WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

6 January – 12 January 2013

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 6 January to 12 January 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.

Queensland experienced prolonged periods of relatively high spot prices toward the end of the week. These price events were driven by hot weather that saw high demand and reduced network capability leading to congestion in central Queensland. Generator rebidding exacerbated the congestion issues and created significant price volatility. The AER's *"Special report - The impact of congestion on bidding and inter-regional trade in the NEM"* provides further detail of the congestion issues in Queensland.

Figure 1: Volume weighted average spot price by region ($/MWh)

	QLD	NSW	VIC	SA	TAS
Average price for 6 Jan - 12 Jan 2013	217	52	48	69	49
% change from previous week*	260	8	-54	-36	-29
12-13 financial YTD	64	57	66	67	49
% change from 11-12 financial YTD**	112	87	141	93	62

*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 11 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.

[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	63	2%	56 (5)	-1%	55	-1%	60	0%
Calendar Year 2014	57 (45)	0%	56 (48)	-1%	54	-1%	58	0%
Calendar Year 2015	51	0%	52	0%	48	0%	50	0%
Three year average	57	1%	55	-1%	52	-1%	56	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.

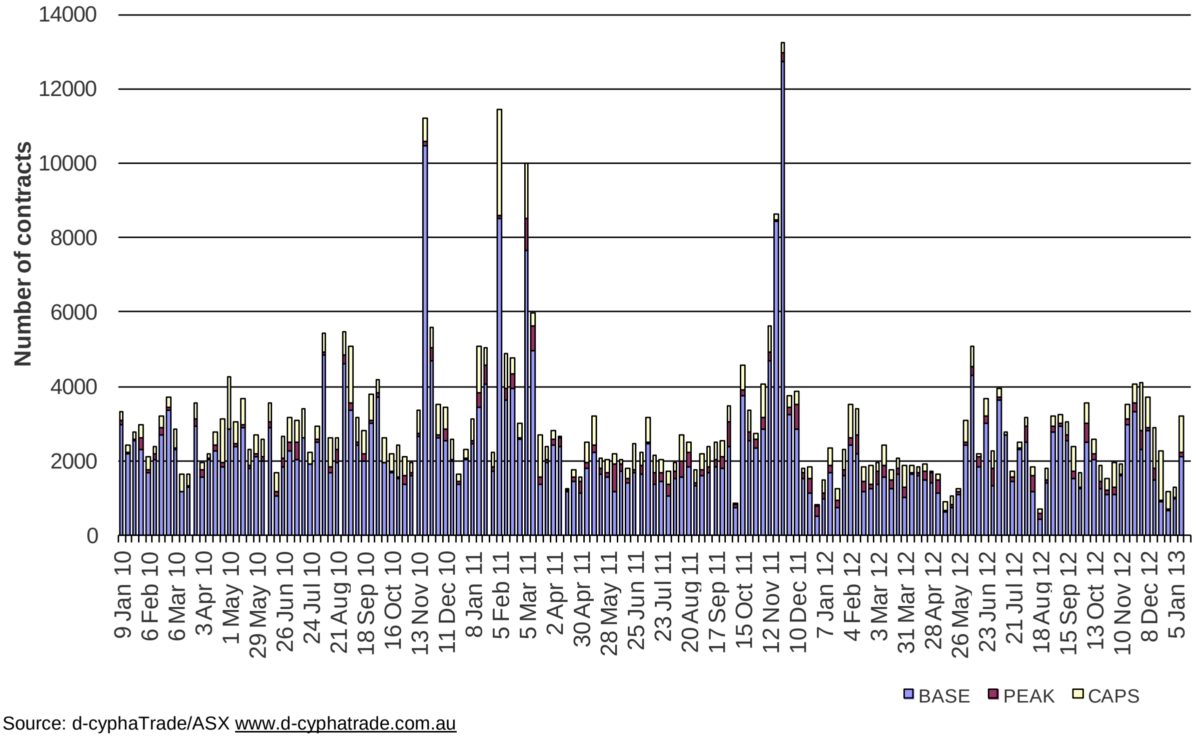
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2013	22 (182)	-8%	6 (252)	-18%	16 (228)	-6%	16 (10)	-18%
2013	8	-6%	4	-6%	6	-4%	7	-10%

