Electricity Report

2 to 8 February 2014

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 2 to 8 February 2014.

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

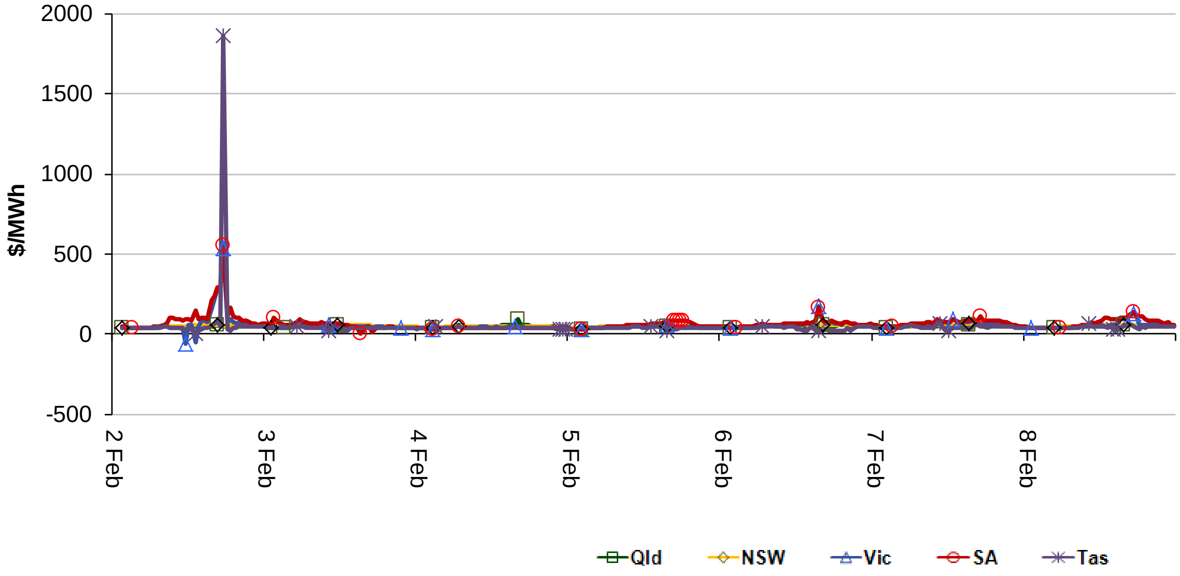


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

 AER reference: 39220 – D14/40457

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

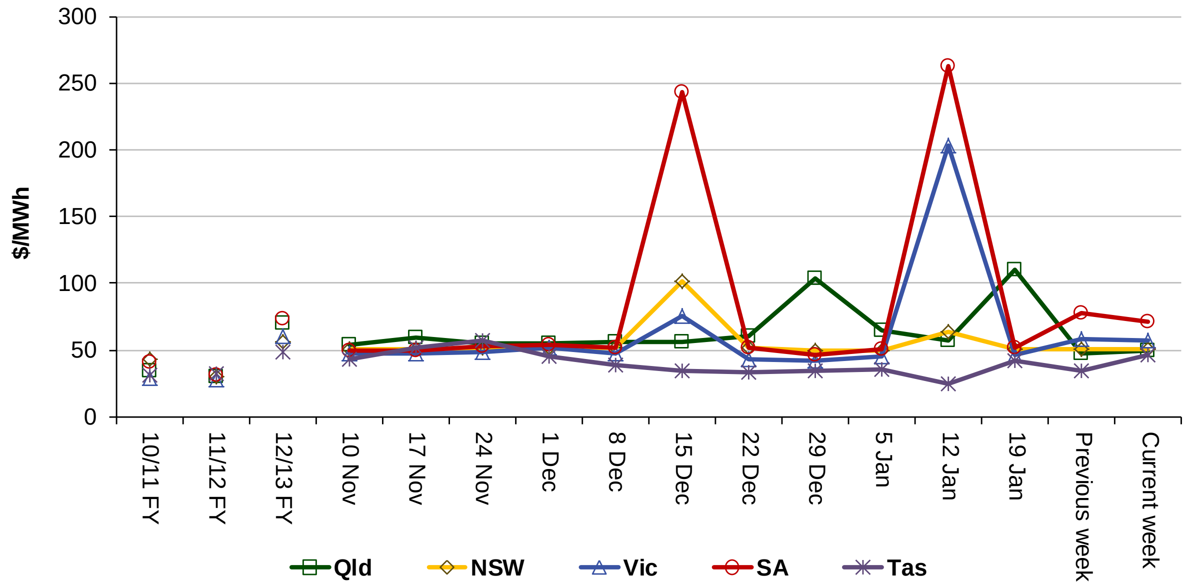


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	50	50	57	71	47
12-13 financial YTD	70	56	61	73	49
13-14 financial YTD	63	54	56	73	43

