Electricity Report

AUSTRALIAN ENERGY REGULATOR

17 - 23 December 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 17 - 23 December 2017.

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

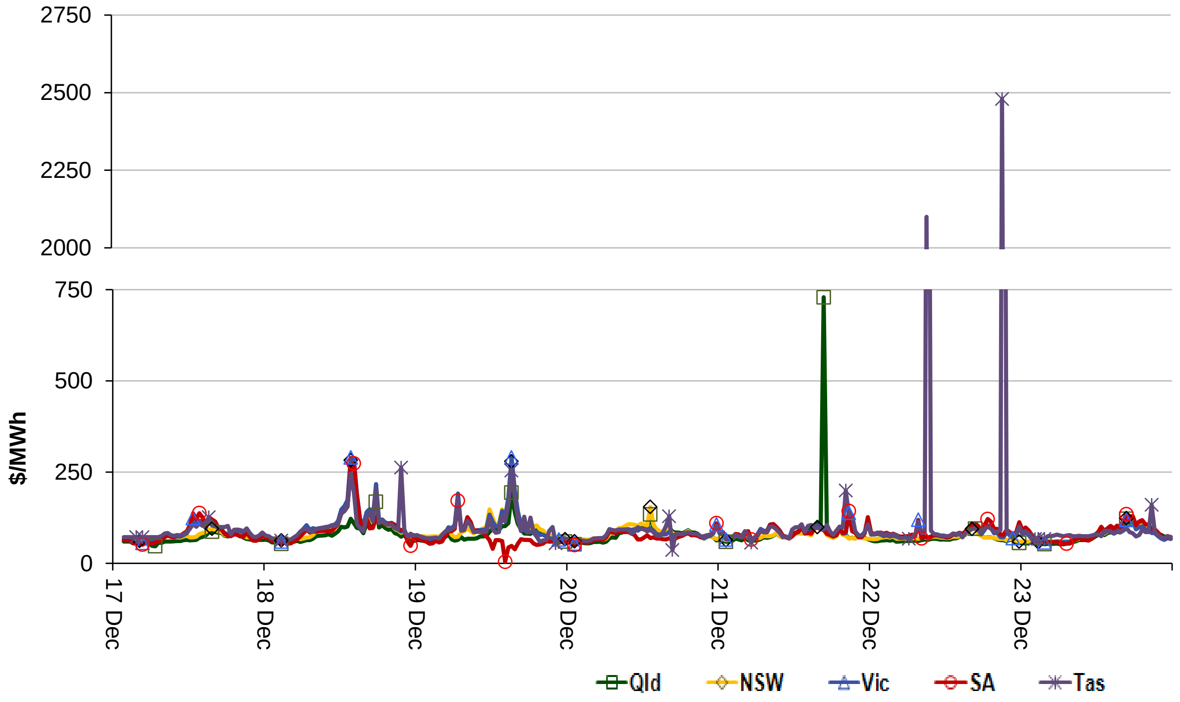


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

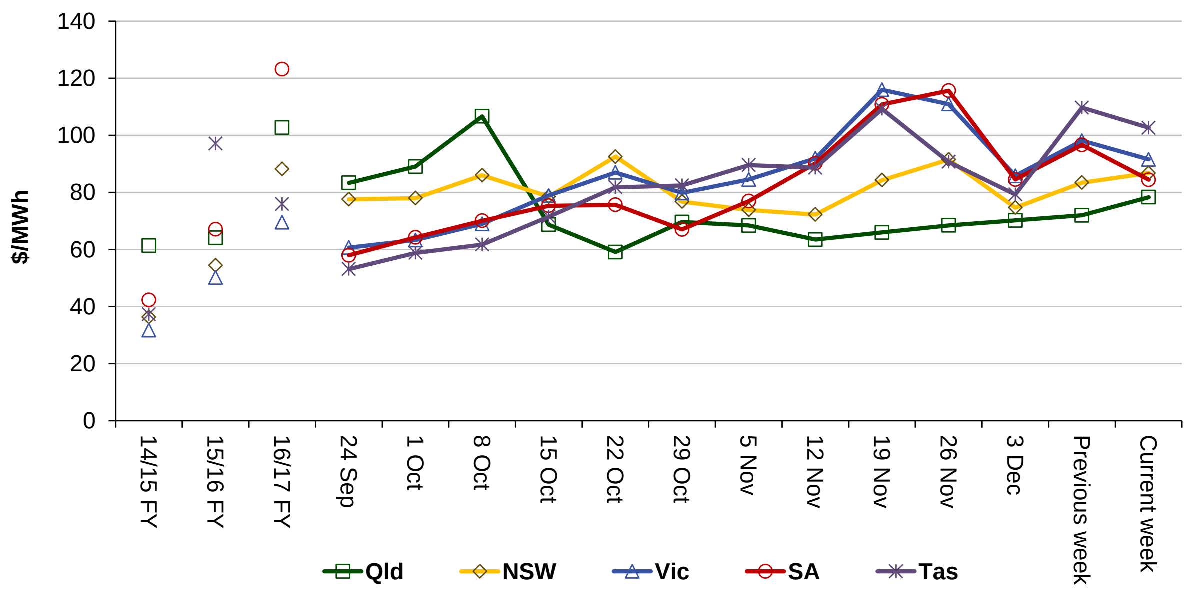


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	78	87	92	84	103
16-17 financial YTD	60	62	45	109	48
17-18 financial YTD	78	89	97	95	92

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 129 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	1	9	0	1
% of total below forecast	61	25	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

