Electricity Report

AUSTRALIAN ENERGY REGULATOR

4 – 10 November 2018

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 November 2018.

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

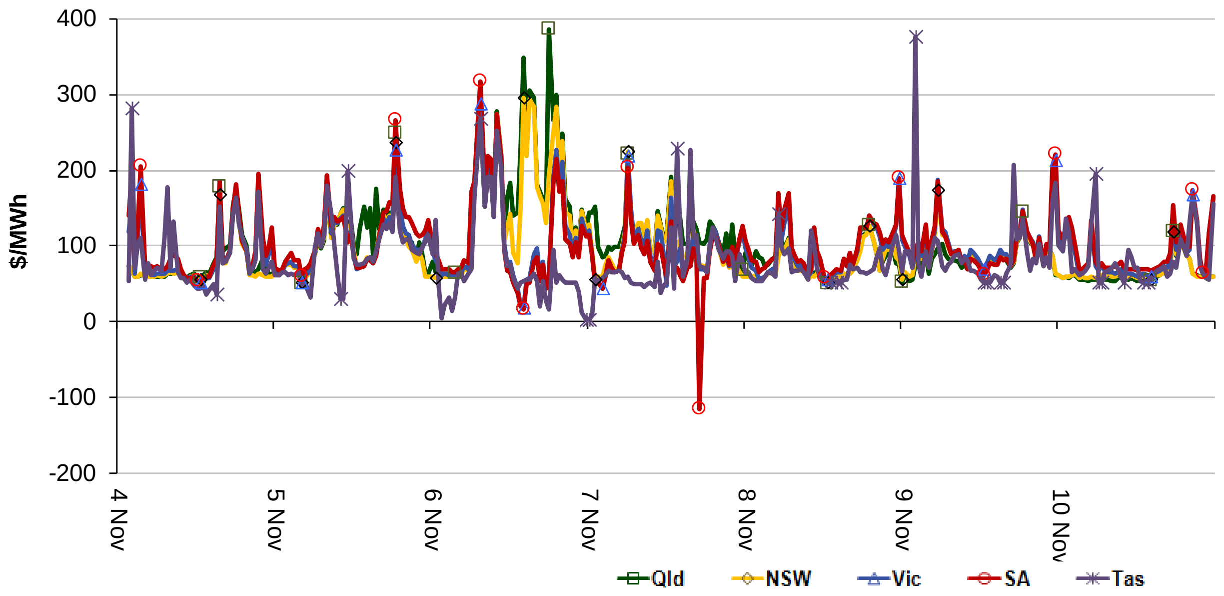


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years..

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

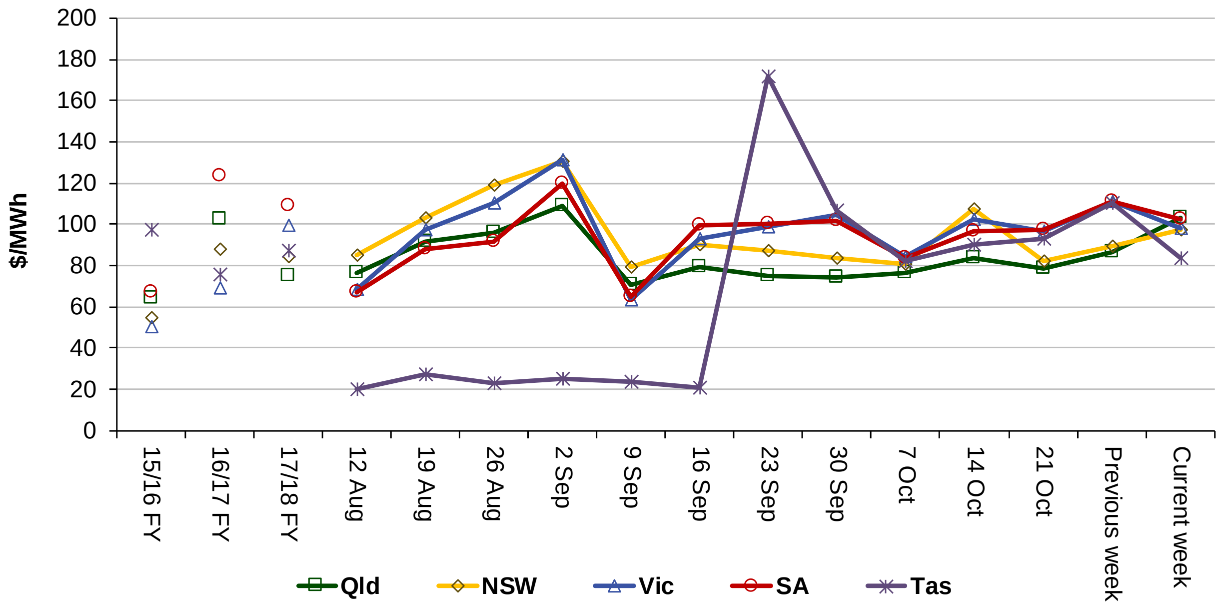


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	103	97	98	103	84
17-18 financial YTD	80	91	96	94	91
18-19 financial YTD	81	90	89	96	57