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

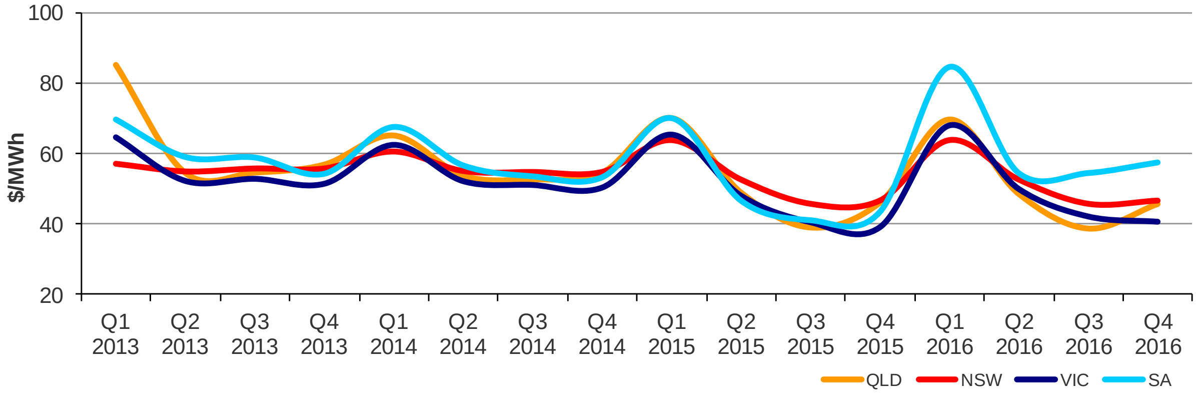


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

[4] Calculated on prices prior to rounding.

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

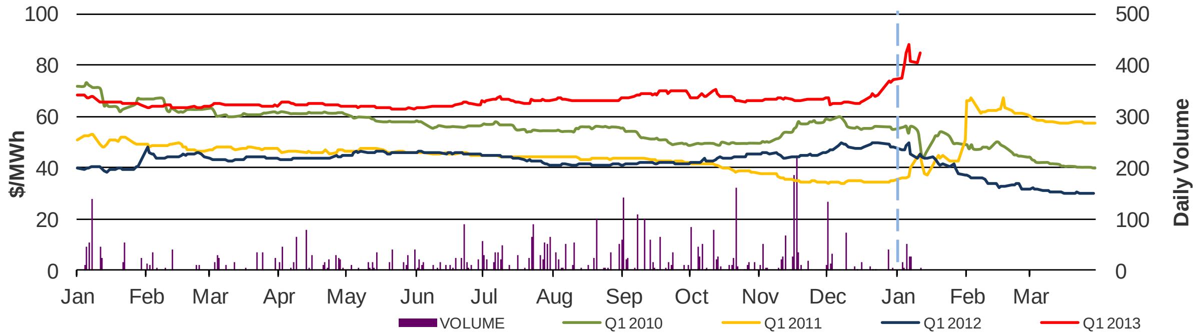
Figure 5: Quarterly base future prices Q1 2013 – Q4 2016



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

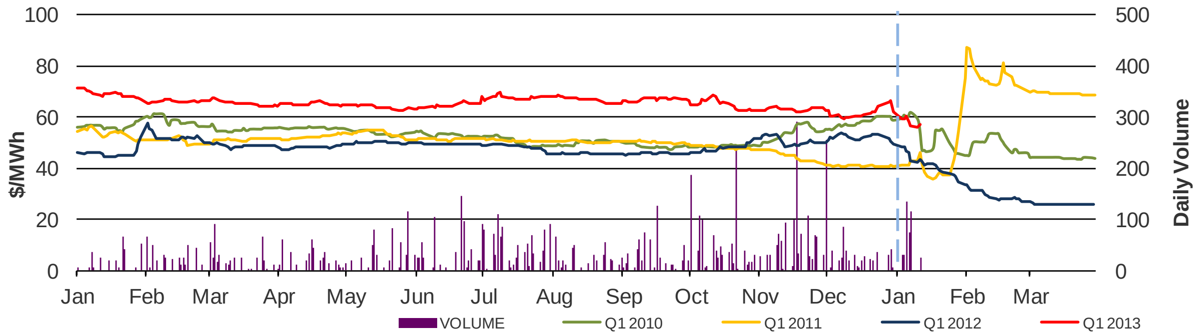
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2010, 2011, 2012 and 2013. Also shown is the daily volume of Q1 2013 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

