WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

31 July - 6 August 2011

Summary

Across all mainland regions weekly average spot prices were around $28/MWh.

In Tasmania the price averaged only $9/MWh as a result of lengthy periods of very low prices on Sunday and Monday.

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 31 July to 6 August 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 31 July - 6 August 2011	28	29	28	28	9
% change from previous week*	-6	-14	-10	-14	-84
11/12 financial YTD	27	31	31	35	33
% change from 10/11 financial YTD **	26	11	9	13	8

*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 is 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 8 August 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	41	0%	46*	0%	42	0%	48	0%
Calendar Year 2013	52	0%	57	0%	51	0%	58	0%
Calendar Year 2014	56	0%	59	0%	60	0%	69	0%
Three year average	49	0%	54	0%	51	0%	58	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.

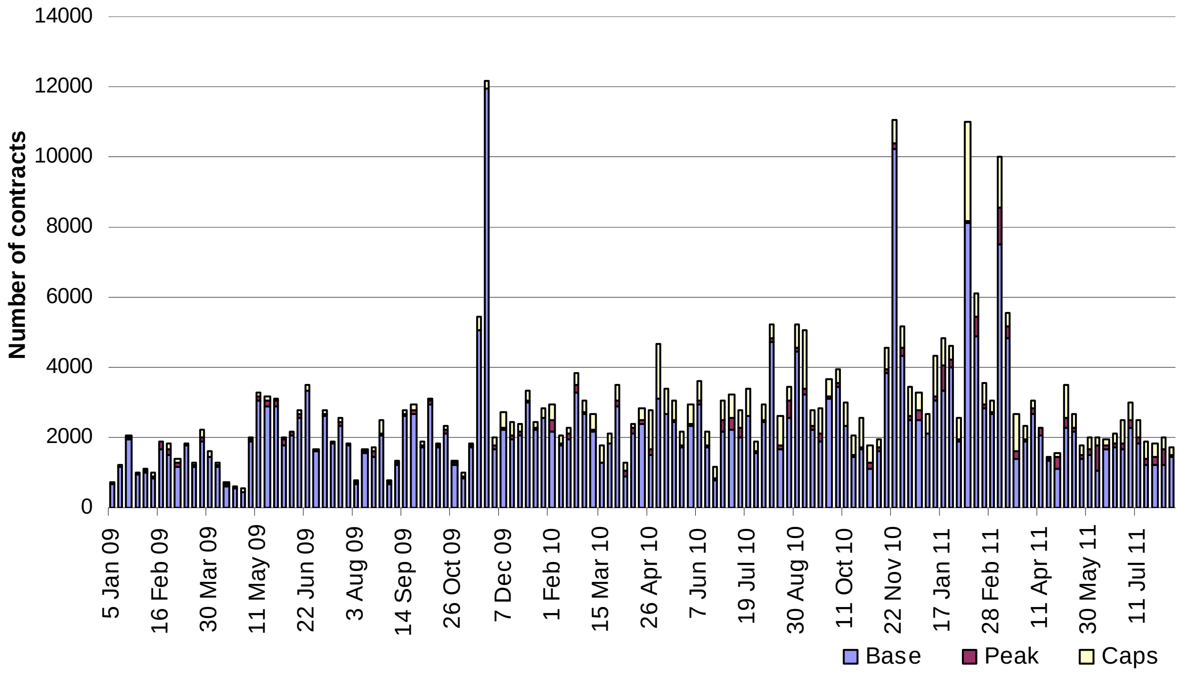
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2012 (% change)	13*	-6%	15*	-5%	15*	-4%	30	-1%
2012 (% change)	7	-7%	10	-4%	6	-3%	12	-2%

