Electricity Report

AUSTRALIAN ENERGY REGULATOR

21 – 27 August 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 21 to 27 August 2016.

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

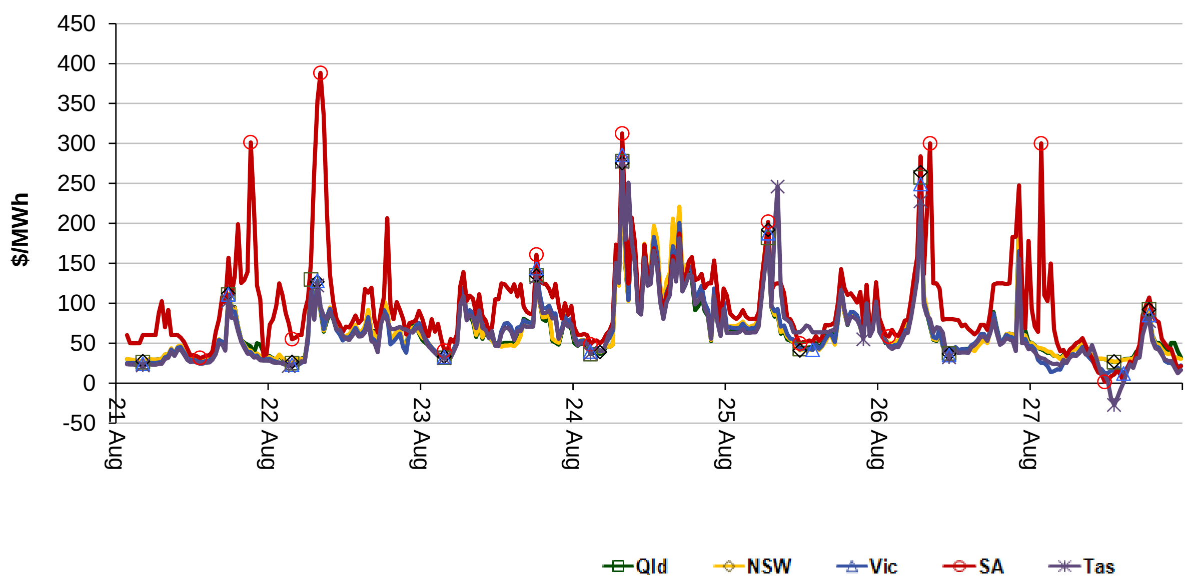


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

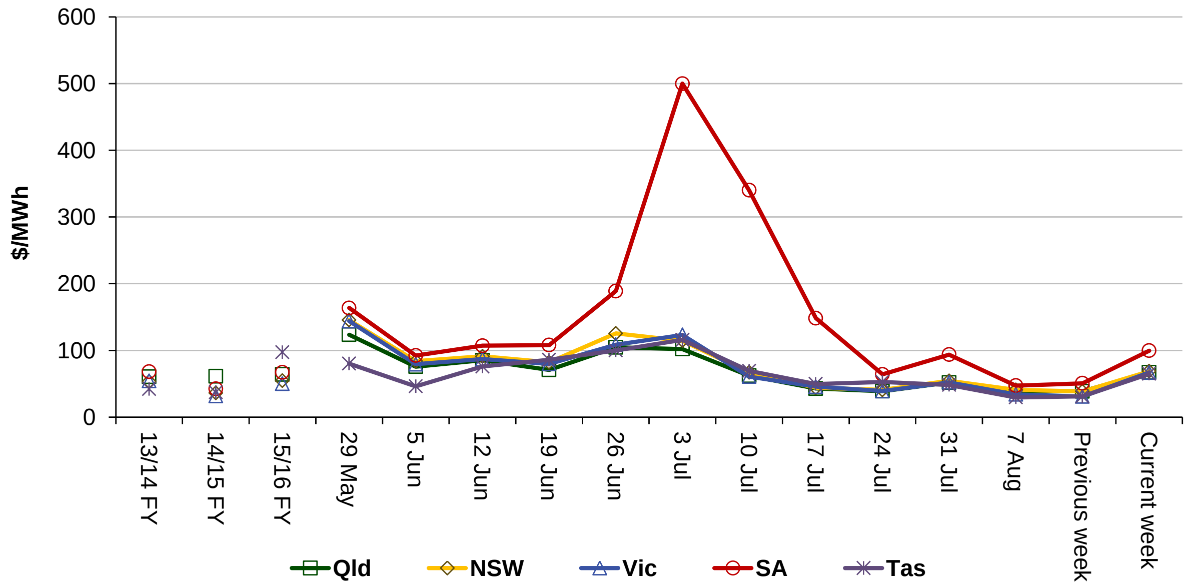


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	67	69	67	100	65
15-16 financial YTD	46	39	36	72	34
16-17 financial YTD	57	62	58	171	59

