Electricity Report

AUSTRALIAN ENERGY REGULATOR

19 – 25 June 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 19 to 25 June 2016.

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

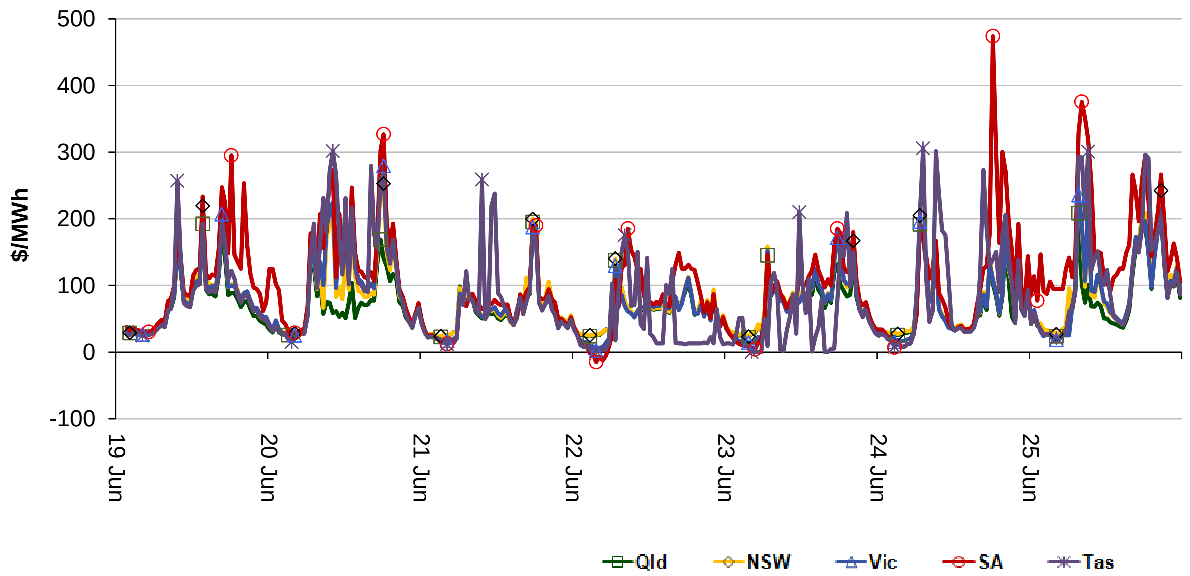


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

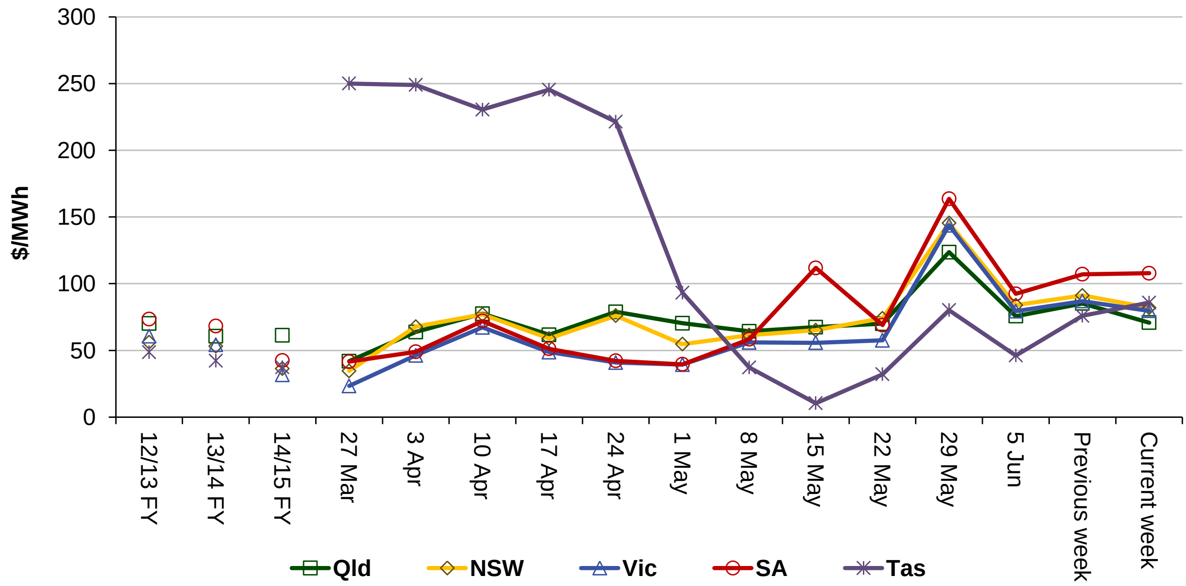


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	71	82	80	108	86
14-15 financial YTD	62	36	32	42	37
15-16 financial YTD	63	53	49	65	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 290 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	6	56	0	2
% of total below forecast	30	4	0	1

