WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

16 October - 22 October 2011

Summary

Weekly average spot prices ranged from $23/MWh in Victoria to $55/MWh in South Australia.

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $3.7 million. The price of all services reached the price cap in South Australia on 19 October, accounting for around $3.2 million of FCAS costs. This is discussed further in the Ancillary Services Market section.

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 16 October to 22 October and the 11/12 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 - 22 Oct 2011	26	28	23	55	31
% change from previous week*	-8	-3	-21	88	-1
11/12 financial YTD	28	30	29	39	30
% change from 10/11 financial YTD **	32	5	15	40	-19

*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 Monday 24 October 2011. 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 -> Monitoring, reporting and enforcement -> Electricity market reports -> Long-term analysis.

[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 2012	43*	2%	50*	2%	44*	0%	54	1%
Calendar Year 2013	53*	3%	59	4%	54*	2%	58	0%
Calendar Year 2014	56	0%	59	0%	58	-3%	69	0%
Three year average	51	1%	56	2%	52	-1%	61	0%

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

* denotes trades in the product.

Figure 3 shows the $300 cap contract price for Q1 2012 and calendar year 2012 and the percentage change[4] from the previous week.

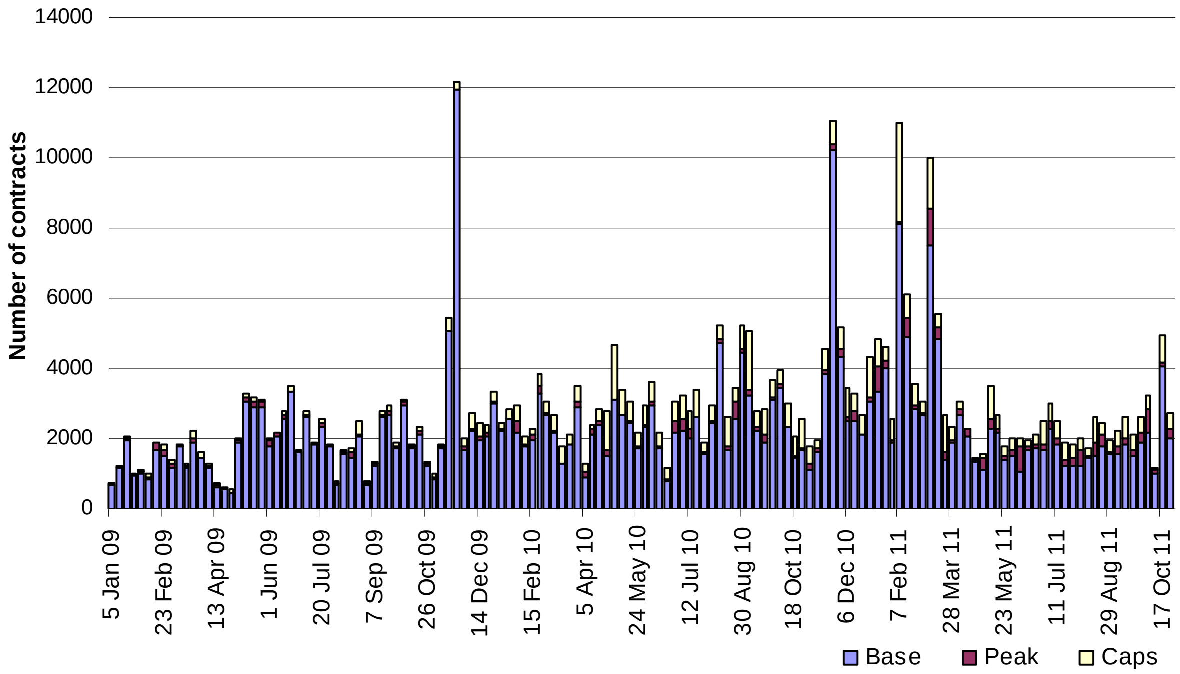
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2012 (% change)	14	2%	15	2%	18*	6%	34	0%
2012 (% change)	7	1%	9	1%	7	6%	12	0%

Source: d-cyphaTrade www.d-cyphatrade.com.au
* denotes trades in the product.

