Electricity Report

AUSTRALIAN ENERGY REGULATOR

26 June – 2 July 2016

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 26 June to 2 July 2016.

On 1 July 2016, the market price cap increased from $13 800/MWh to $14 000/MWh and the cumulative price threshold increased from $207 000 to $210 100.

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

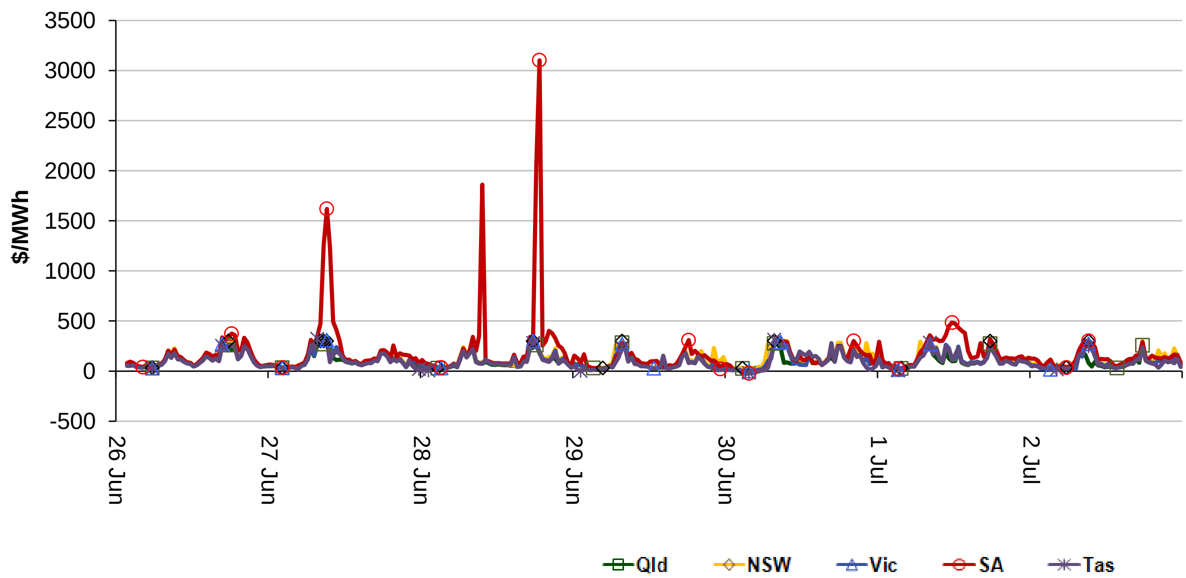


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

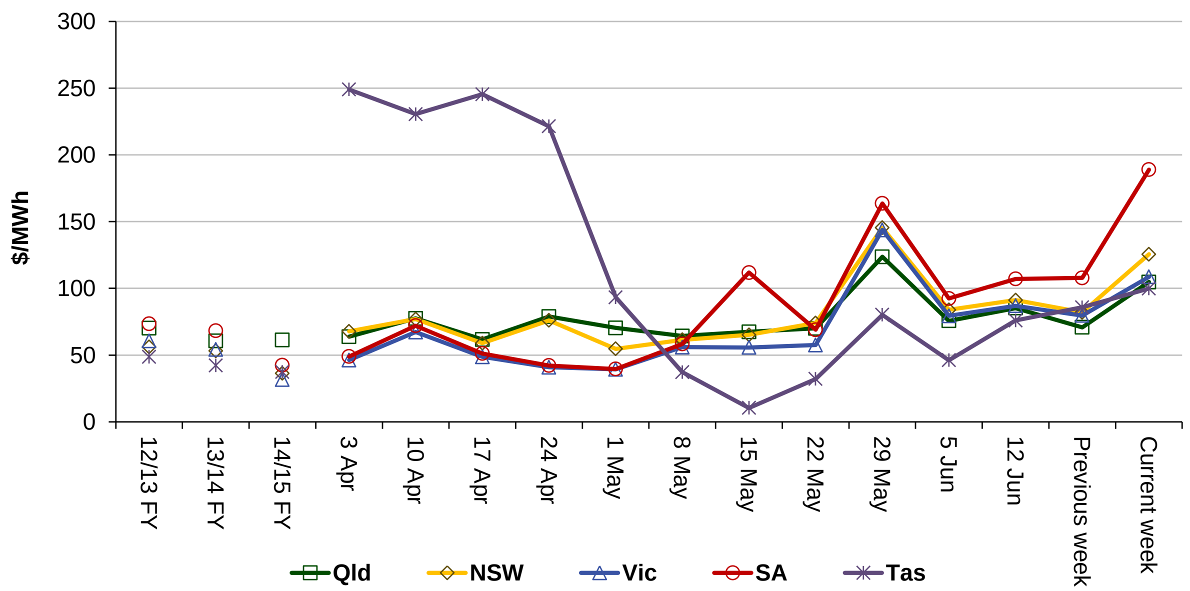


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	105	125	109	189	100
14-15 FY	61	36	32	42	37
15-16 FY	64	55	50	68	97

