WEEKLY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

8 – 14 February 2009

Summary

The average spot prices in Victoria and South Australia were significantly lower than the previous week driven by the cooler temperatures and lower demands, averaging $22/MWh and $23/MWh respectively. The continuing bushfires in Victoria and also in New South Wales impacted on the transmission networks causing volatile prices, including negative pricing in a number of regions.

In Queensland, record demand of 8700 MW occurred on Monday leading to a number of high prices. In New South Wales record Sunday demand combined with the bushfires led to high prices but lower demand during the week led to moderate prices for the remainder of the week. The average spot price for the week was $54/MWh in Queensland and $53/MWh in New South Wales.

The average spot price for the week in Tasmania was $37/MWh for the second consecutive week.

On Sunday morning the power system was split into two between Victoria and New South Wales from 12.16 am to 1.44 am. This led to a requirement for local frequency control ancillary services costing around $6 million. A majority of this cost accrued in the southern regions.

Spot market prices

Figure 1 sets out the volume weighted average prices for 8 to 14 February and the financial year to date across the National Electricity Market. 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)

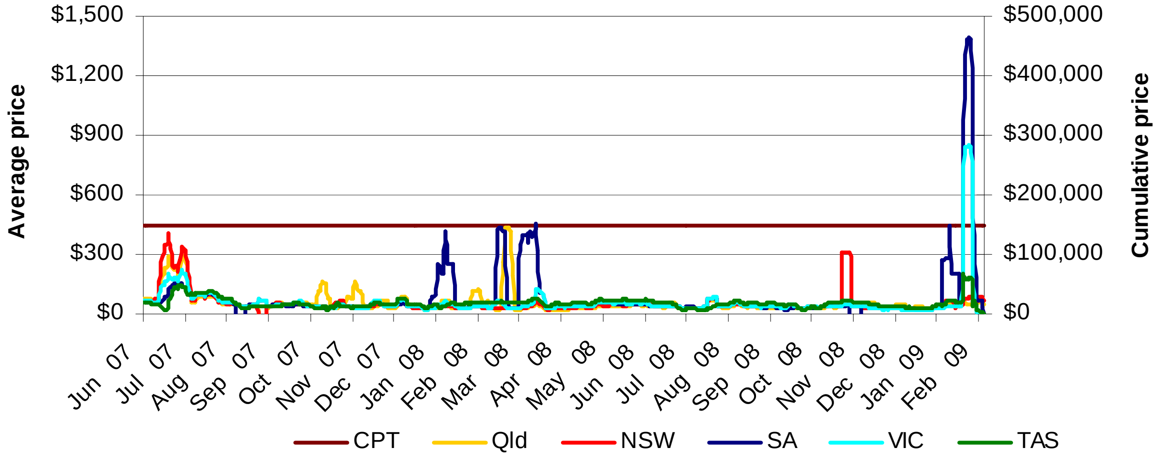
	Qld	NSW	VIC	SA	Tas
Ave price for 8 – 14 February	54	53	22	23	37
Financial year to 14 February	39	48	59	88	49
% change from previous week*	28%	-32%	-68%	-72%	0%
% change from year to date**	-28%	2%	17%	23%	-11%

*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. Details of these events are attached 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 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 16 February. Figure 3 shows the base futures contract prices for the next three financial years, and the three year average. Also shown are percentage changes compared to a week earlier.

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

	QLD		NSW		VIC		SA	
Financial 2009-10	45	-5%	48	-2%*	51	-2%	63	0%
Financial 2010-11	57	-5%	60	-1%	63	-2%	67	0%
Financial 2011-12	63	0%	63	0%	67	-1%	69	0%
Three year average	55	-3%	57	-1%	60	-2%	66	0%

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

* There were trades in this product but not others

Figure 4 shows the $300 cap contract price for the first quarter of 2009 and the 2009 calendar year and the change from the previous week.