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 250 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. 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	9	26	0	1
% of total below forecast	10	46	0	8

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

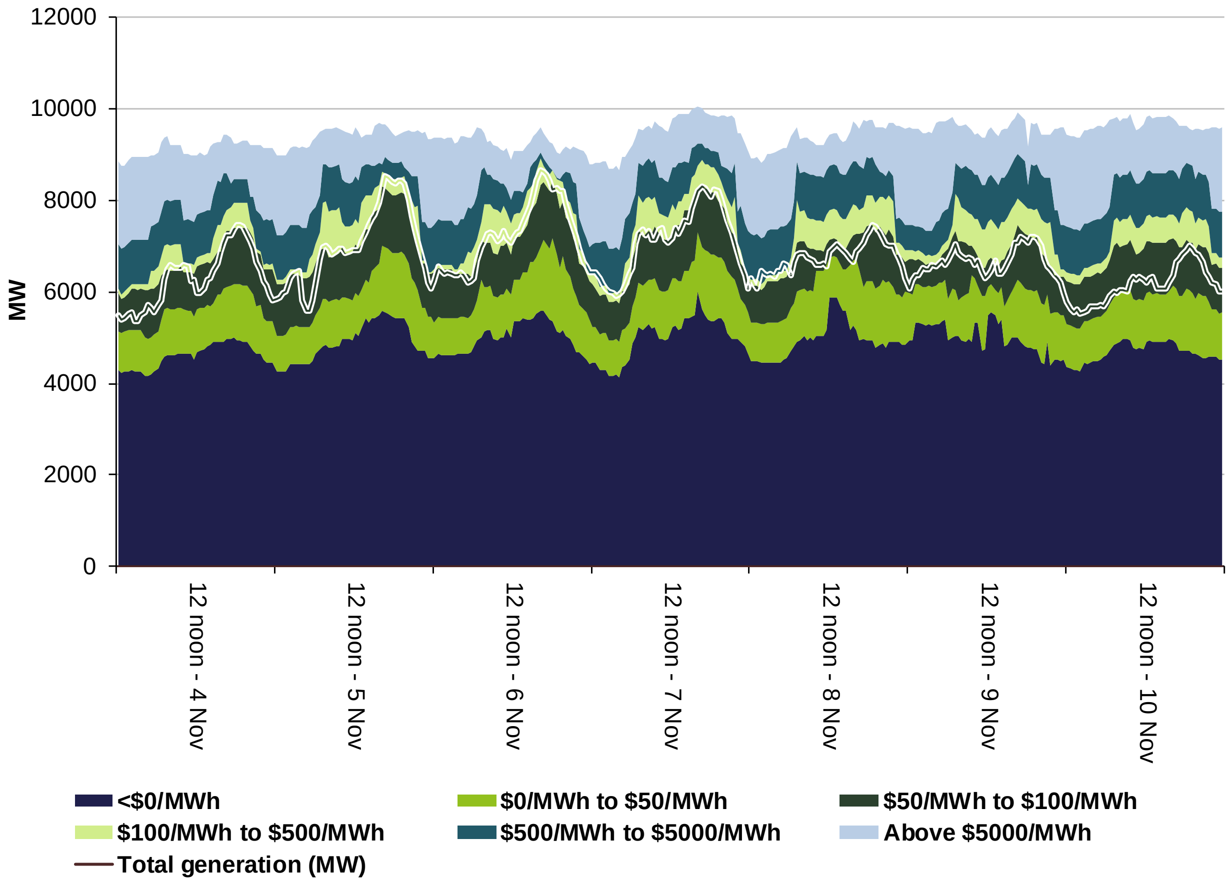


Figure 4: New South Wales generation and bidding patterns

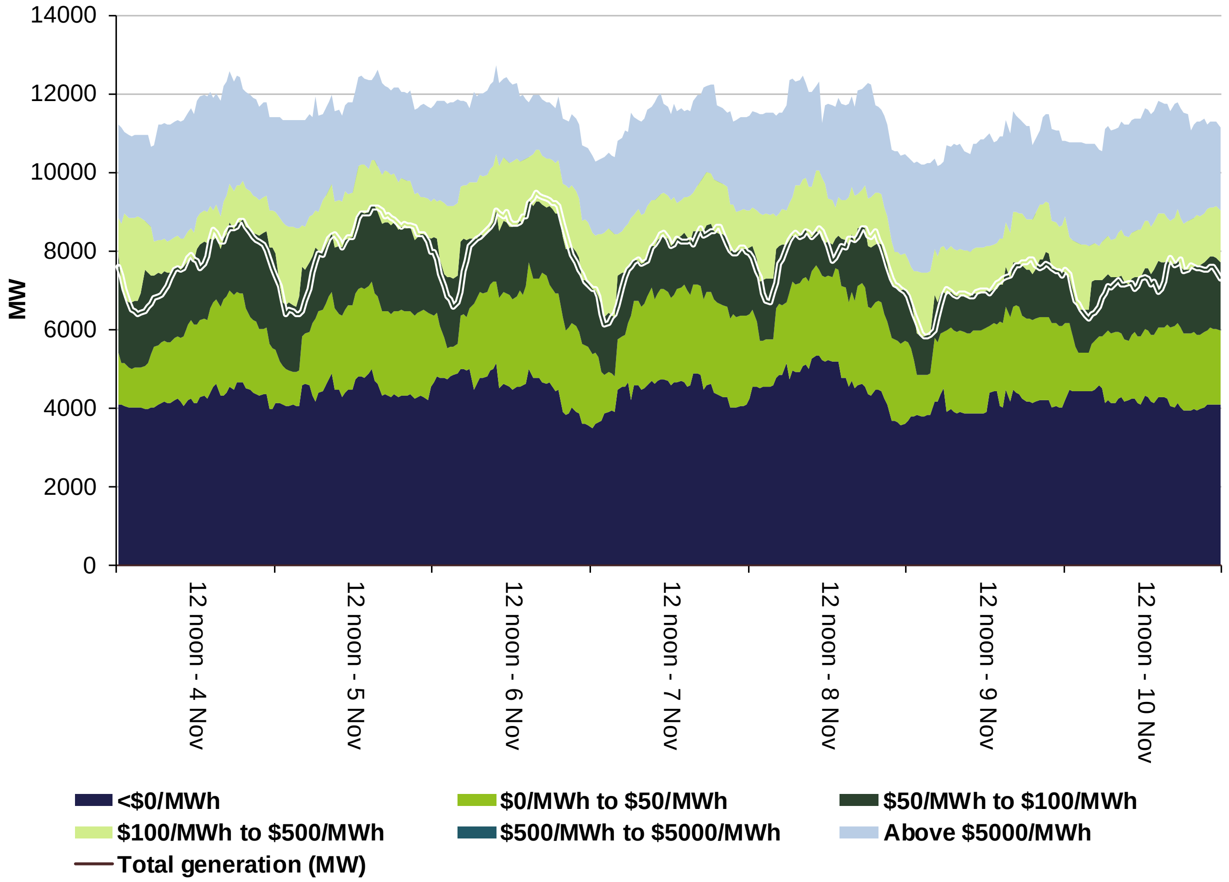