Figure 4 shows 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

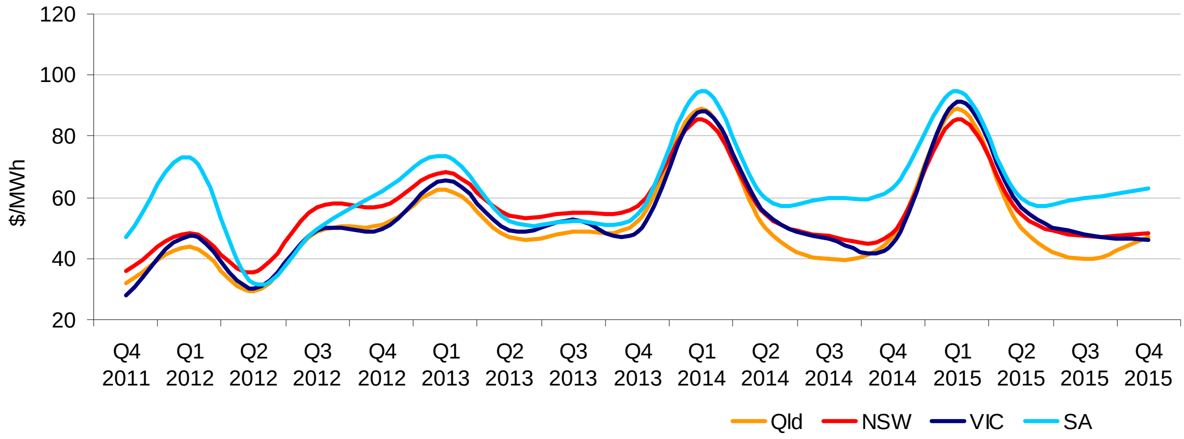


Source: d-cyphaTrade www.d-cyphatrade.com.au

[4] Calculated on prices prior to rounding.

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

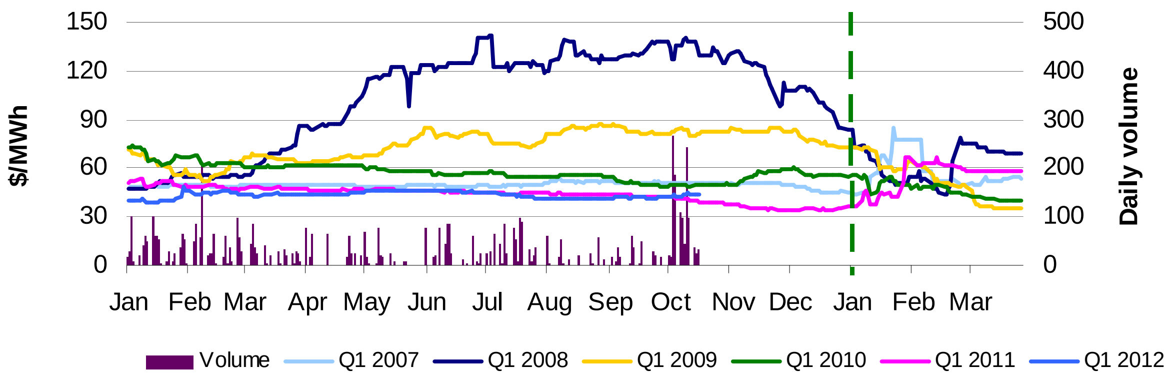
Figure 5: Quarterly base future prices Q4 2011 – Q4 2015



