Electricity Report

4 - 10 June 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 4 – 10 June 2017.

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

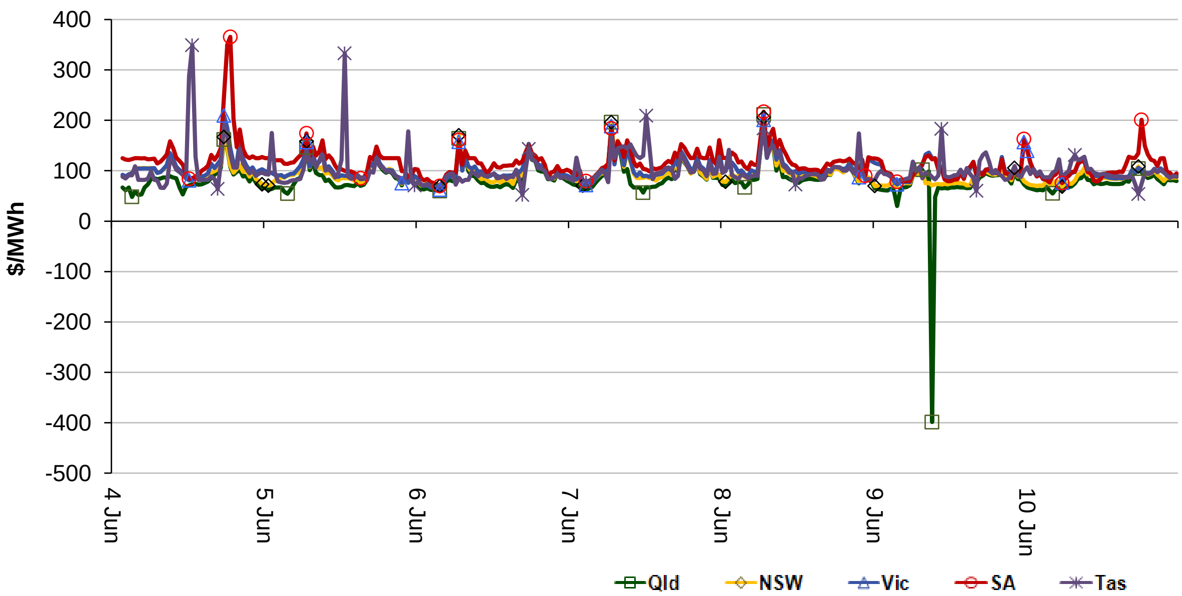


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous three financial years.

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

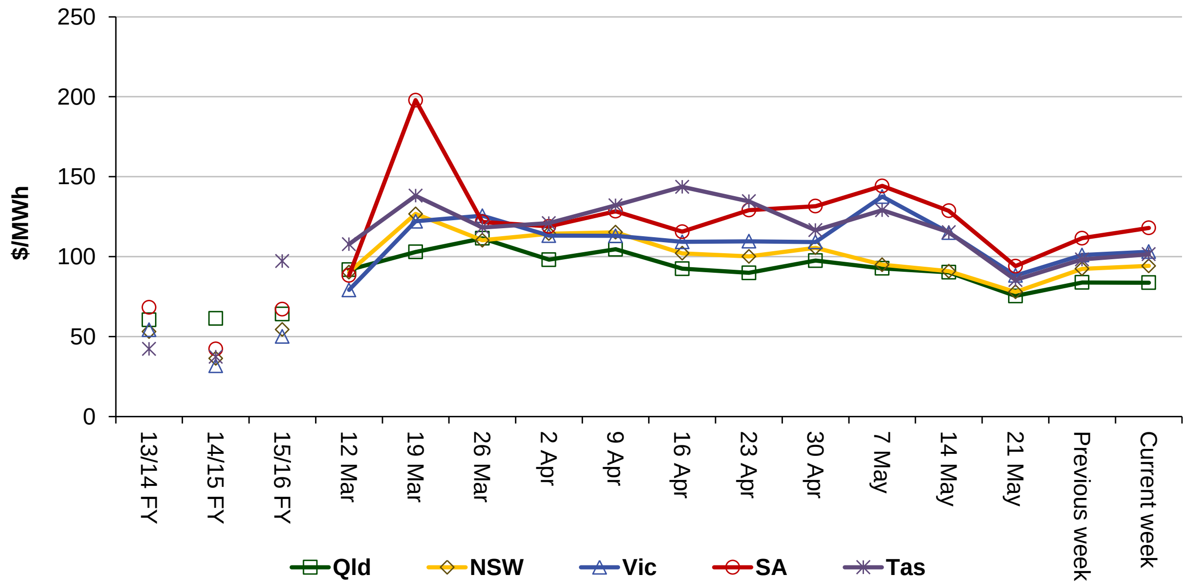


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	84	94	103	118	102
15-16 financial YTD	63	52	48	63	98
16-17 financial YTD	104	89	68	124	74

