Electricity Report

AUSTRALIAN ENERGY REGULATOR

1 – 7 January 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 1 – 7 January 2017.

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

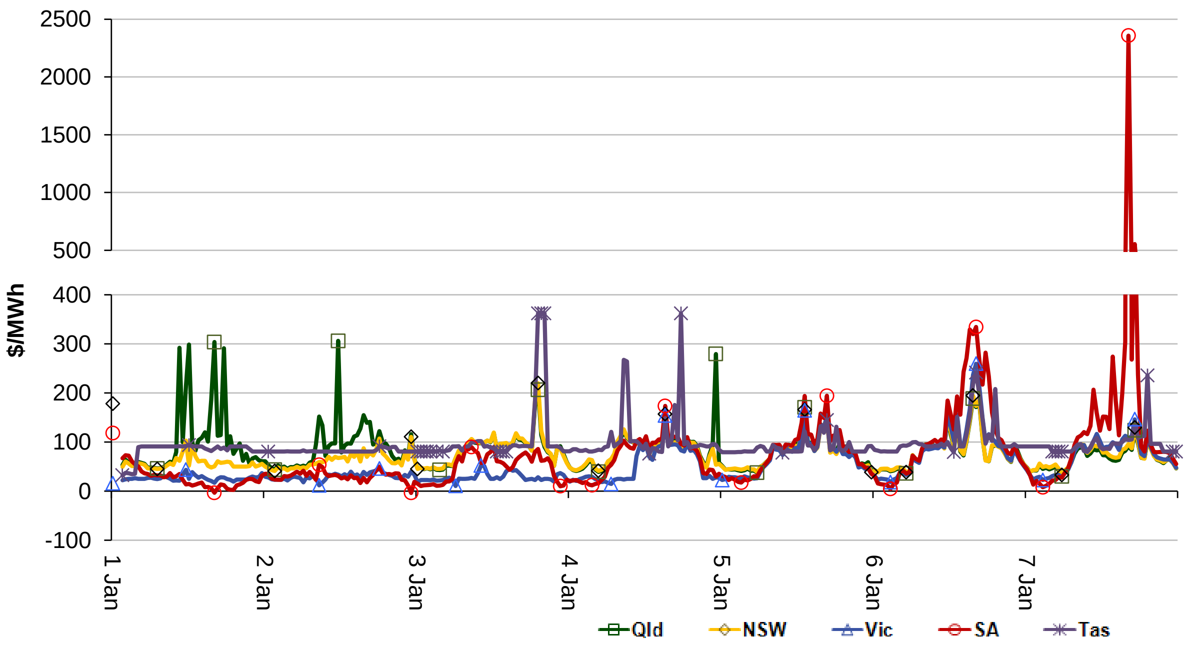


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

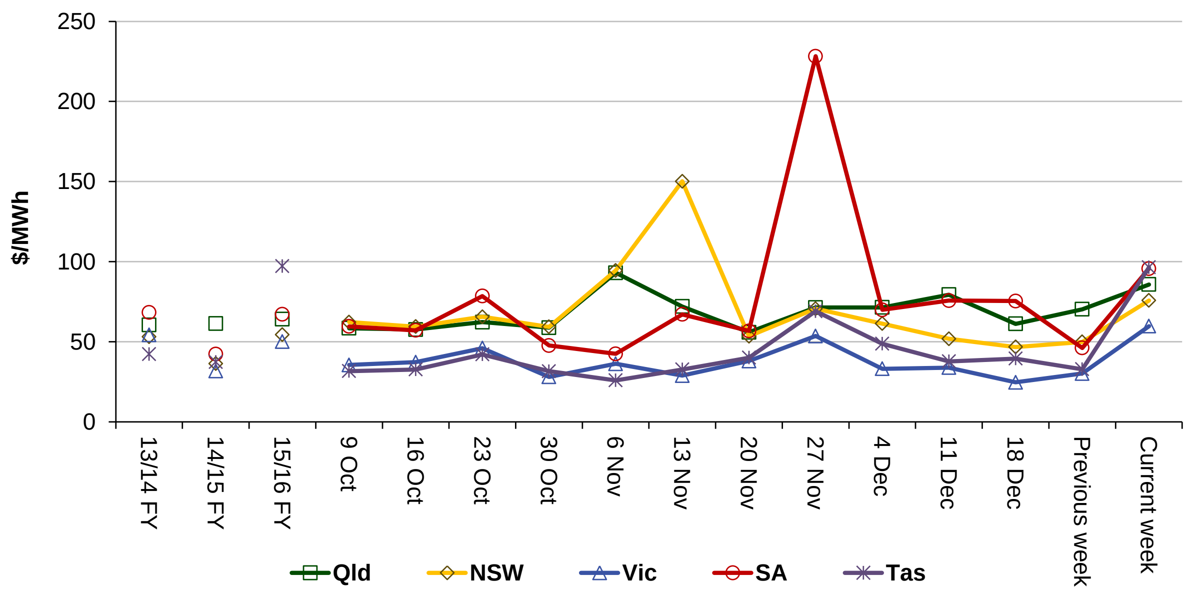


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	86	76	60	96	96
15-16 financial YTD	44	45	40	63	59
16-17 financial YTD	61	62	45	106	49

