Electricity Report

4 – 10 December 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 4 – 10 December 2016.

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

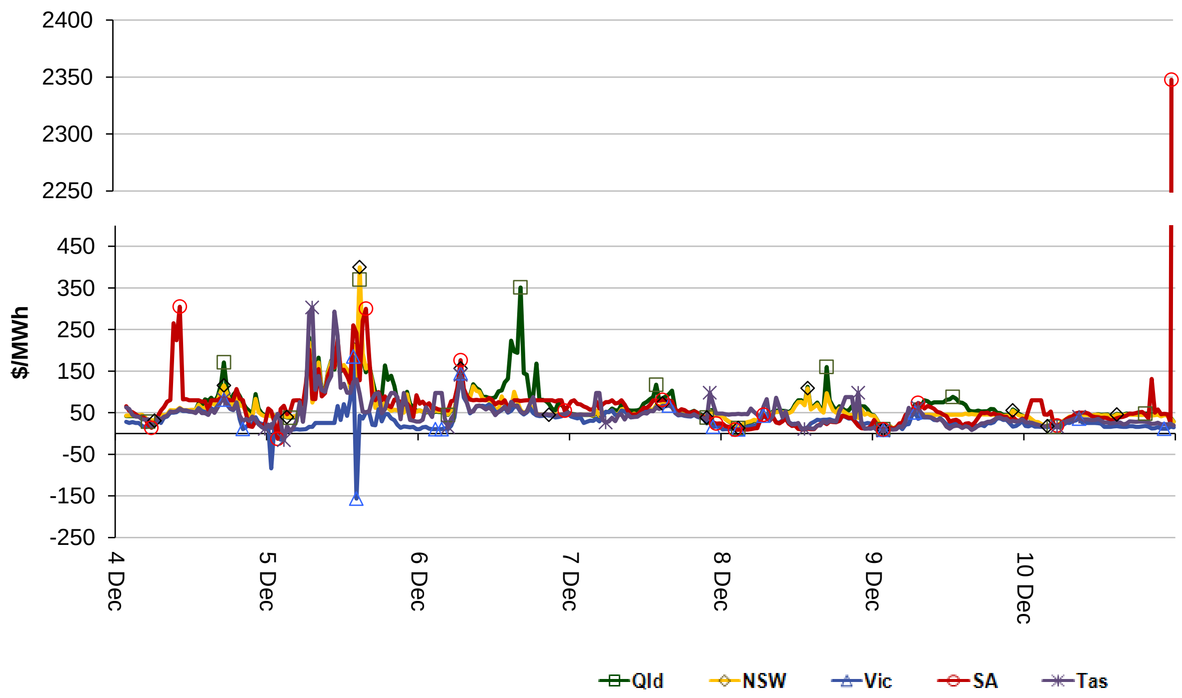


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

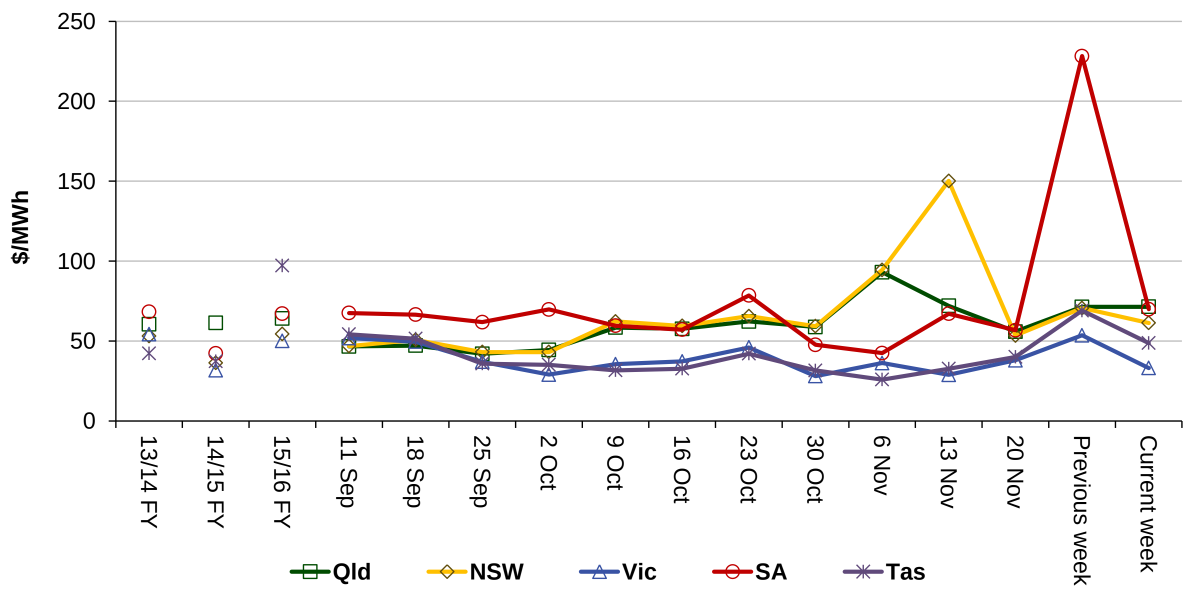


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	71	61	33	70	49
15-16 financial YTD	44	45	39	60	53
16-17 financial YTD	59	63	46	112	48

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 299 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71. 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	36	1	2
% of total below forecast	38	16	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