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 87 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2013 of 97 counts and the average in 2012 of 60. 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	44	0	2
% of total below forecast	12	41	0	1

Note: Due to rounding, the total may not be exactly 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 4 shows there were three significant reductions in available capacity in New South Wales during the week. On 1 February, for the 2 February trading day, a rebid by Snowy Hydro reduced its available capacity by 2 204 MW. The rebid reason given was “17:19:A manage expectation of Murray/UT/T3 constrained on SL”. At 12.47 pm on 7 February, effective from 12.55 pm, another rebid by Snowy Hydro reduced its available capacity by 2 444 MW at Tumut and Upper Tumut. The rebid reason was “12:47 a MNG unfcast binding V>>SML_NIL_1 in dispatch”. The third reduction in available capacity on 8 February was forecast day-ahead.

Figure 5 shows some similar reductions in capacity in Victoria. The reduction on 2 February was the result of rebidding by several generators. Some of the notable rebids were: at 12.16 pm, effective from 12.25 pm, Origin reduced the available capacity at its Mortlake Power Station by 270 MW. At 12.14 pm, effective from 12.25 pm, AGL reduced the available capacity at McKay by 300 MW. The reduction in available capacity on 8 February was forecast day-ahead.

The circle in Figure 7 highlights the effect of a rebid by Hydro Tasmania which is described further in the detailed market analysis section.