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

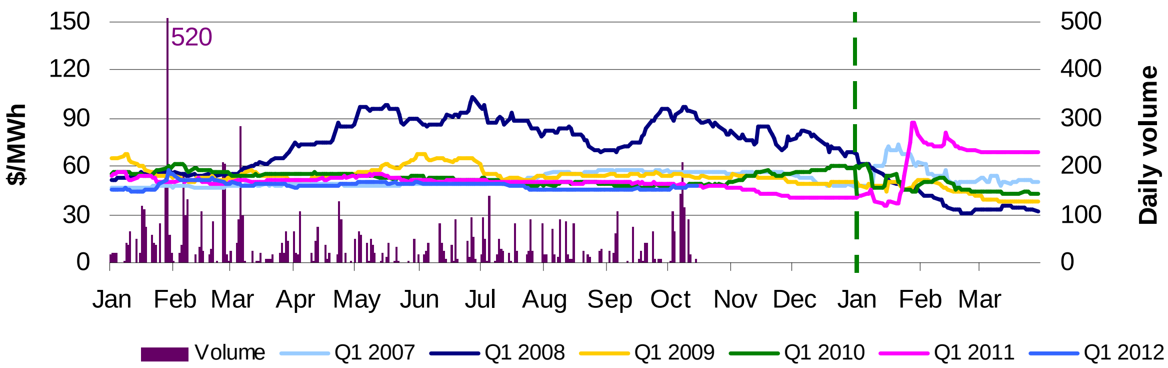
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2007, 2008, 2009, 2010, 2011 and 2012. Also shown is the daily volume of Q1 2012 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased. To understand the diagrams, the dark-blue line in figure 6 demonstrates that throughout the middle of 2007, the market had an expectation of very high spot prices in the first quarter of 2008.

Figure 6: Queensland Q1 2007, 2008, 2009, 2010, 2011 and 2012



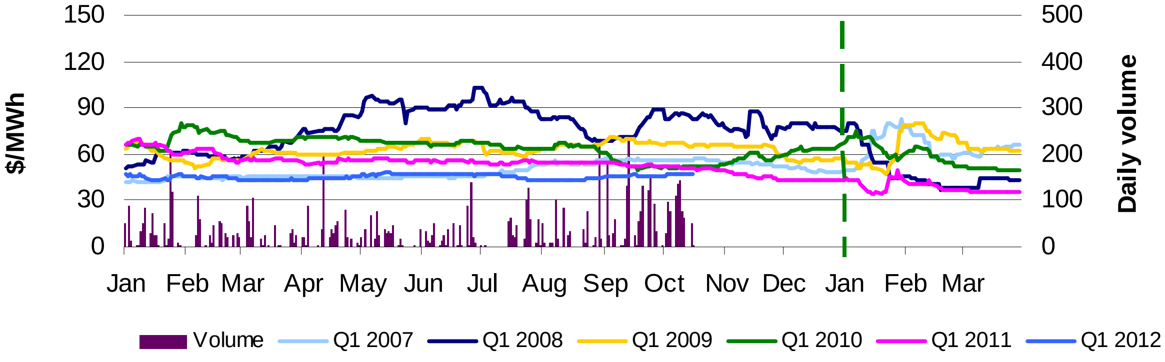
Source: d-cyphaTrade www.d-cyphatrade.com.au

Figure 7: New South Wales Q1 2007, 2008, 2009, 2010, 2011 and 2012



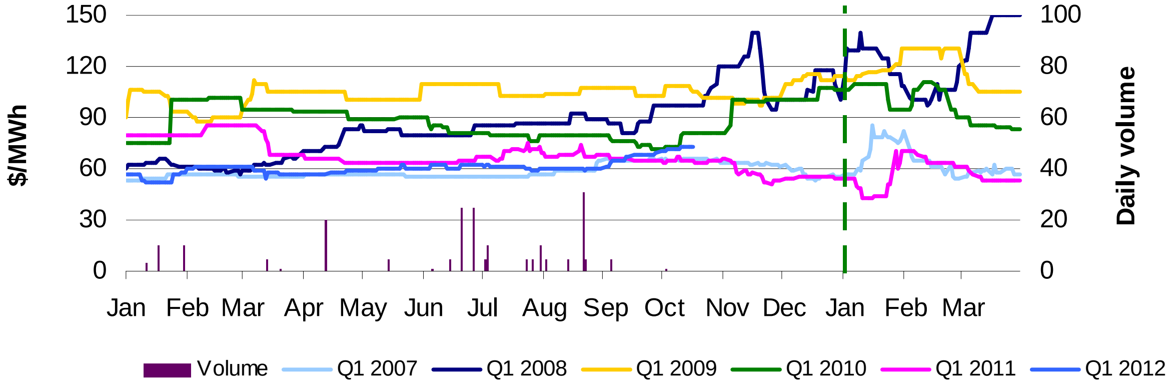
Source: d-cyphaTrade www.d-cyphatrade.com.au