Figure 5: Victoria generation and bidding patterns

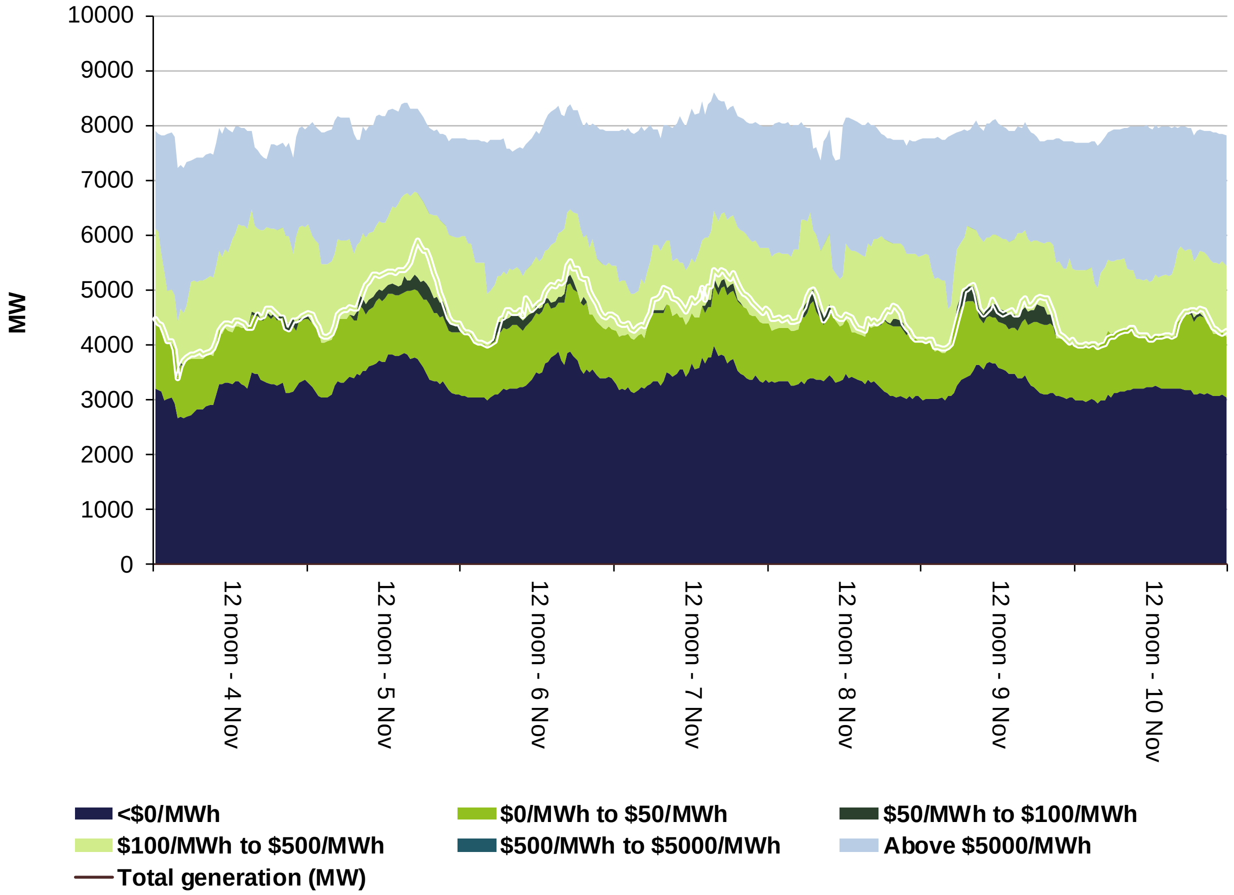


Figure 6: South Australia generation and bidding patterns

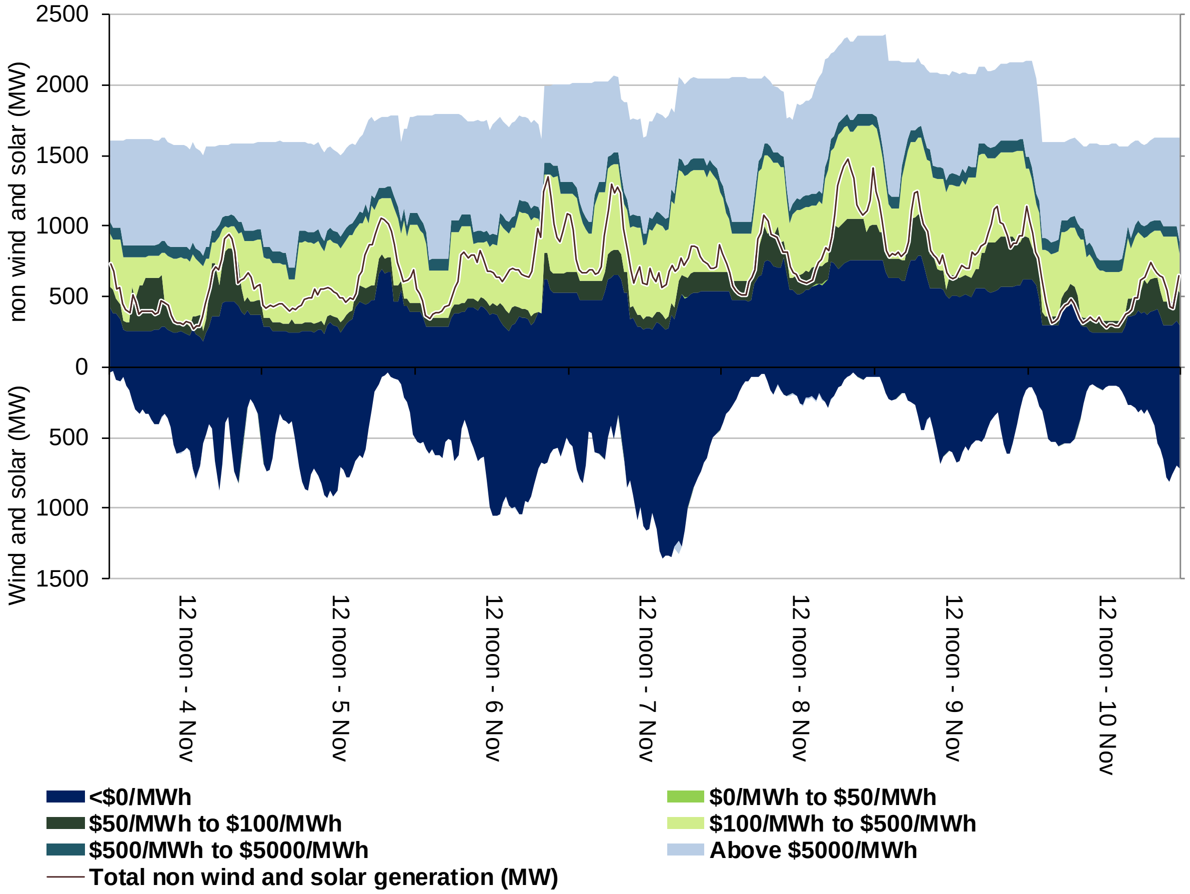
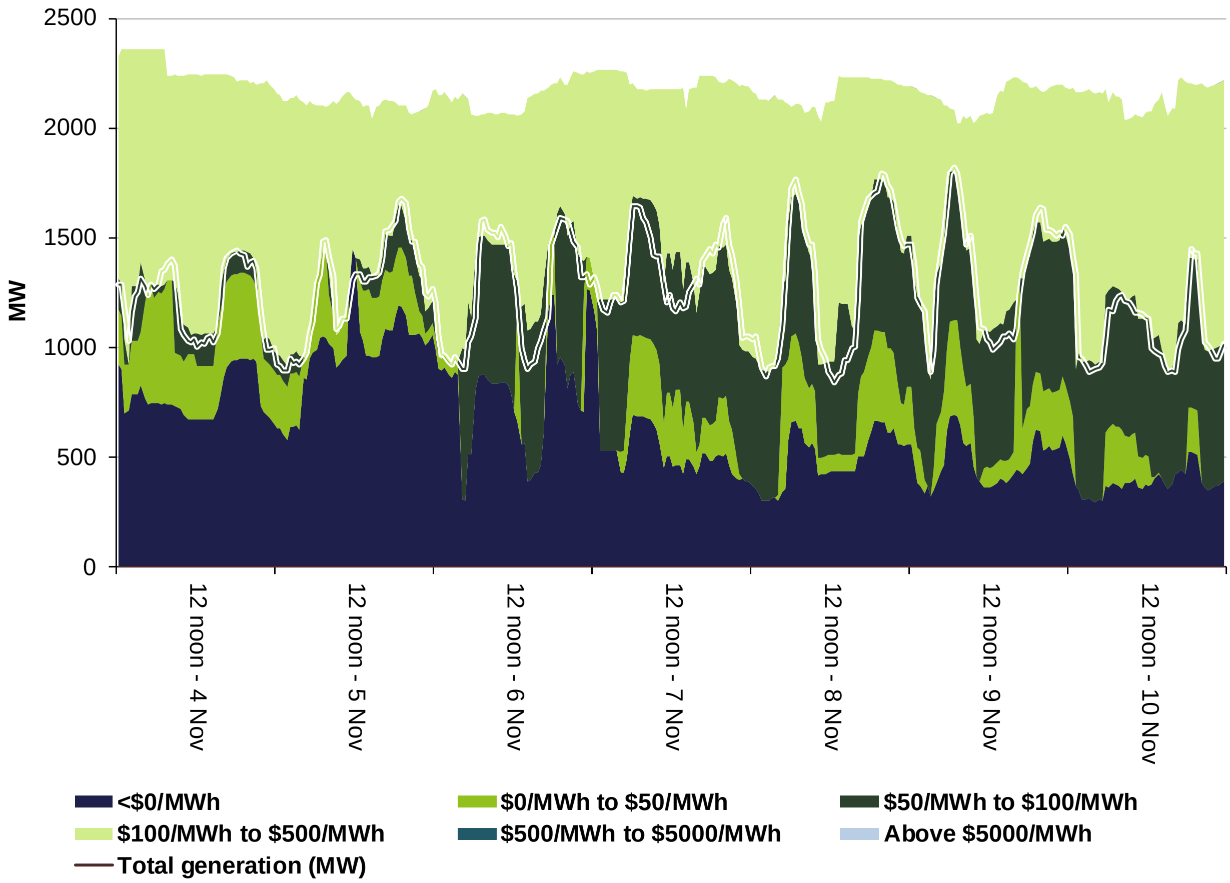


