

27 December 2015 – 2 January 2016

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 27 December 2015 to 2 January 2016. 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 \$46/MWh and above \$250/MWh. There were three occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of \$42/MWh and above \$250/MWh. There were twenty-four occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$81/MWh and above \$250/MWh.

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

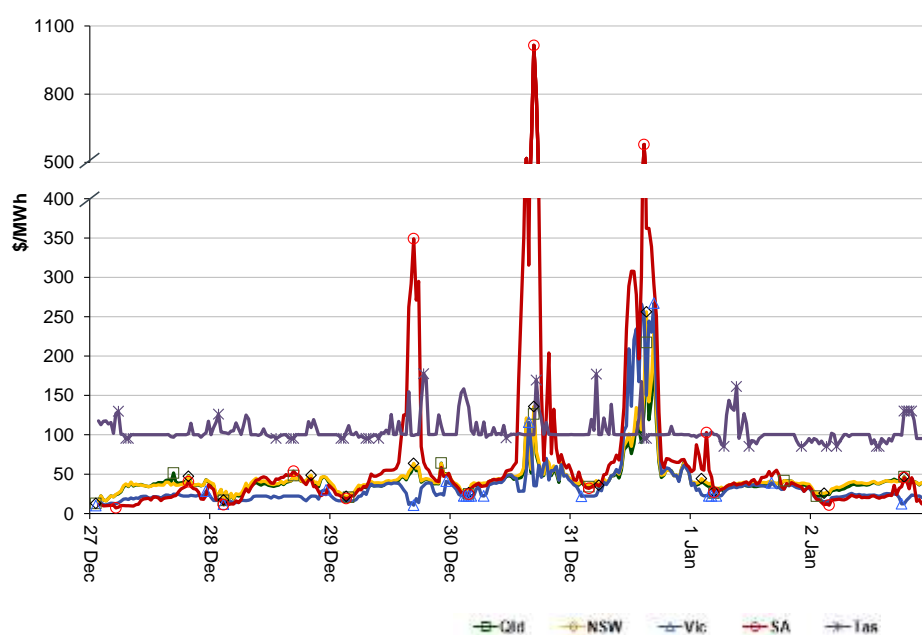


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

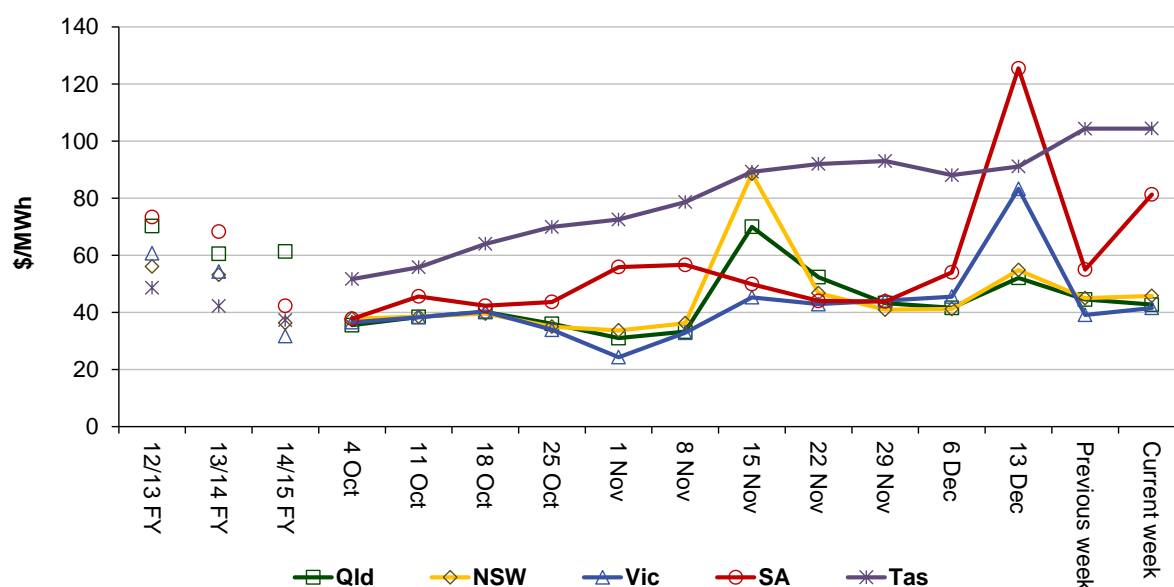


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	43	46	42	81	104
14-15 financial YTD	51	37	33	41	38
15-16 financial YTD	44	46	41	64	58

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 294 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2014 of 71 counts and the average in 2013 of 97. 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