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 159 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	6	33	0	3
% of total below forecast	46	11	0	2

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

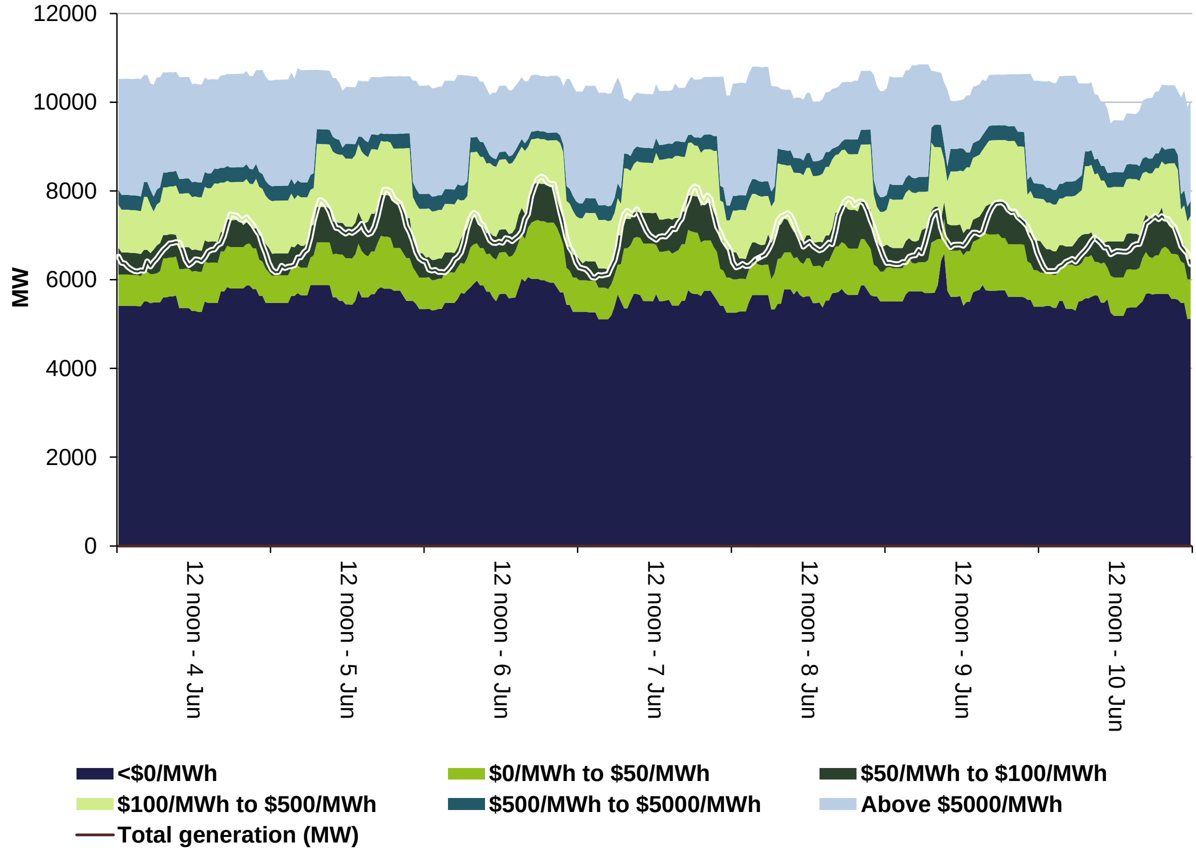


Figure 4: New South Wales generation and bidding patterns

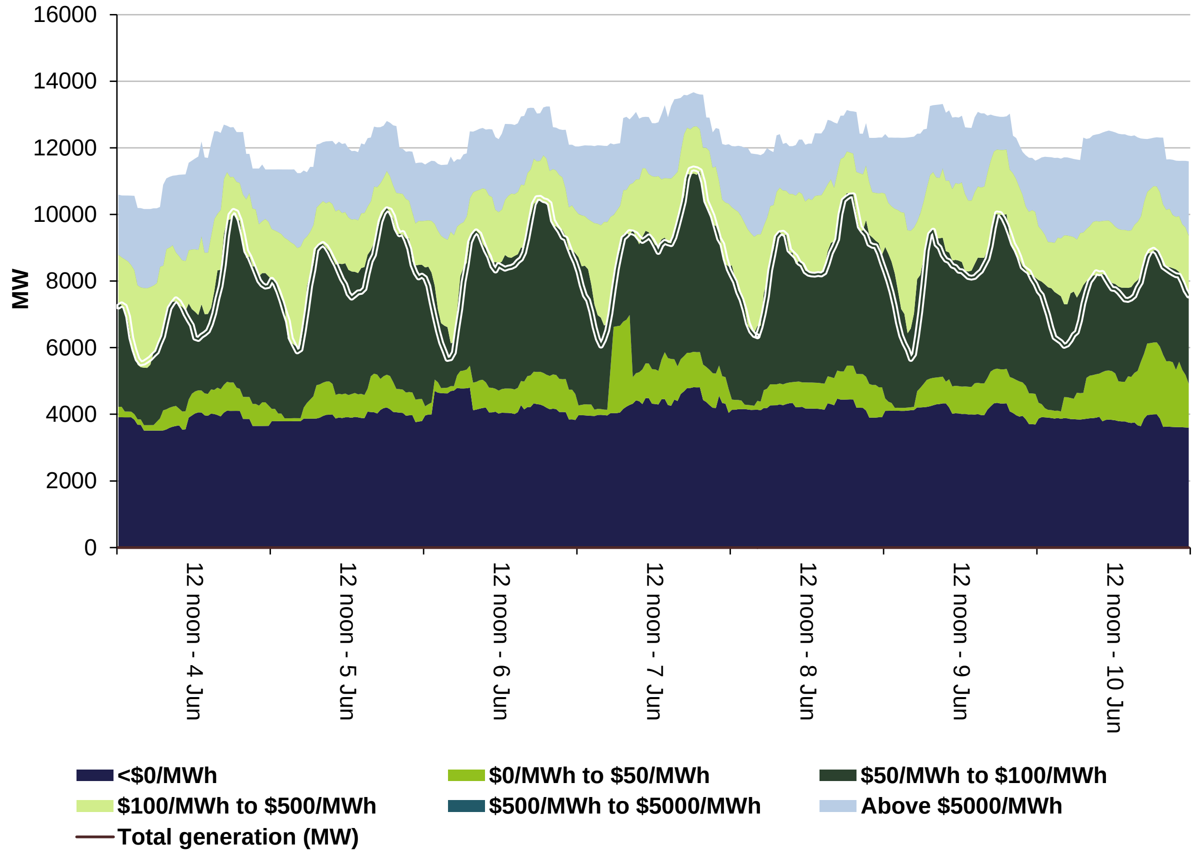