Figure 7: Tasmania generation and bidding patterns



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.

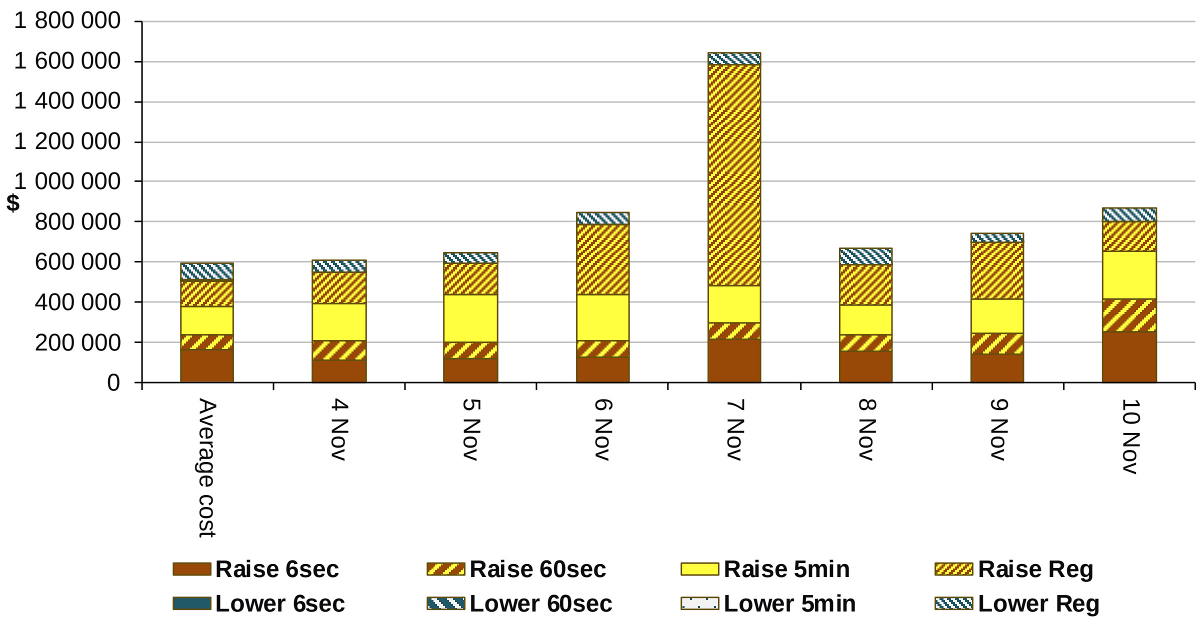
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $5 205 000 or around two per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $830 500 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