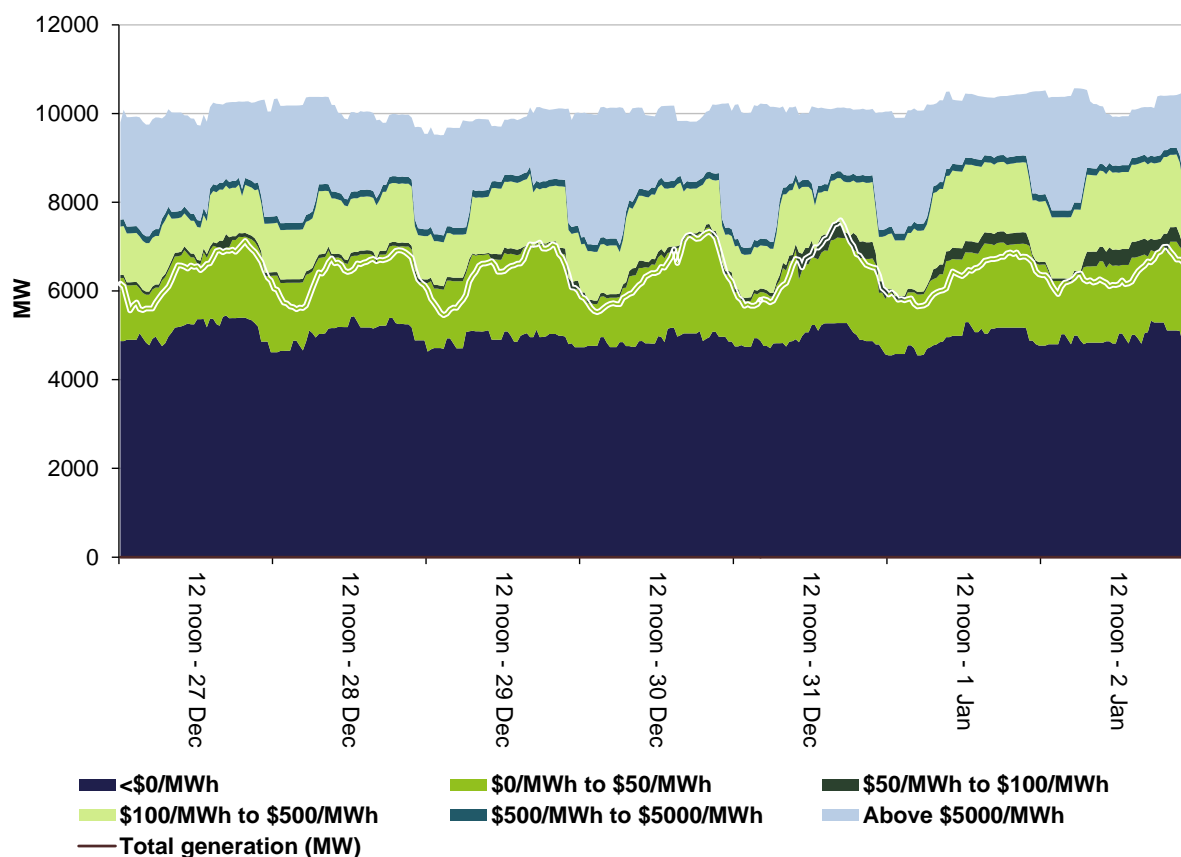
	Availability	Demand	Network	Combination
% of total above forecast	8	23	0	1
% of total below forecast	58	6	0	4

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



The red ellipse in Figure 4, following, highlights a rapid fall in lower priced available generation. This was caused by Origin Energy removing 1670 MW of available capacity at Eraring.