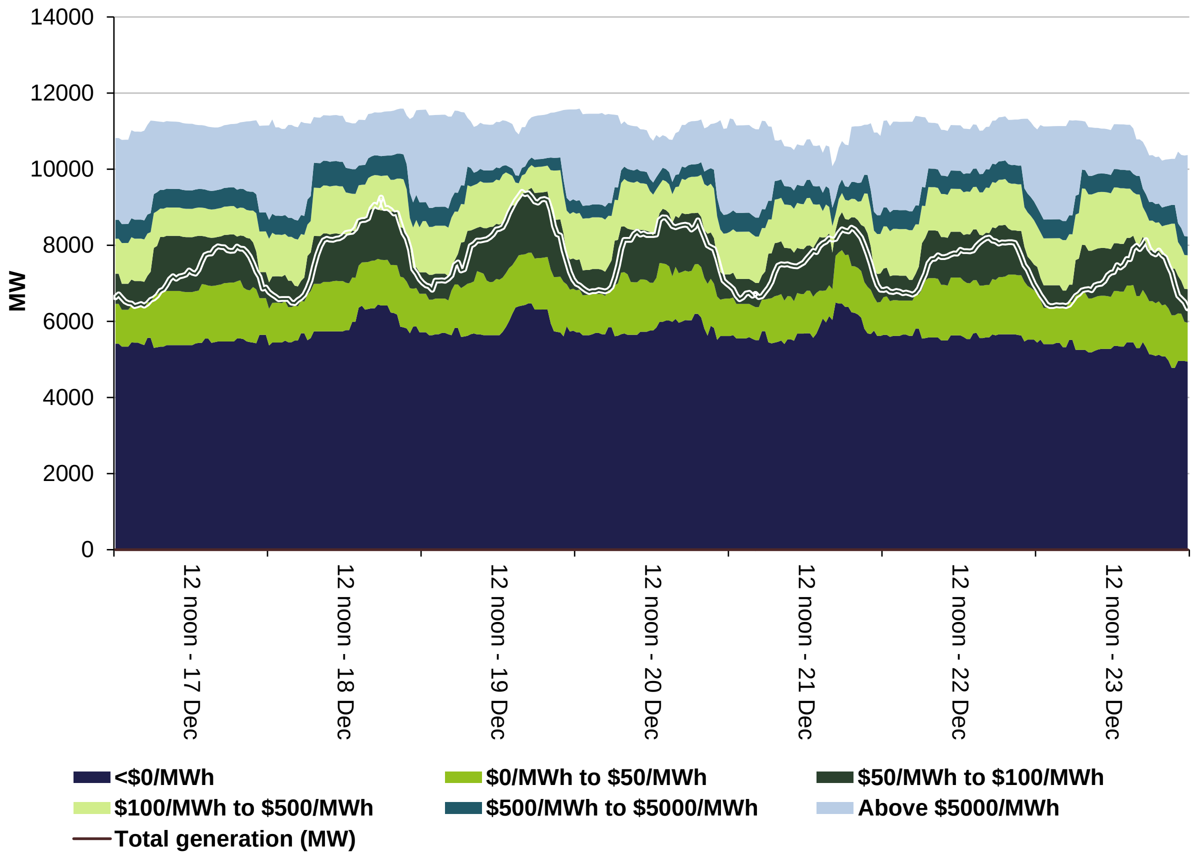


Figure 4: New South Wales generation and bidding patterns

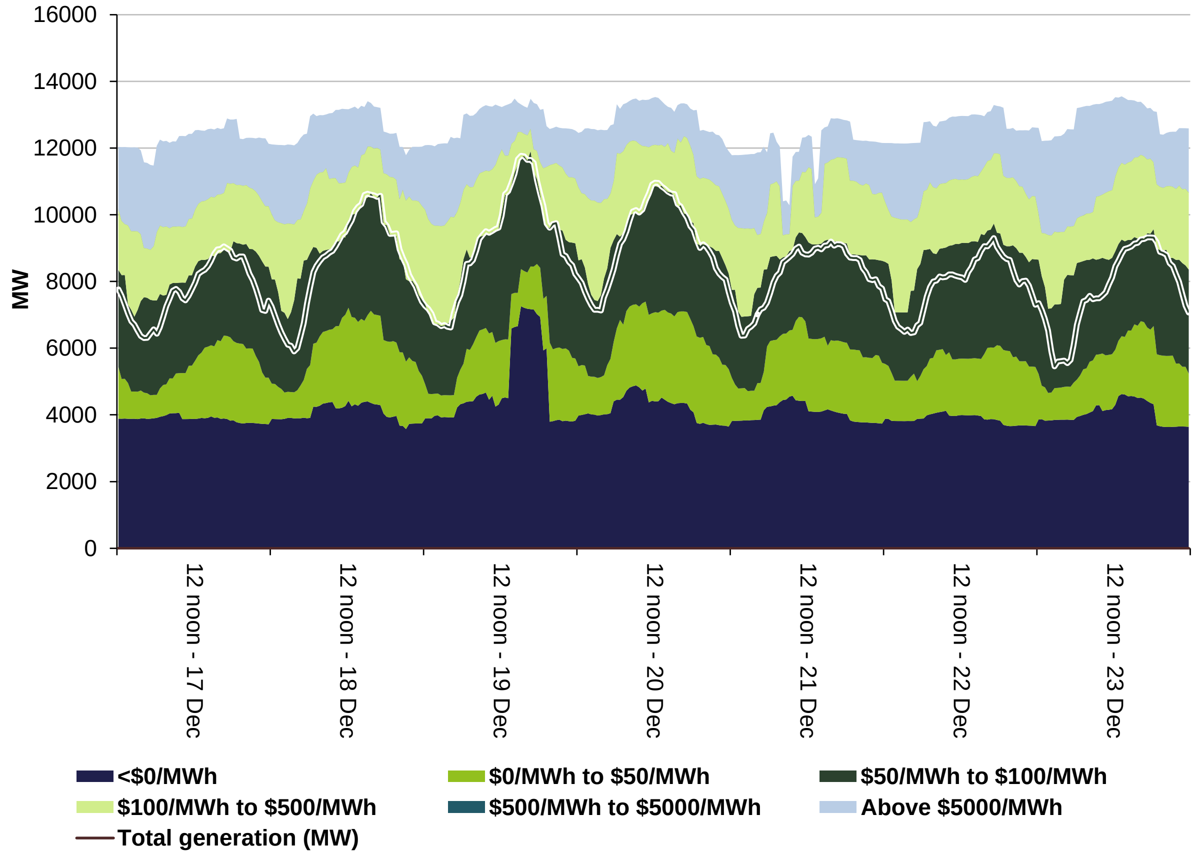


