Electricity Report

5 - 11 November 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 5 - 11 November 2017.

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

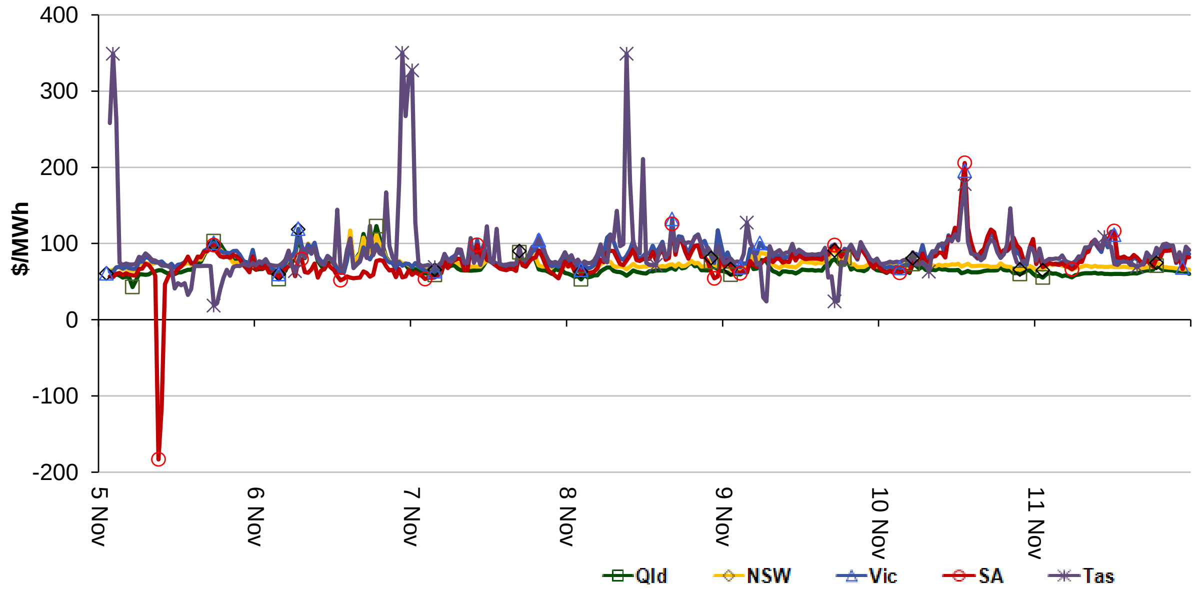


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

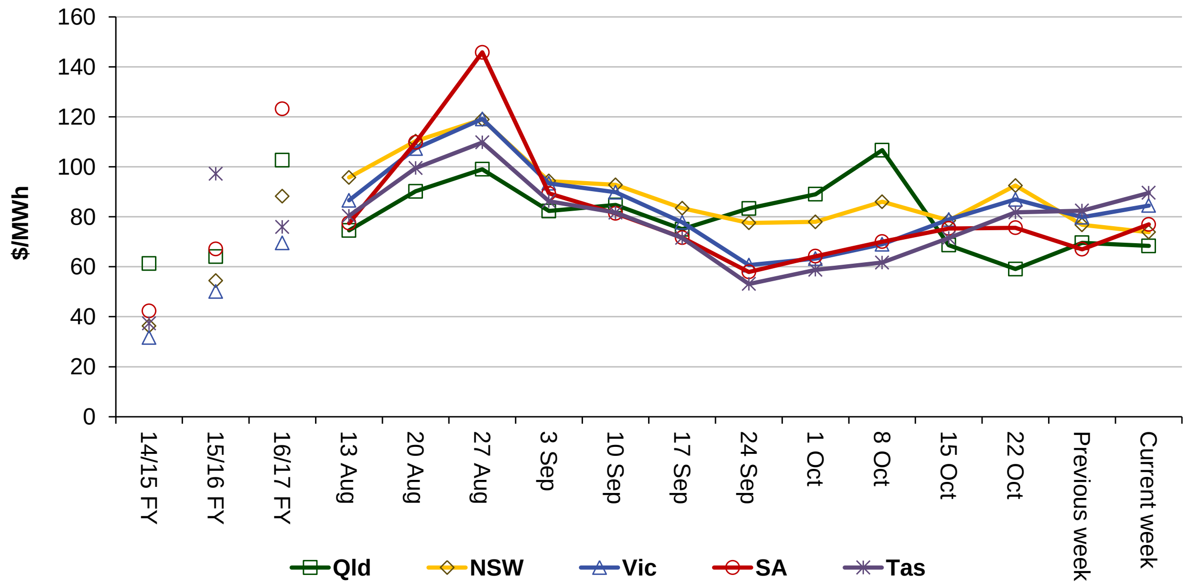


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	68	74	84	77	90
16-17 financial YTD	56	58	48	114	49
17-18 financial YTD	80	91	96	94	91