Figure 3: Queensland generation and bidding patterns

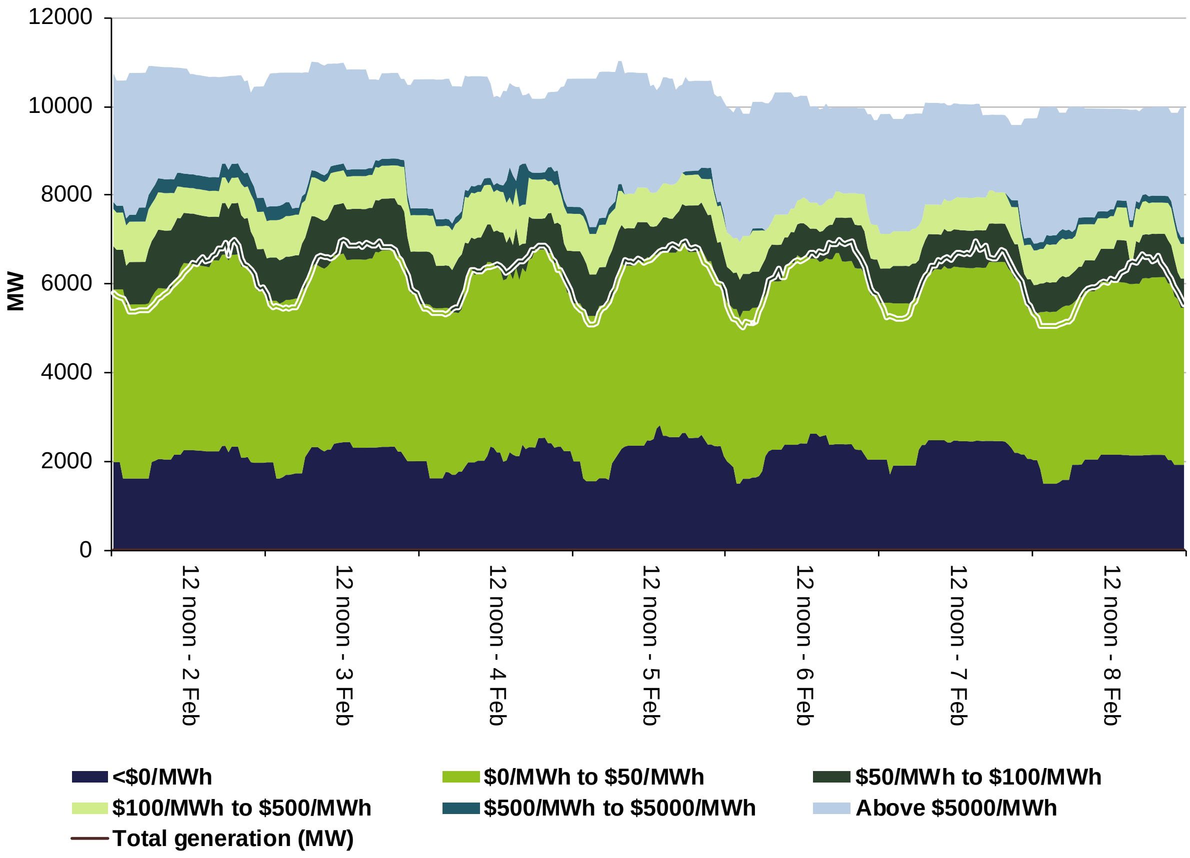


Figure 4: New South Wales generation and bidding patterns

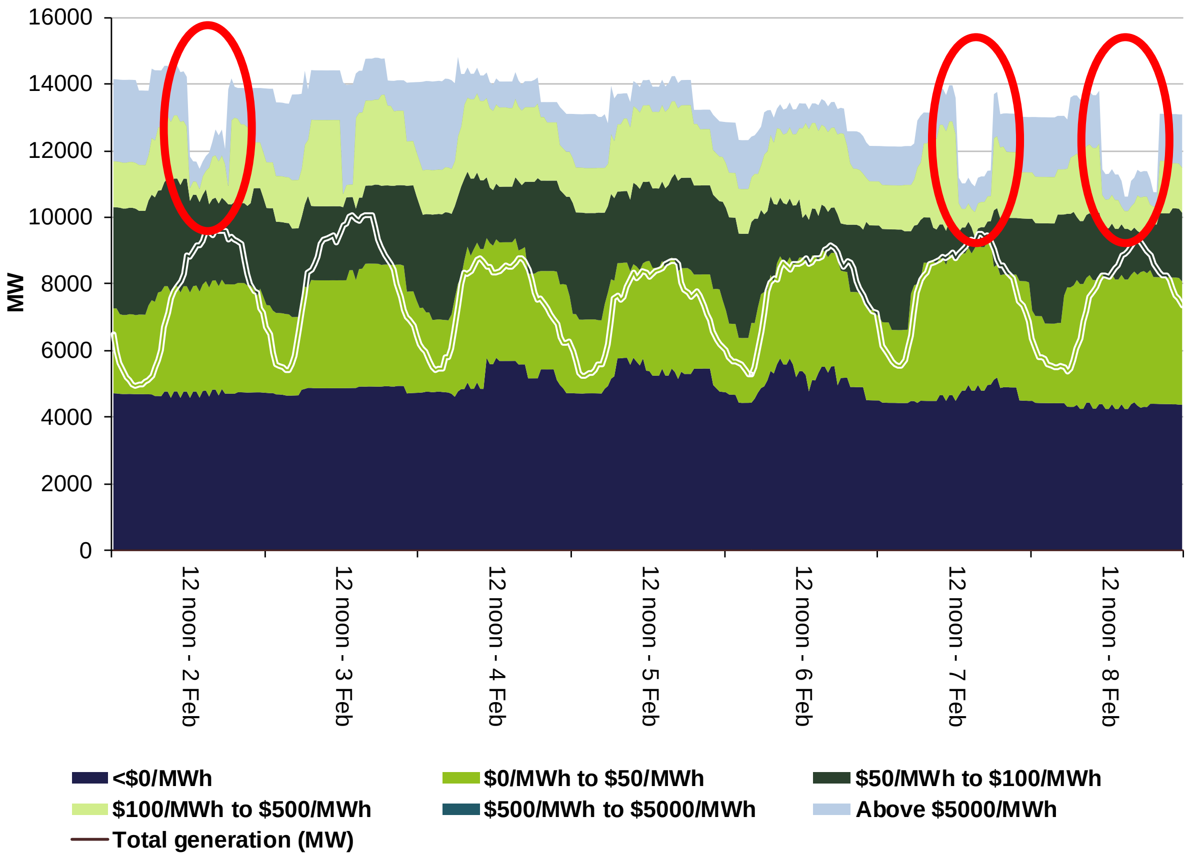


