27 May - 2 June 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 27 May – 2 June 2018.

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

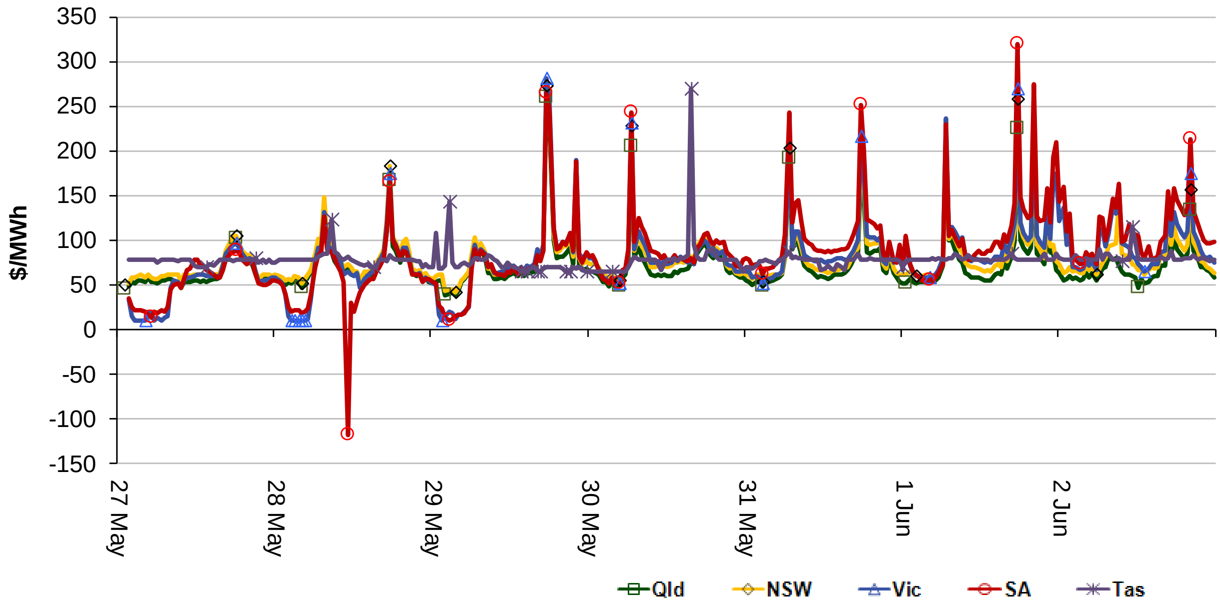


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

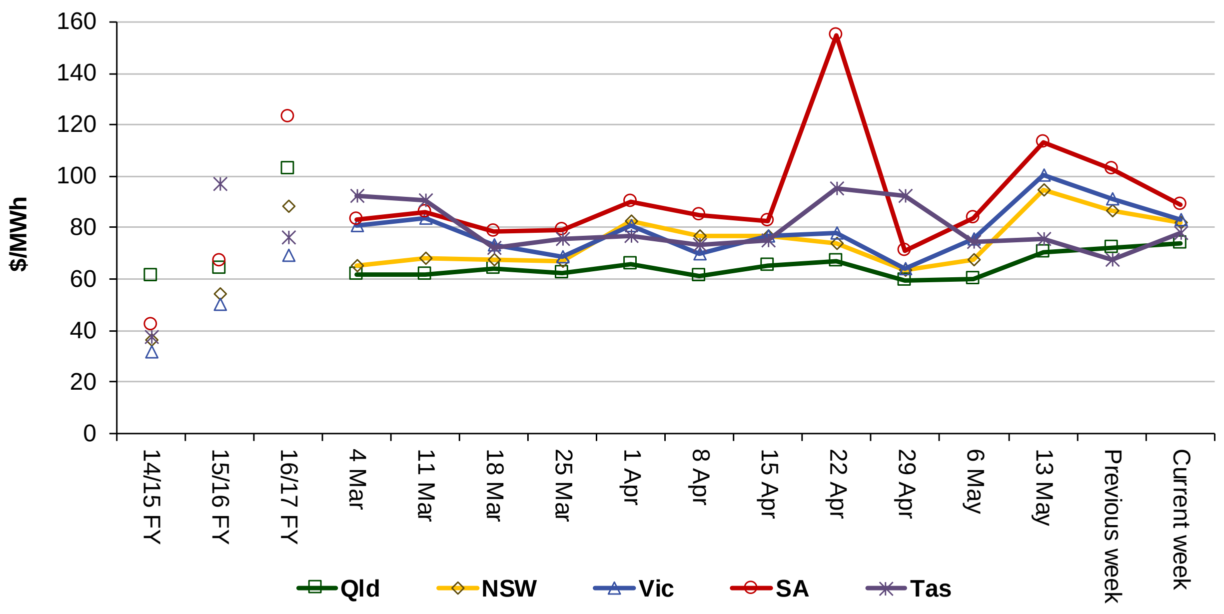


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	74	82	83	89	78
16-17 financial YTD	105	89	67	124	73
17-18 financial YTD	74	83	99	109	89