Figure 5: Victoria generation and bidding patterns

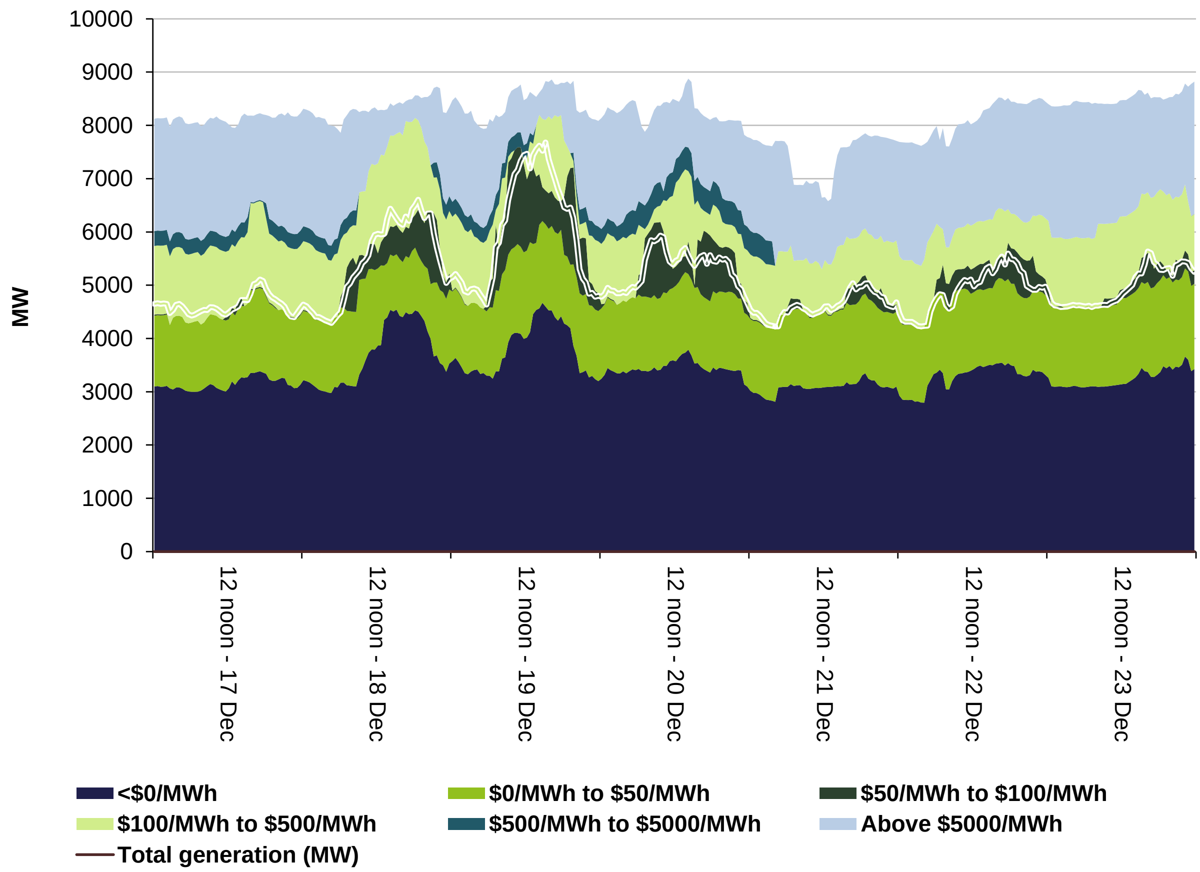