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

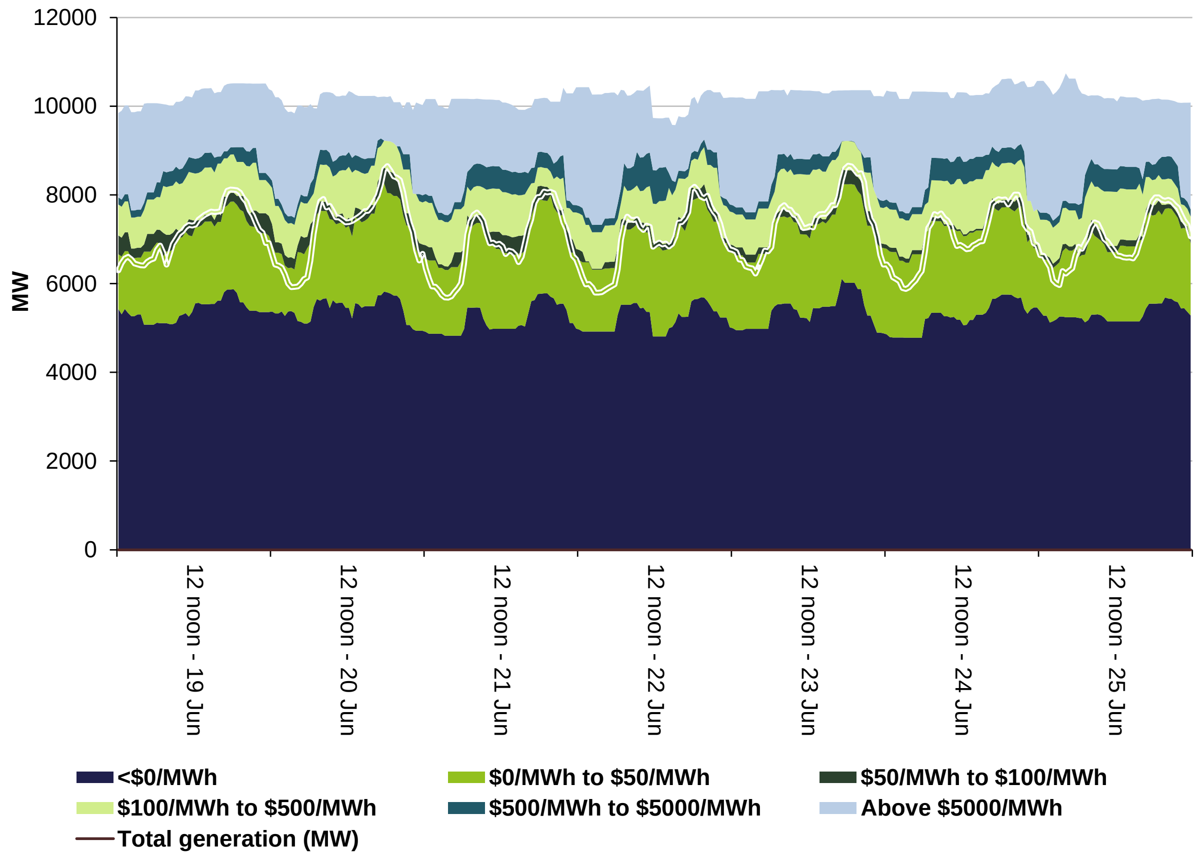


Figure 4: New South Wales generation and bidding patterns