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

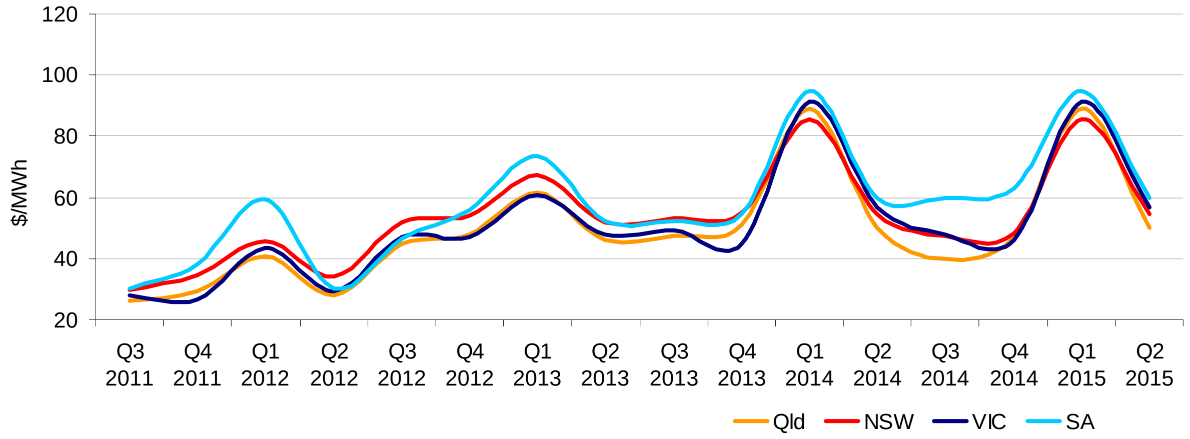


Source: d-cyphaTrade www.d-cyphatrade.com.au

[4] Calculated on prices prior to rounding.

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

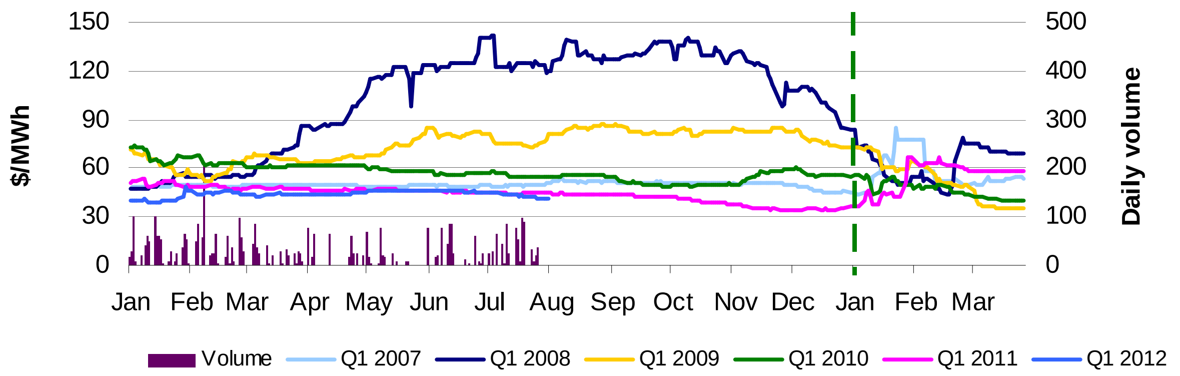
Figure 5: Quarterly base future prices Q3 2011 – Q2 2015