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

	QLD		NSW		VIC		SA	
Q1 2009 price	18	-38%*	16	-5%	38	-3%	85	0%
Calendar 2009	10	-26%	9	-2%	14	-3%	26	1%

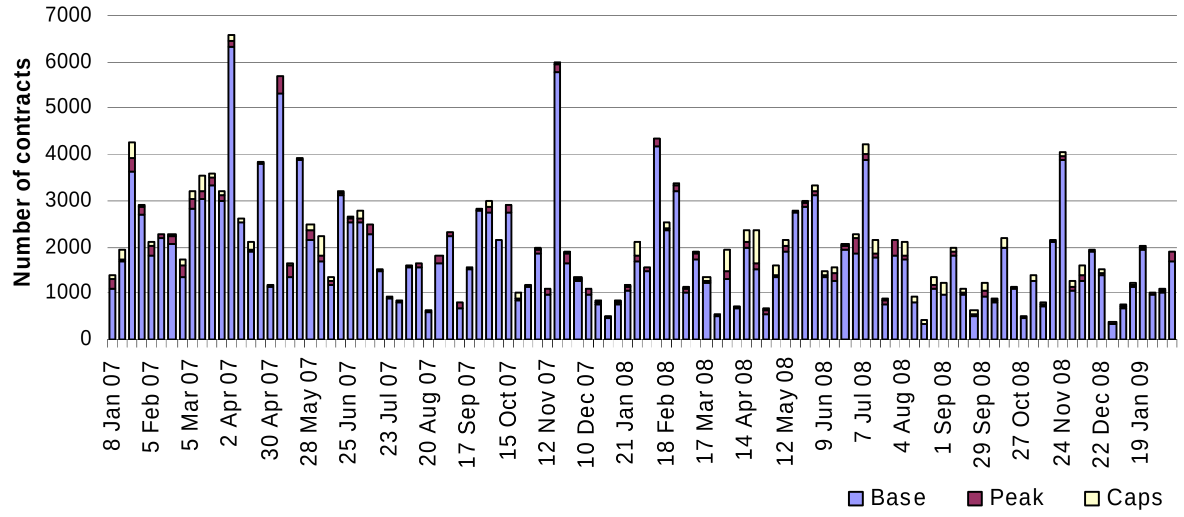
Source: d-cyphaTrade www.d-cyphatrade.com.au

* There were trades in this product but not others.

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

[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.

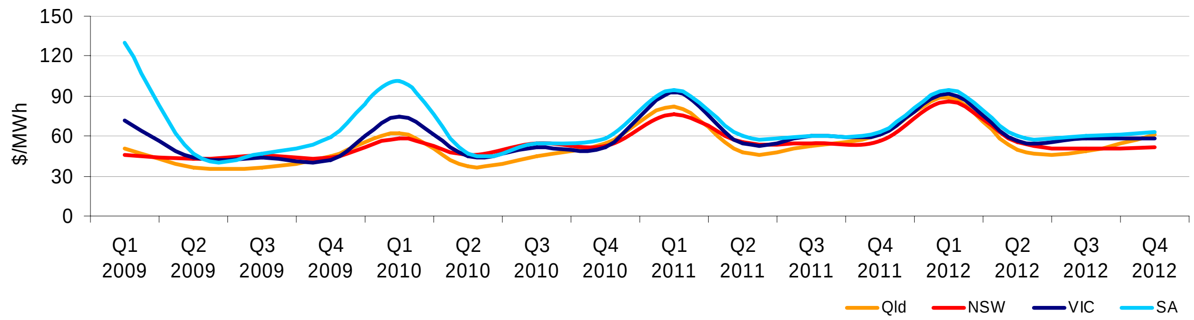
Figure 5: Number of exchange traded contracts per week



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

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

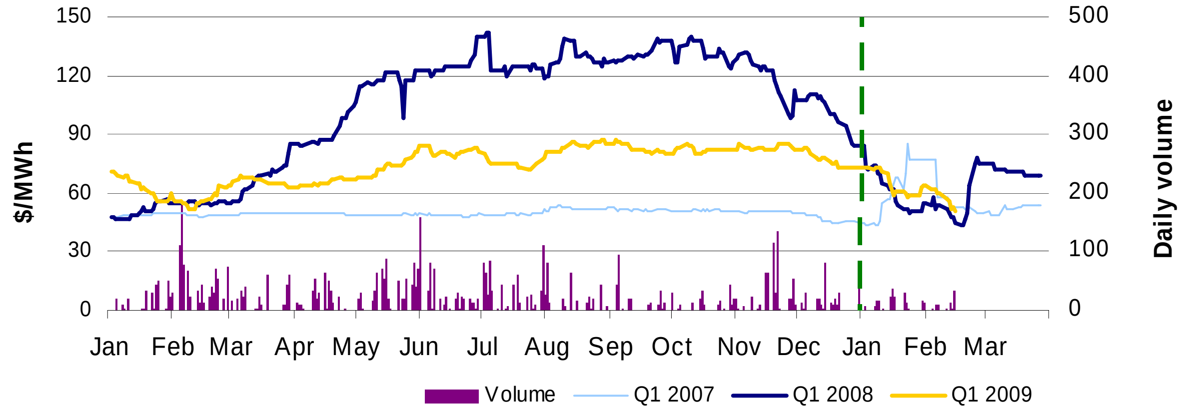
Figure 6: Quarterly base future prices 2009 - 2012