Figure 5: Victoria generation and bidding patterns

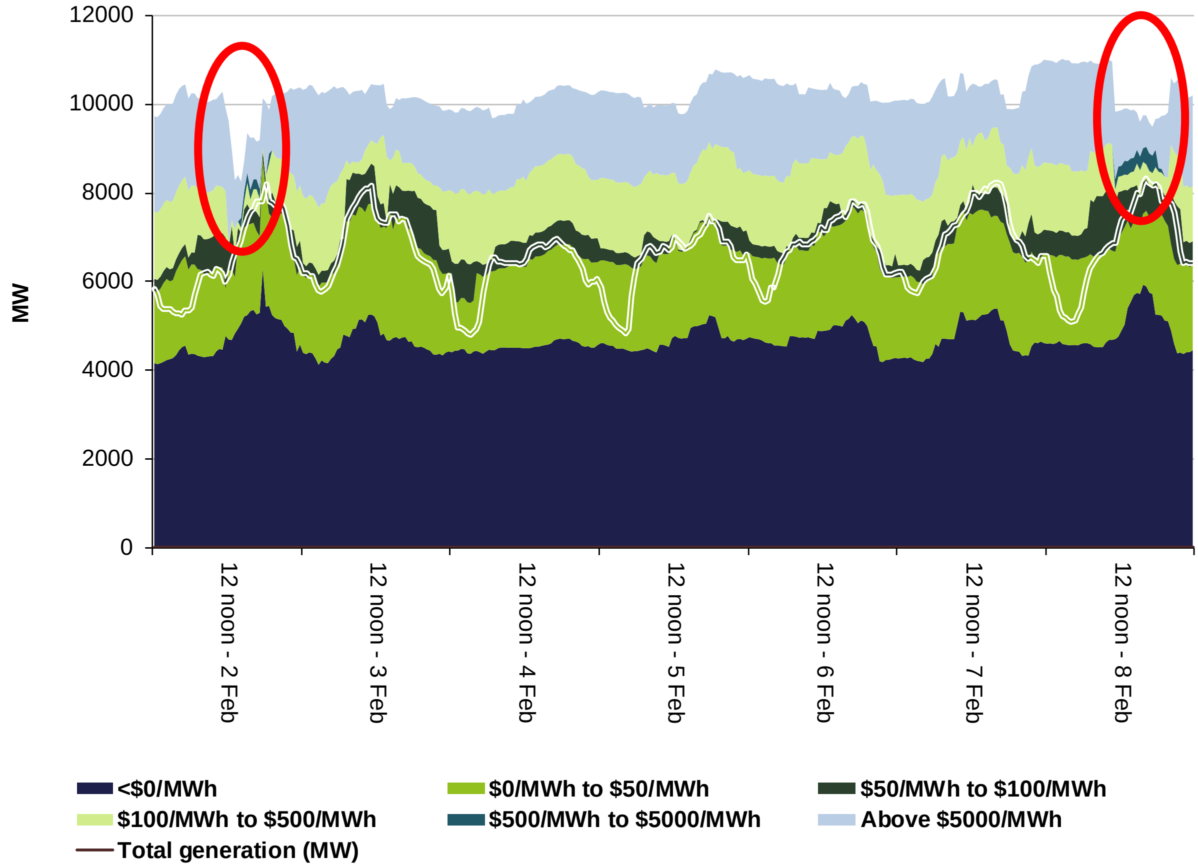


Figure 6: South Australia generation and bidding patterns

