WEEKLY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

7 June-13 June 2009

Summary

The average spot price in Tasmania was $290/MWh, more than three times that for the previous week. This was driven by a number of high spot prices during the week, including three spot prices exceeding $5000/MWh. In accordance with the requirements of the National Electricity Rules (Electricity Rules), the AER will be issuing reports into the circumstances that led to the energy price exceeding $5000/MWh. Preliminary analysis indicates that step reductions in the output of Hydro Tasmania's (mini-hydro) non-scheduled generation units were significant drivers of these high price outcomes.

Average prices in New South Wales and Queensland were around double that for the previous week, at $65/MWh and $59/MWh respectively. This increase was primarily driven by an hour of spot prices above $3000/MWh on Thursday evening.

Spot prices averaged $35/MWh in South Australia and $36/MWh in Victoria.

Spot market prices

Figure 1 sets out the volume weighted average prices for 7 June to 13 June and the financial year to date across the National Electricity Market (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)

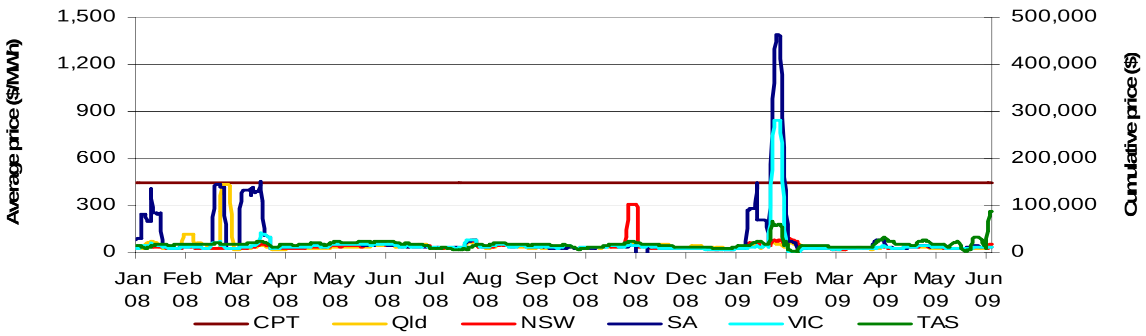
	Qld	NSW	VIC	SA	Tas
Average price for 7 June – 13 June	59	65	36	35	290
Financial year to date	37	43	50	71	55
% change from previous week*	116	84	-4	-15	216
% change from year to date**	-37	-3	-2	-32	-3

*The percentage change between last week's average spot price and the average price for the previous week.
**The percentage change between the average spot price for the current financial year to date and the average spot price over the similar period for the previous financial year.

The AER provides further information if the spot price exceeds three times the weekly average. This is detailed in Appendix A. Longer term market trends are attached in Appendix B.

Figure 2 shows the seven day rolling cumulative price for each region together with the Cumulative Price Threshold (CPT) (and the equivalent seven day time weighted average price).

Figure 2: Seven day rolling cumulative price, corresponding average price, and CPT



Financial markets

Figures 3 to 10 show futures contract[1] prices traded on the Sydney Futures Exchange (SFE) as at close of trade on Monday 15 June. Figure 3 shows the base futures contract prices for the next three calendar years, and the three year average. Also shown are percentage changes compared to the previous week.

Figure 3: Base calendar year futures contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Calendar Year 2010	42*	0%	45*	0%	47*	-1%	54*	-8%
Calendar Year 2011	45*	-2%	49*	0%	51*	-1%	69	0%
Calendar Year 2012	58	0%	61	0%	69	0%	69	0%
Three year average	49	-1%	52	0%	56	-1%	64	-2%

Source: d-cyphaTrade www.d-cyphatrade.com.au
* there were trades in these products but not in others.

Figure 4 shows the $300 cap contract price for the first quarter of 2010 and the 2009-10 financial year and the percentage change from the previous week.