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 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	9	24	0	2
% of total below forecast	35	23	0	7

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

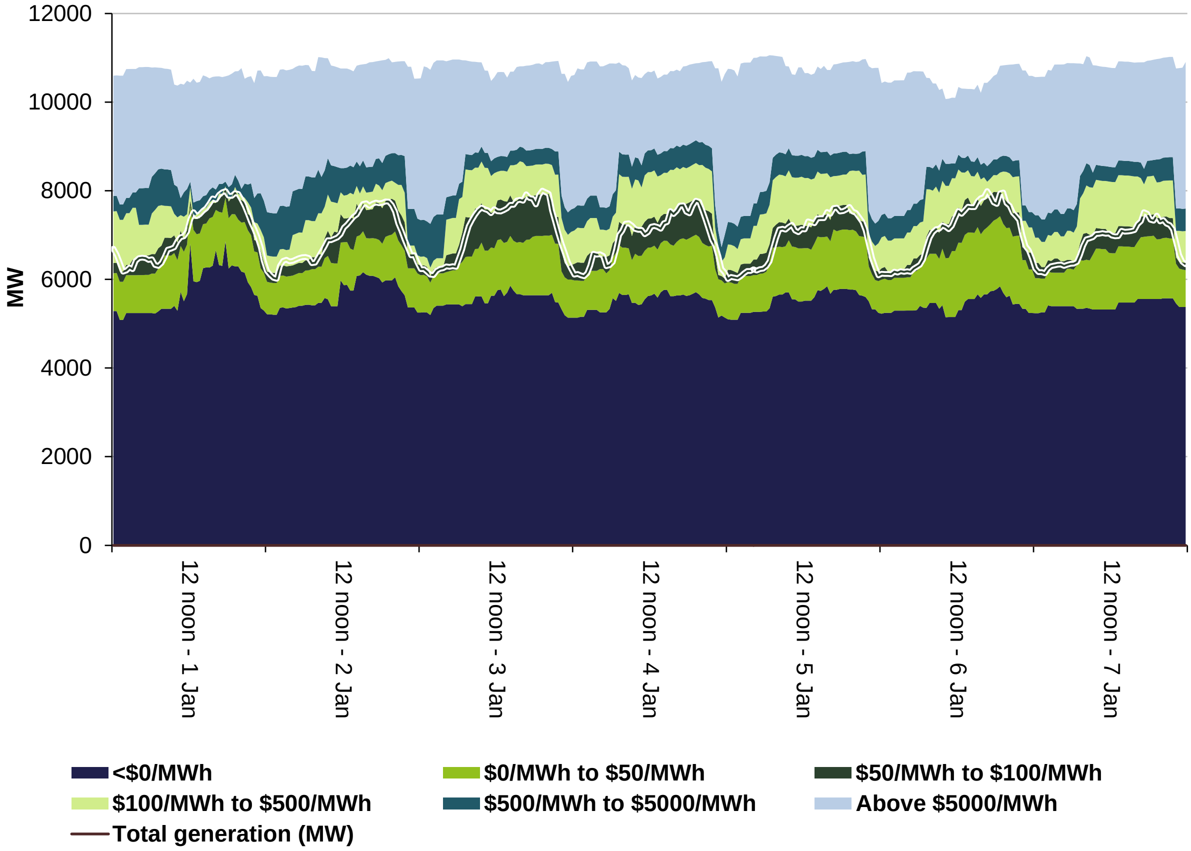


Figure 4: New South Wales generation and bidding patterns

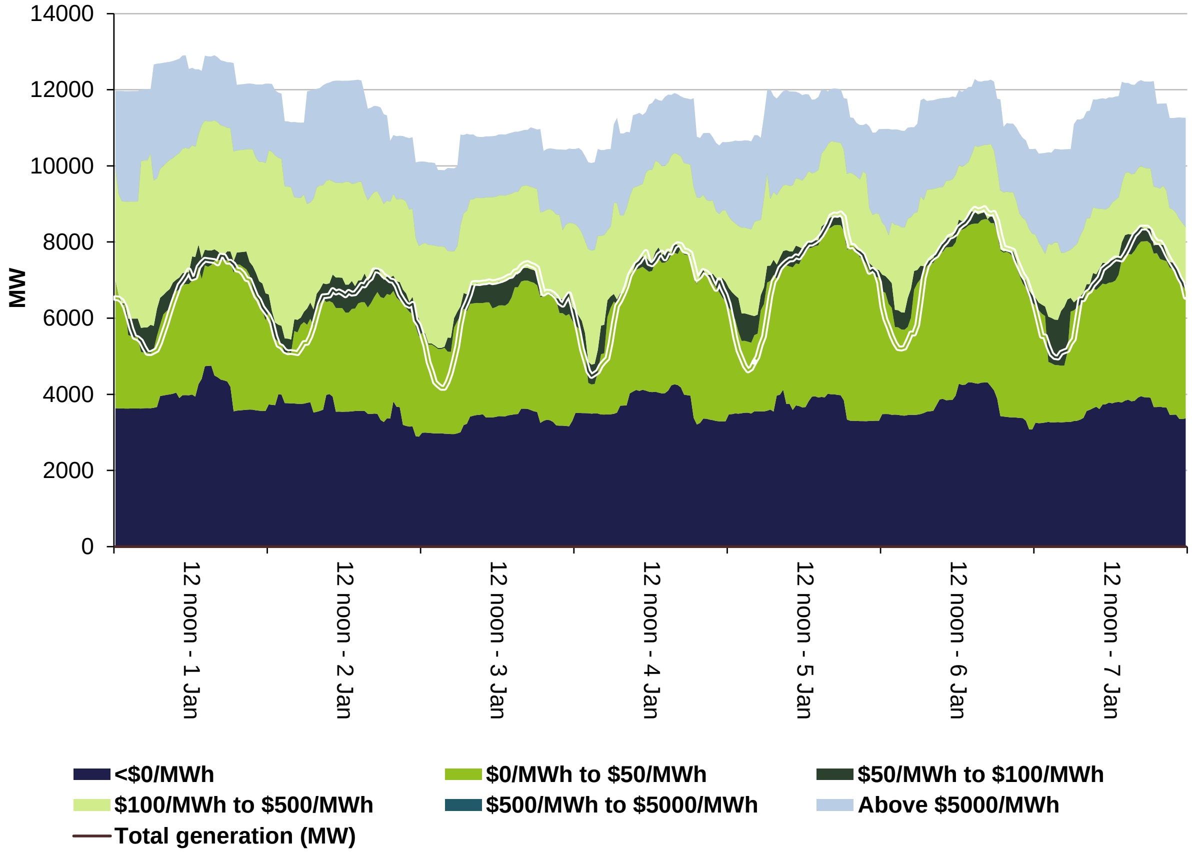


Figure 5: Victoria generation and bidding patterns