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



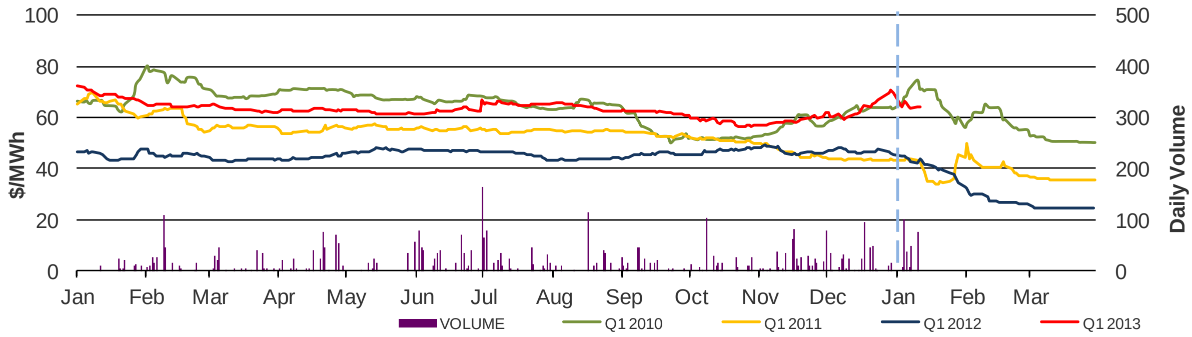
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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



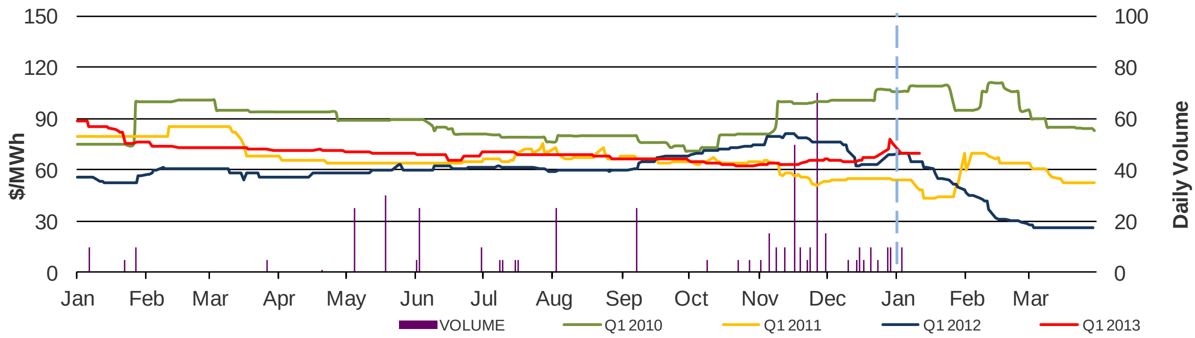
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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 291 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	4	14	0	12
% of total below forecast	52	17	0	0

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 503 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	503	-285	59	880
NSW	246	564	726	1559
VIC	17	498	409	303
SA	-120	-37	-116	7
TAS	-168	60	-279	70
Total	478	800	799	2819

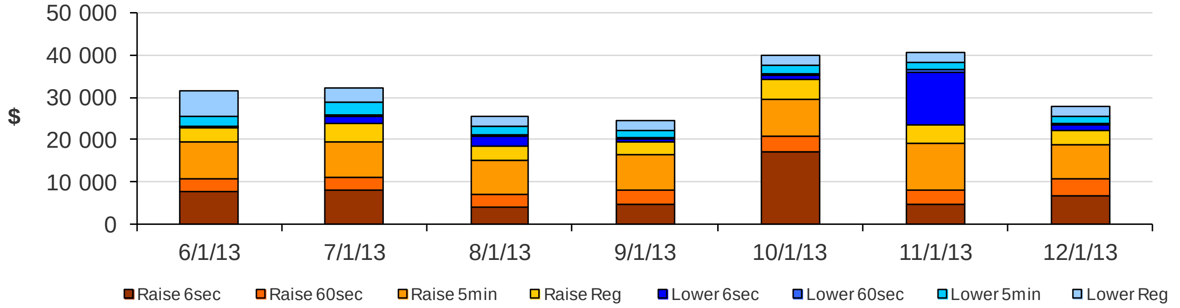
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $149 500 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $73 500 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.

