WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

30 December 2012 – 5 January 2013

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 30 December 2012 to 5 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 30 Dec - 5 Jan 2013	60	49	104	108	70
% change from previous week*	27	2	131	131	69
12-13 financial YTD	58	58	66	67	49
% change from 11-12 financial YTD**	98	86	141	90	63

*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 28 December 2012. 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	62 (5)	4%	56 (6)	-4%	56	-2%	60	-1%
Calendar Year 2014	56 (19)	0%	57 (5)	-2%	55 (5)	1%	58	0%
Calendar Year 2015	51	0%	52	0%	48	-4%	50	-5%
Three year average	56	1%	55	-2%	53	-2%	56	-2%

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

[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.

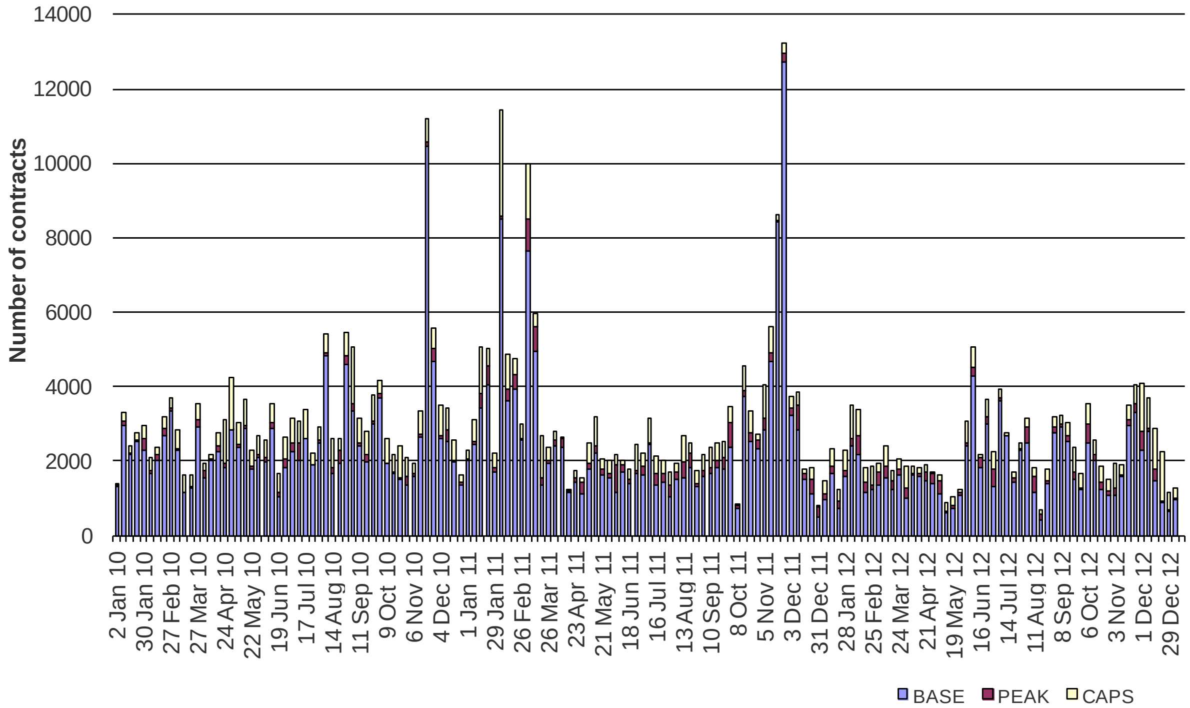
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2013	24 (21)	15%	7 (91)	-46%	17 (102)	-13%	20 (20)	5%
2013	8	9%	4	-26%	6	-11%	8	3%

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.