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 270 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	5	55	0	1
% of total below forecast	31	5	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

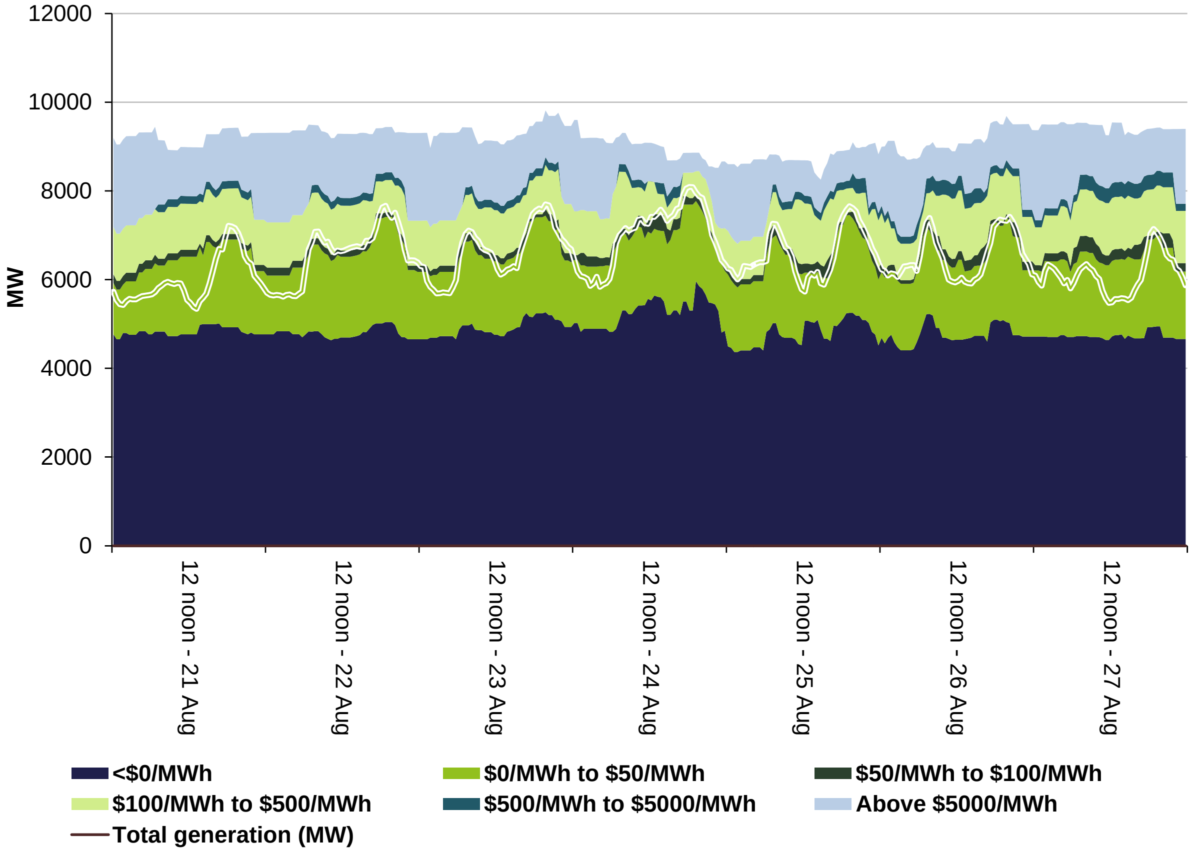


Figure 4: New South Wales generation and bidding patterns

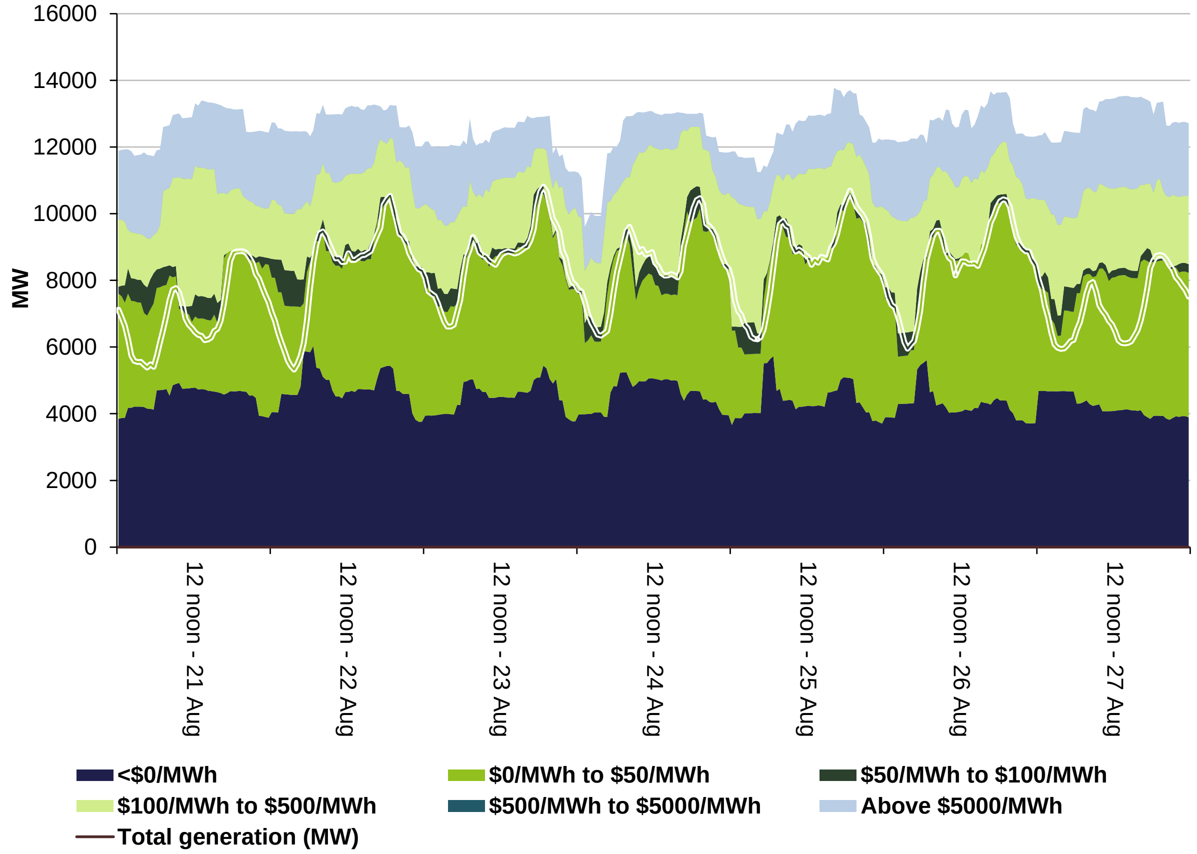


Figure 5: Victoria generation and bidding patterns