Figure 8: Victoria Q1 2007, 2008, 2009, 2010, 2011 and 2012



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

Figure 9: South Australia Q1 2007, 2008, 2009, 2010, 2011 and 2012



Source: d-cyphaTrade 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 158 trading intervals throughout the week where actual prices varied significantly from forecasts[5]. This compares to the weekly average in 2010 of 57 counts and the average in 2009 of 103. 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	8	12	0	0
% of total below forecast	69	10	0	1

[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 233 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	233	-246	246	-191
NSW	-795	874	-115	77
VIC	437	-207	386	23
SA	-78	26	39	85
TAS	-95	-241	-43	-66
TOTAL	-298	206	513	-72

Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $3.7 million or around four per cent of energy turnover on the mainland. Around $3.2 million of this cost was incurred in South Australia on Wednesday 19 October.

At 6.18 am on 19 October, one of the Heywood to South East transmission lines in South Australia tripped during the planned outage of the other, leaving South Australia and Victoria connected only by the Murraylink interconnector. AEMO have advised that the line trip was not related to the planned outage and was a result of a coincidental fuse failure. At the time, there were forced imports of around 125 MW into Victoria from South Australia over Murraylink.

The loss of both Heywood to South East lines (i.e. the Heywood interconnector) resulted in abnormal frequency conditions in South Australia and the requirement for FCAS to be sourced locally within South Australia.

Requirements for lower 60 second service increased from zero to 90 MW at 6.30 am, before reaching 108 MW by 7 am. Lower 6 second requirements increased from zero to 47 MW at 6.30 am, before reaching 59 MW at 7 am. Raise 60 second increased from zero to 90 MW at 6.30 am and decreased slightly to 85 MW by 7 am. Raise 6 second increased from zero to 47 MW at 6.30 am and stayed at or above that level until 7 am. This saw the price of lower 60, lower 6, raise 60 and raise 6 second services reach the price cap for seven consecutive dispatch intervals between 6.30 am and 7 am inclusive.

The requirements for the remaining ancillary services increased from zero to 50 MW or less at 6.30 am. The price of lower regulation, raise regulation and raise 5 minute services reached the price cap from 6.35 am to 7 am inclusive. Lower 5 minute services reached the price cap for one dispatch interval at 6.35 am and at or around $9000/MW from 6.40 am to 7 am inclusive.

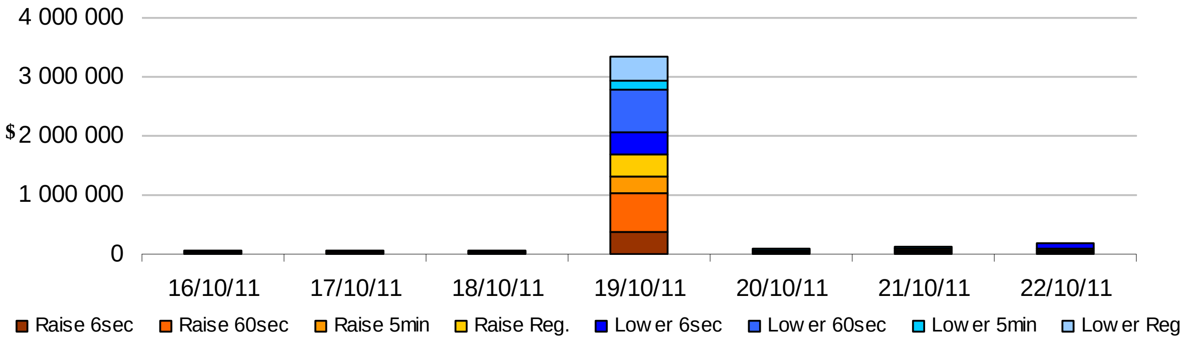
[7] A peak period is defined as between 7 am and 10 pm on weekdays.