Figure 6: South Australia generation and bidding patterns

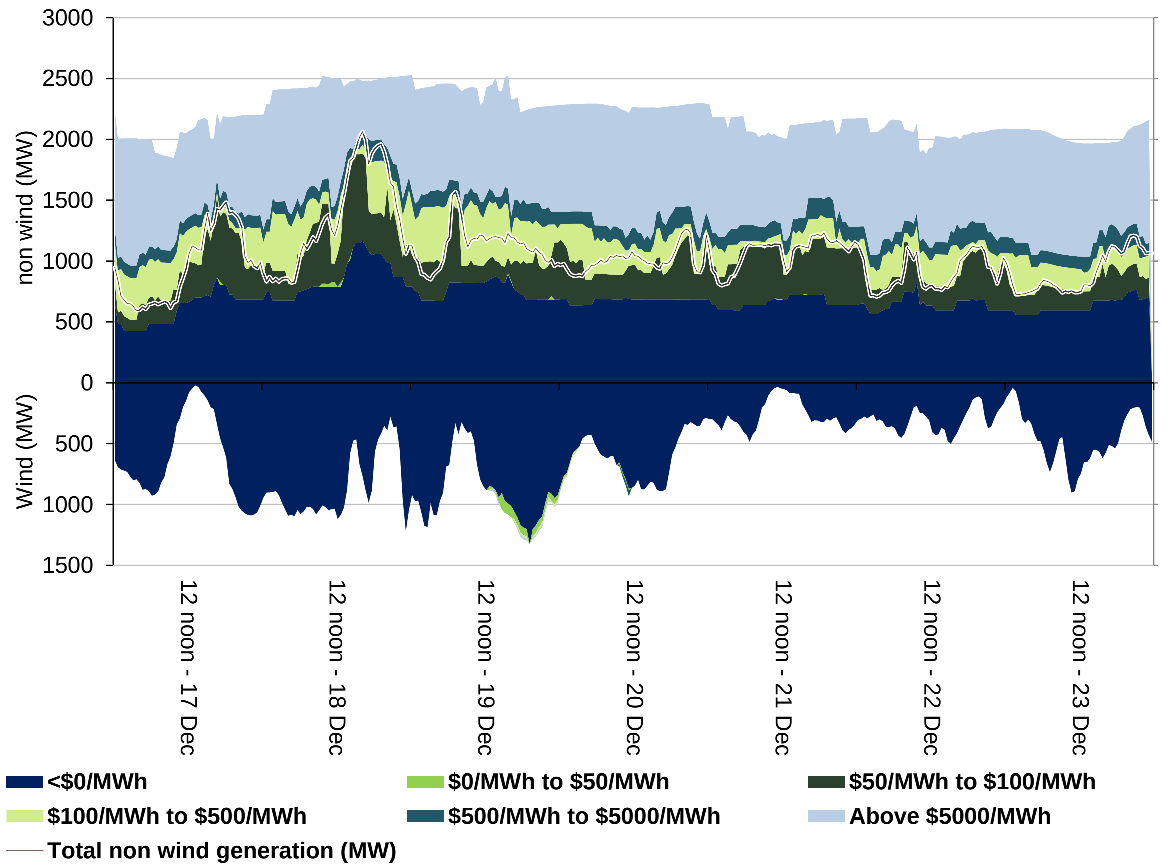
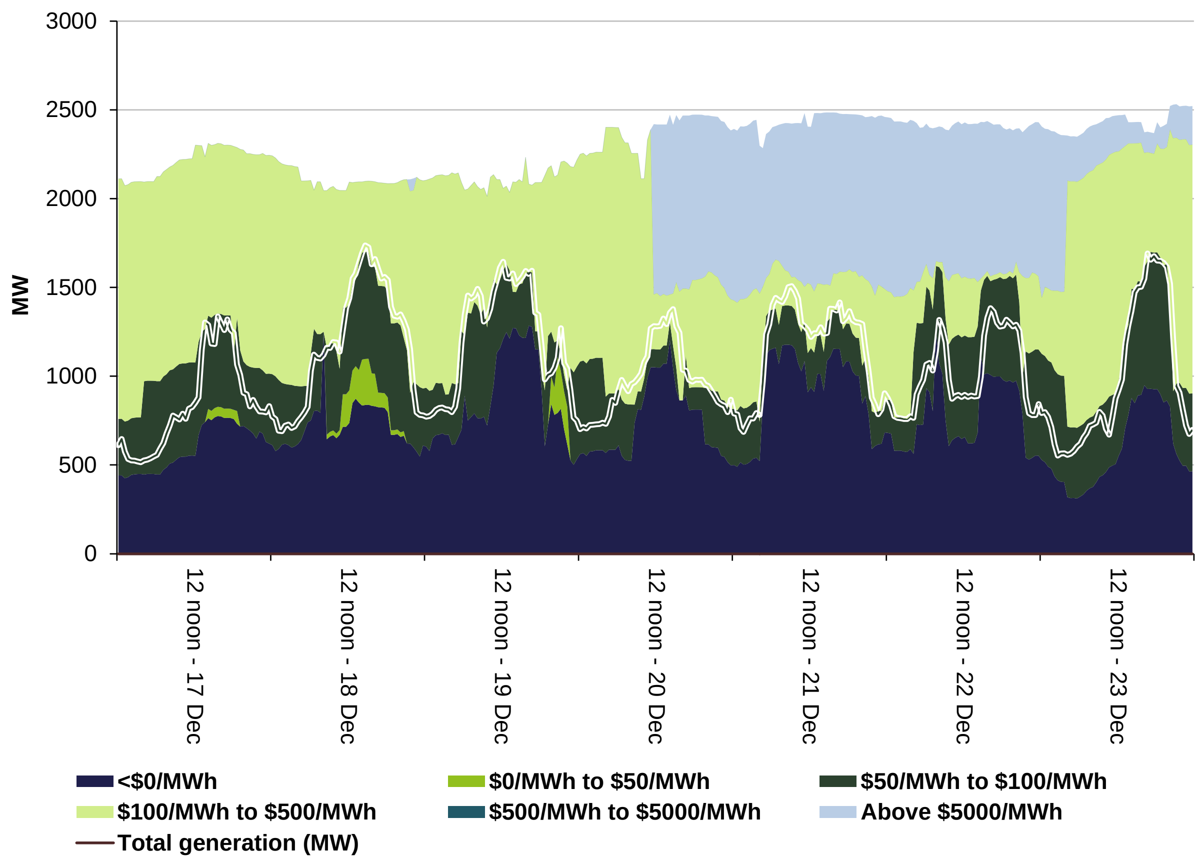


Figure 7: Tasmania generation and bidding patterns



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.