6 January – 12 January 2013

Queensland:

There were twenty-three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $217/MWh and above $250/MWh.

Thursday, 10 January

4:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2228.25	160.52	495.64
Demand (MW)	8118	8108	8340
Available capacity (MW)	9471	9780	9829

Conditions at the time saw demand close to forecast and available capacity around 300 MW less than forecast four hours ahead.

At 4.10 pm, Callide C unit 4 tripped from around 410 MW with all of this capacity priced close to the price floor. Other Queensland generation at the time was either trapped in frequency control ancillary services (FCAS), at maximum output or ramp rate limited, hence higher priced generation was dispatched setting the 4.15 pm five minute dispatch price at $12 229/MWh.

In response, around 700 MW of capacity was rebid to prices at or close to the price floor (420 MW of which was previously priced greater than $9000/MWh). Some of these rebids became effective at 4.20 pm and saw the five minute price fall to around $300/MWh.

There was no other significant rebidding.

Friday, 11 January

12:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1136.20	52.37	52.23
Demand (MW)	5921	5803	5747
Available capacity (MW)	9374	9666	9504

Conditions at the time saw demand around 120 MW greater than forecast and available capacity around 290 MW less than forecast four hours ahead.

At 11.49 pm, CS Energy rebid 160 MW of capacity at Gladstone units 1 and 4 from prices below $53/MWh to the price cap. The rebid was effective from 12.05 am and the reason given was “2348P Portfolio rearrangement due to-c4 and gps 3 rts-sl”. Shortly after at 11.51 pm, effective from midnight, CS Energy reduced the ramp up and down rates at Gladstone unit 3, which was in the process of returning to service, from 5 MW/minute to 1 MW/minute. The rebid also increased the available capacity at the unit by 40 MW (to a total of 110 MW), all of which was priced at $0/MWh. The reason given was “2350P Unit ramping rebid to match-sl”.

The decrease of low priced capacity at Gladstone units 1 and 4, combined with a number of ramp rate limited units saw an increase in imports into Queensland from New South Wales by around 70 MW.

The unforecast increase in imports saw two system normal constraints bind on the QNI interconnector. One of the constraints is used to avoid voltage collapse for the loss of the largest generator, Kogan Creek, and the other to avoid overloading the Calvale to Wurdong 871 line for the loss of the Calvale to Stanwell 855 line, the “Calvale to Wurdong” constraint. More detail about the impact of the Calvale to Wurdong constraint is set out in the next section.

The binding of the Calvale to Wurdong constraint, and ramp rate limited generators saw the dispatch of higher priced generation at Gladstone unit 4 which contributed to setting the 12.05 am five minute price of $6585/MWh.

The five minute price fell to its previous level of around $50/MWh at 12.10 am when a rebid by CS Energy at Wivenhoe became effective. The rebid shifted 312 MW of capacity from the price cap to $0/MWh. The reason given was “0003A Dispatch price higher than 30min forecast-sl”.

There was no other significant rebidding.

Friday, 11 January

6:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	707.63	52.99	55.27
Demand (MW)	5871	6011	5757
Available capacity (MW)	9805	9919	9639
7:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2349.69	53.99	50.49
Demand (MW)	6150	6335	6089
Available capacity (MW)	9572	9919	9919
7:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	700.76	52.66	51.70
Demand (MW)	6495	6710	6474
Available capacity (MW)	9573	9900	9900
8:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	777.15	287.32	55.73
Demand (MW)	7011	7308	7070
Available capacity (MW)	9494	9890	9900
9:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	686.97	363.39	268.27
Demand (MW)	7308	7637	7416
Available capacity (MW)	9348	9898	9898
10:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2085.55	285.99	268.19
Demand (MW)	7378	7710	7539
Available capacity (MW)	9332	9896	9896

These high price events were related to congestion around Gladstone and were caused by a similar set of circumstances as 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.

Conditions at the time saw demand up to around 330 MW less than forecast and available capacity up to around 560 MW less than forecast four hours ahead. High temperatures saw the Calvale to Wurdong constraint bind for the majority of the morning due to significantly lower dynamic line ratings.

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.

Changes in five minute demand, rebidding and/or low priced or constrained generators being ramp rate limited, at maximum output or trapped in FCAS, contributed to the dispatch of high priced generation during various dispatch intervals during the 6.30 am to 10.00 am period. Market participants with peaking plant rebidding available capacity to zero contributed to some price outcomes.