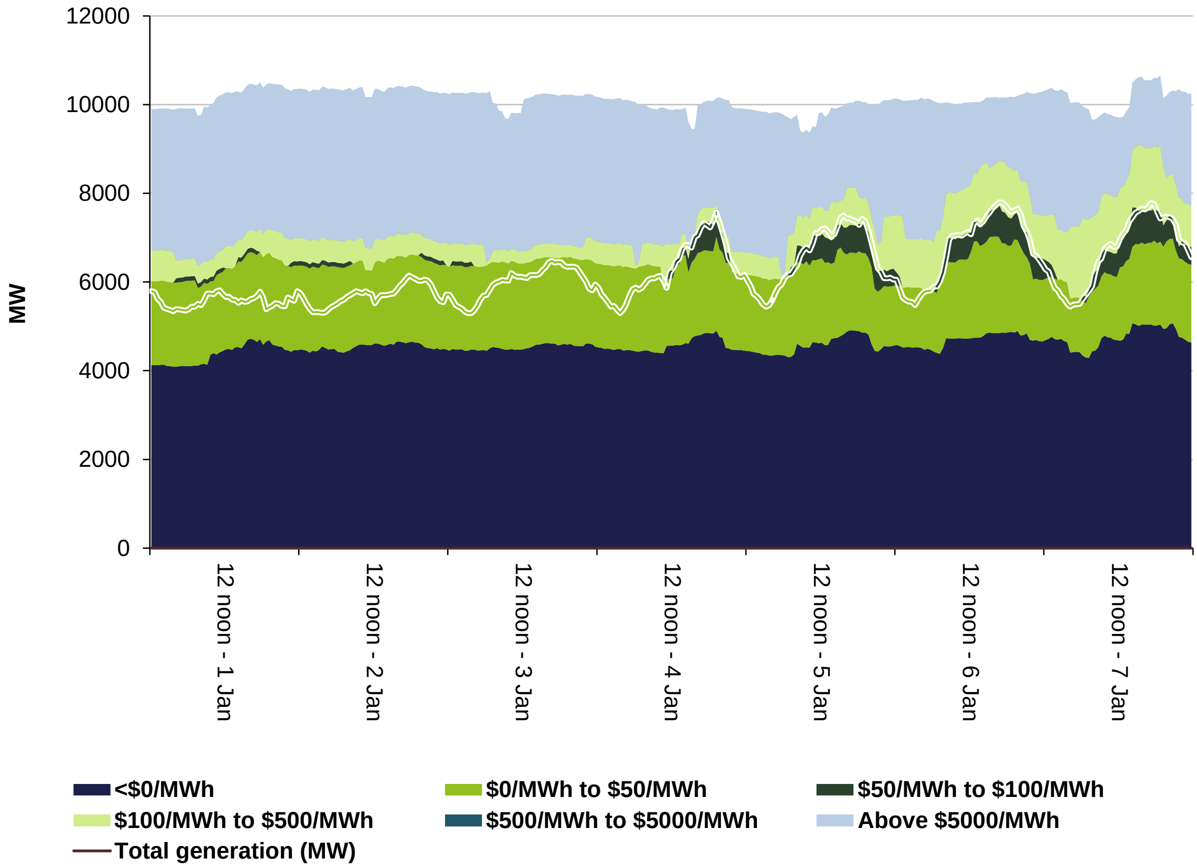


Figure 6: South Australia generation and bidding patterns

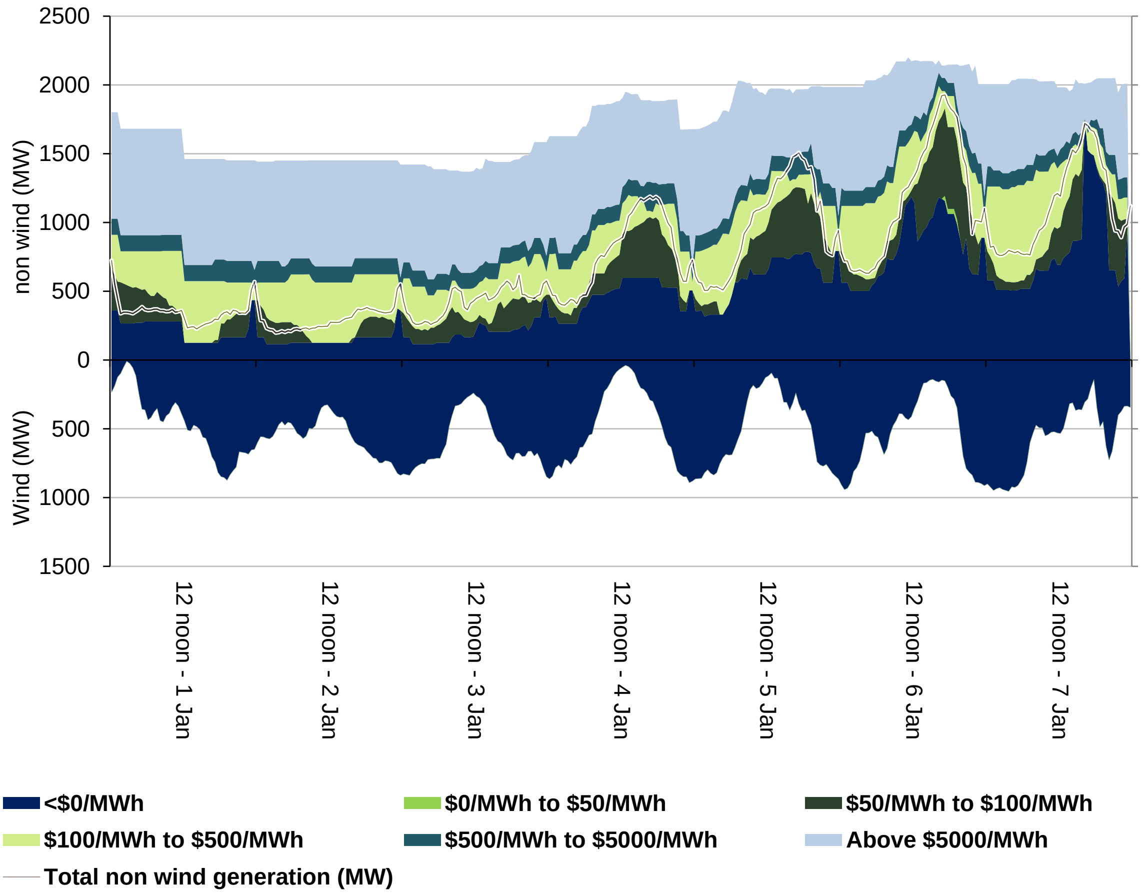
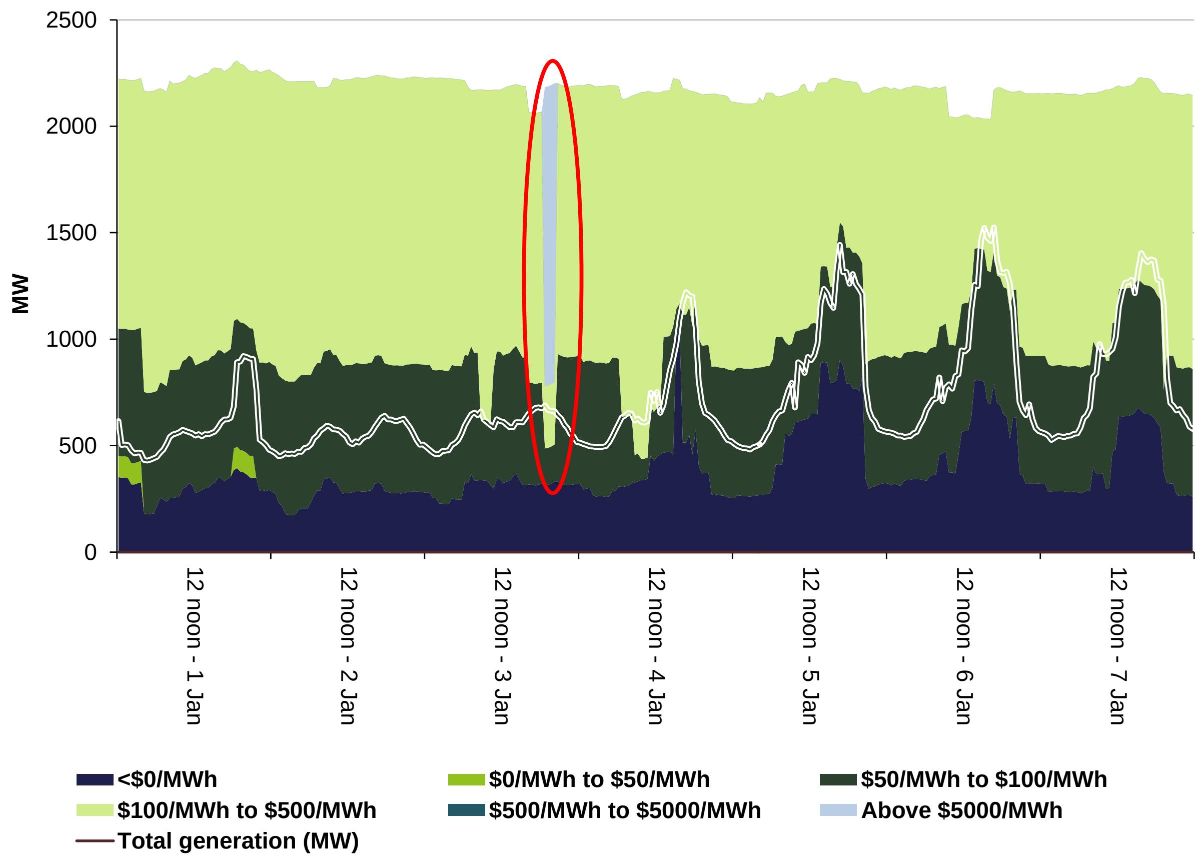


Figure 7: Tasmania generation and bidding patterns



The red ellipse highlights rebidding that contributed to the prices exceeding our reporting threshold on 3 January, discussed in the "Detailed market analysis of significant price events" section.