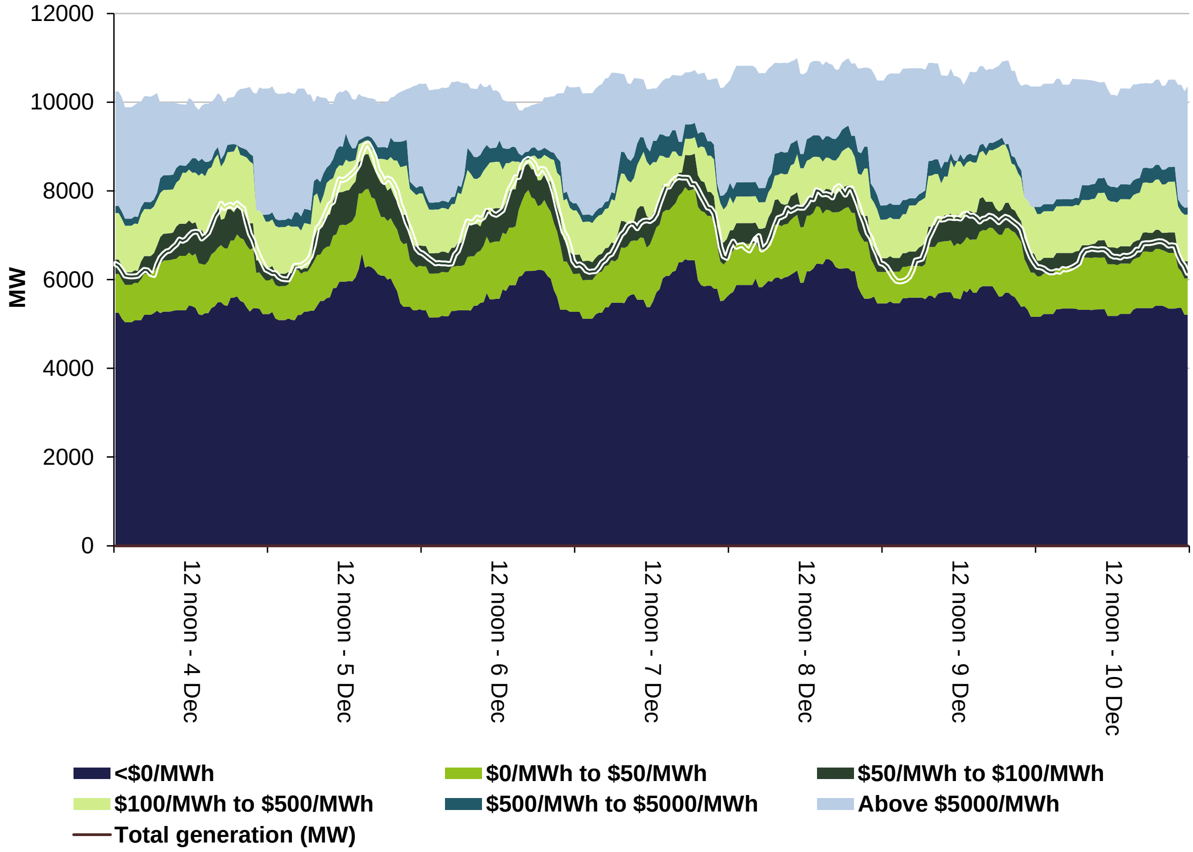


Figure 4: New South Wales generation and bidding patterns

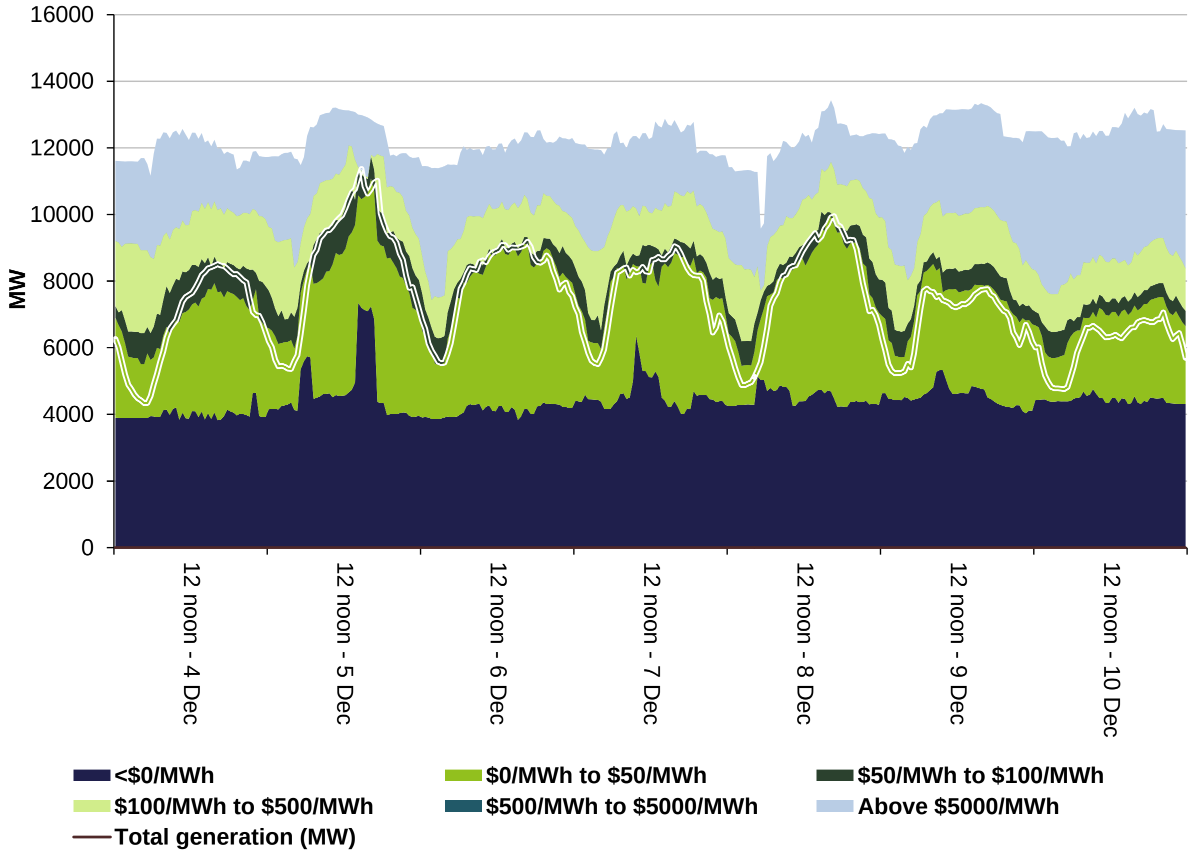