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

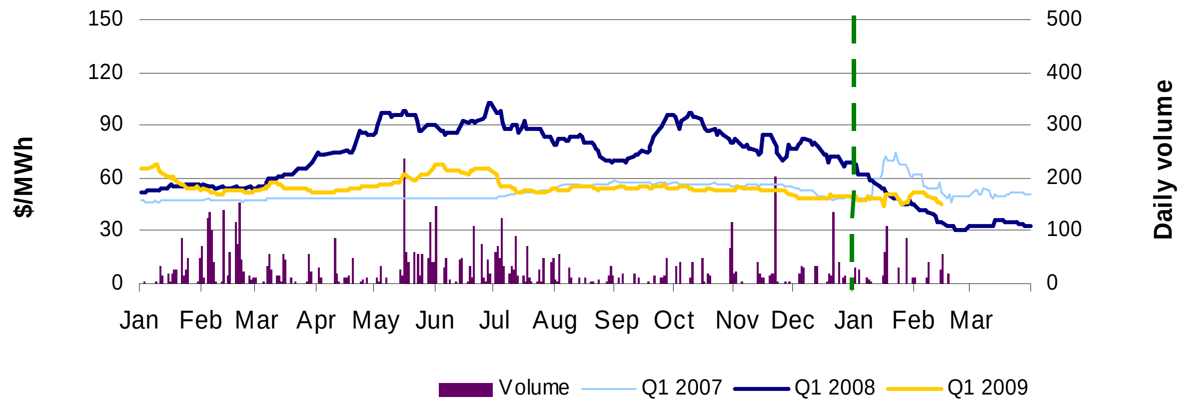
Figures 7-10 compare for each region the closing daily base contract prices for the first quarter of 2007, 2008 and 2009. Also shown is the daily volume of Q1 2009 base contracts traded. The vertical dashed line signifies the start of the Q1 period.

Figure 7: Queensland Q1 2007, 2008 and 2009



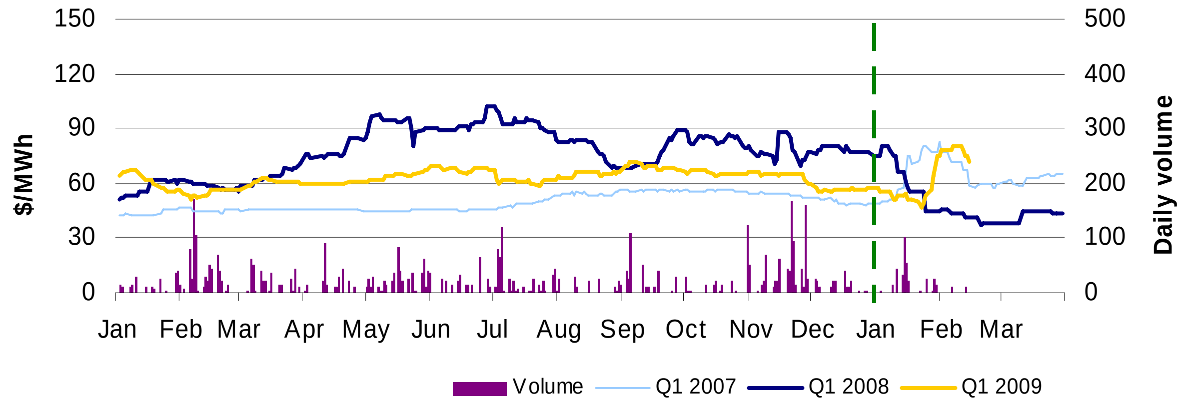
Source: d-cyphaTrade www.d-cyphatrade.com.au