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 311 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71. 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	4	44	0	5
% of total below forecast	32	14	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

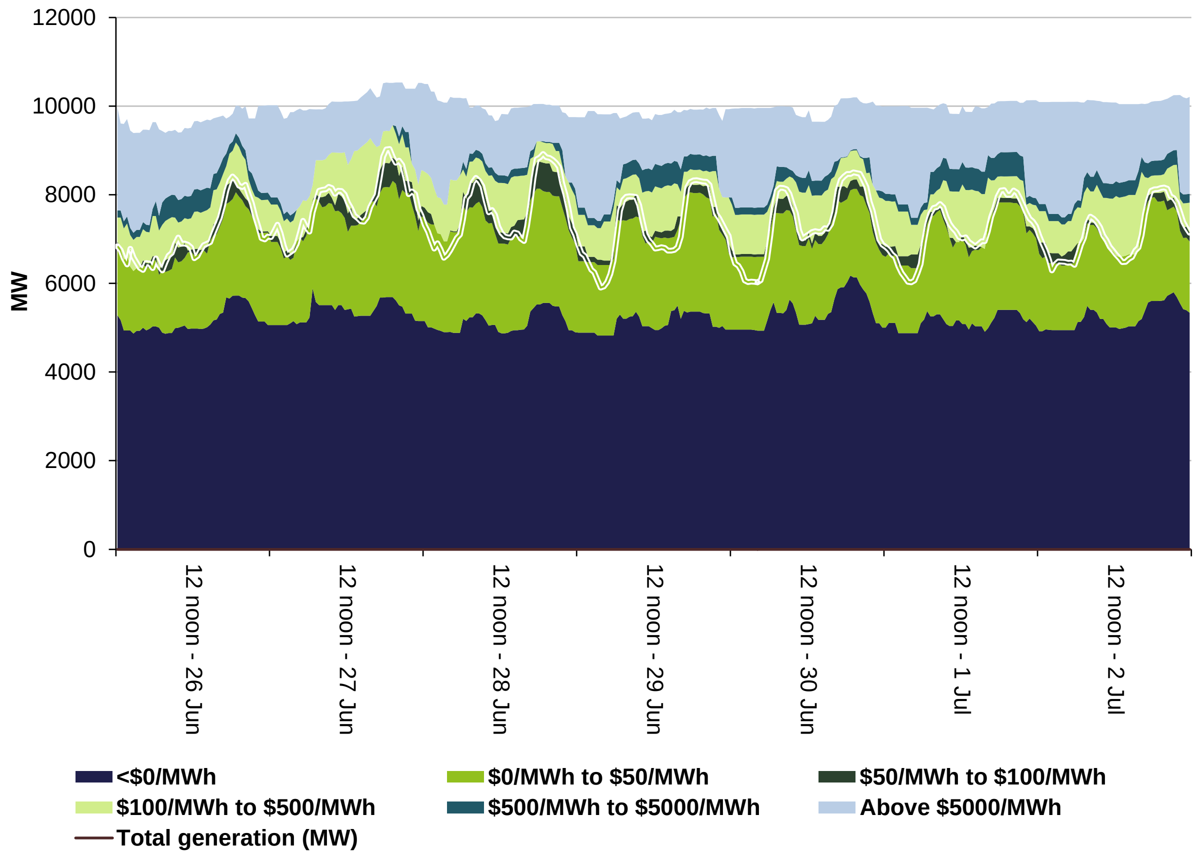


Figure 4: New South Wales generation and bidding patterns

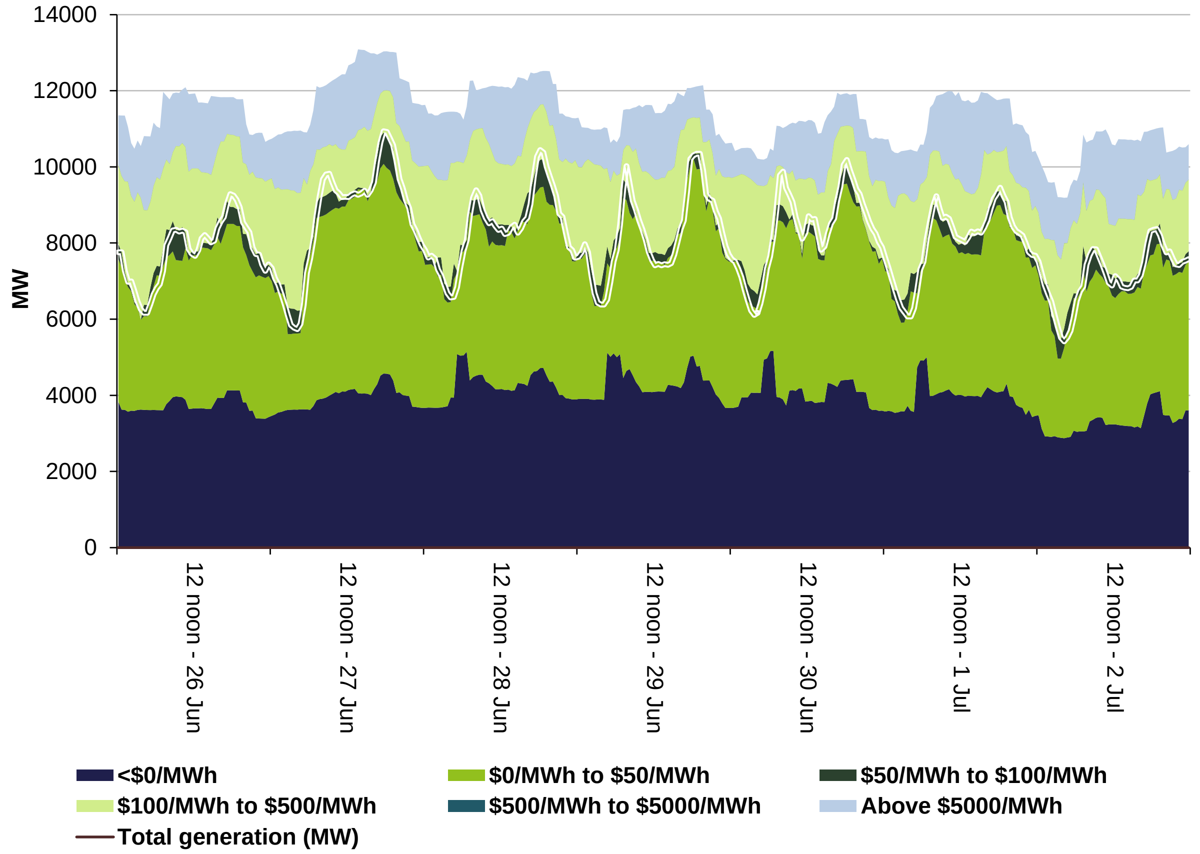