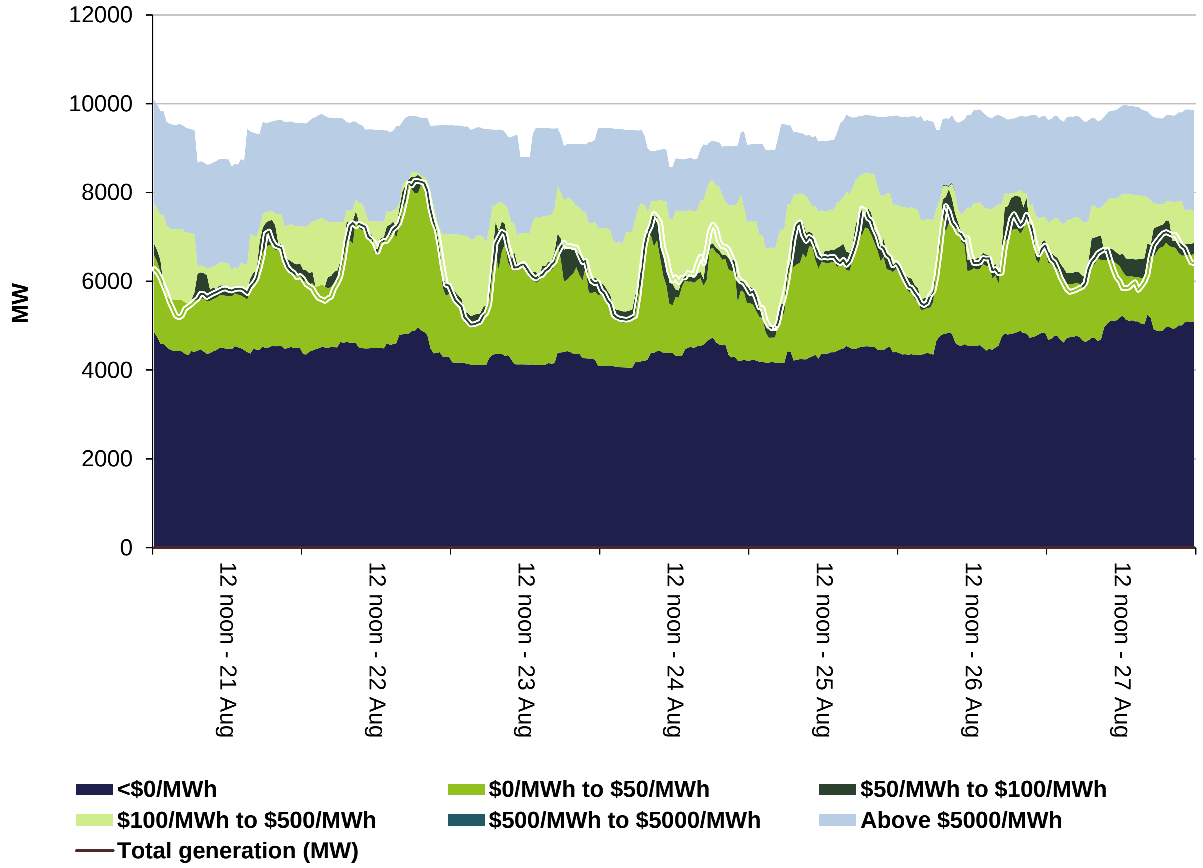


Figure 6: South Australia generation and bidding patterns

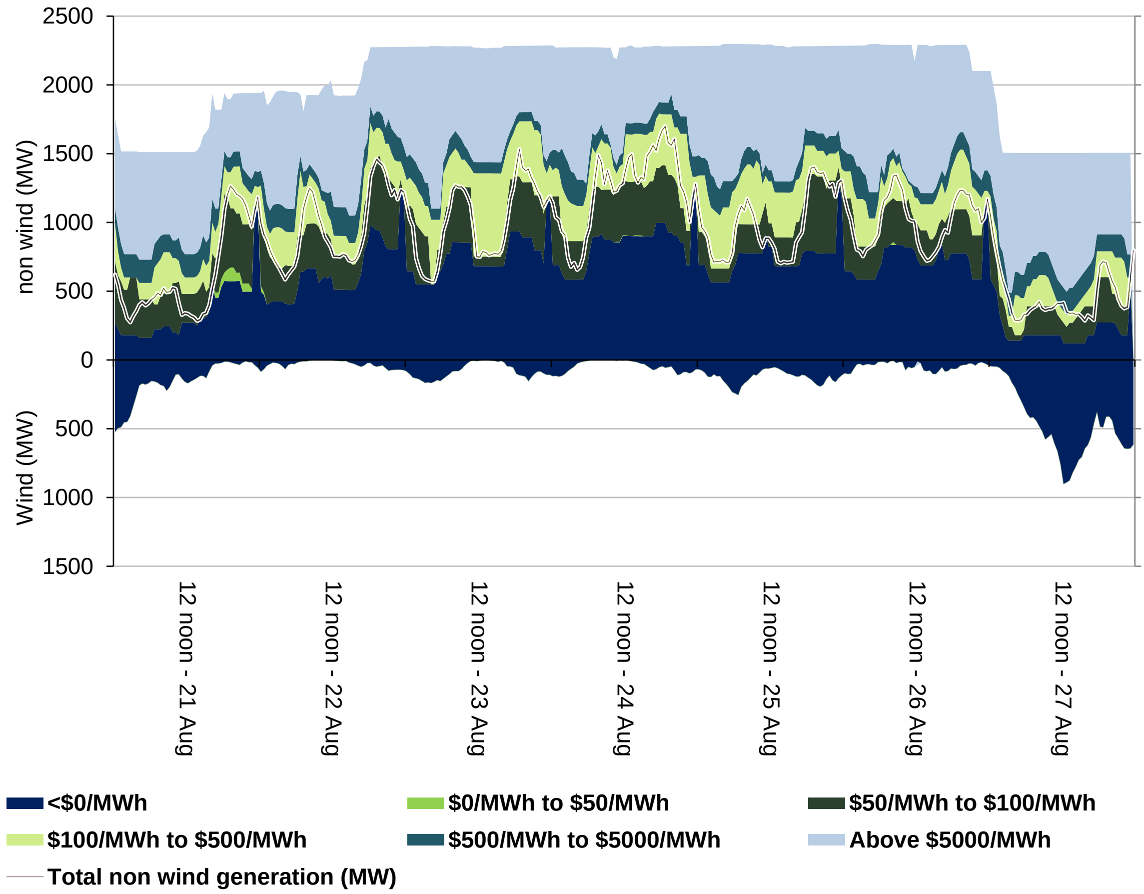
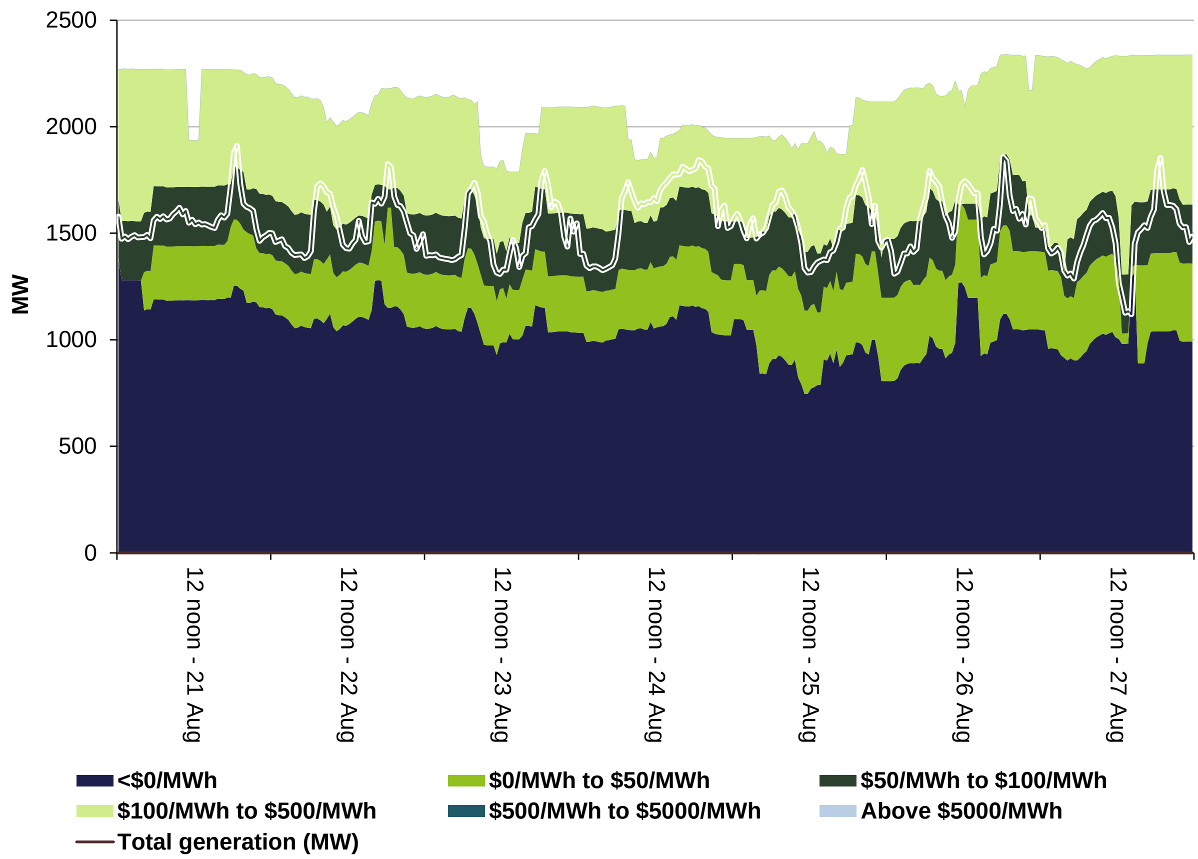


