Electricity Report

10 – 16 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 10 to 16 July 2016. There were two occasions where the spot price in South Australia exceeded $5000/MWh. The AER will be writing reports into the events on the days that caused the price to exceed $5000/MWh as required under the Rules.

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

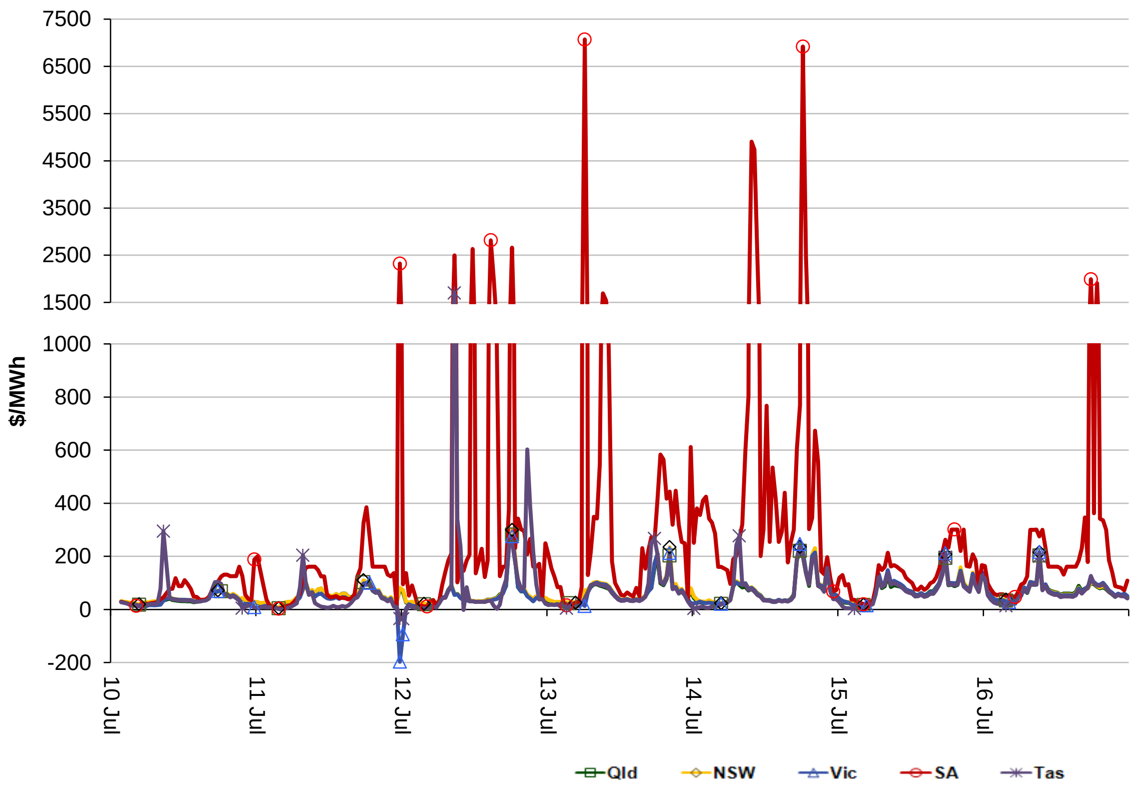


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

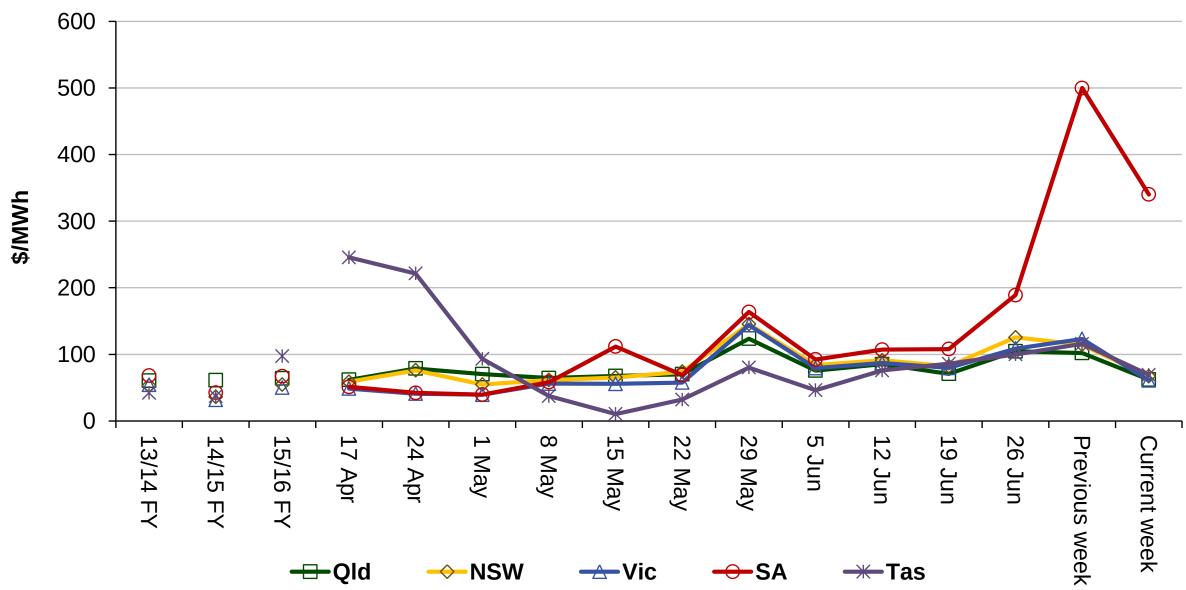


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	62	67	61	340	69
15-16 financial YTD	44	41	37	66	36
16-17 financial YTD	84	95	93	390	93

