WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

10 March – 16 March 2013

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 10 March to 16 March and the 12/13 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 10 Mar - 16 March 2013	78	54	65	56	54
% change from previous week*	27	0	-3	-30	-5
12-13 financial YTD	73	56	63	65	49
% change from 11-12 financial YTD**	141	90	135	98	52

*The percentage change between last week's average spot price and the average price for the previous week. Calculated on VWA prices prior to rounding.
**The percentage change between the average spot price for the current financial year and the average spot price for the previous financial year. Percentage changes are calculated on VWA prices prior to rounding.

Further information is provided in Appendix A when the spot price exceeds three times the weekly average and is above $250/MWh or less than -$100/MWh. Longer term market trends are attached in Appendix B.[1]

Financial markets

Figures 2 to 9 show futures contract[2] prices traded on the Australian Securities Exchange (ASX) as at close of trade on Friday 15 March 2013. 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 -> Australian energy industry -> Performance of the energy sector

[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 2013	67	1%	56	0%	53	-2%	58	0%
Calendar Year 2014	55 (20)	0%	55	0%	51	-2%	57	0%
Calendar Year 2015	50 (25)	0%	49	0%	46 (25)	-1%	49	0%
Three year average	57	0%	53	0%	50	-1%	54	0%

Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au
* a number in brackets denotes the number of trades in the product.

Figure 3 shows the $300 cap contract price for Q1 2013 and calendar year 2013 and the percentage change[4] from the previous week.

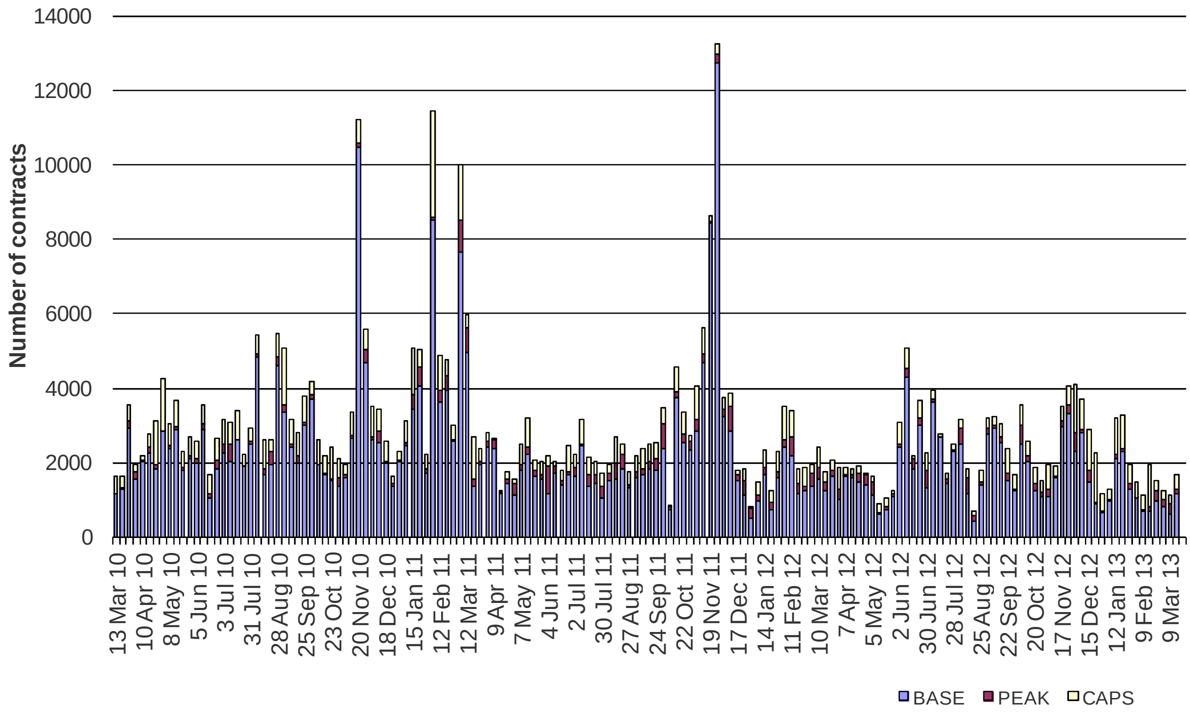
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2013	21	0%	0 (25)	-40%	4 (56)	-49%	5	-43%
2013	8	-1%	2	-3%	3	-27%	4	-18%

Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au
* a number in brackets denotes the number of 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

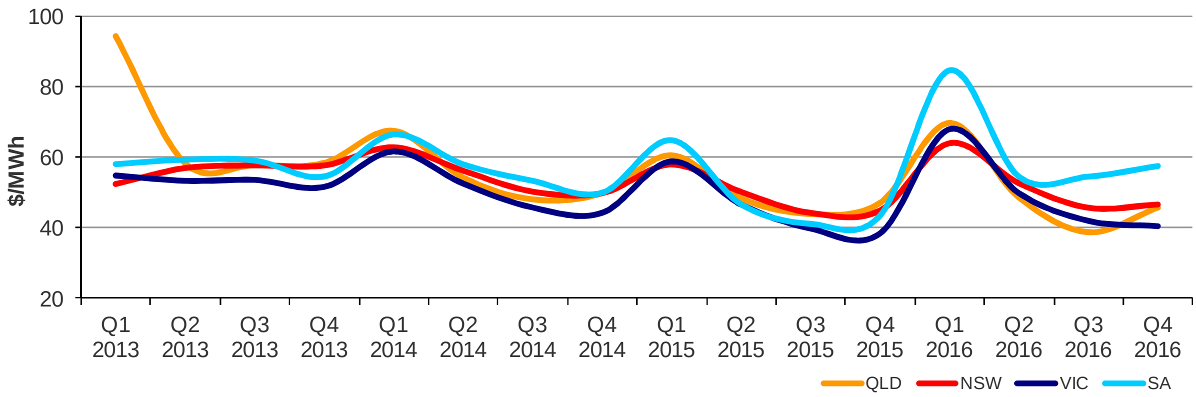


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

[4] Calculated on prices prior to rounding.

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

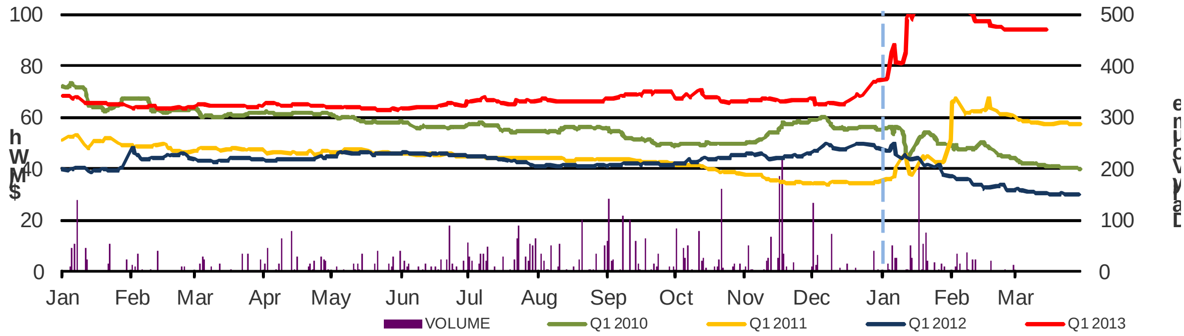
Figure 5: Quarterly base future prices Q1 2013 – Q4 2016



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

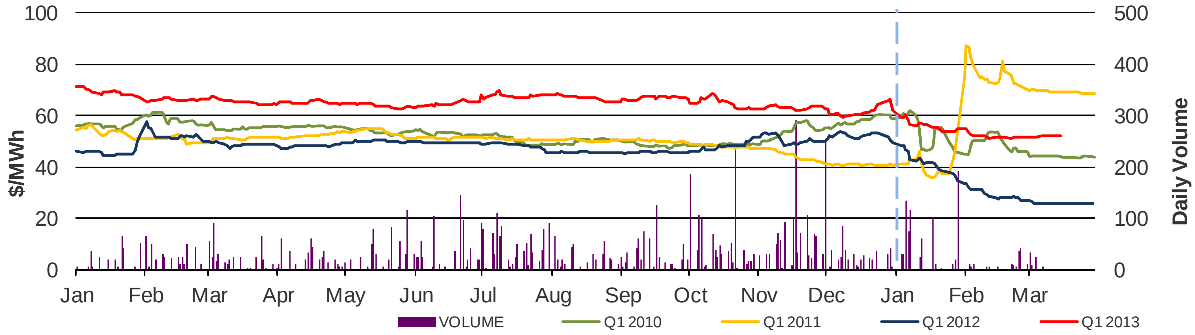
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2010, 2011, 2012 and 2013. Also shown is the daily volume of Q1 2013 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