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 148 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	0	22	0	1
% of total below forecast	64	8	0	5

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

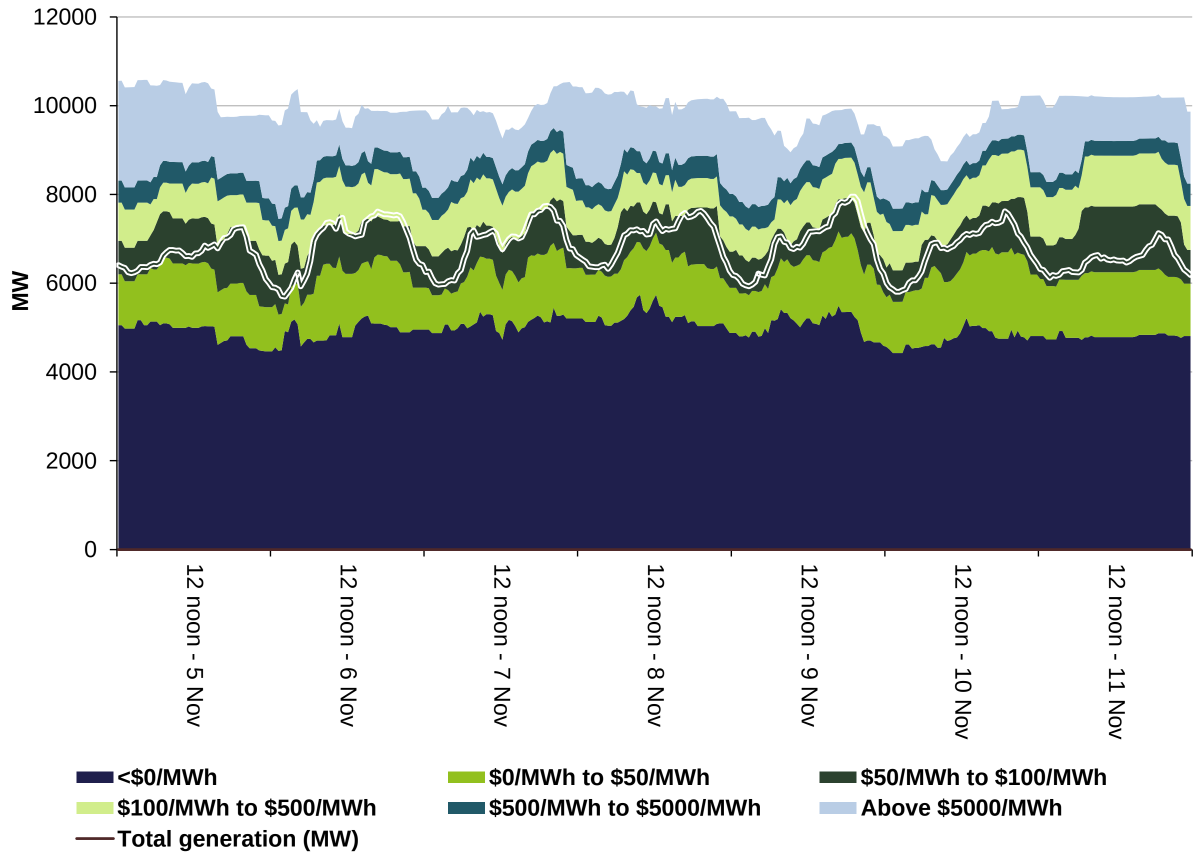


Figure 4: New South Wales generation and bidding patterns

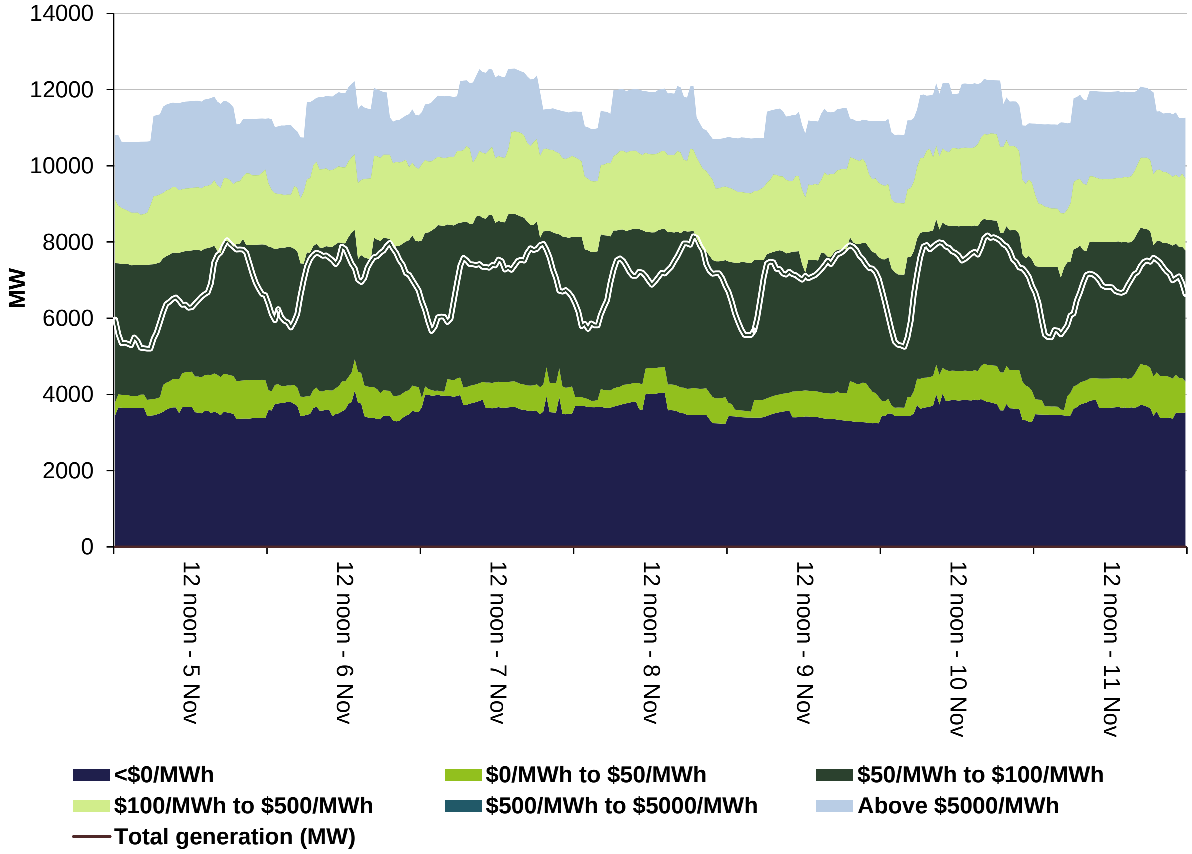