At 2 pm on 7 November a constraint which manages raise regulation requirements violated due to an increase in the global requirement. The price, which was co-optimised with energy and other FCAS markets, reached the cap for one dispatch interval and was the main cause for the higher than average costs on the day.

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 $103/MWh and above $250/MWh.

Thursday, 6 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
2.30 pm	349.57	301.00	300.78	7828	7933	8072	9170	9316	9722
6.30 pm	386.80	199.99	390.73	8299	8351	8573	9159	9299	9553

The 2.30 pm price was aligned with New South Wales and will be discussed as one region.

Demand for both regions was around 550 MW lower than forecast and availability was around 1000 MW lower than forecast, four hours prior.

The reduction in availability in Queensland can mainly be attributed to CS Energy removing 260 MW of capacity priced less than $65/MWh at its Gladstone power station due to a unit trip.

In New South Wales, Delta removed 600 MW of capacity priced at the floor at its Vales Point power station due to a unit trip. Furthermore, over a number of rebids from 11.40 am to 2.15 pm AGL removed 150 MW of capacity priced less than $60/MWh from its Bayswater plant due to plant issues.

The reduction of low priced capacity across both regions resulted in dispatch prices increase from $291/MWh to $388/MWh in Queensland and $127/MWh to $368/MWh in New South Wales.

For the 6.30 pm trading interval demand was around 50 MW lower than forecast while availability was 140 MW lower than forecast, four hours prior.

At 6.20 pm demand increased by 44 MW, imports from New South Wales increased by 191 MW and a number of units in Queensland became trapped or stranded in FCAS. With cheaper priced generation ramp rate limited and unable to set price, the dispatch price increased to $1409/MWh and caused the higher than forecast price.

New South Wales

There were two occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $97/MWh and above $250/MWh.

Thursday, 6 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 pm	296.24	83.16	150.00	9475	9922	10 386	11 914	12 787	12 862

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	292.83	437.29	299.60	9946	10 534	10 851	11 842	12 234	12 927

The 2.30 pm price was aligned with Queensland and is discussed under Table 3 above.

For the 3.30 pm trading interval demand was around 590 MW lower than forecast and availability was around 390 MW lower than forecast, four hours prior.

In the four hours leading up to the start of the trading interval Origin Energy rebid around 310 MW of capacity from the cap and added in an additional 33 MW to prices less than $100/MWh at its Uranquinty power station. The rebid reasons related to constraint management, plant conditions and a change in forecasts. This increase in low priced generation was offset by the removal of 430 MW of cheaply priced generation at Mt Piper and Bayswater power stations due to plant issues.

The lower than forecast demand meant the price for the first two dispatch intervals was around $360/MWh. At 3.06 pm, effective from 3.15 pm, Origin rebid 80 MW from the cap to the floor at Shoalhaven power station. The rebid reason related to demand forecasts. This led to the dispatch price fall to around $290/MWh for the 3.15 pm to 3.25 pm dispatch intervals.

The dispatch price then fell to $172/MWh for the last dispatch interval as Snowy Hydro rebid 600 MW from $300/MWh to $150/MWh at its Tumut station. The rebid reason related to price forecasts. These rebids and the lower than forecast demand led to the lower than forecast spot price for the trading interval.

South Australia

There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of $103/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Tuesday, 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
8 am	316.78	96.29	185.00	1368	1419	1423	2140	2434	2187

Demand was around 50 MW lower than forecast and availability was around 290 MW lower than forecast, four hours prior.

Wind generation was 241 MW lower than forecast which meant higher priced capacity required to meet demand. This led to dispatch prices at around $320/MWh for the entire trading interval.

Wednesday, 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
5.30 pm	-116.72	85.80	58.41	1200	1241	1193	3382	3153	3127

Demand was close to forecast while availability was around 230 MW higher than forecast, four hours prior.

The higher than forecast availability is mainly attributed to the higher than forecast wind generation.

There was no capacity priced between $85/MWh and -$900/MWh. At 5.20 pm wind generation increased by 40 MW which caused the price to decrease to the floor for one dispatch interval and resulting in the negatively priced trading interval.