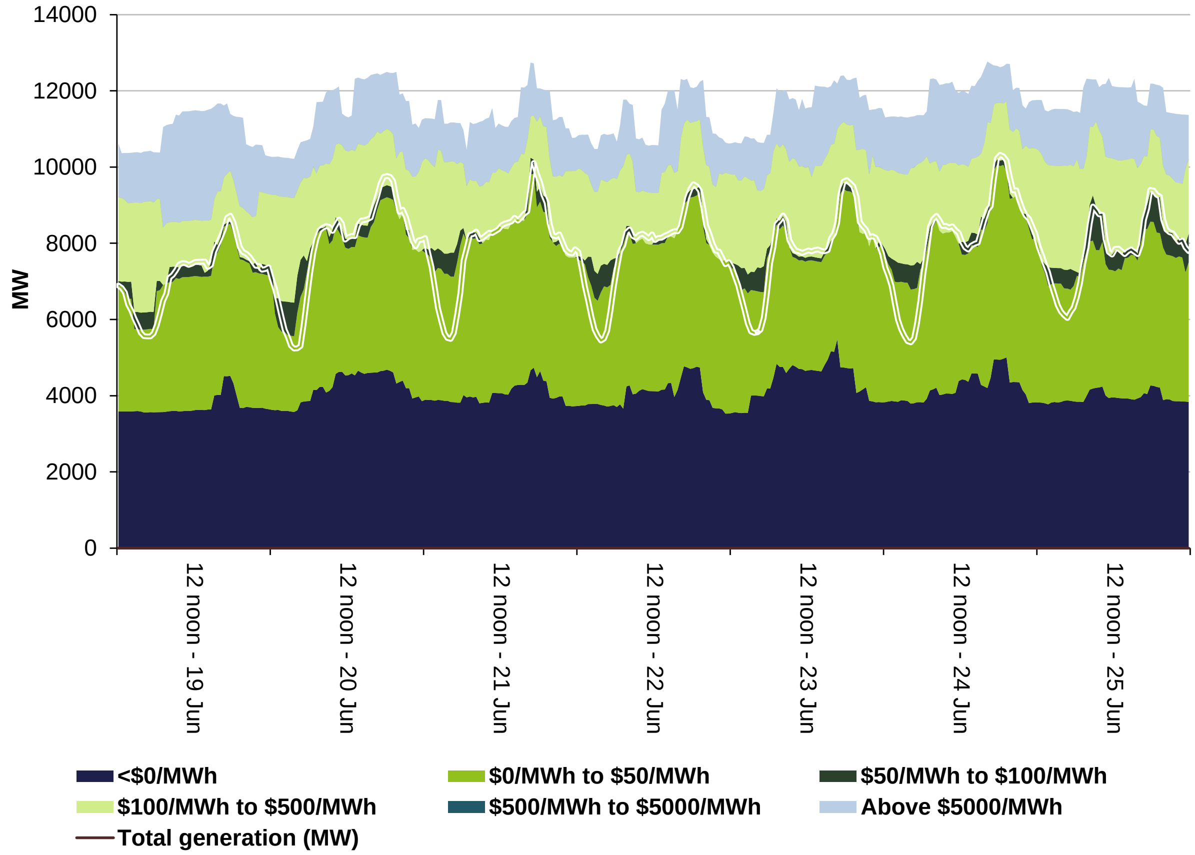


Figure 5: Victoria generation and bidding patterns

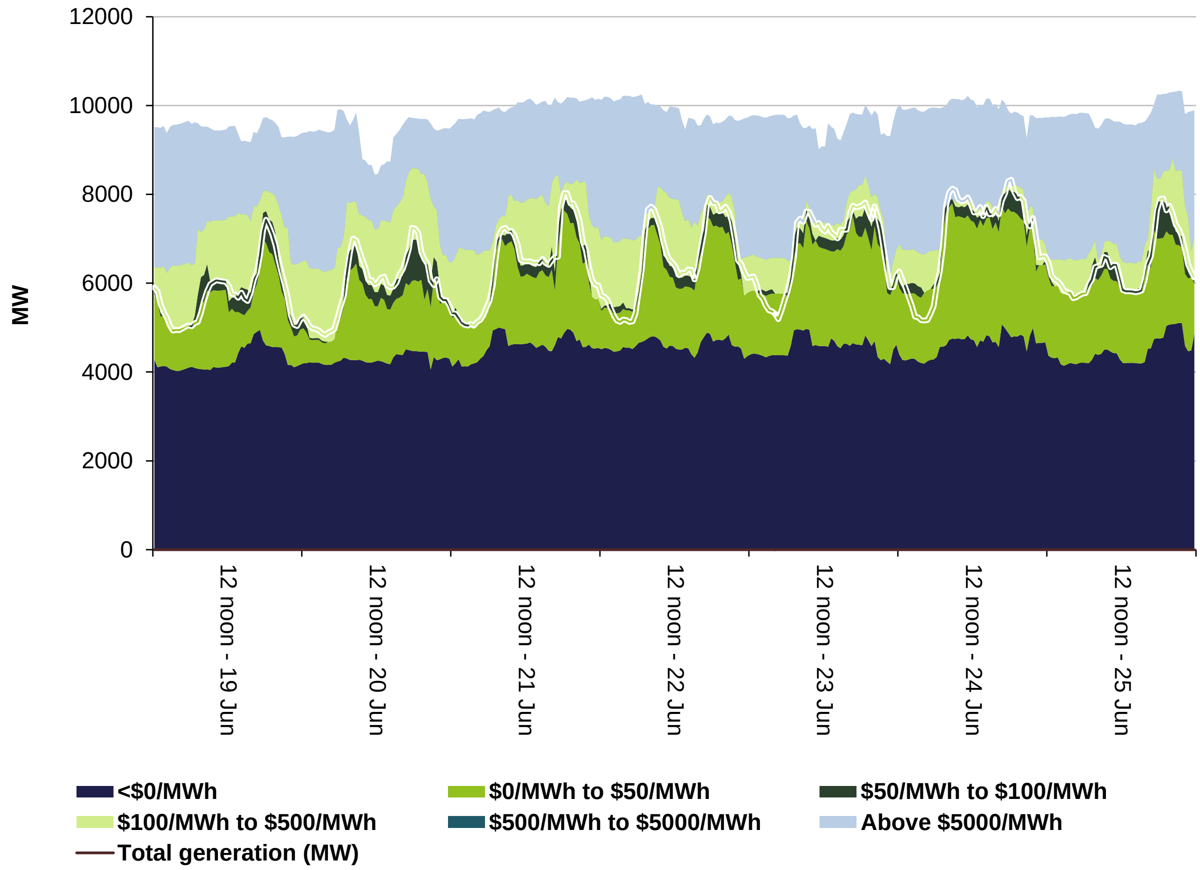