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 303 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	9	46	0	2
% of total below forecast	31	10	0	3

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

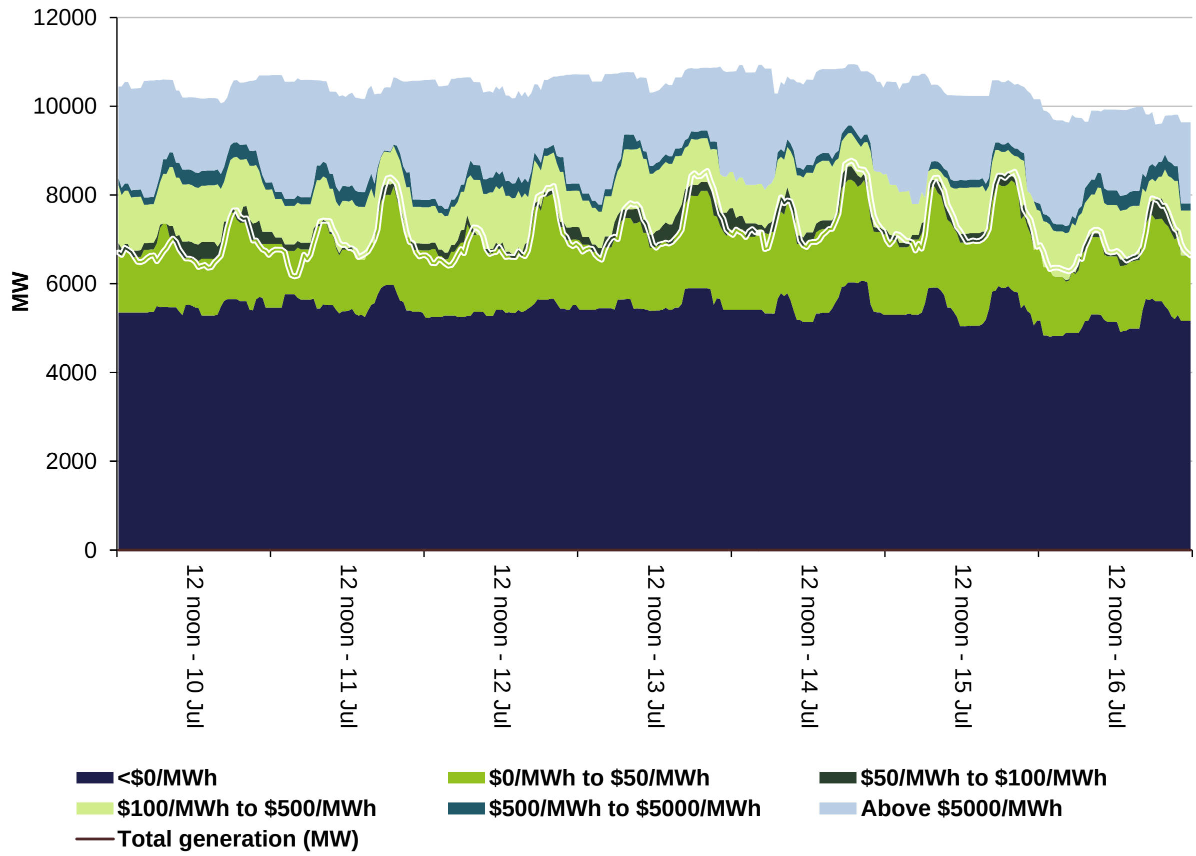