Figure 7: Tasmania generation and bidding patterns



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.

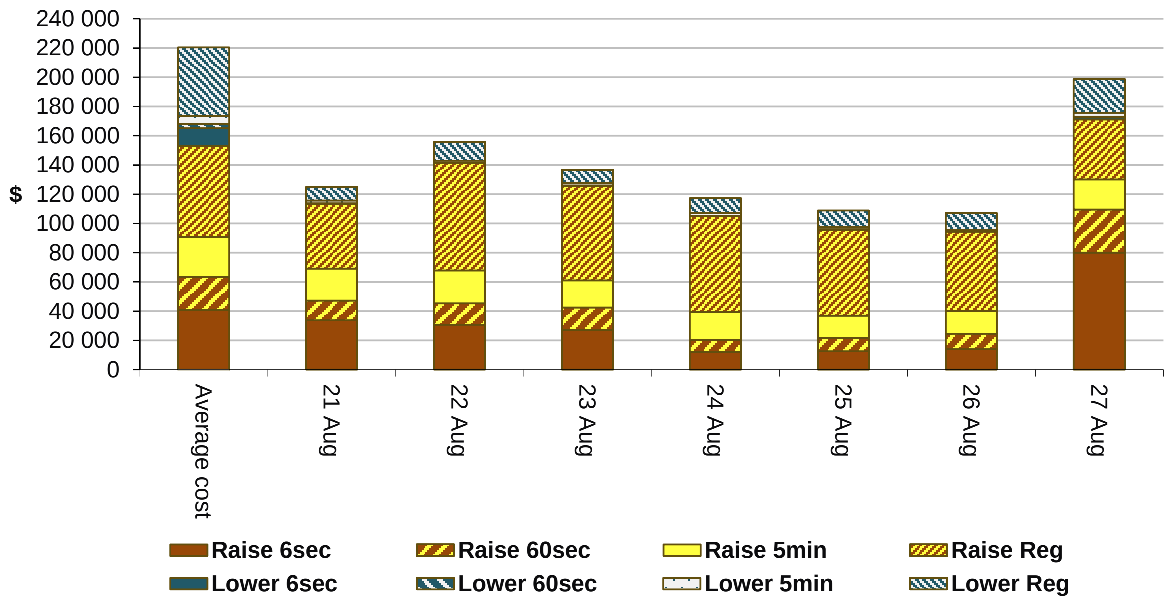
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $8 155 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $133 500 or around 1 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



Detailed market analysis of significant price events

National

There were two occasions 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 $69/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Wednesday, 24 August

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
8 am	275.36	69.81	114.95	26 607	26 162	26 508	35 518	35 847	35 463

Conditions at the time saw demand around 450 MW higher than forecast four hours ahead and availability was around 300 MW lower than forecast four hours ahead.