Figure 5: Victoria generation and bidding patterns

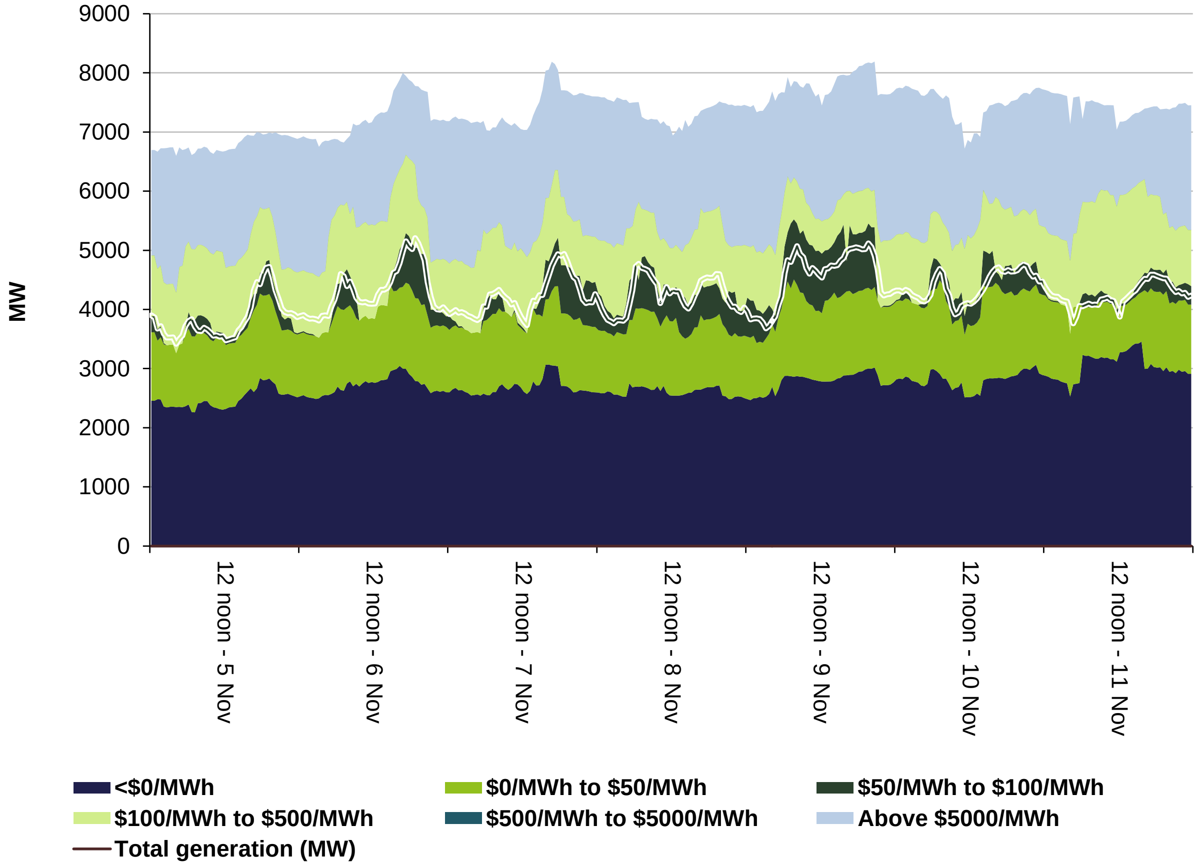


Figure 6: South Australia generation and bidding patterns