Figure 4: New South Wales generation and bidding patterns

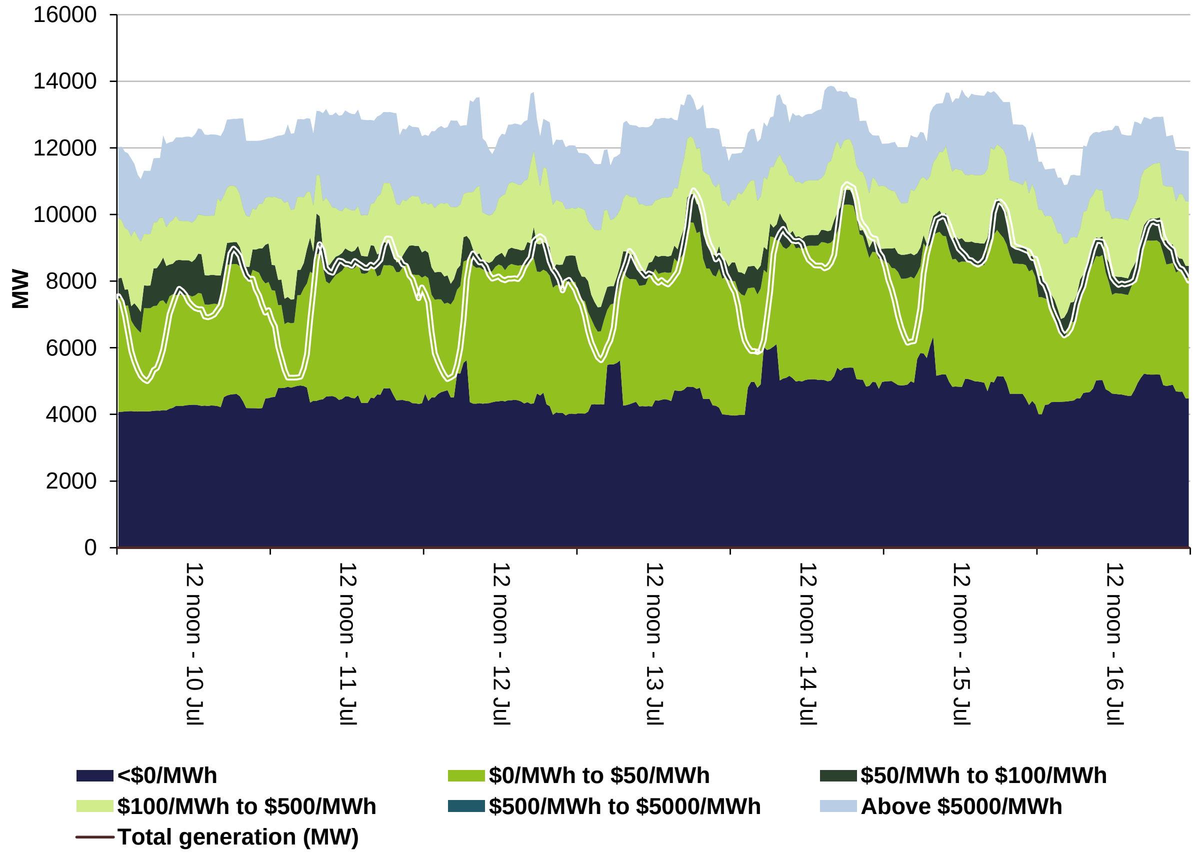


Figure 5: Victoria generation and bidding patterns

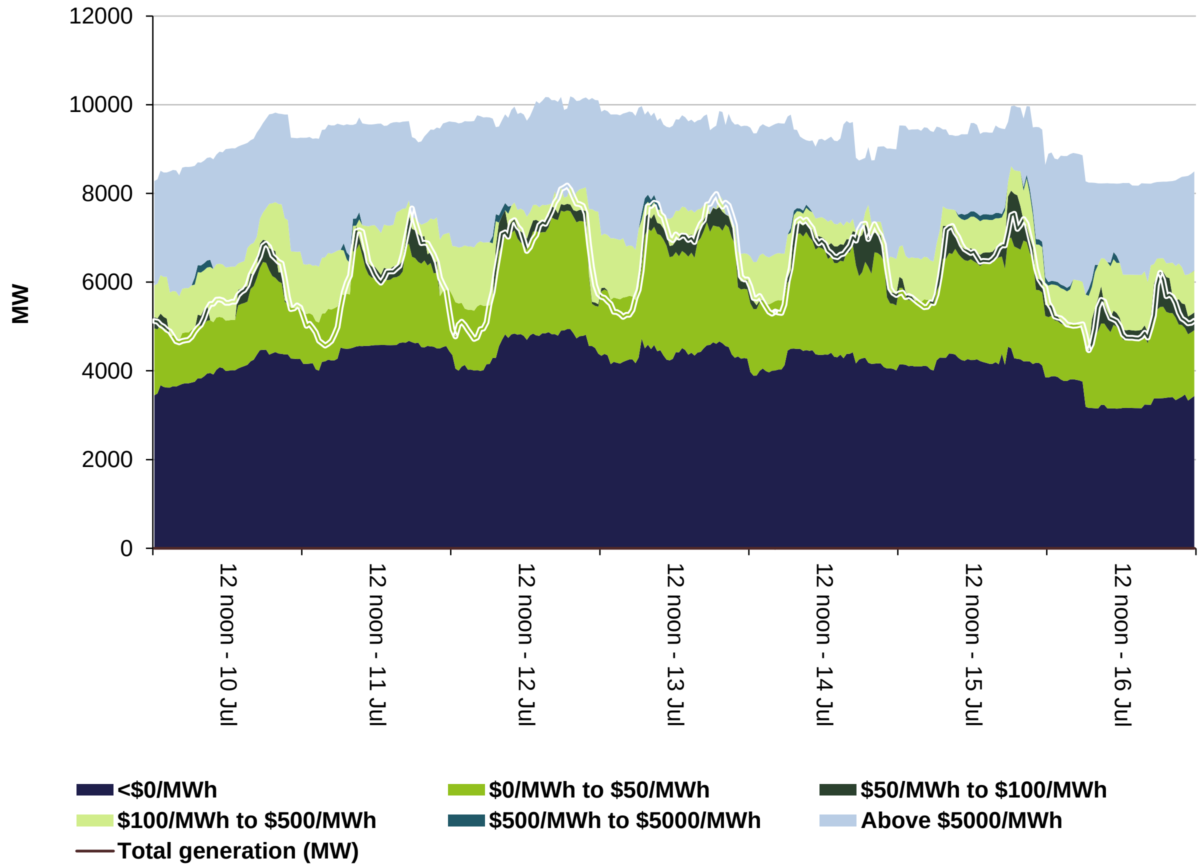