Figure 4: New South Wales generation and bidding patterns

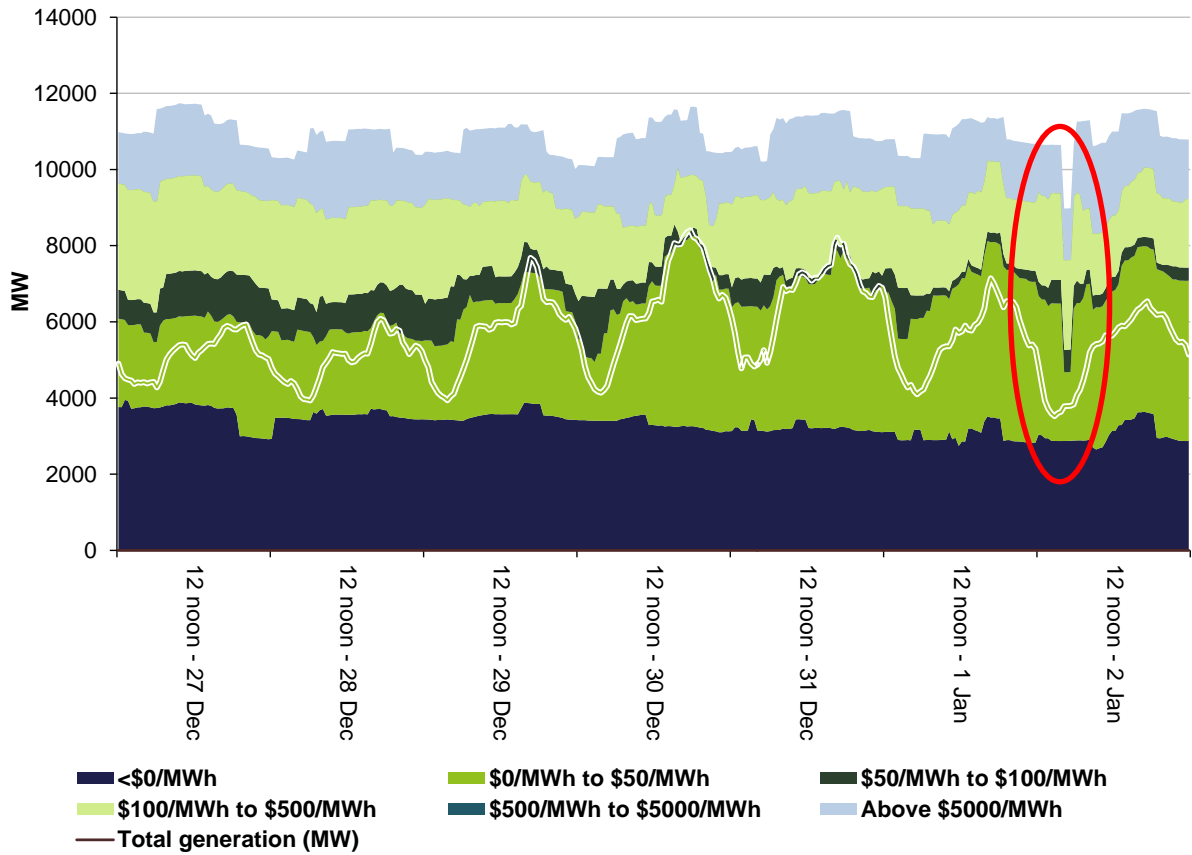
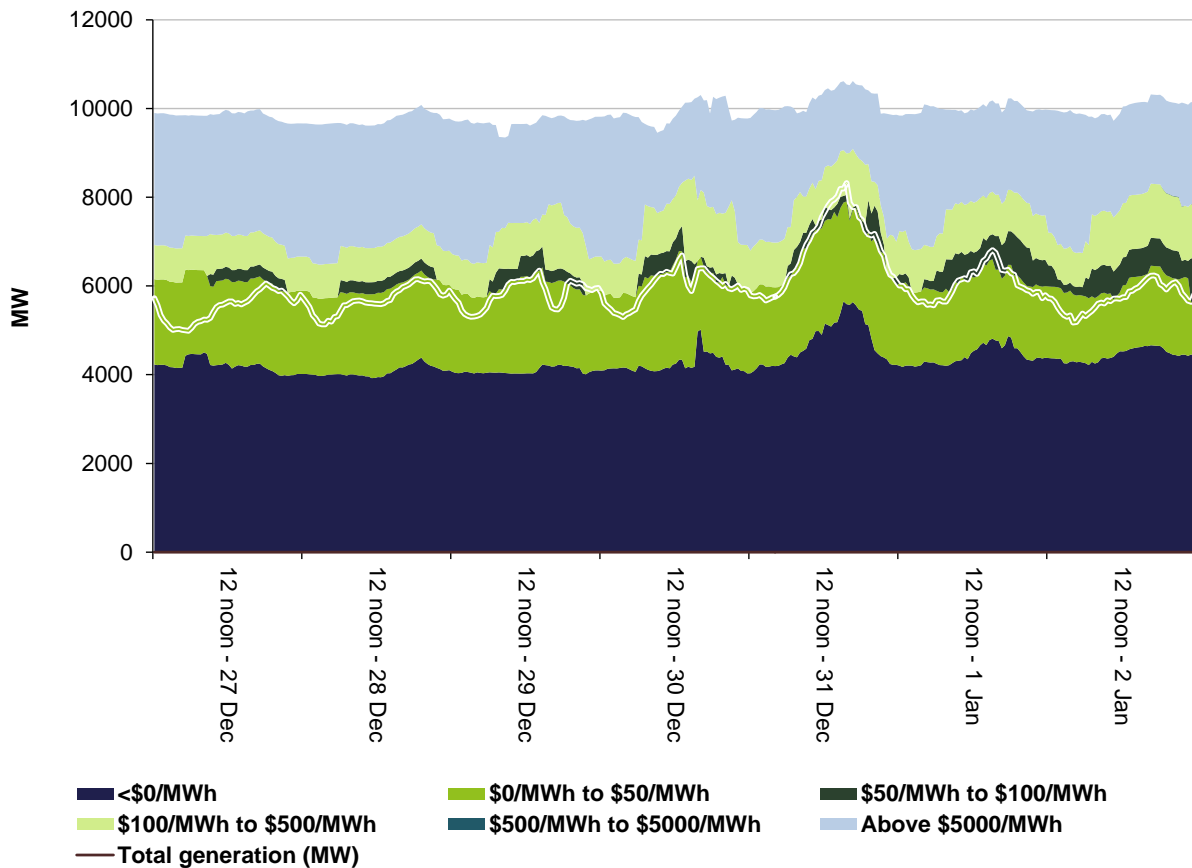


Figure 5: Victoria generation and bidding patterns



The red ellipse in Figure 6, highlights the increase in low-priced capacity driven by high demand conditions in South Australia which coincided with low wind generation.