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



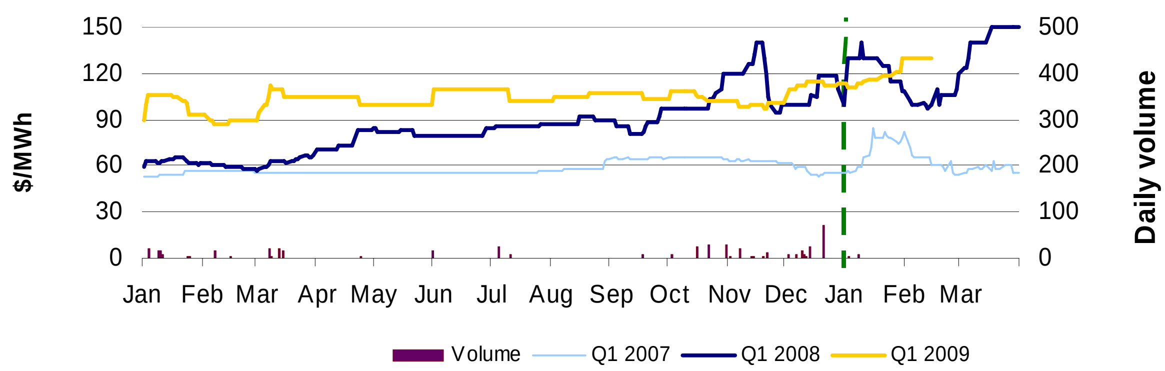
Source: d-cyphaTrade www.d-cyphatrade.com.au

Figure 9: Victoria Q1 2007, 2008 and 2009



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

Figure 10: South Australia Q1 2007, 2008 and 2009



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

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 NEMMCO and the actual spot price and, if there is a variation, state why the AER considers that 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 189 trading intervals where actual prices significantly varied from forecasts[2] throughout the week. 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	6%	32%	3%	1%
% of total below forecast	41%	16%	0%	1%

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 changes to the offer price and available capacity of generation in each region for the peak periods only[4]. For example, in Queensland 94 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 times

$/MWh	<20	Between 20 and 50	Total availability	Change in average demand
Queensland	-94	-171	-247	98
New South Wales	-211	-120	-359	-2440
Victoria	-567	15	-692	-1403
South Australia	-500	14	-756	-1022
Tasmania	-70	21	-201	-6
Total	-1442	-241	-2255	-4773

2 A trading interval is counted as having a variation if the actual price differs significantly from the forecast price either four or twelve 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 twelve 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 twelve and four hour ahead forecasts differ significantly from the actual price will be counted as two variations.