Figure 6: South Australia generation and bidding patterns

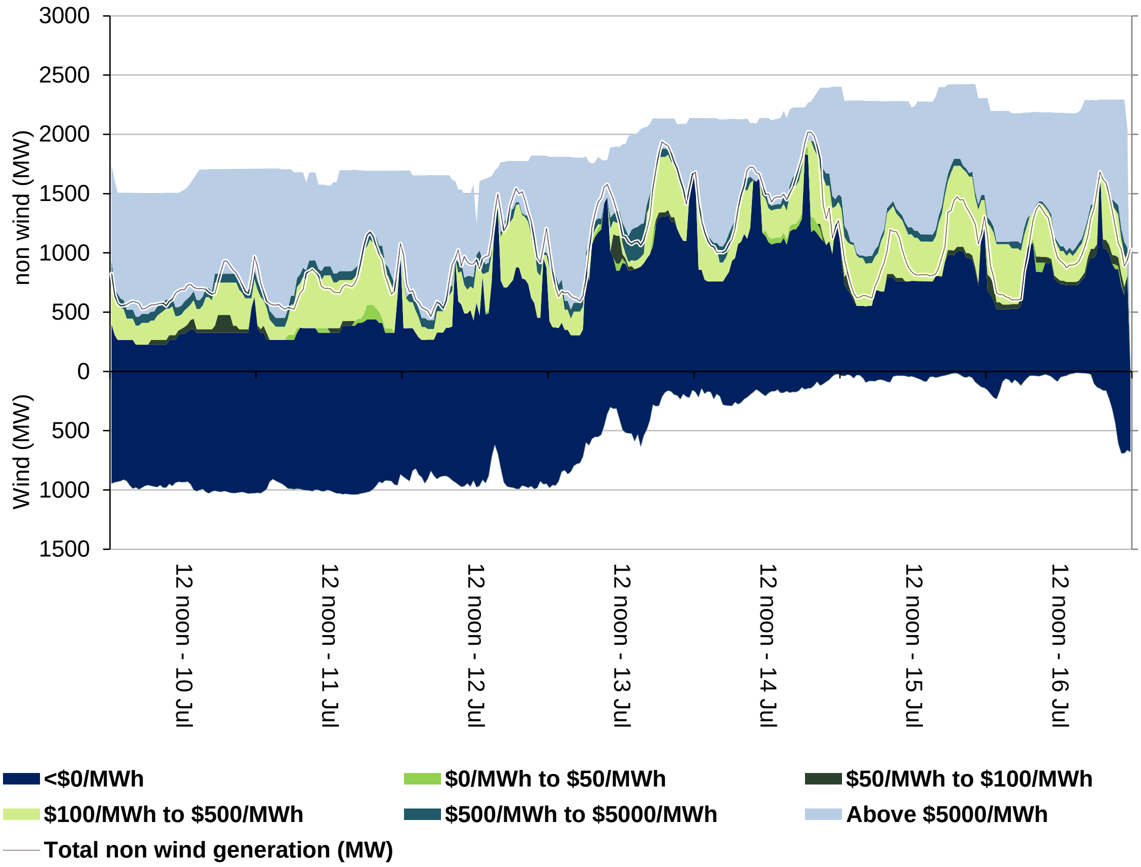
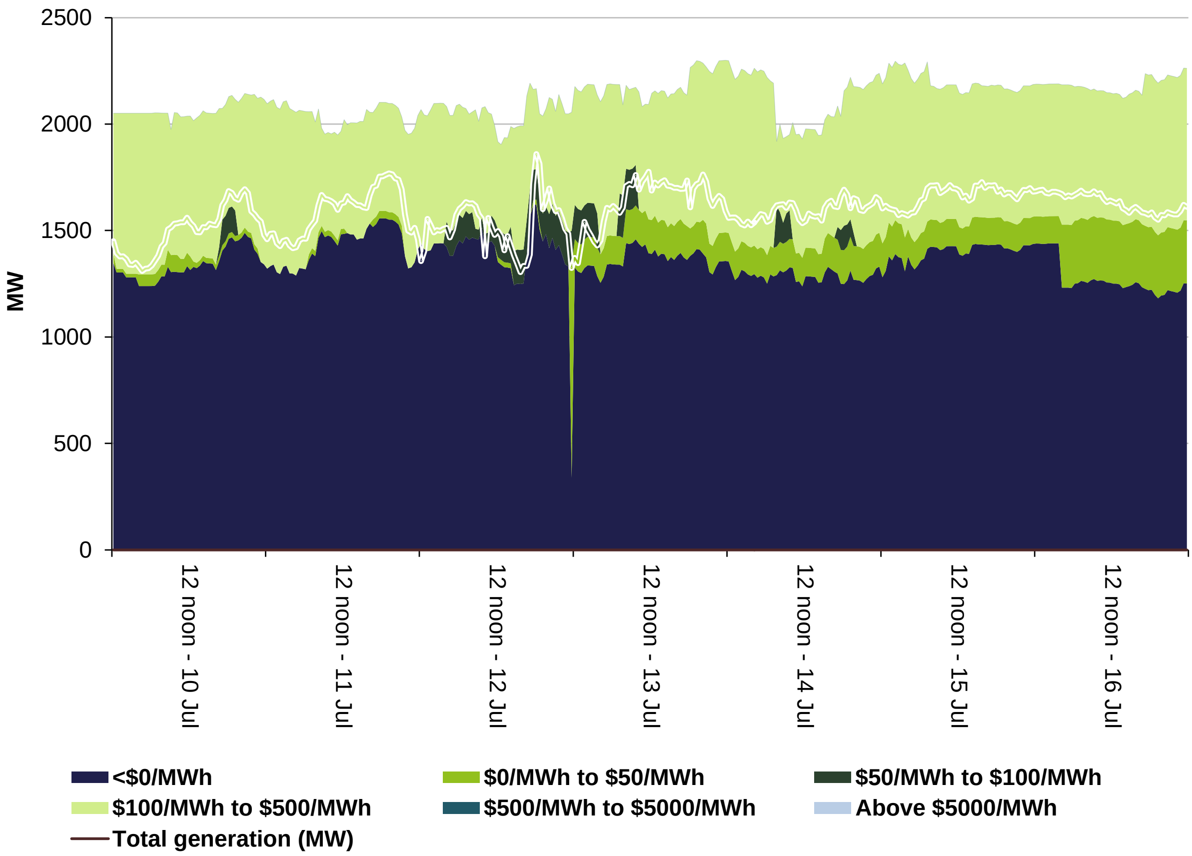


Figure 7: Tasmania generation and bidding patterns



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.