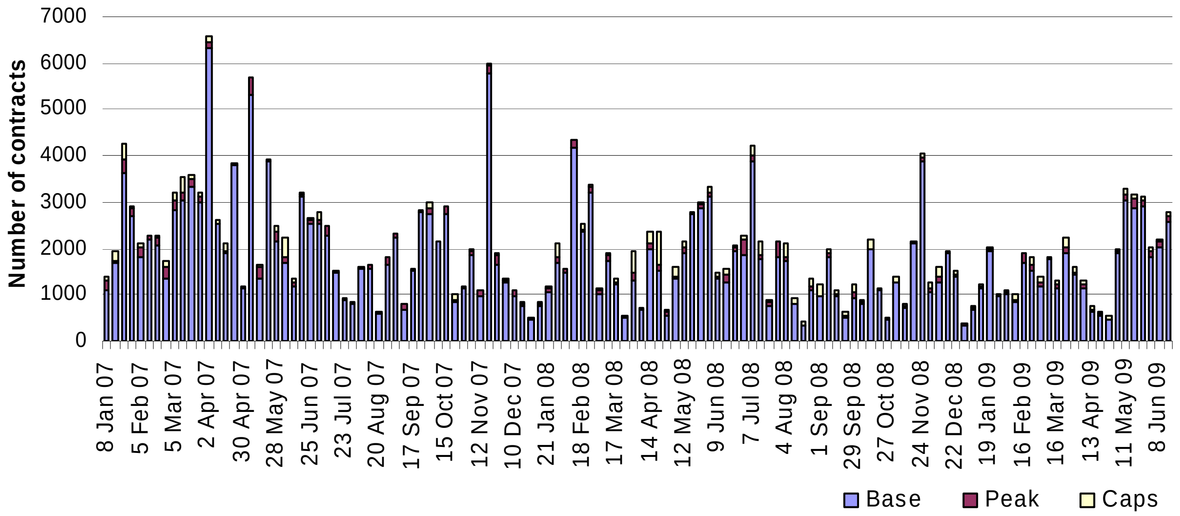
Figure 4: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2010	26	-2%	21	0%	35	0%	45	0%
Financial 2009-10	11	-1%	10	3%	12	1%	16	0%

Source: d-cyphaTrade www.d-cyphatrade.com.au
Note: there were no trades in these products.

Figure 5 shows the weekly trading volumes for base, peak and cap contracts. The date represents the end of the trading week.

Figure 5: Number of exchange traded contracts per week

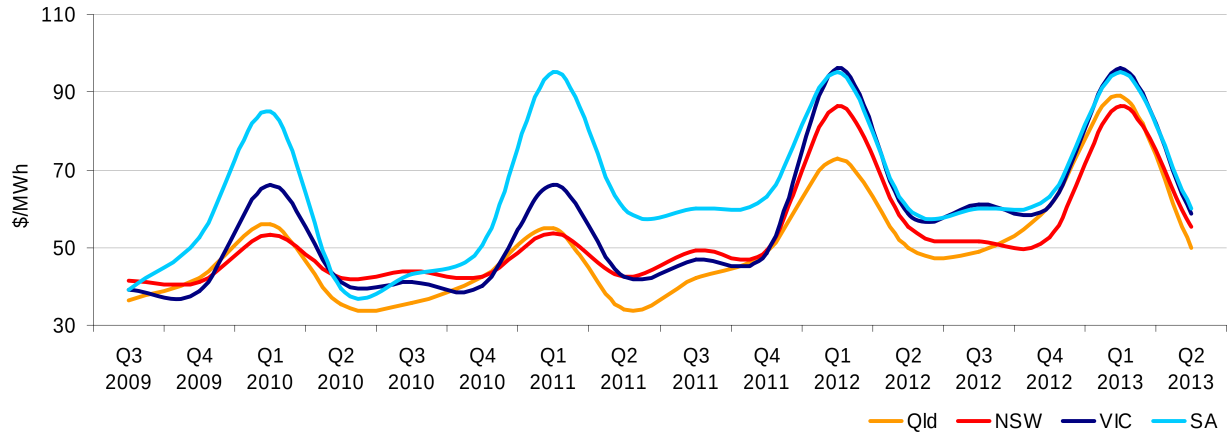


Source: d-cyphaTrade www.d-cyphatrade.com.au

[1] Futures contracts on the SFE 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.

