WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

16 – 22 June 2013

High spot prices occurred in Queensland, Victoria and South Australia as a result of generator and network outages. This drove higher average prices compared to the previous week in those regions.

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for 16 to 22 June 2013 and the 12/13 financial year to date (YTD) across the NEM. It compares these prices with price outcomes from the previous week and year to date respectively.

Figure 1: Volume weighted average spot price by region ($/MWh)

	QLD	NSW	VIC	SA	TAS
Average price for 16 Jun - 22 Jun 2013	96	63	86	138	56
% change from previous week*	77	20	75	124	39
12-13 financial YTD	70	56	61	74	48
% change from 11-12 financial YTD**	136	84	117	128	47

*The percentage change between last week's average spot price and the average price for the previous week. Calculated on VWA prices prior to rounding.

**The percentage change between the average spot price for the current financial year and the average spot price for the previous financial year. Percentage changes are calculated on VWA prices prior to rounding.

Further information is provided in Appendix A when the spot price exceeds three times the weekly average and is above $250/MWh or less than -$100/MWh. Longer term market trends are attached in Appendix B. Longer term market trends are attached in Appendix B.[1]

Financial markets

Figures 2 to 9 show futures contract[2] prices traded on the Australian Securities Exchange (ASX) as at close of trade on Friday 21 June 2013. Figure 2 shows the base futures contract prices for the next three calendar years, and the average over these three years. Also shown are percentage changes[3] from the previous week.

[1] Monitoring the performance of the wholesale market is a key part of the AER's role and an overview of the market's performance in the long term is provided on the AER website. Long-term statistics can be found there on, amongst other things, demand, spot prices, contract prices and frequency control ancillary services prices. To access this information go to www.aer.gov.au -> Australian energy industry -> Performance of the energy sector

[2] Futures contracts traded on the ASX are listed by d-cyphaTrade (www.d-cyphatrade.com.au). A futures contract is typically for one MW of electrical energy per hour based on a fixed load profile. A base load profile is defined as the base load period from midnight to midnight Monday to Sunday over the duration of the contract quarter. A peak load profile is defined as the peak-period from 7 am to 10 pm Monday to Friday (excluding Public holidays) over the duration of the contract quarter.

[3] Calculated on prices prior to rounding.

Figure 2: Base calendar year futures contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Calendar Year 2014	58 (30)	3%	53 (12)	2%	51	4%	56	2%
Calendar Year 2015	47	1%	45	0%	40	1%	47	0%
Calendar Year 2016	51	0%	52	0%	47	0%	63	0%
Three year average	52	1%	50	1%	46	2%	55	1%

Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au
A number in brackets denotes the number of trades in the product

Figure 3 shows the $300 cap contract price for Q1 2014 and calendar year 2014 and the percentage change[4] from the previous week.