Figure 5: Victoria generation and bidding patterns

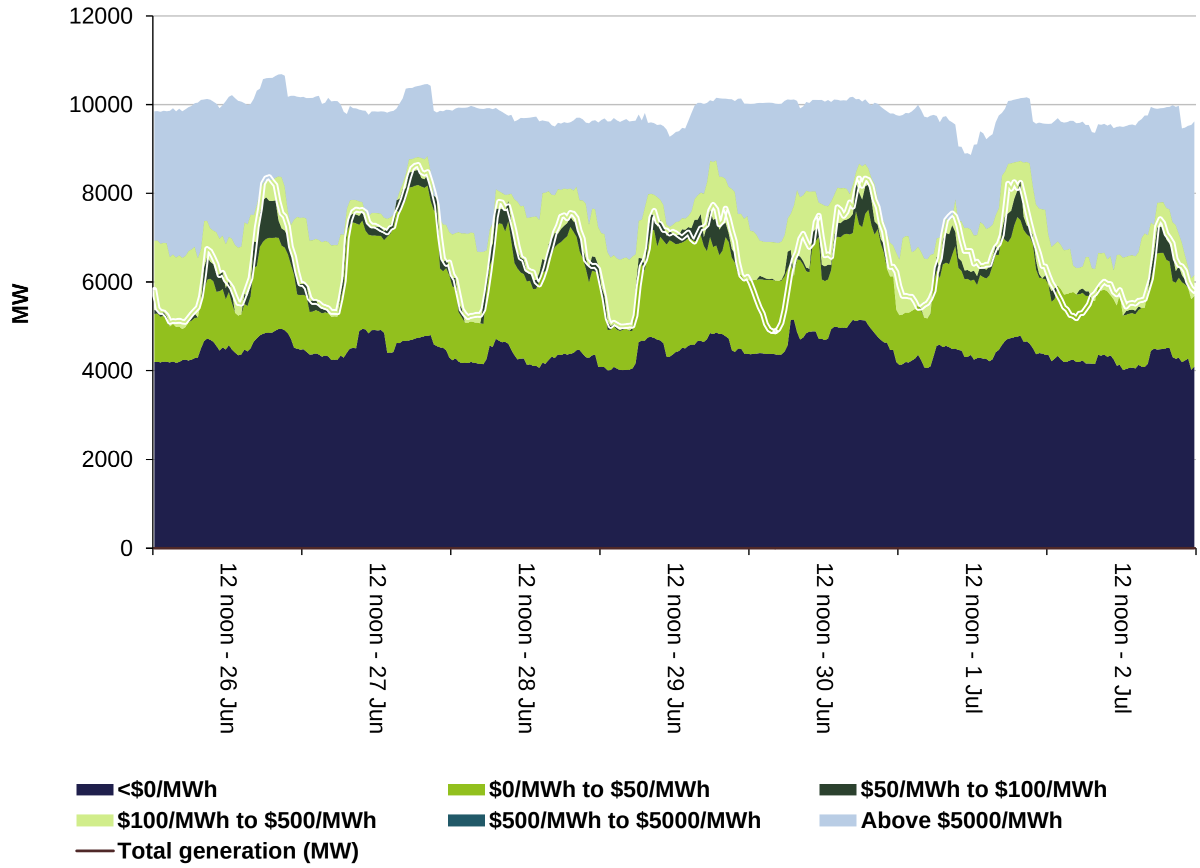


Figure 6: South Australia generation and bidding patterns

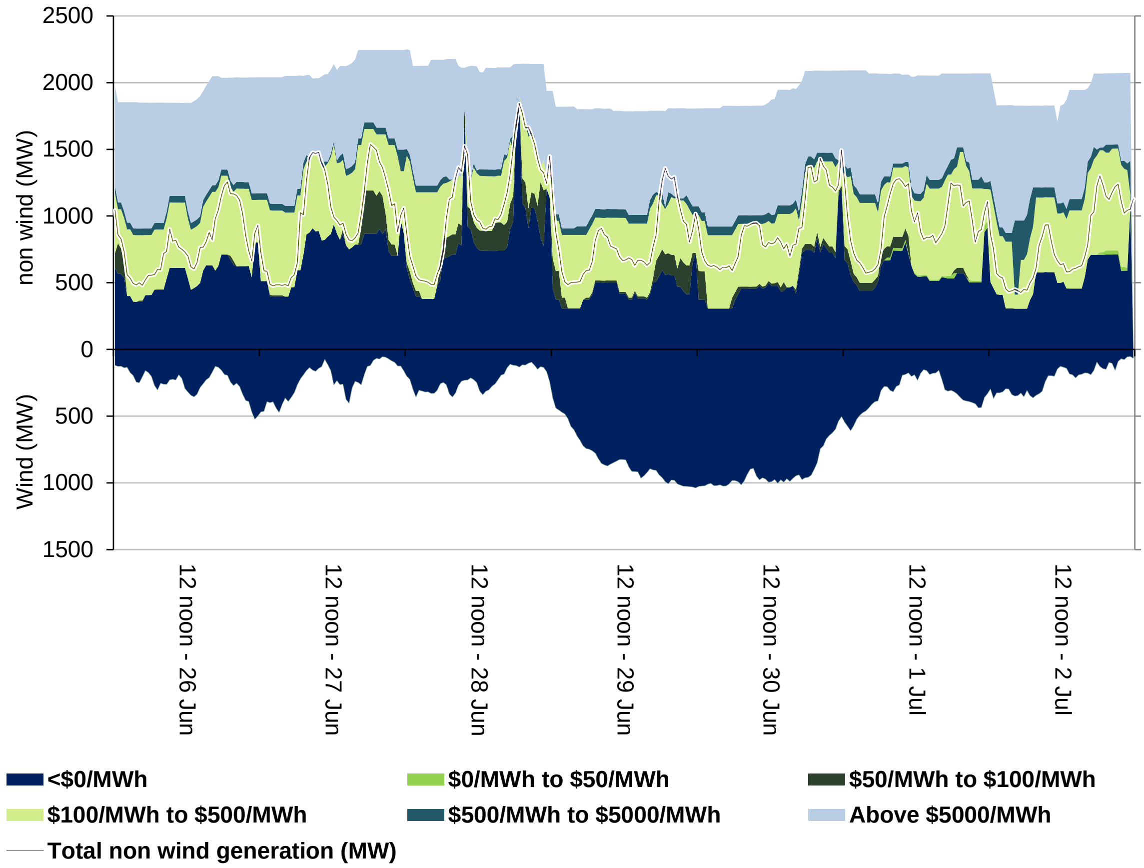
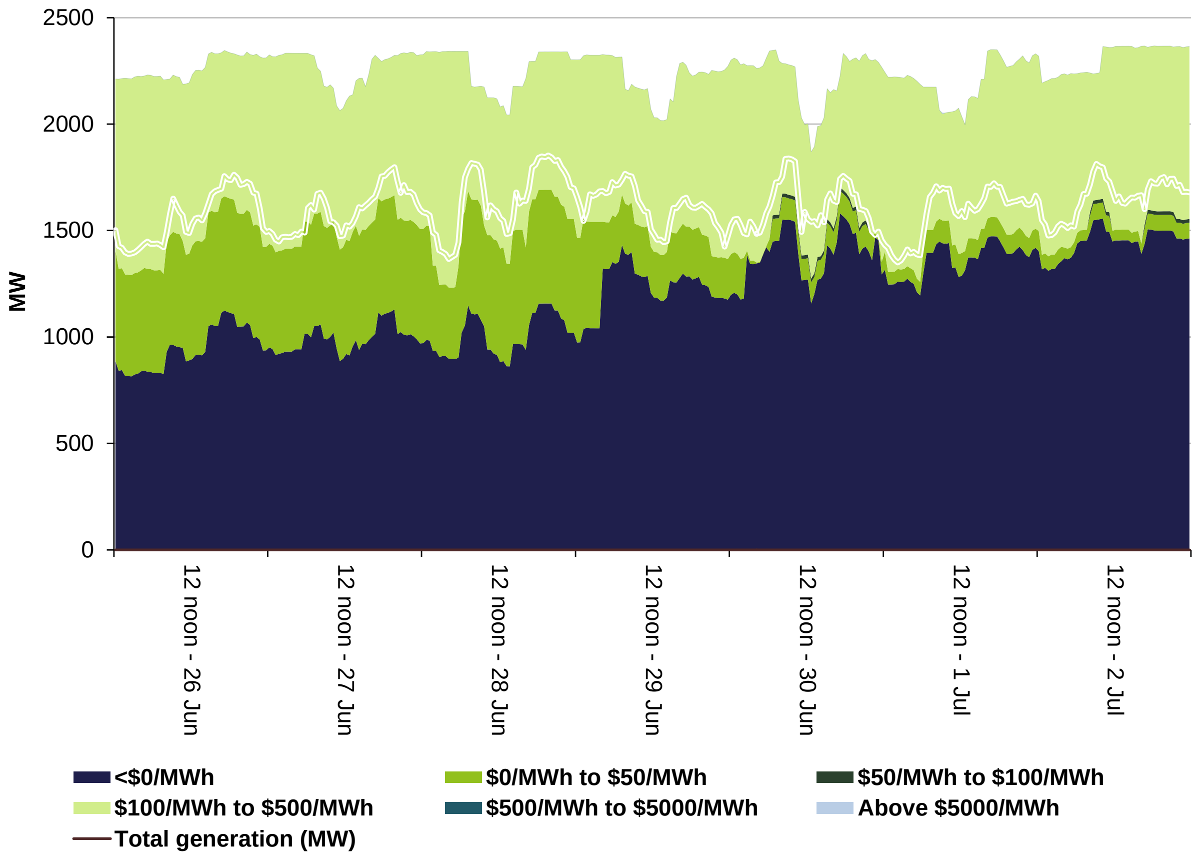