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

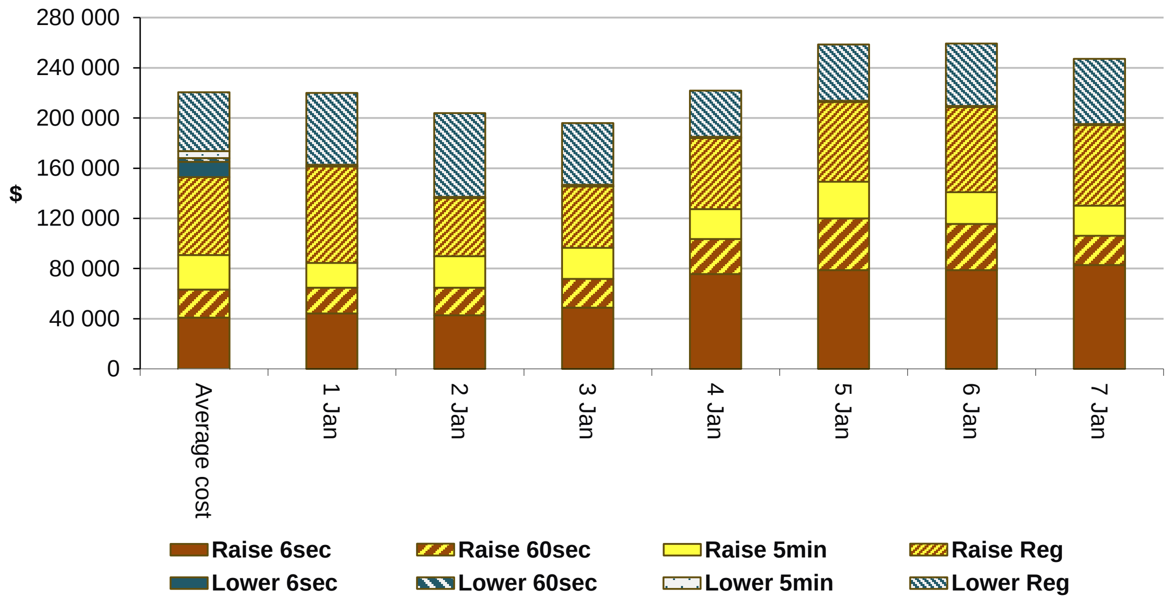
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 250 000 or around half of one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $357 000 or around 2 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 were six occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $86/MWh and above $250/MWh.

Sunday, 1 January

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
11 am	292.05	262.00	85.99	6993	6852	6744	10 414	10 619	10 739
12.30 pm	298.82	76.01	262.00	7281	7185	7081	10 441	10 553	10 723
4.30 pm	303.85	424.36	424.36	7841	7834	7801	10 574	10 682	10 747
6 pm	291.35	209.50	424.36	7934	8065	7967	10 578	10 715	10 759

Conditions at the time saw demand ranging from 141 MW above forecast to 131 MW below forecast four hours ahead, while availability was up to 205 MW below that forecast four hours ahead.

During the day, the dispatch price increased to $1406/MWh at 10.40 am, 12.10 pm, 4.30 pm and 5.40 pm. There was little capacity, available within five minutes, priced between $200/MWh and $1400/MWh. This meant that small changes in demand (45–75 MW) and rebidding (around 60 MW or less) led to the four price spikes and spot prices around $300/MWh.

Monday, 2 January

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
Midday	306.19	204.44	85.99	7220	7174	6880	10 771	10 825	10 953

Conditions at the time saw demand slightly higher and availability slightly lower than that forecast four hours ahead.

From 11.45 am, the 5-minute demand increased by 88 MW then another 112 MW by 11.50 am. Effective from 11.50 am, available capacity was reduced by 27 MW following rebidding at Millmerran and Callide power station.

With other low priced generation at ramp rate limited, trapped/stranded in FCAS, or requiring more than one dispatch interval start, the dispatch price spiked to $1406/MWh at 11.50 am.

Prices returned to lower levels at 11.55 am when 275 MW of high priced capacity was rebid to the price floor and demand reduced by 180 MW.

Wednesday, 4 January

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
11.30 pm	279.33	60.94	48.63	6237	6281	6233	10 582	10 775	10 883

Conditions at the time saw demand close to forecast and available capacity 193 MW lower than forecast four hours ahead.

At 11.05 pm, there was an 80 MW demand increase and as the only available capacity priced between $60/MWh and $1400/MWh required more than five minutes to start the dispatch price at 11.05 pm reached $1406/MWh.

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $60/MWh and above $250/MWh.

Friday, 6 January

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
4.30 pm	259.60	98.29	262.95	7659	6987	6573	10 169	10 099	10 081

Conditions at the time saw demand 672 MW above forecast and availability 70 MW above forecast four hours ahead.

The higher than forecast price was a result of the higher than forecast demand.

South Australia

There were six occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $96/MWh and above $250/MWh.

Friday, 6 January

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	329.10	307.00	1750.05	2486	2324	2471	2328	2378	2378
4 pm	319.67	349.98	10 549.66	2561	2393	2516	2306	2380	2370
4.30 pm	334.40	350.01	10 549.66	2631	2470	2559	2318	2401	2383

Conditions at the time saw prices close to those forecast four hours ahead.

