WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

16 January - 22 January 2011

Summary

Flood damage in Queensland caused multiple transmission outages close to Brisbane, leading to network congestion and in turn high and volatile spot prices on Monday through Wednesday. These high spot prices resulted in a weekly average price in Queensland of $74/MWh.

Weekly average spot prices in other regions ranged from $24/MWh in Victoria to $27/MWh in New South Wales and South Australia.

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 16 January to 22 January and the 10/11 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 Jan - 22 Jan 2011	74	27	24	27	25
% change from previous week*	93	-24	-18	-6	-5
10/11 financial YTD	24	27	23	26	32
% change from 09/10 financial YTD **	-47	-58	-36	-72	15

*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 below $-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 Sydney Futures Exchange (SFE) as at close of trade on Monday 24 January 2011. Figure 2 shows the base futures contract prices

[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 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.

for the 2011 to 2013 calendar years, and the average over these years. Also shown are percentage changes[3] from the previous week.

Figure 2: Base calendar year futures contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Calendar Year 2011	32	7%	36	0%	30	0%	33	0%
Calendar Year 2012	33*	1%	40*	0%	34*	1%	37*	0%
Calendar Year 2013	39	0%	49	0%	46	0%	69	0%
Three year average	35	3%	41	0%	37	0%	47	0%

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

Figure 3 shows the $300 cap contract price for Q1 2011 and calendar year 2011 and the percentage change[4] from the previous week.

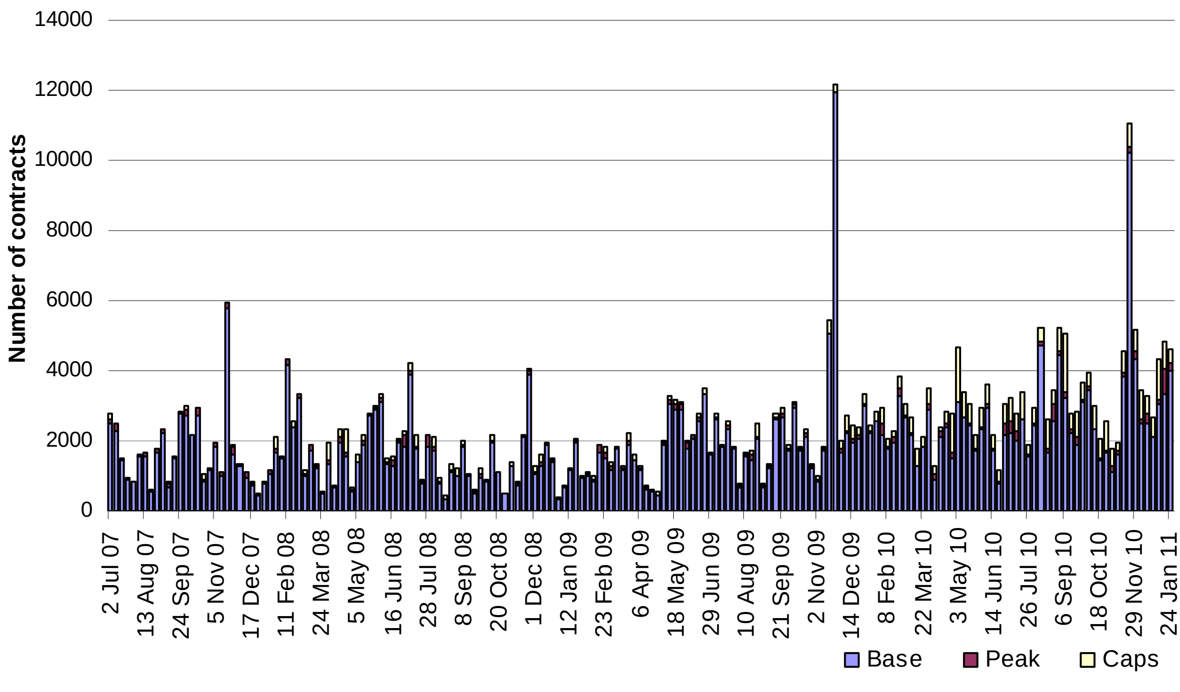
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2011 (% change)	13*	44%	10*	3%	10*	-8%	22	0%
2011 (% change)	6	19%	8	-1%	5	-4%	9	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

