WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

2 – 8 June 2013

Spot prices in South Australia averaged $199/MWh for the week as a result of tight supply conditions. At times this saw short duration price spikes to close to the price cap.

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for 2 to 8 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 2 June - 8 June 2013	53	51	49	199	39
% change from previous week*	-14	-2	-20	60	-15
12-13 financial YTD	70	56	60	73	48
% change from 11-12 financial YTD**	137	86	119	127	48

*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.[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 7 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	56	2%	52	1%	48	0%	55	0%
Calendar Year 2015	47 (11)	0%	45 (4)	0%	40	0%	47	0%
Calendar Year 2016	51	0%	52	0%	47	0%	63	0%
Three year average	51	1%	49	0%	45	0%	55	0%

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.

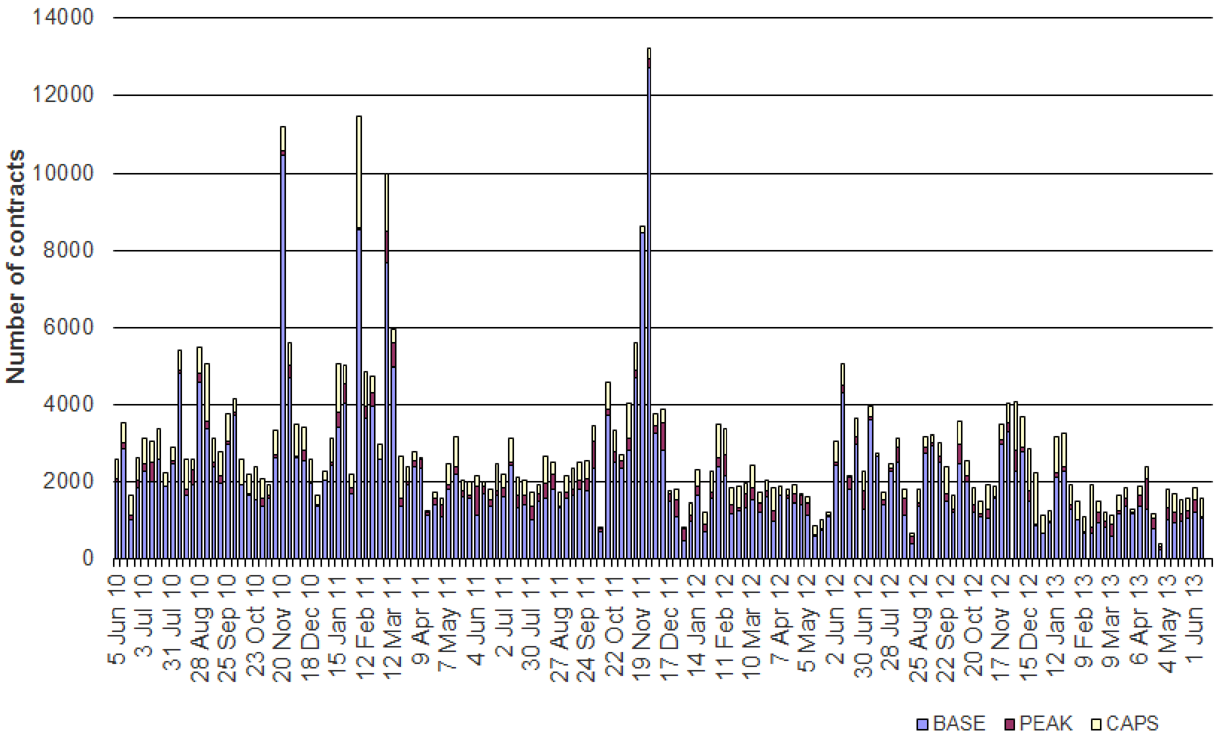
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2014	13 (35)	7%	7	-3%	10	0%	16	0%
2014	7	6%	4	-4%	4	0%	8	1%