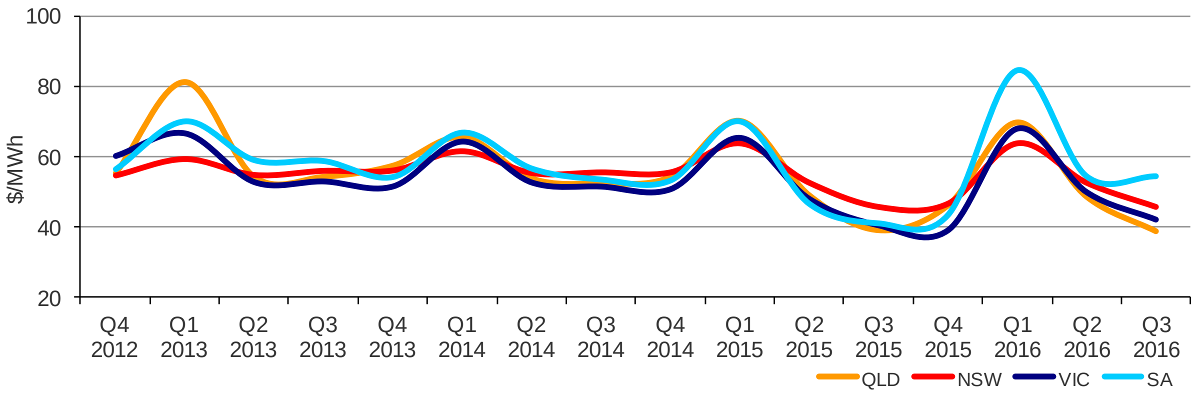
Figure 4: Number of exchange traded contracts per week



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

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

Figure 5: Quarterly base future prices Q4 2012 – Q4 2016

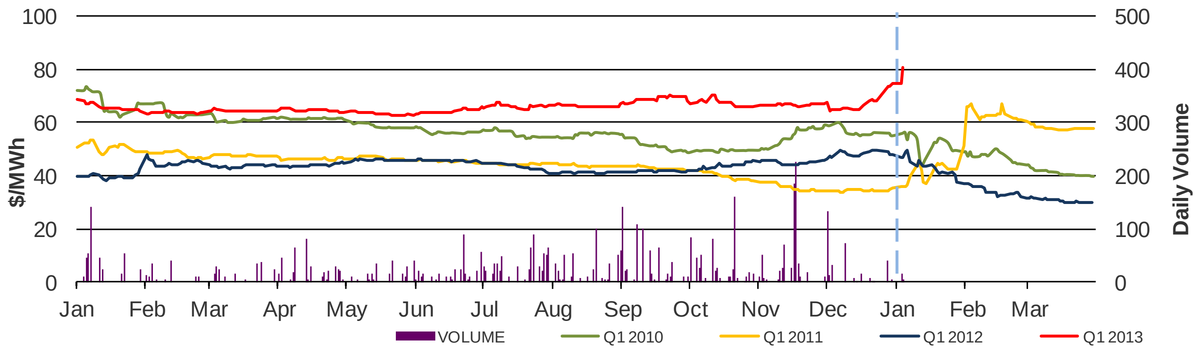


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

[4] Calculated on prices prior to rounding.

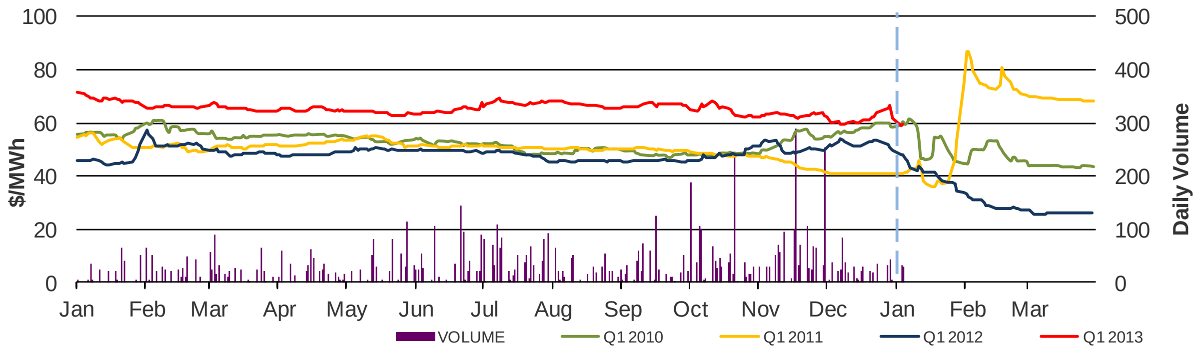
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2010, 2011, 2012 and 2013. Also shown is the daily volume of Q1 2013 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