Figure 6 shows the prices for base contracts for each quarter for the next four financial years.

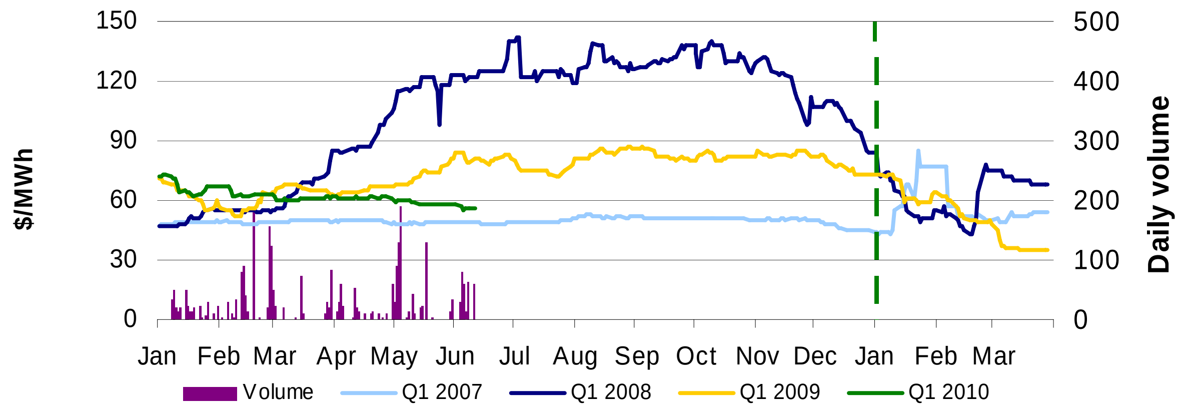
Figure 6: Quarterly base future prices Q3 2009 – Q2 2013



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

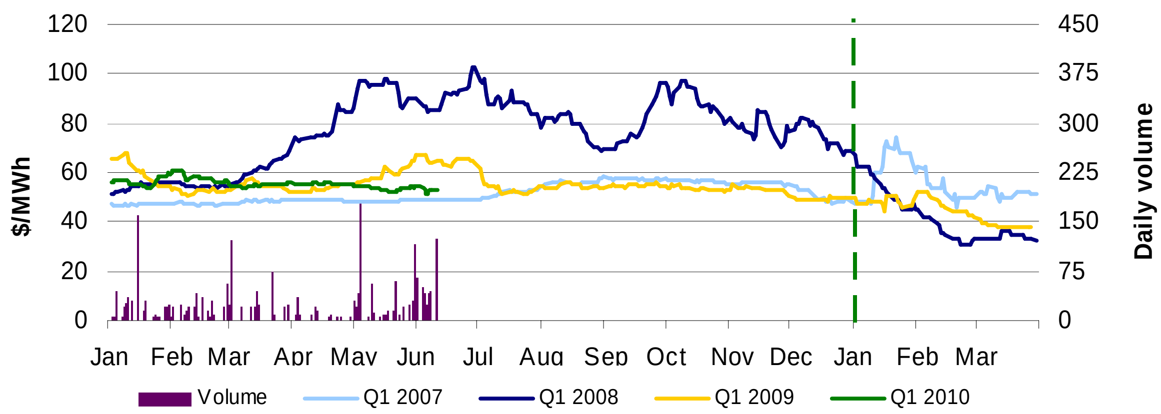
Figures 7-10 compare for each region the closing daily base contract prices for the first quarter of 2007, 2008, 2009 and 2010. Also shown is the daily volume of Q1 2010 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