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 117 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	7	20	0	0
% of total below forecast	5	57	0	11

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

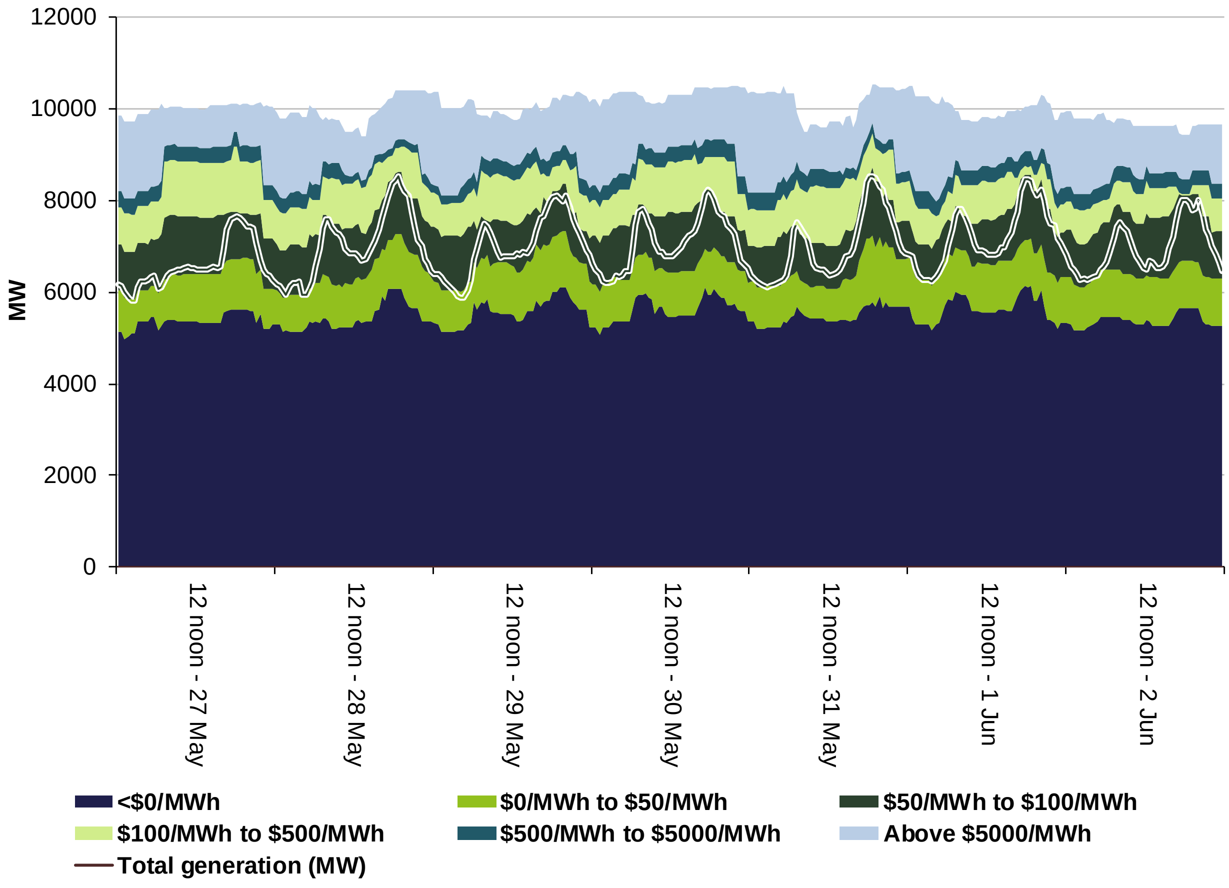


Figure 4: New South Wales generation and bidding patterns

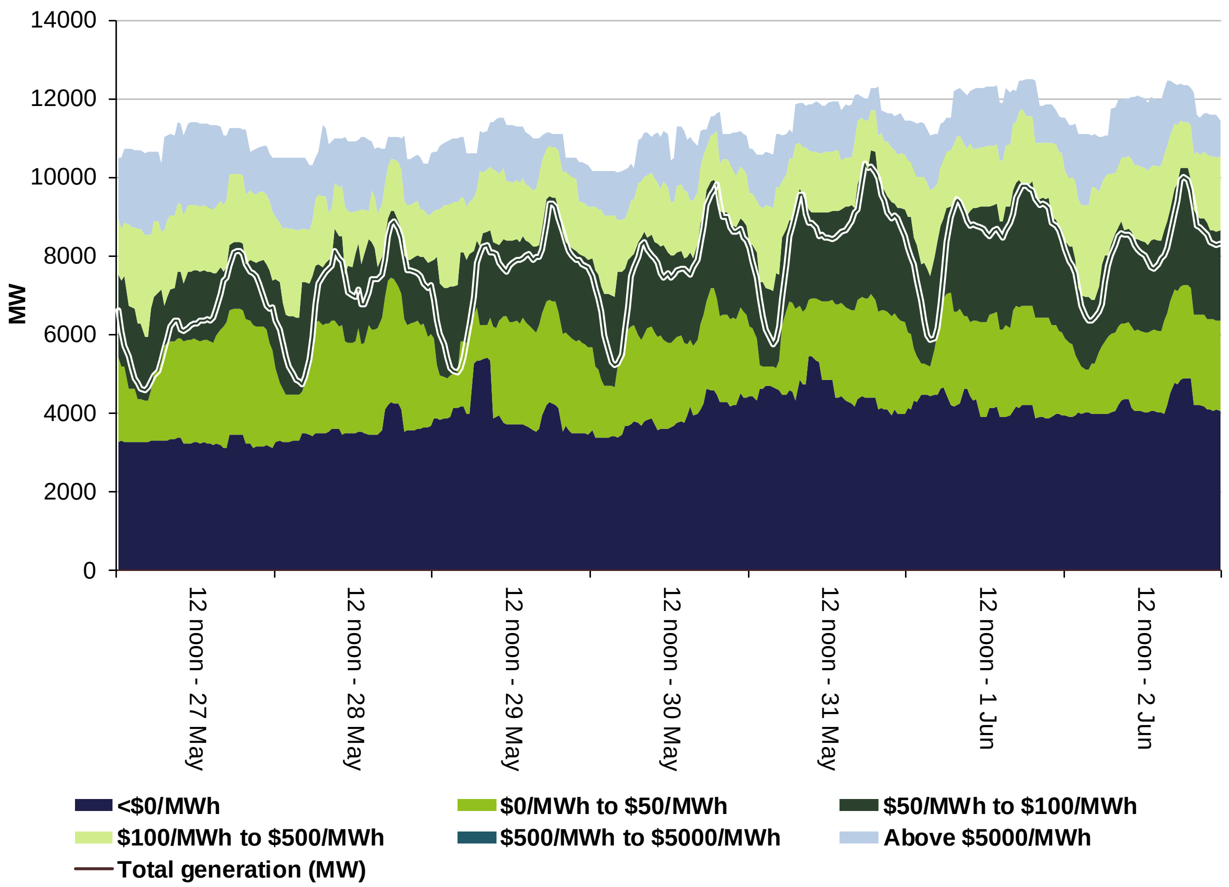


Figure 5: Victoria generation and bidding patterns