Figure 7: Tasmania generation and bidding patterns



Of note in Figure 7 is the increasing volume of energy offered at low prices. We understand that this bears a strong relationship to the levels of water available to run of river generation.

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 $1 339 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $370 000 or less than 2 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

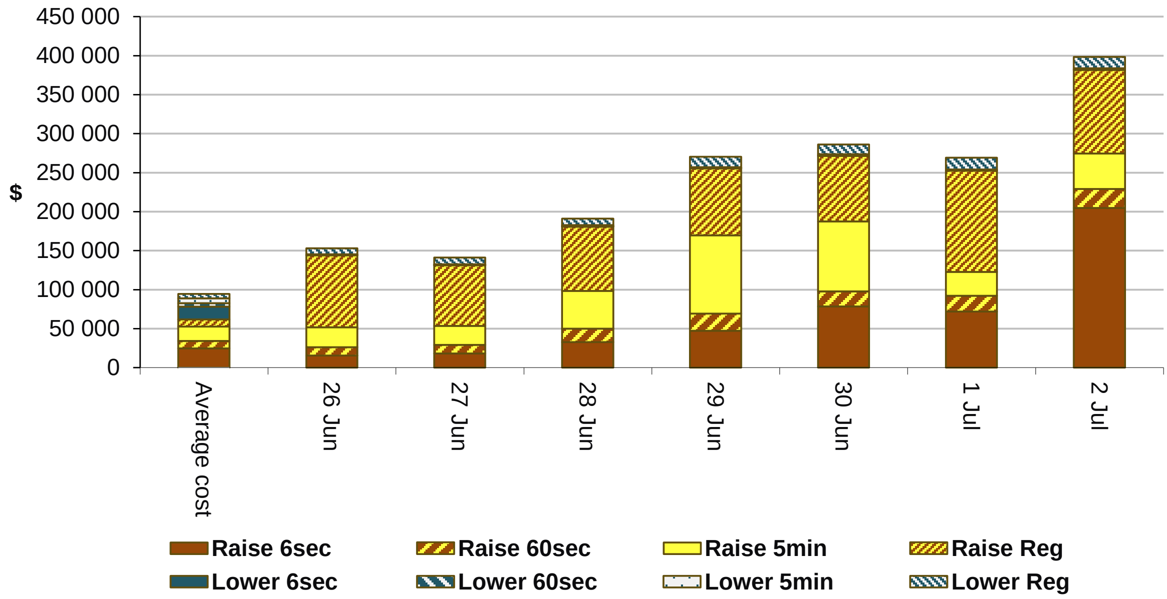


Figure 8 shows that daily FCAS costs were significantly higher than the average cost since the beginning of the previous financial year. The majority of the cost occurred on the mainland. However, the dispatch price for local raise 6 second services in Tasmania reached $6543/MWh for 70 MW of requirement at 11.15 am on Thursday, 30 June. The reasons for high FCAS costs on the mainland were due to limited availability of raise FCAS in the NEM with a maximum price of $250/MW for raise regulation services.