Figure 6: South Australia generation and bidding patterns

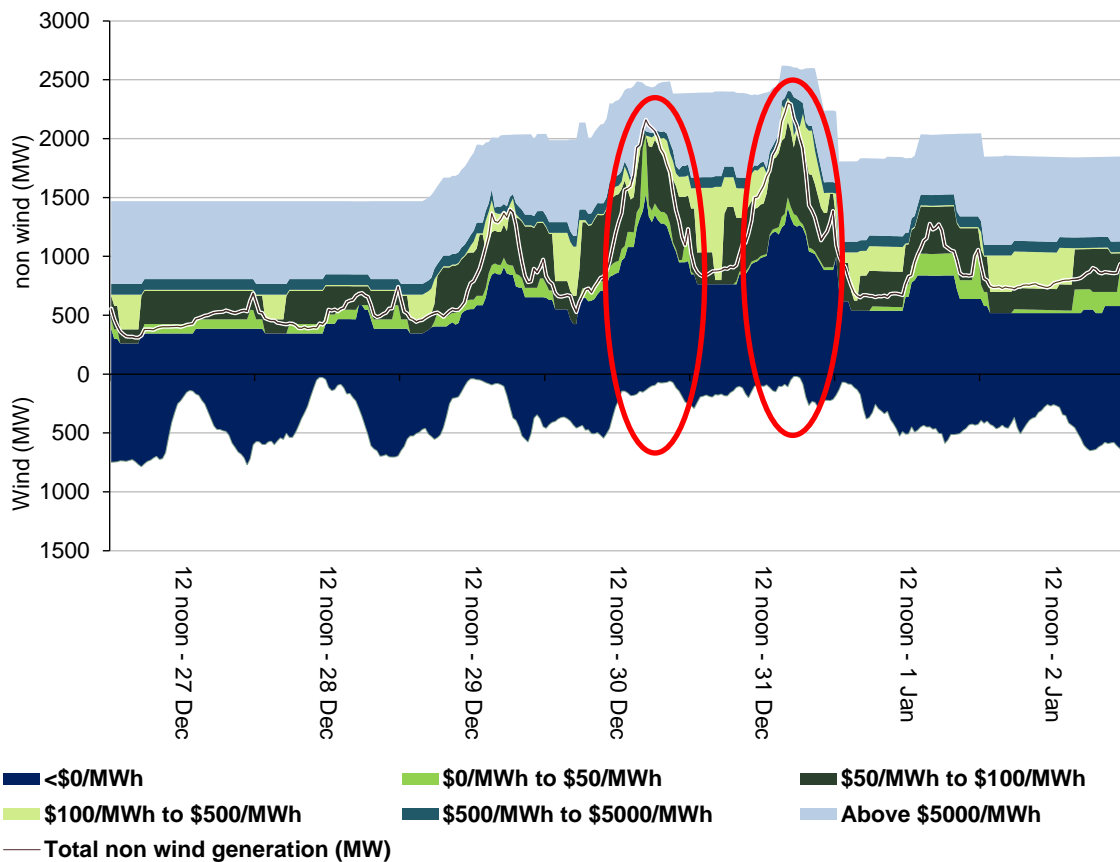
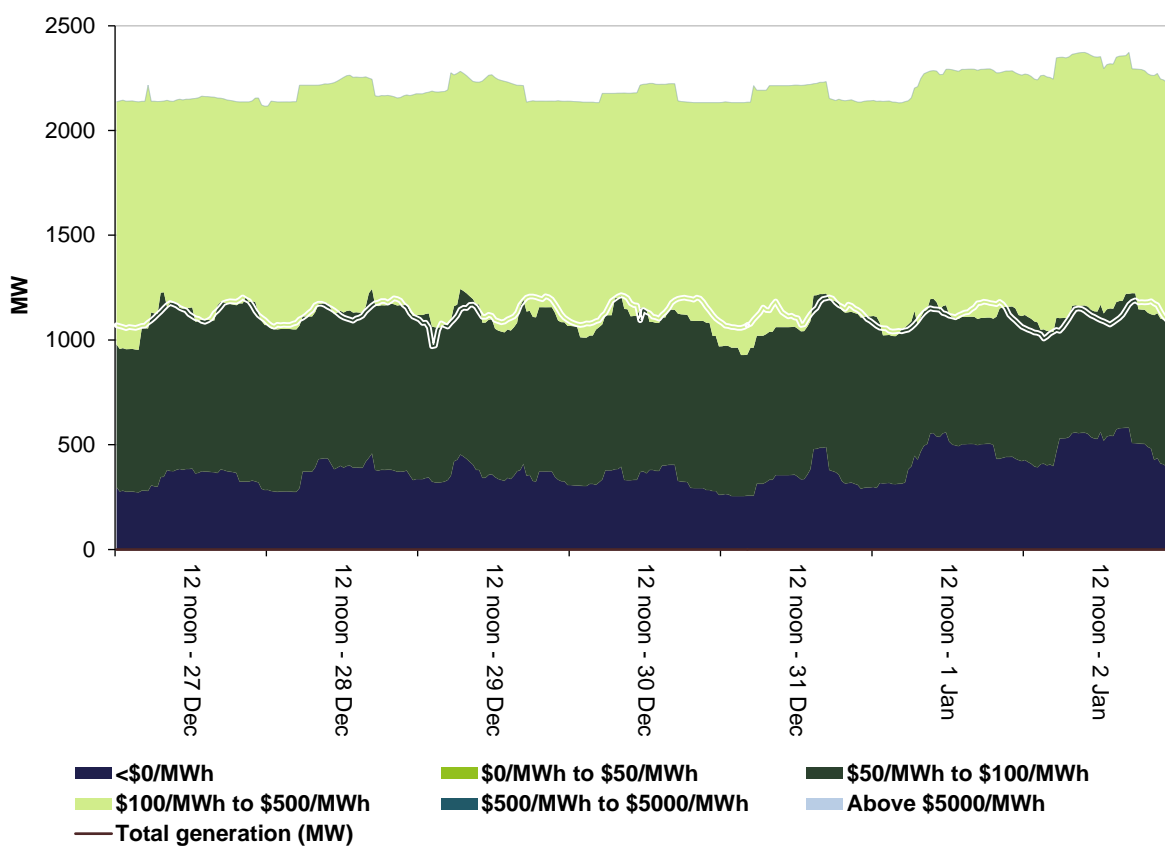