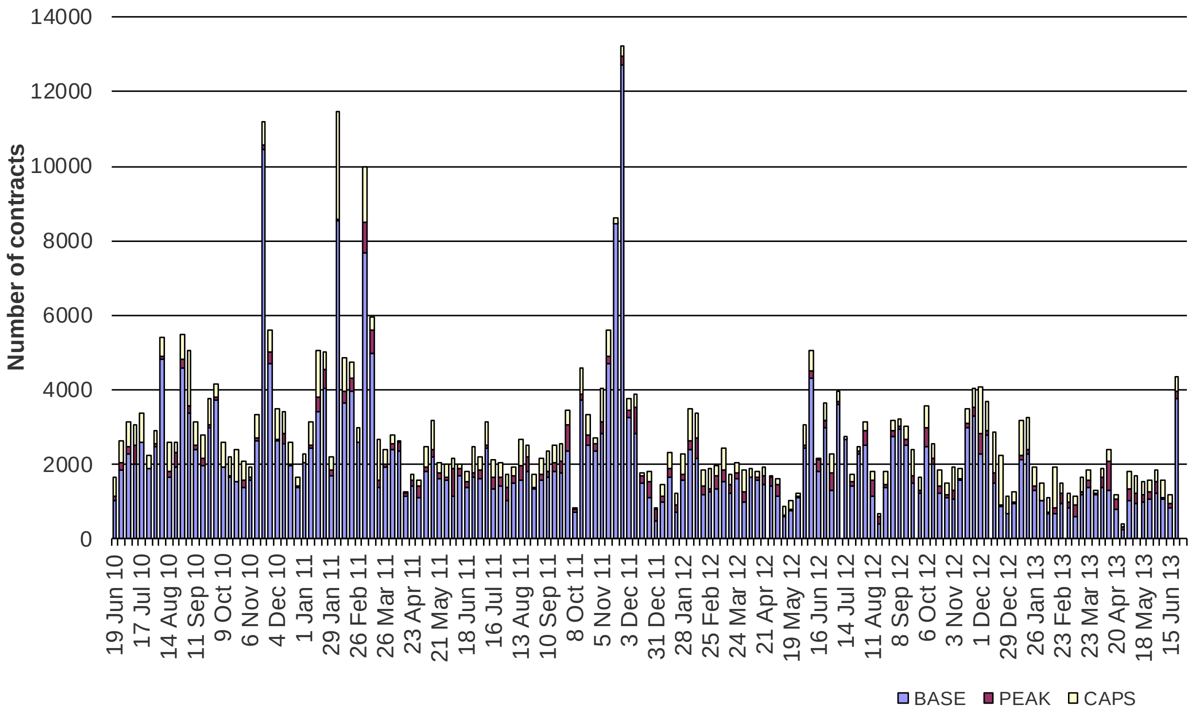
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2014	15 (35)	9%	8 (80)	3%	12 (15)	15%	17	5%
2014	7	12%	4	1%	5	9%	9	8%

Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au
A number in brackets denotes the number of trades in the product.

Figure 4 shows for the last three years the weekly trading volumes for base, peak and cap contracts. The date represents the end of the trading week.

Figure 4: Number of exchange traded contracts per week

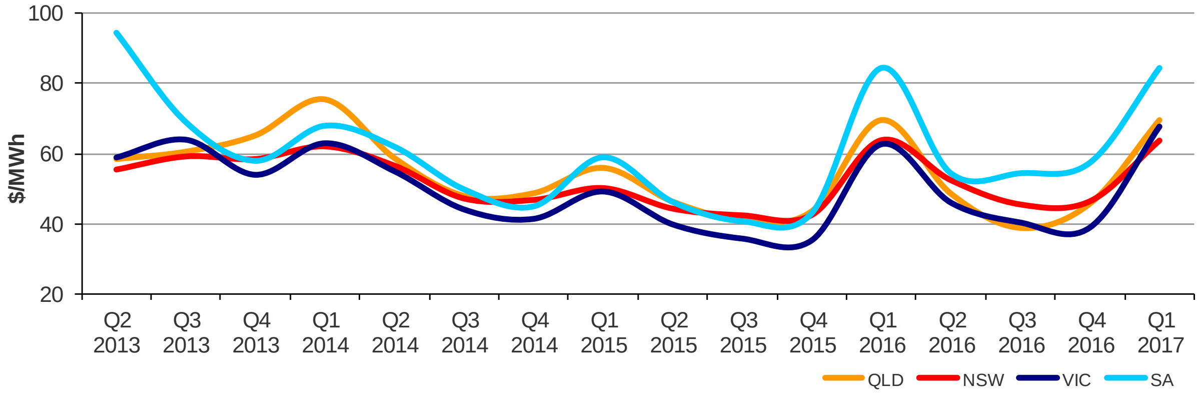


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

[4] Calculated on prices prior to rounding.

Figure 5 shows the prices for base contracts for each quarter for the next four financial years.