Figure 6: South Australia generation and bidding patterns

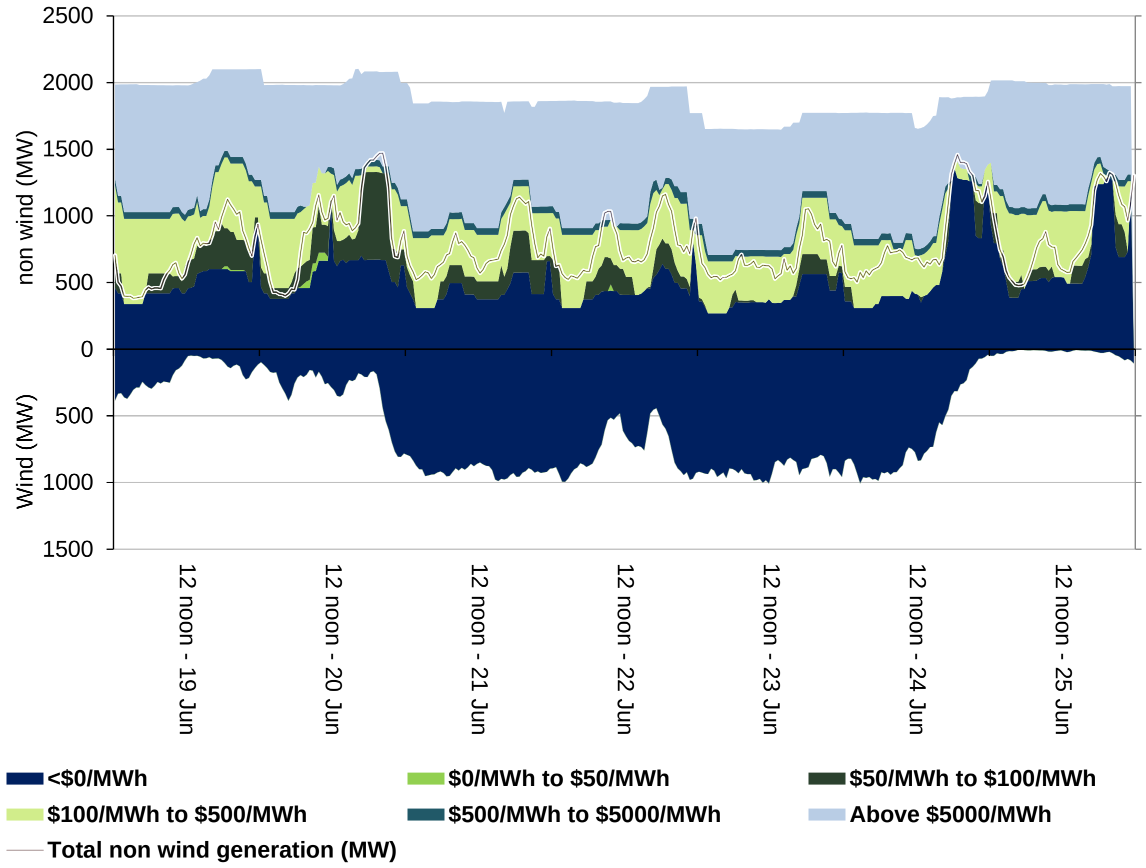
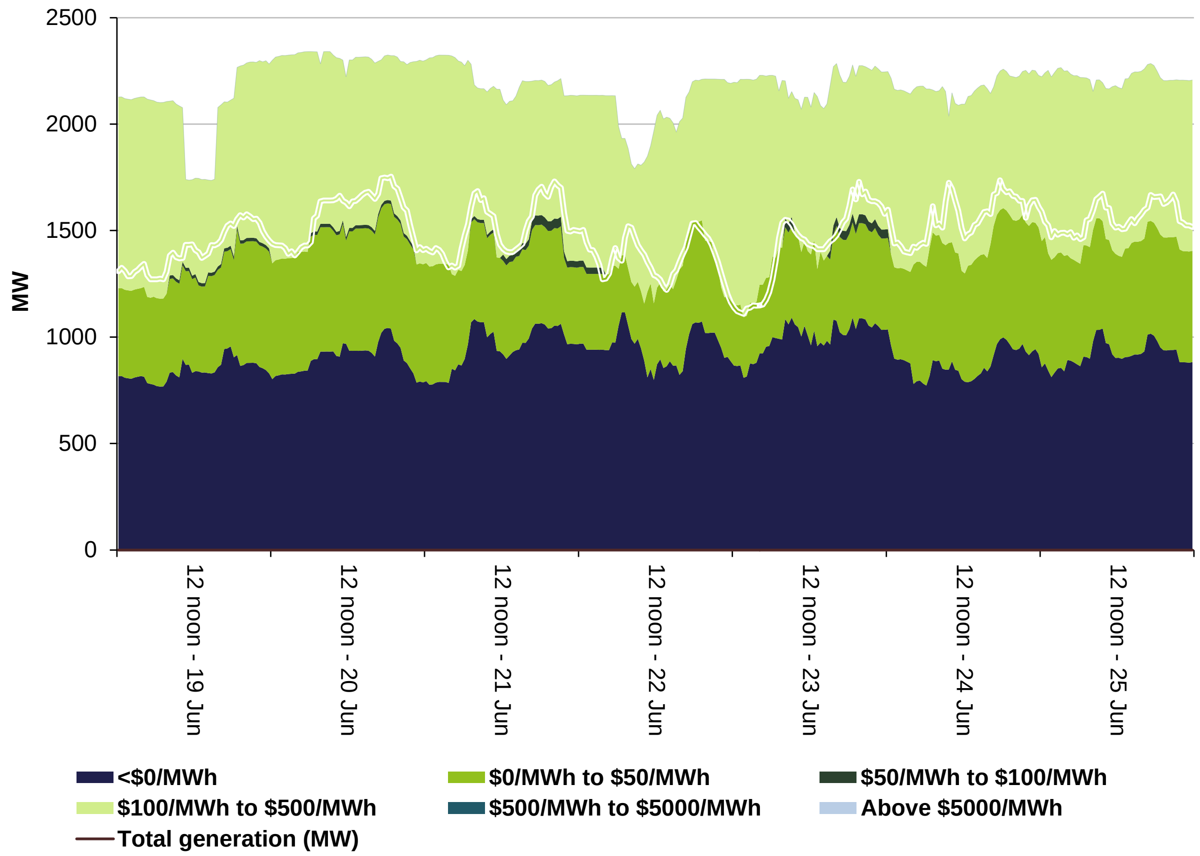