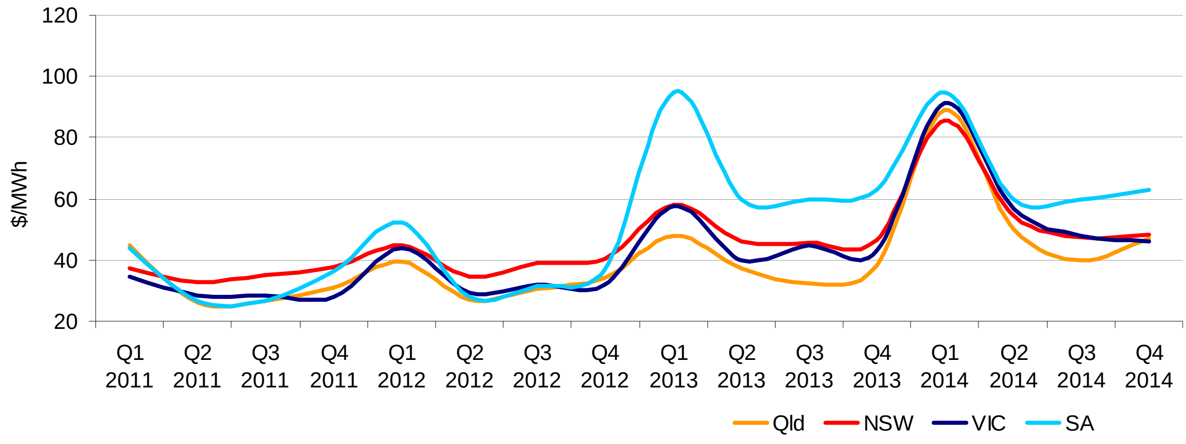


Source: d-cyphaTrade www.d-cyphatrade.com.au

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

3 Calculated on prices prior to rounding.
4 Calculated on prices prior to rounding.

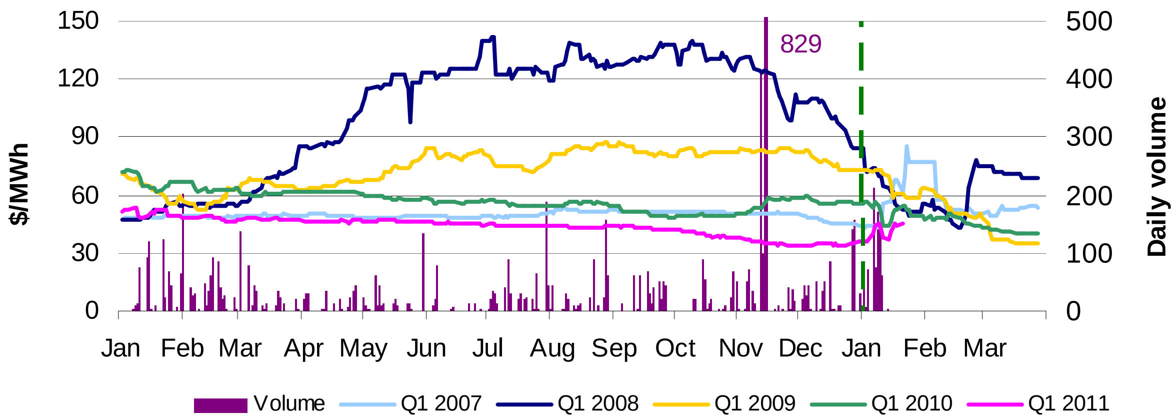
Figure 5: Quarterly base future prices Q1 2011 – Q4 2014



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

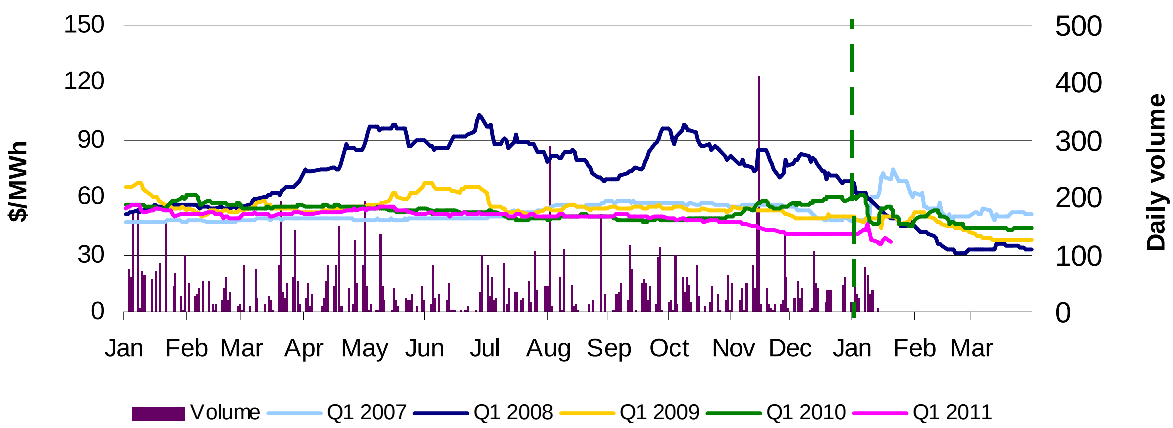
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2007, 2008, 2009, 2010 and 2011. Also shown is the daily volume of Q1 2011 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.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