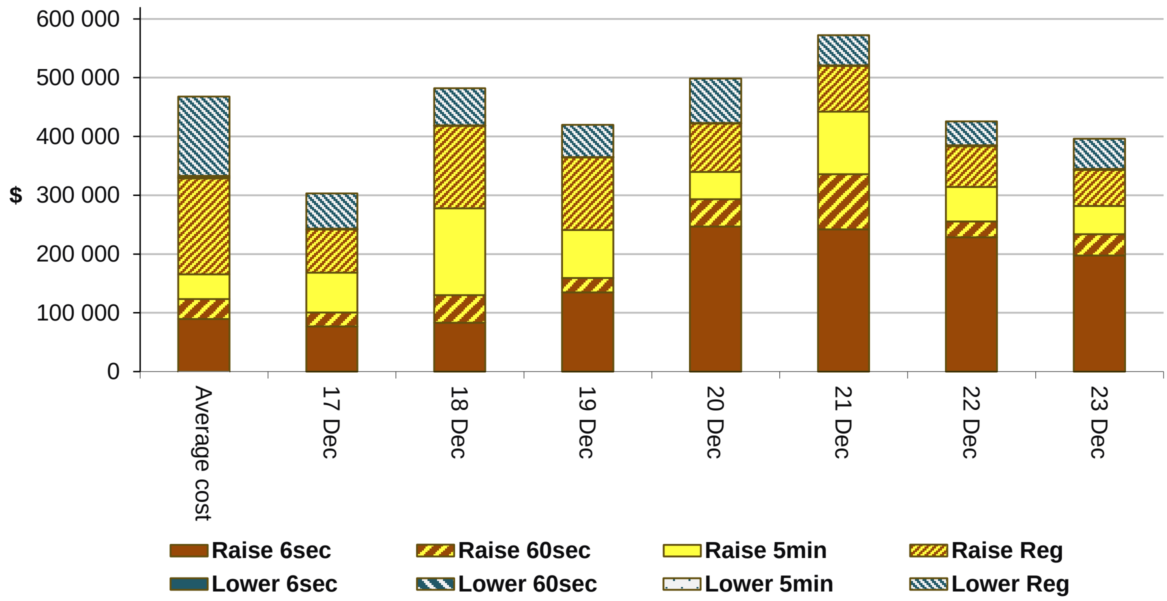
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 789 000 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 308 500 or around seven 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 was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $78/MWh and above $250/MWh.

Thursday, 21 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
5 pm	729.15	95.09	103.73	8210	8279	8211	10 208	10 871	10 932

Conditions at the time saw demand close to forecast and availability was around 660 MW lower than forecast four hours ahead.

The decrease in availability in the four hours leading up to the start of the trading interval was mainly due to a reduction in capacity at Callide C, Gladstone and Tarong power stations. The capacity removed was all priced below $160/MWh, as shown in Table 4 below:

Table 4: Rebidding

Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.10 pm	Callide Power Trading	Callide C	-156	<16	N/A	1308P unit 3 scc stopped large clinker in scc tub.
3.41 pm	CS Energy	Gladstone	-100	<104	N/A	1541P condenser backflush-sl
4.24 pm	Stanwell Corporation	Tarong	-475	<148	N/A	1623P tps transformer oos: manage emissions sl

At 4.55 pm a constraint bound on QNI, setting the import limit to zero, which decreased imports by around 200 MW. With Terranora importing at its limit and cheaper priced generation ramp up constrained higher priced generation was required and the price increased to $3500/MWh.

New South Wales

There were three occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $87/MWh and above $250/MWh.

Monday, 18 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
2 pm	282.46	286.68	299.80	11 300	11 256	11 268	13 160	13 132	13 135
2:30 pm	268.42	299.80	299.80	11 280	11 438	11 444	13 210	13 104	13 124

Prices were close to forecast four hours ahead.

Tuesday, 19 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
3.30 pm	279.57	315.67	307.34	12 949	12 731	13 335	13 291	13 232	13 294

The spot price was close to forecast four hours ahead.

Victoria

There were three occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $92/MWh and above $250/MWh.

Monday, 18 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
2 pm	290.00	110.21	316.92	7010	6855	7892	8304	8204	8072
2.30 pm	283.73	290.00	319.56	7216	6998	8013	8379	8247	8130

Conditions at the time saw demand between 150 MW and 220 MW higher than forecast and availability between 100 MW and 132 MW higher than forecast four hours ahead.

For the 2 pm trading interval, South Australia and Victoria prices were aligned and acting as one region. There was a significant drop in the four hour price forecast compared to the twelve hour forecast in both regions because the demand forecast dropped by over 1000 MW in Victoria.

The actual price was higher than forecast because Victorian participants rebid around 1500 MW of capacity from prices less than $110/MWh to $290/MWh and above. Snowy Hydro rebid around 1300 MW of this capacity at Murray from prices below $180/MWh to $290/MWh and set price for the entire trading interval.

The 2.30 pm trading interval price was close to forecast.

Tuesday, 19 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
3.30 pm	290.00	199.83	290.00	8244	7756	8350	8822	8844	8889

Conditions at the time saw demand around 490 MW higher than forecast and availability was close to that forecast four hours ahead. There was a significant drop in the twelve hour to the four hour forecast price because the demand forecast dropped by around 600 MW.