The return to service of the Heywood interconnector at 7.05 am meant that FCAS could be sourced from outside the region and as a result the local requirements reduced to zero.

The total cost of FCAS in Tasmania for the week was $211 000 or around four 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
December 2011

South Australia

There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $55/MWh and above $250/MWh.

Friday, 21 October

9:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2170.55	38.97	31.65
Demand (MW)	1501	1477	1461
Available capacity (MW)	1821	1995	2208
10 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2033.36	38.77	29.79
Demand (MW)	1391	1430	1417
Available capacity (MW)	1351	2015	2206
12 midnight	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3956.29	42.87	48.00
Demand (MW)	1502	1505	1520
Available capacity (MW)	1575	1941	1950

Conditions at the time saw demand close to forecast and available capacity up to 855 MW less than that forecast twelve hours ahead.

Northern Power Station unit two was due to return to service from an outage for the 8 pm trading interval. At around 11 am, Alinta Energy submitted a rebid that saw the unit remain unavailable for the rest of the day. The reason given was “1100P NPS2 valve leak SL@11:06”. This reduced available capacity in South Australia by around 270 MW, all of which was priced close to the price floor.

At 6.42 pm, first effective from 6.50 pm, AGL reduced the available capacity at Torrens Island B unit two by up to 40 MW, all of which was priced at the price floor. The reason given was “18:41P Chg in testing requ::min gen reqd for testing”.

At 7.37 pm, first effective from 7.45 pm, AGL rebid all available capacity (50 MW) at Angaston from prices around $400/MWh to prices around $11 300/MWh. The reason given was “19:31A Chg in forecast::pd price increase [sa] [$69.4] at 20:30”.

At 8.39 pm, first effective from 9.05 pm, AGL rebid a total of 189 MW of capacity at Torrens Island A unit 3 and Torrens Island B unit 3 from prices below $40/MWh to the price cap. The reason given was “20:31A Chg in forecast::pd price increase [SA] [$48] at 21:30”.

Shortly prior to 9.20 pm, Northern Power Station unit one tripped from 272 MW. Almost all of this capacity was priced below -$950/MWh. With no available capacity priced between around $570/MWh and $11 000/MWh and a number of generators ramp rate limited, higher priced generation offers at Angaston were dispatched, causing the dispatch price to reach the price cap at 9.20 pm. The dispatch price returned to around $35/MWh in the next dispatch interval. Note that as a result of SCADA timing, demand was reported as increasing from 9.15 pm to 9.20 pm, then falling to previous levels at 9.25 pm.

At 9.23 pm, effective from 9.30 pm, Origin Energy reduced the available capacity at Quarantine Power station by 221 MW. All of this capacity was priced above $11 000/MWh. The rebid reason given was “2115P Avail Change – Avoid uneconomic dispatch SL”.

At 9.37 pm, effective from 9.45 pm, AGL extended the rebid made at 8.39 pm and shifted 149 MW of capacity across Torrens Island A unit three and Torrens Island B unit three, from prices below $40/MWh to the price cap. This saw high priced capacity offered for the 9 pm to midnight intervals, inclusive. The reason given was “21:30A Chg in avail capacity: decrease [SA] [494MW]”. At 10.17 pm, AGL rebid a further 65 MW from prices below $40/MWh to the price cap, for the 10.30 pm to midnight intervals. The reason given was “22:01A chg in forecast:: PD price increase [SA][$500] at 23:00”.