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



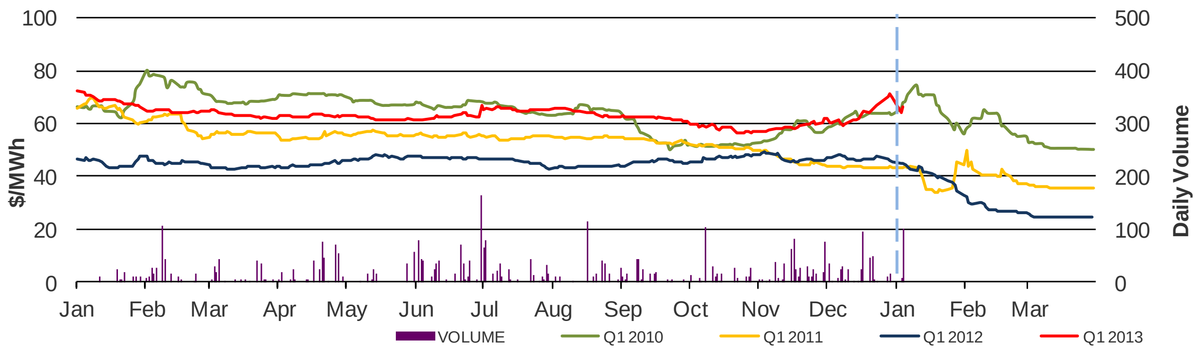
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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



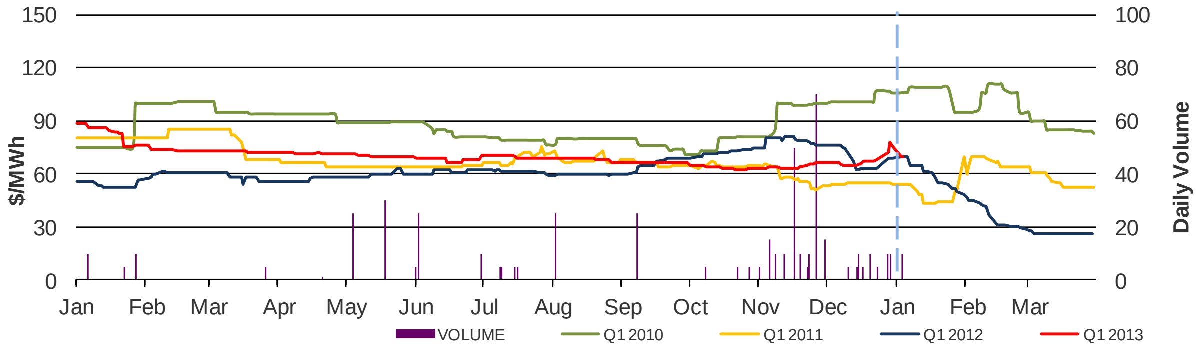
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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 246 trading intervals throughout the week where actual prices varied significantly from forecasts[5]. This compares to the weekly average in 2011 of 78 counts and the average in 2010 of 57. 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	4	13	2	6
% of total below forecast	67	7	0	0

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 788 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	788	-388	266	528
NSW	8	531	744	908
VIC	551	191	218	1127
SA	432	-47	760	632
TAS	-1	421	-49	94
TOTAL	1778	708	1939	3289

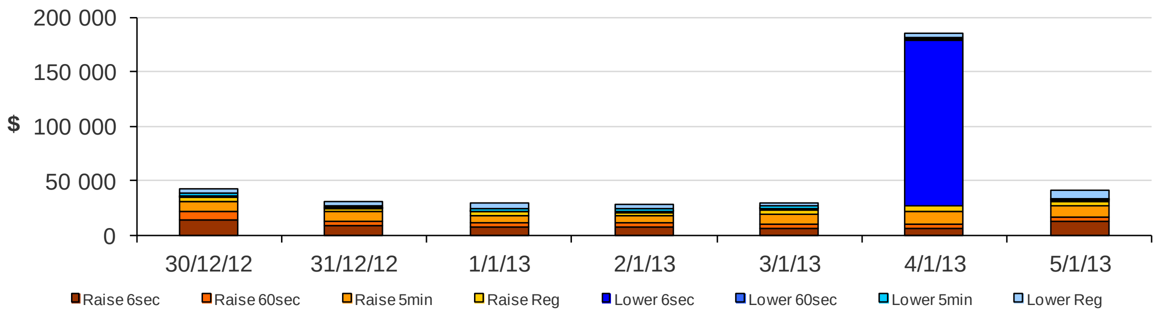
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $176 000 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $207 500 or around two per cent of energy turnover in Tasmania. This was driven by events on the afternoon of 4 January. High energy prices in Victoria (see Appendix A for more information) saw maximum exports from Tasmania. This led to large local lower FCAS requirements in Tasmania. Lower 6 second services in Tasmania reached $12 500/MW at 2.45 pm, $1102/MW at 3 pm and $1402.86/MW at 3.40 pm, at a cost of close to $150 000 for the three dispatch intervals.