Figure 7: Tasmania generation and bidding patterns



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.

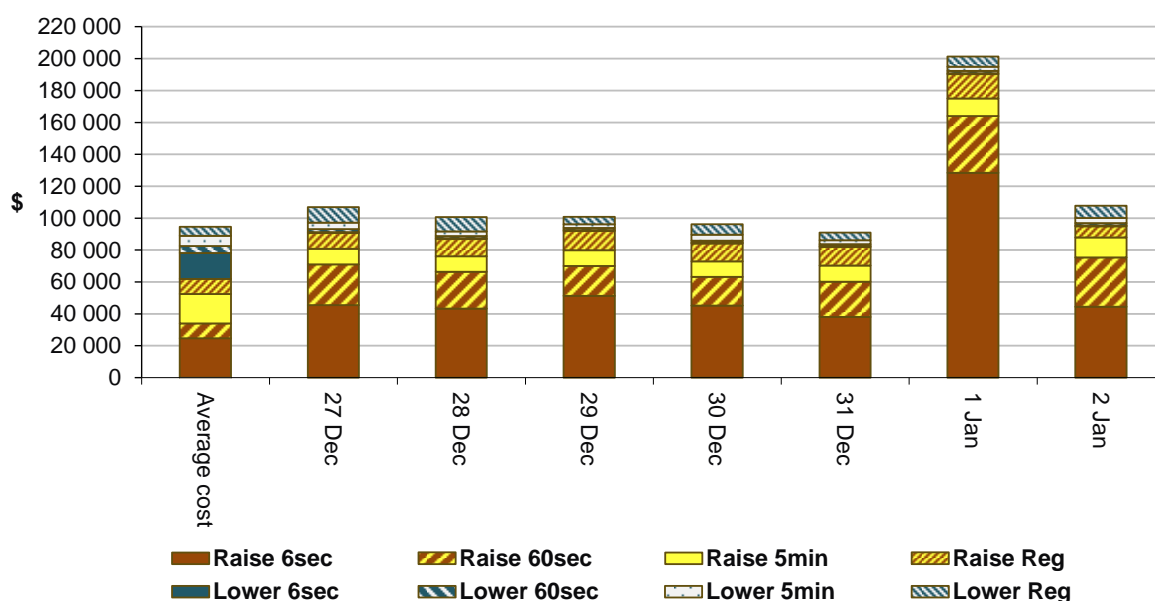
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$581 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$222 500 or around 1.2 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



The high raise 6 second cost on 1 January was a result of the co-optimisation of the Energy and FCAS markets in Tasmania.

Detailed market analysis of significant price events

We provide more detailed analysis of events where the spot price was greater than three times the weekly average price in a region and above \$250/MWh or was below -\$100/MWh.

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 \$46/MWh and above \$250/MWh.

Thursday, 31 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
3:30 pm	256.19	246.95	257.12	8404	8298	8090	11 486	11 353	11 435

Price, demand and availability were all close to forecast 4 hours ahead.

Victoria

There were three occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of \$42/MWh and above \$250/MWh.