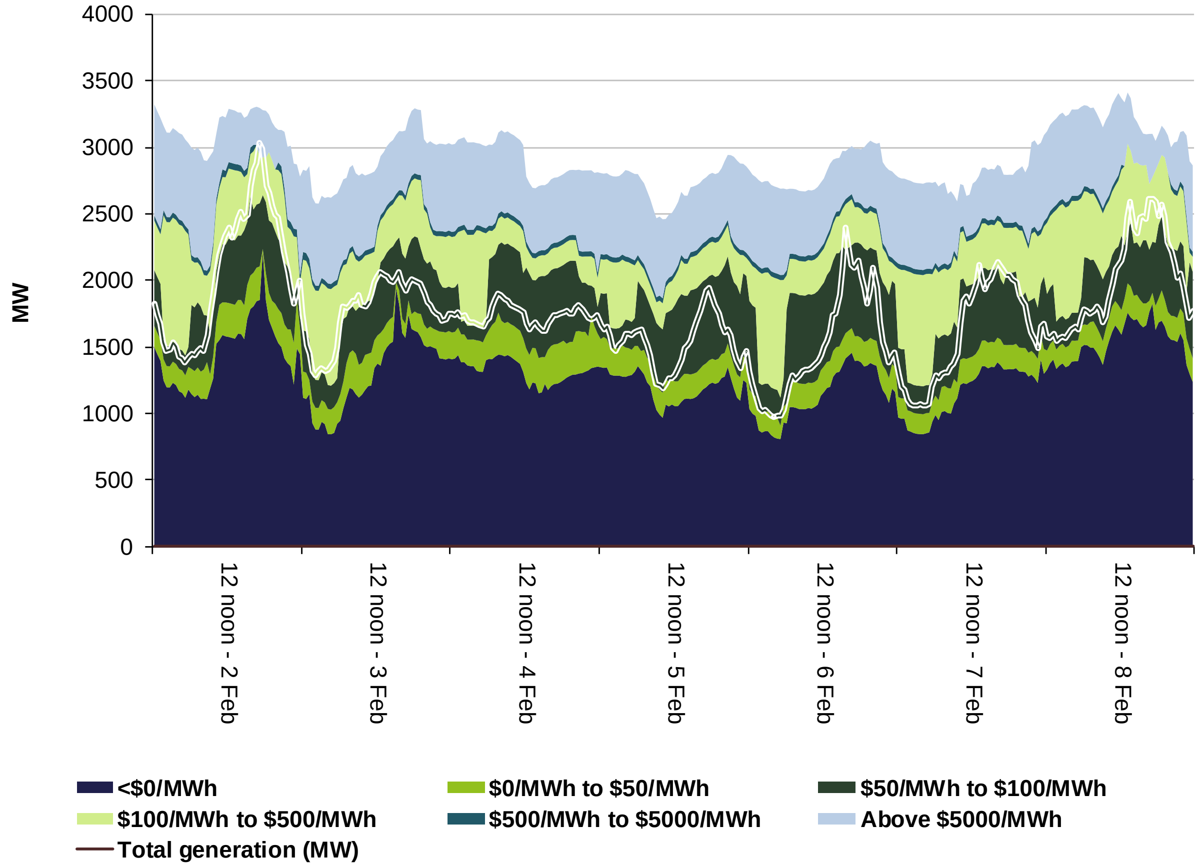
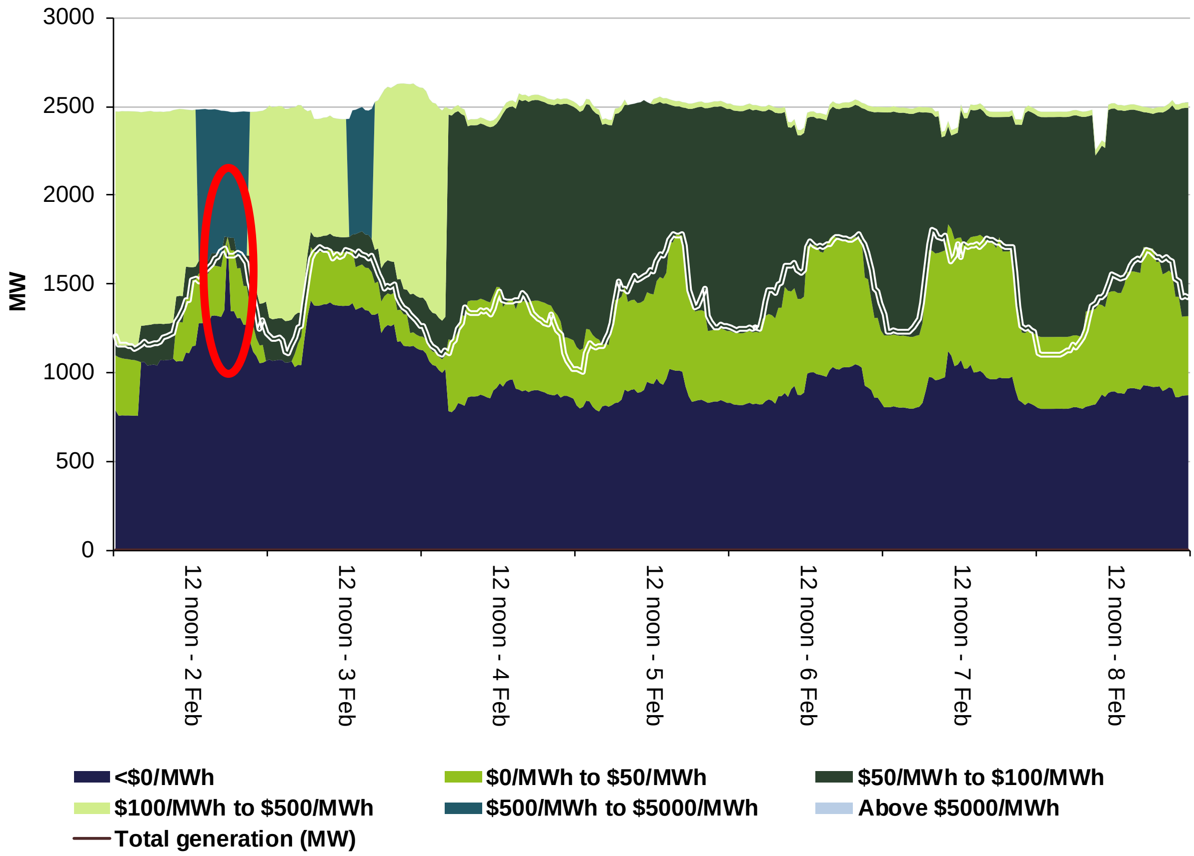


Figure 7: Tasmania generation and bidding patterns



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.