Figure 7: Tasmania generation and bidding patterns



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 $1 309 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $404 000 or around 2.5 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

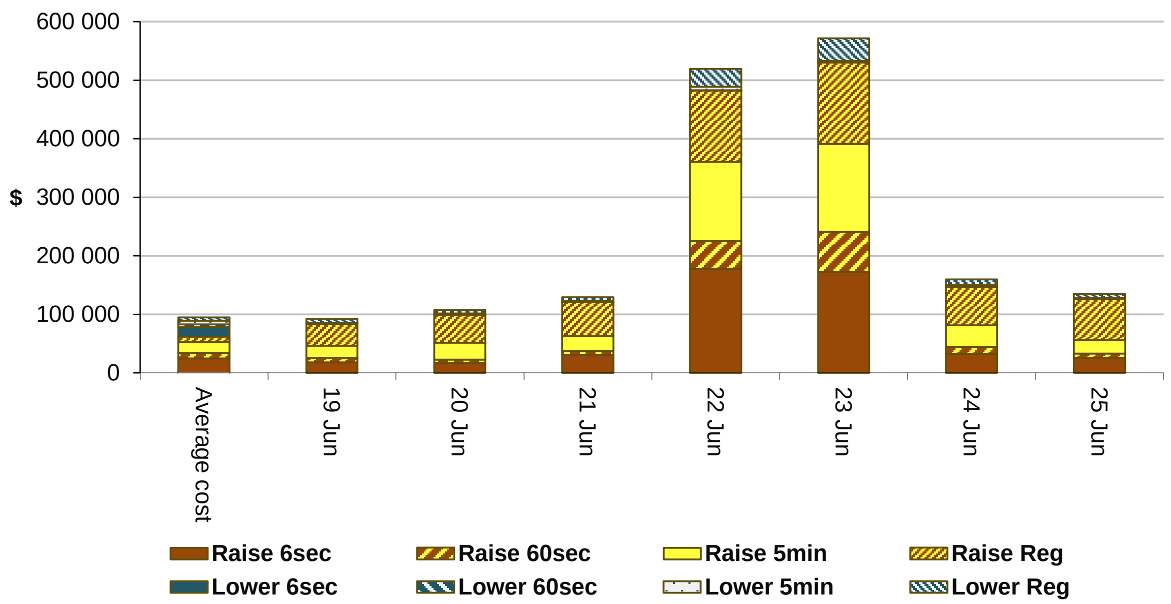


Figure 8 shows that daily FCAS costs were significantly higher than the average of the previous financial year. The majority of the cost occurred on the mainland. The reasons for high FCAS costs were due to limited availability of raise FCAS in the NEM with a maximum price of $150/MW for raise regulation 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.