Figure 6: Queensland Q1 2010, 2011, 2012 and 2013



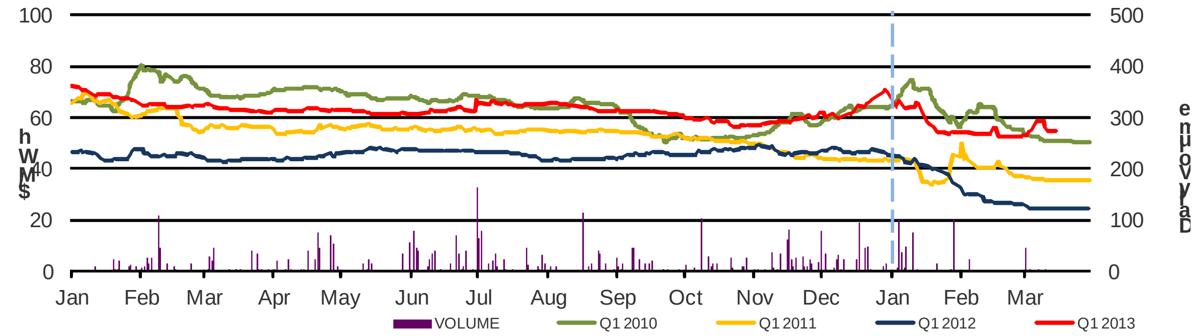
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 7: New South Wales Q1 2010, 2011, 2012 and 2013



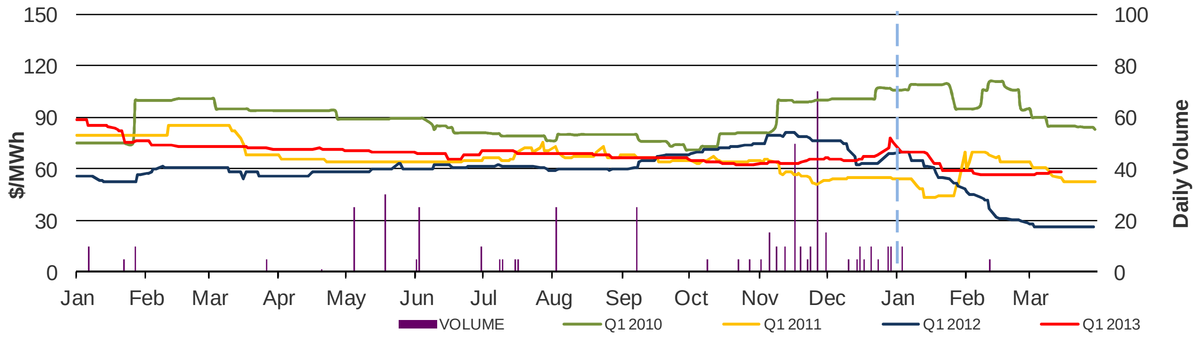
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 8: Victoria Q1 2010, 2011, 2012 and 2013



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

Figure 9: South Australia Q1 2010, 2011, 2012 and 2013



Source: d-cyphaTrade/ASX 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 177 trading intervals throughout the week where actual prices varied significantly from forecasts[5]. This compares to the weekly average in 2012 of 60 counts and the average in 2011 of 78. Reasons for these variances are summarised in Figure 10[6].

[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.

Figure 10: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	0	31	0	2
% of total below forecast	48	14	0	6

The total may not equal 100% due to rounding

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 65 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	-65	-605	158	-85
NSW	10	-240	140	80
VIC	-154	203	104	-612
SA	-93	91	-132	-401
TAS	95	-190	117	-53
Total	-207	-741	387	-1071

