Electricity Report

AUSTRALIAN ENERGY REGULATOR

29 January – 4 February 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 29 January – 4 February 2017.

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

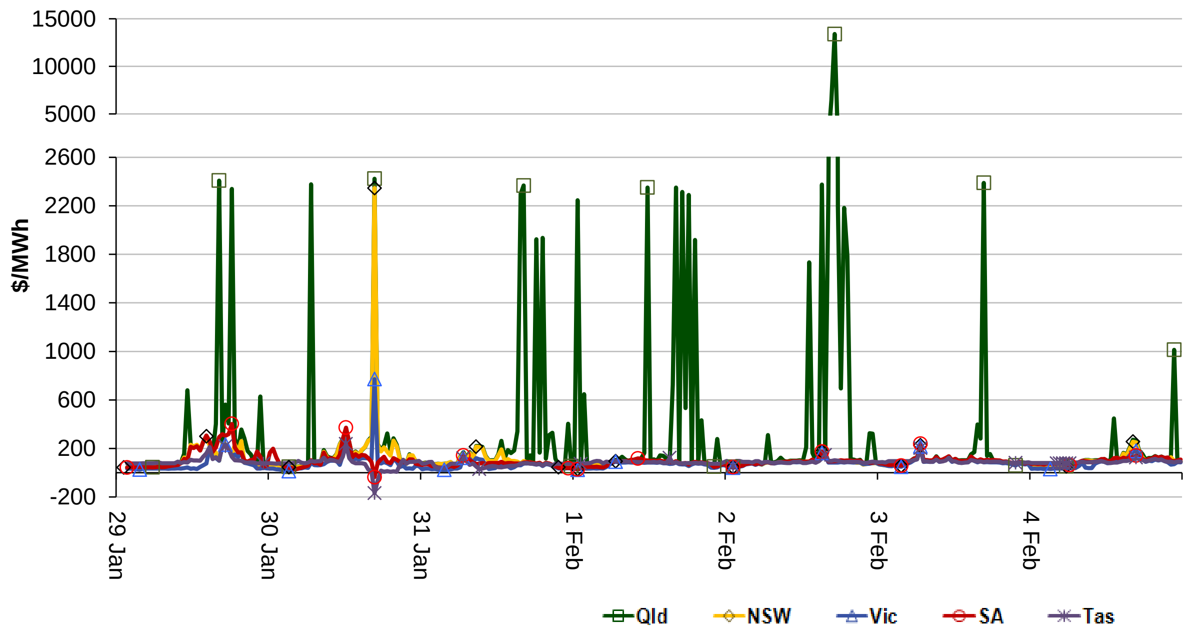


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

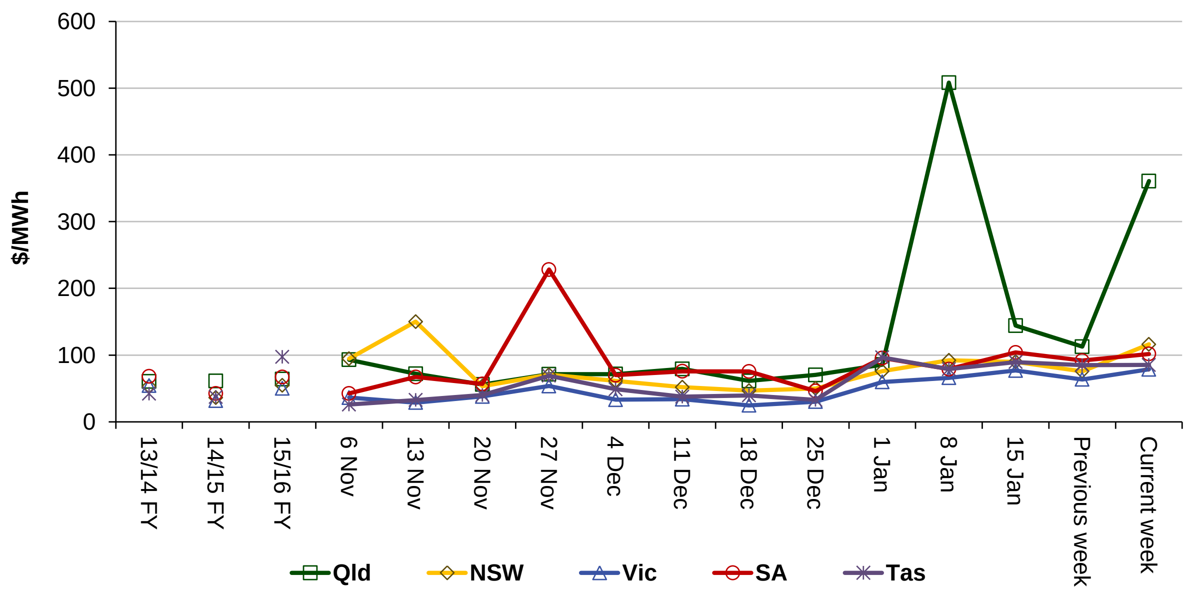


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	361	116	79	102	85
15-16 financial YTD	49	46	43	62	66
16-17 financial YTD	93	66	48	104	53

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 251 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	4	35	0	3
% of total below forecast	27	22	0	9