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

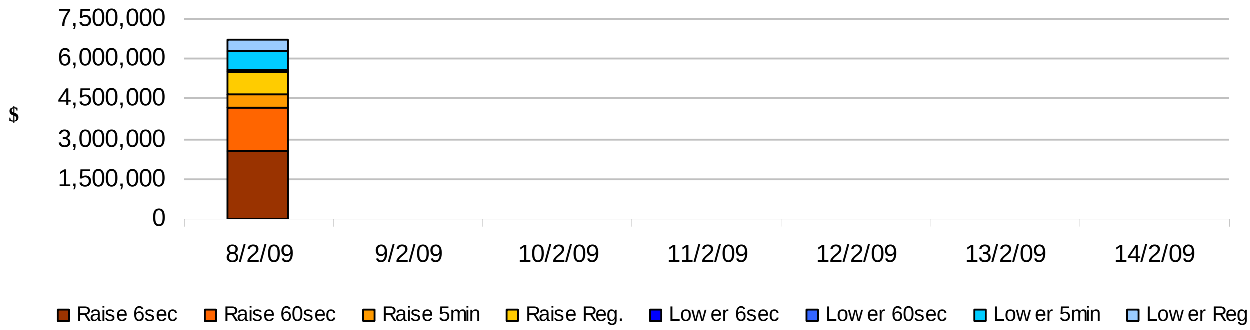
Ancillary services market

The total cost of frequency control ancillary services on the mainland for the week was $6.3 million or almost four per cent of turnover in the energy market. The majority of this cost occurred on Sunday morning when the loss of the Dederang to Shepparton 220kV line and the Buronga to Balranald 220kV line split the power system into two: Victoria/South Australia/Tasmania; and New South Wales/Queensland between 12.16 am and 1.44 am. This led to a requirement for local raise ancillary services costing around $5 million with the prices for all raise services for the southern regions reaching the price cap. The average price of raise services in the southern regions was $2777/MWh. Local lower ancillary services cost $1 million. The average price of lower local services in the southern regions was $1300/MWh. A majority of this cost accrued in the southern regions.

The total cost of ancillary services in Tasmania for the week was $0.5 million or more than seven per cent of turnover in the energy market in Tasmania. The majority of this cost accrued during the Sunday morning separation event. The price for the Lower 5 minute service exceeded $5000/MWh, the Lower reg price reached the price cap and raise prices reached the price cap for five dispatch intervals.

Figure 13 shows the daily breakdown of cost for each frequency control ancillary service for the NEM.

Figure 13: Daily frequency control ancillary service cost



Australian Energy Regulator
March 2009

Detailed Market Analysis

AUSTRALIAN ENERGY REGULATOR

8 – 14 February 2009

Queensland: There were eight occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $54/MWh.

Sunday, 8 February

2:00 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1593.85	19.84	19.97
Demand (MW)	4943	5095	5093
Available capacity (MW)	9709	10 009	9973

At 2 am NEMMCO revoked the constraint managing the loss of the Dederang to Shepparton 220kV line and the Buronga to Balranald 220kV lines (following reconnection of the northern and southern power systems), reducing imports into New South Wales across the VIC-NSW interconnector from around 1340 MW at 1.55 am to around 400 MW at 2 am.

As a result of limited ramp rate capability in New South Wales and Queensland, the five-minute dispatch price increased from $8/MWh at 1.55 am to $9495/MWh at 2 am, with prices returning to previous levels at 2.05 am. The prices in Victoria and South Australia fell to $-667/MWh and the price floor ($-1000/MWh) respectively, at the same time.

There was no significant rebidding.

Sunday, 8 February

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	214.47	89.99	76.99
Demand (MW)	6875	6951	6950
Available capacity (MW)	9975	9829	10 109
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	178.01	90.44	79.00
Demand (MW)	6847	6971	6971
Available capacity (MW)	9978	9818	10 109

Conditions at the time saw demand 125 MW lower than that forecast four and 12 hours ahead. Available capacity was 160 MW higher than that forecast four hours ahead.

At 2.52 pm, effective for the 3.30 pm trading interval, Stanwell Corporation rebid 150 MW of capacity at Gladstone from prices below $35/MWh to above $230/MWh. The reason given was “Extend previous bid::change avail/MW distrib”. At 3.16 pm Stanwell Corporation extended the previous bid for the 4 pm trading interval.

The high prices in New South Wales at the time saw exports from Queensland around 400 MW higher than forecast.

There was no other significant rebidding.

Sunday, 8 February

8:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	195.92	45.44	45.95
Demand (MW)	6980	7046	7104
Available capacity (MW)	9692	10 129	10 201

Conditions at the time saw demand close to that forecast four hours ahead. Available capacity was around 440 MW lower than that forecast four hours ahead.

Over several rebids from 4.32 pm CS Energy reduced the capacity of Kogan Creek by 225 MW as a result of ash handling issues. All of this capacity was priced below $15/MWh.

Over two rebids at 7.26 pm and 7.36 pm Stanwell Corporation rebid 300 MW of capacity at Gladstone from prices below $75/MWh to above $230/MWh. The reasons given were "Extend previous bid::change avail/MW distrib" and "Portfolio optimisation: change MW distrib".

At 7.32 pm, effective at 7.40 pm, AGL Hydro removed all 150 MW of capacity offered at its Oakey power station Unit two, giving the reason "Portfolio Optimisation::Avoid Dispatch below offer price". All of this capacity was priced above $230/MWh.

There was no other significant rebidding.