Table 4: Rebids for the 8 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.15 am		Snowy Hydro	Tumut	95	100	300	06:11 A VIC: 5MPD PRICE $62.82 HGR THN 30MPD 07:00@06:01
6.45 am		Origin Energy	Darling Downs	127	<76	249	0644P PLANT CONDITIONS - AVOID DB USE SL
6.57 am		AGL Energy	Loy Yang A	540	<25	500	0648~P~010 UNEXPECTED/PLANT LIMITS~104 COAL
6.59 am		Energy Australia	Mt Piper	-60	40	N/A	06:57 P ADJ AVAIL DUE TO COAL QUALITY LIMIT
7.23 am		AGL Energy	Loy Yang A	-50	16	N/A	0720~P~010 UNEXPECTED/PLANT LIMITS~101 MILLING LIMITS
7.43 am	7.50 am	AGL Energy	Loy Yang A	-50	16	N/A	0740~P~010 UNEXPECTED/PLANT LIMITS~105 DUST LIMITS

The above rebidding saw prices across the NEM at around $275/MWh for a majority of the trading interval.

Friday, 26 August

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
7 am	263.73	88.73	50.98	25 153	24 694	24 700	35 144	35 931	36 838

Conditions at the time saw demand around 460 MW higher than forecast four hours ahead and availability was around 790 MW lower than forecast four hours ahead. The spot price was aligned during the 7 am trading interval across the NEM, with the New South Wales and Queensland spot prices exceeding the reporting threshold.

Table 6: Rebids for the 7 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.29 am		CS Energy	Callide B	-30	17	N/A	0328P MARCH CURRENT UNIT OUTPUT-SL
4.02 am		AGL Energy	Mckay	-115	<69	N/A	0400~P~020 REDUCTION IN AVAIL CAP~203 PLANT FAILURE 135MW
4.17 am		CS Energy	Gladstone	-170	<49	N/A	0417P UNIT RTS REVISED-DELAYED-SL
4.41 am		CS Energy	Gladstone	-15	-1000	N/A	0441P UNIT RTS REVISED-DELAYED-SL
4.44 am		CS Energy	Wivenhoe	160	>300	0	0443P PORTFOLIO REARRANGEMENT DUE TO-GPS 1 DELAYED RTS-SL
5.24 am		CS Energy	Gladstone	-40	-1000	N/A	0524P UNIT RTS REVISED-DELAYED-SL
5.55 am		CS Energy	Gladstone	-50	-1000	N/A	0555P UNIT RTS REVISED-DELAYED-SL
5.55 am		EnergyAustralia	Mt Piper	100	40	290	05:52 P ADJ AVAIL DUE TO AMBIENT CONDITIONS

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.01 am		EnergyAustralia	Mt Piper	100	290	13 405	06:00 P ADJ AVAIL DUE TO AMBIENT CONDITIONS
6.15 am		AGL Energy	Mckay	-165	0	N/A	0610~P~020 REDUCTION IN AVAIL CAP~203 PLANT FAILURE 165MW
6.45 am	6.55 am	EnergyAustralia	Mt Piper	-200	<40	N/A	06:44 P ADJ AVAIL FUEL SUPPLY LIMIT

At 6.40 am, there was a 400 MW increase in demand in the NEM (largely driven by demand increases in New South Wales, Victoria and Queensland). This, combined with the above rebidding, saw the dispatch price in the NEM regions increase from less than $95/MWh at 6.35 am to between $240/MWh to $300/MWh at 6.40 am. Dispatch prices remained between $240/MWh to $300/MWh for the remainder of the trading interval.

South Australia

There were seven occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $100/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 six occasions are presented below.

Sunday, 21 August

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
9.30 pm	301.39	119.99	296.00	1724	1646	1678	1958	1987	2048

Conditions at the time saw demand 78 MW higher than forecast four hours ahead and availability was close to forecast four hours ahead.

Table 8: 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
8.03 pm		Origin Energy	Quarantine	123	125	14 000	2001A DEC SA DEM 5PD 1719 MW < 30PD 1784 MW @ 2030 SL

There was no capacity priced between $193/MWh and $300/MWh meaning small changes in demand and availability could lead to volatile prices. The above rebid saw the price increase from $126/MWh at 9 pm to $301/MWh at 9.05 pm. The dispatch price remained above $300/MWh for the remainder of the trading interval.

