WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

20 – 26 January 2013

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 20 to 26 January 2013 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 20 Jan - 26 Jan 2013	80	50	48	52	56
% change from previous week*	-64	-8	2	1	21
12-13 financial YTD	70	57	64	66	49
% change from 11-12 financial YTD**	137	88	138	92	58

*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 25 January 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.

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

	QLD		NSW		VIC		SA	
Calendar Year 2013	70	2%	56	0%	53	0%	59	0%
Calendar Year 2014	57	0%	56 (7)	0%	54	0%	57	0%
Calendar Year 2015	51	0%	52	0%	48	0%	50	0%
Three year average	59	1%	55	0%	52	0%	55	0%

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

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

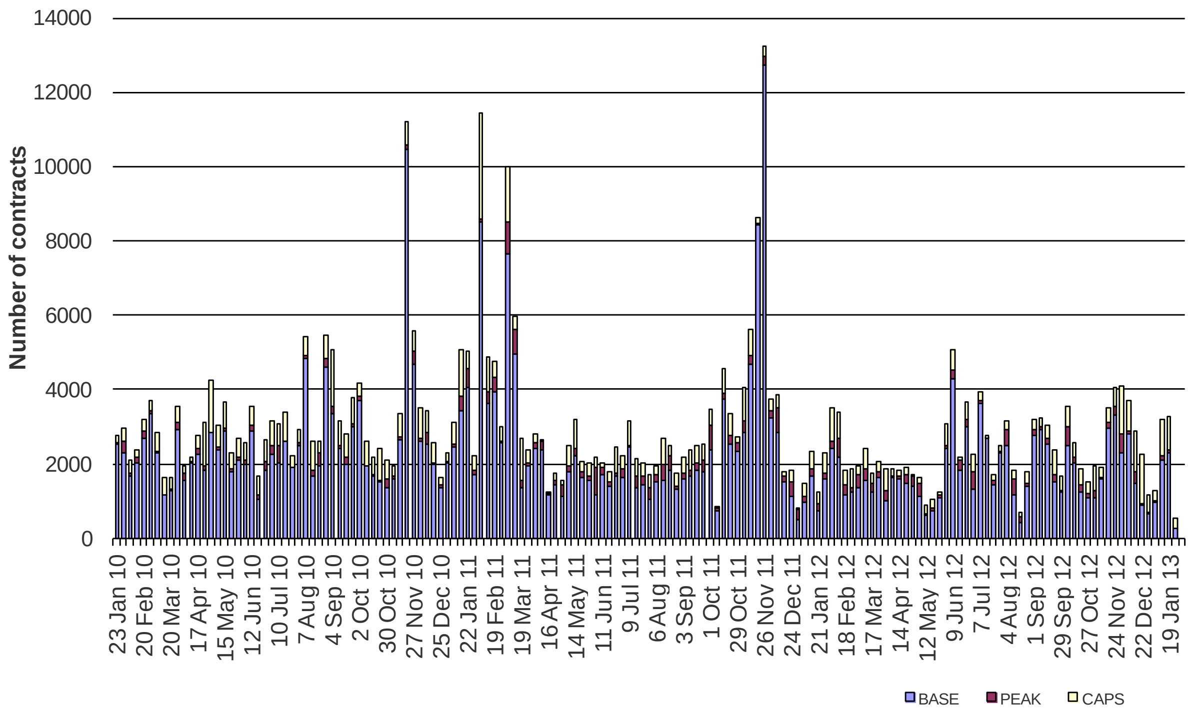
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2013	30 (156)	-14%	4 (25)	-4%	7	-16%	9	-38%
2013	10	-11%	4	-2%	4	-8%	5	-20%

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

Figure 4 shows for the last three years the weekly trading volumes for base, peak and cap contracts. The date represents the end of the trading week.