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

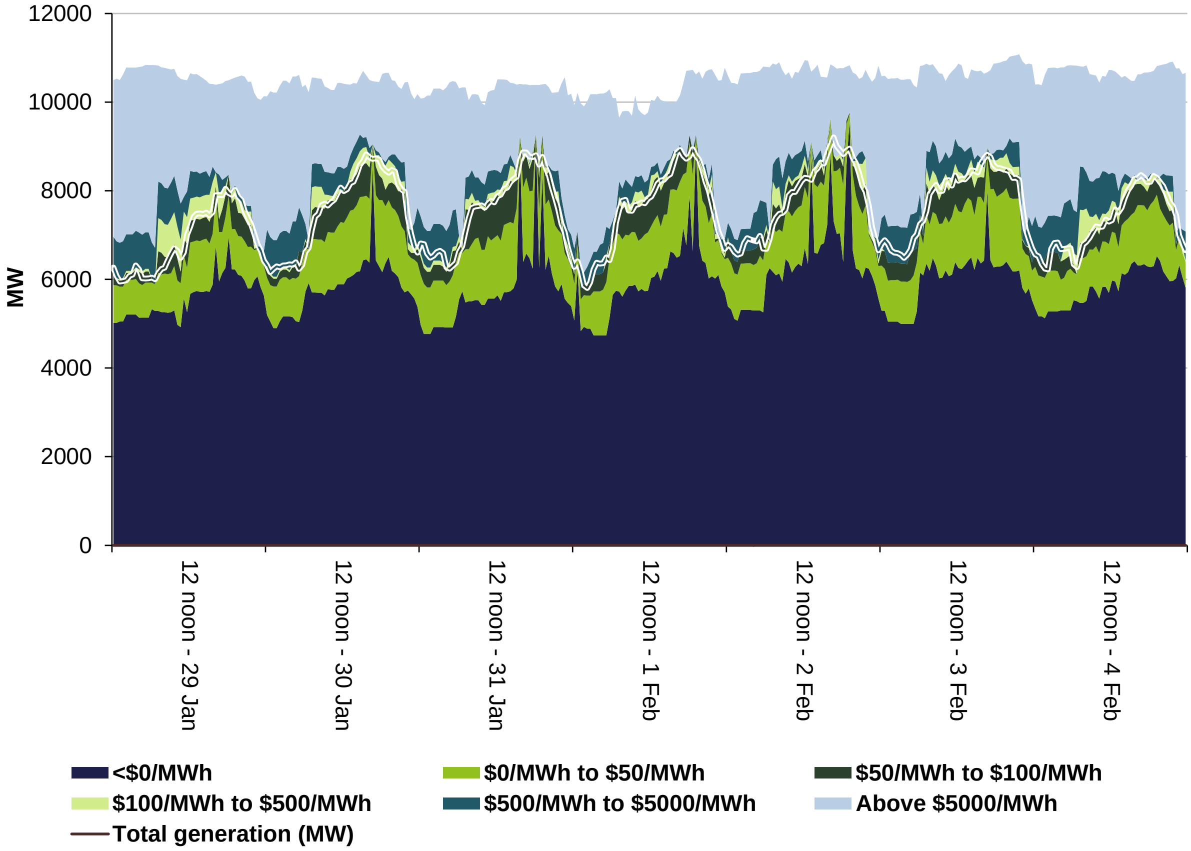


Figure 4: New South Wales generation and bidding patterns

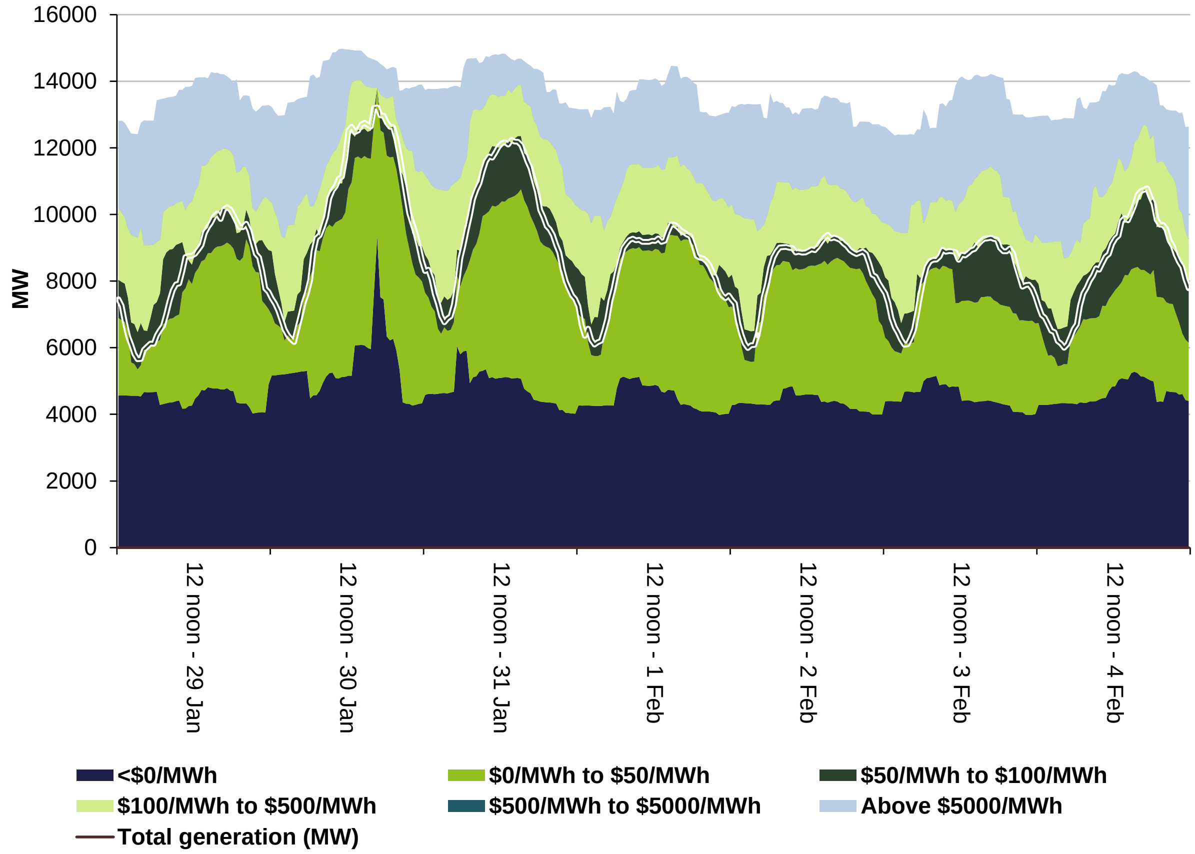