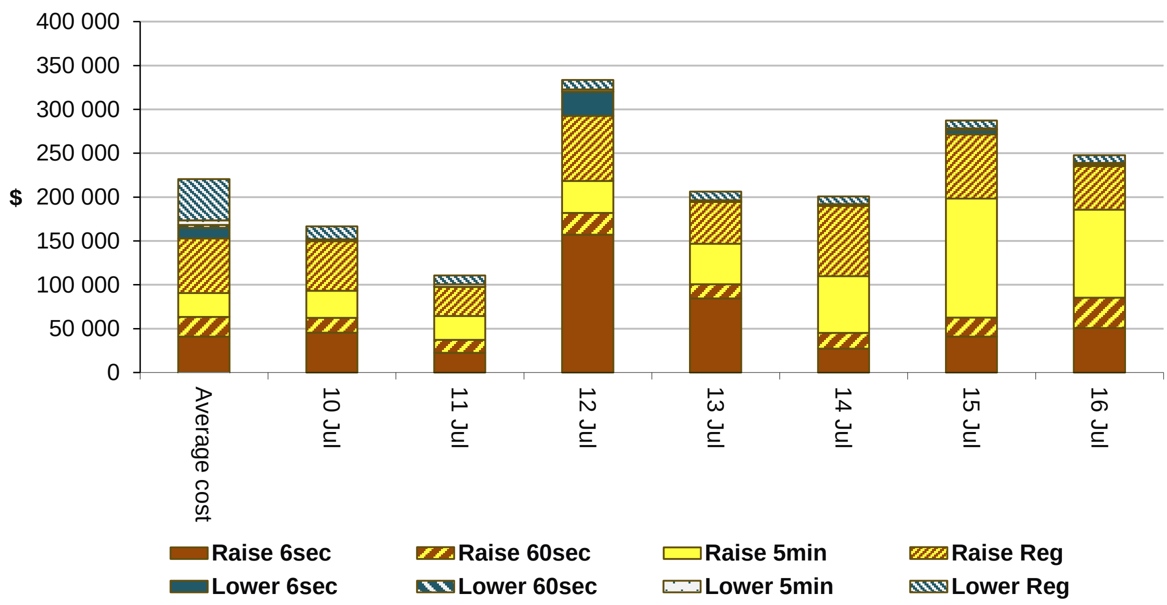
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 161 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $390 500 or less than 3 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



The majority of the raise 6 seconds service cost occurred in Tasmania on 12 and 13 July. On 12 July, the maximum price for raise 6 seconds services reached $4073/MW, due to the reclassification of credible contingencies. On 13 July the price reached $4839/MW at 6 pm when Basslink entered the no-go zone and the local requirement for raise 6 seconds service in Tasmania increased by around 50 MW. At 6.05 pm the requirement increased a further 20 MW and the price reached $4998/MW.

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.

National

There was one occasion where the spot price aligned nationally and the New South Wales price was greater than three times the New South Wales weekly average price of $67/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Tuesday, 12 July

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
6.30 pm	299.80	99.60	60.96	28 727	27 781	28 209	37 928	39 264	40 457

Conditions at the time saw demand almost 1000 MW higher than forecast four hours ahead and availability was around 1300 MW lower than forecast four hours ahead.

Table 4: Rebids for the 6.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.45 pm		CS Energy	Callide B	-10	16	N/A	1445P COAL QUALITY-SL
3.48 pm		Callide Power Trading	Callide C	-36	16	N/A	1547P POOR COAL CV.
4.47 pm		CS Energy	Callide B	-30	16	N/A	1647P MILL LIMIT-SL
5.01 pm		CS Energy	Callide B	-50	16	N/A	1701P COAL QUALITY-SL
5.33 pm		Millmerran Energy Trader	Millmerran	100	7	14044	17:20 A PD RUN 2016071227: HHE 18:00: 186CHANGEINQLD_PLUS_500 SL
5.45 pm		CS Energy	Callide B	-10	16	N/A	1745P COAL QUALITY-SL
5.42 pm		Delta Electricity	Vales Point	-630	<279	N/A	1742P UNIT TRIP
6.04 pm	6.15 pm	Origin Energy	Mortlake	-275	250	N/A	1803A AVOID UNECONOMIC START - AVOID SHORT RUN SL

The higher than forecast demand and above rebidding saw prices across the NEM at around $300/MWh for the majority of the trading interval.

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 $67/MWh and above $250/MWh. One of these occurred when prices were generally aligned across all regions and is detailed in the national market outcomes section. The remaining occasion is presented below.

Tuesday, 12 July

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	254.94	76.35	60.96	10 527	10 212	10 687	13 332	13 460	14 243

Conditions at the time saw demand 315 MW higher than forecast four hours ahead and available capacity slightly lower than forecast four hours ahead. Prices were aligned with the other region but New South Wales was the only region that triggered our reporting thresholds.

The higher than forecast demand and rebidding shown in Table 4 resulted in the dispatch price increase to around $300/MWh at 5.40 pm and remained there for the rest of the trading interval.