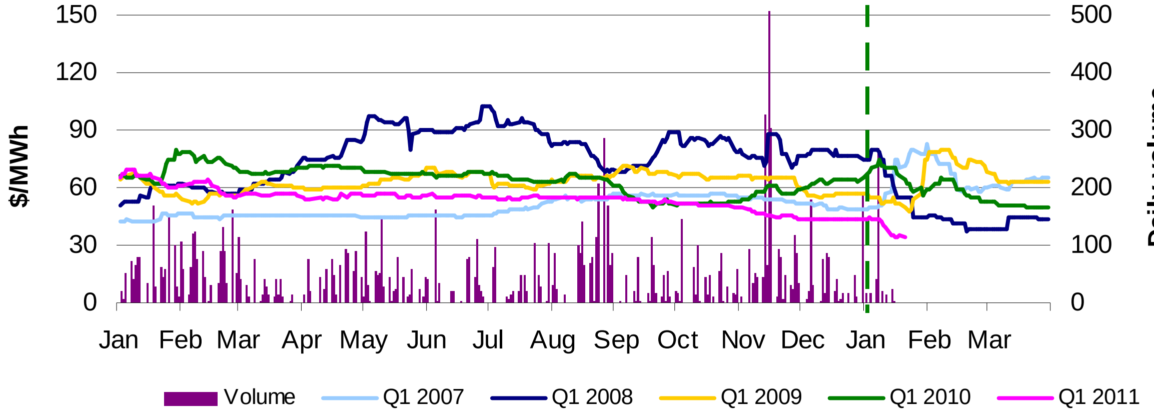
Source: d-cyphaTrade www.d-cyphatrade.com.au

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



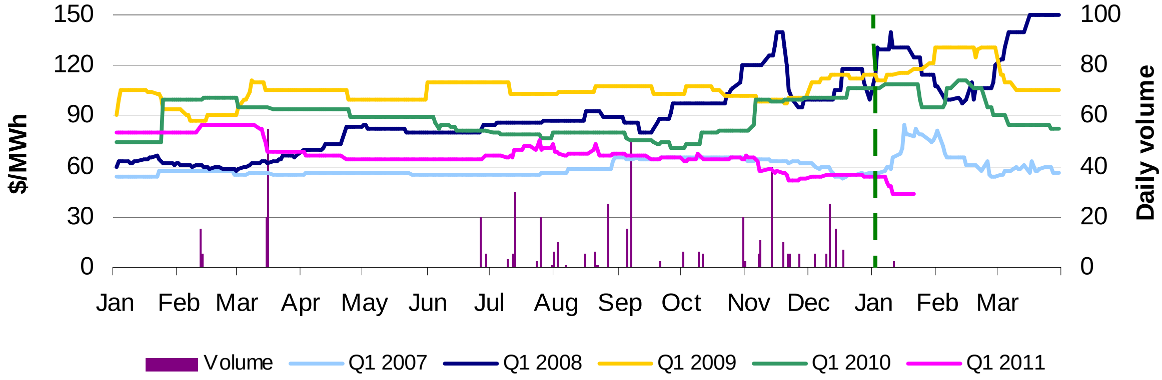
Source: d-cyphaTrade www.d-cyphatrade.com.au

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



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

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



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 98 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	14	25	15	6
% of total below forecast	17	11	9	3

[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 1935 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	1935	-253	1519	605
NSW	749	-26	1118	174
VIC	-181	-40	-160	-291
SA	-127	110	14	15
TAS	-277	202	72	-19
TOTAL	2099	-7	2563	484