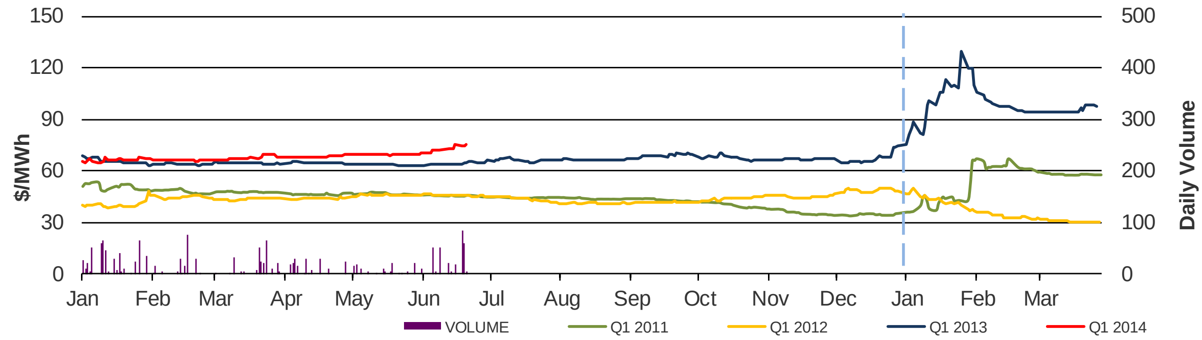
Figure 5: Quarterly base future prices Q2 2013 – Q1 2017



Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

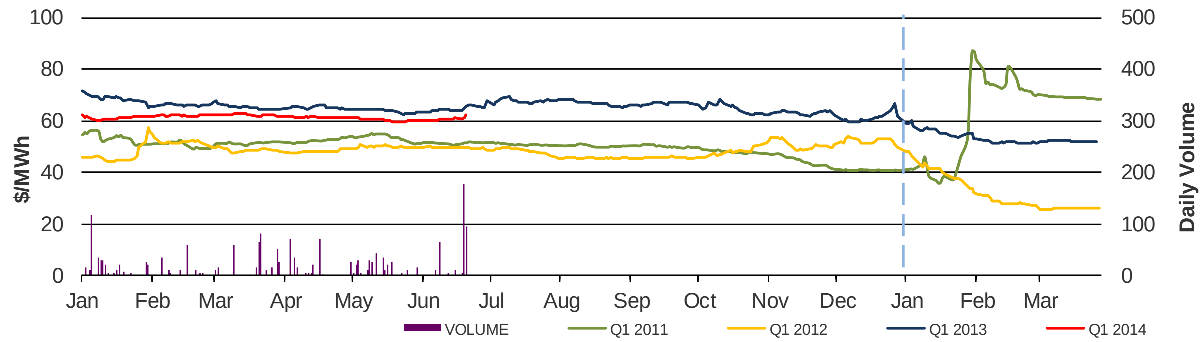
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2011, 2012, 2013 and 2014. Also shown is the daily volume of Q1 2014 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

Figure 6: Queensland Q1 2011, 2012, 2013 and 2014



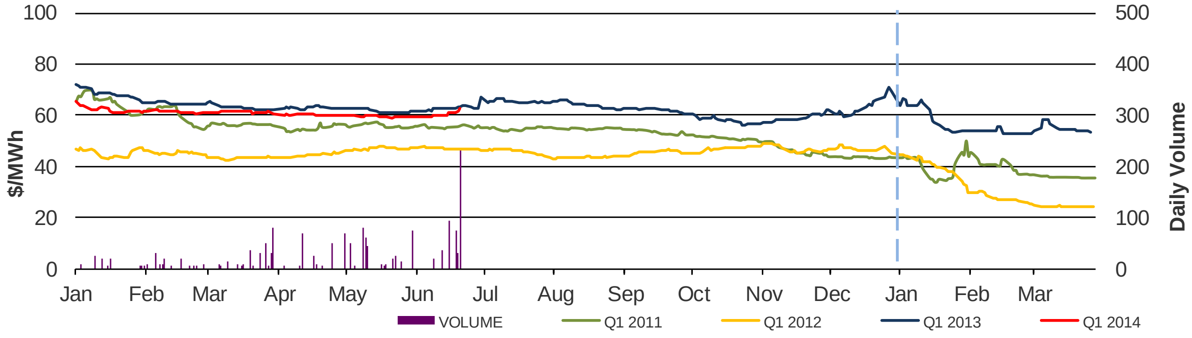
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 7: New South Wales Q1 2011, 2012, 2013 and 2014