Figure 7: Queensland Q1 2007, 2008, 2009 and 2010



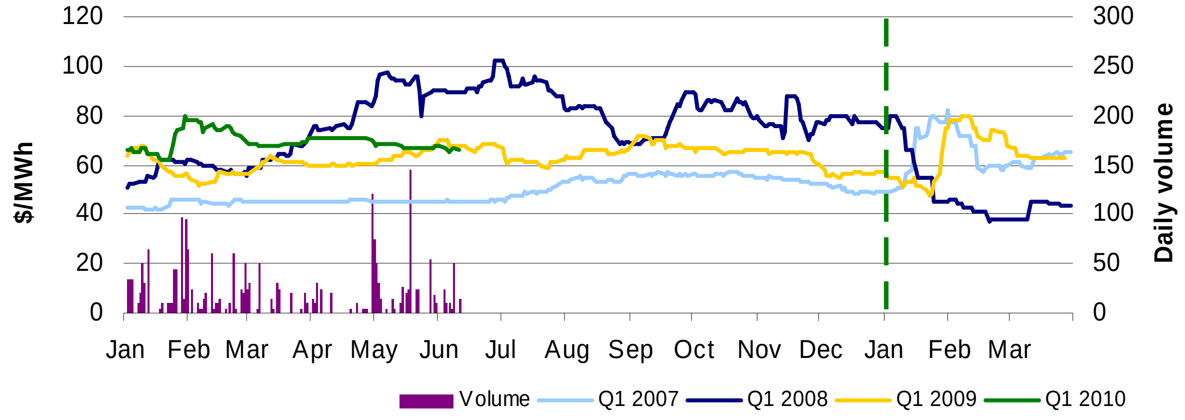
Source: d-cyphaTrade www.d-cyphatrade.com.au

Figure 8: New South Wales Q1 2007, 2008, 2009 and 2010



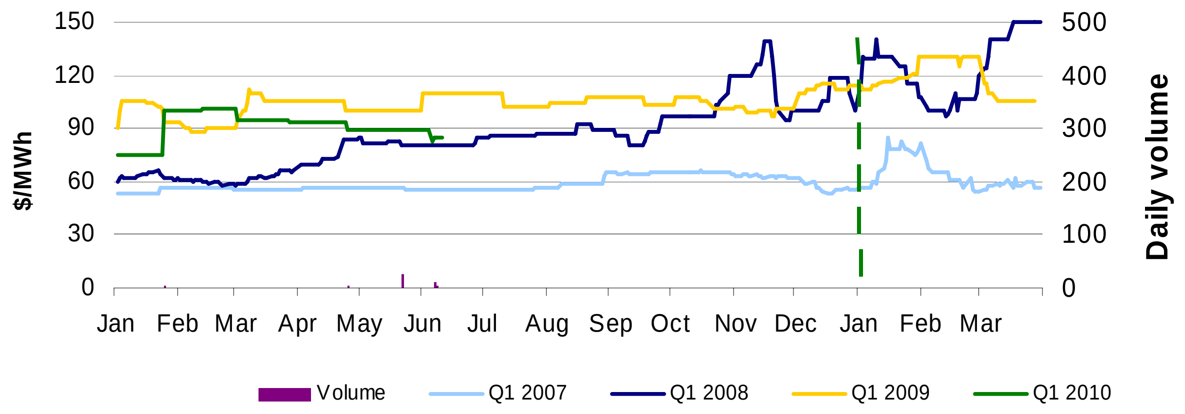
Source: d-cyphaTrade www.d-cyphatrade.com.au

Figure 9: Victoria Q1 2007, 2008, 2009 and 2010



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

Figure 10: South Australia Q1 2007, 2008, 2009 and 2010



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

Spot market forecasting variations

The AER is required under the Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the National Electricity Market Management Company, 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 126 trading intervals throughout the week where actual prices varied significantly from forecasts[2]. This compares to the weekly average in 2008 of 130 counts. Reasons for these variances are summarised in Figure 11[3].

Figure 11: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	2	76	0	0
% of total below forecast	22	0	0	0

[2] 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.