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

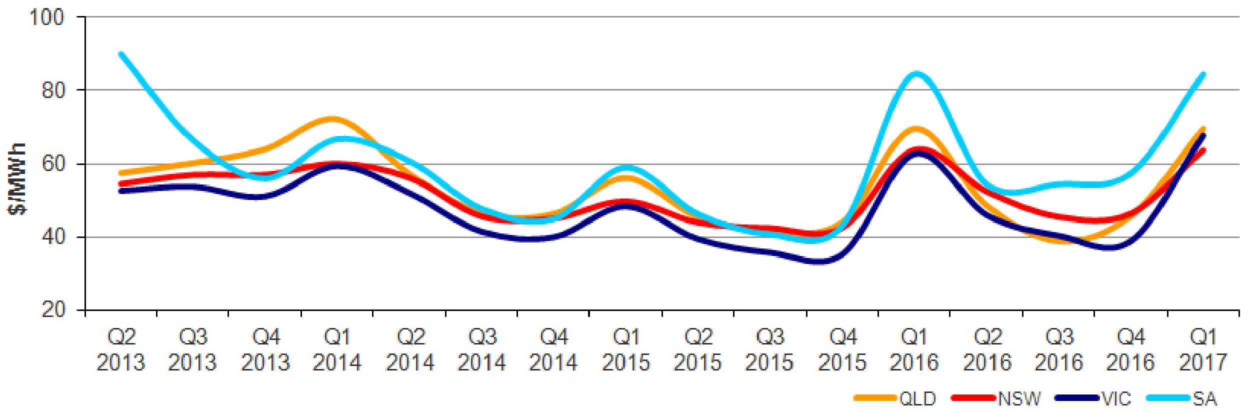


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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

[4] Calculated on prices prior to rounding.

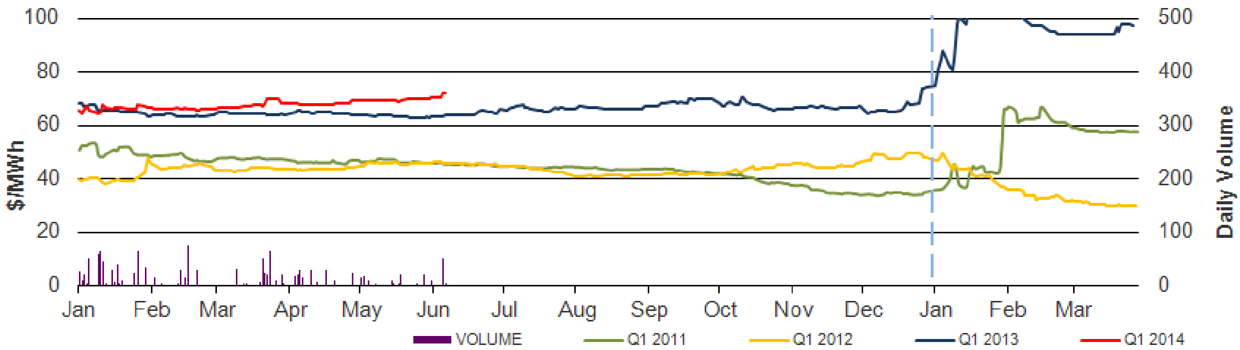
Figure 5: Quarterly base future prices Q2 2013 – Q1 2017



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

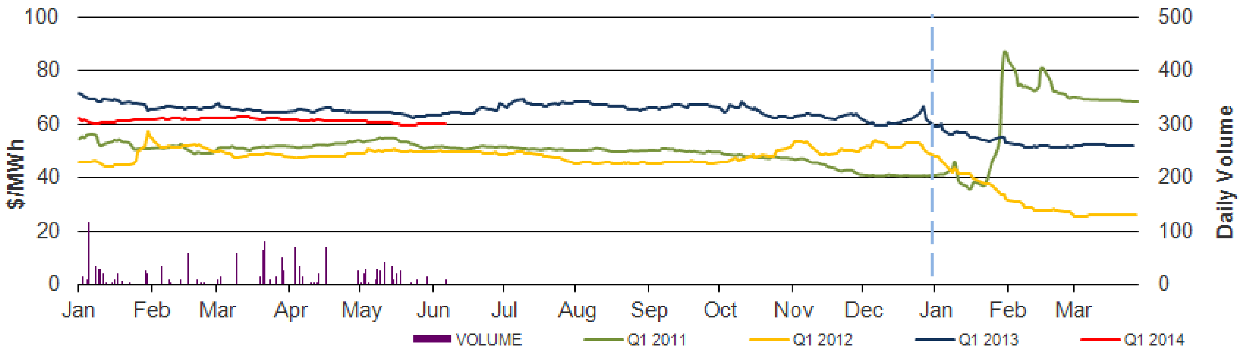
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2011, 2012, 2013 and 2014. Also shown is the daily volume of Q1 2014 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

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



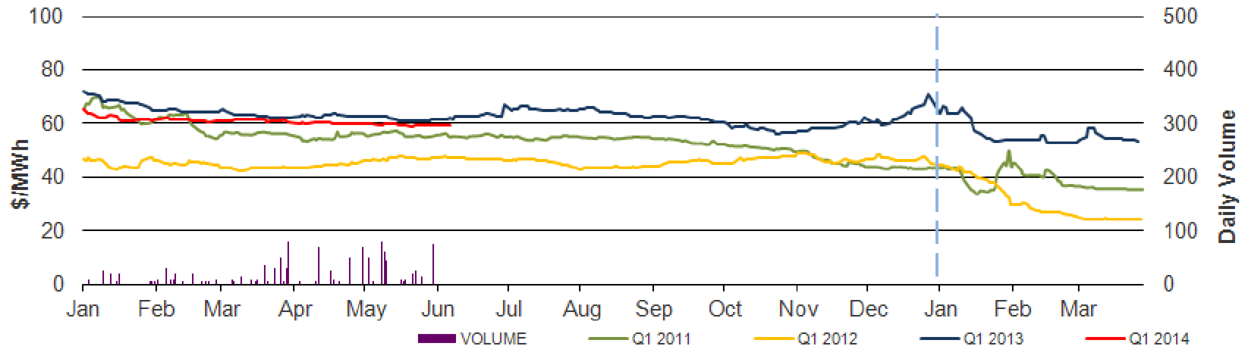
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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