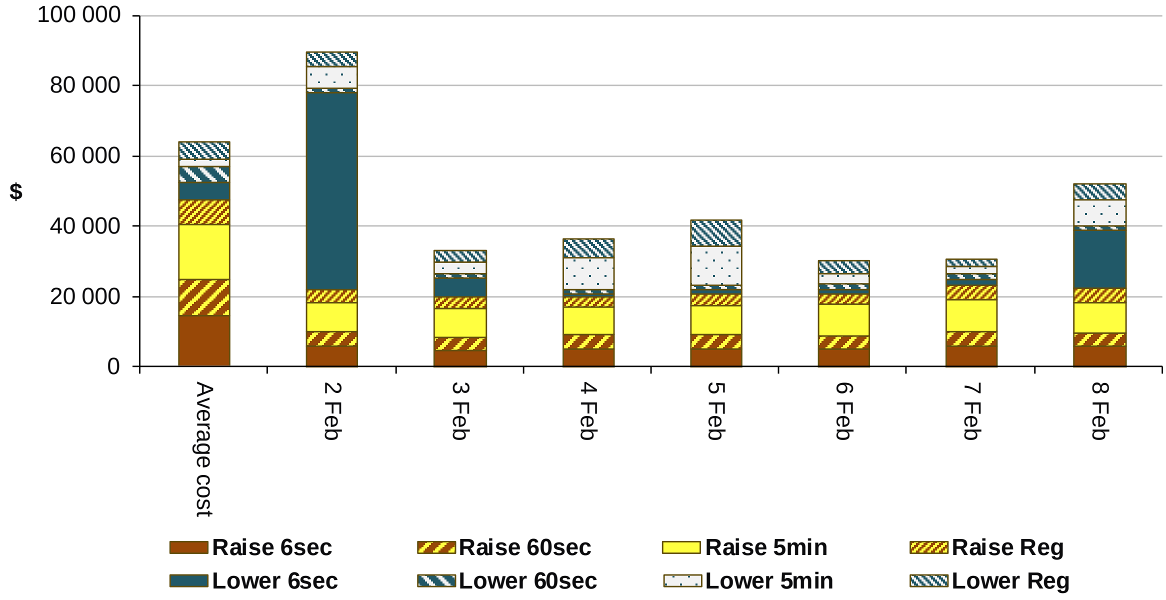
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $212 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $100 500 or around 1 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

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.

Victoria

There were three occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $57/MWh and above $250/MWh.

Table 3: Victoria, Sunday 2 February

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
5.00 PM	283.65	40.62	40.91	8 735	8 155	7 373	9 219	10 310	10 213
5.30 PM	293.21	81.20	61.43	8 784	8 174	7 358	9 180	9 628	10 226
6.00 PM	539.57	40.62	67.51	8 741	8 146	7 298	9 449	9 462	9 866

Actual demand in all three trading intervals was around 600 MW higher than forecast four hours ahead. Available generation was 1091 MW and 448 MW lower than forecast four hours ahead for the 5.00 pm and 5.30 pm trading intervals, respectively. Available generation for the 6.00 pm trading interval was close to forecast.

The reduction in available generation was the result of rebidding from generators including Snowy Hydro (in order to avoid uneconomic ramping and being constrained on) and Energy Australia's Yallourn generators (due to dust limits and coal conservation). The forecast of available generation became closer to actual available generation from around 2 pm in pre dispatch. Around this time, the forecast price was still lower than the actual price ($50–170/MWh).

The high prices began during the 4.30 pm trading interval. At 4.20 pm, demand increased by 52 MW and a constraint designed to avoid the voltage collapse for the loss of largest Victorian generating unit or Basslink, which had been binding since 3.45 pm, reduced imports from New South Wales by 40 MW. This resulted in the five minute price increasing from $189/MWh at 4.15 pm to $282/MWh at 4.20 pm.

The five minute price stayed around this level for the remainder of the 4.30 pm trading interval, and for both the 5.00 pm and 5.30 pm trading intervals. The main driver behind the sustained high price was demand. Demand increased 70 MW during the remainder of the 4.30 pm trading interval and 136 MW during the 5.00 pm trading interval. This level of demand was maintained throughout the 5.30 pm trading interval. Demand reached 8 855 MW at 5.45 pm, which is a record for a Sunday in Victoria. The previous record was around 600 MW lower.

The main contributor to the 6.00 pm price was a reduction in flows from Tasmania by 200 MW in the 5.50 pm dispatch interval. The reduction occurred as prices in Tasmania reached $13 100/MWh following a rebid by Hydro Tasmania. This is discussed further in the Tasmania section below.

There was no significant rebidding.

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 $71/MWh and above $250/MWh.