Figure 5: Victoria generation and bidding patterns

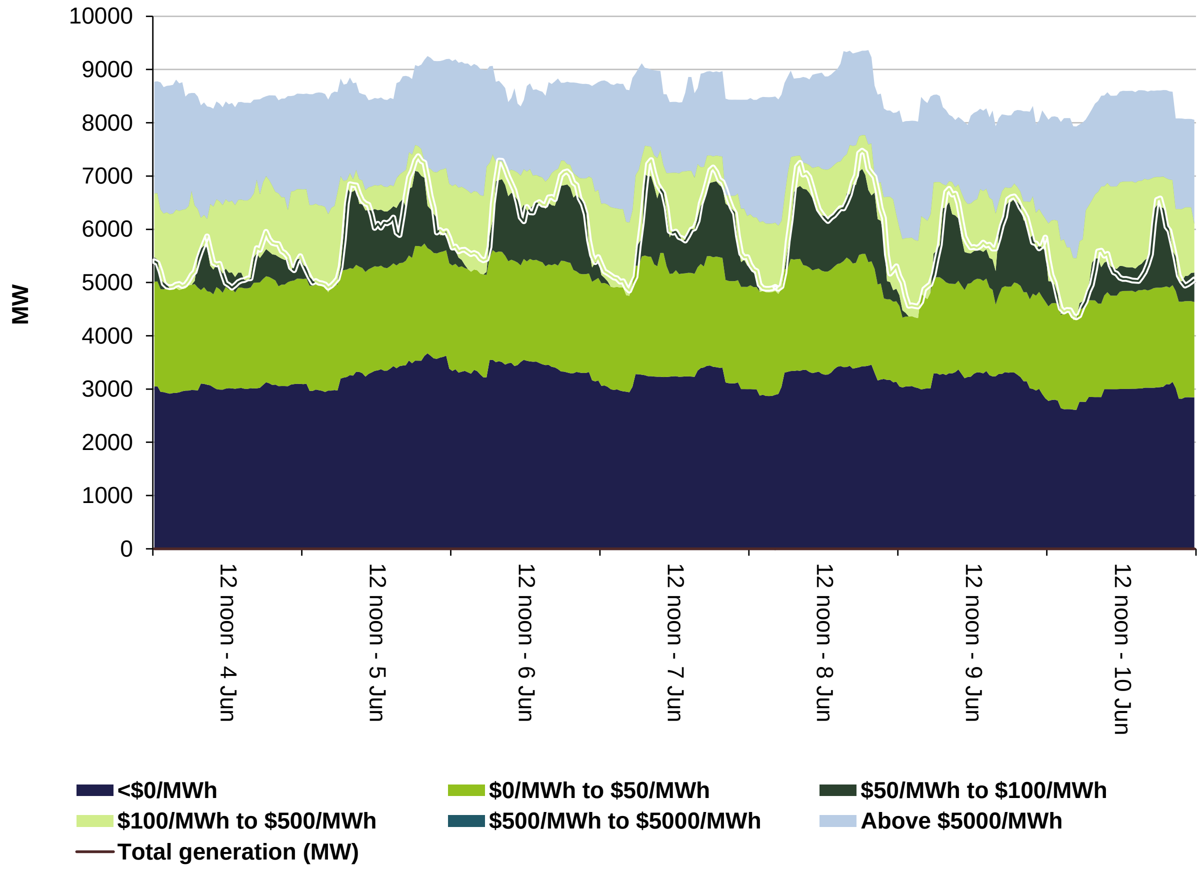


Figure 6: South Australia generation and bidding patterns