Monday, 9 February

2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	231.79	79.00	120.58
Demand (MW)	8619	8040	8040
Available capacity (MW)	10 367	10 533	10 338
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	269.52	243.50	152.68
Demand (MW)	8617	8273	8049
Available capacity (MW)	10 346	10 530	10 338

Conditions at the time saw demand up to 580 MW higher than forecast four hours ahead, with available capacity up to 185 MW lower than forecast four hours ahead.

There was no significant rebidding.

Monday, 9 February

4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1833.64	245.99	83.95
Demand (MW)	8675	8357	8067
Available capacity (MW)	10 281	10 474	10 338

Conditions at the time saw demand 320 MW higher than that forecast four hours ahead and 600 MW higher than that forecast 12 hours ahead. Available capacity was around 200 MW lower than forecast four hours ahead.

At 3.49 pm, effective from 3.55 pm, CS Energy rebid 82 MW of capacity at Swanbank E from prices below zero to above $7900/MWh. The reason given was “Dispatch differs pre-dispatch”.

At 3.50 pm Stanwell Corporation’s Stanwell unit three tripped reducing capacity by 360 MW a majority of which was priced below $45/MWh. This led to a price spike for the 3.55 pm dispatch interval of $9811/MWh as higher priced generation was dispatched. Prices returned to previous levels at 4 pm.

There was no other significant rebidding.

Monday, 9 February

7:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1478.13	39.21	30.60
Demand (MW)	8198	8062	7651
Available capacity (MW)	9741	10 410	10 347

Conditions at the time saw demand around 130 MW higher than forecast four hours ahead and 520 MW than forecast 12 hours ahead. Available capacity was 670 MW lower than that forecast four hours ahead.

Over several rebids Tarong reduced capacity by up to 260 MW across Tarong unit one and Tarong North. The reasons given were “Unit running requirement::volume profile change” and “Emissions::adjust availability”.

At 3.50 pm Stanwell Corporation’s Stanwell unit three tripped reducing capacity by 360 MW a majority of which was priced below $45/MWh. At 5.31 pm the capacity of Stanwell unit two was reduced by 90 MW due to technical issues.

At 5.56 pm Origin Energy reduced the capacity of Mount Stuart units one and two, by 144 MW each, to zero. The rebid for unit one was effective for the 6.30 pm and 7 pm trading intervals whilst for unit two was first effective for the 7 pm trading interval which commences at 6.35 pm. The dispatch price at 6.35 pm reached $8700/MWh. At 6.34 pm, effective at 6.40 pm, Origin energy reversed the rebid on unit two returning it to service at 144 MW. The reason given was “Change in PDS”. Prices returned to previous level at 6.40 pm.

There was no other significant rebidding.

New South Wales: There were nine occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $53/MWh.

Sunday, 8 February

2:00 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1677.91	21.00	21.00
Demand (MW)	7474	7606	7513
Available capacity (MW)	12 862	12 798	13 103

At 2 am NEMMCO revoked the constraint managing the loss of the Dederang to Shepparton 220kV line and the Buronga to Balranald 220kV lines (following reconnection of the northern and southern power systems), reducing imports into New South Wales across the VIC-NSW interconnector from around 1340 MW at 1.55 am to around 400 MW at 2 am.

As a result of limited ramp rate capability in New South Wales and Queensland, the five-minute dispatch price increased from $8/MWh at 1.55 am to $9495/MWh at 2 am, with prices returning to previous levels at 2.05 am. The prices in Victoria and South Australia fell to $-667/MWh and the price floor ($-1000/MWh) respectively, at the same time.

There was no significant rebidding.

Sunday, 8 February

2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	197.77	68.96	95.25
Demand (MW)	12 228	11 755	11 803
Available capacity (MW)	14 104	14 539	14 538
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	282.83	90.97	96.41
Demand (MW)	12 334	11 839	11 887
Available capacity (MW)	14 062	14 539	14 538
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	307.09	92.37	96.37
Demand (MW)	12 335	11 865	11 881
Available capacity (MW)	13 852	14 500	14 538
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3006.80	92.81	96.05
Demand (MW)	12 304	11 856	11 897
Available capacity (MW)	13 552	14 479	14 538
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	310.00	93.28	94.35
Demand (MW)	12 225	11 779	11 778
Available capacity (MW)	13 582	14 776	14 538
5:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	310.00	61.59	93.73
Demand (MW)	12 232	11 812	11 745
Available capacity (MW)	13 612	14 792	14 538
5:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	175.77	40.00	46.00
Demand (MW)	12 108	11 702	11 691
Available capacity (MW)	13 642	14 792	14 538

Conditions at the time saw demand up to 495 MW higher than forecast four hours ahead. Available capacity was up to 1200 MW lower than that forecast four hours ahead.