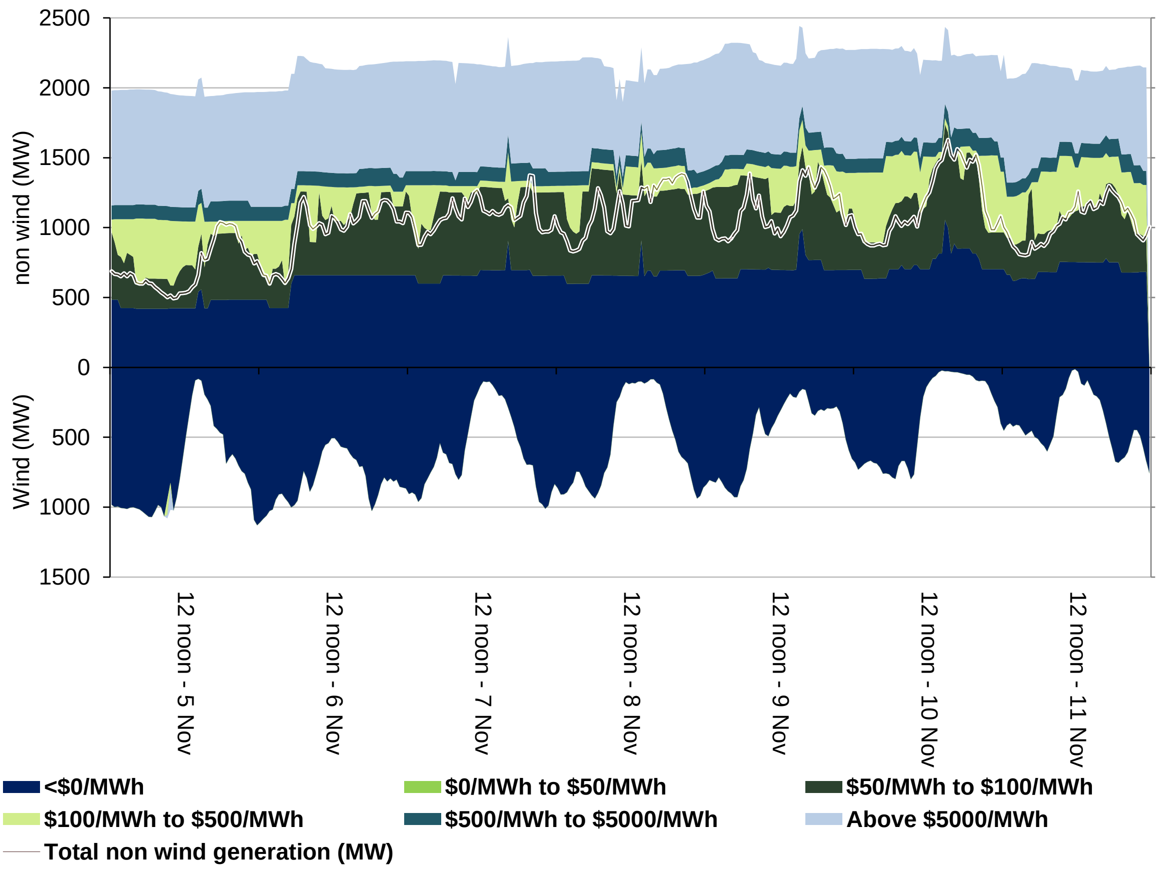
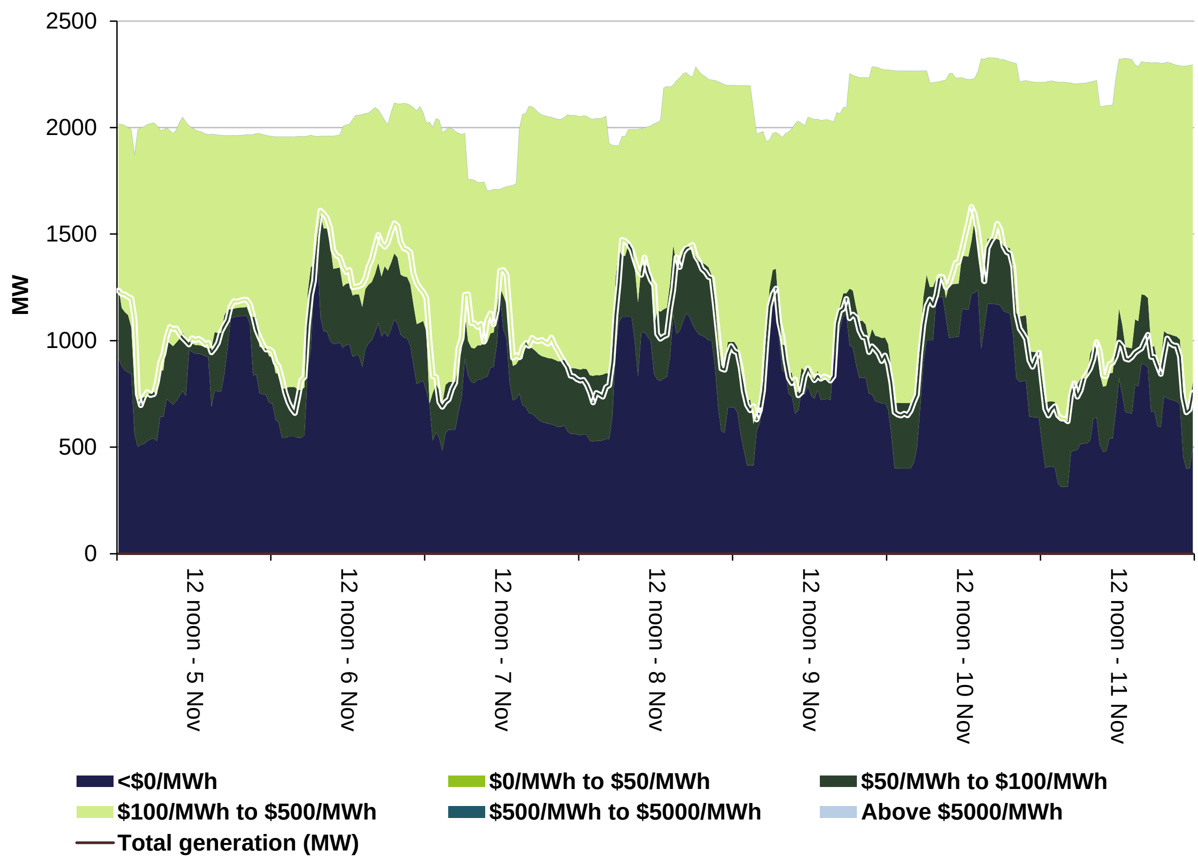


Figure 7: Tasmania generation and bidding patterns



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.