At 6.41 am, first effective from 6.50 am, CS Energy rebid 320 MW of capacity at Gladstone, all priced between $50/MWh and $90/MWh to the price cap. The reason given was “0641P Portfolio rearrangement due to-g1 online-sl”. With lower priced capacity either constrained by the Calvale to Wurdong constraint or at maximum output, the higher priced offers at Gladstone were dispatched and contributed to setting the five minute price to $6071/MWh at 6.50 am and to $1664/MWh at 6.55 am.

For the majority of the 8.30 am trading interval, the dispatch price was around $645/MWh. At around 8.22 am, first effective at 8.30 am, Origin Energy rebid 135 MW of capacity at Darling Downs priced around $290/MWh to the price cap. The reason given was “0820P Management of fuel and linepack sl”. This saw Darling Downs receive a target to decrease its output by around 50 MW for the 8.30 am dispatch interval. Generators required to increase their output to continue to meet demand were ramp rate limited and as a result, the dispatch of higher priced generation set the price to $2001/MWh at 8.30 am.

At 9.19 am, effective only for the 9.30 am dispatch interval, CS Energy rebid 120 MW of capacity at Gladstone units 3, 4 and 6 all priced around $50/MWh to the price cap. The reason given was “0919A 855_871 constraint-sl”. Ramp rate limitations for lower priced generation saw higher priced generation at Gladstone dispatched and contributing to setting the price to $1856/MWh at 9.30 am.

At around 9.27 am, effective at 9.35 am, CS Energy extended the aforementioned rebid at Gladstone for the 10 am trading interval. The reason given was “0927A 855_871 constraint-sl”. Lower priced generation continued to be ramp rate limited and again, this higher priced generation at Gladstone was dispatched and contributing to setting the price to around $6066/MWh for the 9.35 am and 9.40 am dispatch intervals. By 9.50 am, following rebidding by other participants of capacity into lower prices and certain generators no longer being ramp rate limited, the dispatch price fell to $58/MWh.

There was no other significant rebidding.

Saturday, 12 January

6:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	878.88	175.17	44.53
Demand (MW)	5442	5539	5306
Available capacity (MW)	9617	9646	9656
9:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	715.29	115.31	63.35
Demand (MW)	6837	6729	6647
Available capacity (MW)	8981	9599	9604
10:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1002.78	199.27	175.94
Demand (MW)	6972	7093	6859
Available capacity (MW)	9272	9589	9594
2:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1336.30	203.62	207.63
Demand (MW)	7659	7530	7465
Available capacity (MW)	9161	9507	9513
3:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	778.30	227.77	255.80
Demand (MW)	7773	7596	7618
Available capacity (MW)	9105	9507	9513
3:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	898.92	227.77	255.79
Demand (MW)	7807	7716	7676
Available capacity (MW)	9094	9505	9508

4:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1589.47	345.42	265.62
Demand (MW)	7875	7776	7716
Available capacity (MW)	9052	9532	9533
4:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	675.77	345.42	227.77
Demand (MW)	7884	7828	7721
Available capacity (MW)	9096	9572	9578
6:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	821.83	455.64	285.99
Demand (MW)	7750	7738	7594
Available capacity (MW)	9054	9524	9578
6:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	861.26	285.99	217.06
Demand (MW)	7613	7526	7468
Available capacity (MW)	9052	9524	9578

For the majority of the high priced trading intervals, demand was greater than forecast four hours ahead and available capacity less than that forecast four hours ahead. Continuing hot weather, and its impact on dynamic line ratings, saw the constraints managing the Calvale to Wurdong or Calvale to Stanwell lines (Q>>NIL_855_871 or Q>>NIL_871_855) bind for all of the high priced periods.

As with the previous day's price events, the price outcomes were related to this congestion in the Gladstone region. 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

The constraint managing the Calvale to Wurdong line continued to bind interchangeably with the constraint managing the Calvale to Stanwell line for the majority of the day. Five minute dispatch prices were volatile throughout the day, with the majority of dispatch prices exceeding $200/MWh. Small changes in demand and/or last minute rebidding at times saw the five minute dispatch price spike to levels in excess of $2000/MWh for the 10.30 am, 1.45 pm, 2.55 pm, 3.30 pm, 4 pm, 5.33 pm and 6.20 pm dispatch intervals. Between 6.30 am and 6.30 pm, CS Energy rebid capacity within price bands at Gladstone 42 times, all within the trading interval or very close to the start of the trading interval, and Stanwell rebid capacity within price bands at Stanwell 136 times, 40 of these were within the trading interval. Significant contributing rebids for those dispatch intervals are set out below:

- at 9.19 am, effective for the 9.25 am and the 9.30 am dispatch interval, CS Energy rebid 90 MW of capacity at Gladstone units 3, 4 and 6 all priced at $51/MWh to the price cap. The reason given was "0918A Dispatch price higher than 30min forecast-sl". This high priced generation at Gladstone was dispatched and contributed in setting the price to $1569/MWh for both the 9.25 am and 9.30 am dispatch intervals. The 5-minute dispatch price fell to around $321/MWh for the 9.35 am dispatch interval once the Gladstone rebids ceased to be effective.
- at 10.08 am, effective at 10.15 am for the remainder of the 10.30 am trading interval, CS Energy rebid 90 MW of capacity at Gladstone units 3, 4 and 6 priced at $51/MWh to the price cap. The reason given was "1007A Dispatch price higher than 30min forecast-sl".
- at around 2.47 pm, first effective at 2.55 pm for the rest of the 3.00 pm trading interval, Stanwell rebid 320 MW of capacity across all four Stanwell units priced between around $1000/MWh and $2000/MWh to prices around $5000/MWh. The reason given was "1446A Manage q>>nil_871_855 - constrained up sl" .
- a similar rebid at Stanwell at 3.21 pm which was effective only for the 3.30 pm dispatch interval saw the five minute dispatch price reach $2261/MWh at 3.30 pm. The reason for the rebid was "1520A Manage q>>nil_855_871 - constrained up sl". The price fell to around $662/MWh in the next dispatch interval once the rebid was no longer effective
- at around 3.52 pm, effective only for the 4 pm dispatch interval, Stanwell rebid 320 MW of capacity across all four units priced between around $1000/MWh and $2000/MWh to the price cap. The reason given was "1546A Manage q>>nil_855_871 - constrained up sl".
- at around 5.24 pm, effective for the 6 pm trading interval, Stanwell rebid 240 MW of capacity priced between around $1000/MWh and $2000/MWh to prices around $5000/MWh. The reason given was "1721A manage q>>nil_855_871 - constrained up sl". The same rebid also shifted 40 MW across the four Stanwell units from prices around $1000/MWh to prices around $1600/MWh for the 6.30 pm trading interval.

At various times during the day, other market participants with peaking plant rebid their capacity unavailable to avoid short duration starts which, at times, contributed to price outcomes. There was no other significant rebidding.

Saturday, 12 January

7:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3624.84	285.99	140.92
Demand (MW)	7535	7442	7359
Available capacity (MW)	9084	9516	9583

7:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3183.13	458.58	208.15
Demand (MW)	7583	7475	7364
Available capacity (MW)	8968	9536	9585

8:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1196.24	455.64	140.92
Demand (MW)	7527	7389	7290
Available capacity (MW)	9211	9541	9590
8:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	688.24	455.23	148.43
Demand (MW)	7417	7279	7212
Available capacity (MW)	9069	9544	9580
10:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	840.92	666.89	255.85
Demand (MW)	6816	6618	6608
Available capacity (MW)	9429	9519	9580

High prices continued into the evening of Saturday 12 January. These prices were not related to network congestion in the Gladstone region, with the Calvale to Wurdong and Calvale to Stanwell lines unconstrained during this period. Prices were higher than that forecast four hours ahead, with demand between 100-200 MW higher than the four hour forecast. Available capacity was lower than forecast four hours ahead.

During the evening there was a tight supply of capacity priced below $500/MWh compared to demand. Slight variations in demand and/or rebidding of low priced capacity also contributed to a number of high five minute dispatch prices. At times some low priced generators were ramp rate limited or at maximum output, which also contributed to the dispatch of high priced generation. Five minute dispatch prices exceeded $2000/MWh for the 6.50 pm to 7.00 pm and the 7.15 pm to 7.45 pm five minute dispatch intervals, with the five minute prices for the 7.00 pm and 7.20 pm dispatch intervals reaching over $12 000/MWh.