Monday, 22 August

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
8 am	353.76	124.99	119.99	1761	1701	1657	1937	2232	2252
8.30 am	388.17	296.00	124.99	1807	1761	1713	1929	2231	2245
9 am	334.40	278.81	124.99	1759	1729	1691	1928	2221	2238

Conditions at the time saw demand up to 60 MW higher than forecast, while availability was up to 300 MW lower than forecast. This was due to wind generation being up to 53 MW less than forecast four hours ahead and all 235 MW of available capacity at Pelican Point being withdrawn due to a unit start issues.

Table 10 Rebids for the 8 am, 8.30 am and 9 am trading intervals

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.42 am		GDF Suez	Pelican Point	-165	<300	N/A	0441P UPDATE RTS - UNIT START ELECTRICAL FAULT
5.49 am		GDF Suez	Pelican Point	-70	-1000	N/A	0548P UPDATE AVAIL: STARTING DEVICE UNABLE TO SYNC UNIT SL
7.18 am		Origin Energy	Quarantine	120	296	14 000	0715A CONSTRAINT MANAGEMENT - V:S_PA_SVC_575 SL
7.36 am	7.45 am	Snowy Hydro	Angaston	35	349	13 958	07:31 A SA: 5MPD PRICE $68.82 HGR THN 30MPD 08:00@07:31
7.50 am	8 am	AGL Energy	Torrens Island	70	300	>485	0601~A~050 CHG IN AEMO PD~50 PD AVAILABLE GENERATION

There was no capacity priced between $193/MWh and $300/MWh meaning small changes in demand and availability could lead to volatile prices. The reduction in capacity at Pelican Point saw forecast prices increase to between $300/MWh and $370/MWh. The subsequent rebidding resulted in dispatch prices remaining above $300/MWh for the 8 am, 8.30 am and 9 am trading intervals.

Friday, 26 August

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
8.30 am	300.00	300.00	300.00	1878	1790	1784	2296	2331	2337

The spot price was as forecast.

Saturday, 27 August

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
2 am	299.99	349.95	49.99	1390	1339	1320	1684	1769	1973

The spot price was close to that forecast four hours ahead.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $65/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.

Wednesday, 24 August

Table 13: Price, Demand and Availability

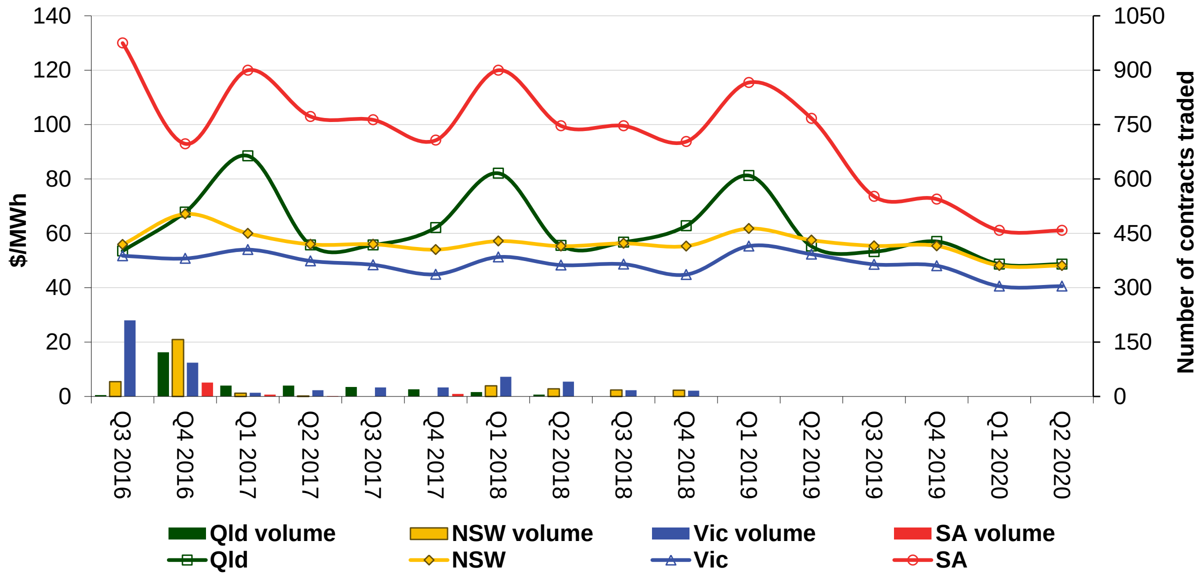
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
9 am	250.82	407.55	102.81	1433	1477	1480	1846	1842	1851

Conditions at the time saw demand and availability close to that forecast. There was no capacity priced between $81/MWh and $276/MWh meaning small changes in demand and availability could lead to volatile prices. At 8.35 am there was a planned decrease in the available capacity of Poatina 110kV, which had been setting the price at 8.30 am. With all low-priced generation stranded in FCAS or fully dispatched the price increase from $80/MWh at 8.30 am to $277/MWh at 8.35 am and stayed at that price for the rest of the trading interval.

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.