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

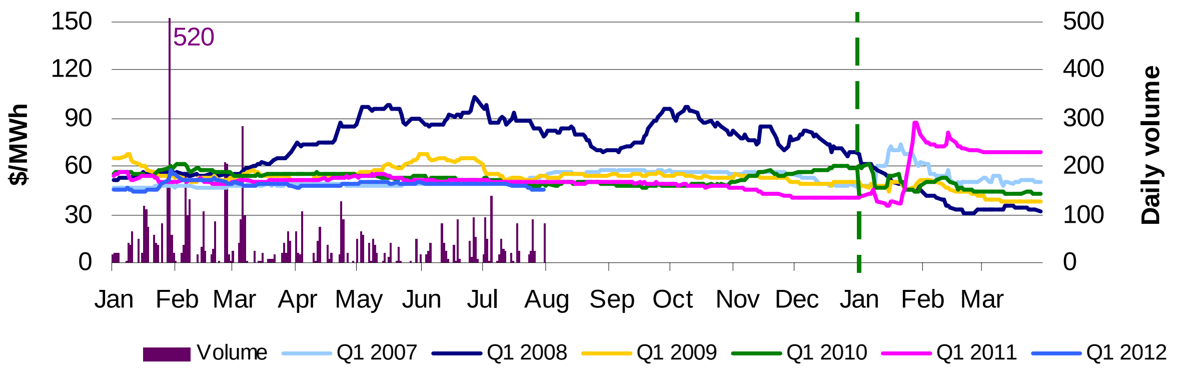
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2007, 2008, 2009, 2010, 2011 and 2012. Also shown is the daily volume of Q1 2012 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased. 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



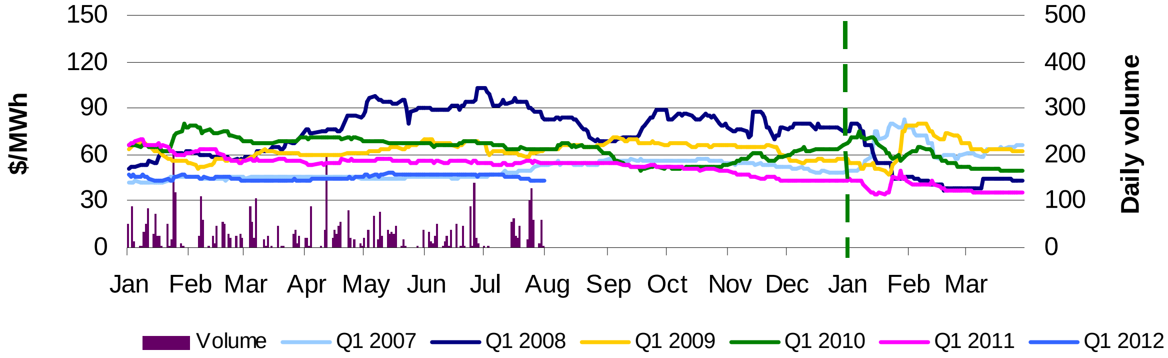
Source: d-cyphaTrade www.d-cyphatrade.com.au

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



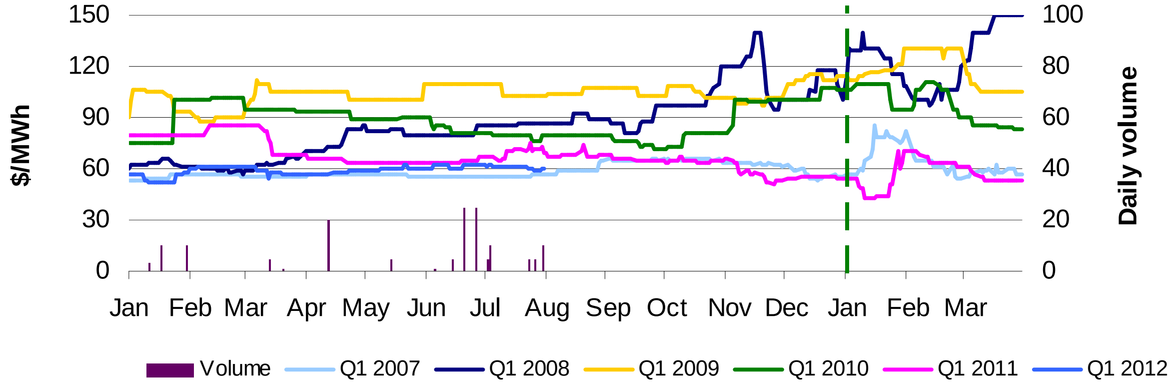
Source: d-cyphaTrade www.d-cyphatrade.com.au

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 93 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	6	7	2	1
% of total below forecast	34	0	48	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 542 MW less 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	-542	88	-355	-174
NSW	181	-437	-227	-791
VIC	-569	-165	-1011	-607
SA	-213	-99	-361	-142
TAS	181	113	-37	-94
TOTAL	-962	-500	-1991	-1808

Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $272 000 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $164 000 or 9 per cent of energy turnover in Tasmania. On 31 July, binding constraints on Basslink saw flows forced from Victoria into Tasmania from 8.15 am, counter price for the period from 8.20 am to 8.30am.