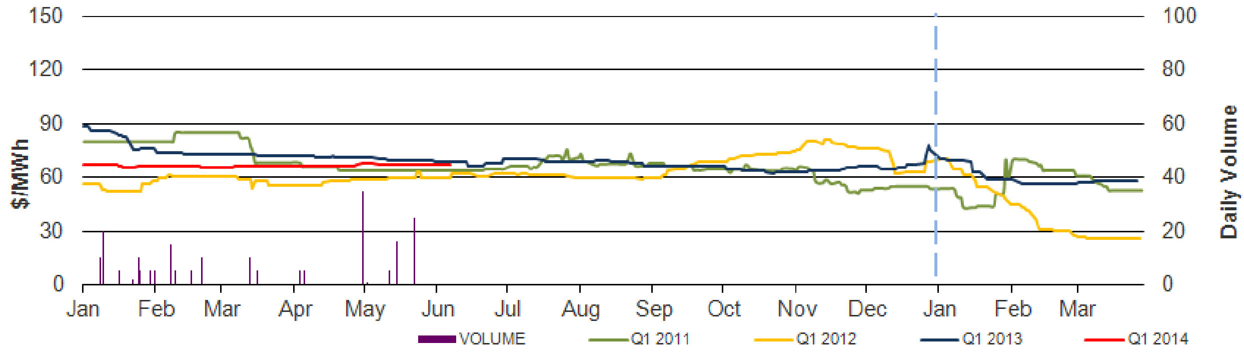
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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 122 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	9	0	0
% of total below forecast	19	59	0	8

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 273 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	273	-105	137	-47
NSW	184	-184	-74	130
VIC	470	-45	183	17
SA	277	35	-21	43
TAS	189	356	-17	-12
TOTAL	1393	57	208	131

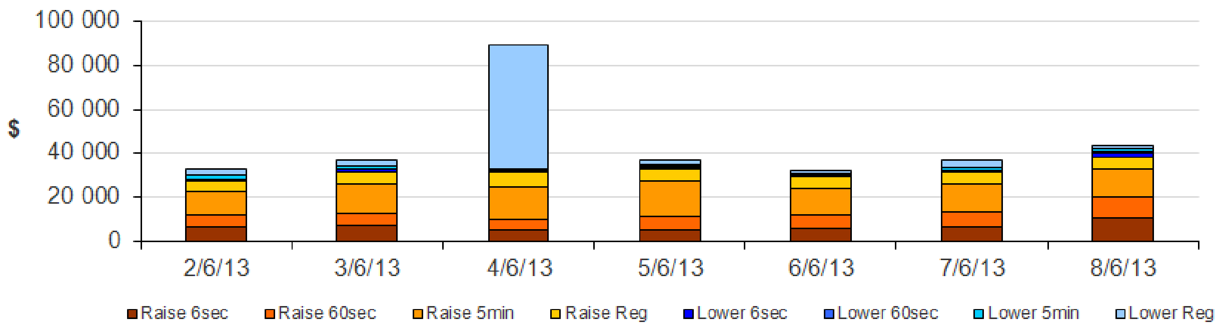
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $230 500 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $78 000 or around 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

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

AUSTRALIAN ENERGY REGULATOR

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South Australia:

There were twenty-one occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $199/MWh and above $250/MWh. These events were driven by tight supply conditions and resulted in many 5-minute price spikes at close to the price cap. The reasons for these price spikes are discussed below.

In addition, the Murraylink interconnector continued to be offline after its trip on 15 May and 3 Torrens Island B units remained offline following a fire in its 6.6 kV switchyard for auxiliary equipment on 31 May. 1 of the 3 units returned to service on the 7 June while the other 2 units remained offline for the duration of the week.

Sunday, 2 June

6:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2156.22	12 195.07	12 195.07
Demand (MW)	1788	1870	1796
Available capacity (MW)	1710	1771	1753

Actual demand was 82 MW lower than forecast four hours before. Available capacity was close to forecast.