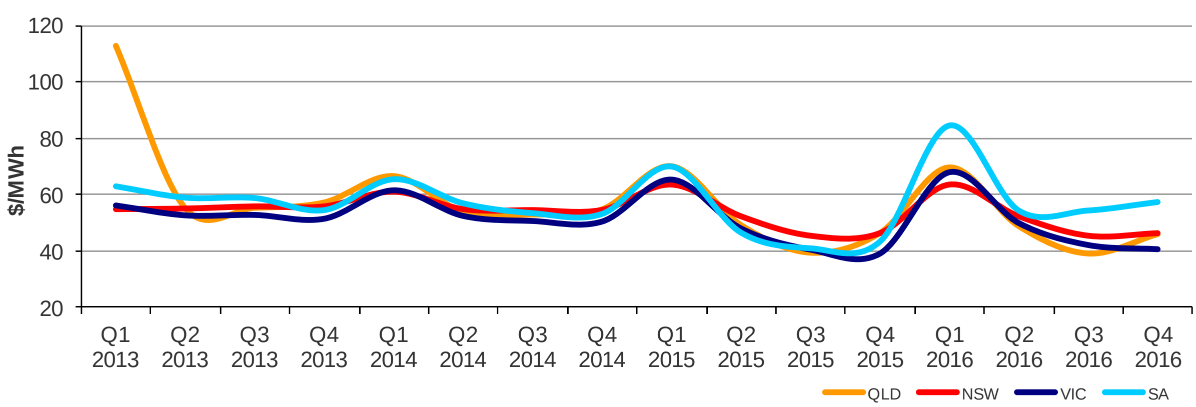
Figure 4: Number of exchange traded contracts per week



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

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

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

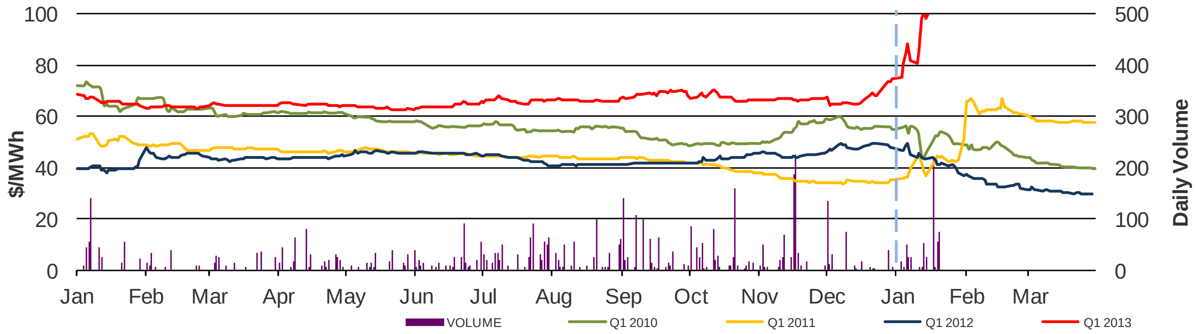


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

4 Calculated on prices prior to rounding.

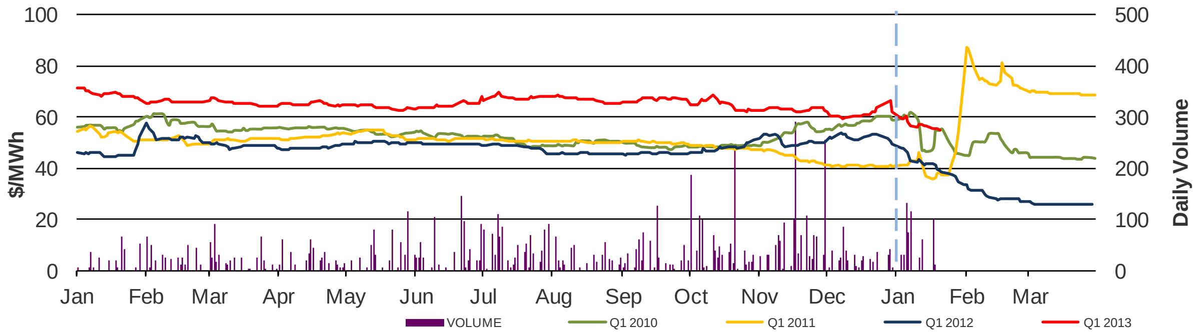
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2010, 2011, 2012 and 2013. Also shown is the daily volume of Q1 2013 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