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.

Queensland:

There were three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $60/MWh and above $250/MWh.

The high prices at 6.30 am and 10 am were caused by congestion around Gladstone 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.

Wednesday, 2 January

6:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1952.91	41.73	39.68
Demand (MW)	5135	4949	4809
Available capacity (MW)	9558	9565	9565
10:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	329.45	50.42	45.50
Demand (MW)	6474	6119	5989
Available capacity (MW)	9534	9530	9580

Conditions at the time saw available capacity close to forecast and demand up to 355 MW above that forecast four hours ahead.

Over a number of rebids between 3.22 am and 9.45 am CS Energy made rebids for the 6.30 am and 10 am trading intervals. These rebids shifted 700 MW of capacity at Callide B between $0/MWh and $32/MWh to close to the price floor and 240 MW of capacity priced below $51/MWh at Gladstone Power station units to $89/MWh (for the 6.30 am trading interval) and to $12 752/MWh (for the 10 am trading interval) . The reasons given for the rebids was "855_871 constraint-constraining units down-sl".

At 6.52 am, Callide Power Trading rebid 206 MW of available capacity priced at $34/MWh at Callide C Power Station to -$948/ MWh. The reason given was "0651F 855-871 manage constraint - sl".

The dynamic rating of the Calvale to Wurdong line reduced by around 70 MVA between 6.20 am and 6.30 am, with a further reduction of 50 MVA from 9.55 am to 10 am. This required large changes in dispatch - increasing output from generators north of Calvale (e.g. Gladstone and Stanwell Power Stations), reducing generation south of Calvale, and increasing the flow on the QNI interconnector towards New South Wales.

Following the reduction in the dynamic rating of the Calvale to Wurdong line between 6.20 am and 6.30 am, limited ramp up rate capability of low priced capacity saw high priced capacity at Swanbank E cleared for one dispatch interval at 6.30 am. This resulted in the 6.30 am 5-minute dispatch price reaching $11 500/MWh and the 6.30 am spot price reaching $1952/MWh.

After the further reduction in the dynamic rating of the Calvale to Wurdong line between 9.55 am and 10.00 am, limited ramp up rate capability of low priced capacity again saw high priced generation cleared at Gladstone. This resulted in the 10 am 5-minute dispatch price reaching $1534/MWh and the 10 am spot price reaching $329/MWh.

Around $800 000 of negative settlement residues accrued during the day as a result of congestion around Gladstone leading to counter price flows into New South Wales.

4:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	258.76	51.63	49.37
Demand (MW)	7642	7163	6912
Available capacity (MW)	9542	9623	9686

Conditions at the time saw available capacity close to forecast and demand 479 MW above that forecast four hours ahead.

At 12.22 pm, Stanwell Corporation rebid 260 MW of capacity at its Stanwell Power Station priced below $50/MWh to around $290/MWh. The reason given was ”1218A extend previous bid to manage 855-871”.

For the entire 4 pm trading interval, Gladstone Power Station units 1 and 6 were either trapped or stranded in FCAS services (so that energy output could not be varied). Higher priced generation had to be dispatched from Stanwell Power Station and Tarong Power Station during the trading interval, resulting in the 4 pm price reaching $259/MWh.

There was no other significant rebidding.

Victoria:

There were four occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $103/MWh and above $250/MWh.

Friday, 4 January

2:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1408.92	65.82	72.98
Demand (MW)	8767	8512	8261
Available capacity (MW)	10 300	10 802	10 371
3:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2199.91	74.91	76.40
Demand (MW)	8815	8598	8343
Available capacity (MW)	10 143	10 740	10 333

Conditions at the time saw demand up to 255 MW above and available capacity 597 MW below that forecast four hours ahead.

Hot weather contributed to increased demand, with the temperature in Melbourne exceeding 41 degrees. This coincided with high temperatures and increased demand in both South Australia and Tasmania. As temperatures increased during the day, wind generation decreased in Victoria, falling from a high of 715 MW at 10.25 am to 267 MW at 2.30 pm. Wind generation averaged around 200 MW for the remainder of the afternoon.