Victoria

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

Monday, 11 July

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	-196.93	16.15	0	5190	5207	5124	9625	9268	9737

Condition at the time saw demand close to forecast and availability around 360 MW higher than forecast four hours ahead.

At 11.30 pm the dispatch price in South Australia reached the price cap (see South Australian section for details) as a result imports into Victoria across Murraylink reduced by around 130 MW. This impacted a system normal constraint which affects the Vic-NSW interconnector. The Vic-NSW interconnector went from exporting to New South Wales at 649 MW at 11.30 pm to importing into Victoria at 326 MW at 11.35 pm. This step change resulted in excess generation in Victoria and the price fell to the price floor. The price remained zero or negative for the rest of the trading interval.

South Australia

There were sixteen occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $340/MWh and above $250/MWh. One of these occurred when prices were generally aligned across all regions and is detailed in the national market outcomes section. The remaining fifteen occasions are presented below.

Monday, 11 July

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
Midnight	2324.03	110.74	239.34	1587	1543	1519	2586	2741	2738

Conditions at the time saw demand 44 MW higher than forecast four hours ahead, while availability was 175 MW lower than forecast 12 hours ahead.

Demand increased by 221 MW at 11.35 am due to hot water load, while wind generation was 250 MW lower than forecast four hours ahead. With lower priced generation being either fully dispatched or constrained down, the dispatch price increased from $13/MWh at 11.30 am to $14 000/MWh at 11.35 am.

Tuesday, 12 July

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
9 am	2495.79	300.99	300.99	1668	1657	1658	2574	2661	2722
Midday	2632.01	44.48	124.99	1638	1415	1398	2519	2661	2716
3 pm	2815.68	124.99	122.99	1696	1521	1417	2395	2663	2695
3.30 pm	1964.58	124.99	124.99	1730	1548	1438	2293	2668	2700
6.30 pm	2661.36	501.24	350.01	2178	2018	1904	2772	2822	2825

Conditions at the time saw demand up to 220 MW higher than forecast, while availability was up to 375 MW lower than forecast as a result of lower than forecast wind generation.

A planned outage of the Tailem Bend West Bus and the South East to Tailem Bend line, as part of the upgrade to the Heywood interconnector, was limiting imports across Heywood and at times forcing flow into Victoria counter-price. Further, a constraint managing the overload of the Buangor to Ararat 66kV line on the loss of the Ararat to Horsham line was limiting imports across Murraylink to less than 75 MW.

Supply conditions in South Australia were tight, with no capacity available priced between $300/MWh and $13 900/MWh. At 8.50 am there was a 17 MW reduction in semi-scheduled wind, this combined with a small increase in demand saw 7 MW of high price capacity dispatched. The dispatch price increased from $579/MWh at 8.45 am to $13 999/MWh at 8.50 am. In response to the high price participants rebid capacity from high to low prices and the price fell to $36/MWh at 8.55 am.

At midday there was a small increase in demand and an increase in forced flows into Victoria across the Heywood interconnector. With all low-priced capacity fully dispatched or ramp rate limited the dispatch price increased from $590/MWh at 11.55 am to the price cap at midday.

At 3 pm there was a 136 MW reduction in availability as wind generation reduced. With other low-priced generation either fully dispatched or ramp rate limited the dispatch price increased from $579/MWh at 2.55 pm to the price cap at 3 pm and $13 999/MWh at 3.05 pm. In response to the high prices participants rebid around 500 MW of capacity to the price floor and the dispatch fell to negative prices until 3.35 pm.

At 6.30 pm there was a small increase in demand and a decrease in wind generation. With other low-priced generation either fully dispatched or trapped in FCAS the dispatch price increased from $763/MWh at 6.25 pm to the price cap at 6.30 pm.

Wednesday, 13 July

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
6.30 am	7068.49	124.99	18.66	1191	1180	1154	2429	2706	2704

In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh.

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
9.30 am	1692.55	763.46	604.36	1691	1671	1686	2270	2504	2516
10 am	1543.95	1498.20	604.36	1642	1637	1641	2142	2454	2479

Conditions at the time saw demand close to forecast and available capacity up to 312 MW lower than that forecast four hours ahead, predominately due to lower than forecast wind generation. The continued outage at Tailem Bend was forcing exports into Victoria, counter-price, across Heywood by around 220 MW. Murraylink was importing at its nominal limit.

Table 11: Rebids for the 9.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
8.44 am		Origin Energy	Quarantine	44	482	13 239	0840A ENSURE ECONOMIC DISPATCH - AVOID SHORT

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
							SHUTDOWN SL
8.46 am		AGL Energy	Torrens Island	-52	-1000	N/A	0843~P~010 UNEXPECTED/PLANT LIMITS~108 LOAD/RAMP VARIATION DURING RTS / RTS DELAYED

With little capacity priced between $400/MWh and $10 000/MWh and other low-priced capacity ramp rate limited when the above rebids became effective at 9.05 am the dispatch price increased from $579/MWh at 9 am to $13 330/MWh. In response to the high price participants in South Australia rebid around 200 MW from high prices to the price floor and they price went negative for the remainder of the trading interval.

The price for 10 am was close to that forecast four hours ahead.

Thursday, 14 July

Table 12: 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	4905.67	10 669.99	10 669.99	1812	1699	1710	2270	2310	2270
10.30 am	4734.70	10 669.99	13 299.01	1758	1637	1650	2248	2313	2273
11 am	2332.41	13 299.01	13 299.01	1690	1559	1581	2279	2315	2261

Conditions at the time saw demand higher than forecast and availability slightly lower than forecast. The continued outage at Tailem Bend was forcing exports into Victoria, counter-price, across Heywood by up to 185 MW. Murraylink was importing at its nominal limit at times of high dispatch prices. Wind generation was between 222 MW and 280 MW.

