Electricity spot prices
above $5000/MWh

7 December 2009
New South Wales

AUSTRALIAN ENERGY REGULATOR

Introduction

The AER is required to publish a report whenever the electricity spot price exceeds $5000/MWh.[1] The report:

- describes the significant factors contributing to the spot price exceeding $5000/MWh, including factors such as withdrawal of generation capacity and network availability;
- assesses whether rebidding contributed to the spot price exceeding $5000/MWh;
- identifies the marginal scheduled generating units; and
- identifies all units with offers for the trading interval equal to or greater than $5000/MWh and compares these dispatch offers to relevant dispatch offers in previous trading intervals.

Summary

On Monday 7 December 2009, the spot price in New South Wales exceeded $5000/MWh for six out of eight trading intervals between 12 pm and 3.30 pm inclusive. These prices were significantly higher than forecast.

The temperature in western Sydney reached 40°C with demand reaching a maximum of 12 808 MW[2] at 4 pm, which was slightly higher than forecast.

A 'system normal' transmission network constraint reduced the dispatch of low-priced generation and imports from Victoria and Queensland between 11 am and 5 pm. The market impact of this constraint was made significantly worse following rebidding by Delta Electricity—initially by shifting capacity into higher prices and then reducing its generator ramp rates and maximum availability. The effects of the constraint and Delta's behaviour are explored in detail in this report.

A planned transmission network outage between Sydney West and Yass exacerbated the impact of the system normal constraint until midday, when the line was returned to service earlier than forecast.

Actual and forecast demand and price

Figure 1 compares, for the high-priced period, the actual demand and spot price in New South Wales with that forecast by the Australian Energy Market Operator (AEMO) four and 12 hours ahead of dispatch.

Conditions during the high-priced period saw demand up to 450 MW higher than forecast. With the exception of the 3.30 pm trading interval, actual prices were also significantly higher than forecast. Available capacity was close to forecast during the period.

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[1] This requirement is set out in clause 3.13.7 (d) of the National Electricity Rules.
[2] This compares to record summer demand in New South Wales of 14 097 MW on 6 February 2009.

Figure 1: Actual and forecast demand and spot price in New South Wales

12:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	11 783	11 370	11 240
Spot price ($MW/h)	7715	39	38
12:30 PM*	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	11 921	11 469	11 400
Spot price ($MW/h)	714	88	45
1:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12 020	11 621	11 581
Spot price ($MW/h)	5024	116	49
1:30 PM*	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12 184	11 963	11 728
Spot price ($MW/h)	1806	344	90
2:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12 410	12 099	11 932
Spot price ($MW/h)	9060	432	120
2:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12 463	12 287	12 122
Spot price ($MW/h)	9176	3406	120
3:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12 608	12 411	12 240
Spot price ($MW/h)	9134	3406	120
3:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12 733	12 556	12 381
Spot price ($MW/h)	6308	7952	120
4:00 PM*	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12808	12573	12402
Spot price ($MW/h)	4016	3406	120
4:30 PM*	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12683	12439	12274
Spot price ($MW/h)	1656	643	120
5:00 PM*	**Actual**	**4 hr forecast**	**12 hr forecast**
Demand (MW)	12556	12226	12068
Spot price ($MW/h)	1177	508	120

* Trading intervals with spot prices less than $5000/MWh are included to show the price trend during the high-priced period.

Generator offers and rebidding

Day ahead offers

Around 13 300 MW[3] of capacity was offered through initial offers (the day ahead) for the New South Wales region. Around 11 760 MW (or 88 per cent) of this capacity was initially priced at less than $300/MWh with the remaining 1540 MW priced at above $8800/MWh.

With no capacity priced between $300/MWh and $8800/MWh, any reductions in import capability, rebidding of capacity into high price bands or increases in demand, had the potential to result in a significant jump in the spot price.

Rebidding activity

At 8.21 am, Delta Electricity rebid a total of 330 MW of capacity across Munmorah unit three, Mount Piper units one and two, Vales Point units five and Wallerawang unit seven, from prices below $115/MWh to above $8600/MWh. The reason given was “0802A Predispatch price change $119 VS $230::Band Shift”. This rebid was effective from the 1 pm trading interval to the 5 pm trading interval. Following this rebid the forecast prices for

[3] Summer rating capacity in New South Wales is 15 900 MW.

the afternoon increased significantly—for example the 3.30 pm trading interval increased from $230/MWh to $4000/MWh.