A constraint was invoked early in the morning that forced flows from New South Wales into Victoria to manage system security in Victoria as a result of the bushfires. This constraint was revised several times during the day as the conditions varied in Victoria. At the time of high prices flows were being forced into Victoria at around 400 MW, whilst forecasts showed flows into New South Wales.

A tight supply and demand condition existed in New South Wales with no capacity priced between $310/MWh and $8000/MWh. At 3.55 pm and 4 pm the dispatch price reached $8800/MWh and $8000/MWh respectively with 9 MW and 32 MW of high priced generation being dispatched.

Over two rebids at 12.50 pm and 1.01 pm Eraring Energy reduced the availability of its Eraring units by 370 MW (up to 340 MW was priced below $120/MWh). The reason given was “Lake temperature management-station capacity limit”.

Over two rebids at 2.03 pm and 2.17 pm Delta Electricity reduced the available capacity of Munmorah unit four (which came online during the afternoon) and Wallerawang unit seven by a total of 190 MW (a majority of which was priced below $35/MWh). The reasons given were “Return to service::capacity/ROC change” and “Milling capacity::capacity limit change”.

At around 3 pm Macquarie Generation’s Bayswater unit one tripped during a routine test from full load reducing available capacity by 660 MW. All of this capacity was priced below $25/MWh.

There was no other significant rebidding.

Sunday, 8 February

8:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	208.65	44.81	44.99
Demand (MW)	11 326	11 139	11 216
Available capacity (MW)	13 059	13 159	13 923

Conditions at the time saw demand 190 MW higher than forecast four hours ahead. Available capacity was 100 MW lower than forecast four hours ahead but 860 MW lower than forecast 12 hours ahead.

Over several rebids from 5.45 pm Eraring Energy reduced the capacity of its Eraring units by 100 MW. The reason given was “Lake temperature management-station capacity limit”.

There was no other significant rebidding.

Victoria: There were three occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $22/MWh.

Sunday, 8 February

1:00 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	322.68	20.27	22.18
Demand (MW)	5169	5354	5340
Available capacity (MW)	9163	9020	8752

Conditions at the time saw demand 185 MW lower than forecast four hours ahead. Available capacity was 140 MW and 410 MW higher than that forecast four and 12 hours ahead and prices in South Australia and Victoria were aligned.

At 12.16 am, with bushfires and lightning in the vicinity, the Dederang to Shepparton 220kV line and the Buronga to Balranald 220kV line tripped, separating the main Victorian and New South Wales power systems. Due to this line loss, a constraint was invoked that forced flow from Victoria into New South Wales by up to 470 MW.

At 12.26 am International Power rebid 386 MW of available capacity at Loy Yang B from prices below zero to prices above $1500/MWh. The reason given was “Energy/FCAS optimisation”.

Over several rebids from 10.23 pm on 7 February, LYMMCO rebid 820 MW of available capacity at Loy Yang A from prices below $20/MWh to prices above $4600/MWh. The reasons given were "change in predispatch" and "prices higher than forecast".
There was no other significant rebidding.

Tuesday, 10 February

7:00 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	83.11	23.92	46.45
Demand (MW)	6221	6075	6372
Available capacity (MW)	8857	8846	8841

Conditions at the time saw demand 146 MW higher than that forecast four hours ahead. Available capacity was close to forecast.

Demand increased by 180 MW between 6.35 am and 6.55 am, before returning to previous levels.

At 5.38 am, TRUenergy reduced available capacity at Yallourn unit one by 50 MW that was priced below zero. The reason given was "Plant Conditions – Limit Lifted".

There was no other significant rebidding.

Thursday, 12 February

8:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	99.81	27.65	27.89
Demand (MW)	6200	6167	6197
Available capacity (MW)	9370	9582	9627

Conditions at the time saw demand close to forecast, with available capacity up to 257 MW lower than forecast.