At 6.58 am Origin Energy rebid up to 153 MW of capacity at Quarantine unit 5 from around $13 200/MWh to -$993/MWh. The reason given was related to higher than forecast demand. Other participants rebid small amounts of capacity from high to low prices. These rebids resulted in prices being lower than forecast four hours ahead.

Table 13: 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
6.30 pm	6917.55	14 000.00	13 299.02	2061	2158	2094	2381	2529	2531
7 pm	2462.83	433.94	350.01	2115	2206	2163	2410	2537	2536

In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh.

Saturday, 16 July

Table 14: 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	1992.34	299.99	406.89	1660	1665	1745	2399	2327	2325
7 pm	1910.47	485.94	578.81	1921	1871	1970	2440	2364	2396

Conditions at the time saw demand and availability close to forecast. The continued outage at Tailem Bend was limiting imports to around 2 MW across Heywood. Murraylink was importing at its nominal limit. Wind generation was around 150 MW.

Table 15: Rebids for the 6 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.38 pm		AGL Energy	Torrens Island	30	300	13 993	1531~A~050 CHG IN AEMO PD~55 PD PRICE INCREASE SA $279
5.13 pm		EnergyAustralia	Hallett	50	<583	>10 649	17:12 A ADJ BANDS MAT CHANGE SA 30MPD PRICE @ 1900 10669.99

There was no capacity priced between $411/MWh and $10 000/MWh meaning small changes in demand and availability could lead to volatile prices. The above rebids and a small change in demand at 6 pm and 6.40 pm saw the price increase from $301/MWh at 5.55 pm to $10 579/MWh at 6 pm and from $350/MWh at 6.35 pm to $10 670/MWh at 6.40 pm. In response to the high price at 6.40 pm participants rebid capacity from high to low prices and the price fell to $127/MWh at 6.45 pm.

Tasmania

There were nine occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $69/MWh and above $250/MWh. One of these occurred when prices were generally aligned across all regions and is detailed in the national market outcomes section. The remaining eight occasions are presented below.

Sunday, 10 July

Table 16: 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	294.59	362.32	343.90	1264	1278	1278	2052	2053	2052

The price was close to forecast.

Tuesday, 12 July

Table 17: 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	1695.07	131.76	64.95	1311	1318	1308	2067	2061	2066
9.30 am	339.15	125.50	29.86	1322	1310	1299	2013	2061	2068
6.30 pm	255.79	95.06	59.64	1479	1449	1418	2166	2336	2335
9 pm	602.95	98.30	31.22	1313	1320	1310	2145	2323	2334
9.30 pm	389.62	32.20	20.82	1331	1285	1279	2059	2202	2334

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

From around 8.50 am AEMO invoked constraints to manage the reclassification of numerous lines in Tasmania as a credible contingency due to lightning. As a result of the network limitations dispatch prices varied between -$24/MWh and $9239/MWh until the constraints were revoked at around 10.15 pm.

Wednesday, 13 July

Table 18: 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	254.45	84.71	339.20	1438	1375	1451	2147	2182	2215
6 pm	267.01	308.84	270.48	1448	1415	1494	2136	2181	2215

Conditions at the time saw demand 63 MW higher than forecast four hours ahead and availability was 33 MW lower than forecast four hours ahead.

There was no capacity priced between $5/MWh and $250/MWh. At 5.05 pm there was a small increase in demand with all low-priced generation either trapped or stranded in FCAS or fully dispatched the price increase from $78/MWh at 5 pm to $254/MWh at 5.05 pm and stayed at that price for the rest of the trading interval.

The price at 6 pm was close to forecast.

Thursday, 14 July

Table 19: 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

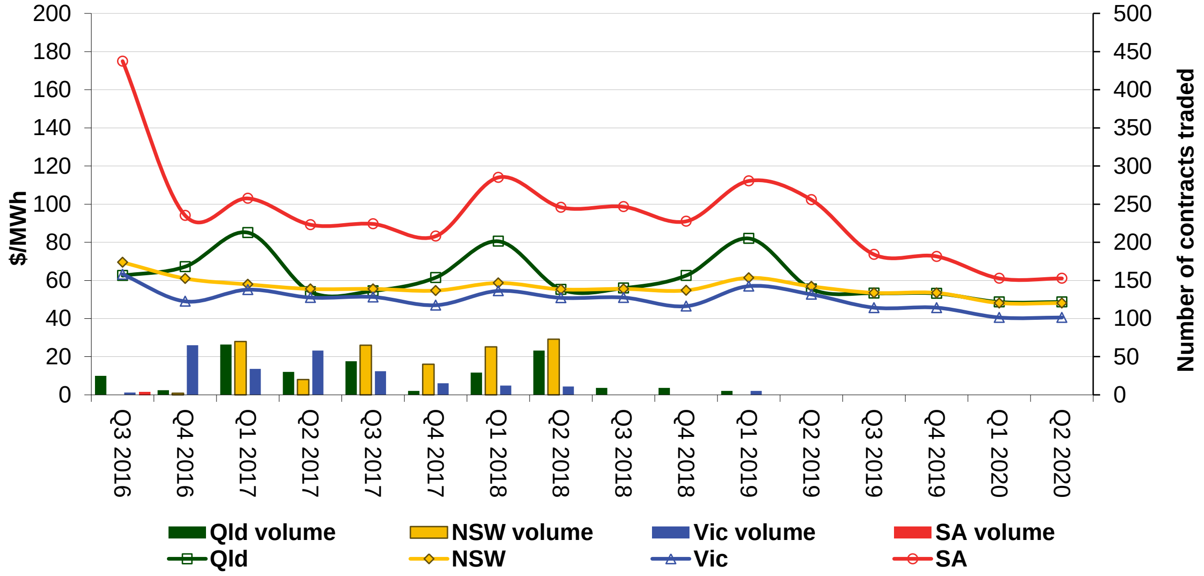
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
8 am	277.21	344.23	96.23	1344	1390	1401	1975	2129	2130

The price was close to that forecast four hours ahead.