Figure 5: Victoria generation and bidding patterns

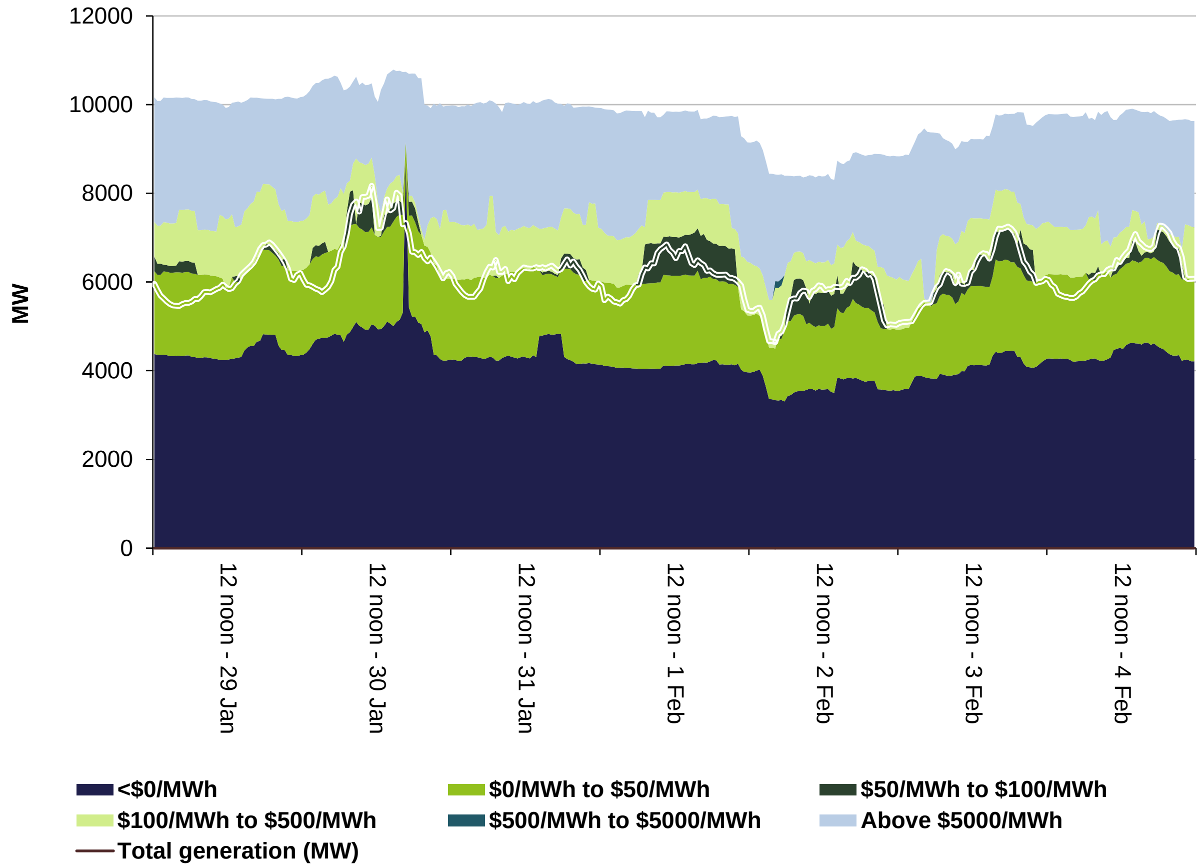


Figure 6: South Australia generation and bidding patterns