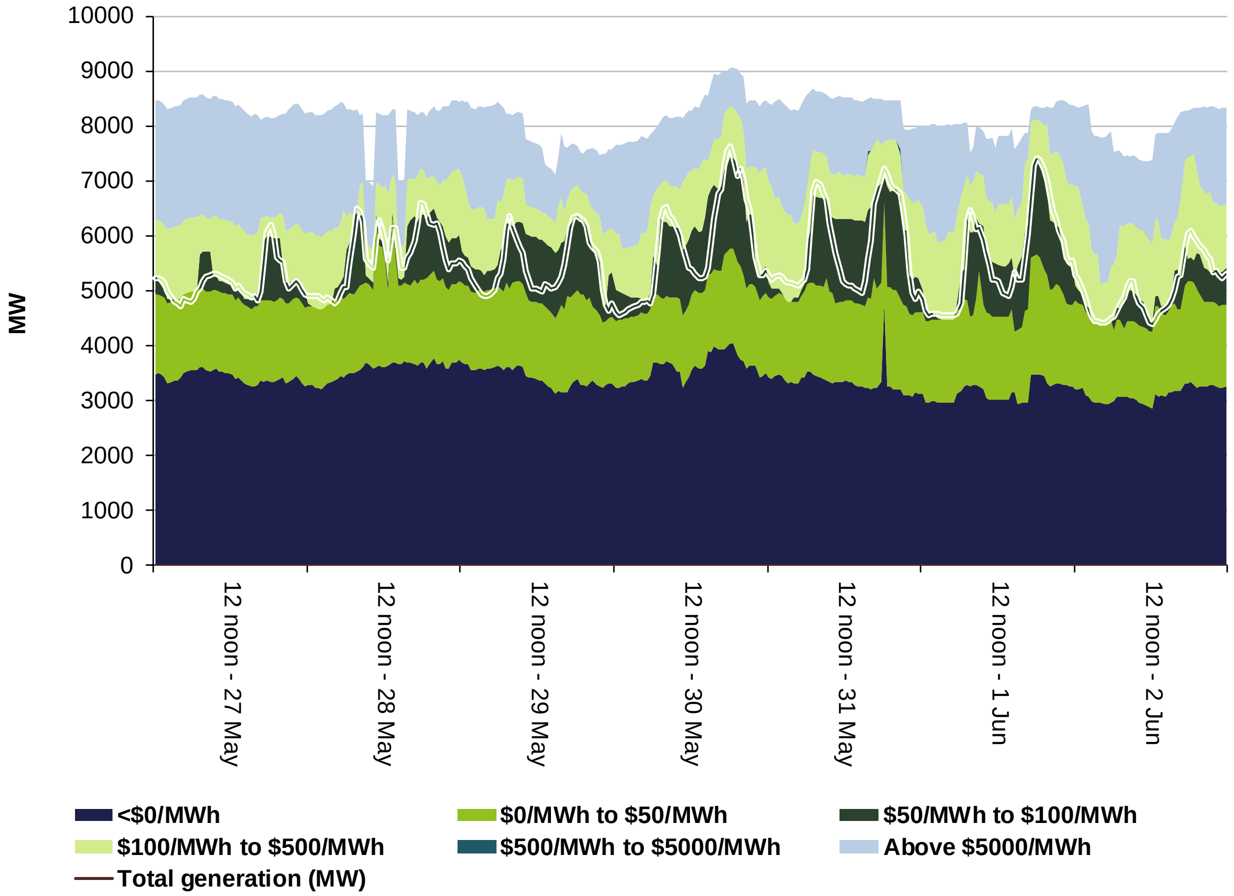


Figure 6: South Australia generation and bidding patterns

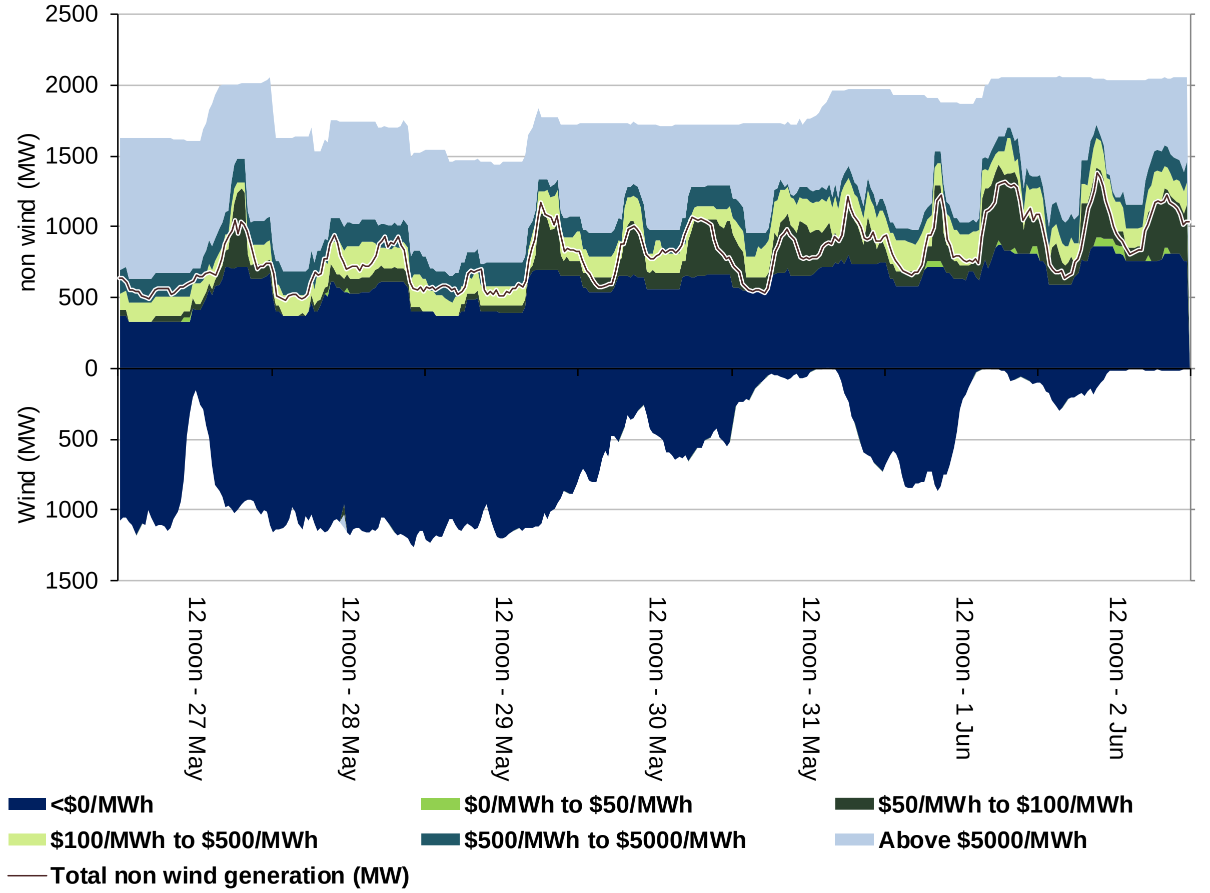
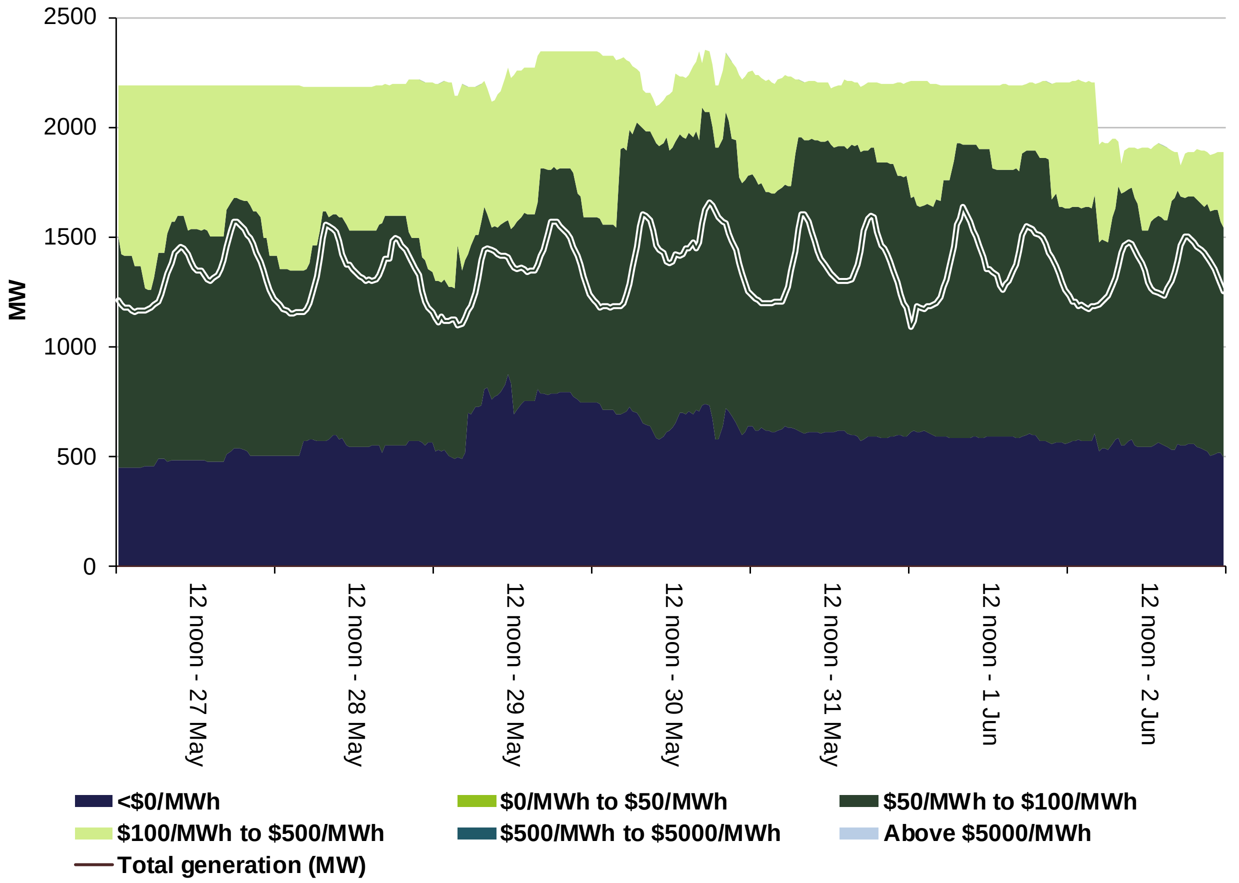