Detailed market analysis of significant price events

We provide more detailed analysis of events where the spot price was greater than three times the weekly average price in a region and above $250/MWh or was below -$100/MWh.

South Australia

There were six occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $189/MWh and above $250/MWh.

Monday, 27 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 am	1252.20	13 481.81	1850.60	1826	1830	1858	2209	2265	2280
9.30 am	1618.74	13 300.00	590.07	1797	1781	1804	2199	2256	2257
10 am	1241.39	13 296.94	413.07	1731	1728	1759	2178	2230	2236

The above spot prices were lower than forecast four hours ahead.

A planned outage of the Moorabool-Sydenham 500 kV line restricted imports across the Heywood interconnector into South Australia. At approximately 3 am, forecast imports into South Australia for the 9 am, 9.30 am and 10 am trading intervals decreased by about 150 MW, causing the relevant forecast spot prices to increase to about $13 500/MWh four hours ahead. The four-hour forecast prices did not eventuate, however, as Origin Energy, Engie and Energy Australia subsequently rebid a total of 350-400 MW of capacity from high to low prices.

Table 4: Rebids for 9 am, 9.30 am, 10 am trading intervals

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.13 am		Origin Energy	Ladbroke Grove	84	13800	-1000	0610A INC NEM DEM 5PD 23296 MW > 30PD 22696 MW @ 0630 SL
6.46 am		Energy Australia	Hallett	20	13482	-1000	06:44 A ADJ BANDS SA PRIC>30MPD PRICE @ 0630 166.68>66.01
7.04 am		Origin Energy	Quarantine	120	13800	<120	0700A INC NEM DEM 5PD 26665 MW > 30PD 26192 MW @ 0730 SL
7.04 am		Engie	Dry Creek	46	13800	<300	0704A SA DEMAND TRACKING AHEAD 5PD>30PD +51MW
7.42 am		Engie	Dry Creek	46	13800	<361	0741A SA DEMAND TRACKING AHEAD 5PD>30PD +62MW 08:00

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
8.17 am		Energy Australia	Hallett	18	>12195	590	08:16 A ADJ BANDS SA 5MPD PRICE>FCST @ 0900 1656.93>410.42
8.36 am	8.45 am	Engie	Snuggery	21	13800	-1000	0836A RESPOND TO SA VOLATILITY

Tuesday, 28 June – South Australia

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
10 am	1862.16	412.36	484.99	1660	1652	1676	2342	2370	2345
6.30 pm	2054.51	410.69	1502.62	2003	1974	2032	2260	2308	2346
7 pm	3102.23	410.69	1428.99	2027	1997	2056	2273	2322	2371

The spot prices for these trading intervals were higher than forecast four hours ahead.

A constraint managing the outage of the Kincraig-Penola West 132 kV line was binding, from 8.20 am to 9.40 am constraining off low-priced generation in the South East and limiting flows into South Australia from Victoria across the Heywood interconnector to less than 300 MW.

At 9.23 am, effective from 9.35 am, AGL rebid 140 MW of capacity at Torrens Island, from prices less than $485/MWh to $10 760/MWh. The reason given was '0920~A~040 chg in AEMO disp ~ 45 price increase vs pd SA $300.62 vs $160.99.'

With no capacity priced between $300/MWh and $10 500/MWh, the price, for the 9.35 am dispatch interval, increased to $10 760/MWh. In response, effective from 9.40 am, South Australian generators rebid 300 MW of high-priced capacity to the price floor and the dispatch price decreased to $160/MWh at 9.40 am. The dispatch price stayed below $160/MWh for the remainder of the trading interval.

The four hour ahead forecast for the 6.30 pm and 7 pm spot prices was lower than the 12 hour ahead forecast because of a decrease in forecast demand.

Four hours before the 6.30 pm and 7 pm trading intervals, forecast showed about 150 MW flowing on Murraylink into South Australia. However a constraint managing a planned outage of the Ballarat to Horsham line reversed flows on Murraylink to around 35 MW into Victoria. Further, actual wind generation for the 6.30 pm and 7 pm trading intervals was around 200 MW, 82 MW and 88 MW lower than forecast four hours ahead, respectively.