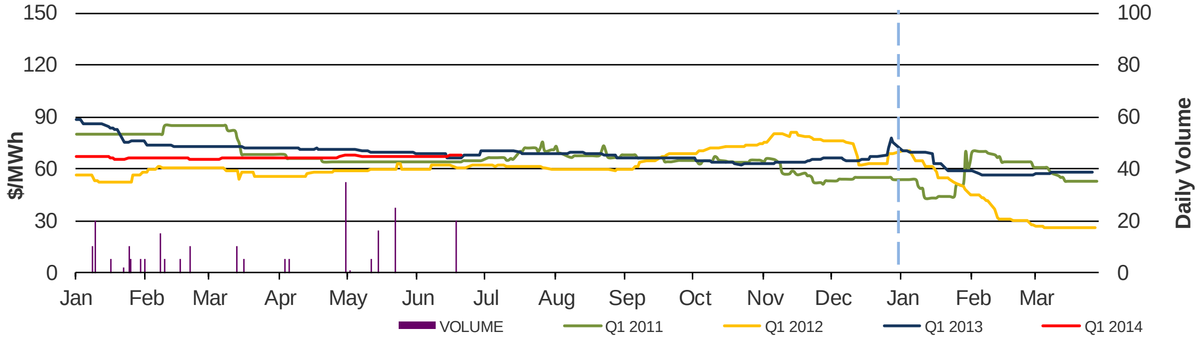
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 8: Victoria Q1 2011, 2012, 2013 and 2014



Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 9: South Australia Q1 2011, 2012, 2013 and 2014



Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au
The daily volume scale for South Australia is smaller than for other regions to reflect the lower liquidity in the market in South Australia.

Spot market forecasting 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 as participants react to changing market conditions. There were 182 trading intervals throughout the week where actual prices varied significantly from forecasts.[5] This compares to the weekly average in 2012 of 60 counts and the average in 2011 of 78. Reasons for these variances are summarised in Figure 10[6].

Figure 10: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	5	18	1	3
% of total below forecast	22	43	0	9

The total may not equal 100% due to rounding.

[5] A trading interval is counted as having a variation if the actual price differs significantly from the forecast price either four or 12 hours ahead.

[6] 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.

Demand and bidding patterns

The AER reviews demand, network limitations and generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 11 shows the weekly change in total available capacity at various price levels during peak periods[7]. For example, in Queensland 424 MW more capacity was offered at prices under $20/MWh this week compared to the previous week. Also included is the change in average demand during peak periods, for comparison.

Figure 11: Changes in available generation and average demand compared to the previous week during peak periods

MW	<$20/MWh	Between $20 and $50/MWh	Total availability	Change in average demand
QLD	424	-367	-576	261
NSW	328	457	419	700
VIC	741	-989	-97	454
SA	136	-88	-64	156
TAS	-182	33	-29	103
TOTAL	1447	-954	-347	1674

[7] A peak period is defined as between 7 am and 10 pm on weekdays.

Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $783 500 or less than one per cent of energy turnover on the mainland.

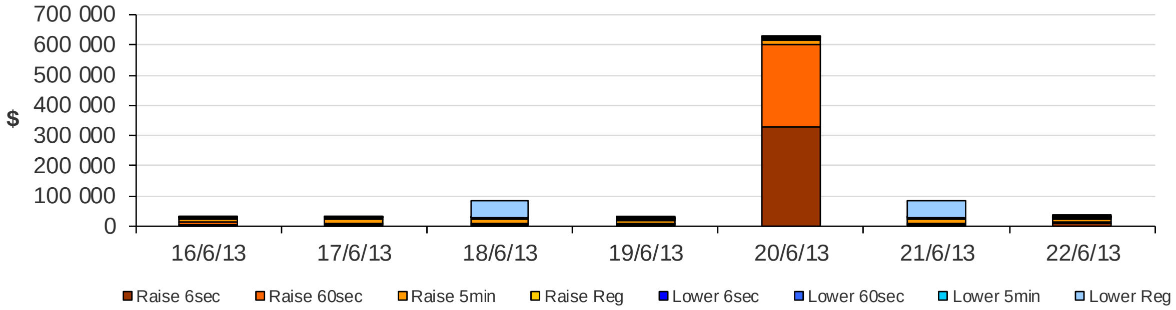
A majority of these costs occurred on Thursday 20 June as a result of two five minute dispatch interval price spikes in Queensland at 7.30 am and 7.35 am for Raise 60 and Raise 6 second services.