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.

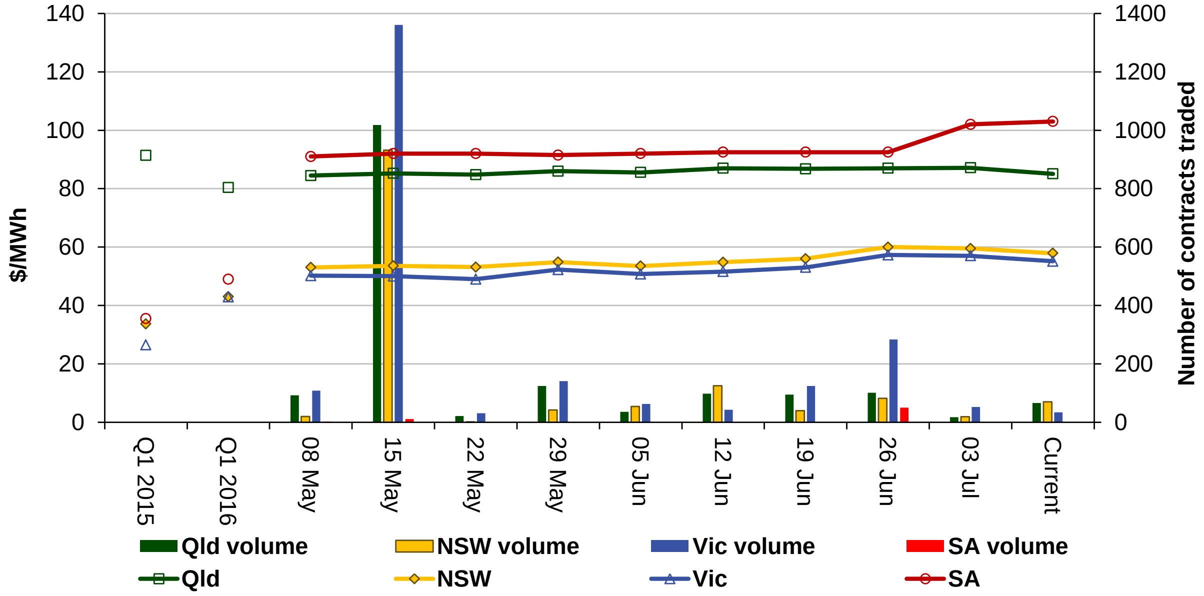
Figure 9: Quarterly base future prices Q3 2016 – Q2 2020



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)



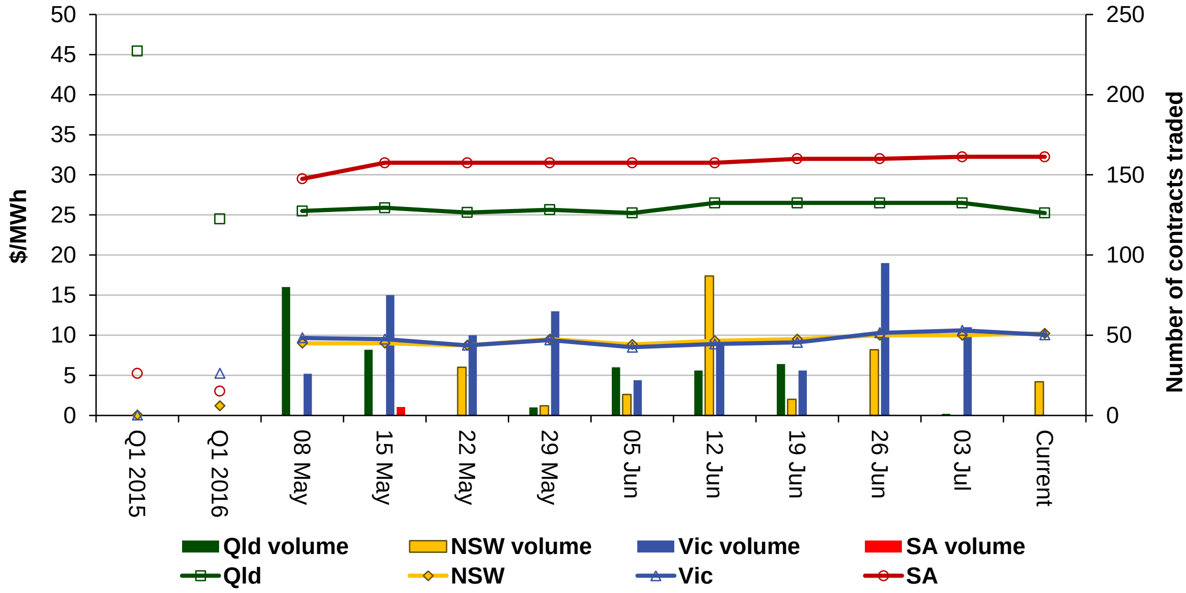
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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

Australian Energy Regulator
August 2016