With little capacity priced between $50/MWh and $12 000/MWh, any reductions due to rebidding of capacity into high price bands, withdrawal of capacity, or increased demand had the potential to cause a signification jump in the spot price.

At 2.25 pm, an automated constraint set to manage power system security for the trip of the Rowville Yallourn 220 kV transmission line was invoked. This resulted in Yallourn power station being constrained down from 2.30 pm to manage the constraint. For the same 5-minute trading interval, Murray power station was also constrained down from dispatching low priced generation by a system normal constraint managing power system security for the trip of the Dederang to Murray 330 kV transmission line. This required higher priced generation to be dispatched to meet demand. This resulted in the 2.30 pm 5-minute dispatch price reaching $7759/MWh.

At 2.39 pm, unit 2 at Loy Yang A power station tripped from 529 MW – all of this was priced at less than $50/MWh At 2.45 pm, two binding system normal constraints (managing the loss of the Shepparton to Bendigo 220kV transmission line and one of the Dederang to Murray 330kV lines) reduced import limits into Victoria on the Vic-NSW interconnector. Limited ramp rate capability of low priced capacity meant that generation priced at the cap at Mackay power station was required for one dispatch interval, resulting in a spot price of $2200/MWh.

Friday, 4 January

4:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2319.05	166.28	90.17
Demand (MW)	9135	8853	8641
Available capacity (MW)	9666	10 582	10 155
4:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4281.90	245.47	102.40
Demand (MW)	9087	8923	8663
Available capacity (MW)	9610	10 583	10 141

Conditions at the time saw demand up to 282 MW above that forecast four hours ahead and available capacity 973 MW below that forecast four hours ahead. Demand reached a peak of 9135 MW at 4 pm, which exceeded the 2012 peak demand of 9079 MW.

Tight supply conditions continued from earlier in the afternoon because of the Loy Yang A unit trip, reducing wind generation (to as low as 100 MW by 4.25 pm), and two binding system normal constraints (managing the loss of the Shepparton to Bendigo 220kV line and the Dederang - South Morang 330kV line) reducing the import limit into Victoria across the VIC-NSW interconnector to less than 50 MW.

At 3.33 pm, effective from 3.40 pm, Energy Australia reduced the availability of low priced generation at its Yallourn power station unit 2 by 80 MW. The reason given for the rebid was "15:32 P mill limit". A further rebid at 3.52 pm, effective from 4 pm, saw the availability of generation priced below $50/MWh at unit 1 reduced by 60 MW for the same reason.

At 9.03 am Ecogen Energy committed Newport power station. At around 3 pm further rebids by Ecogen Energy committed Jeeralang units A 3, B1 and B2 by rebidding capacity at into low prices.
At 3.30 pm, effective from 3.40 pm, Ecogen Energy rebid 100 MW of capacity at its Newport power station priced at -$997/MWh to $11 852/MWh. The reason given for the rebid was "15:28 A redist MWs due to Vic auto constraint outcome". A further rebid at 3.50 pm, effective from 4 pm, saw 60 MW of capacity across at its Jeeralang A and B power station shifted from -$964/MWh to $12 435/MWh. The reason given was "15:48 A band adj improved auto constraint outcome Vic".

Under these conditions, to meet demand at 3.40 pm, high priced generation had to be dispatched from Dry Creek in South Australia, resulting in the 5-minute price reaching $1449/MWh. At 4 pm, high priced generation at Newport was dispatched at $11 888/MWh, resulting in the 4 pm spot price reaching $2319/MWh.

At 4.12 pm, effective at 4.20 pm, Snowy Hydro rebid 300 MW of capacity at its Laverton North power station priced at zero to $12 872/MWh. The reason for the rebid given was "16:01 A Vic: 5mpd price $1,431.45 lwr thn 5mpd 16:15@15:56".

The tight supply conditions, limited ramp rate capability, generators trapped in FCAS and small increases in demand led to five-minute dispatch interval prices reaching $12 898/MWh at 4.20 pm and $12 497/MWh at 4.25 pm.

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 $108/MWh and above $250/MWh.

Friday, 4 January

2:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1487.68	80.80	80.80
Demand (MW)	2759	2702	2599
Available capacity (MW)	3307	3498	3520
3:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2201.54	81.00	80.80
Demand (MW)	2684	2764	2622
Available capacity (MW)	3300	3485	3504
4:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2284.10	171.00	95.01
Demand (MW)	2730	2814	2710
Available capacity (MW)	3061	3424	3479
4:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4203.38	257.98	110.80
Demand (MW)	2772	2849	2779
Available capacity (MW)	3062	3396	3450

Conditions at the time saw demand close to forecast four hours ahead but available capacity up to 363 MW less than forecast four hours ahead.