The actual forecast price dropped compared to the four hour price as a result of the fall in demand and the following participant rebidding:

- at 4.50 pm, effective from 5 pm, GDF Suez rebid 40 MW of available capacity at Mintaro power station from prices above $12 600/MWh to close to the price floor. The reason given for the rebid was ‘1649A constraint management V>S_460 SL’
- at 4.52 pm, effective from 5 pm, Energy Australia rebid 70 MW of available capacity at Hallett power station from prices above $11 835/MWh to below $300/MWh. The reason given was ‘16:50 a band adj due to change in 5-min PD SL’, and
- at 5.11 pm, effective from 5.20 pm, Origin Energy rebid 42 MW of available capacity at Ladbroke Grove power station from prices above $12 300/MWh to below $60/MWh. The reason given was ‘1708A constraint management - V>S_460 SL’.

At 6.25 pm the 5-minute price was $170/MWh. At 6.30 pm, a small increase in demand (from 1813 MW at 6.25 pm to 1821 MW at 6.30 pm), with three Torrens Island A units trapped in FCAS services and Heywood importing at its limit saw higher priced generation dispatched at Northern power station. This led to the 5-minute price reaching $12 194/MWh at 6.30 pm.

There was no other significant rebidding.

Monday, 3 June

On 3 June, the South Australia spot price exceeded $1800/MWh on 13 occasions. All of these high spot prices were associated with five-minute dispatch price spikes above $11 000/MWh. For the majority of the spot prices, the 12 hours ahead forecast showed prices would exceed $12 100/MWh. Few of these prices were revised down for the four hour ahead forecast. This demonstrates that there were extremely tight supply conditions on the day. Therefore small changes to demand, wind generation or imports had significant impact on prices.

Earlier on the day, at 5.40 am, Torrens Island A unit 4 tripped from 120 MW, all of which was priced less that $65/MWh. The unit attempted to return to service throughout the morning, generating very low output and was ultimately bid unavailable as a result of a tube leak at 12.40 pm. This worsened the tight supply conditions in South Australia and was a major factor for the high prices on the day.

7:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2079.82	60.80	60.90
Demand (MW)	1476	1538	1557
Available capacity (MW)	1541	1721	1755
8:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2106.55	300.07	300.07
Demand (MW)	1534	1666	1654
Available capacity (MW)	1523	1702	1733

Conditions at the time saw demand up to 132 MW and available capacity up to 180 MW less than that forecast four hours ahead.

At 7.20 am, there was an increase in demand of around 40 MW. At the same time, the import limit reduced by 45 MW due to a constraint managing post contingent load on the Heywood 275/500 kV transformer. The step reduction in import capability and increase in demand was unable to be met by low priced generation which was either ramp rate limited or trapped in FCAS. This led to high priced generation being dispatched and the 5-minute price increasing from $61/MWh at 7.15 am to $12 199/MWh at 7.20 am.

At 7.42 am, effective from 7.50 am, Alinta Energy rebid 30 MW of capacity at Northern power station priced at $49/MWh to $11 753/MWh. The reason for the rebid was ‘0740A NPS1 increase in PD 12194 VS 300@07:42’.

Similar to the 7.20 am event, there was an increase in demand of around 38 MW for the 8 am dispatch interval. At the same time, the import limit was reduced by 48 MW due to the constraint managing post contingent load on the Heywood 275/500 kV transformer. The step reduction in import capability and increase in demand was unable to be satisfied by low priced generation with limited ramp up rate. This led to high priced generation being dispatched and the 5-minute price increasing from $61/MWh to $12 199/MWh at 8 am.

There was no other significant rebidding.

8:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2130.29	12 195.07	12 194.65
Demand (MW)	1583	1764	1733
Available capacity (MW)	1533	1691	1712
9:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2079.80	12 199.20	12 195.07
Demand (MW)	1613	1789	1742
Available capacity (MW)	1584	1676	1694
9:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2078.52	12 195.07	12 195.07
Demand (MW)	1585	1753	1720
Available capacity (MW)	1518	1700	1683

Conditions at the time saw demand 182 MW and available capacity 158 MW less than that forecast four hours ahead.

Over two rebids at 6.19 am and 6.43 am, EnergyAustralia rebid 85 MW of capacity at Hallett from prices above $11 800/MWh to below $600/MWh. The reasons given were '06:17 a band adj due to inc prices in SA 5M PD' and '06:41 a band adj act SA price at 0640 higher than fcst'.

Over a number of rebids between 6.33 am and 8.06 am, GDF Suez rebid a total of 87 MW of capacity at Dry Creek and Port Lincoln from prices above $12 210/MWh to below -$970/MWh. The reason given referred to the high South Australian pre-dispatch prices.

The above rebid saw a reduction in the forecast spot prices to below $300/MWh.