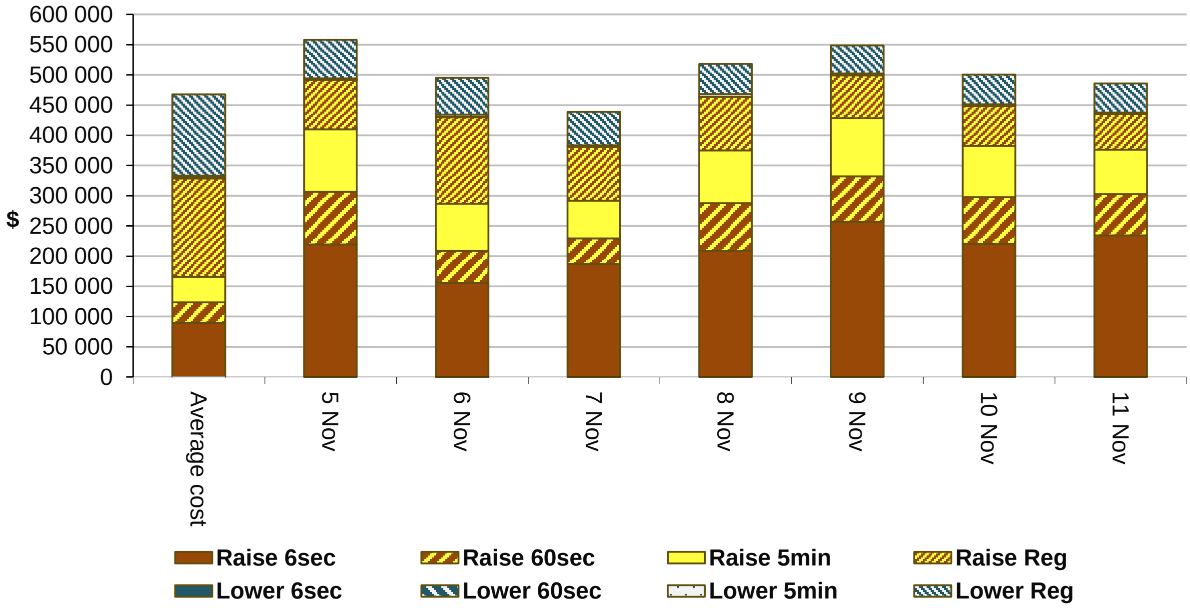
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 735 000 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $809 000 or around five 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

South Australia

There were two occasions where the spot price in South Australia was below -$100/MWh.

Sunday, 5 November

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
9:30 am	-183.30	58.57	60.53	801	749	756	3045	2797	2738
10 am	-113.63	58.15	59.70	770	697	717	2949	2756	2712

Conditions at the time saw demand between 50 – 70 MW higher than forecast and availability between 190 – 248 MW greater than forecast four hours ahead, this was because semi-scheduled wind generation was up to 230 MW greater than forecast. High wind generation for the morning meant any small decrease in demand or increase in wind generation could lead to negatively priced dispatch intervals.

For the 9.25 am dispatch interval, demand dropped by 25 MW and wind generation increased by 11 MW. With higher priced generation either trapped in FCAS or ramp down constrained, the price hit the floor for one dispatch interval and led to a negative spot price.

For the 9.40 am dispatch interval, wind generation increased by 154 MW, with higher priced generation ramp down constrained, the price hit the floor and led to a negative spot price.

Tasmania

There were five occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $90/MWh and above $250/MWh.

Sunday, 5 November

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 am	348.92	72.46	72.08	1053	1043	1040	1990	1987	1997

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

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

FCAS constraints forced exports from Tasmania into Victoria, around 190 MW greater than forecast four hours ahead.

In the four hours leading up to the start of the 2.30 am trading interval, over four rebids Hydro Tas shifted around 80 MW of capacity from around $70/MWh to $349/MWh, the reasons related to prices. As a result the dispatch price was set at $349/MWh for the whole trading interval.

Monday, 6 November

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
11 pm	350.21	69.86	70.16	1010	990	966	2078	2031	2060

Conditions at the time saw demand 20 MW higher and availability was around 50 MW higher than that forecast four hours ahead.

In the four hours leading up to the start of the 11 pm trading interval, over six rebids Hydro Tas shifted 44 MW of capacity from around $70/MWh and below to $349/MWh, the reasons related to lake levels and forecast prices.

System normal constraints also forced exports from Tasmania to Victoria across Basslink, around 50 MW higher than forecast four hours prior.

As a result, the price hovered around $350/MWh for the whole trading interval.