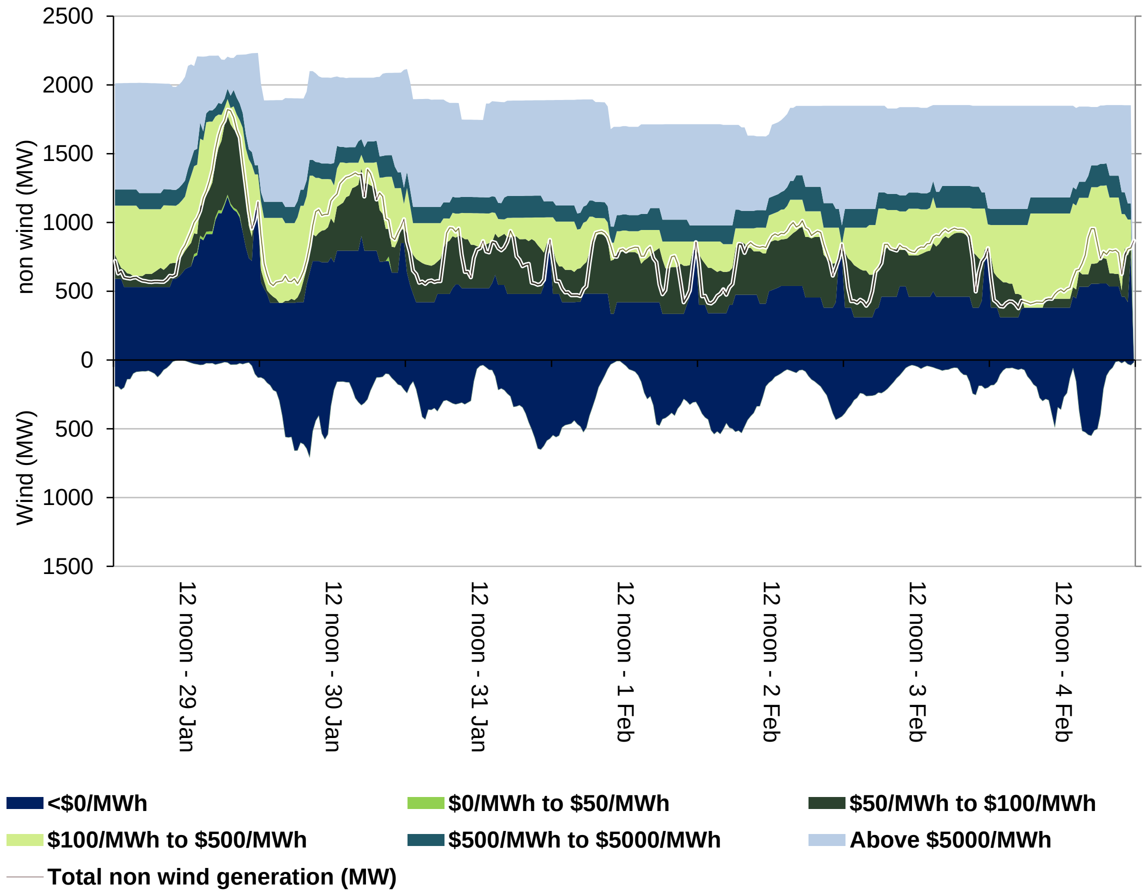
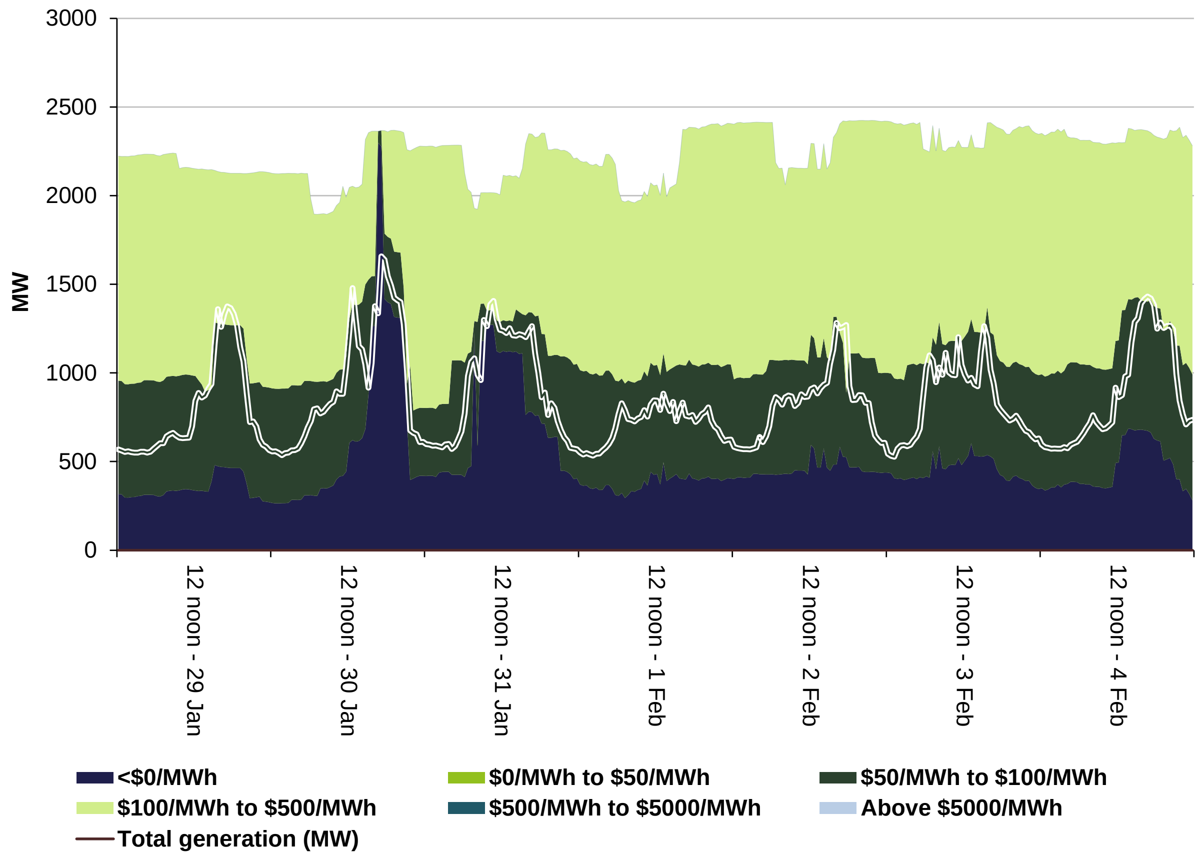


Figure 7: Tasmania generation and bidding patterns



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.