National

There were two occasions where the spot price was aligned nationally and at least one of those occasions saw the spot price greater than three times the region's weekly average price and above $250/MWh.

Monday, 20 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
6 pm	248.77	299.80	105.45	28 351	28 240	27 957	37 018	37 422	37 362
6.30 pm	252.78	299.80	100.97	28 315	28 302	27 930	37 000	37 267	37 674

The spot prices were similar to the four hours ahead forecast, but around $150/MWh higher than the 12 hours ahead forecast. The difference between the 12 hours ahead forecast and actual was due to the delayed return to service of Origin Energy's Eraring unit 1. The market was notified of this delay at 9 am. This effectively reduced evening supply by 640 MW (all of which was priced below $30/MWh). Following this reduction, the forecast price in each region increased to around $300/MWh.

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $108/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 four occasions are presented below.

Friday, 24 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
6.30 pm	473.86	350.00	350.00	2027	1979	1972	2198	2302	2318

Conditions at the time saw demand close to forecast and availability around 100 MW lower than forecast.

At 2 pm, AGL notified the market of the delayed return to service of Torrens A unit 4, following a trip earlier in the day, effectively reducing available supply in South Australia by 120 MW. All of this capacity was priced below $160/MWh.

The reduction in supply combined with generation being constrained down at Lake Bonney, to manage the network limitations around Snuggery and Keith, saw the South Australian dispatch price increase from $300/MWh at 6.10 pm to $1527/MWh at 6.15 pm. Prices returned to below $150/MWh for the remainder of the trading interval.

Saturday, 25 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
8 am	329.39	123.69	159.99	1437	1405	1371	2006	2094	2015
8.30 am	375.45	160.99	299.99	1524	1487	1453	2007	2096	2011
9 am	351.00	160.99	299.99	1570	1515	1497	2006	2097	2011

Conditions at the time saw availability close to forecast. Wind generation was only around 40 MW, around 70 MW lower than forecast four hours ahead.

The reduction in forecast prices 12 and 4 hours ahead for 8.30 am and 9 am trading intervals were a result of rebidding by AGL at Torrens Island. During the high price period, South Australia had a steep supply curve with no capacity priced between $160/MWh and $300/MWh. Small changes in demand and wind dispatch resulted in dispatch prices between $160/MWh and $410/MWh during the high priced period.

Tasmania

There were 15 occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $86/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 14 occasions are presented below.

Monday, 20 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
10 am	270.58	341.72	300.32	1394	1372	1366	2333	2343	2335
10.30 am	301.67	66.74	68.04	1382	1338	1335	2319	2344	2341
11 am	265.93	97.76	77.72	1396	1307	1296	2309	2345	2341

Conditions at the time saw demand up to 59 MW higher than the four hours ahead forecast.

During the high price periods, Tasmania had a steep supply curve, with no capacity priced between $65/MWh and $285/MWh.

The 10 am interval price was slightly lower than forecast four hours ahead as export to Victoria were slightly lower than forecast.

The 10.30 am and 11 am trading intervals saw demand greater than forecast four hours ahead (by up to 89 MW), resulting in the dispatch price at around $300/MWh for all but one dispatch interval at 11 am.

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
4.30 pm	279.65	94.84	49.32	1380	1293	1264	2287	2331	2341

Conditions at the time saw demand 87 MW less than forecast four hours ahead.

Again Tasmania had a steep supply curve, with no capacity priced between $70/MWh and $285/MWh. Small changes in demand resulted in the dispatch price increasing from $91/MWh at 4.10 pm to $398/MWh at 4.15 pm and then fluctuate between $300/MWh and $398/MWh for the remainder of the trading interval.

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
6.pm	258.31	300.32	99.36	1502	1448	1390	2321	2347	2341

Price was close to forecast four hours ahead.

Tuesday, 21 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
10 am	258.79	400.38	31.02	1321	1333	1330	2151	2192	2205

Conditions at the time saw demand and availability close to forecast and the actual price lower than forecast four hours ahead.

At 7.33 am, Hydro Tasmania rebid 54 MW of capacity at Trevallyn priced at $400/MWh to-$50/MWh. The reason given was “0735P increasing inflow forecast – South esk, meander rivers”. This resulted in all but one dispatch interval priced at $300/MWh for the trading interval.