Thursday, 31 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
2.30 pm	266.25	107.75	98.73	7806	7707	7395	10 499	10 465	10 636
3 pm	254.43	276.18	299.90	7957	7838	7482	10 614	10 469	10 637
5 pm	267.24	60.29	152.84	8201	8110	7797	10 617	10 516	10 611

Conditions at the time saw demand 100 MW above forecast 4 hour ahead and availability close to forecast 4 hours ahead. The price for the 3.30 pm trading interval was close to that forecast.

Between 2 pm and 5 pm, dispatch prices fluctuated between \$30/MWh and \$320/MWh. This was in part driven by tight supply conditions and increasing demand requirements. For much of this period there was little available generation capacity priced between \$60/MWh and \$290/MWh.

Table 5: Rebids for 2.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
1.55 pm	2.05 pm	Snowy Hydro	Murray	100	35	300	13:51 A NSW: 5MPD PRICE \$147.39 LWR THN 30MPD 14:35@13:32
1.56 pm	2.05 pm	GDF Suez	Loyang B	100	11	446	1356A VIC PRICE LOWER THAN 30MPD: \$96.57 < \$296.42 HHE 14:00
2 pm	2.10 pm	Ecogen Energy	Newport	100	296	60	13:59 A BAND ADJ DUE TO MATERIAL CHANGE IN NEM DEMAND

Table 6: Rebids for 5 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
3.57 pm	4.05 pm	Snowy Hydro	Murray	418	<49	300	15:56 A NSW: 5MPD PRICE \$206.78 HGR THN 5MPD 16:05@15:51
4.24 pm	4.35 pm	Snowy Hydro	Murray	100	98	300	16:24 A NSW: 5MPD PRICE \$207.46 LWR THN 30MPD 16:35@16:02
4.45 pm	4.55 pm	Snowy Hydro	Murray	100	300	98	16:42 A NSW: ACT PRICE \$39.76 LWR THN 5MPD 16:45@16:36

As a result of the tight supply demand, the above rebidding and with cheaper priced generation fully dispatched or stranded in FCAS, the dispatch price remained between \$250/MWh and \$300/MWh for the majority of the three trading intervals identified above.

South Australia

There were twenty-four occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$81/MWh and above \$250/MWh.

Tuesday, 29 December

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	262.23	64.99	64.99	1672	1679	1735	2092	2126	2146
4:30 pm	291.91	64.99	64.99	1727	1730	1794	2088	2142	2168
5 pm	349.11	72.54	68.72	1743	1798	1860	2117	2177	2195
5:30 pm	270.99	64.99	70.99	1757	1850	1902	2135	2218	2230
6 pm	294.98	64.99	65.84	1794	1869	1925	2213	2273	2267

Conditions at the time saw demand and available capacity slightly below that forecast four hours ahead. Total wind generation was less than 200 MW.

During the trading intervals outlined above, supply conditions were limited with approximately 125 MW of priced capacity available between \$60/MWh and \$350/MWh. Both interconnectors were importing into South Australia at maximum capacity but around 220 MW lower than forecast 4 hours ahead.

At 2.53 pm effective for the duration of the above trading intervals, AGL rebid 200 MW of available capacity at Torrens Island from prices below \$95/MWh to above \$351/MWh. The reason for the rebid was “1431~F~070 CHG IN IC OPERATION~70 UNEXPECTED EFFECT OF IR CONSTRAINT - V>>SML_NIL_MLTS_N-2 REDUCE PD FORECAST EXPORT LIMIT FOR V-SA, S>>NIL_SETB_KHTB1 REDUCE PD FORECAST EXPORT LIMIT FOR V-S-MNSP1”.

As a result of the above rebids further limiting availability of cheaper generation, and with demand increasing during this period, dispatch prices remained between \$250/MWh and \$350/MWh for the majority of the dispatch intervals.

Wednesday, 30 December

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
2.30 pm	263.18	64.97	64.99	1971	1954	2089	2612	2632	2858
3 pm	352.63	69.47	85.89	1953	2023	2142	2632	2641	2873

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	517.32	94.99	88.39	1982	2079	2220	2658	2674	2916
4 pm	315.48	103.78	102.78	2082	2147	2289	2628	2650	2910
4.30 pm	610.83	124.88	104.90	2115	2222	2360	2636	2641	2912
5 pm	1014.48	124.88	113.76	2203	2262	2417	2587	2632	2911
5.30 pm	784.22	351.99	353.45	2220	2331	2471	2559	2620	2646
6 pm	404.01	408.60	351.99	2230	2348	2483	2539	2611	2645

For the majority of the trading intervals, conditions saw demand lower than forecast four hours ahead and availability close to forecast four hours ahead. Hot weather on the day also led to high demand requirements during the period. Total wind generation was less than 300 MW.

Heywood was importing into South Australia 150 MW lower than forecast four hours ahead and Murraylink was being forced into Victoria at around 75 MW.