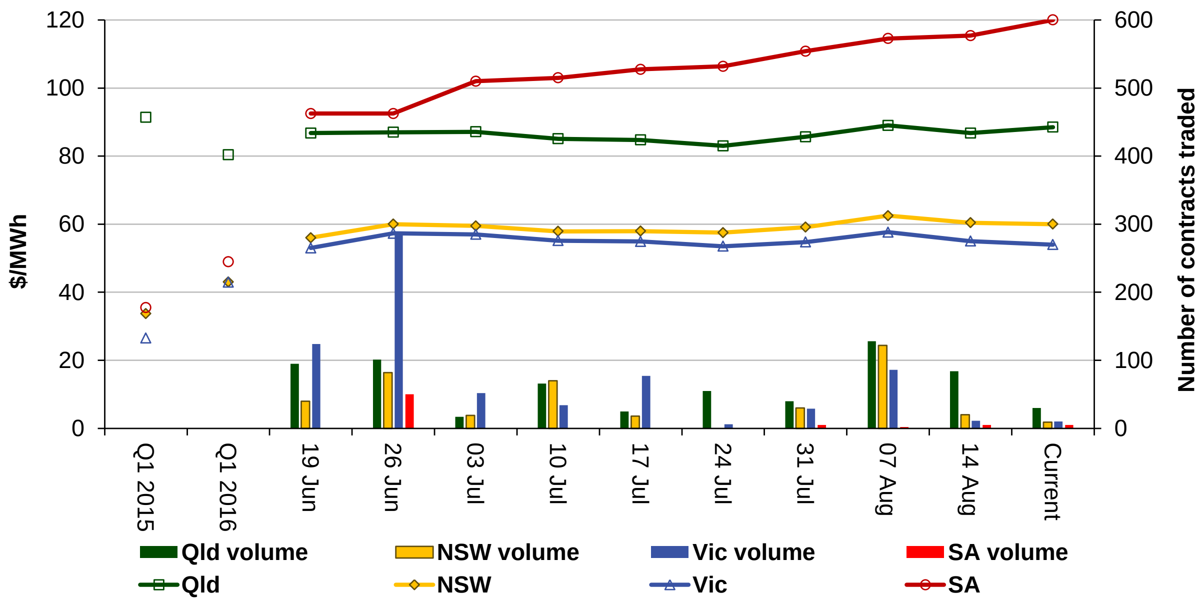
Figure 9: Quarterly base future prices Q3 2016 – Q2 2020



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)



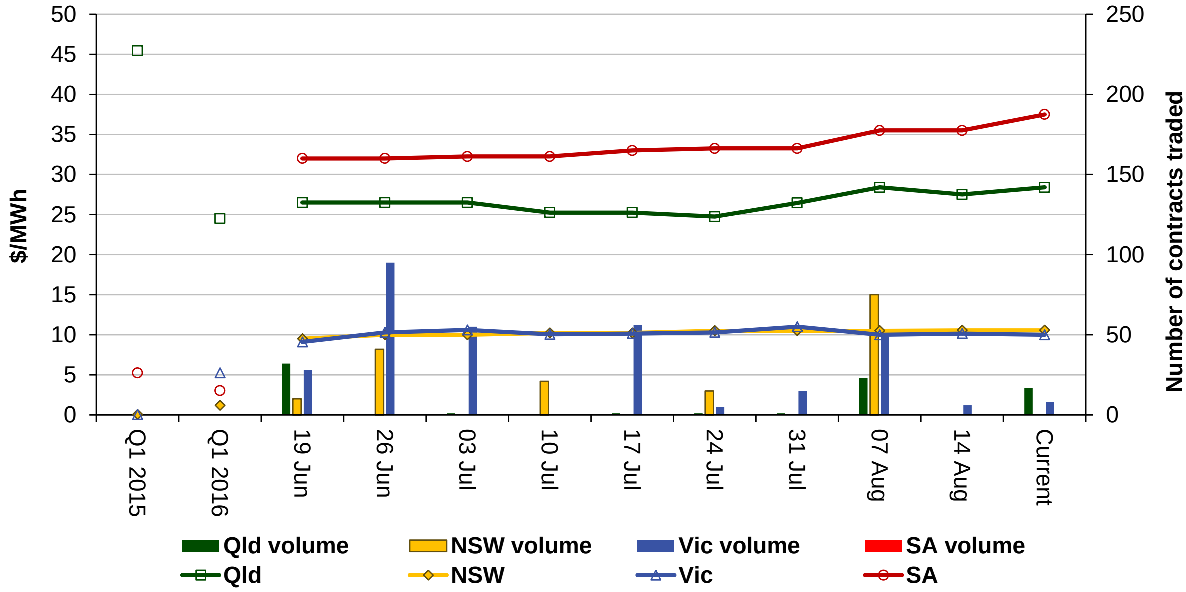
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
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