Figure 5: Victoria generation and bidding patterns

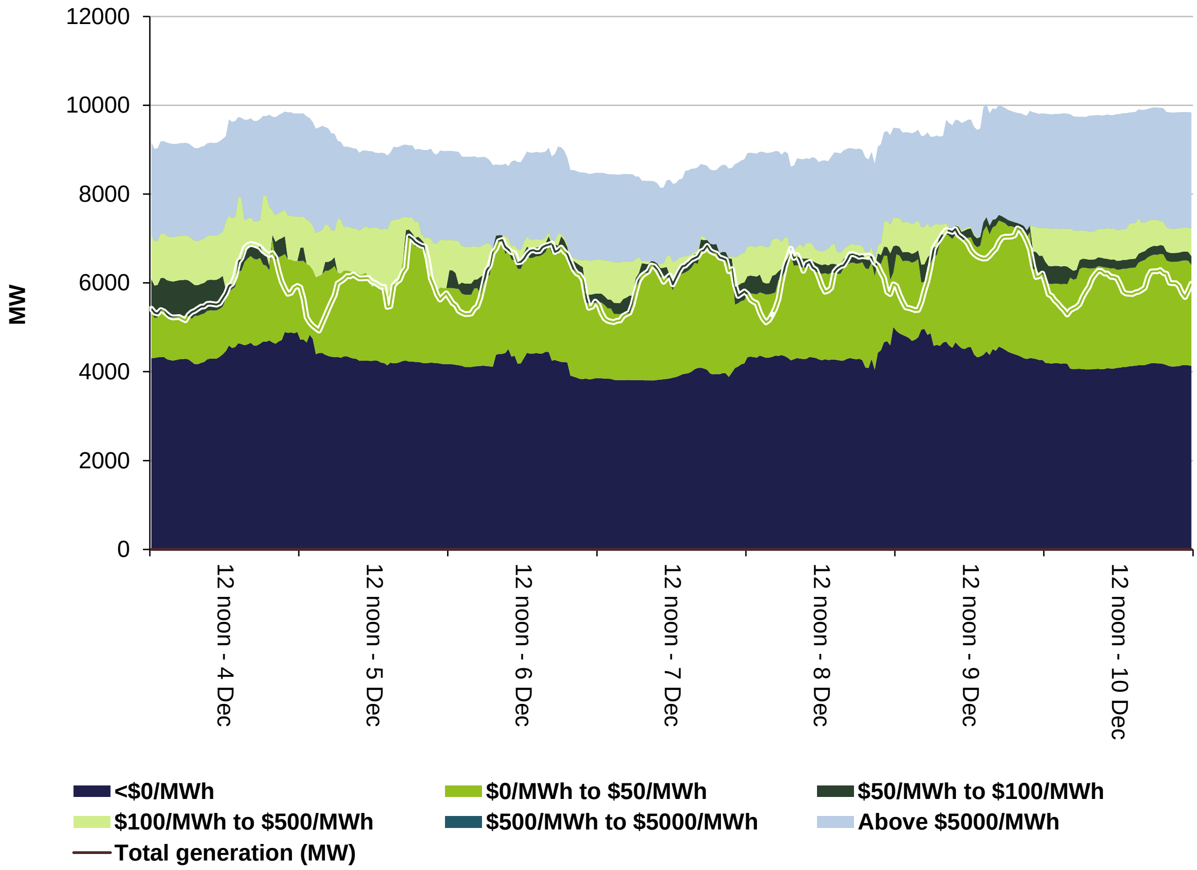