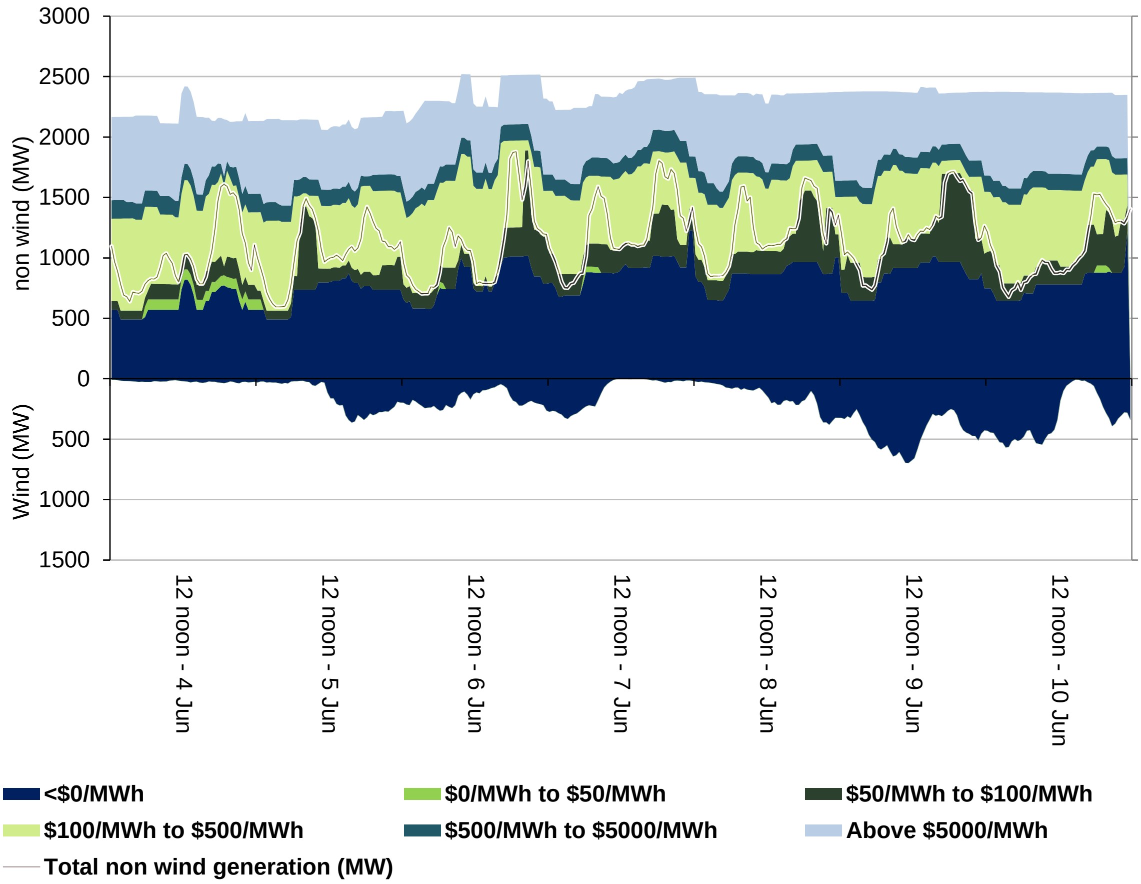
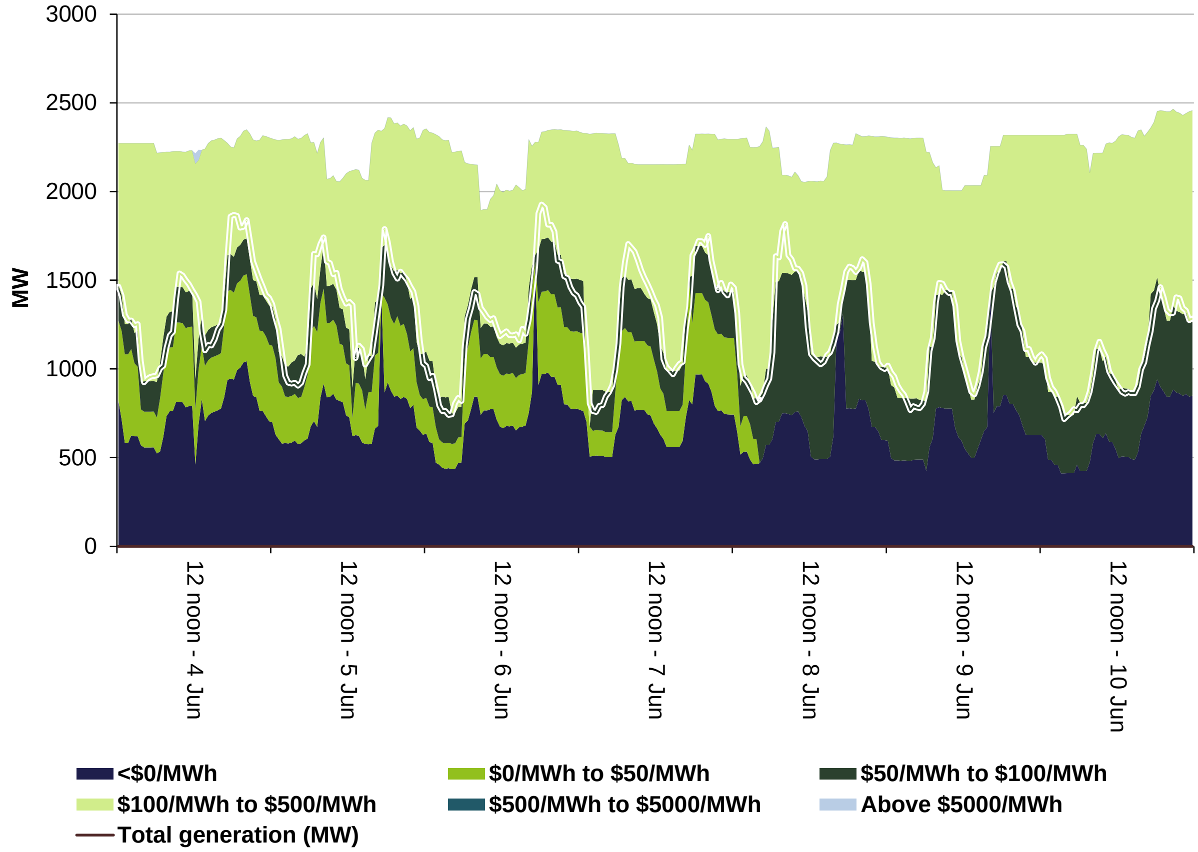


Figure 7: Tasmania generation and bidding patterns



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.