Figure 7: Tasmania generation and bidding patterns



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.

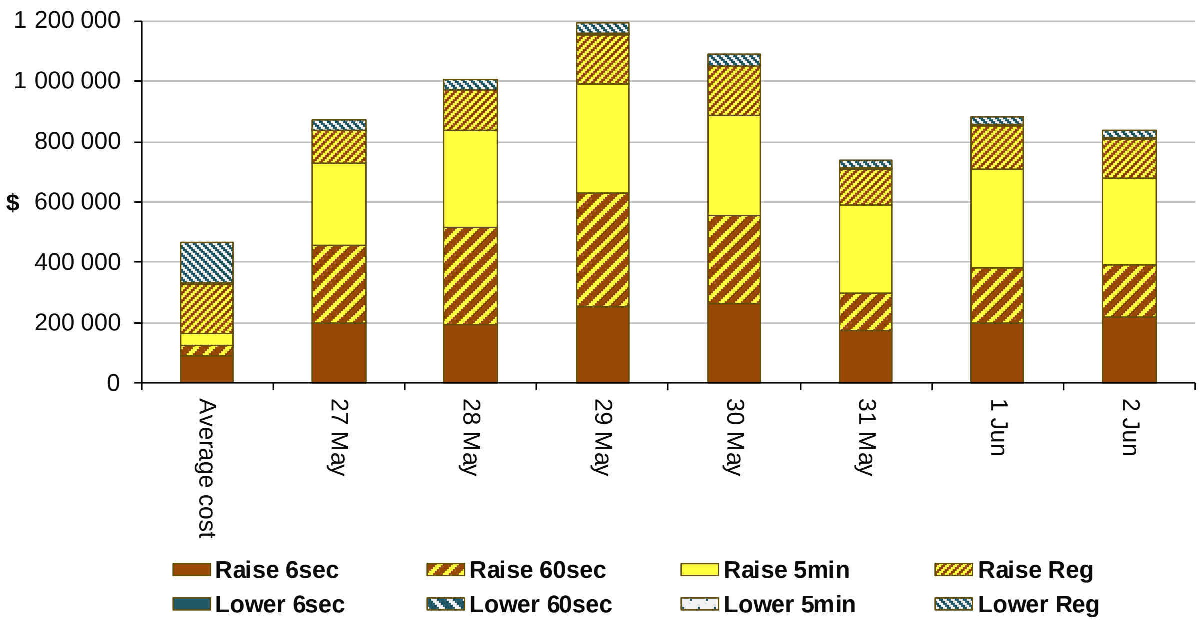
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $6 273 000 or around two per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $354 500 or around two 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