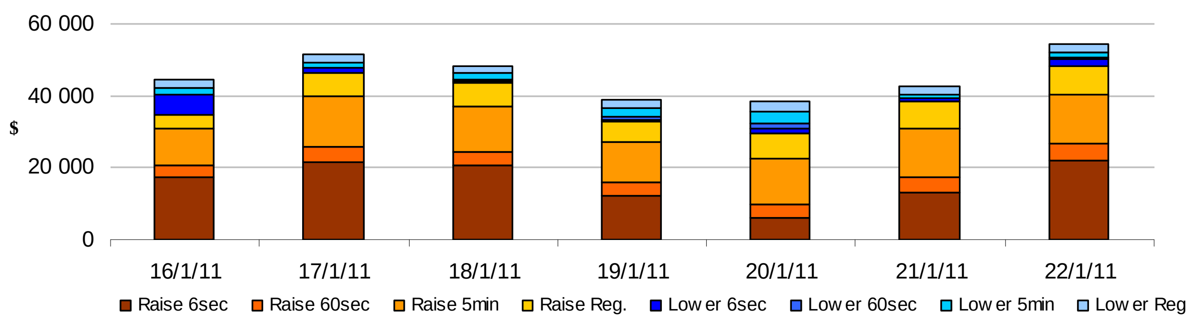
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $196 000 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $123 000 or just below three 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
February 2011

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

Detailed Market Analysis

AUSTRALIAN ENERGY REGULATOR

16 January – 22 January 2011

Queensland:

There were ten occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $74/MWh and above $250/MWh.

Monday, 17 January

4 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2560.66	43.96	43.96
Demand (MW)	7465	7130	7230
Available capacity (MW)	10 933	11 065	11 340

Conditions at the time saw demand 335 MW higher than forecast four hours ahead and available capacity 407 MW below that forecast twelve hours ahead.

The floods in south east Queensland the previous week led to damage to transmission equipment. On 11 January the Blackwall to Rocklea and the South Pine to Rocklea 275 kV transmission lines were taken out of service at short notice as a result of tower erosion. The Rocklea and Tennyson substations were also inundated by the floodwaters and were taken out of service on 12 January. On 13 January the Tarong to South Pine 275 kV transmission line tripped following a tower collapse (also as a result of tower erosion).

A multiple outage constraint was invoked on 13 January to manage the equipment outages.

At 8.40 am on 17 January, a temporary constraint replacing the previous constraint was invoked by AEMO to manage security issues. At 3.35 pm a new multiple outage constraint was invoked to replace this temporary constraint. However, this constraint contained an incorrect emergency rating for the Blackwall to South Pine line. This constraint violated immediately for one dispatch interval at 3.35 pm, causing the 5-minute price to increase to the price cap. The constraint equation was taken out of the market systems ("blocked") for the next two dispatch intervals while the emergency rating was corrected, and the 5-min price fell to $55/MWh. In response to the high price at 3.35 pm generators immediately rebid more than 850 MW of available capacity into negative price bands. At 3.50 pm the constraint was returned to the market systems ("unblocked") causing significant changes in generation dispatch. As a result, the price increased to $1032/MWh and stayed above $500/MWh until 4.20 pm when the price fell to around $-1000/MWh until 4.30 pm.

Monday, 17 January

9:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	302.48	26.23	24.33
Demand (MW)	6500	6666	6487
Available capacity (MW)	11 171	11 202	11 213

In the afternoon significant negative settlement residues began to accrue, with flows across QNI into New South Wales up to 1100 MW. As a result, at 9.05 pm, AEMO invoked a constraint to manage negative settlement residues. Due to this nature of this constraint and its proximity to the regional reference node, the price increased to $1000/MWh for two dispatch intervals.

Tuesday, 18 January

11 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2750.06	33.97	34.99
Demand (MW)	7832	7242	7223
Available capacity (MW)	10 912	11 267	11 317
11:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3035.82	35.87	35.28
Demand (MW)	7831	7299	7279
Available capacity (MW)	10 848	11 314	11 314
12 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	902.55	35.17	36.75
Demand (MW)	7892	7376	7357
Available capacity (MW)	10 824	11 271	11 312
1:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	655.31	40.46	40.66
Demand (MW)	8052	7936	7549
Available capacity (MW)	10 824	11 185	11 293

3:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	480.98	40.56	39.02
Demand (MW)	7909	8316	7639
Available capacity (MW)	10 840	11 176	11 288

Conditions at the time saw demand up to 590 MW above that forecast four hours ahead and available capacity up to 466 MW below that forecast four hours ahead.