At 8.21 am, effective for the 8.30 am, Origin Energy rebid 37 MW of capacity at Ladbroke Grove from prices below $200/MWh to above $12 300/MWh. The reason for the rebid was '0820A constraint mgmt - V>S_460 SL'. Ladbroke Grove was setting the 5-minute price at 8.25 am.

This rebid combined with a 19 MW increase in demand for the 8.30 am dispatch interval and no further imports available (flows were at import limit), saw the dispatch of high priced generation. The 5-minute price increased from $200/MWh to $12 199/MWh at 8.30 am.

At 8.45 am, effective from 8.55 am, Alinta Energy rebid 30 MW of capacity at Northern power station priced at $49/MWh to $11 573/MWh. The reason for the rebid was '0845A NP1 TORRNA4 offline reduced gen avail in SA@08:44'.

With the Heywood interconnector importing into South Australia at its limit and all low priced generation fully dispatched, high priced generation had to be dispatched to meet demand. This led to the 5-minute price increasing from $58/MWh at 8.50 am to $12 190/MWh at 8.55 am.

Subsequent rebidding from participants[8] saw the dispatch price reduced to below $60/MWh. However, these rebids were only effective for the 9 am dispatch interval. Therefore at the start of 9.30 am trading interval, the 9.05 am 5-minute dispatch price returned to above $12 100/MWh.

Over a number or rebids, effective from 9.05 am or 9.10 am, Origin Energy and GDF Suez rebid a combined total of 157 MW of capacity at Ladbroke Grove unit 1, Quarantine unit 5 and Dry Creek units 1 and 3 from prices above $12 100/MWh to the price floor. The reasons given were “0900A constraint mgmt. – V>S_460 SL”, “0854A high SA 5min PD for HHE0930” and “0901A response to MPC in SA dispatch SL”. The 5-minute price returned to below $60/MWh at 9.10 am.

There was no other significant rebidding.

10:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2195.33	300.07	12 194.44
Demand (MW)	1582	1681	1661
Available capacity (MW)	1446	1763	1646

Actual demand was 99 MW lower than forecast four hours before. Available capacity was 317 MW lower than forecast four hours before.

A number of rebids were made making additional capacity available and moving capacity from high prices to low prices in the early hours of the morning which saw around an additional 50 MW of available capacity at prices below $55/MWh for the 10.30 am trading interval. This had the effect of reducing the forecast spot price for South Australia four hours ahead, compared to that of 12 hours ahead.

As discussed earlier, AGL’s Torrens Island A unit 4 tripped earlier in the day. The unit tried to return to service at around 8.30 am and 9.30 am but was not successful. The tight supply conditions again saw the 5-minute price increase from $57/MWh at 10 am to the price cap at 10.05 am.

There was no other significant rebidding.

11:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2079.44	11 048.00	12 194.44
Demand (MW)	1551	1637	1634
Available capacity (MW)	1514	1679	1639

Conditions on the day saw demand and available capacity lower than that forecast four hours ahead. The actual forecast spot price dropped compared to the four hour spot price as a result of the fall in demand and participant rebidding.

At 10.20 am, GDF Suez rebid 47MW of capacity at Dry Creek unit 2 from prices above $12 200/MWh to the price floor. The reason given was ‘1019A SA 5min PD price $300.17’.

[8] At 8.53 am, effective for only the 9 am dispatch interval, Origin Energy rebid a total of 45 MW of capacity at Quarantine unit 5 and Ladbroke Grove unit 1, from prices above $12 100/MWh to below -$960/MWh. The reason given was ‘0853A constraint mgmt - V>S_460 SL’. Also at 8.53 am, effective only for the 9 am dispatch interval, GDF Suez rebid 35 MW of capacity at Dry Creek unit 1 from prices above $12 200/MWh to the price floor. The reason for the rebid was ‘0852A response to SA MPC in dispatch SL’.

At 10.49 am, effective from 10.55 am, Alinta Energy rebid 60 MW of capacity at Northern power station from prices below $50/MWh to above $11 700/MWh. The reason for the rebid was '1047A NPS1 change in PD 57.52 vs 58.01 PRICES@10:48'.

There was an increase in demand of around 23 MW for the 11 am dispatch interval. At the same time, the import limit reduced by 29 MW due to the constraint managing post contingent load on the Heywood transformer. The step reduction in import capability and increase in demand was unable to be satisfied by low priced generation which was fully dispatched. This led to high priced generation being dispatched and the 5-minute price increasing from $56/MWh at 10.55 am to $12 190/MWh at 11 am.

There was no other significant rebidding.

12:00 noon	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1934.09	90.80	11 048.00
Demand (MW)	1577	1601	1596
Available capacity (MW)	1725	1815	1631

Conditions at the time saw demand close to forecast and available capacity 90 MW less than that forecast 4 hours ahead.