Raise 5 minute, raise 60 second and raise 6 second services prices were higher than average throughout the week as cheaper priced capacity could not be sourced from Tasmania due to the on-going outage of Basslink. Over the week:

- Raise 5 minute prices reached or exceeded $100/MW on 34 occasions reaching $128/MW.
- Raise 60 second prices exceeded $100/MW on 12 occasions reaching $223/MW.

- Raise 6 second prices exceeded $100/MW on 15 occasions reaching $197/MW.
- Raise regulation prices reached or exceeded $100/MW on 44 occasions reaching $238/MW.

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $74/MWh and above $250/MWh.

Tuesday, 29 May

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
6 pm	259.29	164.54	149.44	7421	7469	7462	10 251	10 338	10 448

Demand was 48 MW lower than forecast and availability was 87 MW lower than forecast, both 4 hours ahead.

See the Victorian section below for analysis of the 6 pm interval as prices were aligned across Victoria, Queensland and New South Wales.

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 $82/MWh and above $250/MWh.

Tuesday, 29 May

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
6 pm	272.92	171.71	155.89	9887	9757	9761	10 954	11 040	11 839

Demand was 130 MW higher than forecast and availability was 86 MW lower than forecast, both 4 hours ahead.

See the Victorian section below for analysis of the 6 pm interval as prices were aligned across Victoria, Queensland and New South Wales.

Friday, 1 June

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
6 pm	258.63	145.65	147.88	10 715	10 705	10 675	12 276	12 694	12 745

Demand was close to forecast and availability was around 420 MW lower than forecast both four hours prior. Semi-scheduled wind generation in South Australia was 100 MW lower than forecast.

In the four hours leading up to the start of the trading interval AGL withdrew 420 MW of capacity priced between the floor and $0/MWh from Liddell due to a unit tripping. As a result, exports from Victoria into New South Wales were greater than forecast. Also, across two rebids, Snowy Hydro shifted 360 MW of capacity at Tumut power station from less than $105/MWh to $300/MWh, the reasons related to price forecasts. Although there was some shifting of capacity into lower priced bands it was not enough to offset the rebids outlined above and the lower than forecast wind generation in South Australia. This loss of generation and rebidding of capacity into higher priced bands led to capacity priced higher than forecast meeting demand for the entire trading interval.

Victoria

There were three occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $83/MWh and above $250/MWh.

Tuesday, 29 May

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
6 pm	282.09	178.90	178.90	6565	6561	6702	7680	8238	7707
6:30 pm	259.33	178.90	178.90	6591	6600	6704	7644	8232	7688

For the 6 pm trading interval, demand was close to forecast and availability was around 560 MW lower than that forecast four hours prior.

In the four hours leading up to the start of the trading interval, across two rebids, Ecogen withdrew 500 MW of capacity priced between the floor and $250/MWh from Newport power station as the plant tripped. In order to redistribute their portfolio, Ecogen shifted 168 MW of capacity at Jeeralang from $10 000/MWh and above to between the floor and $1/MWh. In Queensland, Callide Power Trading withdrew 156 MW of capacity priced at the floor from Callide C power station due to plant issues. Also in New South Wales, Snowy shifted 500 MW of capacity at Tumut power station from less than $105/MWh to $300/MWh, the reason related to price forecasts. This led to higher priced generation meeting demand across the three regions. The dispatch prices remained between $230 and $315/MWh and resulted in a higher than forecast price.

For the 6.30 pm trading interval, demand was close to forecast and availability was around 590 MW lower than that forecast four hours prior. Semi scheduled wind generation was around 70 MW lower than forecast.

Ecogen's rebids which withdrew 500 MW of capacity priced less than $250/MWh from Newport were still in effect. This removal of low priced capacity combined with the lower than forecast wind generation meant higher priced capacity was required to meet demand.