Over several rebids from 7.05 am, Snowy Hydro rebid the total capacity of Tumut three and Upper Tumut—a total of around 2000 MW—to prices below $1/MWh. The majority of this capacity was originally priced above $120/MWh. The reasons given were:

> *"07:05 A NSW: 5MIN Actual dem 485 higher than 30min pd 06:32 FO"*
> *"09:06 A NSW: 5M pd dem 460 hghr thn 30m pd 08:32 for 9:20"*
> *"10:21 A prvnt constrnd off at Tumut by N>>N-NIL__S at 9.30 am"*
> *"10.55 A NSW: 5 min dem 445 hghr thn 30m pd 10.02 for 10.55"*
> *"11.11 A NSW: 5M pd price $9,208 hghr thn 30m pd 11.02 for 11:5"*
> *"11.25 A NSW: 5M A ct price $460 hghr thn 30m pd 10.32 for 11"*
> *"12:21:P Match bid to output"*
> *"12:59:A prvt being constrnd off in dispatch"*.

These rebids caused the dispatch of Tumut to increase from zero at 11 am to 1340 MW at 11.30 am, 1120 MW greater than was forecast four hours ahead.

Over several rebids from 9.28 am Origin Energy rebid the total capacity of Uranquinty (664 MW) from prices above $9300/MWh into prices below $55/MWh. The reasons given were "0900 EST (N) Change in PDS", "1025 EST Change in PDS" and "1050 ETS (P) Constraint management". These rebids were effective from 11 am until late afternoon. These rebids resulted in the output from Uranquinty increasing from zero at 11 am to 664 MW by 11.50 am (four hours ahead, Uranquinty was forecast to be off).

However, at around 11.50 am, Origin's Energy's Uranquinty unit three tripped. At the time it was generating 166 MW. All of this capacity was priced below zero. This unit was returned to service at 3.35 pm.

Network constraints

The increase in output from both Uranquinty and Snowy Hydro contributed to a reduction in imports from Victoria into New South Wales compared to forecast.

Other rebidding

In an apparent response to the emerging network issues, at 10.31 am, Delta Electricity rebid the ramp rates of Mount Piper units one and two. The rebid took effect from 12.35 pm and reduced the 'ramp down rate' on each unit from 5 MW/min, to the minimum allowable level of 3 MW/min[4]. At the same time, the 'ramp up rate' on each unit was increased from 5 MW/min to 10 MW/min. The reason given was "1030P Line constraint management:ROC Change". A further rebid at 1.19 pm, effective from 1.35 pm, reduced the available capacity at Wallerawang unit seven by 200 MW (all of this capacity was priced at above $9200/MWh). The reason given was "1318P Dust Burdens – ET5hrs::capacity limit". The Wallerawang capacity was restored at 6.30 pm. The reduction in the 'ramp down rate' at Mount Piper and the reduction in availability at Wallerawang had a significant impact on constraint management in the vicinity of these stations, and led to a significant change in dispatch and price outcomes. This is explained further in the "Changes to network availability" section of this report.

[4] Clause 3.8.3A(b) of the Electricity Rules states that Scheduled Generators must provide a ramp down rate to AEMO of at least the lower of 3 MW per minute or 3 per cent of the full capacity of the Scheduled unit. Refer to the AER Rebidding and Technical Parameter Guideline for more information at www.aer.gov.au.

A number of rebids by other participants (including the later rebids by Origin Energy and Snowy Hydro detailed above) were in response to changes in dispatch when network constraints began to bind following the Delta Electricity rebids. At 11.25 am, Macquarie Generation rebid 1430 MW of capacity at Bayswater into negative price bands. The reason given was “1120 constraint management”. Around 15 minutes later, Macquarie Generation rebid the ramp rates at the four Bayswater units and Liddell units one, two and four to reduce the impact of these constraints on its dispatch. The ‘ramp down rate’ on each of the Bayswater units was reduced by 1 MW/min, to the minimum allowable level of 3 MW/min and the ‘ramp up rate’ on each of the Bayswater and Liddell units was increased by 2 MW/min (to 6 MW/min). The reason given was “1135 constraint management”.

There was no other significant rebidding.

A list of generators involved in setting the price during the high-price period, and how that price was determined by the market systems, is detailed in **Appendix A**.

The closing bids for all participants in New South Wales with capacity priced at or above $5000/MWh for the high-price period are presented in **Appendix B**.

Changes to network availability

During the period of high prices flows into New South Wales from Queensland (across the QNI and Terranora interconnectors) and Victoria (across the VIC-NSW interconnector) were at their limits but at much lower levels than the nominal capacity[5]. This was largely as a result of the rebids discussed earlier. This issue is explored further in the “Transmission constraints” section of this report.