- On Wednesday 19 June there was an unplanned outage of the Tamworth to Armidale line in New South Wales, which continued until Thursday evening. Constraints used to manage this outage set local Raise FCAS requirements in Queensland when flows were into Queensland across QNI. This occurred for only nine dispatch intervals and most of the time the price for those services was $2/MW or less.
- On 20 June from 7.20 am flow across QNI into Queensland increased to around 100 MW and then 130 MW creating increased local requirements for raise services in Queensland. At 7.30 am the price of raise 6 and 60 second services reached $7770/MW and $4559/MW, respectively. Flow remained at around 130 MW at 7.35 am with the price of raise 6 and 60 second services reaching the price cap and $12 424/MW, respectively. This saw the costs for raise 6 second and raise 60 second services in the region accrue to $595 824 over ten minutes. There were high prices in the energy market in Queensland at the same time, which is detailed in Appendix A.

The total cost of FCAS in Tasmania for the week was $131 500 or 1 per cent of energy turnover in Tasmania.

Figure 12 shows the daily breakdown of cost for each FCAS for the NEM.

Figure 12: Daily frequency control ancillary service cost



Australian Energy Regulator
July 2013

Detailed Market Analysis

AUSTRALIAN ENERGY REGULATOR

16 – 22 June 2013

Queensland:

There were four occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $96/MWh and above $250/MWh.

Monday, 17 June

7:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4334.62	60.00	75.00
Demand (MW)	6545	6517	6460
Available capacity (MW)	9524	9547	9556

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

At 7.05 am a constraint used to manage the planned outage of the Braemar to Tarong 275kV line was invoked. This constraint manages the overload of the Middle Ridge transformer. The line outage increased flows on the Middle Ridge transformer resulting in generation being constrained down and a reduction in the import limit across QNI from 166 MW at 7.05 am to 7 MW at 7.10 am. Queensland generation could not be ramped quickly enough and fast start plant could not synchronise in time to satisfy the constraint causing the constraint to violate at 7.10 am. This resulted in the 5-minute price reaching the price cap at 7.10 am. At 7.15 am the 5-minute price was also at the price cap as low priced generation was either trapped in FCAS or ramp rate limited again causing high price capacity to be dispatched.

There was no significant rebidding.

Monday, 17 June

5:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2222.33	85.00	85.00
Demand (MW)	6733	6645	6696
Available capacity (MW)	9498	9421	9521

Conditions at the time saw demand and available capacity close to that forecast

The constraint managing the planned outage of the Braemar to Tarong 275kV line was forcing flows out of Queensland across QNI, which was not forecast. At 5.30 pm there was a 56 MW increase in scheduled demand which could not be met by low priced generators in Queensland as they were ramp rate limited, trapped in frequency control ancillary services or were fast start plants that required more than one dispatch interval to synchronise. The 5-minute price increased from $146/MWh at 5.25 pm to the cap at 5.30 pm.

There was no significant rebidding.

Thursday, 20 June

7:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1916.41	75.00	114.96
Demand (MW)	6475	6497	6597
Available capacity (MW)	9086	9286	9286

8:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1658.51	109.57	279.80
Demand (MW)	6535	6588	6685
Available capacity (MW)	9078	9272	9296

Conditions at the time saw demand close to forecast while available capacity was around 200 MW lower than that forecast four hours ahead.

The Calvale – Tarong 275 kV line was out of service for a planned outage from 3.30 pm on 19 June 2013. This outage is part of the initial phase of the project to build two new transmission lines between Halys and Tarong. Between 6.35 am and 7.40 am the constraint to manage this outage resulted in Queensland generation and interconnector flows being constrained.

At 7.20 am, effective from 7.30 am, Millmerran Energy Trader rebid 110 MW of capacity priced at the floor to above $12 300/MWh. The reason given was “07:19 A price above pd - sl”. With low priced capacity either trapped or stranded in FCAS or ramp rate limited the 7.30 am price reached $11 064/MWh, set by the Millmerran units.