At 11.48 am, effective from 11.55 am, Alinta Energy rebid 30 MW of capacity at Northern power station from $49/MWh to $11 573/MWh. The reason for the rebid was '1146A NPS1 5min tracking ahead of 30min PD $90 VS $55@11:48'.

As a result of the rebid and lower priced generators being ramp rate limited, higher priced generation from unit 1 and 2 of Torrens Island A had to dispatched, setting the 11.55 am 5-minute dispatch price at $300/MWh.

At 12 noon, unit 1 of Torrens Island A became trapped in FCAS. With lower priced generators still ramp rated limited and unit 2 of Torrens Island B (which had only just returned to service) fully dispatched, higher priced generation was dispatched, increasing the 5-minute price from $300/MWh at 11.55 am to $11 573/MWh at 12 pm.

There was no other significant rebidding.

6:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1895.66	12 898.50	12 195.07
Demand (MW)	1747	1986	1903
Available capacity (MW)	1760	1692	1818

Actual demand was 239 MW lower than forecast four hours before. Available capacity was close to forecast. The actual forecast spot price dropped compared to the four hour spot price as a result of the fall in demand and participant rebidding.

Prior to the 4 hour forecast AEMO issued notices forecasting level 2 and 3 lack of reserve (LOR) in South Australia from 6 pm to 7.30 pm. If the forecast level 3 LOR was not remedied, then customer load would have to be interrupted. This was later cancelled as a result of a market response from non-scheduled generator entities of around 100 MW and the successful return to service of scheduled generators.

The actual forecast spot price dropped compared to the four hour spot price as a result of the fall in demand (noting that non-scheduled generation is reported as a reduction in demand).

Over two rebids at 4.26 pm and 5.30 pm, Origin Energy delayed the return to service of Osborne (which had been offline since Friday evening) by reducing available capacity by 132 MW, all of which was priced below $80/MWh. The reason given was ‘change in avail – OSB RTS revised SL’.

At 5.43 pm, effective from 5.50 pm, Origin Energy rebid a total of 51 MW of capacity at Ladbroke Grove and Quarantine from prices below zero to above $11 000/MWh. The reason given was ‘1740P MW redistribution - OSB RTS SL’.

There was an increase in demand of around 35 MW for the 6 pm dispatch interval. The step change in supply and demand was unable to be satisfied by low priced generation which was ramp rate limited or trapped in FCAS. This led to high priced generation being dispatched and the 5-minute price increasing from $76/MWh at 5.55 pm to $11 048/MWh at 6 pm.

There was no other significant rebidding.

6:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1889.53	12 899.70	12 800.00
Demand (MW)	1813	2098	2044
Available capacity (MW)	1771	1691	1818

Actual demand was 285 MW lower than that forecast four hours ahead. Available capacity was close to forecast. The actual forecast spot price dropped compared to the four hour spot price as a result of the fall in demand and participant rebidding.

There was an increase in demand of around 34 MW for the 6.10 pm dispatch interval. At the same time, the import limit reduced by 21 MW due to the constraint managing the Heywood transformer. The step reduction in import capability and increase in demand was unable to be satisfied by low priced generation which was ramp rate limited or trapped in FCAS. This led to high priced generation being dispatched and the 5-minute price increased from $76/MWh at 6.05 pm to $11 048/MWh at 6.10 pm.

There was no significant rebidding.

7:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2087.77	12 899.80	12 898.50
Demand (MW)	1853	2121	2074
Available capacity (MW)	1861	1693	1803

Actual demand was 268 MW lower than that forecast four hours ahead. Available capacity was 168 MW higher than that forecast four hours ahead.

At 6.40 pm, effective from 6.50 pm, Origin Energy rebid 40 MW at Ladbroke Grove unit 1 from prices less than -$950/MWh to above $12 000/MWh. The reason given was ‘1834A Dec in SA dem – 5 PD 1807 MW < 30 PD 1957 @ 1900 SL’.

There was an increase in demand of around 43 MW for the 6.55 pm dispatch interval. At the same time, the import limit reduced by 33 MW due to the constraint managing the Heywood transformer. The step reduction in import capability and increase in demand was unable to be satisfied by low priced generation which was ramp rate limited. This led to high priced generation being dispatched and the 5-minute price increased from $61/MWh at 6.50 pm to $12 190/MWh at 6.55 pm.

There was no other significant rebidding.

7:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1898.69	12 899.70	12 850.07
Demand (MW)	1846	2112	2056
Available capacity (MW)	1883	1694	1810

Actual demand was 266 MW lower than that forecast four hours ahead. Available capacity was 189 MW higher than that forecast four hours ahead. The actual forecast spot price dropped compared to the four hour spot price as a result of the fall in demand and participant rebidding.