Saturday, 7 January

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
4 pm	304.06	13 300.01	373.74	2511	2663	2447	2374	2322	2564
4.30 pm	2357.40	13 164.00	426.16	2533	2633	2472	2319	2420	2566
5.30 pm	554.18	13 164.00	578.81	2466	2605	2486	2214	2422	2553

Conditions at the time saw the four hour forecast demand up to 216 MW higher than the 12 hour forecast. Actual demand was 152 MW lower than that forecast four hours ahead. Availability ranged from 52 MW above forecast to 208 MW below forecast four hours ahead.

The increase in forecast price, four hours compared to 12 hours ahead, was a result of the increase in forecast demand. The decrease in actual price, compared to the four hour forecast, was a result of lower than forecast demand and around 300 MW of capacity being rebid from high to low prices.

Tasmania

There were four occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $96/MWh and above $250/MWh.

Tuesday, 3 January

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
7.30 pm	362.29	91.29	361.96	1105	1081	1080	2187	2199	2197
8 pm	362.29	91.29	361.93	1099	1076	1075	2194	2198	2198
8.30 pm	362.29	124.27	361.93	1098	1082	1072	2202	2201	2198

Conditions at the time saw demand and availability close to that forecast four hours ahead.

Over two rebids from 6.47 pm, Hydro Tasmania rebid up to 426 MW of available capacity across its portfolio from prices around $100/MWh to $362/MWh and above. The reasons given related to flow on Basslink being lower than forecast.

This led to the dispatch price increasing to $362/MWh from 6.55 pm until 8.30 pm. The change in available capacity offer prices is highlighted in Figure 7 above.

Wednesday, 4 January

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	361.96	79.45	231.67	1039	1040	1049	2164	2209	2189

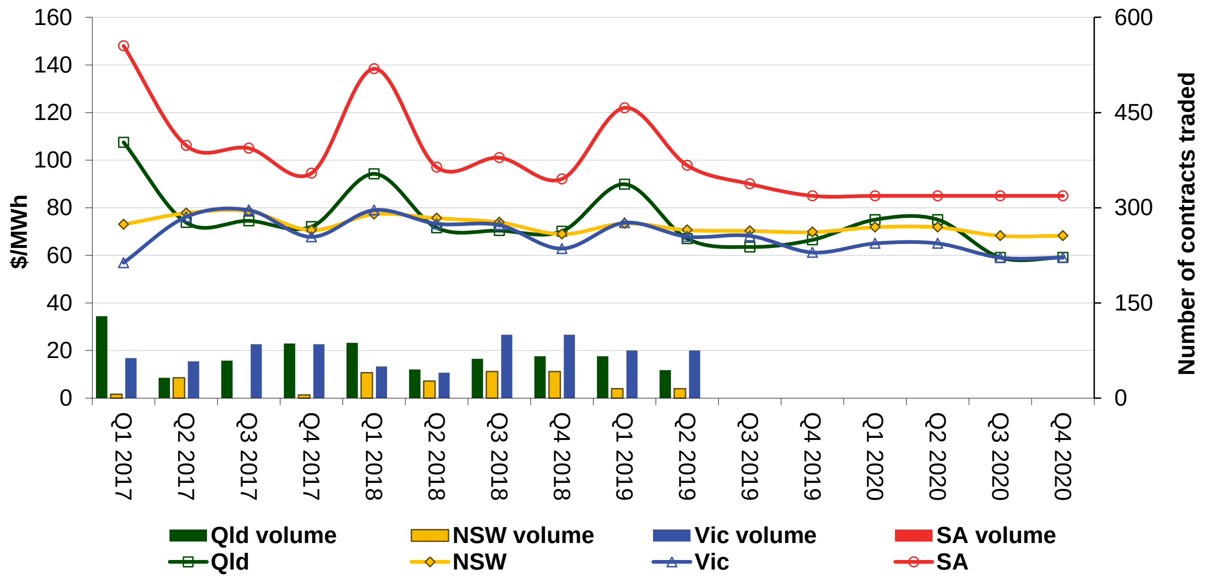
Conditions at the time saw demand and availability close to that forecast four hours ahead.

At 3.12 pm, Hydro Tasmania rebid 105 MW of available capacity at its Tamar Valley power station from -$75/MWh to $362/MWh. The reason given was “1506A price different from forecast: Vic”. As a result, with no capacity priced between $90/MWh and $362/MWh the dispatch price at 5.35 pm reached $362/MWh and stayed there for the entire 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.