Figure 6: South Australia generation and bidding patterns

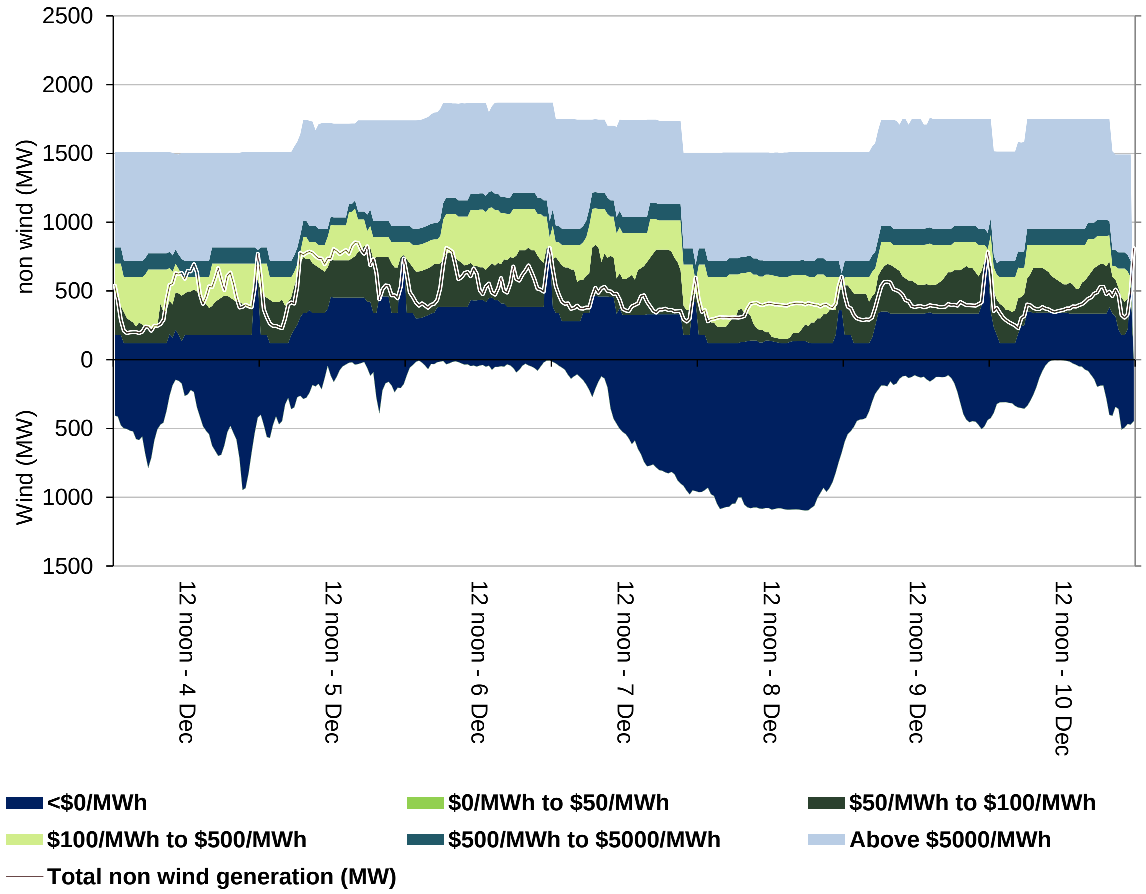
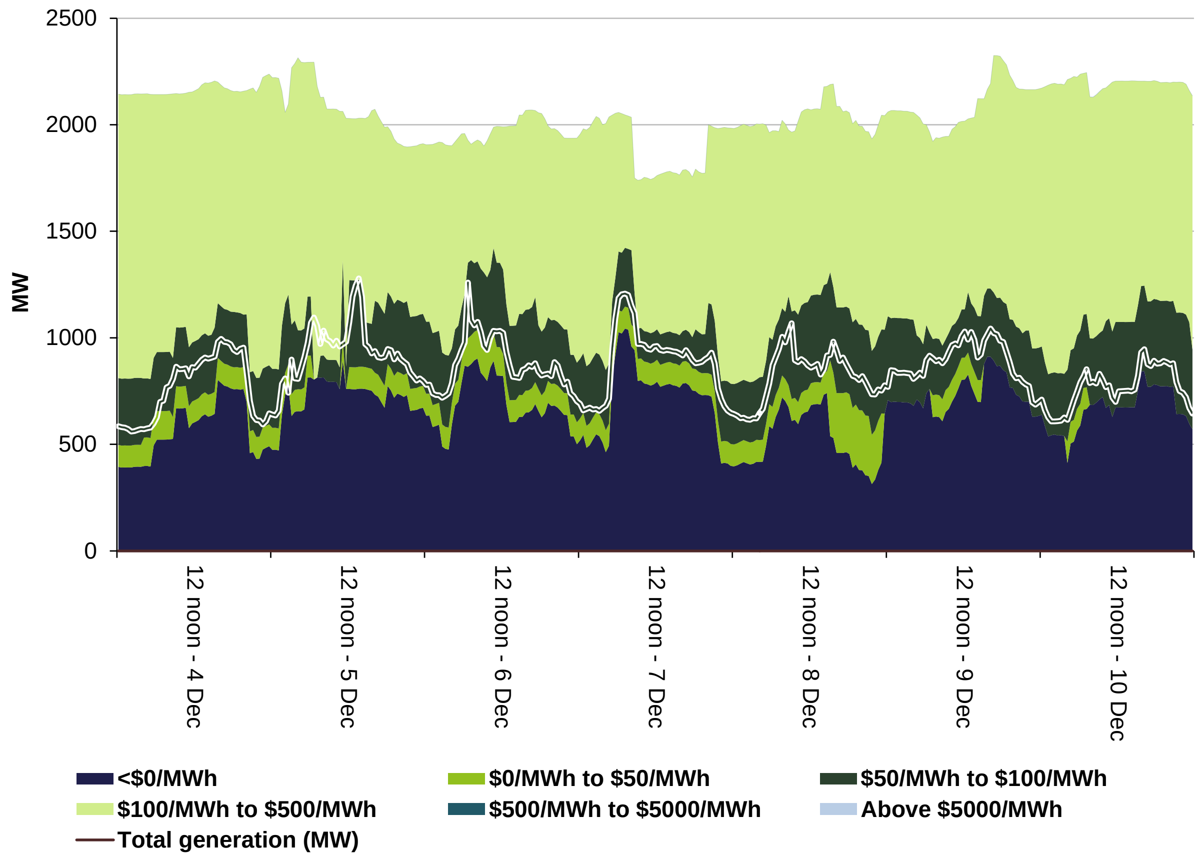


Figure 7: Tasmania generation and bidding patterns



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.