In the four hours leading up to the start of the trading interval Snowy Hydro rebid around 800 MW of capacity at Murray from prices below $200/MWh to $290/MWh and above. This rebidding combined with the demand forecast error led to Murray setting price for the entire trading interval at $290/MWh.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $84/MWh and above $250/MWh.

Monday, 18 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 pm	267.07	113.96	321.99	2113	2430	2443	3326	3478	3427
2:30 pm	273.70	301.48	326.45	2111	2482	2492	3055	3420	3427

The higher than forecast price for the 2 pm trading interval is discussed in the Victorian section under Table 7 above.

The 2.30 pm trading interval price was close to forecast.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $103/MWh and above $250/MWh.

Friday 22 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
9.30 am	2100.23	86.46	86.46	1059	1106	1095	2388	2442	2447
9.30 pm	2479.15	119.70	86.46	1077	1103	1117	2374	2392	2487

Conditions at the time saw demand and availability between 20 MW and 50 MW lower than forecast four hours ahead.

For the 9.30 am trading interval, flow was being forced from Tasmania to Victoria by FCAS constraints which manage frequency on the network. At 9.05 am, local requirement for raise regulation and contingency services increased by around 150 MW. With cheap generation either trapped in FCAS or ramp rate limited and the FCAS and energy markets co-optimisation the dispatch price reached $12 169/MWh for one dispatch interval before returning to the forecast $86/MWh for the remainder of the trading interval.

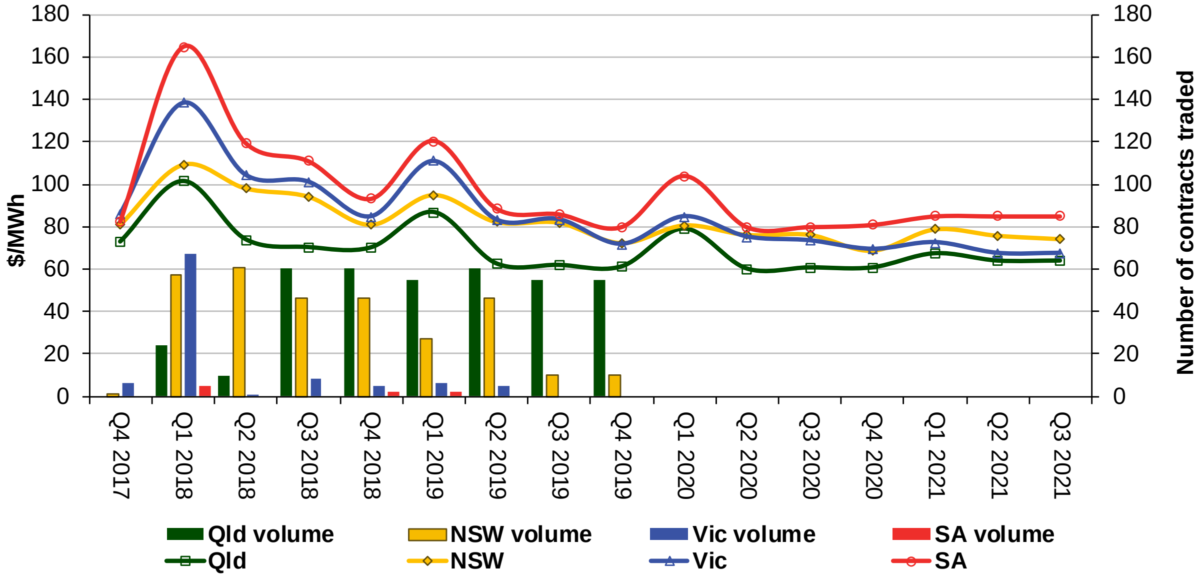
For the first dispatch interval of the 9.30 pm trading interval flow was again being forced from Tasmania to Victoria by FCAS constraints which manage frequency on the network. At 9.05 pm, local requirement for raise regulation and contingency services increased by around 60 MW. With cheap generation either trapped in FCAS or ramp rate limited and the

FCAS and energy markets co-optimisation the dispatch price reached $14 200/MWh for one dispatch 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.