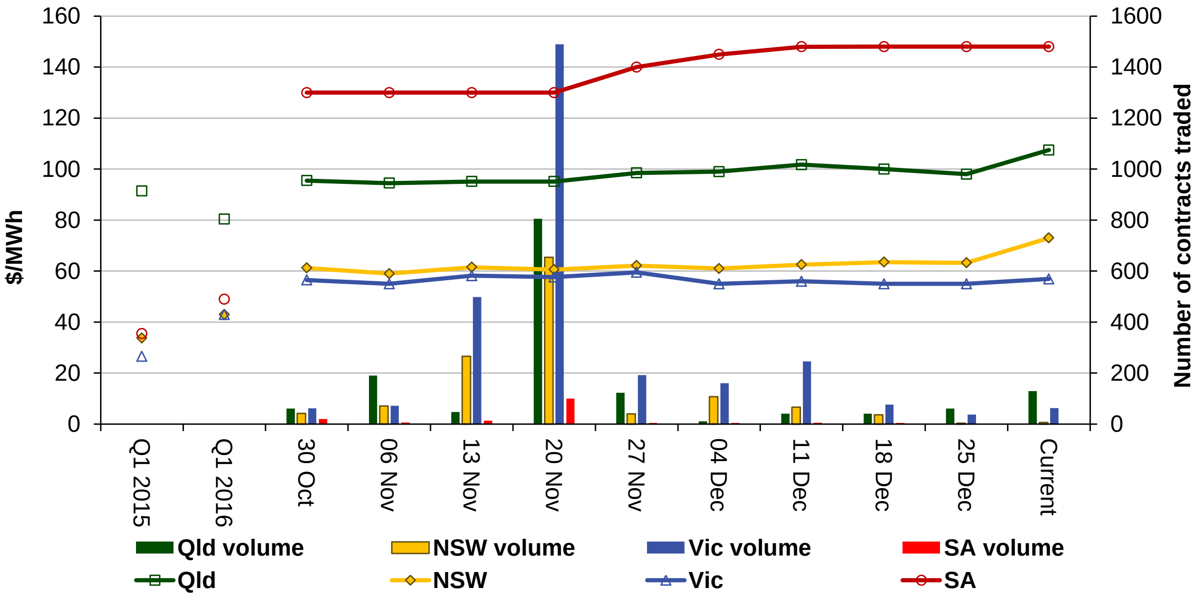
Figure 9: Quarterly base future prices Q1 2017 – Q4 2020



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 2017 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 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 2017 base contracts over the past 10 weeks (and the past 2 years)



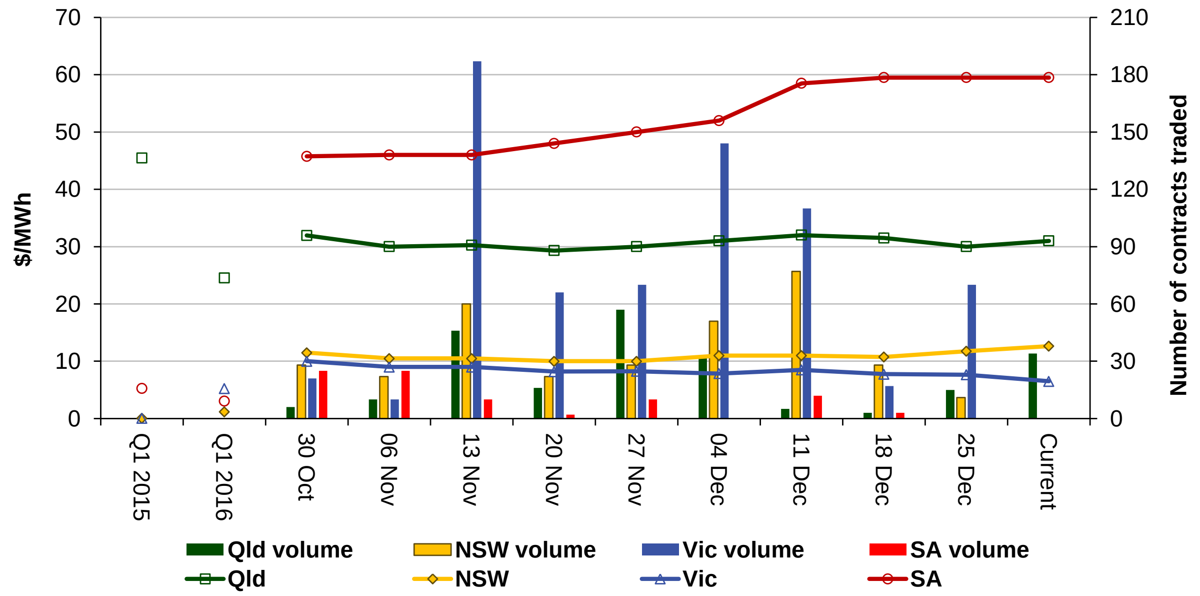
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2017 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown.

Figure 11: Price of Q1 2017 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

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