Demand increased from 1395 MW at 9.40 pm to 1432 MW at 9.45 pm. With a number of fast start units at maximum capacity and a number of generators ramp rate limited, higher priced generation offers set the five-minute price to $12 000/MWh at 9.45 pm, up significantly from $32/MWh at 9.40 pm. However, the five-minute price fell to $69/MWh at 9.50 pm as demand returned to 1395 MW.

For the midnight trading interval, a rapid 200 MW increase in South Australia demand (over 10 minutes) led to higher priced fast start plant at Quarantine Power Station receiving start targets, causing the five-minute price to reach $11 300/MWh at 11.40 pm (up from $69/MWh and $300/MWh in the previous dispatch intervals).

At 11.38 pm, first effective from 11.45 pm, Origin Energy reduced all available capacity (173 MW) at Quarantine units two, three and five, all of which was priced at $11 300/MWh. The rebid reason given was “2335P Avail change - avoid uneconomic dispatch SL”. Higher priced generation was dispatched, setting the price at $12 000/MWh at 11.45 pm. Prices returned to below $70/MWh at 11.50 pm due to an increase in the availability of lower priced generation.

There was no other significant rebidding.

Victoria

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

Saturday, 22 October

4 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-332.92	4.23	4.23
Demand (MW)	4407	4555	4550
Available capacity (MW)	9986	9986	9986

Conditions at the time saw demand around 150 MW less than that forecast four hours ahead.

Prices were around $12/MWh for twelve hours from Friday evening to Saturday morning

The five-minute price reached -$988/MWh at 3.40 am and fell to the price floor at 3.55 am due to lower than forecast demand. A number of generators, including International Power's two Loy Yang B units were trapped in frequency control ancillary services (meaning offers from these units are excluded from dispatch). Almost 700 MW of capacity offered at -$4.50/MWh at Loy Yang B was not able to be dispatched down, resulting in the dispatch down of offers from Anglesea (and Hazelwood) priced at the price floor – setting the price.

There was no significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
16 October - 22 October 2011

AUSTRALIAN ENERGY REGULATOR

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

Financial year	QLD	NSW	VIC	SA	TAS
2011-12 ($/MWh) YTD	28	30	29	39	30
2010-11 ($/MWh) YTD	21	29	25	28	37
Change*	32%	5%	15%	40%	-19%
2010-11 ($/MWh)	34	43	29	42	31

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2011-12 (YTD)	$1.895	63
2010-11	$7.445	204
2009-10	$9.643	206

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)
Jun-11	26	28	29	33	30	0.447
Jul-11	27	32	31	36	34	0.508
Aug-11	29	31	31	36	29	0.483
Sep-11	29	29	28	40	27	0.427
Oct-11 (MTD)	27	29	26	49	31	0.305
Q1 2011	65	90	41	83	27	3.484
Q1 2010	46	52	67	134	27	3.014
Change*	41%	74%	-38%	-38%	2%	15.57%

Table 4: ASX energy futures contract prices at end of 24 October

	QLD		NSW		VIC		SA	
Q1 2012	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 17 Oct ($/MW)	44	67	47	73	47	76	72	125
Price on 24 Oct ($/MW)	44	68	48	75	47	77	73	130
Open interest on 24 Oct	1237	150	2071	521	2238	305	170	5
Traded in the last week (MW)	426	35	113	96	194	80	0	0
Traded since 1 Jan 11 (MW)	6083	186	8165	1074	6997	597	221	5
Settled price for Q1 11($/MW)	57	96	68	118	35	51	53	93

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

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
August 11 with August 10						
MW Priced <$20/MWh	-1212	-877	10	-152	-198	-2429
MW Priced $20 to $50/MWh	96	656	-241	57	-43	524
September 11 with September 10						
MW Priced <$20/MWh	-856	-1281	-424	-614	-345	-3520
MW Priced $20 to $50/MWh	-376	1085	148	175	161	1191
October 11 with October 10 (MTD)						
MW Priced <$20/MWh	-598	-1445	-758	-163	-840	-3804
MW Priced $20 to $50/MWh	-364	1268	387	129	491	1911

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