Friday, 24 June

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
7.30 am	305.75	40.65	35.92	1442	1433	1435	2161	2169	2189

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

During the high price period, Tasmania had a steep supply curve, with no capacity priced between $40/MWh and $280/MWh. Four hours ahead Basslink was forecast to import 90 MW but it actually exported at 90 MW. This change saw the dispatch price at around $300/MWh for the entire trading interval.

Table 11: 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	301.25	71.32	50.67	1411	1485	1487	2153	2166	2179

Conditions at the time saw demand slightly less than forecast and availability close to forecast four hours ahead.

During the high price period, Tasmania had a steep supply curve, with no capacity priced between $40/MWh and $280/MWh. Four hours ahead Basslink was forecast to import around 180 MW, but it actually exported 100 MW. This saw the dispatch price fluctuate between $150/MWh and $428/MWh for the trading interval.

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
5 pm	273.44	51.57	69.11	1363	1328	1370	2175	2169	2174

Conditions at the time saw demand slightly higher than forecast and availability close to forecast four hours ahead.

During the high price period, Tasmania had a steep supply curve, with little capacity priced between $40/MWh and $280/MWh. Four hours ahead Basslink was forecast to export 24 MW, but it actually exported 144 MW. This saw the dispatch price fluctuate between $190/MWh and $480/MWh for the trading interval.

Saturday, 25 June

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
8 am	292.99	43.87	41.11	1303	1234	1231	2209	2236	2247
8.30 am	291.90	400.34	65.52	1388	1295	1290	2183	2227	2244

Conditions at the time saw demand up to 93 MW higher than forecast four hours ahead and available capacity less than forecast.

During the high price period, Tasmania had a steep supply curve, with no capacity priced between $40/MWh and $280/MWh.

The 8 am trading interval saw dispatch pricing between $211/MWh and $396/MWh. This was driven by higher than forecast demand.

For the 8.30 am trading interval, the increase in forecast price from the 12 to four hour ahead was due to a change in the impact of a binding network constraint on Basslink. At around 6 am, the constraint was no longer forecast to bind for the 8.30 am trading interval, as a result the price fell to around $300/MWh.

Table 14: Price, Demand and Availability

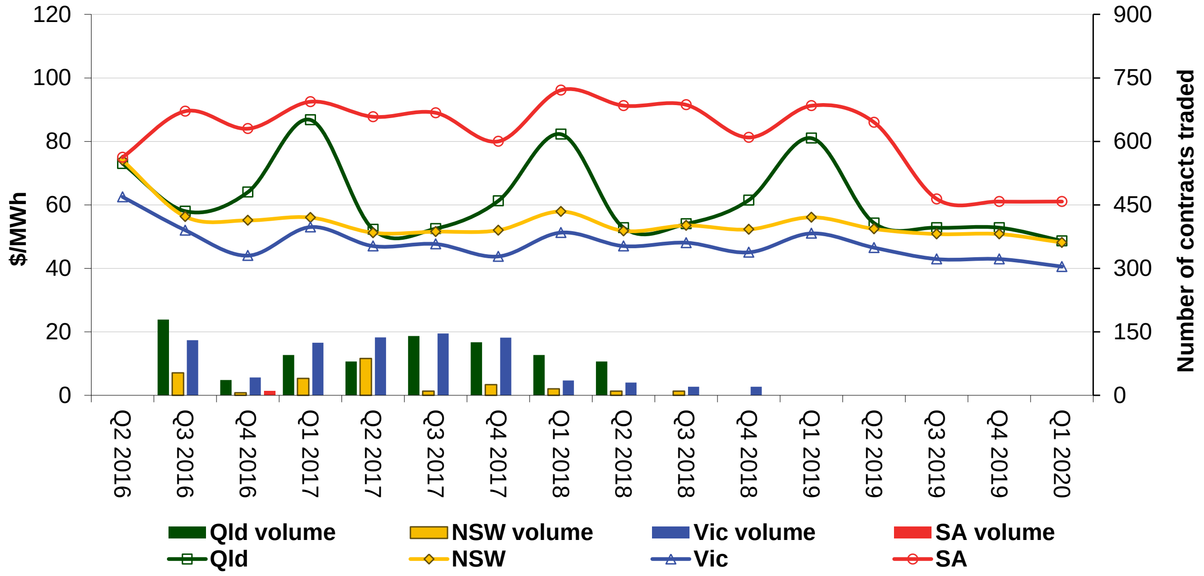
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
9.30 am	300.38	267.62	270.54	1445	1364	1362	2208	2213	2239
6.30 pm	296.30	308.26	286.20	1428	1409	1398	2249	2227	2230
7 pm	290.74	285.39	281.43	1411	1392	1381	2218	2230	2230

Spot prices were close to forecast four and twelve 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.