Figure 2 shows the difference between actual combined import capability into New South Wales from Victoria and Queensland and forecast capability four and 12 hours ahead of dispatch. For the 12 pm to 3 pm trading intervals, combined import capability into New South Wales was up to 2200 MW lower than forecast twelve hours ahead and up to 1900 MW lower than forecast four hours ahead. For the 3 pm and 3.30 pm trading intervals there was an increase in flows into New South Wales across the Victoria to New South Wales interconnector compared to forecast four hours ahead. This was related to the early return to service of the Sydney West to Yass line, which was out for planned maintenance (this is explained further below).

Figure 2: Forecast versus actual import capability into New South Wales (MW)

Time	Actual import limit	4 hr forecast	Difference	12 hr forecast	Difference
12:00 pm	-102	1627	-1729	2179	-2281
12:30 pm	-63	1923	-1986	2110	-2173
1:00 pm	160	1417	-1257	1918	-1758
1:30 pm	479	1473	-994	2235	-1756
2:00 pm	587	1404	-817	2305	-1718
2:30 pm	736	943	-207	2212	-1476
3:00 pm	879	466	413	2135	-1256
3:30 pm	1199	541	658	2029	-830

[5] Nominal limits for flows into New South Wales are: QNI 1078 MW; Terranora 245 MW and VIC-NSW 1800 MW

A planned outage of the Sydney West to Yass 330 kV line commenced at 4.30 am and was originally scheduled to be completed by 6.30 pm. This outage had been planned since 25 November. At around midday, Transgrid increased the ratings of network elements involved in the network constraints used to manage this outage. This allowed an increase in imports from Victoria and dispatch of generation from Uranquinty and Tumut stations. As a result, the New South Wales price fell significantly for a number of dispatch intervals. At 1 pm the line was returned to service, and once again the New South Wales price fell when imports into New South Wales increased by more than 500 MW[6].

From July 2009, Transgrid has been participating in the AER's new Service Target Performance Incentive Scheme, which includes a "market impact" component that aims to reduce the impact of network outages on market outcomes. Transgrid's early return to service of this network element improved market outcomes and is consistent with the objectives of the scheme.

Transmission constraints

In optimising economic generation dispatch and interconnector flows, the National Electricity Market Dispatch Engine (NEMDE) takes into account the maximum network capability that applies at the time. These network constraints are represented as constraint equations that describe the maximum capability of each network element and include generator and interconnector coefficients. The magnitude of a coefficient gives an indication of the significance of the generating unit or interconnector in managing the network limitation (the larger the coefficient the more significant the unit or interconnector). A positive coefficient means that a unit or interconnector is 'constrained-off'[7] if the constraint is binding, where a negative coefficient means a generator is 'constrained-on'[8].

The system normal constraint N>>N-NIL__S[9] bound for much of 7 December[10]. This constraint was managing flows across one of the Mt Piper to Wallerawang 330 kV lines in the event of the loss of the second Mt Piper to Wallerawang line. Figure 3 is a simplified representation of the transmission network in New South Wales, highlighting the flow paths into the regional reference node at Sydney West, the interconnectors and significant generation stations. Also shown are the relevant coefficients for the stations according to the N>>N-NIL__S constraint.

[6] The import limit increased from zero to 514 MW at 12.10 pm (the first dispatch interval after the constraints were revoked). The actual limit prior to this time was negative (forcing flows out of New South Wales), but AEMO had constraints in place to manage negative settlement residues that stopped counter-priced flows into Victoria.