Friday, 1 June

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
6 pm	269.67	157.79	165.19	6810	6573	6716	8346	8412	8405

Demand was around 240 MW higher than forecast and availability was around 70 MW lower than forecast, both four hours prior.

See the New South Wales section above for analysis of the 6 pm interval as prices were aligned across New South Wales, Victoria and South Australia.

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 $89/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Monday, 28 May

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
11:30 am	-118.09	61.14	56.64	991	1086	1096	2787	2598	2571

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.

Demand was 95 MW lower than forecast and availability was 189 MW higher than that forecast four hours prior. For the 11.10 am dispatch interval demand dropped by 36 MW and wind generation increased by 11 MW. Although higher priced generation was dispatched it was either trapped or stranded in FCAS or constrained so could not set price. As a result the price fell to -$996/MWh for one dispatch interval and resulted in a negatively priced trading interval.

Friday, 1 June

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
6 pm	319.69	193.93	203.09	1778	1630	1676	1947	2033	2074
8:30 pm	275.28	291.44	145.50	1802	1763	1761	2029	2055	2172

For the 6 pm trading interval, demand was around 150 MW higher than forecast and availability was around 90 MW lower than forecast, both four hours prior.

See the New South Wales section above for analysis of the 6 pm trading interval as prices were aligned across New South Wales, Victoria and South Australia.

For the 8.30 pm trading interval, the price was close to the four hour forecast price.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $78/MWh and above $250/MWh.

Wednesday, 30 May

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
4 pm	269.04	65.30	65.30	1311	1235	1194	2271	2279	2286

Demand was 76 MW higher than forecast while availability was close to that forecast four hours ahead.

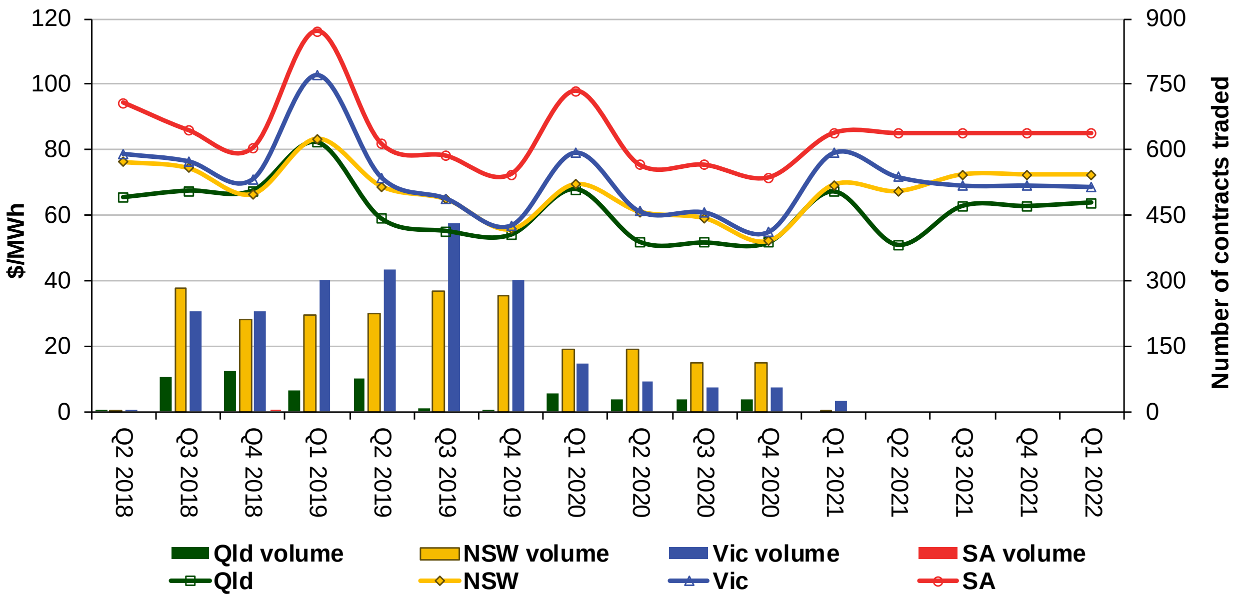
With Basslink out and unable to transfer FCAS to or from the mainland, generators in Tasmania had to provide all FCAS services locally.

At 3.35 pm, the loss of the Farrell-Sheffield parallel 220 kV lines was declared a credible contingency due to lightning. The constraint invoked to manage this affected generation across Tasmania. As a result, FCAS and energy markets in Tasmania were co-optimized for the 3.50 pm dispatch interval with the dispatch price reaching $1056/MWh.

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.