Table 4: South Australia, Sunday 2 February

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
5.00 PM	296.69	300.07	200.17	2 922	2 934	2 839	3 307	3 182	3 153
5.30 PM	296.85	300.07	300.07	2 839	2 926	2 887	3 298	3 171	3 162
6.00 PM	554.50	299.80	300.07	2 806	2 928	2 901	3 264	3 165	3 169

Prices for the 5.00 pm and 5.30 pm trading intervals were close to forecast both 4 and 12 hours before.

The spot price for the 6.00 pm trading interval was around $250/MWh higher than forecast both 4 and 12 hours before.

The main contributor to the 6.00 pm price was a reduction in flows from Tasmania into Victoria by 200 MW in the 5.50 pm dispatch interval. The reduction occurred as prices in Tasmania reached $13 100/MWh following a rebid by Hydro Tasmania. This is discussed further in the Tasmania section below.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $47/MWh and above $250/MWh.

Table 5: Tasmania, Sunday 2 February

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**
6.00 PM	1 865.5	33.39	-.76	1 037	1 009	1 027	2 473	2 497	2 516

Both demand and available generation were close to forecast both 4 and 12 hours before.

At 5.43 pm, effective from 5.50 pm, Hydro Tasmania rebid 1116 MW of capacity from across its portfolio (402 MW of which was priced under $60/MWh with the remaining 714 MW priced around $600/MWh) to the price cap. The reason given was "1740A P5 Vic price higher than previous forecast".

This rebid resulted in no generation being available between the price bands of $40/MWh–$600/MWh for the 5.50 pm five minute interval. Figure 7 above highlights this.

The five minute price increased from $42/MWh at 5.45 pm to $13 100/MWh at 5.50 pm.

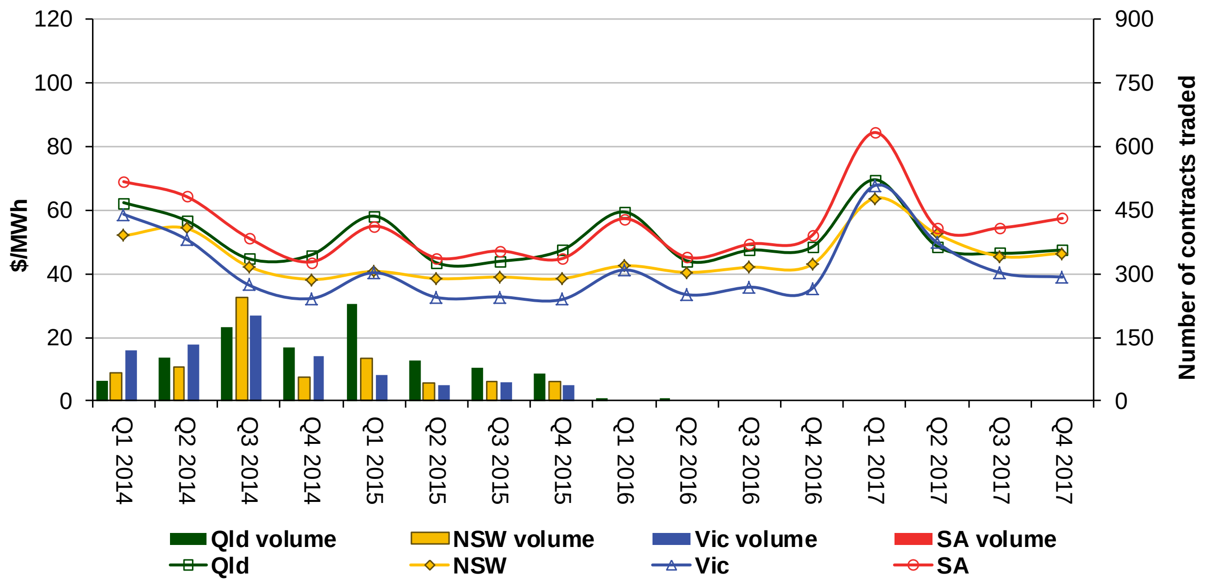
Following the price spike, Hydro Tasmania made a further rebid which was effective at 5.55 pm, which offered generation at cheaper prices. This resulted in a five minute price of -$1 000/MWh for both the 5.55 pm and 6.00 pm dispatch intervals.

There was no other significant rebidding.

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.