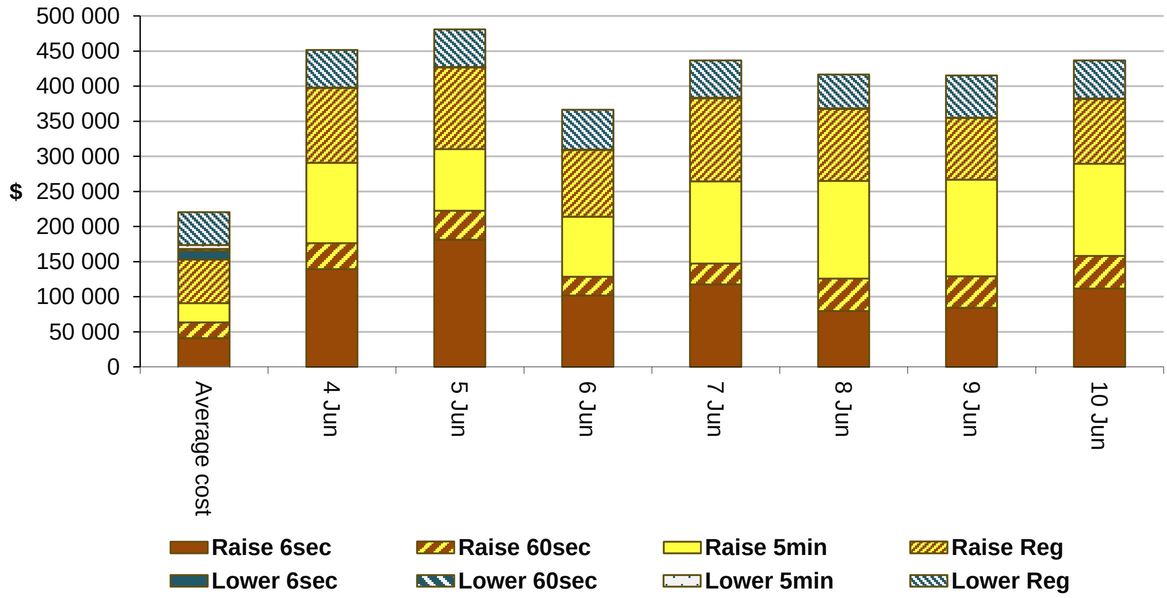
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 348 000 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $656 000 or around three per cent of energy turnover in Tasmania.of the previous financial year.

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



Since 5 May, AEMO limited the contribution of regulation services from Tasmania to the mainland to 50 MW. This has seen prices rise in the mainland and has led to the daily cost being higher than the previous financial year's average.

Detailed market analysis of significant price events

Queensland

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

Friday, 9 June

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	-398.83	71.37	69.84	6159	6430	6272	10 822	10 822	10 837

Demand was around 270 MW lower than forecast and availability was as forecast four hours ahead of dispatch.

In preparation for a planned network outage near Gladstone AEMO invoke ramping constraints which increased exports from Queensland into New South Wales by 124 MW for the 9.10 am dispatch interval. This led to capacity priced at $1405/MWh being dispatched and setting price. In response to this high price, participants rebid over 1000 MW of capacity to the floor from prices above $300/MWh. As a result the dispatch price fell to or near the price floor for the last four dispatch intervals leading to the negative spot price.

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 $118/MWh and above $250/MWh.

Sunday, 4 June

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
7 pm	365.68	166.77	144.86	2106	1995	1967	2191	2260	2245

Demand was 111 MW higher than forecast and availability was 69 MW lower than forecast four hours ahead. Wind generation was 61 MW lower than forecast four hours ahead. With higher than forecast demand and lower than forecast wind generation, demand was met by higher priced generation.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $102/MWh and above $250/MWh.

Sunday, 4 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
1 pm	348.92	82.58	71.21	1265	1197	1195	2236	2285	2302

Demand was around 70 MW higher than forecast and availability was 50 MW lower than that forecast, both four hours ahead.

Over several rebids from midday Hydro Tasmania rebid around 300 MW of capacity across its portfolio from below $83/MWh to $349/MWh and above as shown in Table 6: Significant rebids.