Flows were forced from Victoria into Tasmania across Basslink to manage the loss of the Rowville to Ringwood line in Victoria. At 9 am flows were in the no-go zone, which meant that no ancillary services can be provided across the interconnector. This saw an increased requirement for local lower services. As a result, from 8.55 am to 9.30 am, the price for local lower 6 second services exceeded $500/MW for seven dispatch intervals.

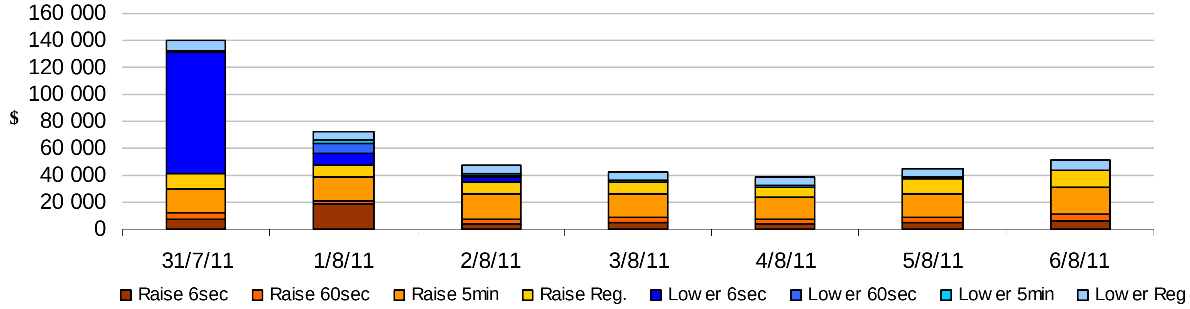
From 9.50 pm, constraints limiting imports into Tasmania over Basslink again saw an increase in the requirement for local lower services and the price for local lower 6 second services exceed $500/MW for three dispatch intervals.

The price of local lower 6 second services in Tasmania for the day exceeded $500/MW for a total of 10 dispatch intervals at a cost of around $83 000 or half the total cost of FCAS in Tasmania for the week.

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

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

Figure 12: Daily frequency control ancillary service cost



Australian Energy Regulator
November 2011

South Australia:

There were five occasions where the spot price in South Australia was less than -$100/MWh.

Sunday, 31 July

8:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-152	21	20
Demand (MW)	1123	1180	1193
Available capacity (MW)	2338	2441	2471
9:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-307	24	23
Demand (MW)	1196	1277	1274
Available capacity (MW)	2219	2379	2394

Conditions at the time saw demand up to 81 MW and reported available capacity up to 160 MW below that forecast four hours ahead. Targeted reductions in output from semi-scheduled wind generation as a result of constraints or in this case, as a result of regional prices lower than their offer price are reported as a reduction in regional available capacity.

At 8.15 am, a constraint used to manage a revised thermal rating on the Brunswick to Richmond 220 kV line in Victoria was invoked and immediately violated. The constraint caused a step change in the transfer limits of both interconnectors to South Australia by a total of around 650 MW, forcing flows into South Australia. Combined limits went from 334 MW into Victoria at 8.10 am to 317 MW into South Australia at 8.15 am. This reduced the requirement for South Australia generation leading to a number of generators being constrained down at their ramp rate limits. This resulted in the dispatch price in South Australia falling to the price floor at 8.15 am. To avoid further violation of the network constraint, at 8.20 am Murraylink changed direction with the limit and flow both into Victoria and the price returned to its previous level.