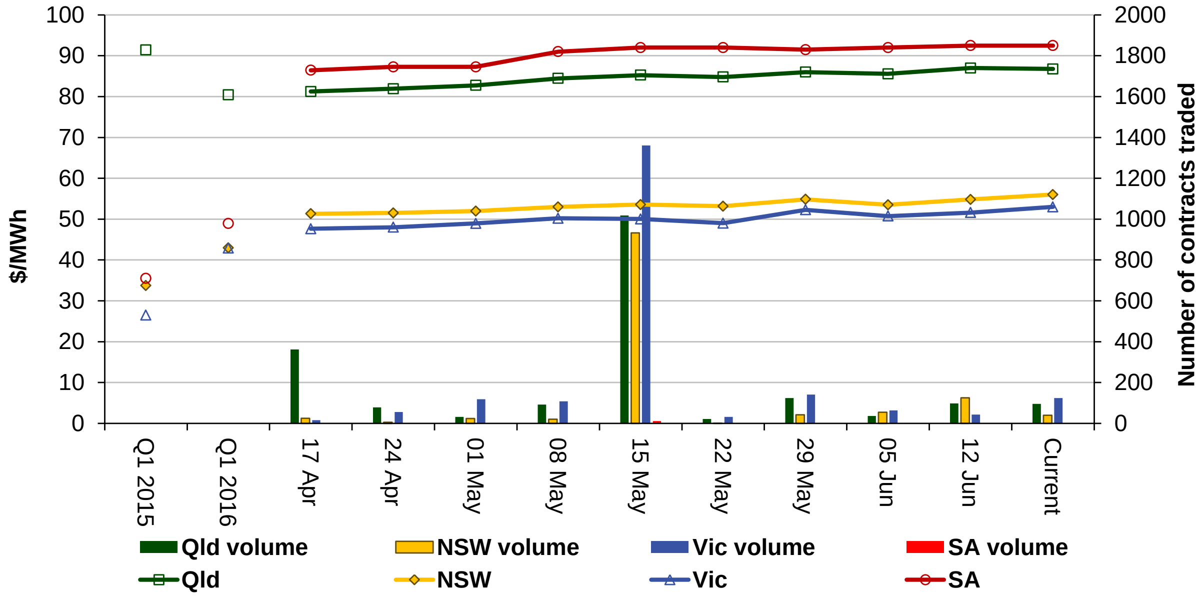
Figure 9: Quarterly base future prices Q2 2016 – Q1 2020



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)



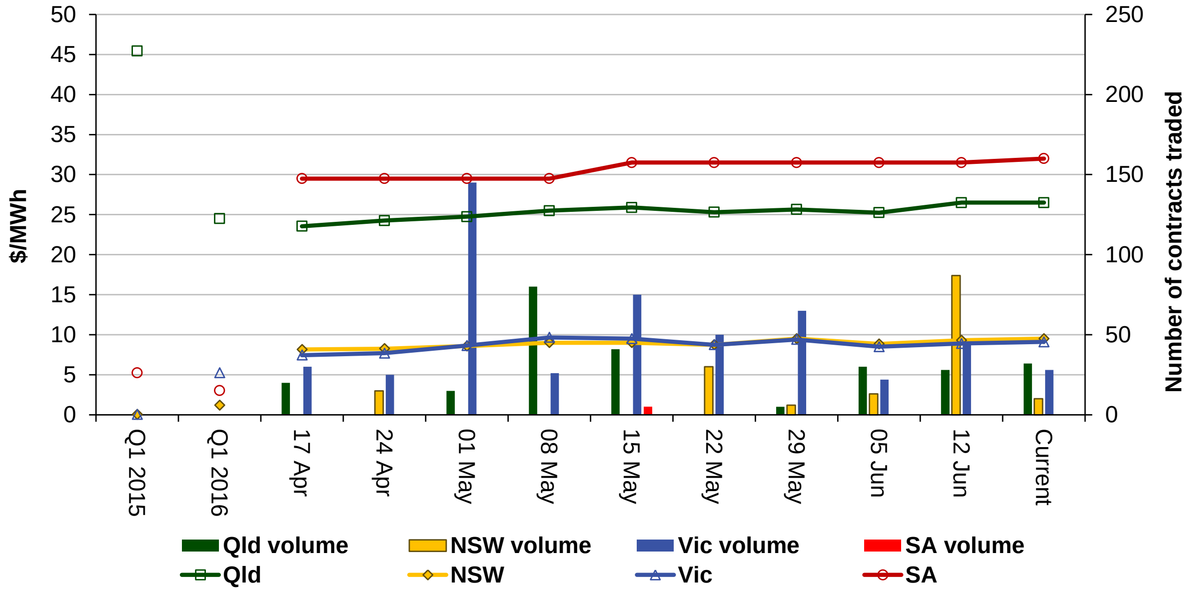
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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

Australian Energy Regulator
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