At 6.08 pm, effective from 6.15 pm, Lumo rebid 111 MW of capacity across its portfolio from the price floor to the price ceiling. The reason given was '18:02 A SA: 30MPD price $66.98 lwr thn 30MPD 18:10@17:32.' With no capacity priced between $400 and $10 700, this rebid combined with ramp rate and FSIP[1] limited plant saw the dispatch price rise to about $10 750/MWh at 6.25 pm and 6.35 pm and $7239/MWh at 6.40 pm. The dispatch price fell to $280/MWh at 6.45 pm when Lumo rebid 111 MW of capacity back to the price floor. The dispatch price remained below $280/MWh for the remainder of the 7 pm trading interval.

Tasmania

There were six occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $100/MWh and above $250/MWh.

Monday, 27 June

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
8 am	321.73	400.44	400.34	1503	1456	1451	2264	2199	2188
8.30 am	300.32	452.45	400.34	1510	1473	1466	2248	2200	2179

The spot prices for the 8 am and 8.30 am trading intervals were somewhat lower than forecast four hours ahead. Demand and availability were both higher than forecast four hours ahead.

For the 8 am trading interval, Basslink was exporting about 100 MW into Victoria, about 60 MW less than forecast and wind generation was 43 MW higher than forecast four hours ahead.

For the 8.30 am trading interval, there was minor rebidding of capacity from high to low prices and wind generation was 27 MW higher than forecast four hours ahead.

Prices remained at around $300/MWh for the majority of the 8 am and 8.30 am dispatch intervals.

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 am	300.56	16.87	300.32	1467	1460	1451	2179	2203	2178
9.30 am	300.32	22.59	300.32	1436	1442	1433	2177	2204	2177

The spot prices for the 9 am and 9.30 am trading intervals were higher than forecast four hours ahead. Availability and demand were close to forecast four hours ahead.

A combination of outages of the Sydenham to Moorabool lines and offer prices in Victoria were such that around 70 MW of power was forecast to be flowing into Victoria 12 hours ahead. Four hours ahead, flows were forecast to flow at a reduced export level of 2 MW at 9

[1] Fast Start Inflexibility Profile

am and import 66 MW at 9.30 am, causing the forecast price to decrease. Actual exports were greater than forecast four hours ahead at around 100 MW.

Thursday, 30 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
8 am	311.74	400.40	400.30	1391	1351	1404	2195	2132	2133
8.30 am	310.99	375.36	297.32	1401	1366	1425	2285	2122	2134

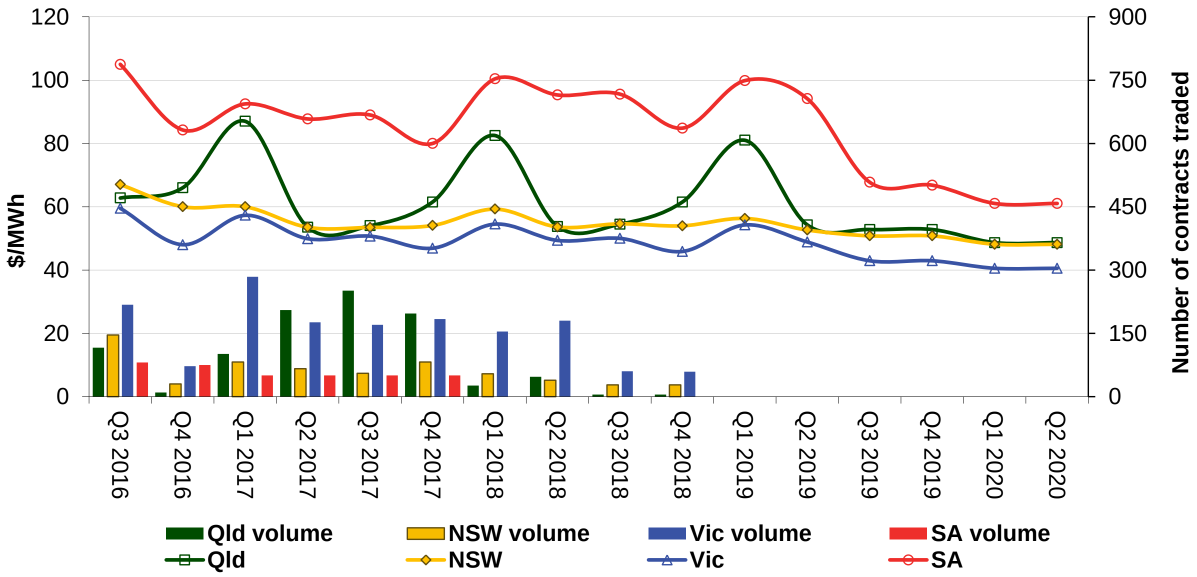
The spot prices for the 8 am and 8.30 am trading intervals were lower than forecast four hours ahead. Availability and demand were both higher than forecast four hours ahead.

For the 8 am trading interval, exports into Victoria were 169 MW but were forecast to be 223 MW four hours ahead. The 8.30 am price was close to forecast

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.