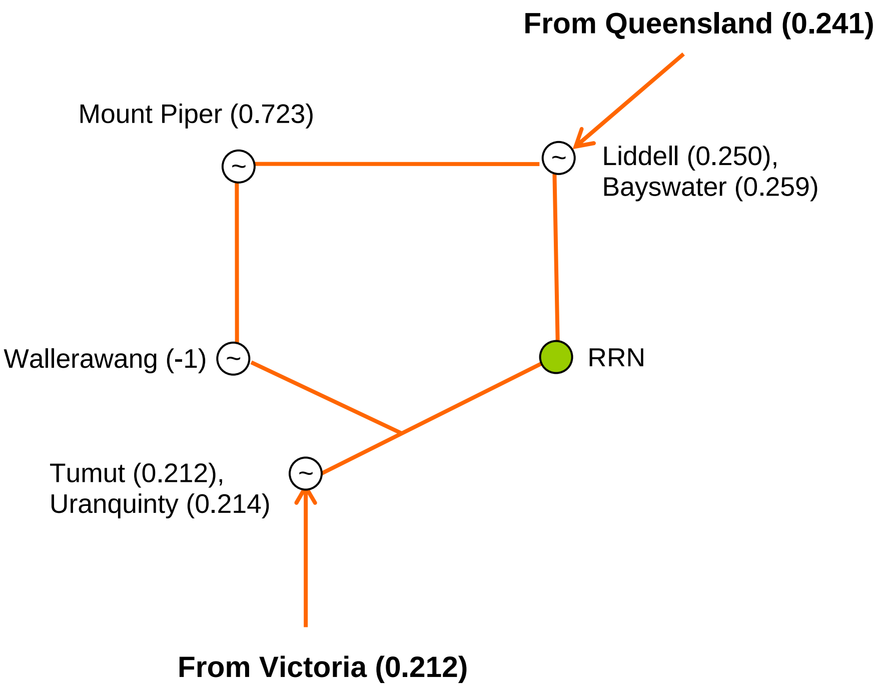
[7] Network constraints can cause generators to be dispatched at a price that is lower than its offer price (constrained-on) or generators to not be dispatched even though its offer price is lower than the regional price (constrained-off).

[8] This is the case where flows must be less than or equal to a given network capability.

[9] Constraint equations are mathematical expressions used in the dispatch engine to describe the physical limitations of the power system. System normal constraints are used when the network is operating in its normal network configuration. The N>>N-NIL__S constraint affects up to 11 700 MW of generation capacity (27 units) in New South Wales, and all three interconnectors into New South Wales.

[10] When a constraint binds it effects economic dispatch and causes generators to be constrained-on or off.

Figure 3: Simplified transmission network in New South Wales



The N>>N-NIL__S constraint is designed to prevent the Mt Piper to Wallerawang line from overloading, which is consistent with Wallerawang and Mount Piper having the largest coefficients. In general, power flows from Mount Piper to Wallerawang. The direction of the power flow means that to avoid overloading it is necessary to increase or constrain-on the Wallerawang units (with a -1 coefficient) and reduce or constrain-off the Mount Piper units (with a 0.723 coefficient). Other generators can also influence flows across this line, but to a lesser extent (e.g. Bayswater with a 0.259 coefficient is likely to be constrained-off ahead of Liddell with a coefficient of 0.250, as it has a larger coefficient). The amount and rate at which a generator is constrained-on or off is, however, limited by the availability and ramp rate offered by those generators. The interconnectors may also be constrained-off in order to satisfy this constraint (with coefficients of 0.212 and 0.241), but unlike generators, there is no ramp rate for interconnectors. Interconnectors are also able to reverse in flow direction (unlike generators), which means at times constraints can force flows from a high-priced to a low-priced region (or counter price).

The Mount Piper and Wallerawang units' coefficients are much greater than those for other generators or interconnectors, given their proximity to the network elements in question. If the ability to 'constrain-on' or 'constraint-off' these units is limited (for example, due to low ramp rates), then other generators and interconnectors will need to be constrained, but by a larger amount (three to four times more) to manage flows on the network.

There were two rebids from Delta Electricity at Mount Piper and Wallerawang that are relevant to this issue:

1. At 10.30 am Delta Electricity reduced the 'ramp down rates' of Mount Piper. Due to Mount Piper's ramp rate being lowered, other generators and interconnectors were required to be constrained-off so that the constraint was not breached. However the lower coefficients of other generators meant that the total impact on dispatch outcomes was far worse.[11]
2. From around 1 pm Delta Electricity reduced the available capacity at Wallerawang unit seven by 200 MW. As output from Wallerawang was increasing at the time due to the constraint, a reduction in availability meant that the other generators in New South Wales and the interconnectors were required to be **reduced** to avoid the constraint being breached.[12] However, the lower coefficients of other generators meant that the total impact on dispatch outcomes was far worse.

Clause 3.8.3A(b) of the Electricity Rules states that Scheduled Generators must provide a 'ramp down rate' to AEMO of at least the lower of 3 MW per minute or three per cent of the full capacity of the Scheduled unit. This is a recent change to the Rules following a rule change proposal from the AER. Prior to this change, generators were permitted to bid as low as 1 MW per minute. If Delta Electricity had bid at a 'ramp down rate' of only 1 MW per minute, the market impact would have been even worse.