At 9 am, a 30 MW reduction in wind generation at Waterloo, amongst other things, saw the Murraylink interconnector change direction again with the limit and flow both into South Australia. The dispatch prices fell to around -$300/MWh until 9.30 am.

As a result of these low prices and constraints all windfarms except North Brown Hill Creek (which was already at zero) received targets to reduce output to zero.

There was no significant rebidding.

Monday, 1 August

3:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	-127	9	0
Demand (MW)	1001	993	997
Available capacity (MW)	2638	2875	2861
4:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-120	-13	-4
Demand (MW)	1015	957	951
Available capacity (MW)	2675	2930	2883

Conditions at the time saw demand close to forecast, while reported available capacity was up to 255 MW below that forecast four hours ahead. Targeted reductions in output from semi-scheduled wind generation as a result of constraints or in this case, as a result of regional prices lower than their offer price are reported as a reduction in regional available capacity.

As detailed in the ‘Ancillary services market” section a constraint used to manage the rating of the Brunswick to Richmond 220 kV line saw changes in interconnector limits. For the 3.30 am and 4.30 am trading intervals, exports from South Australia were around 250 MW below that forecast 4 hours ahead. This un-forecast reduction in the requirement for local generation saw the five-minute price fall from around -$89/MWh at 3 am to -$192/MWh at 3.25 am and from around -$144/MWh at 4 am to -$287/MWh at 4.10 am.

As a result of these low prices, several wind farms received targets to reduce output to zero.

There was no significant rebidding.

6:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	-111	-62	-30
Demand (MW)	1108	1082	1082
Available capacity (MW)	2805	3001	2904

Conditions at the time saw demand close to forecast, while reported available capacity was 196 MW below that forecast four hours ahead. Targeted reductions in output from semi-scheduled wind generation as a result of constraints or in this case, as a result of regional prices lower than their offer price are reported as a reduction in regional available capacity.

The interrelationship between energy and FCAS markets saw the five-minute price fall to -$418/MWh at 6.20 am.

There was no significant rebidding.

<u>Tasmania:</u>

There were twelve occasions where the spot price in Tasmania was less than -$100/MWh.

Sunday, 31 July

9 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-299	25	25
Demand (MW)	1169	1250	1248
Available capacity (MW)	2007	2145	2145

9:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-814	19	20
Demand (MW)	1220	1273	1276
Available capacity (MW)	2007	2145	2145

11 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-319	20	20
Demand (MW)	1237	1273	1273
Available capacity (MW)	1882	2020	2020

11:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-956	19	20
Demand (MW)	1247	1254	1255
Available capacity (MW)	1882	2020	2020

12 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-945	19	20
Demand (MW)	1267	1235	1237
Available capacity (MW)	1882	2020	2020

12:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-767	16	19
Demand (MW)	1250	1214	1214
Available capacity (MW)	1882	2020	2020

1 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-203	19	19
Demand (MW)	1234	1197	1195
Available capacity (MW)	1882	2020	2020
2:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-102	10	20
Demand (MW)	1132	1158	1167
Available capacity (MW)	1882	2020	2020
10 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-353	19	20
Demand (MW)	1206	1225	1277
Available capacity (MW)	2007	2007	2145

Conditions at the time saw demand close to forecast, while available capacity was 138 MW lower than that forecast four and/or twelve hours ahead. Over two rebids at 7.54 am and 10.03 am, Hydro Tasmania reduced John Butters from 138 MW to zero. All of this capacity was priced at $40/MWh. The reasons given were "0753P Plant failure JButters" and "1003P Plant failure JButters".

As detailed in the 'Ancillary services markets' section above, a constraint used to manage a revised thermal rating on the Brunswick to Richmond 220 kV line in Victoria was forcing flows into Tasmania, counter-priced, from 8.15 am.