[3] 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 12 shows the change in total available capacity in each region from the previous week and at the price levels shown, for peak periods[4]. For example, in Queensland 135 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 12: 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	-135	-126	-257	17
NSW	1155	184	1081	605
VIC	628	-383	526	239
SA	270	87	435	-54
TAS	-16	-160	-14	52
TOTAL	1902	-398	1,771	859

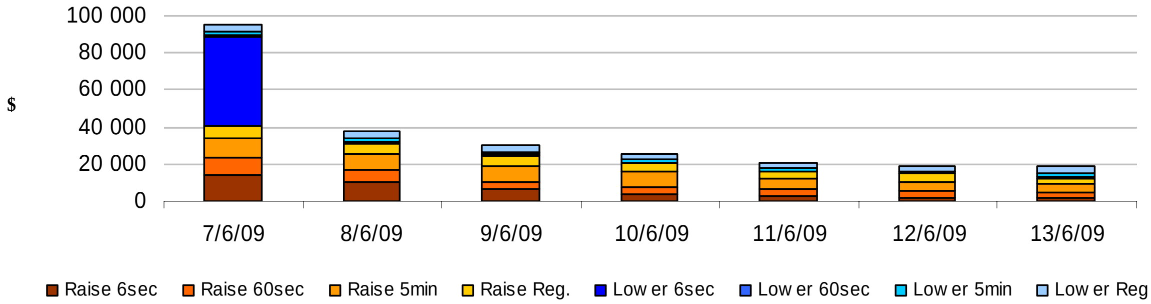
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $128 000 or less than one per cent of turnover in the energy market.

The total cost of FCAS in Tasmania for the week was $120 000 or less than one per cent of turnover in the energy market. In the early morning of 7 June, the Tasmania Lower 6 second service requirement increased, leading to a dispatch price of $4860/MWh at 4.15 am.

Figure 13 shows the daily breakdown of cost for FCAS for the NEM.

Figure 13: Daily frequency control ancillary service cost



Australian Energy Regulator

July 2009

[4] A peak period is defined as between 7 am and 10 pm on weekdays, which aligns with the SFE contract definition.

7 June - 13 June 2009

National: There were three occasions where the spot price aligned across all mainland regions and the price in at least one region was greater than three times the weekly average price for that region. The New South Wales spot price has been used as a proxy national price as New South Wales is located in the centre of the NEM.

Wednesday, 10 June

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	284.01	228.19	59.85
Demand (MW)	31 745	31 297	30 829
Available capacity (MW)	37 939	38 349	38 312
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	298.11	280.49	58.96
Demand (MW)	32 028	31 419	31 029
Available capacity (MW)	37 903	38 391	38 314
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	163.95	89.38	55.36
Demand (MW)	31 923	31 102	30 791
Available capacity (MW)	37 892	38 446	38 302

Conditions at the time saw demand around 1000 MW higher than forecast 12 hours ahead and 600 MW higher than that forecast four hours ahead. Available capacity was up to 488 MW lower than forecast four hours ahead.

Over four rebids at 9.43 am, 3 pm, 4.48 pm and 4.49 pm, Delta Electricity shifted 1450 MW of capacity across its portfolio from prices below $90/MWh to above $9600/MWh. The reasons given were “Demand higher than NEMMCO forecast::band shift/ROC change”, “Spot price change::Band shift/ROC change” and “Demand forecast change:: Band shift”

At 12.15 pm Macquarie Generation rebid 965 MW of capacity across its portfolio from prices below $55/MWh to above $8300/MWh. The reason given was “Revised demand forecast”.

There was no other significant rebidding.

Queensland/New South Wales: There were three occasions where the spot price aligned in Queensland and New South Wales and the price was greater than three times the weekly average price. The New South Wales spot price has been used as a proxy.

Thursday, 11 June

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	788.91	298.13	119.97
Demand (MW)	20 162	20 352	20 094
Available capacity (MW)	23 421	24 123	24 289
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3131.16	298.13	222.64
Demand (MW)	20 460	20 328	20 185
Available capacity (MW)	23 462	24 003	24 290
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3640.93	119.97	119.97
Demand (MW)	20 496	20 261	20 097
Available capacity (MW)	23 466	24 005	24 289

Conditions at the time saw demand up to 235 MW greater than forecast four hours ahead and available capacity up to 702 MW below forecast four hours ahead.

At 9.17 am Delta Electricity reduced the available capacity of Wallerawang unit seven by 500 MW (a majority of which was priced below $20/MWh). The reason given was “Tube leak condition:band shift”. Then at 11.06 am it rebid 420 MW of available capacity at Vales Point from prices below $90/MWh to above $9600/MWh. The reason given was “NEMMCO forecast load change::band shft/roc change”. A further rebid at 5.02 pm saw 200 MW of capacity across its Mount Piper units shifted from prices below $300/MWh to above $9600/MWh. The reason given for these rebids was “Predis changed::band shift”.