With the return of the Sydney West to Yass line at 1 pm, network congestion was relieved. As a result, generators that were constrained-off were able to be increased towards unconstrained dispatch levels. The Mount Piper units' dispatch increased from around 579 MW at 1.05 pm to 660 MW at 1.20 pm. This rapid increase was possible, as the Mount Piper units had increased their 'ramp up rates' to 10 MW/min through rebidding. When the constraint bound again, however, Mount Piper was constrained-off (between 1.30 pm and 5 pm), but at the lower rate of 3 MW/min. During this period there were further significant impacts on other New South Wales generators, (with around 600 MW of low-priced generation constrained-off) and limitations on the interconnectors that limited imports into New South Wales.

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[11] The coefficient of Mount Piper is 0.723 and Bayswater is 0.259. The rebid reduced the rate at which Mount Piper could be constrained-off from 300 MW per hour (5 MW/min) to 3 MW/min or 180 MW per hour. If the constraint required Mount Piper to reduce by 300 MW in one hour it would only reduce Mount Piper by 180 MW (due to its limiting ramp down rate) and would need to reduce say Bayswater by (0.723/0.259 x 120 MW) 335 MW, a total reduction in generation of 515 MW. Alternatively the constraint could reduce imports from Victoria by (0.723/0.212 x 120 MW) 409 MW, a total reduction in supply of 589 MW. Each of these is a greater impact on dispatch outcomes than just reducing the output of Mount Piper by 300 MW.

[12] A 200 MW reduction in available capacity at Wallerawang meant that other generators, say Bayswater would need to reduce its generation by a further (-1/0.259 x 200 MW) 772 MW, which is almost a four-fold increase in the impact on dispatch.

Flows across Victoria to New South Wales interconnector decreased from 900 MW at 11 am (into New South Wales) to 175 MW into Victoria at 12 pm. At the time, prices in New South Wales were higher than in Victoria, resulting in counter-price flows and the consequent accrual of negative settlement residues[13]. The combined flows across the Terranora and QNI interconnectors also decreased from 349 MW at 11 am (into New South Wales) to 244 MW into Queensland at 11.30 am. At the time prices in New South Wales were also higher than in Queensland, resulting in counter-price flows and the consequent accrual of negative settlement residues.

From around 11.50 am, AEMO invoked a number of constraints to minimise the accrual of negative settlement residues. The constraint to restrict flows across the Victoria to New South Wales interconnector was invoked for two periods from 11.50 am to 12.05 pm and 12.25 pm to 1.25 pm[14]. The constraints to restrict flows across the New South Wales to Queensland interconnectors were all revoked by 3.30 pm.

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[13] When a region exports to a higher priced region the generators in the exporting region do not receive the higher price paid by customers in the importing region; they receive the lower price that prevails in their region. This causes a surplus of funds to build up, known as inter-regional settlement residues (IRSRs), which are collected by AEMO. Units corresponding to shares of IRSRs are auctioned to market participants as a hedge against inter-regional price differences. This facilitates inter-regional trading. On occasion, however, power flows from higher-priced regions to lower-priced regions. In this case, “negative settlement residues” may accrue between two regions. Since AEMO has a limited means for funding large negative residues, AEMO takes action to prevent the accumulation of negative settlement residues when they would otherwise arise.

[14] Around $586 000 of negative settlement residues were accumulated on the day, $356 000 of which accrued across the New South Wales to Queensland interconnector (into Queensland) and around $230 000 was accrued across the Victoria to New South Wales interconnector (into Victoria). AEMO invoked constraints on both interconnectors at 11.55 am, which remained until 1.25 pm on Victoria to New South Wales and until around 3.30 pm on QNI. The constraints limited export out of New South Wales to zero.

Appendix A – Price setters for 7 December 2009

The following table identifies, for each of the trading intervals above $5000/MWh, each five minute dispatch interval price and the generating units involved in setting the energy price. Also shown is the energy (or ancillary service) offer price involved in determining the dispatch price and the contribution to the total energy price. Frequency control ancillary services (FCAS) can contribute to the energy price when in order for a unit to be dispatched for energy its dispatch in FCAS is altered and this must be made up by another unit. The column labeled "marginal change" shows the quantity of the service that is dispatched to meet an increment of demand at the regional reference node. The 30-minute spot price is the average of the six dispatch interval prices. This information is published by AEMO[15].