Extreme weather contributed to the high demand, with the temperature in Adelaide reaching 45 degrees. This coincided with high temperatures and demand in both Victoria and Tasmania.

The high prices in South Australia were driven by the events described in Victoria (above). Both regions experienced high demand requiring higher priced generation to be dispatched to meet demand.

At around 3 pm, Torrens Island power station unit B3 tripped from around 190 MW, which reduced the availability of low priced capacity. The unit did not come back online until after 5 pm.

In addition, there was low wind generation in South Australia with as little as 135 MW at 4.25 pm. This coincided with low Victoria wind generation output and the time of peak demand in both regions.

Tasmania:

There were five occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $70/MWh and above $250/MWh.

Tuesday, 1 January

12:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2183.84	188.66	187.12
Demand (MW)	780	841	855
Available capacity (MW)	2576	2576	2576

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 12.10 am, causing the five-minute dispatch price to reach the price cap. The effects of this constraint is discussed in further detail in the 5 January event below.

Friday, 4 January

2:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1233.81	57.30	65.67
Demand (MW)	1171	1061	1062
Available capacity (MW)	2487	2497	2497
3:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1060.22	66.80	68.93
Demand (MW)	1107	1075	1071
Available capacity (MW)	2456	2497	2497

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

The high prices in Tasmania were driven by the events in Victoria and South Australia (above). Both regions experienced high demand requiring high priced generation to be dispatched and maximum exports from Tasmania.

Saturday, 5 January

10:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2188.83	194.75	198.59
Demand (MW)	1052	1030	1030
Available capacity (MW)	2499	2499	2499
11:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2182.86	40.99	196.84
Demand (MW)	1013	994	999
Available capacity (MW)	2485	2499	2499

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.

Increased flows on the Hadspen-Georgetown 220 kV line occurred during the 10.30 am and 11.30 am dispatch intervals (and during the 12.10 am 5-minute dispatch interval on 1 January). 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, with flows on Basslink reduced to levels below that required by the constraint to meet demand in Tasmania. The 5-minute dispatch price spiked to the price cap at 10.30 am and 10.50 pm, resulting in the price cap reaching $2189/MWh at 10.30 am and $2183/MWh at 11.00 pm.

With Basslink flows reduced below 50 MW the interconnector is unable to transfer FCAS, resulting in increased local requirements for these services. This also led to a significant increase in prices for raise 6 second and lower regulation prices during the subsequent dispatch intervals on 5 January, reaching up to $326/MW and $507/MW respectively.

There was no significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis

30 December - 5 January 2013

AUSTRALIAN ENERGY REGULATOR

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

Financial year	QLD	NSW	VIC	SA	TAS
2012-14 ($/MWh) YTD	58	58	66	67	49
2011-13 ($/MWh) YTD	29	31	27	35	30
Change*	98%	86%	141%	90%	63%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-14 (YTD)	5.997	100
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)
August-12	55	58	57	65	48	0.971
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
Q4 2012 (QTD)	57	55	67	60	47	2.775
Q4 2011 (QTD)	30	32	25	33	30	1.431
Q1 2013*	6563%	4917%	12323%	12726%	7977%	211,433,404.914

Table 4: ASX energy futures contract prices at end of 20 December 2013

	QLD		NSW		VIC		SA	
Q1 2013	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 20 Dec ($/MWh)	68	87	61	76	64	85	67	85
Price on 20 Dec ($/MWh)	68	87	61	76	64	85	67	85
Open Interest on 20 Dec ($/MWh)	1347	301	2163	676	1250	129	255	0
Traded in the last week (MW)	41	5	67	15	17	1	15	0
Traded since 1 Jan 12(MW)	5126	569	7803	1042	3858	209	436	0
Settled price for Q1 12 ($/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
October 12 with October 11						
MW Priced $20/MWh	-3085	-908	-2042	-48	98	-5985
MW Priced $20/MWh to $50/MWh	2830	-1652	857	-175	148	2008
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 (MTD)						
MW Priced $20/MWh	-2843	-181	-1593	-81	-196	-4894
MW Priced $20/MWh to $50/MWh	2503	-533	645	-264	64	2415

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

** Estimated value