Also on 19 June there was an unplanned outage of the Tamworth to Armidale line in New South Wales, which continued until Thursday evening. This led to local FCAS requirements and restricted imports into Queensland. These constraints bound between 7.10 am and 7.35 am, limiting flows into Queensland to around 130 MW and causing high FCAS prices for 7.30 am and 7.35 am.

At 7.35 am, the trade-off between provision of FCAS and energy from Queensland generators saw the 5-minute energy price reach the price cap.

In response to the high prices Queensland generators rebid around 4000 MW of capacity at or close to the price floor. This saw the 5-minute price fall to the price floor from 7.50 am to 8 am.

There was no other significant rebidding.

Victoria:

There were two occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $86/MWh and above $250/MWh.

Friday, 21 June

10:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2026.38	61.45	86.74
Demand (MW)	7062	7242	7335
Available capacity (MW)	8968	9999	9458
11:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1937.34	59.75	58.80
Demand (MW)	6691	7009	7013
Available capacity (MW)	8725	9684	9514

Conditions at the time saw demand lower than that forecast and available capacity up to 1031 MW below that forecast four hours ahead. Prices in South Australia and Tasmania reflected the conditions in Victoria.

Over three rebids between 5.44 am and 5.50 am, EnergyAustralia reduced the availability of three Yallourn units to 200 MW each from 5.55 am – a combined reduction of 310 MW. The reason given was ‘P industrial action – sl’. All three units at Yallourn subsequently tripped at around 9.35 am from 200 MW each.

At around 9.40 am GDF Suez’s Hazelwood unit 7 tripped from around 135 MW.

At 9.37 am, effective from 9.45 am, Alinta Energy rebid 40 MW of capacity at Northern unit 1 (in South Australia) from prices below $87/MWh to above $11 750/MWh. The reason given was “NPS1 SA dispatch price at $299.8v$76.26@09:37”.

At 9.38 am, effective from 9.45 am, Snowy Hydro rebid 1392 MW of capacity at Murray to the price floor from prices between $48/MWh and the price cap. The reason given was “Vic price $270”. At 9.42 am, effective from 9.50 am, Snowy Hydro rebid the ramp down rate of Murray to the minimum allowed of 3 MW/min. The reason given was “Vic:act price $11,663.04 ghr thn 5mpd 09:45@09:36”.

With low priced generation either trapped in FCAS or constrained off high price generation had to be dispatched leading to the 5-minute price reaching $11 784/MWh in Victoria and the price cap in South Australia at 9.45 am.

In response to the high price around 1300 MW of capacity in Victoria and 150 MW of capacity in South Australia was rebid to the price floor and around 100 MW of non-scheduled generation in South Australia came on-line. There was also an apparent 110 MW demand side response from an aluminium smelter in Victoria. This saw the price in both Victoria and South Australia initially fall to previous levels and then to just below zero.

At 10.35 am, in response to the loss of the three Yallourn units and one Hazelwood unit (which are all on the 220 kV network) AEMO invoked a network constraint. This constraint manages the overload of the Hazelwood to Yallourn 220kV No 1 line on the trip of the No 2 line and affects almost all Victorian generators and all interconnectors into Victoria.

The constraint immediately bound and constrained off around 500 MW of Victorian generation in the Latrobe Valley and forced flows into Tasmania across Basslink, by up to 200 MW. It also forced flow into South Australia across Heywood by up to 53 MW counter-price.

The 5-minute price reached the price cap in Victoria and $2477/MWh in South Australia at 10.35 am.

Counter price forced flows into New South Wales occurred at a cost of around $631 000 for the 11 am trading interval

In response to the high price around 1700 MW of capacity in Victoria and 450 MW of capacity in South Australia was rebid to the price floor. There was also around 1100 MW of capacity in Tasmania rebid close to the price floor. This saw the 5-minute price in Victoria, South Australia and Tasmania fall to as low as -$976/MWh, -$900/MWh and the price floor respectively during the 11 am trading interval.