Tasmania

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

Sunday, 4 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
2.30 am	281.30	94.97	64.45	1021	1005	997	2359	2340	2340

Demand and availability were both close to that forecast four hours prior.

From 1 am to 1.40 am, Hydro Tasmania rebid 164 MW of capacity priced less than $100/MWh to $290/MWh at its Gordon and Poatina stations. The rebid reasons related to FCAS availability. These rebids set the prices for the first two dispatch intervals around $290/MWh.

At 2.20 am a constraint managing the planned outage on the Hadspen to Palmerston line bound. The constraint limits the output from a number of generators in Tasmania. At the same time FCAS constraints forced exports across Basslink into Victoria. With a number of generators limited by the constraint mentioned above, or ramp up constrained and unable to set price, the dispatch price increased to $422/MWh.

The dispatch price then decreased to around $290/MWh for the remainder of the trading interval as the constraint continued to force exports from Tasmania into Victoria.

Tuesday, 6 November

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
8 am	268.66	81.11	155.06	1297	1259	1272	2062	2093	2078

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
10.30 am	251.82	127.81	181.73	1230	1151	1163	2068	2078	2080

Conditions for the 8 am trading interval saw demand around 40 MW higher than forecast while availability was around 30 MW lower than forecast, four hours prior.

A number of times within the trading interval cheaper priced generation was either trapped or stranded in FCAS and unable to set price. This combined with the higher than forecast demand and lower than forecast availability meant the dispatch price remained around $270/MWh for the entire trading interval.

For the 10.30 am trading interval, demand around 80 MW higher than forecast while availability was close to that forecast four hours ahead.

For the majority of the trading interval a number of generators' output in the region was constrained due to a constraint managing the planned outage on the Hadspen to Palmerston 220 kV line binding. With other cheaper priced generation trapped or stranded in FCAS the dispatch price remained between $156/MWh to $275/MWh for the entire trading interval.

Friday, 9 November

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 am	377.04	77.55	84.19	1056	1056	1057	2160	2156	2135

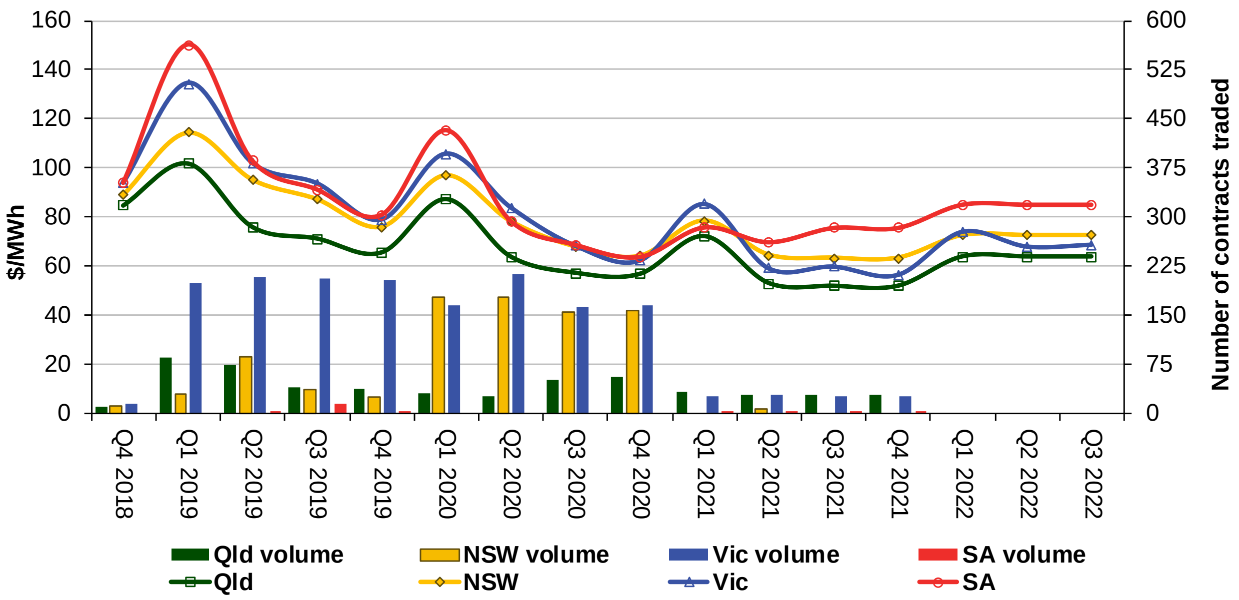
Demand and availability were both close to that forecast four hours prior.

For 2.05 am to 2.25 am there were local requirements for raise 6 second, raise 5 minute and raise regulation services. Cheaper priced generation was trapped in FCAS and unable to set price. As a result the dispatch prices were set at around $420/MWh during this time and led to the higher than forecast spot price.

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.