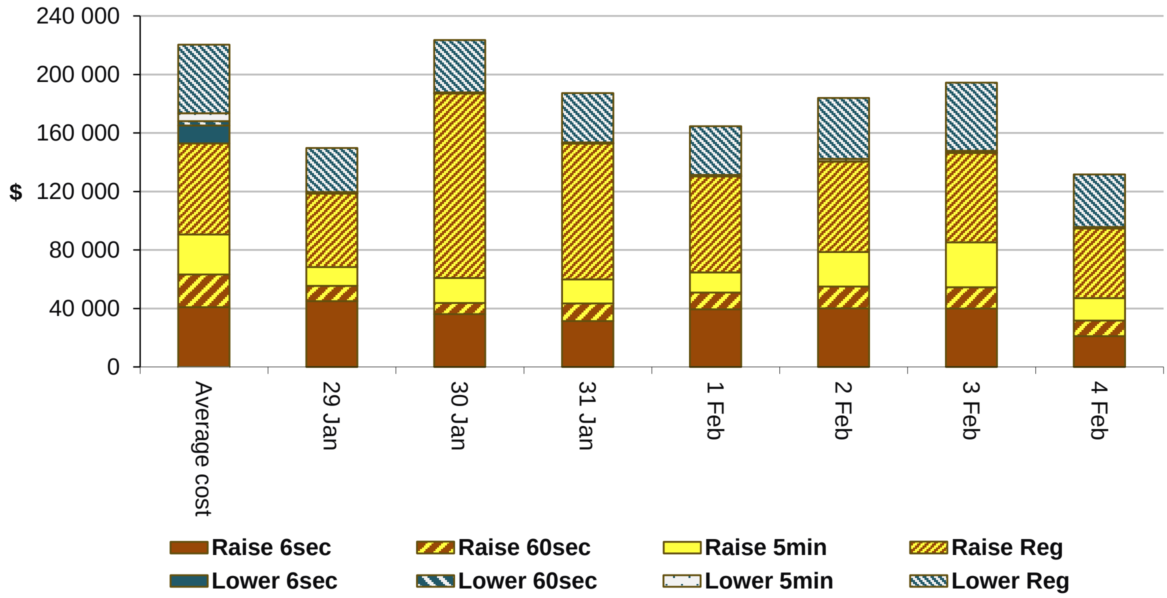
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $894 500 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $340 500 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 23 occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $361/MWh and above $250/MWh.

Sunday, 29 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
4.30 pm	2408.10	310.03	310.03	7506	7395	7438	10 391	10 689	10 739
6.30 pm	2339.46	1405.69	2150.10	7789	7795	7784	10 487	10 692	10 773

For the 4.30 pm trading interval, demand was about 100 MW higher than forecast and availability was around 300 MW lower than that forecast four hours ahead.

For the 4.05 pm dispatch interval, there was a step change in offers which shifted around 270 MW of capacity at Tarong and Gladstone power stations from low to high priced bands. At the same time a system normal constraint used to avoid voltage collapse on the loss of Kogan Creek power station bound which decreased the import limit into Queensland on QNI. With cheaper priced generation ramp up constrained or taking longer than five minutes to start the price increased to $13 999/MWh. For the 6.30 pm trading interval, demand was close to forecast and availability was around 200 MW lower than that forecast four hours ahead.

In the four hours leading up to the trading interval Millmerran rebid around 135 MW of capacity from the floor to the cap. At the start of the 6.30 pm trading interval, due to a step change in offers at Tarong power station, 110 MW of capacity priced less than $100/MWh was no longer available.

For the 6.05 pm dispatch interval, a system normal constraint used to avoid voltage collapse on the loss of Kogan Creek power station bound which decreased the import limit into Queensland on QNI. This combined with the decrease in low price capacity saw the price increase to $14 000/MWh.

Monday, 30 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
7 am	2377.63	2150.30	2150.30	6698	6916	6895	10 360	10 622	10 662
5 pm	2423.63	3500.69	13 641	8532	8569	8541	10 473	10 496	10 756

The 7 am trading interval was close to that forecast four hours prior.

The 5 pm trading interval price variation is discussed in the New South Wales section below.

Tuesday, 31 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
4 pm	2297.84	1405.69	3500.69	8493	8454	8453	10 386	10 586	10 630
4.30 pm	2367.31	2150.30	3500.69	8707	8549	8533	10 408	10 628	10 669
6.30 pm	1924.42	13 399.95	3500.69	8490	8488	8445	10 387	10 497	10 688
7.30 pm	1935.96	13 641	13 641	8429	8582	8501	10 395	10 455	10 511

For the 4 pm trading interval, demand was close to forecast and availability was 200 MW lower than that forecast four hours ahead.

For the 3.40 pm dispatch interval, demand increased by 105 MW and imports on the QNI interconnector from New South Wales were constrained and reduced by 30 MW. Wivenhoe shifted 250 MW of capacity priced at $0/MWh to the cap. The increase in demand, constrained imports and loss of low priced generation meant higher priced generation had to be dispatched and the price increased to $13 400/MWh. In response to the high priced dispatch interval, participants shifted around 780 MW of capacity priced greater than $2000/MWh to $0/MWh and below, leading to the dispatch price remaining below $70/MWh for the remainder of the trading interval.

The 4.30 pm trading interval was close to that forecast four hours ahead.

For the 6.30 pm trading interval, demand was close to forecast and availability was 110 MW lower than that forecast four hours ahead. As forecast, the price hit the cap for the first dispatch interval. Participants rebid over 650 MW of capacity priced at the price cap into price bands of $0/MWh and below in response to the high price, leading to a lower than forecast spot price.