Further rebids occurred for the 11.30 am trading interval, which saw the 5-minute price in Victoria, South Australia and Tasmania fall to as low as -$985/MWh,-$881/MWh and -$949/MWh, respectively:

- At 11.04 am, effective from 11.15 am, Hydro Tasmania rebid 1183 MW of capacity across its portfolio to the price floor (from between -$1/MWh and $55/MWh). The reason given was “Basslink flow different from forecast”.
- At 11.17 am, effective from 11.25 am, AGL rebid 450 MW of capacity to close to the price floor at Loy Yang A (from between $30/MWh and $90/MWh). The reason given was “unfcast network constraint::constr off out of merit odr”.

There was no other significant rebidding.

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 $138/MWh and above $250/MWh. There was also one occasion were the price was below -$100/MWh

Tuesday, 18 June

7:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2099.99	12 195.07	12 199.20
Demand (MW)	2148	2274	2278
Available capacity (MW)	2025	2014	1969
7:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1918.70	12 194.43	12 195.07
Demand (MW)	2174	2263	2268
Available capacity (MW)	2045	2021	1972

Conditions at the time saw demand up to 126 MW lower than that forecast four hours ahead, while available capacity was close to forecast.

At 5 pm effective from 5.10 pm, EnergyAustralia rebid 122 MW of capacity (62 MW at $11 835/MWh and 60 MW at $291/MWh) to prices below $110/MWh. The reason given was "Band adj due to SA price higher thn fcast SL". This saw the forecast price drop to $111/MWh for this period.

At 6.37 pm, effective from 6.45 pm, Origin Energy rebid 72 MW of capacity across Ladbroke and Quarantine from the price floor to above $11 735/MWh. The reason given was "Constraint mgmt. – V>S_460 SL". As a result the 5-minute price increased from $96/MWh at 6.40 pm to $12 194/MWh at 6.45 pm.

In response to the high price there was an apparent demand side of around 120 MW for the next dispatch interval. Up to 45 MW of this reduction was the result of an increase in non-scheduled generation at Angaston and Port Stanvac.

At 7.23 pm, effective from 7.30 pm, AGL rebid 100 MW of capacity at Torrens Island from the price floor to above $11 000/MWh. The reason given was "19:01A chg in dispatch::demand decrease vs pd [SA] [>50MW]". As a result the 5-minute price increased from $85/MWh at 7.25 pm to $11 090/MWh at 7.30 pm.

In response there was another apparent demand side response of around 110 MW in the next 5 minutes and prices returned to previous levels.

There were no other significant rebids.

Wednesday, 19 June

7:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2015.13	300.07	12 195.07
Demand (MW)	2200	2243	2318
Available capacity (MW)	2015	2079	2076

Conditions at the time saw demand 75 MW lower than that forecast 12 hours ahead and 43 MW lower than that forecast four hours ahead. Available capacity was 64 MW lower than that forecast.

With no capacity priced between $200/MWh and $11 000/MWh, any reductions in import capability, rebidding of capacity into high price bands or increases in demand, had the potential to result in a significant jump in the spot price.

The 75 MW difference in forecast demand between the 12 and 4 hour forecast was sufficient for the forecast spot price to fall from $12 195/MWh to $300/MWh.

Over two rebids at 7.22 pm and 7.23 pm, effective from 7.30 pm, AGL rebid a total of 120 MW of capacity at Torrens Island from prices between $200/MWh and $300/MWh to above $11 000/MWh. The reasons given were “19:20A chg in forecast::1930 5PD demand decrease VS30PD <35MW” and “19:20A chg in forecast::5pd demand decrease SA v 30pd <30MW”.

As a result the 5-minute price increased from $199.99/MWh at 7.25 pm to $11 090/MWh at 7.30 pm.

In response to the high price there was an apparent demand side response of 95 MW (44 MW of this was due to increased non-scheduled generation output). This saw the 7.35 pm price fall to previous levels.

There were no other significant rebids.

Friday, 21 June

10:00 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2217.13	64.68	90.80
Demand (MW)	1740	1656	1725
Available capacity (MW)	2803	2881	2837

11:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	-156.32	60.00	61.29
Demand (MW)	1783	1527	1547
Available capacity (MW)	2644	2877	2853

Prices in South Australia were driven by events in Victoria (see the Victorian section for details).

3:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2088.82	65.54	59.05
Demand (MW)	1537	1606	1489
Available capacity (MW)	2448	2694	2739

Conditions at the time saw demand and available capacity lower than that forecast four hours ahead.