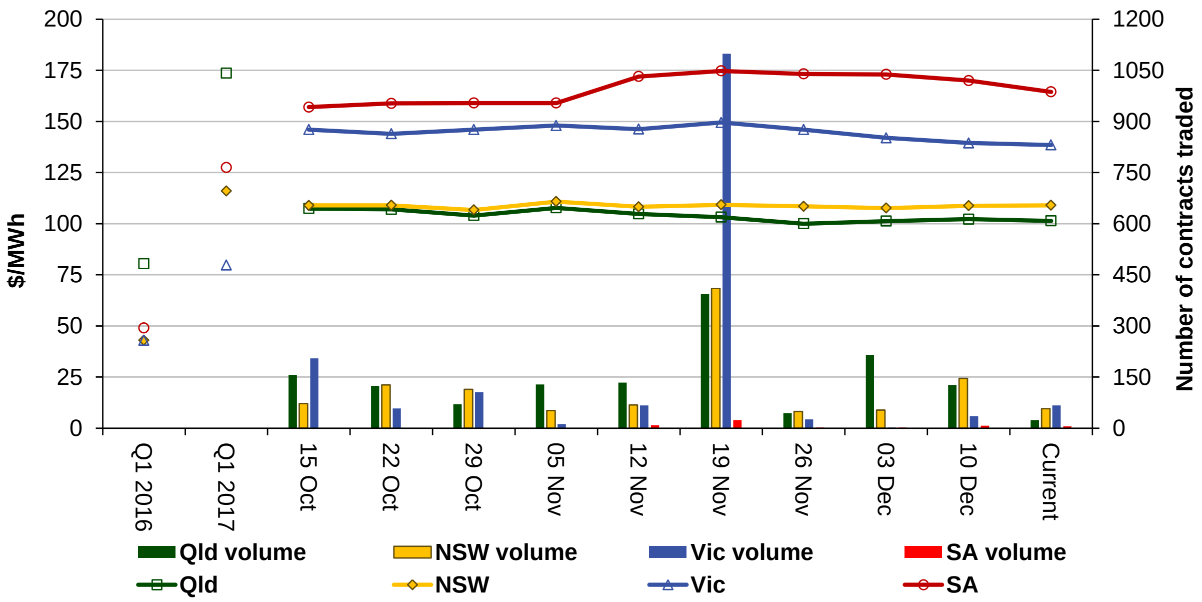
Figure 9: Quarterly base future prices Q4 2017 – Q3 2021



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2018 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 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 2018 base contracts over the past 10 weeks (and the past 2 years)



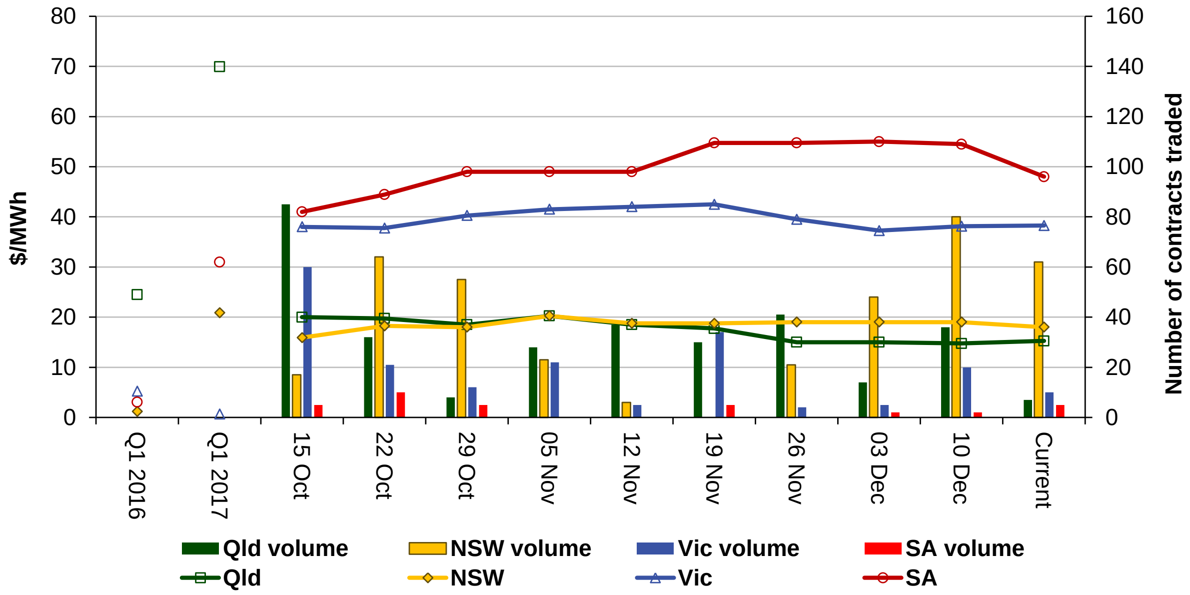
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2018 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 prices are also shown.

Figure 11: Price of Q1 2018 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
January 2018