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



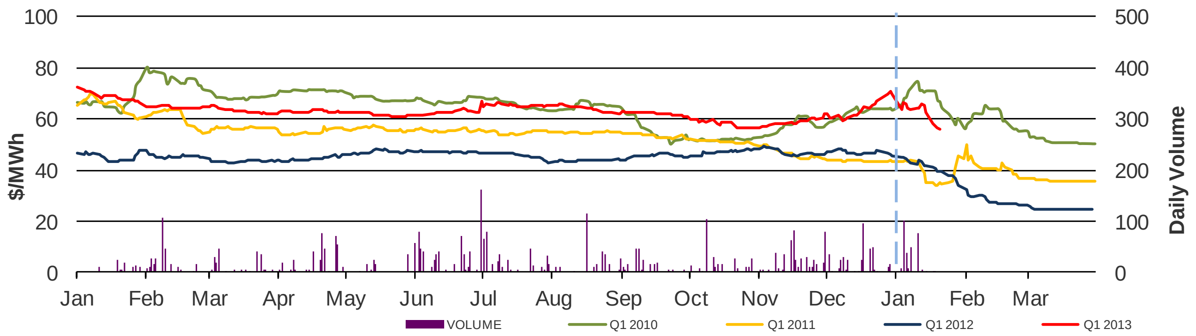
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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



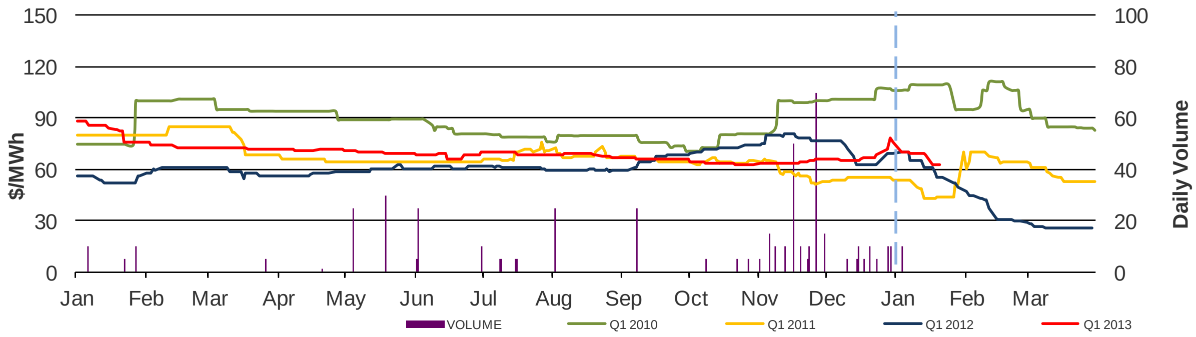
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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 169 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].

Figure 10: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	7	16	5	2
% of total below forecast	26	42	0	2

The total may not equal 100% due to rounding

[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 683 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	683	-876	-186	-112
NSW	227	-10	101	-111
VIC	-477	83	-374	-12
SA	-72	59	-169	-118
TAS	28	45	99	0
TOTAL	389	-699	-529	-353

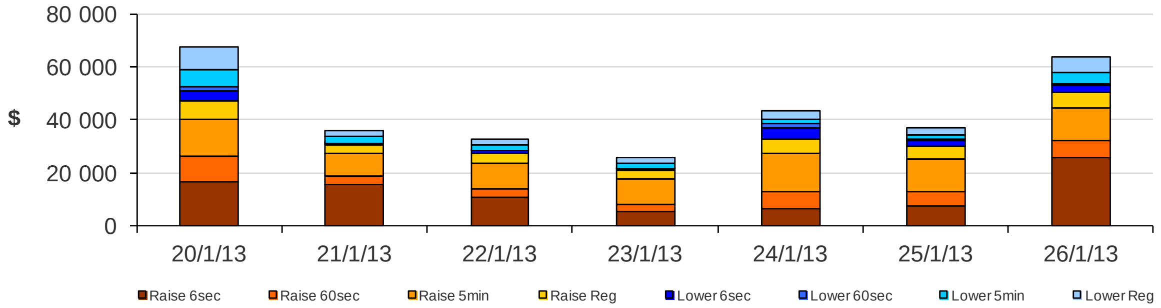
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $210 500 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $97 000 or less than one 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 2013

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

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Queensland:

There were eight occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $81/MWh and above $250/MWh.