Tuesday, 7 November

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
Midnight	319.61	78.21	73.66	996	983	952	2071	2041	2053
12:30 am	326.95	78.36	76.08	977	984	950	2021	2037	2050

Conditions at the time saw demand and availability close to that forecast four hours ahead. FCAS constraints forced exports into Victoria and prevented cheaper generation in other regions setting price for both trading intervals.

For the midnight trading interval, in the four hours leading up to the start, over five rebids Hydro Tas shifted 63 MW of capacity from around $64/MWh and below to $349/MWh, the reasons related to lake levels and forecast prices. As a result, the price hovered around $350/MWh for the first four dispatch intervals. Demand dropped for the last two dispatch intervals so the price fell to around $260/MWh.

Similarly, for the 12.30 am trading interval, in the four hours leading up to the start, over six rebids Hydro Tas shifted 23 MW of capacity from around $64/MWh and below to $349/MWh, the reasons again related to lake levels and forecast prices. The dispatch price hovered between $282/MWh and $349/MWh for the trading interval.

Wednesday, 8 November

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	349.03	98.49	89.50	1170	1178	1158	1992	1953	1954

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

In the four hours leading up to the start of the 9.30 am trading interval, over four rebids Hydro Tas shifted around 230 MW of capacity from around -$1/MWh and below to $349/MWh, the reasons related to price.

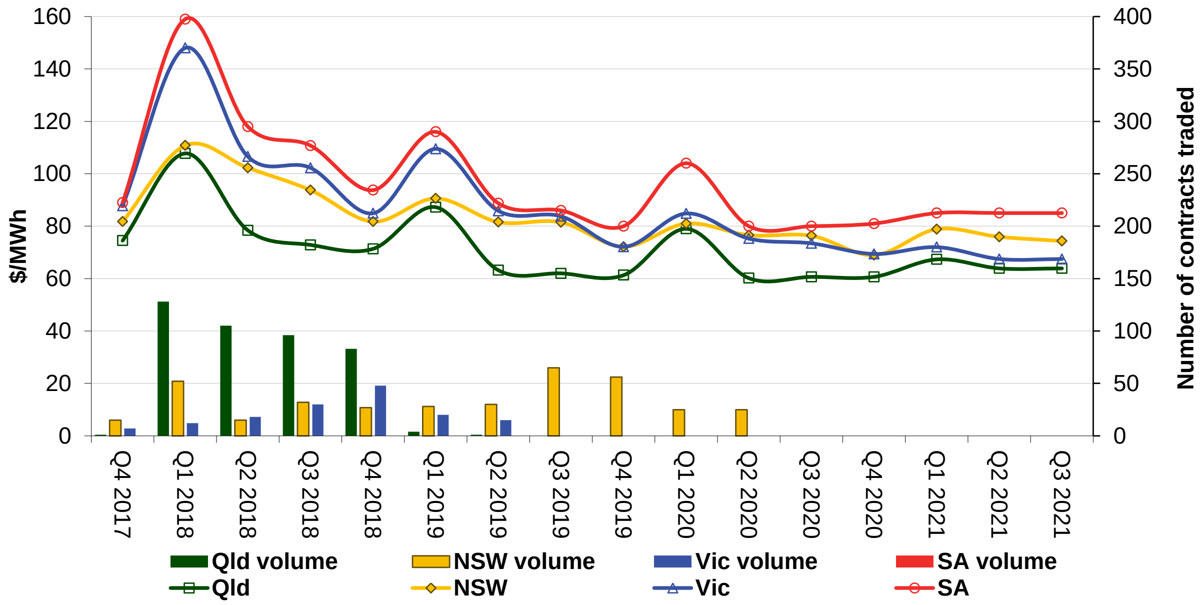
System normal constraints also forced exports from Tasmania to Victoria across Basslink, around 120 MW higher than forecast four hours prior which prevented cheaper generation in other regions setting price.

As a result, the price hovered around $349/MWh for the whole trading 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.