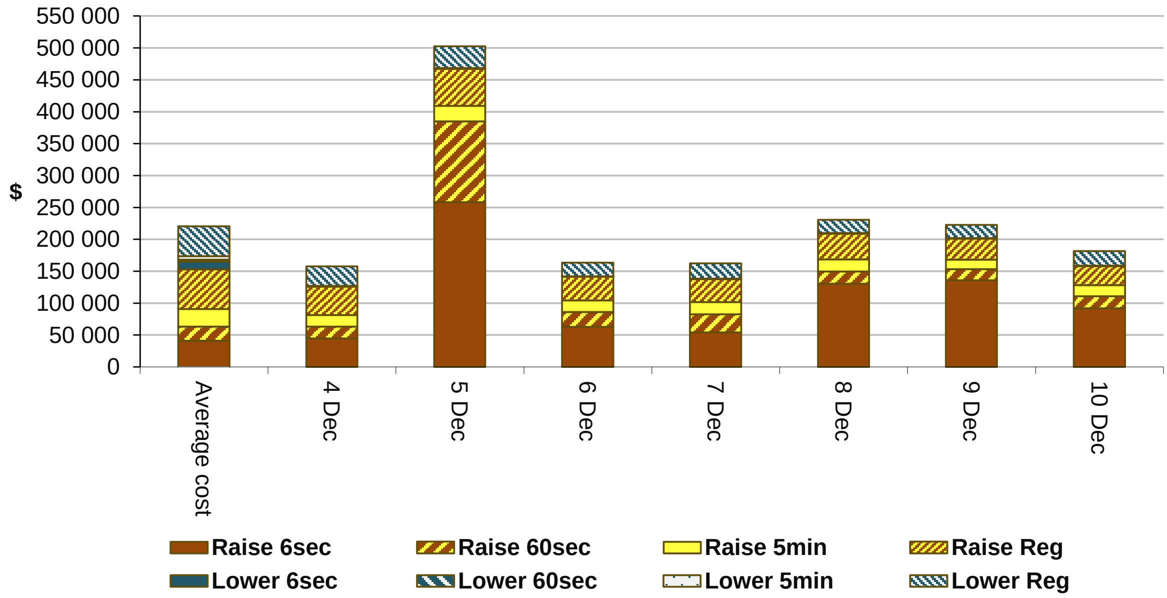
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $958 500 or around a half per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $661 000 or around eight 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



Early in the morning on 5 December there was a simultaneous trip of Basslink and the Farrell to Sheffield No.1 line. Due to lightning in the area further lines were reclassified as a credible contingency. As a result the requirement for raise 6 second services increased and the price of raise 6 second services in Tasmania was above $100/MW on 21 occasions, with a maximum of $3061/MW due to the co-optimisation of the Energy and FCAS markets.

Detailed market analysis of significant price events

Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $71/MWh and above $250/MWh.

Monday, 5 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 pm	370.08	422.00	263.00	8038	8288	8270	10 165	10 125	10 570

Conditions at the time saw demand 250 MW lower than forecast while availability was around 400 MW greater than forecast four hours ahead. This saw prices slightly lower than that forecast four hours ahead.

Tuesday, 6 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
4.30 pm	351.33	90.00	390.69	8680	8349	8706	9899	10 177	10 524

Conditions at the time saw the price lower than forecast 12 hours ahead and greater than that forecast four hours ahead. This was as a result of demand being lower than forecast 12 hours ahead and greater than that forecast four hours ahead.

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 $61/MWh and above $250/MWh.

Monday, 5 December

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
3 pm	399.84	407.39	248.53	11 505	11 280	10 974	13 019	13 165	13 178

Conditions at the time saw the spot price close to that forecast four hours ahead.

Victoria

There was one occasion where the spot price in Victoria was below -$100/MWh.

Monday, 5 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
2.30 pm	-156.69	17.40	53.74	5089	4916	5264	8895	8929	8905

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

From 6 am there was a planned outage of the Gullen Range to Yass line in Southern New South Wales, limiting flow from generators in Southern New South Wales to Sydney. At 2.20 pm Snowy Hydro rebid 550 MW of capacity at Tumut from $300/MWh to the price floor causing an increase in generation. The reason given was "14:11:00 A NSW 5MIN PD price $1,462.04 higher than 5MIN PD 14:35@14:06 ($1,547.70)". This increase in generation was forced into Victoria across the Vic-NSW interconnector due to the network limitations. Forced imports into Victoria increased from 101 MW at 2.15 pm to 532 MW at 2.20 pm and generation in Victoria decreased by 382 MW.

This step change in interconnector flow, combined with generation in Victoria ramp rate down constrained, caused the price to decrease to -$1000/MWh for the 2.20 pm dispatch interval.

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 $70/MWh and above $250/MWh.