Over two rebids at 1.36 pm and 4.18 pm, Macquarie Generation shifted 180 MW of available capacity at its Liddell units one, two and three from prices below $30/MWh to above $9300/MWh. The reasons given were “Revised demand forecast” and “Coal conservation”.

Over several rebids from 2.12 pm, Millmerran Energy shifted 125 MW of capacity at Millmerran unit two, from prices below $10/MWh to above $9700/MWh. The reasons given were “QNI PD constraint::change MW distribution” and “Change PD::Adjust MW Dist”.

At 2.37 pm, Stanwell Corporation rebid 180 MW of capacity across its Gladstone units from prices below $80/MWh to above $9300/MWh. The reason given was “Manage transmission constraint:change MW distrib”.

Over two rebids at 3.25 pm and 3.41 pm, CS Energy reduced the available capacity at Kogan Creek power station by 750 MW, all of which was priced below $10/MWh. The reasons given were “P KPP_1 mill trip” and “P KPP_1 unit trip”.

There was no other significant rebidding.

Victoria: There were five occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $36/MWh. Three of these occurred when prices were generally aligned across all regions and are detailed in the national market outcomes section. The remaining two occasions are presented below.

Thursday, 11 June

8:30 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	110.69	52.38	41.53
Demand (MW)	7245	7310	7362
Available capacity (MW)	9372	9286	9288

Conditions at the time saw demand close to forecast four hours ahead and available capacity around 90 MW greater than forecast.

Over three rebids at 6.04 pm, 6.28 pm and 6.30 pm, Loy Yang Market Management Company (LYMMCo) reduced available capacity across its Loy Yang A units by around 1033 MW, all of which priced below $20/MWh. The reasons given were “Revised plant limits” and “Coal conservation”. This available capacity was returned over two rebids at 6.43 pm and 6.49 pm, with 933 MW priced at around $240/MWh and 100 MW at $0/MWh with a reason of “Coal conservation”.

There was no other significant rebidding.

Friday, 12 June

8:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	121.46	46.70	46.70
Demand (MW)	7365	7345	7491
Available capacity (MW)	8810	9353	9338

Conditions at the time saw demand close to forecast four hours ahead and available capacity around 540 MW lower than that forecast.

Over two rebids at 6.50 am and 7.29 am, LYMMCo reduced the available capacity at Loy Yang A unit one by 530 MW, (all of which was priced below $20/MWh). The reason given was "revised plant limits".

There was no other significant rebidding.

South Australia: There were four occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $35/MWh. Three of these occurred when prices were generally aligned across all regions and are detailed in the national market outcomes section. The other occasion is presented below.

Friday, 12 June

8:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	112.21	36.69	36.69
Demand (MW)	1788	1727	1665
Available capacity (MW)	2991	3139	3062

Conditions at the time saw demand up to 116 MW greater than forecast 12 hours ahead and available capacity around 120 MW less than forecast.

At 7.16 am International Power reduced the available capacity of Pelican Point by 235 MW (all of which was priced below $100/MWh). The reason given was "Recently advised plant condition".

There was no other significant rebidding.

Tasmania: There were 23 occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $290/MWh.

Wednesday, 10 June

6:00 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1062.79	38.28	38.28
Demand (MW)	1066	1043	1062
Available capacity (MW)	1973	1973	1973

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

There was only 60 MW of capacity priced between $36/MWh and $1929/MWh. A decrease in non-scheduled generation from 194 MW at 5.30 am to 135 MW at 6 am saw the dispatch of higher priced generation.

There was no significant rebidding.

Wednesday, 10 June

9:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	6211.93	35.59	35.33
Demand (MW)	1455	1416	1436
Available capacity (MW)	1919	1904	1904

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

There was a significant decrease in non-scheduled generation from 122 MW at 9 am to 76 MW at 9.15 am. This reduction in generation resulted in an increase in demand and saw the dispatch of higher price generation. In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh.