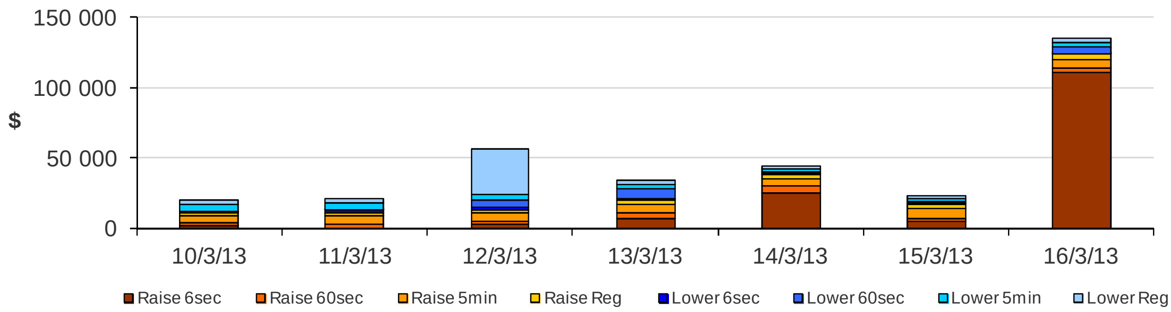
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $152 500 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $184 000 or 1.9 per cent of energy turnover in Tasmania. The majority of FCAS costs in Tasmania were for local raise 6 second services, when the price of these services reached an average of around $400/MW from 7 am to 11.20 am on 16 March 2013. This was driven by network constraints managing local raise 6 second services for the loss of generation 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
April 2013

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

AUSTRALIAN ENERGY REGULATOR

10 March – 16 March 2013

Queensland:

There were three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $78/MWh and above $250/MWh.

Friday, 15 March

11:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1456.77	70.00	55.89
Demand (MW)	5651	5809	5677
Available capacity (MW)	10 269	10 311	10 286

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

For the 10.35 pm dispatch interval, there was a sudden increase in 5 minute demand[8] by around 90 MW. A number of low priced generators were ramp rate limited (including Callide C, Darling Downs and Tarong). As a result, generation priced at $8500/MWh was dispatched at Callide B, setting the price for the 10.35 pm dispatch interval. At 10.40 pm, with generators no longer ramp rate limited, the dispatch price fell to $55/MWh.

There was no significant rebidding.

Saturday, 16 March

5:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2229.61	60.63	155.03
Demand (MW)	6385	6297	6431
Available capacity (MW)	10 180	10 255	10 280

Conditions at the time saw demand around 90 MW more than that forecast four hours ahead and available capacity 75 MW less than forecast four hours ahead.

Over three rebids between 3.02 pm and 4.38 pm, QGC Sales reduced the available capacity at Condamine from 167 MW to 100 MW. All of this capacity was priced at less than -$800/MWh. The reason given for the rebids was “change in plant capabilities sl”.

[8] *Total demand* is used for the regional price calculations in dispatch, pre-dispatch and to determine dispatch targets for generating units.

At 4.33 pm, Origin Energy rebid the up and down ramp rates at Darling Downs from 10MW/minute to the minimum allowable of 3MW/minute.[9] The same rebid also moved 230 MW of capacity at Darling Downs from prices above $49/MWh to the price floor. The reason given was "1632A constraint management - N^^Q_NIL_B1 sl".

At 4.53 pm, Millmerran unit 1 tripped from around 430 MW, all of which was priced at less than zero. This saw a significant increase in generation from the remaining Queensland units. With a number of units being ramp rate limited or trapped in FCAS services, high priced generation was dispatched from Stanwell, Gladstone and Callide C, which saw the five minute dispatch price set at the price cap for the 5 pm dispatch interval. The five minute dispatch price fell to $436/MWh for the next interval as generators were no longer ramp rate limited and fast start plant received instructions to start, and continued to fall to $61/MWh by 5.20 pm.

There was no other significant rebidding.

10:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1462.65	72.05	52.19
Demand (MW)	5800	5724	5757
Available capacity (MW)	9817	9856	10 311

Conditions at the time saw demand and available capacity close to that forecast four hours ahead.

At 9.57 pm, effective from 10.05 pm, Braemar Power Projects rebid 186 MW of capacity at Braemar A power station from prices close to the price floor to above $10 800/MWh . The reason given was "2156P BR2 & BR3 Gas linepack management - SL @21:56".

The combination of rebidding, an increase in demand of around 45 MW and generators being ramp rate limited, stranded in FCAS or offline saw the 10.25 pm five minute price reached $8500/MWh.