For the 7.30 pm trading interval, demand was around 150 MW lower than forecast and availability was 60 MW lower than forecast four hours ahead. As forecast, the first trading dispatch price reached $13 440/MWh. In response to this high price, participants rebid over 750 MW of capacity, priced greater than $13 400/MWh to the price floor, leading to a lower than forecast spot price.

Wednesday, 1 February

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
1 am	2245.84	2148.99	2148.99	6044	6131	6172	10 183	10 158	10 263
Midday	2350.60	99.51	125.14	7974	7690	7781	10 259	10 613	10 703
4.30 pm	2349.64	98.66	3500.69	8874	8754	8700	10 449	10 592	10 893

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 pm	2314.28	395.69	13 399.95	8761	8693	8710	10 413	10 553	10 899
6.30 pm	2290.15	74.74	2150.30	8627	8495	8512	10 708	10 802	10 913
7.30 pm	1919.33	149.99	3500.69	8660	8673	8660	10 615	10 811	10 926

The 1 am trading interval was close to that forecast four hours ahead.

For the midday trading interval, demand was around 280 MW higher than forecast and availability was around 350 MW lower than that forecast four hours ahead. During the trading interval, around 180 MW of low priced capacity was withdrawn. By the last dispatch interval, demand increased by 71 MW, the interconnectors were at their limit and higher priced local generation was required and the dispatch price reached $13 400/MWh.

For the 4.30 pm trading interval, demand was 120 MW higher than forecast and availability was 143 MW lower than forecast four hours ahead. Rebidding of capacity into lower price bands caused the four hour forecast price to be lower than the 12 hour forecast price. The price was between $98/MWh and $200/MWh for the first five dispatch intervals. For the last dispatch interval, demand increased by 60 MW, both interconnectors were operating at their limits and Alinta Energy rebid 140 MW at is Braemar A power station from $75/MWh to the cap. With local generation ramp constrained and demand at such high levels, the price reached $13 450/MWh for one dispatch interval.

For the 5.30 pm trading interval, demand was around 70 MW higher than forecast and availability was 140 MW lower than forecast four hours ahead. Rebidding of capacity into lower price bands caused the four hour forecast price to be lower than the 12 hour forecast price. For the 5.25 pm dispatch interval, demand increased by 96 MW and both interconnectors were constrained which prevented cheaper priced generation in other regions setting price. As a result, the price jumped to $13 450/MWh for one dispatch interval. For the last dispatch interval, demand dropped by 109 MW, participants rebid around 310 MW of capacity to floor and QNI was no longer constrained. The price then fell to $66/MWh as cheaper priced generation in Victoria set price.

For the 6.30 pm trading interval, demand was 132 MW higher than forecast and availability was 94 MW lower than that forecast 4 hours ahead. Rebidding of capacity into lower price bands caused the four hour forecast price to be lower than the 12 hour forecast price. For the 6.15 pm dispatch interval, demand increased by 56 MW and with only 24 MW priced between $100/MWh and $13400/MWh, high priced generation had to be dispatched to meet the increased demand. In response to the high priced dispatch interval, participants rebid into lower priced bands and the price fell to below $50/MWh for the remainder of the trading interval.

For the 7.30 pm trading interval, demand was close to forecast and availability was around 200 MW lower than that forecast four hours ahead. Rebidding of capacity into lower price bands caused the four hour forecast price to be lower than the 12 hour forecast price.

In the four hours before dispatch, participants rebid around 310 MW of capacity from low prices to the cap. For the 7.05 pm dispatch interval, with both interconnectors operating at their limit, due to a small increase in demand and the reduction in low priced capacity, the price reached $13 400/MWh. In response to the high priced dispatch interval, participants rebid into lower priced bands and the price fell to between $102/MWh and the price floor for the remainder of the trading interval.

Thursday, 2 February

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
1.30 pm	1733.15	2150.20	420.99	8178	8491	8485	10 842	11 027	11 122
3.30 pm	2375.83	13 399.95	13 399.95	8657	8963	8959	10 672	11 006	11 041
4.30 pm	2314.86	14 000	14 000	8871	9233	9209	10 850	10 964	11 047
5 pm	6455.75	14 000	14 000	8996	9290	9285	10 855	10 989	11 047
5.30 pm	13 399.95	13 399.95	14 000	8971	9238	9244	10 758	10 961	11 017
6 pm	2191.34	13 399.95	13 899.95	8868	9164	9203	10 769	10 828	11 023
7 pm	2183.77	149.99	13 641	8845	9027	9152	10 793	10 882	11 027
7.30 pm	1785.26	13 399.95	13 899.95	8800	9120	9183	10 817	10 875	11 026

Demand was between 182 and 362 MW lower than forecast and availability was between 58 MW and 334 MW lower than forecast, both four hours ahead.

Temperatures in Queensland were high for several days in the lead up to the high price events. AEMO’s forecasts also indicated that spot prices would exceed $13 400/MWh for extended periods from mid to late afternoon. This was because cheaper imports of electricity from neighbouring states were predicted to be limited and local high priced supply would need to be used to meet the high demand for electricity. Many of the predicted high prices did not occur because demand for electricity was lower than anticipated and generators shifted their offers into low prices.

The cause behind these high priced trading intervals is discussed further in the Electricity spot prices above $5000/MWh Queensland, 2 February 2017 report.

Friday, 3 Wednesday

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
5 pm	2389.49	3500.69	13 641	8713	8725	8808	10 672	10 935	10 957

Demand was close to forecast while availability was around 260 MW lower than forecast four hours ahead for the 5 pm trading interval.