There was around 80 MW of capacity available priced between \$60/MWh and \$300/MWh and 135 MW available between \$350/MWh and \$1500/MWh. This resulted in a steep supply curve for much of the above trading intervals.

With high demand conditions, and cheaper generation fully dispatched, prices remained around \$300/MWh for the majority of the dispatch intervals during this period. On nine occasions the dispatch price spiked above \$1000/MWh as a result of sudden increases in demand (likely caused by sudden reductions in non-scheduled generation).

Thursday, 31 December

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
Midday	288.78	124.99	96.31	1997	2104	2119	2478	2570	2589
12.30 pm	307.90	124.99	95.84	2040	2161	2171	2491	2600	2621
1 pm	307.51	94.99	124.99	2030	1955	2234	2483	2595	2648
1.30 pm	278.07	111.36	126.38	2122	2012	2289	2516	2672	2694
2.30 pm	302.66	124.99	351.99	2198	2183	2410	2607	2654	2691
3 pm	578.19	351.99	396.34	2284	2256	2447	2603	2660	2707

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	362.21	360.81	590.07	2280	2380	2507	2721	2693	2744
4 pm	362.32	351.99	352.41	2300	2433	2543	2707	2679	2736
5 pm	291.45	1480.76	1099.59	2342	2507	2631	2665	2682	2724
5.30 pm	250.32	1658.31	1382.31	2295	2516	2652	2624	2677	2719

Conditions at the time saw demand higher than forecast for the 1 pm to 3 pm trading intervals and lower than forecast for the remaining intervals. Availability was close to that forecast four hours ahead. Total wind generation at the time was less than 200 MW.

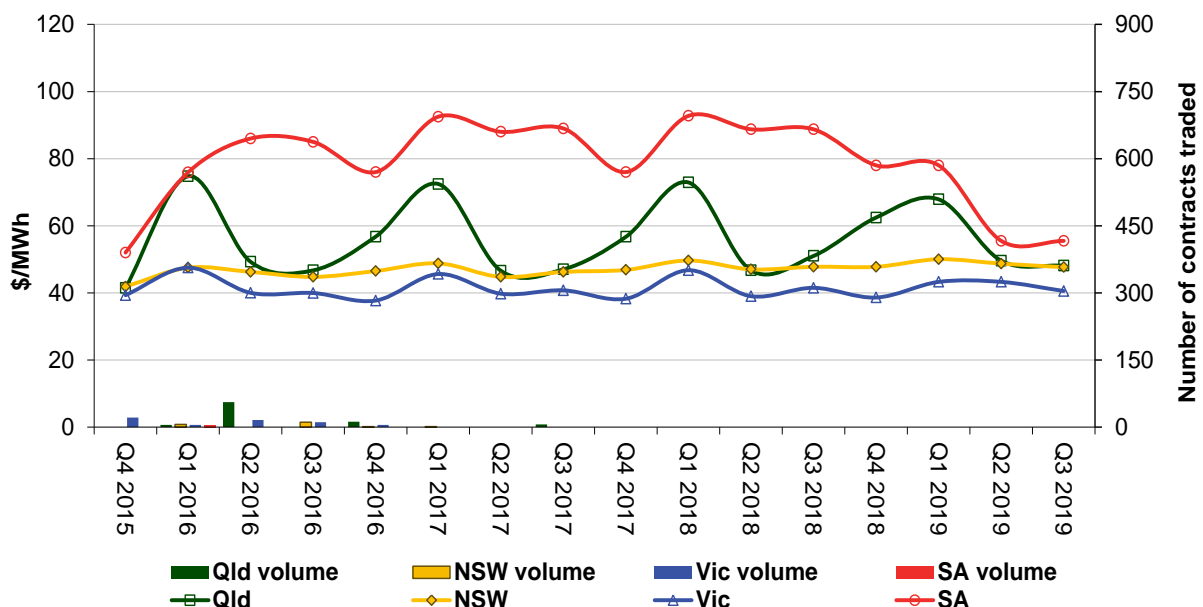
There were tight supply and demand conditions with limited capacity priced between \$60/MWh and \$300/MWh. This resulted in a steep supply curve during this period. This meant that small changes in demand, rebidding and interconnector flows could have significant effect on prices.

The dispatch price remained between \$250/MWh and \$360/MWh for the majority of the period. From Midday to 3 pm imports into South Australia across Murraylink were significantly lower than forecast and from 2.30 pm flows were forced flows into Victoria. This saw prices higher than forecast. Prices from 3.30 pm were close to or lower than forecast as a result of demand being less than forecast.

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.