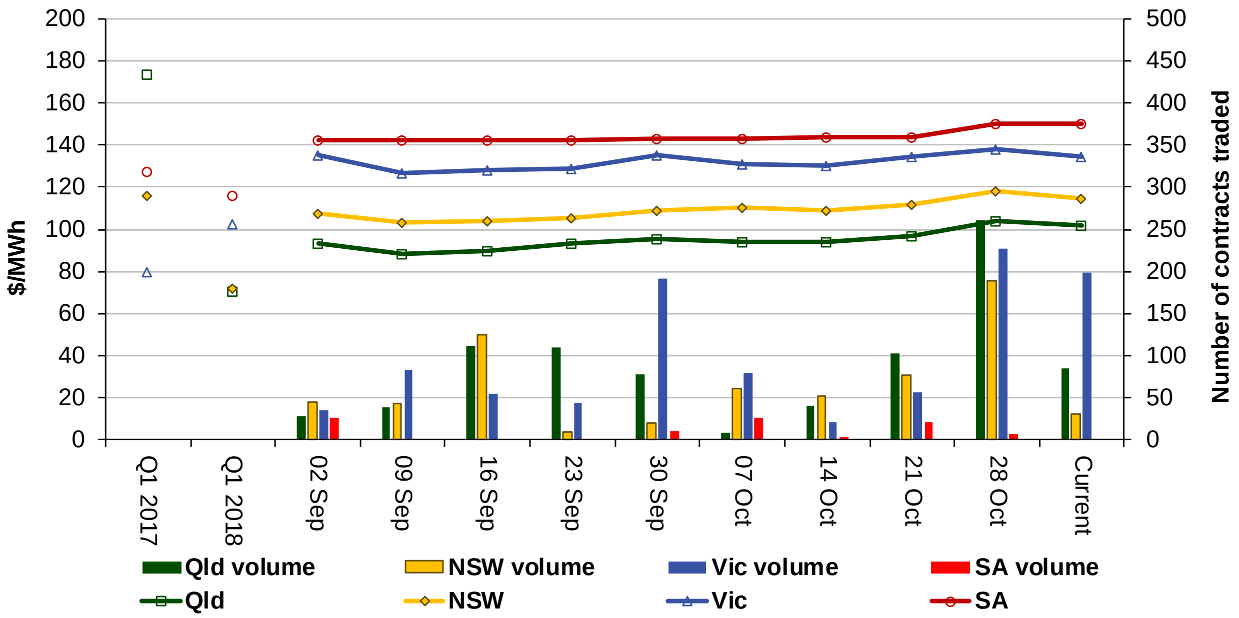
Figure 9: Quarterly base future prices Q4 2018 – Q3 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 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 2019 base contracts over the past 10 weeks (and the past 2 years)



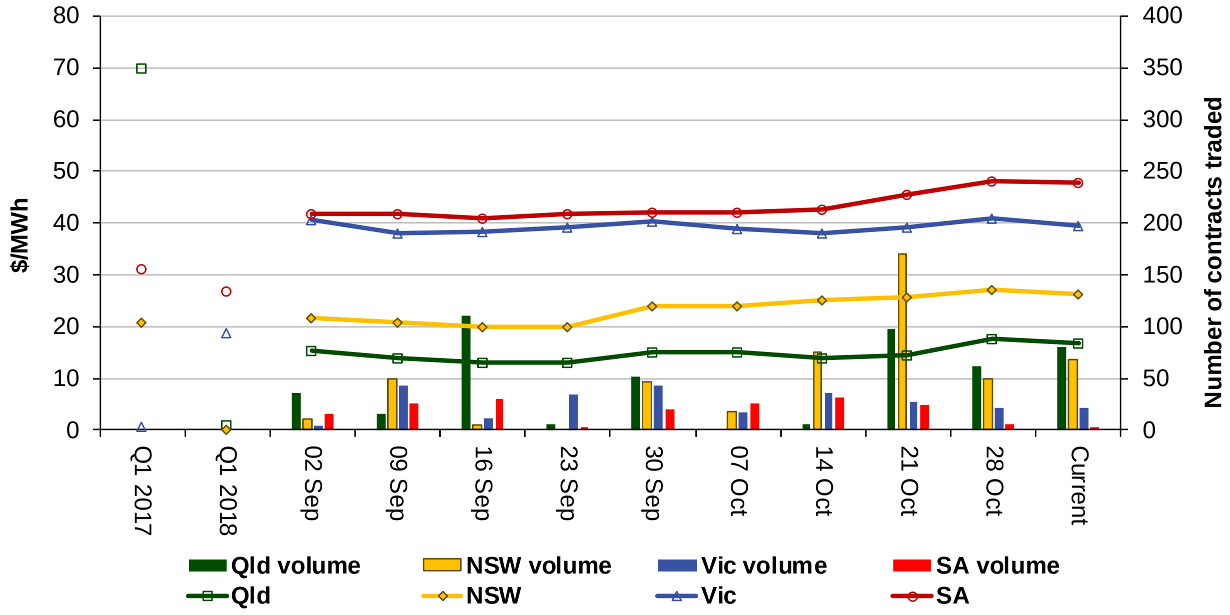
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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