Over two bids at 7.46 am and 7.59 am, LYMMCO rebid 435 MW of available capacity at Loy Yang A from prices below $90/MWh to prices above $240/MWh. The reason given was "coal conservation".

At 7.21 am, International Power reduced 230 MW of available capacity, the majority of which was priced below $15/MWh, from Loy Yang B units. The reason given was "Fuel management".

There was no other significant rebidding.

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 $23/MWh.

Sunday, 8 February

1:00 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	319.76	20.64	22.46
Demand (MW)	1555	1618	1602
Available capacity (MW)	2699	2816	2874

Conditions at the time saw demand and available capacity lower than forecast and prices in South Australia and Victoria were aligned.

At 12.16 am, with bushfires and lightning in the vicinity, the Dederang to Shepparton 220kV line and the Buronga to Balranald 220kV line tripped, separating the main Victorian and New South Wales power systems.

At 12.28 am International Power rebid 100 MW of available capacity at Pelican Point from prices below $40/MWh to prices above $990/MWh. The reason given was “FCAS/energy optimisation”.

There was no other significant rebidding.

Tuesday, 10 February

7:00 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	79.26	25.69	45.77
Demand (MW)	1440	1372	1417
Available capacity (MW)	2583	2513	2508

Conditions at the time saw demand and available capacity 70 MW higher than forecast.

Flow across Murraylink was being forced into Victoria at 120 MW, as forecast.

Demand increased by 110 MW between 6.35 am and 7 am, before returning to previous levels.

At 6.39 am AGL reduced capacity by 59 MW at its Torrens Island Power Station unit A1 due to “Plant Failure::Capacity Change due to Plant Problems”. The majority of this capacity was priced under $50/MWh.

There was no other significant rebidding.

Thursday, 12 February

8:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	98.16	30.17	31.06
Demand (MW)	1501	1482	1477
Available capacity (MW)	2409	2321	2257

Conditions at the time saw demand close to forecast, with available capacity 80 MW higher than forecast.

Prices were aligned with conditions in Victoria.

There was no significant rebidding.

Detailed NEM Price and Demand Trends

AUSTRALIAN ENERGY REGULATOR

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

Financial year	QLD	NSW	VIC	SA	TAS
2008-09 ($/MWh) YTD	39	48	59	88	49
2007-08 ($/MWh) YTD	55	48	50	71	54
Change	-28%	2%	17%	23%	-10%
2007-08 ($/MWh)	58	44	51	101	57

Table 2: NEM turnover

Financial year	NEM Turnover* ($, billion)	Energy (TWh)
2008-09 YTD	$6.8	132
2007-08	$11.1	208
2006-07	$12.7	206
Change (2006-07 to 2007-08)	-12%	0.8%

* estimated value

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)
Oct-08	43	94	41	37	47	1.05
Nov-08	40	32	36	34	51	0.60
Dec-08	36	25	23	26	33	0.48
Jan-09	44	57	190	374	85	1.96
Feb-09 MTD	48	66	47	59	37	0.47
Q4 2008	39	51	34	32	44	2.13
Q4 2007	56	41	44	46	44	2.35
Change	-29%	23%	-23%	-30%	0%	-0.48%

Table 4: ASX energy futures contract prices at 16 February

	QLD		NSW		VIC		SA	
Q1 2009	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 09 Feb ($/MW)	60	100	50	75	80	140	130	200
Price on 16 Feb ($/MW)	51	82	46	68	72	140	130	200
Open interest on 16 Feb	2534	263	2782	231	2420	484	267	20
Traded in the last week (MW)	60	0	100	20	10	20	0	0
Traded since 1 Jan 08	6111	544	6594	295	5094	807	529	40
Settled price for Q1 08($/MW)	68	97	32	42	43	65	152	322

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

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
December 08 with December 07						
MW Priced <$20	-78	295	805	-142	16	897
MW Priced $20 to $50	320	414	-150	145	140	870
January 09 with January 08						
MW Priced <$20	-423	-799	25	39	-26	-1184
MW Priced $20 to $50	420	1043	178	52	-64	1629
February 09 with February 08						
MW Priced <$20	-253	11	-195	137	61	-239
MW Priced $20 to $50	306	181	99	-83	-6	497