Table 6: Significant rebids

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
12.14 pm	12.25 pm	Hydro Tasmania	Tamar Valley CCGT	138	-75	349	1213A fcas requirement different to forecast+slow>180
12.15 pm	12.25 pm	Hydro Tasmania	Gordon	8	-75	349	1213A fcas requirement different to forecast
12.15 pm	12.25 pm	Hydro Tasmania	John Butters	9	50	349	1213A fcas requirement different to forecast
12.15 pm	12.25 pm	Hydro Tasmania	Reece	38	<50	>349	1213A fcas requirement different to forecast
12.15 pm	12.25 pm	Hydro Tasmania	Tarralea	58	-1000	12 115	1213A fcas requirement different to forecast+unmanned
12.15 pm	12.25 pm	Hydro Tasmania	Tungatinah	50	-1	349	1213A fcas requirement different to forecast

FCAS constraints forced exports across Basslink into Victoria at around 50 MW. With no access to imports across Basslink, the rebidding resulted in the dispatch price reaching around $349/MWh and it remained there for the entire trading interval.

Monday, 5 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
1 pm	333.00	98.56	100.37	1165	1209	1201	2119	2113	2056

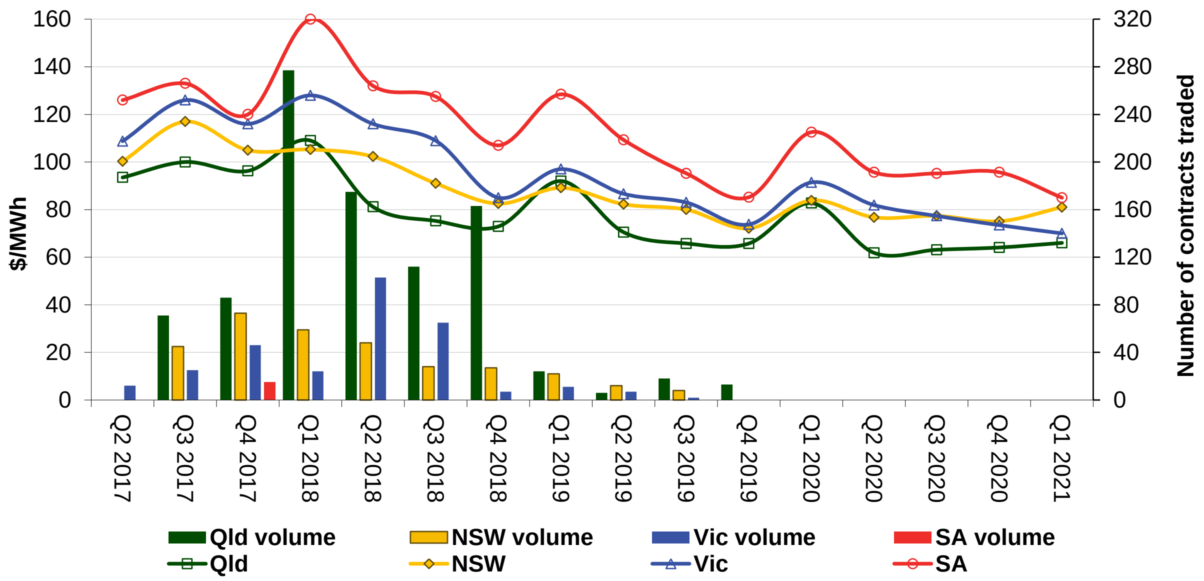
Demand and availability were both close to forecast, four hours ahead of dispatch. Basslink was also forecast to import around 100 MW of generation into Tasmania.

Binding FCAS constraints forced around 50 MW of exports on the Basslink interconnector into Victoria. This means that Tasmania had to generate around 150 MW more than what was forecast four hours ahead. With Basslink exporting rather than importing energy, higher priced capacity was dispatched.

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.

