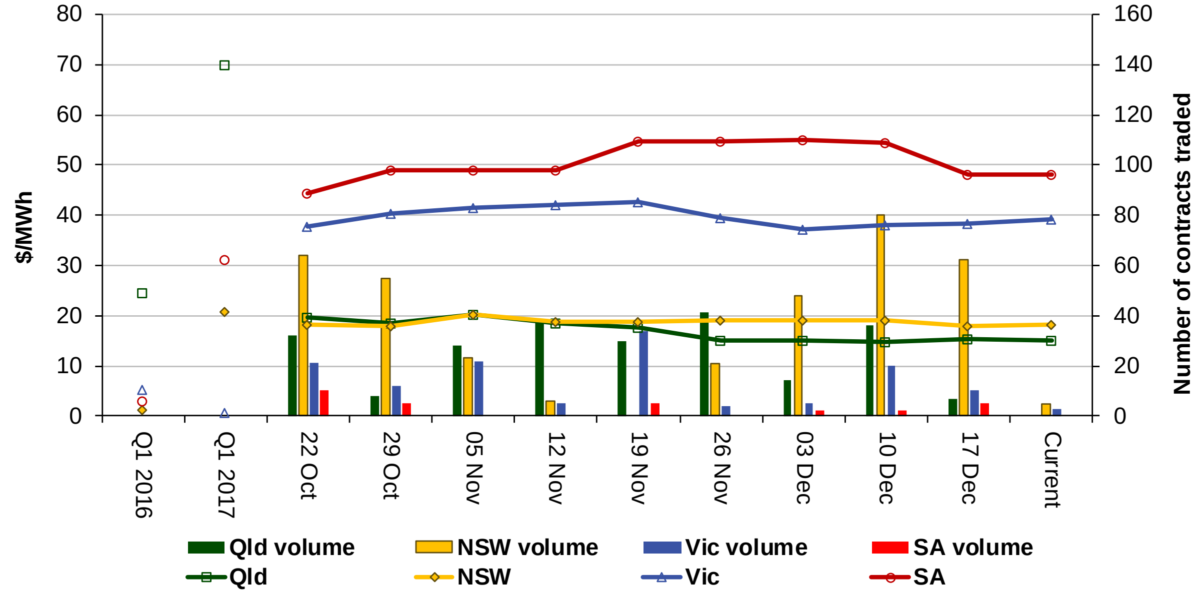
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2018 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 prices are also shown.

Figure 11: Price of Q1 2018 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au