The forecast price dropped by over $10 000/MWh between the 12 and four hour forecasts. This was due to a steep supply curve, rebidding of capacity into lower priced bands by participants and a small decrease in forecast demand.

The lower than forecast price (from four hours prior) was a result of participants rebidding capacity from high to low prices.

New South Wales

There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $76/MWh and above $250/MWh.

Monday, 30 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
5 pm	2346.05	299.80	299.80	13 945	13 818	13 337	14 600	14 811	14 893

Conditions at the time saw demand around 130 MW higher than forecast and availability around 210 MW lower than forecast. For this trading interval New South Wales and Queensland prices were aligned and acting as one region.

The Vic-NSW interconnector was importing into New South Wales at its limit, lower than forecast, meaning only Queensland or local generation could set price. Between the 4.35 and 4.50 pm trading intervals Snowy Hydro shifted 649 MW of capacity priced at $300/MWh to 13 99/MWh. With no capacity priced between $300/MWh and $13 500/MWh, Oakey in Queensland set the price at $13 037/MWh in both regions for the 4.50 pm dispatch interval. At 4.55 pm imports from Victoria increase by around 140 MW and the price decreased to $56/MWh. Rebidding of capacity into low priced bands then caused the dispatch price to fall further to -$0.05/MWh for the 5 pm dispatch interval.

Victoria

There were two occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $79/MWh and above $250/MWh.

Monday, 30 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
12.30 pm	261.63	103.45	103.12	6053	6913	6864	10 062	10 510	10 420
5 pm	771.35	158.71	153.16	6083	6533	7808	10 739	10 797	10 814

For the 12.30 pm trading interval, demand was 860 MW lower than forecast and availability was around 450 MW lower than forecast four hours ahead.

In the four hours leading up to the trading interval participants either removed or rebid over 1300 MW of capacity from prices <$100/MWh. This resulted in higher priced generation than forecast being dispatched to meet demand for the entire trading interval.

For the 5 pm dispatch interval demand was 450 MW lower than forecast and availability was close to forecast.

Over two rebids, Snowy Hydro rebid 124 MW of capacity at Laverton North, from $0/MWh to the price cap, effective for the 4.50 pm dispatch interval. As a result, higher priced generation from another region set price for one dispatch interval, resulting in the 4.50 pm dispatch price reaching $5270/MWh. Participants responded to the high priced dispatch price and shifted capacity into lower priced bands, leading to the price falling to the price floor for the last dispatch intervals.

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 $102/MWh and above $250/MWh.

Sunday, 29 January

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
2:30 pm	307.06	115.66	124.96	1732	1474	1491	2244	2231	2240
5 pm	317.44	349.99	316.90	2213	1920	1812	2245	2235	2238
6 pm	318.35	349.95	368.81	2383	2123	1992	2215	2233	2228
6:30 pm	402.45	349.95	350.01	2431	2208	2052	2199	2229	2228

For the 2.30 pm trading interval, demand was around 260 MW greater than forecast and availability was close to forecast, four hours ahead. This led to higher priced generation being dispatched to meet demand.

For the 5 pm, 5.30 pm and 6.30 pm trading intervals were close to that forecast four hours ahead.

Monday, 30 January

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
12.30 pm	371.80	299.99	135	2038	2015	1833	2271	2363	2303

For the 12.30 pm trading interval, demand was close to forecast and availability was around 90 MW lower than forecast, four hours ahead. Wind generation was around 70 MW lower than forecast four hours ahead, which led to higher priced generation being dispatched than what was forecast.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $85/MWh and above $250/MWh.

Monday, 30 January

Table 13: Price, Demand and Availability

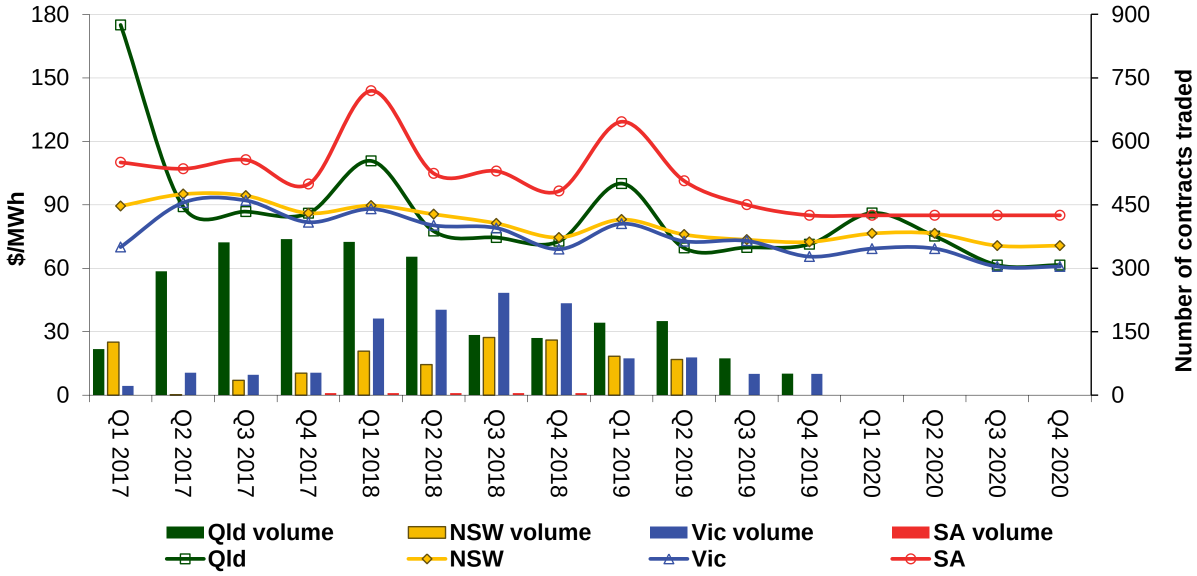
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5 pm	-168.30	78.38	102.25	1088	1110	1083	2363	2354	2357

Both demand and availability were close to that forecast four hours ahead. In response to a high price in Victoria (see Table 10) HydroTas rebid around 1000 MW of capacity to prices <$0/MWh and the price decreased to -$75/MWh and -$961/MWh for the last two dispatch intervals.