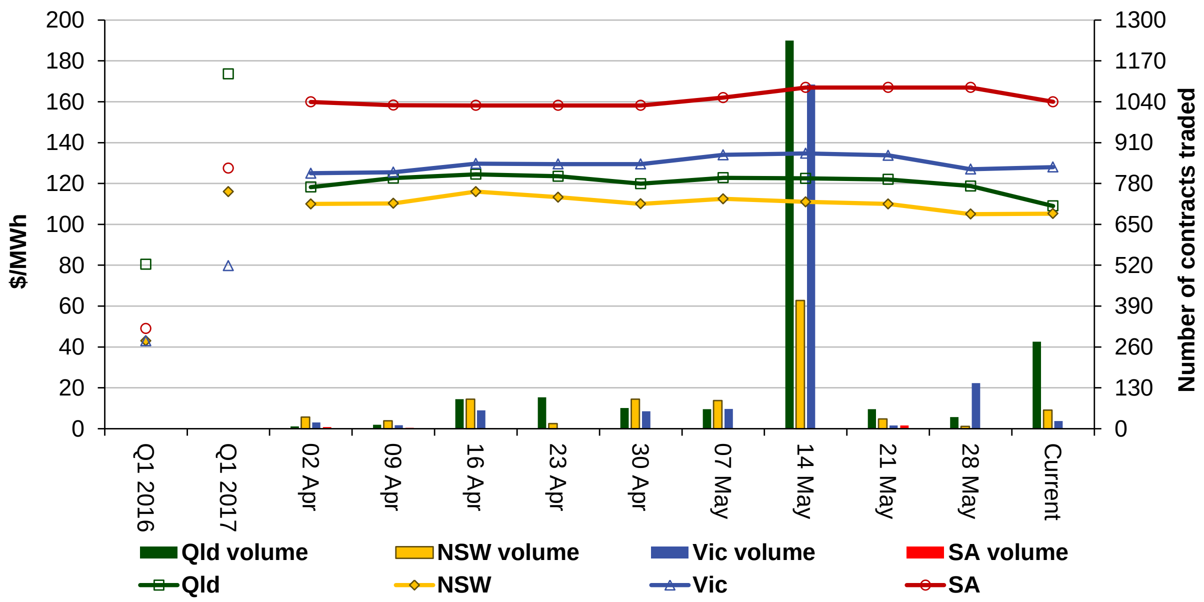
Figure 9: Quarterly base future prices Q2 2017 – Q1 2021



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. The high volumes for the week starting 14 May were a result of the conversion of 2017/18 financial year base load options to base future contracts.

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



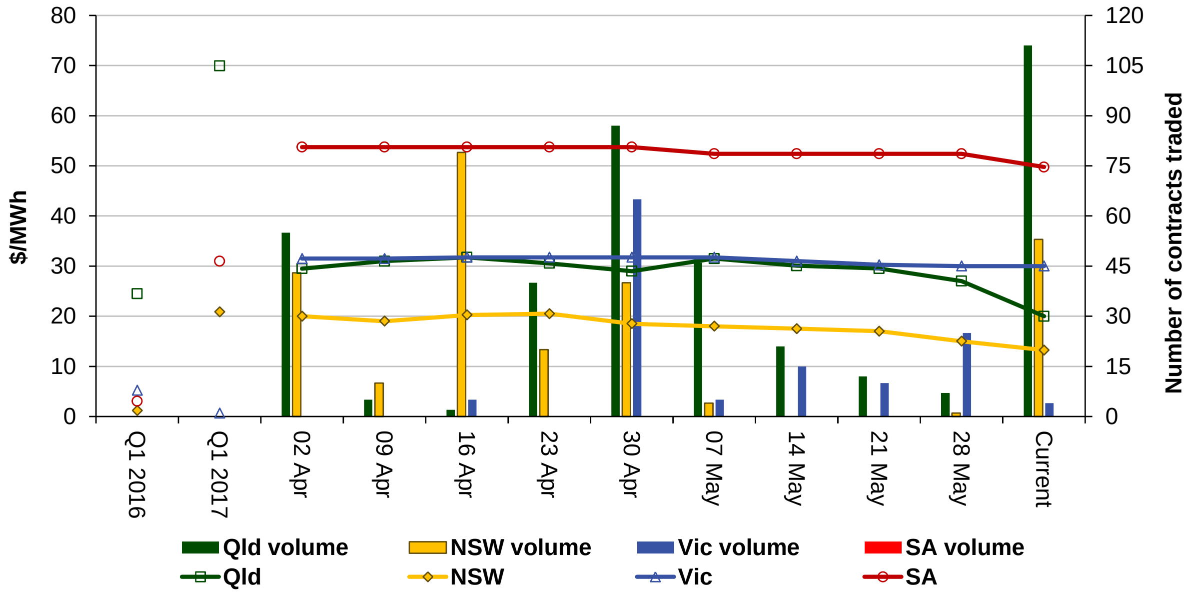
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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. The increase in Queensland trades coincide with the Queensland government's energy policy announcement.

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
June 2017