At 10.21 pm, effective from 10.30 pm, CS Energy rebid 250 MW of capacity at Gladstone from prices above $12 700/MWh to less than -$990/MWh. The reason given was "2221A dispatch price higher than 5min forecast –sl". At 10.24 pm, effective from 10.30 pm, Braemar Power Projects rebid 38 MW of capacity at Braemar A unit 2 from prices above $10 000/MWh to prices below -$940/MWh. The reason given was "2221A QLD DS prices at $8500 Vs $55 –SL @ 22:23". The five minute price fell to $47/MWh at 10.30 pm, as generators were no longer ramp rate constrained.

There was no other significant rebidding.

[9] The ramp rate of 3MW/minute is the minimum allowable without a technical reason.

Victoria:

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $65/MWh and above $250/MWh.

Tuesday, 12 March

2:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2138.88	68.45	66.37
Demand (MW)	9312	8673	8319
Available capacity (MW)	10 308	10 665	10 849

Conditions at the time saw demand around 640 MW higher than forecast four hours ahead and almost 1000 MW greater than that forecast 12 hours ahead. Available capacity was 357 MW less than forecast four hours ahead.

High demand was driven by temperatures in Melbourne exceeding 36 degrees on the day. This was the last day of a ten day heatwave in which temperatures in Melbourne reached at least 30 degrees.

At around 11.36 am, Origin Energy's Mortlake unit 1 tripped from 271 MW, 238 MW of which was priced less than $50/MWh. The unit returned to service at 2.50 pm. The reason given was "1441 change in avail – fire detection issues resolved".

At 11.50 am, AGL Hydro Partnership rebid 224 MW of capacity at Dartmouth and Eildon from prices close to the price floor to above $12 700/MWh. The reason for the rebids was "1101A chg in f/c::PD demand incr Vic +270MW 1430 since 10:30".

At 1.20 pm, the constraint managing post-contingent loading of southerly flows on the Murray to Dederang 330kV line for an outage of the Dederang DBUSS began to bind, restricting imports into Victoria across the VIC–NSW and Murraylink interconnectors. Actual flows into Victoria were around 300 MW lower than forecast four hours ahead.

At 2.25 pm demand increased in Victoria by around 135 MW in five minutes leading to a step change in the dispatch of generation. With low priced generation at Murray Power Station ramp down constrained (by the constraint that was also restricting imports from New South Wales), the five minute price reached the price cap at 2.25 pm. The five minute price fell to $48/MWh at 2.30 pm as there was a demand side response of around 420 MW.

There was no other significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis

10 March - 16 March 2013

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

Financial year	QLD	NSW	VIC	SA	TAS
2012-13 ($/MWh) YTD	73	56	63	65	49
2011-12 ($/MWh) YTD	30	30	27	33	32
Change*	141%	90%	135%	98%	52%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 YTD	8.662	138
2011-12	5.987	199
2010-11	7.445	204

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)
November-12	55	58	94	72	51	1.045
December-12	62	50	55	57	47	0.881
January-13	170	51	60	68	57	1.489
February-13	60	53	56	63	46	0.855
March-13 MTD	68	54	64	66	54	0.531
Q1 2013 QTD	109	52	59	66	52	2.876
Q1 2012 QTD	33	26	25	28	38	1.190
Change*	234%	100%	132%	138%	35%	1.416

Table 4: ASX energy futures contract prices at end of 15 March 2013

	QLD		NSW		VIC		SA	
Q1 2013	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 8 Mar ($/MWh)	94	109	52	55	59	71	58	72
Price on 15 Mar ($/MWh)	94	108	52	55	55	64	58	72
Open Interest on 15 Mar ($/MWh)	1512	341	2461	691	1269	178	275	0
Traded in the last week (MW)	0	0	0	0	4	0	0	0
Traded since 1 Jan 12 (MW)	5961	705	8876	1070	4302	293	486	0
Settled price for Q1 12 ($/MWh)	30	37	26	28	25	29	26	30

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

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
January 13 with January 12						
MW Priced $20/MWh	-2772	-2217	-1360	-41	-235	-6625
MW Priced $20/MWh to $50/MWh	1812	1269	1255	-346	339	4330
February 13 with February 12						
MW Priced $20/MWh	-3691	-1475	-1023	-157	-399	-6745
MW Priced $20/MWh to $50/MWh	2240	47	635	-421	389	2891
March 13 with March 12 MTD						
MW Priced $20/MWh	-4638	-1536	-1060	214	-263	-7283
MW Priced $20/MWh to $50/MWh	2551	-659	1044	-276	413	3072

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

** Estimated value