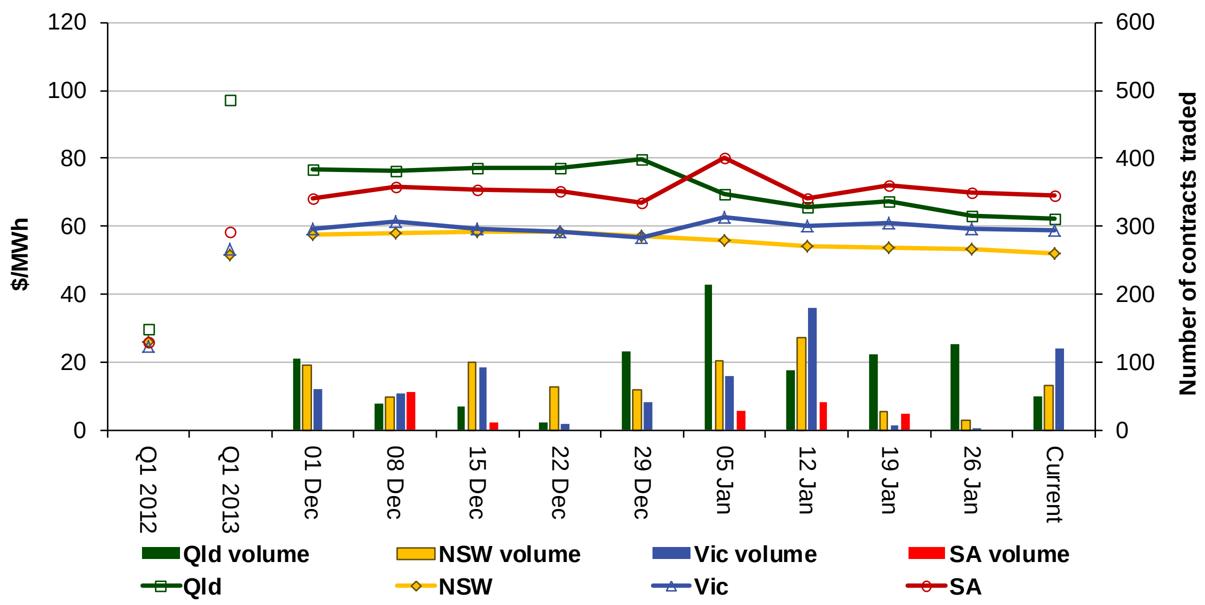
Figure 9: Quarterly base future prices Q1 2014 – Q4 2017



Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2014 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2012 and quarter 1 2013 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 2014 base contracts over the past 10 weeks (and the past 2 years)



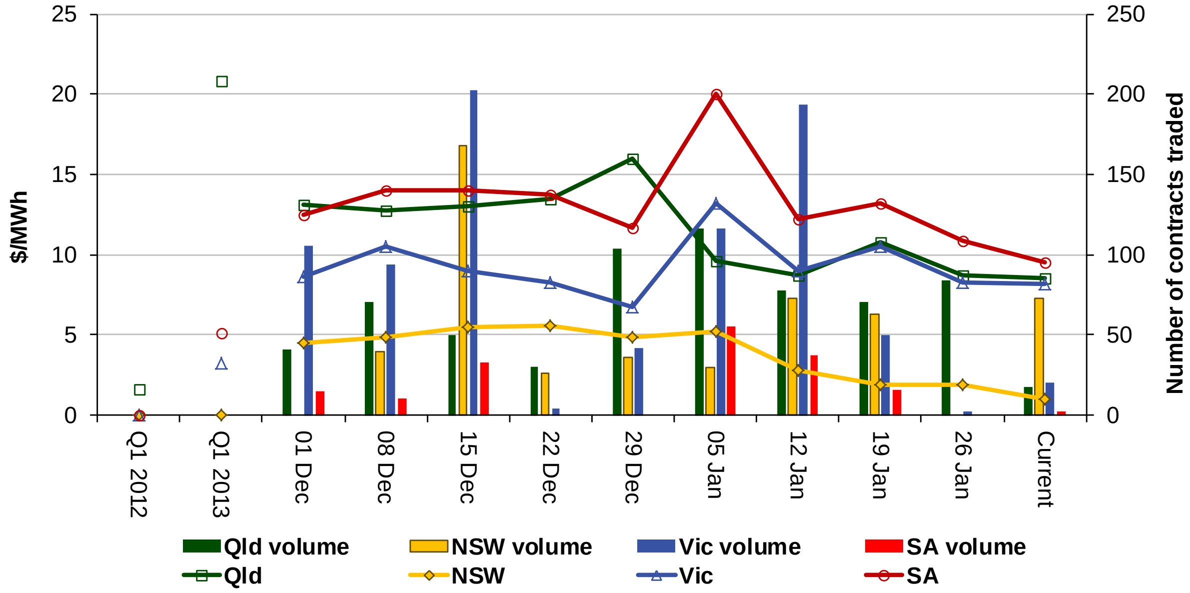
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Performance of the Energy Sector section of our website.

Figure 11 shows how the price for each regional Quarter 1 2014 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2012 and quarter 1 2013 prices are also shown.

Figure 11: Price of Q1 2014 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

Australian Energy Regulator

April 2014