New South Wales – 12 noon

Time	Dispatch price	Participant	Unit	Service	Offer price	Marginal change	Contribution
11:35	$9900.00	Eraring Energy	ER03	Energy	$9900.00	0.33	$3299.97
		Eraring Energy	ER02	Energy	$9900.00	0.33	$3299.97
		Eraring Energy	ER01	Energy	$9900.00	0.33	$3299.97
11:40	$8148.00	Tarong	TARONG#1	Energy	$20.91	8.06	$168.56
		Macquarie Generation	BW01	Energy	-$1000.00	-3.99	$3989.71
		Macquarie Generation	BW02	Energy	-$1000.00	-3.99	$3989.71
11:45	$9244.50	Macquarie Generation	BW02	Energy	-$1000.00	-2.99	$2994.37
		Macquarie Generation	BW01	Energy	-$1000.00	-2.99	$2994.37
		Macquarie Generation	BW03	Energy	-$1000.00	-2.99	$2994.37
		Delta Electricity	WW7	Lower reg	$1.00	-9.24	-$9.24
		Stanwell	GSTONE1	Lower reg	$0.99	9.24	$9.14
		Stanwell	GSTONE1	Energy	$28.31	9.24	$261.45
11:50	$496.81	Tarong	TARONG#3	Energy	$20.93	1.33	$27.81
		CS Energy	SWAN_B_3	Raise 5 min	$0.75	-0.44	-$0.33
		Delta Electricity	MP1	Raise 5 min	$0.50	0.44	$0.22
		Delta Electricity	MP1	Energy	-$1000.00	-0.47	$469.11
11:55	$9250.01	Eraring Energy	ER02	Energy	$9250.01	0.50	$4625.01
		Eraring Energy	ER01	Energy	$9250.01	0.50	$4625.01
12:00	$9250.00	Eraring Energy	ER03	Energy	$9250.00	1.00	$9250.00
Spot price		**$7715/MWh**					

New South Wales – 1 pm

Time	Dispatch price	Participant	Unit	Service	Offer price	Marginal change	Contribution
12:35	$20.95	Eraring Energy	ER01	Energy	$20.95	0.33	$6.98
		Eraring Energy	ER03	Energy	$20.95	0.33	$6.98
		Eraring Energy	ER02	Energy	$20.95	0.33	$6.98
12:40	$1695.16	Delta Electricity	WW7	Energy	$9500.00	0.18	$1679.03
		LYMMCO	LYA4	Energy	$19.20	0.84	$16.12
12:45	$8803.58	Delta Electricity	VP6	Energy	$8803.58	0.50	$4401.79
		Delta Electricity	VP5	Energy	$8803.58	0.50	$4401.79
12:50	$2015.75	Snowy Hydro	UPPTUMUT	Energy	$0.00	-0.16	$0.00
		Origin Energy	MSTUART1	Energy	$101.45	1.38	$139.86
		Macquarie Generation	BW04	Energy	-$1000.00	-1.74	$1736.01
		Origin Energy	MSTUART3	Energy	$101.45	1.38	$139.86
12:55	$8803.58	Delta Electricity	VP6	Energy	$8803.58	0.50	$4401.79
		Delta Electricity	VP5	Energy	$8803.58	0.50	$4401.79
13:00	$8803.58	Delta Electricity	VP6	Energy	$8803.58	0.50	$4401.79
Spot price		**$5024/MWh**					

15 Details on how the price is determined can be found at www.aemo.com.au

New South Wales – 2 pm

Time	Dispatch price	Participant	Unit	Service	Offer price	Marginal change	Contribution
13:35	$8803.58	Delta Electricity	VP6	Energy	$8803.58	0.50	$4401.79
		Delta Electricity	VP5	Energy	$8803.58	0.50	$4401.79
13:40	$8803.58	Delta Electricity	VP6	Energy	$8803.58	0.50	$4401.79
		Delta Electricity	VP5	Energy	$8803.58	0.50	$4401.79
13:45	$9250.01	Eraring Energy	ER02	Energy	$9250.01	0.50	$4625.01
		Eraring Energy	ER01	Energy	$9250.01	0.50	$4625.01
13:50	$9250.00	Eraring Energy	ER03	Energy	$9250.00	1.00	$9250.00
13:55	$9250.00	Eraring Energy	ER03	Energy	$9250.00	1.00	$9250.00
14:00	$9000.00	Delta Electricity	MM3	Energy	$9000.00	1.00	$9000.00
Spot price		**$9060/MWh**					

New South Wales – 2.30 pm

Time	Dispatch price	Participant	Unit	Service	Offer price	Marginal change	Contribution
14:05	$8803.58	Delta Electricity	VP6	Energy	$8803.58	1.00	$8803.58
14:10	$9250.00	Eraring Energy	ER03	Energy	$9250.00	1.00	$9250.00
14:15	$9250.00	Eraring Energy	ER03	Energy	$9250.00	1.00	$9250.00
14:20	$9250.01	Eraring Energy	ER02	Energy	$9250.01	0.50	$4625.01
		Eraring Energy	ER01	Energy	$9250.01	0.50	$4625.01
14:25	$9250.01	Eraring Energy	ER01	Energy	$9250.01	0.50	$4625.01
		Eraring Energy	ER02	Energy	$9250.01	0.50	$4625.01
14:30	$9250.01	Eraring Energy	ER02	Energy	$9250.01	0.50	$4625.01
		Eraring Energy	ER01	Energy	$9250.01	0.50	$4625.01
Spot price		**$9176/MWh**					