At 6.40 pm, effective from 6.50 pm, Origin Energy rebid 40 MW of capacity at Ladbroke Grove unit 1 from the prices less than -$950 to $12 321/MWh. The reason for the rebid was '1838A dec in SA dem - 5PD 1807 MW < 30PD 1957 @ 1900 SL'.

At 7.18 pm, effective from 7.25 pm, Alinta Energy rebid 60 MW of capacity at Northern power station prices below $2180/MWh to above $11 753/MWh. The reason for the rebid was '1916A 5M DS tracking behind 30M $60 V $11048@19:18'.

At 7.25 pm, a 60 MW increase in demand combined with rebidding by Alinta saw the 5-minute price increase from $61/MWh at 7.20 pm to $11 048/MWh at 7.25 pm.

There was no other significant rebidding.

12 midnight	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1889.86	57.68	12 190.10
Demand (MW)	1644	1691	1746
Available capacity (MW)	1876	1939	1844

Demand and available capacity was close to forecast.

At 3.46 pm, Origin Energy increased the available capacity at Osborne power station by 189 MW, 160 MW of which was priced below $50/MWh. The reason given was '1325P change in avail - unit RTS delayed SL'. This significantly contributed to the reduction in the forecast price for the midnight intervals in the 4 hours ahead forecast compared to that of the 12 hour ahead forecast.

There was a step change in demand increasing from 1522 MW at 11.30 pm to 1716 MW at 11.35 pm. This sharp increase in scheduled demand was related to off peak hot water load. Low priced capacity was either ramp rate up limited or trapped or stranded in FCAS. This led high-priced capacity being dispatched to meet the increase in demand. As a result, the 5-minute price increased from $58/MWh at 11.30 pm to $11 048/MWh at 11.35 pm.

There was no other significant rebidding.

Tuesday, 4 June

6:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2079.97	11 048.00	11 048.00
Demand (MW)	1794	1825	1828
Available capacity (MW)	1877	1901	1896
6:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1891.72	12 190.10	12 190.10
Demand (MW)	1867	1904	1907
Available capacity (MW)	1881	1900	1897
7:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1891.60	12 194.44	12 194.44
Demand (MW)	1874	1943	1946
Available capacity (MW)	1890	1902	1899
7:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1889.12	12 190.10	12 190.10
Demand (MW)	1839	1911	1911
Available capacity (MW)	1902	1888	1906

Conditions at the time saw demand and available capacity close to forecast. The forecast prices following the four hour ahead forecast decreased as a result of participant rebidding.

Over two rebids at 3.14 pm and 4.47 pm, GDF Suez rebid a total of 95 MW of capacity at Mintaro and Dry Creek unit 3 from prices above $12 200/MWh to below zero. The reason for the rebid was ‘1513A SA 5min PD 1661MW > 30min PD 1638MW hhe 15:30 SL’ and ‘1647A SA 5min PD 1769MW > 30min PD 1740MW hhe 17:00’.

At 5.46 pm, effective for only the 5.55 pm and 6 pm dispatch intervals, Alinta Energy rebid 60 MW of capacity at Northern power station from prices below $50/MWh to $11 753/MWh. The reason given was ‘1745A NPS1 SA dispatch price at $56.91 V $57.19@17:46’.

At 6 pm, there was 106 MW increase in demand. At the same time, the import limit was restricted to 414 MW (a decrease of 9 MW from the previous dispatch interval) due to the constraint managing the Heywood transformer constraint. The step change in demand was unable to be satisfied by low priced generation which was either ramp rate limited or trapped in FCAS. This saw the dispatch of high priced generation and the 5-minute price increased from $59/MWh at 5.55 pm to $12 194/MWh at 6 pm. This resulted in the 6 pm trading price being set at $2080/MWh.

At 6.05 pm high priced generation was still required to be dispatched as a number of low priced generators remained trapped in FCAS, which saw the 6.05 pm dispatch price reach $11 048/MWh. This resulted in the 6.30 pm trading price being set at $1892/MWh.

At 6.50 pm, there was a step increase in demand of around 88 MW. At the same time, the Heywood transformer constraint reduced the import limit into South Australia across the Heywood interconnector to 443 MW (17 MW reduction from the previous dispatch interval). The step reduction in supply and increase in demand was unable to be satisfied by low priced generation which was fully dispatched. This led to the dispatch of high priced generation and saw the 5-minute dispatch price increase from $60/MWh at 6.50 pm to $11 048/MWh at 6.55 pm. This resulted in the 7 pm trading price being set at $1892/MWh.

At 7.15 pm, there was a step increase in demand of around 136 MW. At the same time, the Heywood transformer constraint limited flows into South Australia across the Heywood interconnector to 444 MW (a 16 MW reduction from the previous dispatch interval). The step reduction in supply and increase in demand was unable to be satisfied by low priced generation which was fully dispatched. This led to the dispatch of high priced generation and saw the 5-minute price increase from $56/MWh at 7.10 pm to $11 048/MWh at 7.15 pm. This resulted in the 7.30 pm trading price being set at $1889/MWh.