The high prices were mainly caused by congestion around Gladstone (on the Calvale to Wurdong and Calvale to Stanwell lines) and were similar to the circumstances explained in the "*Special report - The impact of congestion on bidding and inter-regional trade in the NEM"* published by the AER in December 2012. The report is available at http://www.aer.gov.au/node/18855.

Congestion on the Calvale to Wurdong and Calvale to Stanwell lines can be alleviated through a combination of increasing output from generators north of Calvale (e.g. Gladstone and Stanwell Power Stations), reducing generation south of Calvale and/or increasing the flow on the QNI interconnector towards New South Wales. A number of low priced or constrained generators were ramp rate limited or trapped in FCAS at the relevant times, contributing to the dispatch of high priced generation. Forced exports from Queensland to New South Wales, counter-priced, saw negative settlement residues accrue on the QNI interconnector.

Sunday, 20 January

Midnight	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	292.29	48.42	48.30
Demand (MW)	6070	6041	5956
Available capacity (MW)	9611	9648	9693
12:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	407.55	48.19	48.22
Demand (MW)	5820	5806	5781
Available capacity (MW)	9546	9671	9700
9 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1344.98	50.48	48.30
Demand (MW)	5910	6164	6111
Available capacity (MW)	9734	9744	9749

Actual demand and available capacity was close to forecast.

On 19 January at 11.40 pm there was a dynamic rating change (a reduction of 42 MVA) for the Calvale to Wurdong line causing forced exports into New South Wales to increase by 194 MW. With Queensland generation either trapped or ramp rate limited the 5-minute price reached $1513/MWh.

At 11.43 pm on 19 January, effective from 11.50 pm, CS Energy rebid 690 MW of capacity at Callide B from between zero and $42/MWh to below $-900/MWh. The reason given was “2343A 855_871 constraint – SL.”

At 11.45 pm on 19 January, effective from 11.55 pm, Callide Power Trading rebid 206 MW of capacity at Callide C from $35/MWh to below $0/MWh. The reason given was “2345A constraint 855_871.” At 11.59 pm, effective from 12.10 am 20 January, the above rebid was extended for the remainder of the 12.30 am trading interval.

At 12.02 am, effective from 12.10 am, CS Energy rebid a total of 120 MW of available capacity at Gladstone units 2, 4, and 6 from prices below $60/MWh to above $12 000/MWh. The reason given was ‘0001A 855_871 constraint-SL’.

At 12.30 am there was a dynamic rating change (a reduction of 50 MVA) of the Calvale to Wurdong line causing forced exports into New South Wales to increase by 174 MW. With Queensland generation either trapped or ramp rate limited the 5-minute price reached $1508/MWh.

At 6.46 am, effective from 6.55 am, CS Energy rebid 670 MW of capacity at Callide B from between zero and $42/MWh to below $-900/MWh. The reason given was “0643A 855_871 constraint-binding-SL.” A further rebid at 6.56 am, effective from 7.05 am, saw CS Energy rebid a total of 360 MW of capacity at Gladstone units 2, 4, and 6 from prices below $60/MWh to above $12 000/MWh for the 9 am interval. The reason given was ‘0656A 855_871 constraint-binding-SL’.

At 7.27 am, Stanwell Corporation rebid 160 MW of capacity at Stanwell power station from prices below $336/MWh to above $1000/MWh. The reason given was “0726A manage binding constraint 855-871 SL.”

At 8.35 am there was a dynamic rating change (a reduction of 50 MVA) of the Calvale to Wurdong line causing forced exports into New South Wales to increase by 114 MW. With Queensland generation either trapped or ramp rate limited the 5-minute price reached $7812/MWh at 8.35 am. At 8.40 am forced exports into New South Wales decreased by 53 MW and the 5-minute price reduced to $792/MWh.