With transmission equipment still unavailable, the constraint used to manage the multiple outages was still effective. On advice from Powerlink, AEMO progressively reduced the line rating on the Blackwall to South Pine line from 10.45 am to 11.30 am. At 10.55 am, with demand increasing, the constraint bound constraining off negatively priced generation resulting in the dispatch of higher priced generation. The 5-minute price spiked from $57/MWh to the price cap for the 10.55 am dispatch interval and stayed above $1000/MWh until 11.50 am. The 5-minute price fluctuated between $1941/MWh and the price floor from 11.15 am until 4.10 pm.

In response to the high price at 10.55 am (that was not forecast), generators in Queensland rebid over 3000 MW of capacity to prices close to the price floor by midday. The constraint had the effect of occasionally constraining off the negatively priced generation (around 85 per cent of Queensland capacity was priced close to the price floor) causing the 5-minute price to fluctuate.

Negative settlement residues commenced from early in the morning and totalled around $1.3 million for the day.

Wednesday, 19 January

9:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	715.40	34.10	52.41
Demand (MW)	7294	7323	7321
Available capacity (MW)	11 042	11 059	11 161
11:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	453.49	35.94	43.29
Demand (MW)	7576	7555	7612
Available capacity (MW)	10 912	11 104	11 134

2 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2103.50	30.25	47.13
Demand (MW)	7820	7874	7817
Available capacity (MW)	10 814	11 069	11 115

Conditions at the time saw demand close to forecast while available capacity was up to 255 MW below that forecast four hours ahead.

For the third consecutive day, the constraint used to manage the multiple transmission outages was still effective. The constraint again had the effect of occasionally constraining off negatively priced generation. The 5-minute price exceeded $800/MWh from the 9.15 am to 9.40 am dispatch intervals then fell to the price floor from 9.45 am to 10.15 am.

From 11 am to 11.30 am the 5-minute price exceeded $800/MWh on four occasions, and was around $35/MWh for the other two dispatch intervals, contributing to the high price for the 11.30 am trading interval.

The 5-minute price spiked to the price cap at 1.45 pm, causing the high price for the 2 pm trading interval.

Negative settlement residues commenced from early in the morning and totalled around $1.44 million for the day.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
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Table 1: Financial year to date spot market volume weighted average price

Financial year	QLD	NSW	VIC	SA	TAS
2010-11 ($/MWh) YTD	24	27	23	26	32
2009-10 ($/MWh) YTD	45	64	36	95	28
Change*	-47%	-58%	-36%	-72%	15%
2009-10 ($/MWh)	37	52	42	82	30

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2010-11 (YTD)	$2.908	114
2009-10	$9.643	206
2008-09	$9.413	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)
Sep-10	22	24	23	27	21	0.386
Oct-10	20	23	21	25	18	0.358
Nov-10	18	23	19	26	29	0.346
Dec-10	23	23	17	19	17	0.315
Jan-11(MTD)	46	30	27	28	25	0.363
Q4 2010	21	23	19	23	21	1.050
Q4 2009	53	100	29	134	31	3.555
Change*	-61%	-77%	-35%	-83%	-30%	-70.47%

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

	QLD		NSW		VIC		SA	
Q1 2011	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 17 Jan ($/MW)	37	55	37	54	35	55	43	80
Price on 24 Jan ($/MW)	45	66	37	53	35	55	44	80
Open interest on 24 Jan	1647	163	2793	339	2601	215	217	9
Traded in the last week (MW)	454	0	145	0	67	0	0	0
Traded since 1 Jan 10 (MW)	8915	248	10348	606	12216	414	482	9
Settled price for Q1 10($/MW)	40	65	44	68	50	89	83	160

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

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
November 10 with November 09						
MW Priced <$20/MWh	-73	-20	777	227	994	1906
MW Priced $20 to $50/MWh	393	95	-524	-110	-663	-809
December 10 with December 09						
MW Priced <$20/MWh	-526	-481	952	295	753	992
MW Priced $20 to $50/MWh	329	140	-399	-32	-343	-306
January 11 with January 10 (MTD)						
MW Priced <$20/MWh	-660	-1119	-423	363	431	-1408
MW Priced $20 to $50/MWh	44	-82	48	183	-360	-167

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