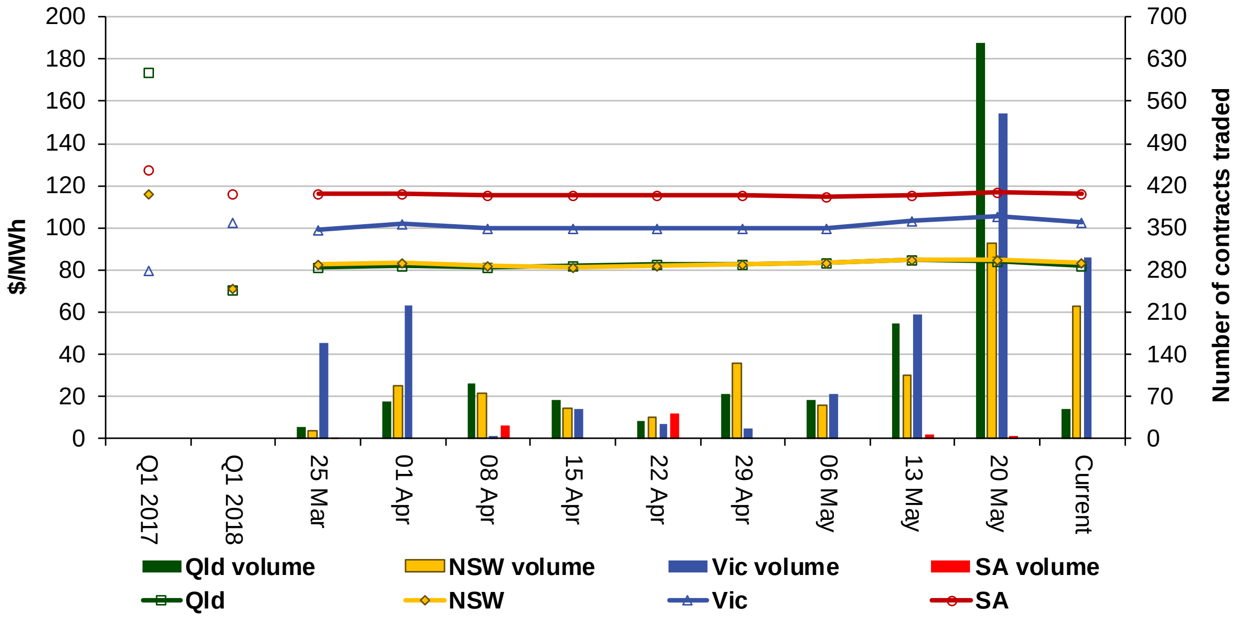
Figure 9: Quarterly base future prices Q2 2018 – Q1 2022



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)



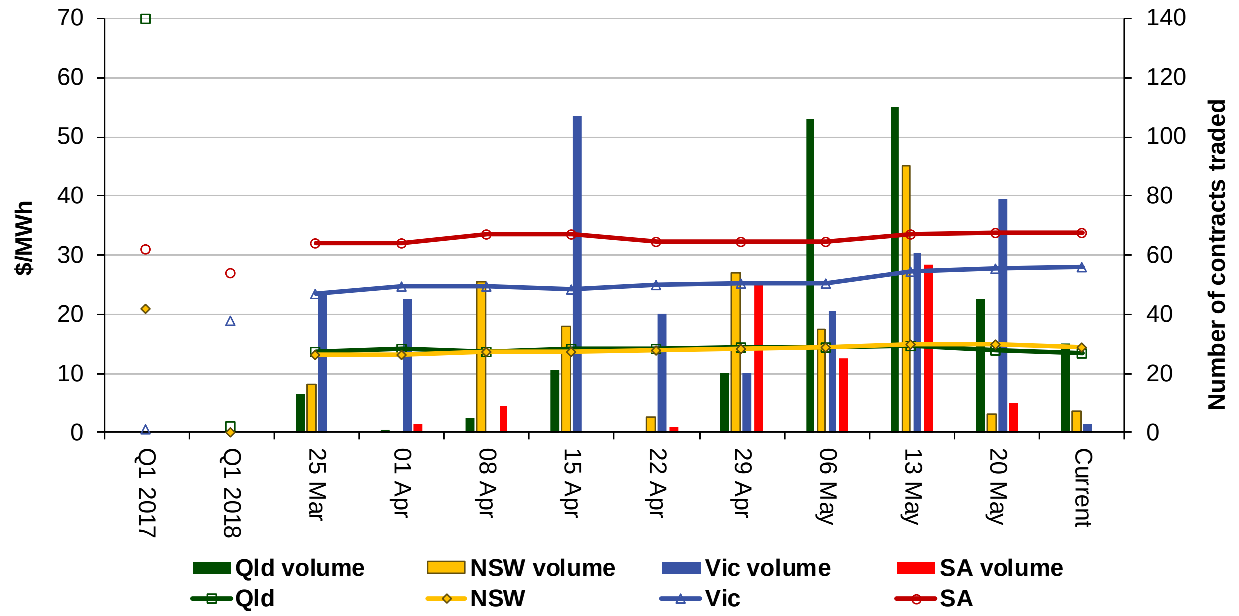
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
June 2018