There was no other significant rebidding.

Monday, 21 January

8 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	390.32	59.25	53.27
Demand (MW)	6565	6778	6641
Available capacity (MW)	9485	9563	9645
9:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	373.26	206.48	206.48
Demand (MW)	7046	7313	7195
Available capacity (MW)	9541	9667	9629
Midday	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	375.28	92.67	206.53
Demand (MW)	7310	7364	7606
Available capacity (MW)	9547	9576	9608

Available capacity was close to forecast and demand was lower than forecast.

At 5.20 am, effective from 5.30 am, CS Energy rebid up to 700 MW of capacity at Callide B from prices above zero to below $-900/MWh. The reason given was “0519A 855_871 constraint – SL.”

At 5.25 am, Callide Power Trading rebid 170 MW of capacity at Callide 3 and 4 from $35/MWh to below zero. The reason given was “0525A constraint 855_871.” The rebid was effective for the 8 am, 9.30 am, and midday trading intervals.

At 7.33 am, effective from 7.40 am, CS Energy rebid 195 MW of capacity at Gladstone units 2, 4, and 6 from prices below $60/MWh to above $12 700/MWh. The reason given was “0732A 855_871 constraint-SL”. The 5-minute price at 7.40 am reached $1549/MWh. At 9.01 am, effective from 9.10 am, CS Energy repeated this rebid. The reason given was “0900A 855_871 constraint-SL”. The 5-minute price at 9.10 am reached $1566/MWh.

At 11.41 am, effective from 11.50 am, CS Energy rebid 195 MW of capacity at Gladstone units 2, 4 and 6 from prices below $60/MWh to above $12 700/MWh. The reason given was ‘1131A 855_871 constraint-SL’.

At 11.42 am, effective from 11.50 am, Stanwell Corporation rebid 315 MW of capacity at Stanwell price at $336/MWh to above $1000/MWh. The reason given was ‘1141A transmission constraint 855-871’.

At 11.51 am, effective from midday, AGL rebid 166 MW of capacity at Yabulu , which was offline at the time to avoid a start of the unit, priced at $459/MWh to above $12 7000/MWh. The reason given was “1045A transmission constraint 855-871”.

The 5-minute price at midday reached $1577/MWh.

Tuesday, 22 January

7:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	259.16	52.33	297.38
Demand (MW)	7159	6968	7306
Available capacity (MW)	9411	9632	9641

Conditions at the time saw demand around 150 MW lower than forecast 12 hours ahead and around 200 MW higher than that forecast 4 hours ahead.

At 6.05 am CS Energy rebid 675 MW of capacity at Callide B from between zero and $43/MWh to below $-900/MWh. The reason given was "0604A 855_871 constraint binding - SL."

At 7.02 pm, effective from 7.10 pm, CS Energy rebid 225 MW of capacity at Gladstone units 2, 4 and 6 from prices below $60/MWh to above $12 700/MWh. The reason given was '1901A dispatch price higher than 30 min forecast – SL.'

At 7.04 pm, effective from 7.15 pm, Origin Energy rebid 67 MW of capacity at Roma, which had just shutdown and was offline at the time to avoid a start of the unit, from prices below $250/MWh to above $500/MWh. The reason given was '1900A avoid uneconomic dispatch SL.'

Wednesday, 23 January

9 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	381.70	55.58	52.00
Demand (MW)	6914	7000	6870
Available capacity (MW)	9519	9564	9644

Actual demand and available capacity was close to forecast.

Over two rebids at 4.21 am and 7.46 am, CS Energy reduced the available capacity at Callide B by a total of 115 MW from prices below $0/MWh. The reasons given were "0420P coal quality-SL" and "0745P coal quality-SL".

At 7.42 am, effective from 7.50 am, Stanwell Corporation rebid 450 MW of capacity at Stanwell from prices below $1005/MWh (120 MW was priced below $50/MWh) to above $1900/MWh. The reason given was '0742A QNI binding north'.