Sunday, 4 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
9.30 am	265.14	44.15	38.14	1229	1115	1165	1773	2180	2276
10.30 am	304.99	58.05	60.51	1246	1193	1192	1645	2136	2128

Conditions at the time saw demand up to 114 MW higher than forecast while availability was around 400 MW lower than what was forecast four hours ahead. Wind output was over 350 MW and 480 MW lower than that forecast four hours ahead for the 9.30 am and 10.30 am trading intervals respectively. This led to higher priced generation meeting demand for both trading intervals.

Monday, 5 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
2 pm	260.41	227.74	79.99	1298	1117	1162	1771	1811	1793

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	270.83	221.92	124.99	1294	1263	1210	1736	1817	1814
4 pm	299.99	299.99	124.99	1314	1319	1244	1753	1819	1823

Conditions at the time saw demand slightly higher than forecast four hours ahead for the 2 pm and 3.30 pm trading intervals and close to forecast for the 4 pm trading interval. As a result prices were slightly higher or as forecast four hours ahead.

Sunday, 11 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
Midnight	2347.55	39.78	31.90	1360	1393	1376	1939	2008	2015

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

At 11.35 pm demand increased by 124 MW, due to hot water load. With only Torrens Island (which was ramp rate limited) and wind farms generating, the dispatch price increased from $23/MWh at 11.30 pm to $14 000/MWh at 11.35 pm.

Tasmania

There were three occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $49/MWh and above $250/MWh.

Monday, 5 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
7 am	287.62	97.59	97.59	1070	1039	1140	2294	2278	2278
7.30 am	303.01	97.59	55.92	1051	1079	1129	2181	2171	2163
11 am	293.32	42.70	57.48	1011	995	1015	2062	2094	2084

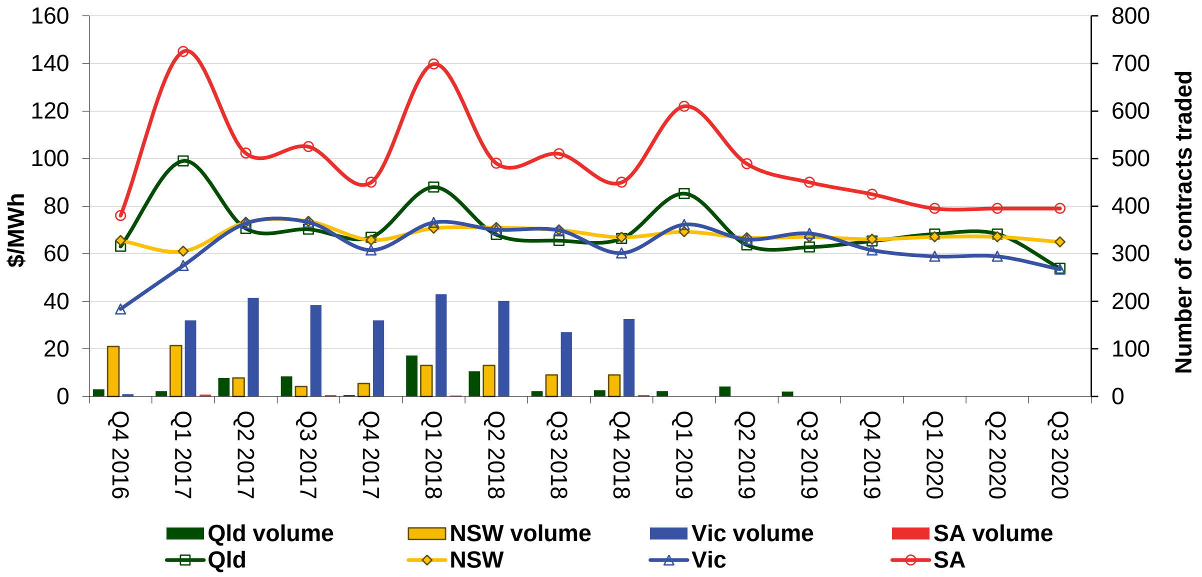
Conditions at the time saw demand and available capacity close to that forecast four hours ahead.

Throughout the morning a network constraint designed to control Basslink, which forms part of the network control special protection scheme bound limiting imports into Tasmania. There was also an outage of one of the Sheffield to Georgetown lines which reduced output from nine units. As a result dispatch prices varied between $100/MWh and $350/MWh for most of the morning.

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.