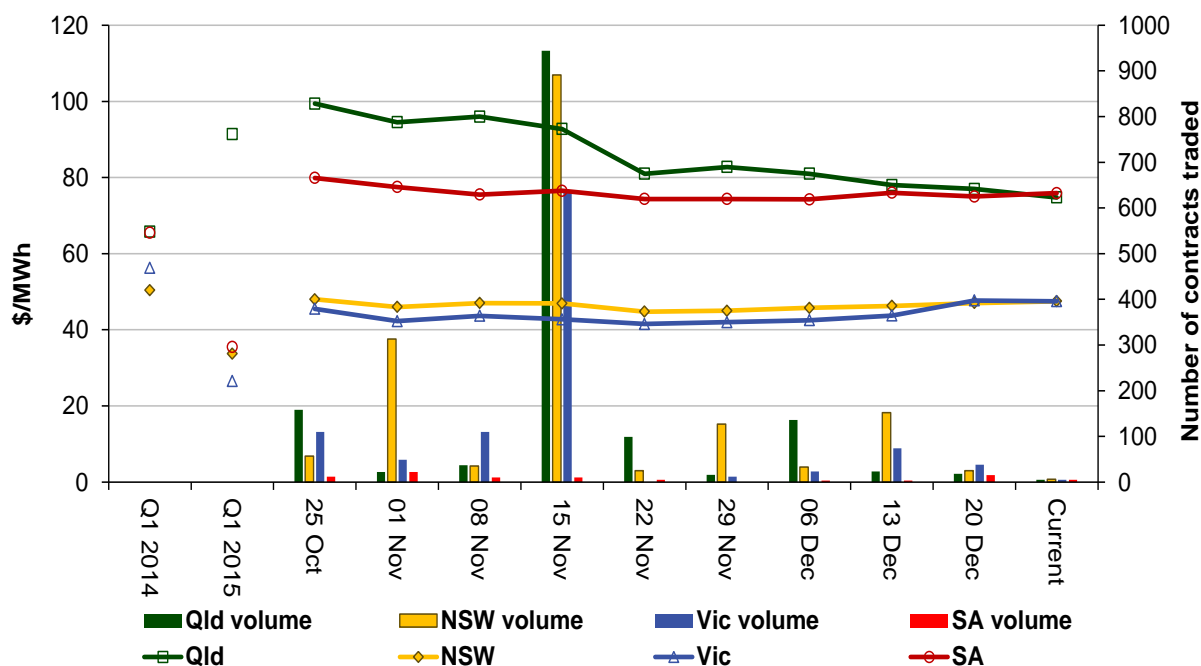
Figure 9: Quarterly base future prices Q4 2015 – Q3 2019



Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades. The high volume of trades in Figure 9, 10, and 11 are due to options on calendar year base load expiring on Thursday 19 November.

Figure 10: Price of Q1 2016 base contracts over the past 10 weeks (and the past 2 years)



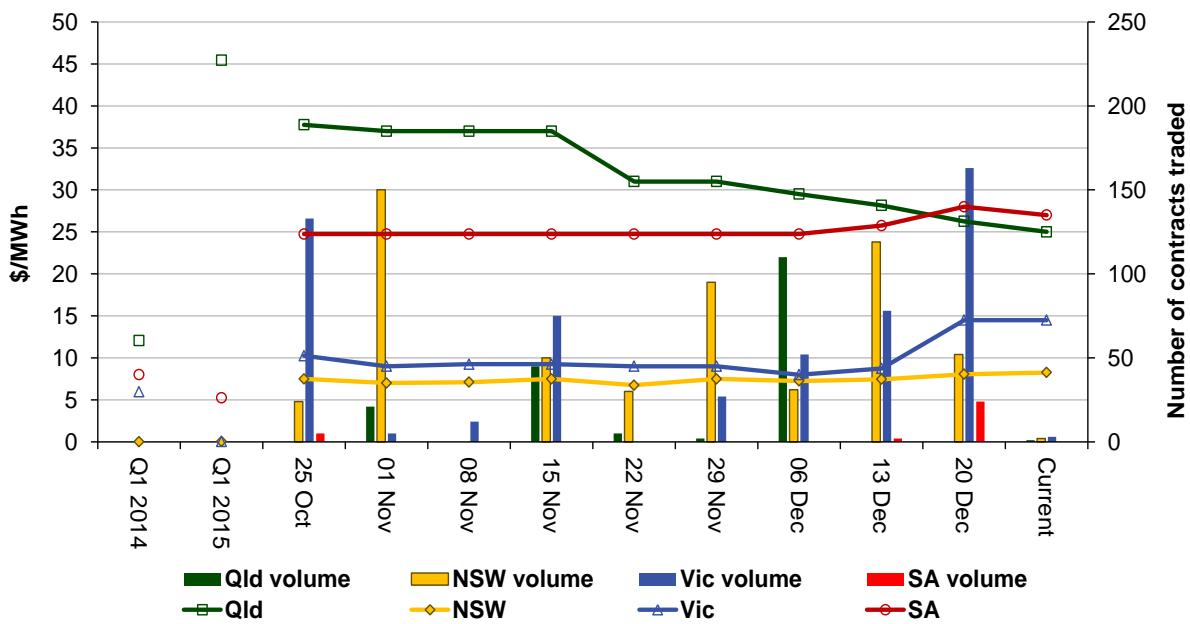
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

Australian Energy Regulator
January 2016