At 8.40 am, effective from 8.50 am, CS Energy rebid a total of 105 MW of capacity at Gladstone units 2, 4 and 6 from prices below $60/MWh to above $12 700/MWh. The reason given was "0840A interconnector constaint-SL". The 5-min price at 8.50 am reached $2000/MWh, set by the Stanwell units.

Tasmania:

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $56/MWh and above $250/MWh.

Monday, 21 January

6 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2544.07	42.38	41.28
Demand (MW)	1081	1132	1098
Available capacity (MW)	2293	2293	2293

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

The high prices were driven by network constraints in Tasmania. The constraint T>>T_NIL_BL_EXP_5F is a network control scheme managing post contingent flows on the Hadspen to Georgetown 220 kV lines, preventing an overload on the parallel line in the event of a trip. The constraint affects Tasmanian generation and forces exports to Victoria across Basslink.

The ratings of the Hadspen-Georgetown 220 kV line reduced during the 5.50 am dispatch interval, and increased flows occurred during the 6 am dispatch interval. This activated the T>>T_NIL_BL_EXP_5F constraint, which causes generating units in eastern and southern Tasmania to be constrained down and generating units in western and southern Tasmania to be constrained on.

Due to limited ramp rate capability (and trapped generators) the constraint violated for the 5.50 am and 6 am dispatch intervals, with flows on Basslink reduced to levels below that required by the constraint to meet demand in Tasmania (flows were reduced to 79 MW and 99 MW respectively). Five minute dispatch prices reached the price cap ($12 900/MWh) and $2194/MWh at 5.50 am and 6 am respectively leading to a 30 minute spot price of $2544.07/MWh for the 6 am trading interval.

There was no significant rebidding.

Tuesday, 22 January

11:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2185.89	40.63	41.85
Demand (MW)	1099	1021	1006
Available capacity (MW)	2237	2237	2180

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

The high price in Tasmania was driven by a network system control protection scheme constraint which violated for one dispatch interval at 11.30 pm as a result of limited ramp rate capability (and trapped generators), and the five minute dispatch price reached the price cap ($12 900/MWh). The details of this event are similar to the 21 January event above.

There were no significant rebids.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis

20 January - 26 January 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 ($/MWh) YTD	70	57	64	66	49
2011-12 ($/MWh) YTD	30	30	27	34	31
Change*	137%	88%	138%	92%	58%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 YTD	6.997	112
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)
September-12	53	53	55	56	40	0.812
October-12	53	58	52	52	44	0.848
November-12	55	58	94	72	51	1.045
December-12	62	50	55	57	47	0.881
January-13 MTD	155	52	62	72	56	1.211
Q1 2013 QTD	155	52	62	72	56	1.211
Q1 2012 QTD	34	25	25	28	39	0.398
Change*	362%	109%	154%	158%	43%	2.044

Table 4: ASX energy futures contract prices at end of 25 January 2013

	QLD		NSW		VIC		SA	
Q1 2013	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 18 Jan ($/MWh)	106	136	55	63	57	77	63	87
Price on 25 Jan ($/MWh)	108	132	54	60	54	66	59	79
Open Interest on 25 Jan ($/MWh)	1535	324	2468	691	1304	176	270	0
Traded in the last week (MW)	175	14	12	6	18	1	0	0
Traded since 1 Jan 12 (MW)	5739	599	8446	1065	4114	289	481	0
Settled price for Q1 12 ($/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
November 12 with November 11						
MW Priced $20/MWh	-3407	78	-1859	-61	-283	-5533
MW Priced $20/MWh to $50/MWh	2797	-1617	452	-242	77	1467
December 12 with December 11						
MW Priced $20/MWh	-2990	273	-1725	-115	-219	-4777
MW Priced $20/MWh to $50/MWh	2632	-867	605	-235	33	2168
January 13 with January 12 MTD						
MW Priced $20/MWh	-2789	-2322	-1319	-23	-223	-6675
MW Priced $20/MWh to $50/MWh	1953	1400	1232	-360	328	4553

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

** Estimated value