Wednesday, 10 June

5:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2569.87	42.38	35.63
Demand (MW)	1365	1366	1328
Available capacity (MW)	1946	1973	1973
5:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1932.33	93.45	41.50
Demand (MW)	1465	1428	1374
Available capacity (MW)	1946	1973	1973

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

At the time of high dispatch prices, there was around 110 MW of capacity priced between $37/MWh and $4726/MWh.

There was a 50 MW decrease in non-scheduled generation from 171 MW at 4.40 pm to 121 MW at 4.55 pm and a 40 MW decrease between 5.10 pm and 5.20 pm. These reductions in generation resulted in an increase in demand and the dispatch of higher price generation.

The increase in demand combined with a small decrease in imports into Tasmania saw the dispatch of up to 27 MW of generation priced above $4700/MWh for several 5 minute dispatch intervals.

At 4.44 pm Hydro Tasmania reduced the availability of Bastyan by 80 MW (25 MW of which was priced below zero). The reason given was “Fail to start:Bastyan”.

There was no other significant rebidding.

Wednesday, 10 June

9:30 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1149.72	38.14	38.16
Demand (MW)	1439	1380	1374
Available capacity (MW)	1973	1973	1973
10:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2000.24	67.20	67.22
Demand (MW)	1336	1289	1269
Available capacity (MW)	1973	1973	1973

Conditions at the time saw demand around 60 MW higher than that forecast four hours ahead and available capacity close to dispatch.

There was only a small amount of capacity priced between $38/MWh and $2000/MWh. A small decrease (40 MW) in non-scheduled generation interval resulted in a small increase in demand which led to volatile pricing.

There was no significant rebidding.

Thursday, 11 June

1:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1433.25	67.22	2000.26
Demand (MW)	1100	1033	1042
Available capacity (MW)	1983	1973	1973

Conditions at the time saw demand around 70 MW higher than forecast four hours ahead and available capacity close to forecast.

As there was only a small amount of capacity priced between $36/MWh and $1894/MWh, a 30 MW decrease in non-scheduled generation resulting in a small increase in demand had significant impacts on actual prices.

There was no other significant rebidding.

Thursday, 11 June

5:00 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	3375.59	38.16	2495.28
Demand (MW)	1044	1027	1048
Available capacity (MW)	1993	2008	1973
6:00 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3001.92	67.23	2495.28
Demand (MW)	1151	1141	1131
Available capacity (MW)	1993	1993	1973

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

As there was only a small amount of capacity priced between $65/MWh and $2377/MWh, a 64 MW decrease in non-scheduled generation, resulting in an increase in demand, had significant impacts on actual prices.

There was no significant rebidding.

Thursday, 11 June

9:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	7576.61	38.14	38.52
Demand (MW)	1510	1535	1526
Available capacity (MW)	1887	1875	1875
10:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3078.53	38.18	38.12
Demand (MW)	1476	1476	1473
Available capacity (MW)	1923	1875	1875

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

Non-scheduled generation decreased by up to 77 MW. This reduction resulted in an increase in demand and the dispatch of higher price generation. In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh.

Thursday, 11 June

3:30 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1697.55	38.18	38.18
Demand (MW)	1240	1338	1361
Available capacity (MW)	1875	1849	1875

Conditions at the time saw demand 100 MW lower than that forecast four hours ahead and available capacity close to dispatch.

There was only 22 MW priced between $36.26/MWh and $9560/MWh. As a result of limited ramp rate capability, the five-minute dispatch price increased from $38/MWh at 3.05 am to $9992/MWh at 3.10 am, with prices returning to previous levels at 3.15 am.

There was no significant rebidding.

Thursday, 11 June

5:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3366.77	41.25	37.09
Demand (MW)	1394	1417	1452
Available capacity (MW)	1993	1973	1973
5:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3745.17	106.88	60.89
Demand (MW)	1469	1500	1519
Available capacity (MW)	1993	1973	1973
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1699.12	47.02	58.79
Demand (MW)	1470	1478	1517
Available capacity (MW)	2011	2028	1973
8:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1578.48	54.42	43.26
Demand (MW)	1451	1460	1481
Available capacity (MW)	2008	1993	1973

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

There was only 60 MW of capacity priced between $39/MWh and $9554/MWh. Non-scheduled generation decreased then increased a number of times by up to 71 MW. These reductions resulted in increases in demand and the dispatch of higher-priced generation.