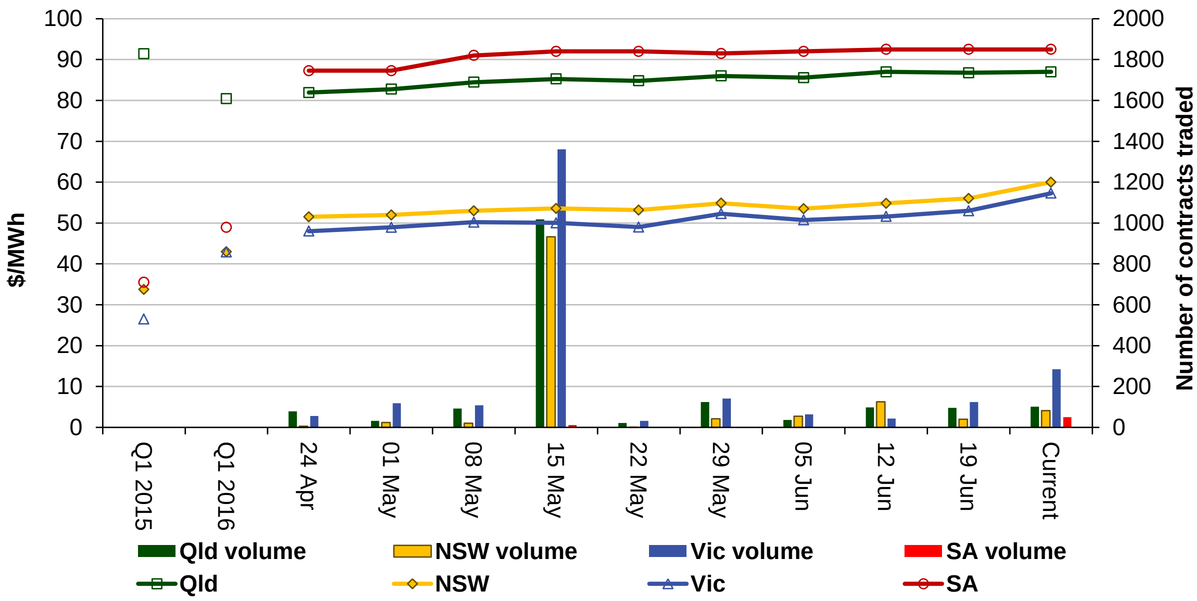
Figure 9: Quarterly base future prices Q2 2016 – Q1 2020



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 2017 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 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 2017 base contracts over the past 10 weeks (and the past 2 years)



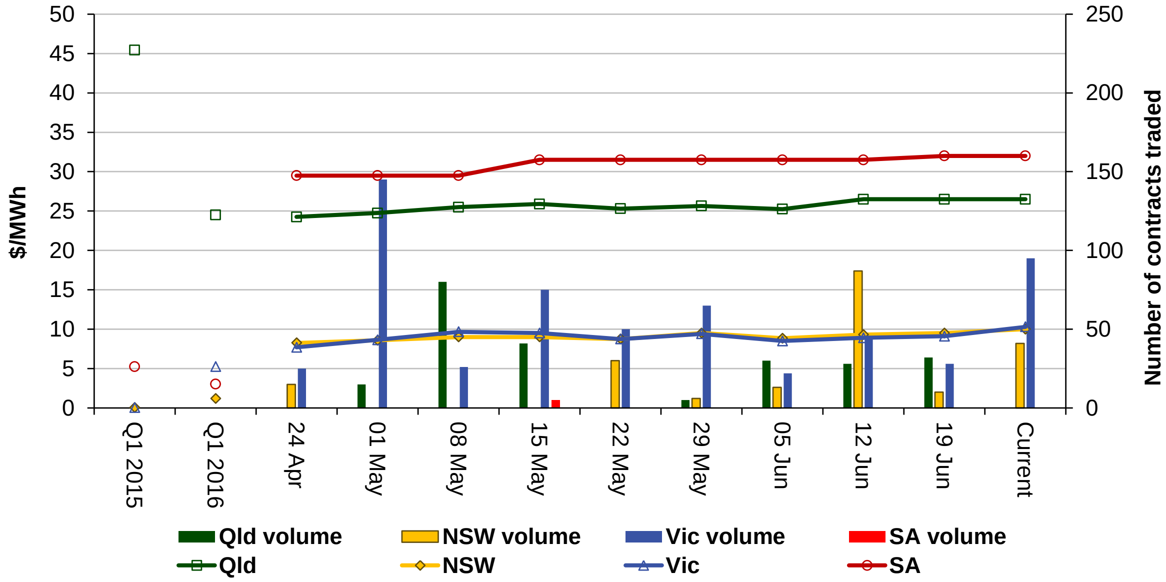
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2017 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown.

Figure 11: Price of Q1 2017 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

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