On a number of occasions throughout the high priced period, there were sudden decreases in scheduled demand due to the increase of non-scheduled generation from Port Stanvac and Angaston power station. This had the effect of reducing prices to below $70/MWh.

There was no other significant rebidding.

12:00 midnight	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1890.44	64.03	199.99
Demand (MW)	1630	1659	1708
Available capacity (MW)	1886	1959	2001

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

There was a large change in demand with increases in five minutes of 194 MW from 11.30 pm and 81 MW from 11.35 pm to 11.40 pm. This sharp increase in scheduled demand was related to off peak hot water load. Limited ramp up rates from low priced capacity and a number of units being trapped in FCAS led high priced capacity to be dispatched to meet the increase in demand. As a result, the 5-minute price increased from $70.64/MWh at 11.35 pm to $11 048/MWh at 11.40 pm.

There was no significant rebidding.

Wednesday, 5 June

6:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2163.68	65.32	90.38
Demand (MW)	1890	1815	1829
Available capacity (MW)	2117	2213	2162

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

At 5.37 pm, effective from 5.45 pm, Alinta Energy rebid 50 MW of capacity at Northern power station unit 1 from prices below $60/MWh to above $11 700/MWh. The reason given was '1746A NPS1 SA dispatch price at $79.88 V $300.07 @ 17:36'.

At 5.43 pm, effective from 5.50 pm, Origin rebid 80 MW of capacity at Quarantine 5 priced at $298/MWh to $12 190/MWh. The reason given related to avoiding a start of the unit, which was offline at the time[9]. Despite the unit not starting this bid set the five minute price which increased from $298/MWh at 5.45 pm to $12 190/MWh at 5.50 pm.

At 5.55 pm, there was a sudden decrease in scheduled demand (due to the increase of non-scheduled generation from Port Stanvac and Angaston power station) from 1945 MW at 5.50 pm to 1844 MW at 5.55 pm. This had the effect of reducing prices to below $60/MWh.

There was no other significant rebidding.

Friday, 7 June

7:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1915.54	98.50	12 194.44
Demand (MW)	1870	1996	1985
Available capacity (MW)	2099	2098	1966

Actual demand was 126 MW lower than forecast four hours ahead. Available capacity was close to that forecast four hours ahead.

At 7.19 am, AGL increased the available capacity at Torrens Island B unit 3 by 200 MW at prices below $200/MWh. The reason given was '05:33P increase in avail cap::RTS earlier than exp / RR'. This resulted in the decrease between 12 hour and 4 hour ahead forecast prices.

At 6.22 pm, effective from 6.30 pm, Alinta Energy rebid 110 MW at Northern power station unit 1 from prices below $290/MWh to above $11 700/MWh. The reason given was '1821A NPS1 SA dispatch price at $199.99 V $90.80@18:21'.

At 6.40 pm the import limit reduced by 34 MW due to the constraint managing post contingent load on the Heywood 275/500 kV transformer. There was also a 35 MW increase in demand. The step reduction in supply and increase in demand was unable to be satisfied by low priced generation. This led to high priced generation being dispatched and the 5-minute price increasing from $199.99/MWh at 6.35 pm to $11 091/MWh at 6.40 pm.

There was no other significant rebidding.

[9] The reason given was '1743E correct prev bid – incorrect time selected SL'. The reason given for the previous rebid, where no parameters were changed, was '1735A avoid uneconomic start sl'.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis

2 June - 8 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 ($/MWh) YTD	70	56	60	73	48
2011-12 ($/MWh) YTD	30	30	27	32	33
Change*	137%	86%	119%	127%	48%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 YTD	11.186	182
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	53	51	48	182	40	0.252
Q2 2013 QTD	57	55	53	109	45	2.070
Q2 2012 QTD	28	32	30	30	34	1.125
Change*	104%	73%	76%	257%	31%	0.841

Table 4: ASX energy futures contract prices at end of 7 Jun 2013

	QLD		NSW		VIC		SA	
Q1 2014	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 31 May ($/MWh)	70	89	60	72	60	77	67	92
Price on 7 Jun ($/MWh)	72	89	60	72	59	77	67	92
Open Interest on 7 Jun ($/MWh)	831	145	1324	265	787	265	128	35
Traded in the last week (MW)	65	0	10	0	0	0	0	0
Traded since 1 Jan 13 (MW)	1299	116	1394	480	1160	325	204	35
Settled price for Q1 13 ($/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	-3471	416	-406	-120	-279	-3860
MW Priced $20/MWh to $50/MWh	1827	-1927	289	-585	291	-105

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

** Estimated value