New South Wales – 3 pm

Time	Dispatch price	Participant	Unit	Service	Offer price	Marginal change	Contribution
14:35	$9000.00	Delta Electricity	MM3	Energy	$9000.00	1.00	$9000.00
14:40	$9250.00	Eraring Energy	ER03	Energy	$9250.00	1.00	$9250.00
14:45	$9250.00	Eraring Energy	ER03	Energy	$9250.00	1.00	$9250.00
14:50	$8804.28	Delta Electricity	VP5	Raise 5 min	$0.10	-1.00	-$0.10
		Delta Electricity	VP5	Energy	$8803.58	1.00	$8803.58
		TRUenergy (SA)	TORRB3	Raise reg	$0.80	1.00	$0.80
14:55	$9250.01	Eraring Energy	ER02	Energy	$9250.01	0.50	$4625.01
		Eraring Energy	ER01	Energy	$9250.01	0.50	$4625.01
15:00	$9250.01	Eraring Energy	ER02	Energy	$9250.01	0.50	$4625.01
		Eraring Energy	ER01	Energy	$9250.01	0.50	$4625.01
Spot price		**$9134/MWh**					

New South Wales – 3.30 pm

Time	Dispatch price	Participant	Unit	Service	Offer price	Marginal change	Contribution
15:05	$8804.26	Delta Electricity	VP5	Lower reg	$1.40	-0.83	-$1.17
		Delta Electricity	VP5	Raise reg	$0.10	-1.00	-$0.10
		Delta Electricity	VP5	Energy	$8803.58	1.00	$8,803.58
		Eraring Energy	ER03	Raise reg	$0.70	1.00	$0.70
		CS Energy	CALL_B_1	Lower reg	$1.50	0.83	$1.25
15:10	$8804.57	Delta Electricity	VP6	Raise 5 min	$0.10	-1.00	-$0.10
		Delta Electricity	VP6	Raise 60 sec	$0.10	-1.00	-$0.10
		Delta Electricity	VP6	Energy	$8803.58	1.00	$8,803.58
		Stanwell	GSTONE1	Raise reg	$0.94	1.00	$0.94
		Eraring Energy	ER03	Raise 60 sec	$0.25	1.00	$0.25
15:15	$8000.00	Delta Electricity	CG2	Energy	$8000.00	1.00	$8,000.00
15:20	$8000.00	Delta Electricity	CG2	Energy	$8000.00	1.00	$8,000.00
15:25	$2120.87	Delta Electricity	WW7	Energy	$9500.00	0.20	$1,878.82
		Ecogen	NPS	Energy	$20.70	0.03	$0.67
		Stanwell	GSTONE3	Energy	$295.00	0.82	$241.39
15:30	$2120.77	Delta Electricity	WW7	Lower reg	$1.00	0.20	$0.20
		Delta Electricity	WW7	Energy	$9500.00	0.20	$1,878.63
		International Power	PPCCGT	Energy	$29.69	0.03	$0.91
		Delta Electricity	MP1	Lower reg	$1.40	-0.20	-$0.28
		Stanwell	GSTONE3	Energy	$295.00	0.82	$241.33
Spot price		**$6308/MWh**					

Appendix B – Closing bids

Figures B1 to B3 highlight the half hour closing bids for participants in New South Wales with capacity priced at or above $5000/MWh during the trading intervals in which the spot price exceeded $5000/MWh. The figures also show the generation output of the relevant participants and the spot price.