Over a number of rebids from 8.26 am, first effective at 8.35 am and continuing throughout the periods of low prices, Hydro Tasmania shifted up to around 1100 MW of capacity across its portfolio from prices up to $244/MWh to close to the price floor. The reasons given were "Hydrological optimisation" and "Co-optimisation of energy & fcas" and "hydrological optimisation mersey forth". These rebids affected all trading intervals between 9 am and 1 pm, except for the 10 am and 10.30 am trading intervals. This resulted in no capacity priced between $25/MWh and -$945/MWh in Tasmania at the times of low prices. These rebids combined with a decrease in import limit for flows into Tasmania (from 143 MW at 8.50 am to 60 MW at 8.55 am) saw the five-minute price fall from around zero at 8.50 am to close to the price floor by 9 am and remained below -$750/MWh for a total of 26 dispatch intervals until 12.45 pm.

The 2.30 pm trading interval price was set by the interrelationship between energy and FCAS markets which saw the five-minute price fall to -$274/MWh at 2.05 pm. Basslink was importing around 230 MW of capacity during the 2.30 pm trading interval.

At 9.43 pm, effective from 9.50 pm, Hydro Tasmania rebid 55 MW of capacity at Reece unit one close to the price floor. The reason given was "2140A Tas price <forecast". This again left no capacity priced between $25/MWh and -$945/MWh. This saw the five-minute price fall from -$1/MWh at 9.45 pm to -$766/MWh by 9.55 am. There was no other significant rebidding.

Monday, 1 August

1 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	-229	10	0
Demand (MW)	980	1060	1061
Available capacity (MW)	1799	2007	2145
2:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-117	-52	-1
Demand (MW)	981	1039	1034
Available capacity (MW)	1799	2007	2145
3:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-153	9	0
Demand (MW)	992	1017	1032
Available capacity (MW)	1799	2007	2145

Conditions at the time saw demand up to 80 MW below forecast, while available capacity was 208 MW lower than that forecast four hours ahead and 346 MW lower than that forecast twelve hours ahead. At 12.01 am, Aurora Energy reduced the output from its Tamar Valley combined cycle plant from 208 MW to zero. All of this capacity was priced above $12 480/MWh. The reason given was "Unit ramp down profile".

A continuation of constraints from the previous day saw flow forced into Tasmania, counter-priced, during the early morning.

With no capacity priced between -$1/MWh and -$951/MWh, any changes in import capability or demand, had the potential to result in a significant changes in the spot price. The five-minute price fell from -$1/MWh at 12.40 am to less than -$100/MWh for a total of 11 dispatch intervals until 3.30 am.

There was no other significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
31 July - 6 August 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 ($/MWh) YTD	27	31	31	35	33
2010-11 ($/MWh) YTD	22	28	28	31	31
Change*	26%	11%	9%	13%	8%
2010-11 ($/MWh)	34	43	29	42	31

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2011-12 (YTD)	$0.655	21
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)
Apr-11	25	27	26	28	27	0.374
May-11	28	30	35	35	39	0.499
Jun-11	26	28	29	33	30	0.447
Jul-11	27	32	31	36	34	0.508
Aug-11 (MTD)	28	29	29	31	26	0.087
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 8 August

	QLD		NSW		VIC		SA	
Q1 2012	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 01 Aug ($/MW)	42	68	47	74	44	72	61	106
Price on 08 Aug ($/MW)	41	65	46	72	44	71	60	106
Open interest on 08 Aug	1311	103	1695	415	1711	236	155	5
Traded in the last week (MW)	56	25	196	1	262	6	15	0
Traded since 1 Jan 11 (MW)	4358	121	6377	612	4087	257	169	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
June 11 with June 10						
MW Priced <$20/MWh	-1001	-98	-842	261	107	-1574
MW Priced $20 to $50/MWh	579	647	612	1	-84	1755
July 11 with July 10						
MW Priced <$20/MWh	-826	-665	-448	99	121	-1718
MW Priced $20 to $50/MWh	202	753	-162	29	-282	539
Aug 11 with Aug 10 (MTD)						
MW Priced <$20/MWh	-1477	-753	24	-49	182	-2072
MW Priced $20 to $50/MWh	203	584	-776	-139	-161	-288

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