Contributing rebids are set out below:

- at 6.45 pm, effective at 6.55 pm for the remainder of the 7 pm trading interval, Stanwell rebid 300 MW of capacity price between around $1600/MWh and $2000/MWh to prices around $5000/MWh. The reason given was “1841A Qld price higher fcast - 1845di $1595 v pd5min $659 sl”.
- at around 7.01 pm, effective at 7.10 pm for the remainder of the 7.30 pm and the 8 pm trading intervals, CS Energy rebid 210 MW of capacity from prices below $52/MWh to the price cap. The reason given was “1901A Reviewed sensitivities-sl”.
- at around 7.13 pm, effective at 7.20 pm for the remainder of the 7.30 pm trading interval, Stanwell rebid 220 MW of capacity from prices below $2000/MWh to the price cap. The reason given was “1910A Qld price lower than fcast-1915di $2001 v pd5min”.
- at around 10.03 pm, effective from 10.10 pm, CS Energy rebid 120 MW of capacity priced at $51/MWh to the price cap. The reason given was “2202A Dispatch price lower than 30min forecast-sl”.

There were no other significant rebids.

South Australia:

There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of $69/MWh and above $250/MWh.

Monday, 7 January

5:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2356.86	80.80	80.80
Demand (MW)	2775	2668	2581
Available capacity (MW)	2970	3341	3350

Conditions at the time saw demand around 100 MW greater than forecast and available capacity around 370 MW less than forecast four hours ahead.

High demand was driven by temperatures in Adelaide exceeding 40 degrees on the day. Wind generation was around 100 MW lower than forecast four hours ahead for the 5.30 pm trading interval.

At around 5.03 pm, Northern Power Station unit 1 tripped from around 270 MW. The step change in dispatch saw several generators dispatched at their maximum ramp rates and all four Torrens Island A units trapped in raise FCAS for the 5.10 pm dispatch interval. As a result a number of network constraints were violated, with imports from Victoria into South Australia on the Heywood interconnector increasing by around 60 MW to 477 MW, violating the import limit.

This saw the five minute price set at the price cap at 5.10 pm for one dispatch interval. The five minute price fell to $966/MWh at 5.15 pm, as fast start plant received instructions to start and the constraints no longer violated.

There was no significant rebidding.

Tasmania:

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $49/MWh and above $250/MWh.

Sunday, 6 January

1:00 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2180.96	196.03	198.59
Demand (MW)	996	999	985
Available capacity (MW)	2471	2499	2499

At 12.55 am increased flows across the Hadspen-George Town 220kV lines saw the network special protection scheme (NCSPS) constraint become active. The NCSPS constraint is used to manage the post-contingent loading on one of the Hadspen-George Town lines.

To satisfy the constraint, it required the increase of exports into Victoria, reduction in output from generating units in eastern and southern Tasmania and an increase from generating units in western and southern Tasmania. However, the output of a number of generators was unable to be changed sufficiently to satisfy the constraint due to ramp rate limitations, with the constraint violating during the 12.55 am dispatch interval. This saw the five minute price set to the price cap for the dispatch interval.

A demand side response of around 130 MW saw the price fall to $30/MWh at 1 am and the constraint no longer violated with exports to Victoria on Basslink increasing to around 125 MW.

There was no significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
6 January - 12 January 2013

AUSTRALIAN ENERGY REGULATOR

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

Financial year	QLD	NSW	VIC	SA	TAS
2012-13 ($/MWh) YTD	64	57	66	67	49
2011-12 ($/MWh) YTD	30	31	27	35	30
Change*	112%	87%	141%	93%	62%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 YTD	6.384	104
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	157	51	80	94	62	0.598
Q1 2013 QTD	157	51	80	94	62	0.598
Q1 2012 QTD	44	24	23	26	35	0.195
Change*	258%	110%	240%	261%	78%	2.070

Table 4: ASX energy futures contract prices at end of 11 January 2013

	QLD		NSW		VIC		SA	
Q1 2013	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 4 Jan ($/MWh)	81	110	59	74	66	94	70	85
Price on 11 Jan ($/MWh)	85	118	57	67	64	93	70	85
Open Interest on 11 Jan ($/MWh)	1428	317	2326	688	1301	175	270	0
Traded in the last week (MW)	107	0	349	12	171	76	0	0
Traded since 1 Jan 12 (MW)	5259	574	8260	1057	4088	285	481	0
Settled price for Q1 12 ($/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	-2722	-2788	-1132	145	-110	-6607
MW Priced $20/MWh to $50/MWh	2121	1401	1124	-325	329	4650

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

** Estimated value