There was no significant rebidding.

Friday, 12 June

12:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1578.53	67.16	495.26
Demand (MW)	1142	1094	1097
Available capacity (MW)	1993	2008	1973

Conditions at the time saw demand around 50 MW higher than that forecast four hours ahead and available capacity close to forecast.

There was only a small amount of capacity priced between $38/MWh and $4731/MWh. Non-scheduled generation decreased by around 60 MW. This reduction resulted in an increase in demand and the dispatch of higher-priced generation.

There was no significant rebidding.

Friday, 12 June

6:00 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	976.61	41.26	9992.29
Demand (MW)	1148	1101	1124
Available capacity (MW)	1993	1993	1973
9:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9992.30	36.04	38.18
Demand (MW)	1508	1462	1485
Available capacity (MW)	1925	1948	1928
10:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3207.23	38.16	38.16
Demand (MW)	1400	1403	1410
Available capacity (MW)	1948	1948	1948
11:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2352.80	38.18	38.18
Demand (MW)	1391	1338	1349
Available capacity (MW)	1948	1948	1948
12:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1094.79	38.18	38.18
Demand (MW)	1362	1317	1329
Available capacity (MW)	1958	1948	1948

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

Non-scheduled generation decreased then increased a number of times by up to 67 MW. These reductions resulted in increases in demand and the dispatch of higher-priced generation. In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh.

Friday, 12 June

5:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2280.57	38.16	41.16
Demand (MW)	1404	1380	1381
Available capacity (MW)	2103	2103	2083

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

There was only 64 MW priced between $38/MWh and $9554/MWh. Non-scheduled generation decreased by 66 MW. This reduction resulted in an increase in demand and the dispatch of higher-priced generation.

There was no significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
7 June - 13 June 2009

AUSTRALIAN ENERGY REGULATOR

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

Financial year	QLD	NSW	VIC	SA	TAS
2008-09 ($/MWh) YTD	37	43	50	71	55
2007-08 ($/MWh) YTD	59	45	51	104	57
Change*	-37%	-3%	-2%	-32%	-3%
2007-08 ($/MWh)	58	44	51	101	57

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2008-09 YTD	$9.071	198
2007-08	$11.125	208

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)
Feb-09	42	47	38	47	40	0.709
Mar-09	27	26	26	35	37	0.466
Apr-09	34	38	40	38	69	0.622
May-09	28	31	33	35	49	0.550
Jun-09 MTD	45	52	37	39	201	0.405
Q1 2009	37	43	87	161	55	3.136
Q1 2008	80	34	50	243	54	3.358
Change*	-53%	28%	73%	-34%	1%	1.09%

Table 4: ASX energy futures contract prices at 15 June

	QLD		NSW		VIC		SA	
Q1 2010	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 05 Jun ($/MW)	58	99	54	89	67	120	90	102
Price on 15 Jun ($/MW)	56	95	53	83	66	120	85	121
Open interest on 15 Jun	1961	135	1633	25	1615	35	38	0
Traded in the last week (MW)	280	15	275	5	90	0	15	0
Traded since 1 Jan 09 (MW)	2890	170	2383	47	2202	50	48	0
Settled price for Q1 09($/MW)	35	48	38	48	62	114	102	200

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

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
April 09 with April 08						
MW Priced <$20/MWh	-755	-678	323	366	-41	-785
MW Priced $20 to $50/MWh	698	-218	-214	-33	57	290
May 09 with May 08						
MW Priced <$20/MWh	-276	-484	523	122	22	-92
MW Priced $20 to $50/MWh	547	198	-80	21	236	921
June 09 with June 08						
MW Priced <$20/MWh	83	225	318	-60	210	776
MW Priced $20 to $50/MWh	512	560	6	35	239	1352

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