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.

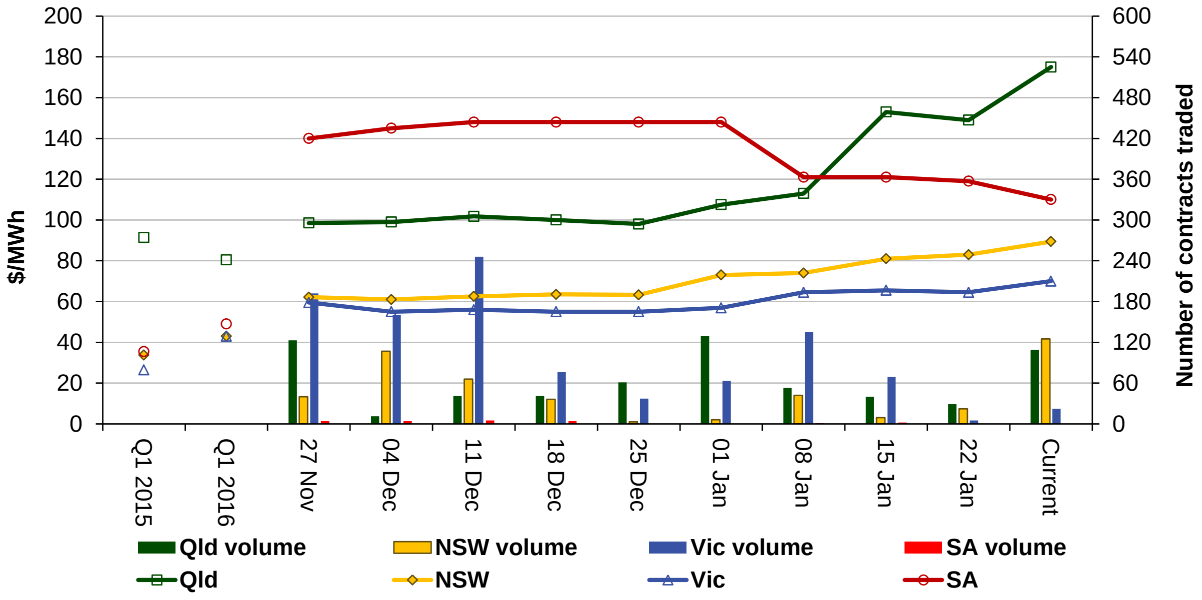
Figure 9: Quarterly base future prices Q1 2017 – Q4 2020



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)



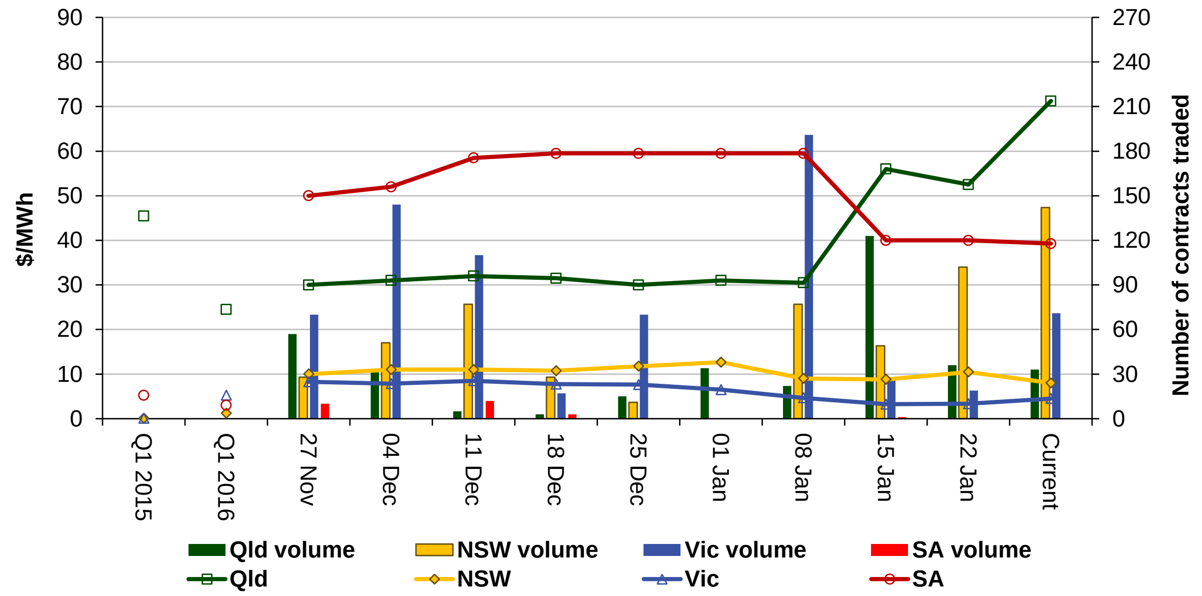
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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

Australian Energy Regulator
December 2017