A constraint managing the earlier trip of the Yallourn Power Station (see the Victorian analysis) continued to bind and was forcing imports into South Australia at around 440 MW (counter-price at times). At 2.35 pm, AEMO invoked a constraint to manage the accumulation of negative settlement residues from Victoria to South Australia. At 3.20 pm, this reduced imports into South Australia across the Heywood interconnector by 138 MW.

At 3.12 pm, effective from 3.20 pm, Alinta Energy rebid 70 MW of capacity at Northern unit 1 from prices below $90/MWh to above $11 700/MWh. The rebid reason given was “NPS1 SA dispatch price @ $300.07 v $72@15:11”.

At 3.13 pm, effective from 3.20 pm, Origin Energy reduced the capacity of its offline Quarantine unit 5 by 125 MW (80 MW at $298/MWh and 45 MW at $12 194/MWh). The reason given was “Avoid uneconomic start SL”.

With low priced generation either ramp rate limited or trapped in FCAS and imports from Victoria limited by a constraint managing negative settlement residues, high priced generation was dispatched causing the 5-minute price to reach $12 194/MWh at 3.20 pm.

There was no other significant rebidding.

<u>Tasmania:</u>

There were two occasions where the spot price in Tasmania was below -$100/MWh.

Friday, 21 June

11:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-334.24	55.30	55.28
Demand (MW)	1407	1449	1435
Available capacity (MW)	2427	2395	2395
11:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-250.62	55.28	55.28
Demand (MW)	1406	1416	1412
Available capacity (MW)	2415	2395	2395

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

Prices in Tasmania were driven by events in Victoria (see the Victorian section for details).

Detailed NEM Price and Demand Trends

for Weekly Market Analysis

16 June - 22 June 2013

AUSTRALIAN ENERGY REGULATOR

Table 1: Financial year to date spot market volume weighted average price

Financial year	QLD	NSW	VIC	SA	TAS
2012-13 ($/MWh) YTD	70	56	61	74	48
2011-12 ($/MWh) YTD	30	30	28	32	33
Change*	136%	84%	117%	128%	47%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 YTD	11.706	190
2011-12	5.987	199
2010-11	7.445	204

Table 3: Recent monthly and quarterly spot market volume weighted average price and turnover

Volume weighted average ($/MWh)	QLD	NSW	VIC	SA	TAS	Turnover ($, billion)
February-13	60	53	56	63	46	0.855
March-13	76	53	55	62	50	0.986
April-13	56	55	51	80	45	0.836
May-13	59	56	56	116	45	0.982
June-13 MTD	67	55	61	130	46	0.773
Q2 2013 QTD	60	55	56	107	45	2.590
Q2 2012 QTD	29	33	32	32	34	1.427
Change*	105%	68%	75%	236%	32%	0.815

Table 4: ASX energy futures contract prices at end of 21 June 2013

	QLD		NSW		VIC		SA	
Q1 2014	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 14 Jun ($/MWh)	73	89	61	72	60	77	67	92
Price on 21 Jun ($/MWh)	76	89	62	75	63	79	68	92
Open Interest on 21 Jun ($/MWh)	939	145	1513	275	1034	265	148	35
Traded in the last week (MW)	169	0	288	25	430	0	20	0
Traded since 1 Jan 13 (MW)	1543	116	1752	505	1645	325	224	35
Settled price for Q1 13 ($/MWh)	97	110	52	54	53	62	58	69

Table 5: Changes to availability of low priced generation capacity offered to the market

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
April 13 with April 12						
MW Priced $20/MWh	-4017	-164	-415	-348	-316	-5259
MW Priced $20/MWh to $50/MWh	2269	-1179	951	-513	284	1811
May 13 with May 12						
MW Priced $20/MWh	-4007	-399	-985	-453	-277	-6121
MW Priced $20/MWh to $50/MWh	2294	-1499	255	-603	293	740
June 13 with June 12 MTD						
MW Priced $20/MWh	-3368	265	269	-210	-270	-3314
MW Priced $20/MWh to $50/MWh	1912	-1805	-77	-552	185	-337

*Note: These percentage changes are calculated on VWA prices prior to rounding

** Estimated value