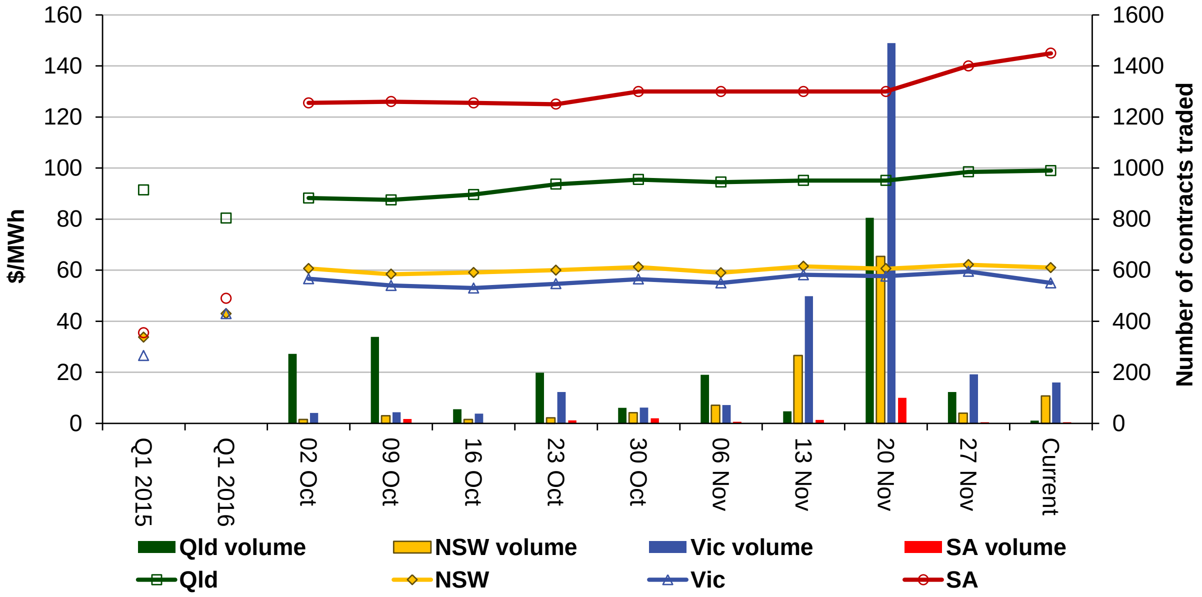
Figure 9: Quarterly base future prices Q4 2016 – Q3 2020



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)



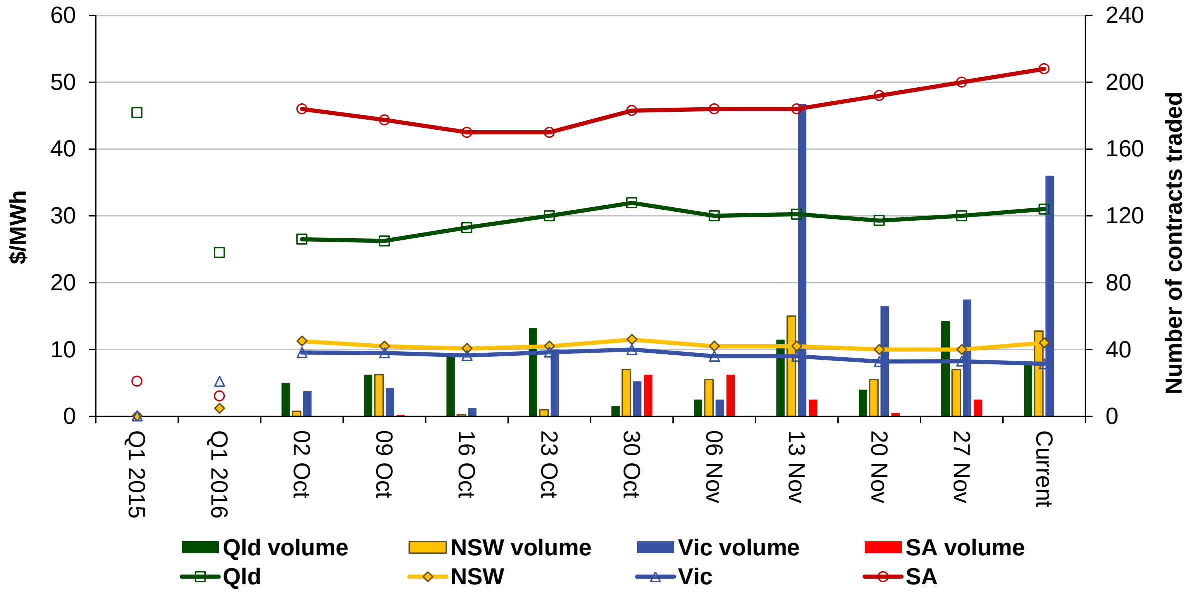
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
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