Figure B1: Delta Electricity closing bid prices, dispatch and spot price

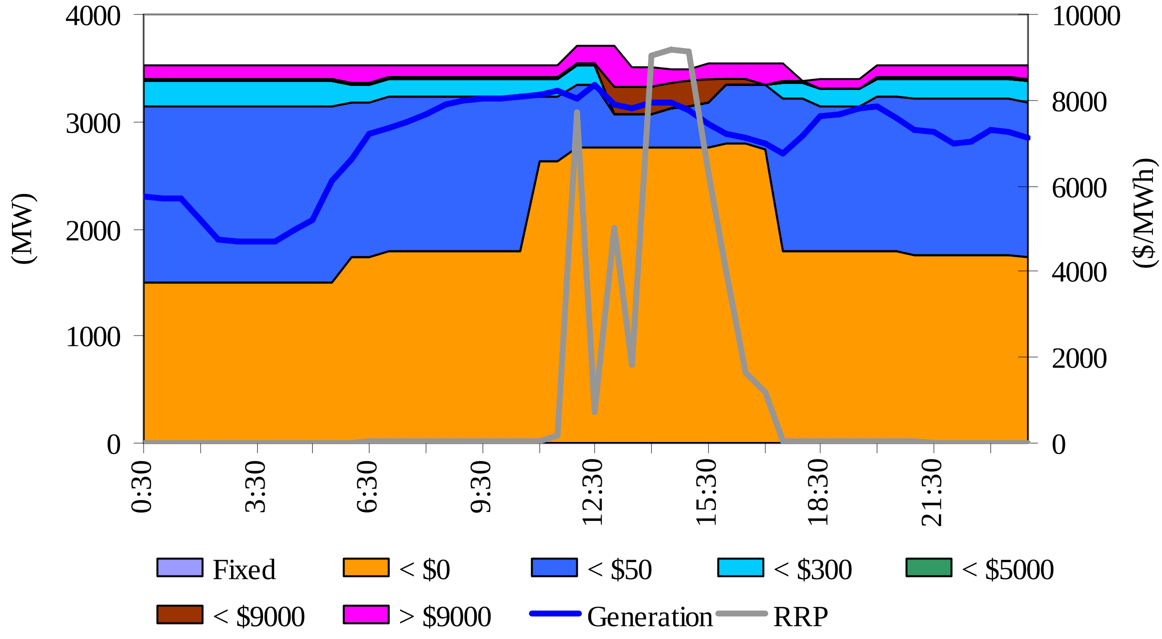

Figure B2: Eraring Energy closing bid prices, dispatch and spot price

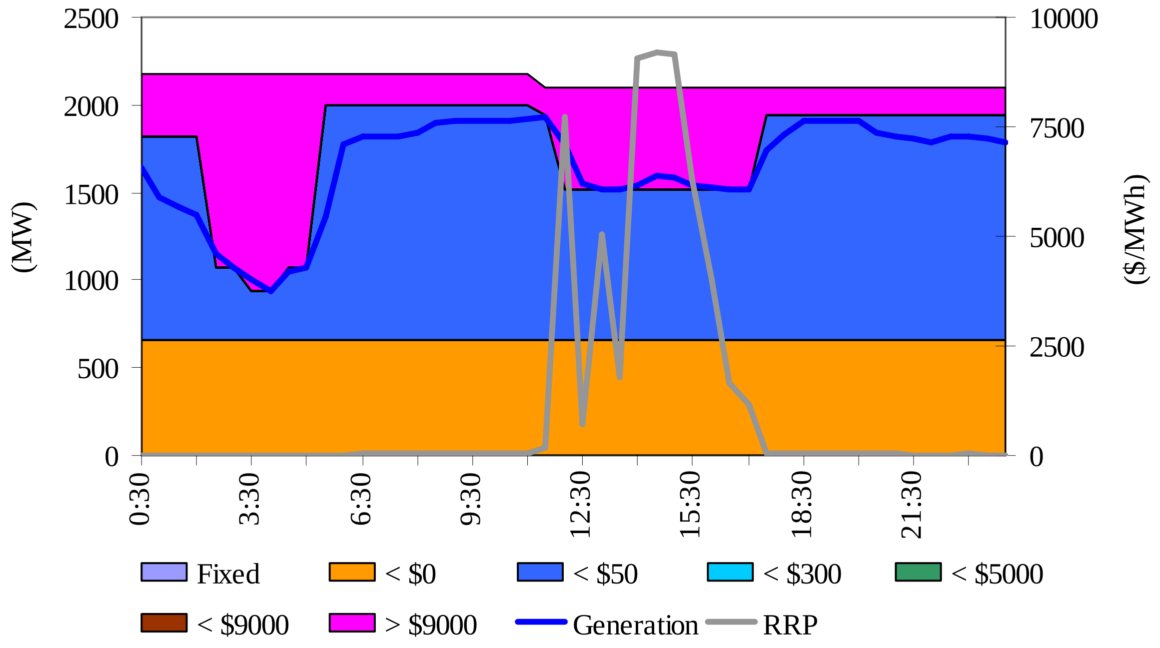

Figure B3: Macquarie Generation closing bid prices, dispatch and spot price