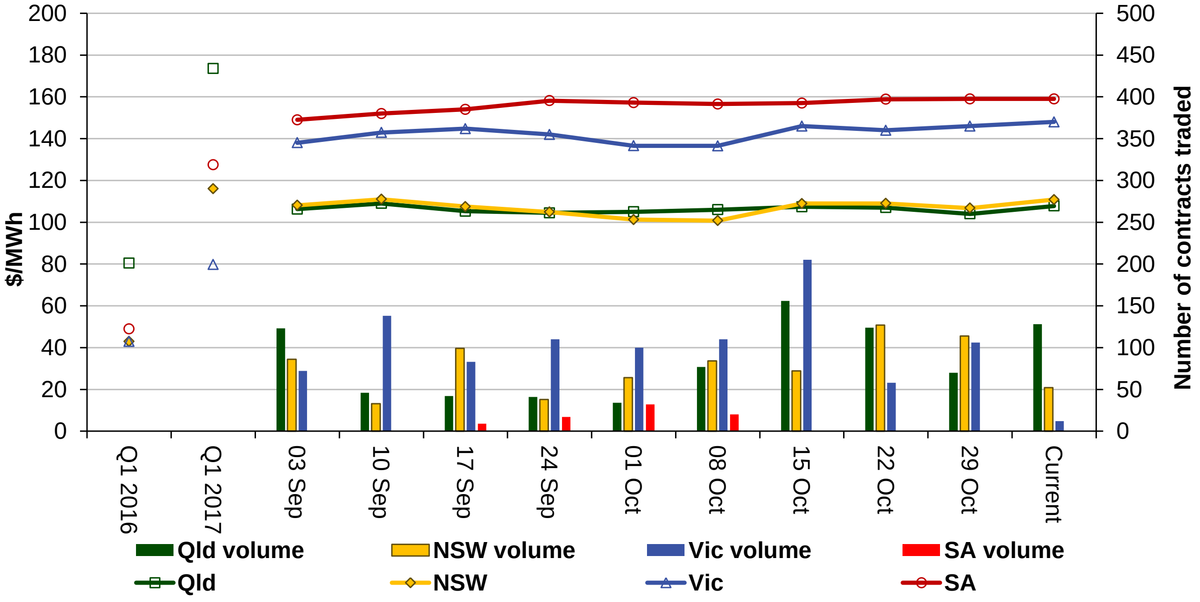
Figure 9: Quarterly base future prices Q4 2017 – Q3 2021



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)



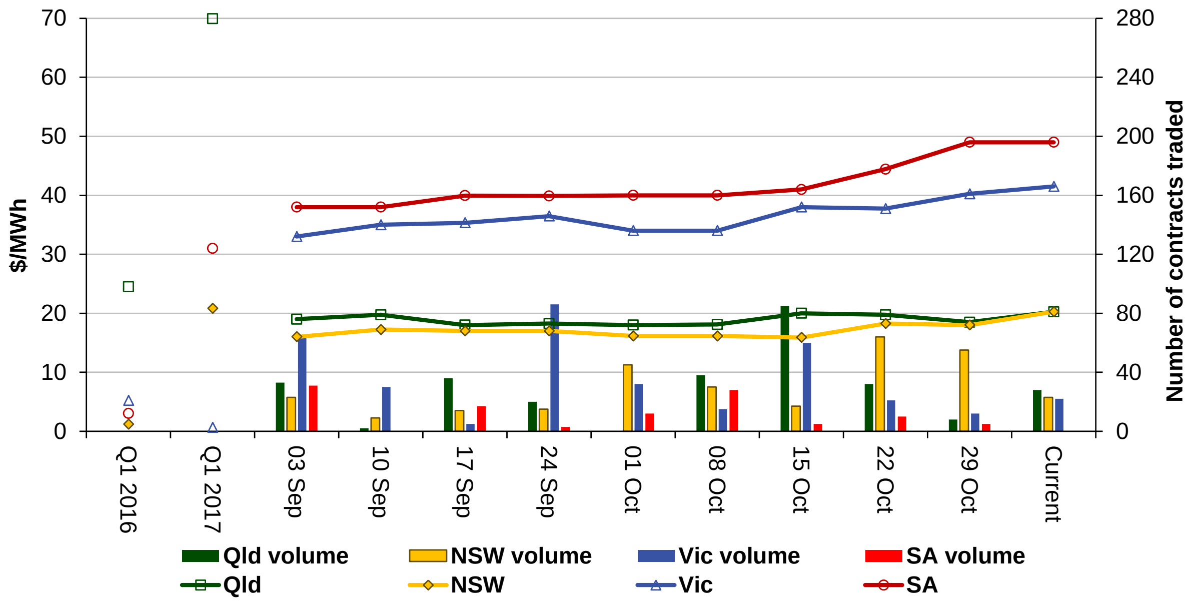
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
November 2017