ELECTRICITY MARKET EVENT REPORT

High NSW Prices and Negative Queensland Prices – 10 August 2010

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FINAL

Contents

1 Introduction

This report has been prepared to explain the unusual market outcomes and circumstances that led to high energy prices in New South Wales and negative energy prices in Queensland on Tuesday 10 August 2010.

New South Wales experienced energy prices of $6266.50 per MWh and $5738.78 per MWh for trading intervals (TIs) ending 0830 and 0900 hrs respectively, and Queensland experienced energy prices of -$488.22 per MWh and -$326.88 per MWh respectively in the same TIs.

Wallerawang Power Station Unit 7 (WW7) in New South Wales was being returned to service with the Marulan–Mt Piper (36) 330kV transmission line out of service for construction work. Returning the unit to service required short notice system reconfiguration switching, resulting in lower thermal ratings for the Mt Piper–Wallerawang (70 and 71) 330kV transmission lines. An outage and a system normal constraint equation both violated for 4 dispatch intervals (DIs) due to the lower line ratings, setting the NSW 5-minute dispatch prices at the market price cap (MPC) of $12,500 per MWh.

Immediately following the first high price in New South Wales, a number of rebids by Generators in New South Wales resulted in approximately 11,000 MW of capacity being offered at negative prices, with high ramp-up and low ramp-down rates of change. This resulted in a rapid increase in the amount of generation dispatched in New South Wales, reducing imports from Queensland. With excess generation[1] in Queensland, an energy offer of -$1,000 per MWh was marginal during the four over-constrained DIs, resulting in negative Queensland prices for the two TIs in question.

2 Event Details

2.1 Prior to the Event

The Marulan–Mt Piper (36) 330kV line had been removed from service from 6 August 2010 for conversion to 500 kV as part of construction work by TransGrid. On 10 August, the line remained available to be recalled to service if required by power system conditions. However, the recall time was 100 hours.

Table 1 shows the constraint sets that had been invoked to manage the power system with the line out of service.

Table 1 Invoked Constraint Sets

Constraint Set	Description	# Equations
N-NIL_PRE36	NSW System Normal constraint set containing renamed constraints that would be modified after removal of 36 line.	73
N-NIL	NSW System Normal constraint set without constraints that would be modified after removal of 36 line.	51
N-MNMP_ONE	Prior outage of either 35 or 36 Marulan–Mt Piper 330 kV lines.	20

In particular, system normal constraint equation N>>N-NIL_PRE36__S and the outage constraint equation N>>N-MNMP_ONE_1 had both been invoked to manage flow on the Mt Piper–Wallerawang (70) 330kV line on trip of the other Mt Piper–Wallerawang (71) 330kV line.

AEMO's constraint formulation guidelines state that system normal constraint sets are, in general, invoked all the time unless a transmission element outage increases a power system limit. There is

[1] Excess generation is defined in the NER as "aggregate self dispatch level of self-committed generation which is in excess of the quantity needed to meet the expected power system demand and reserve requirements". In effect, this means the total amount of generation and import from other regions offered at less than $0 per MWh is greater than the forecast demand in the region.

a general assumption in practice that system normal constraints will not be as limiting as constraints prepared for a transmission outage.

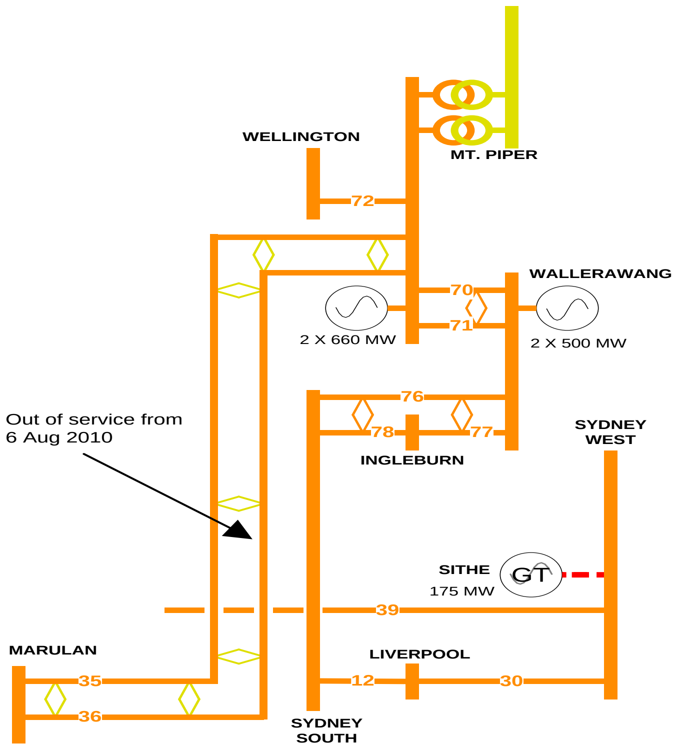
However, under some circumstances the system normal constraint will be more limiting that the outage constraint. In these cases, the dispatch outcome will be secure but will not be as optimal as might be the case if the system normal constraint had been revoked. It should be noted that this was not the case on 10 August 2010[2]. In this case, although the outage affects power flows around the power system, it does not affect the transfer limit between Mt Piper and Wallerawang and so the system normal constraints were left invoked.

Both Wallerawang Power Station Units 7 and 8 were out of service, with WW7 being returned to service at the time, and have the largest influence on the transfer limit between Mt Piper and Wallerawang. These outages generally resulted in higher flows on the lines and increased the amount of action required elsewhere to control the flows.

Under procedures advised in AEMO Communication No.328, issued on 24 May 2010, an operational solution had been implemented by the local Transmission Network Service Provider (TNSP), TransGrid, to use the full extent of the thermal rating of the No.70 line. Market notice 32549[3] was issued on 6 August 2010 to inform the market of the system re-configuration switching and the increased available ratings for the Mt Piper–Wallerawang (70 and 71) 330kV lines.

A simplified diagram of the surrounding transmission system is shown in Figure 1.

Figure 1 Marulan–Mt Piper Single Line Diagram



2 AEMO, *Constraint Formulation Guidelines*, p21, section 11 Application of Constraints, available at http://www.aemo.com.au/electricityops/170-0040.html.

3 Participants have access to all current and historical market notices via their participant fileshare and on the website at http://www.aemo.com.au/data/market_notices/MARKETNOTICEINDEX.shtm. Contact AEMO's electricity Helpdesk for further information.

2.2 Wallerawang Unit 7 Return to Service

Delta Electricity indicated that WW7 would return to service at various times on 9 and 10 August 2010 through a number of rebids. The expected dispatch targets from four selected predispatch solutions over the 24 hours before event are shown in Figure 2. The WW7 initial MW and dispatch targets are shown in Figure 3.

Figure 2 WW7 Pre-Dispatch Solutions

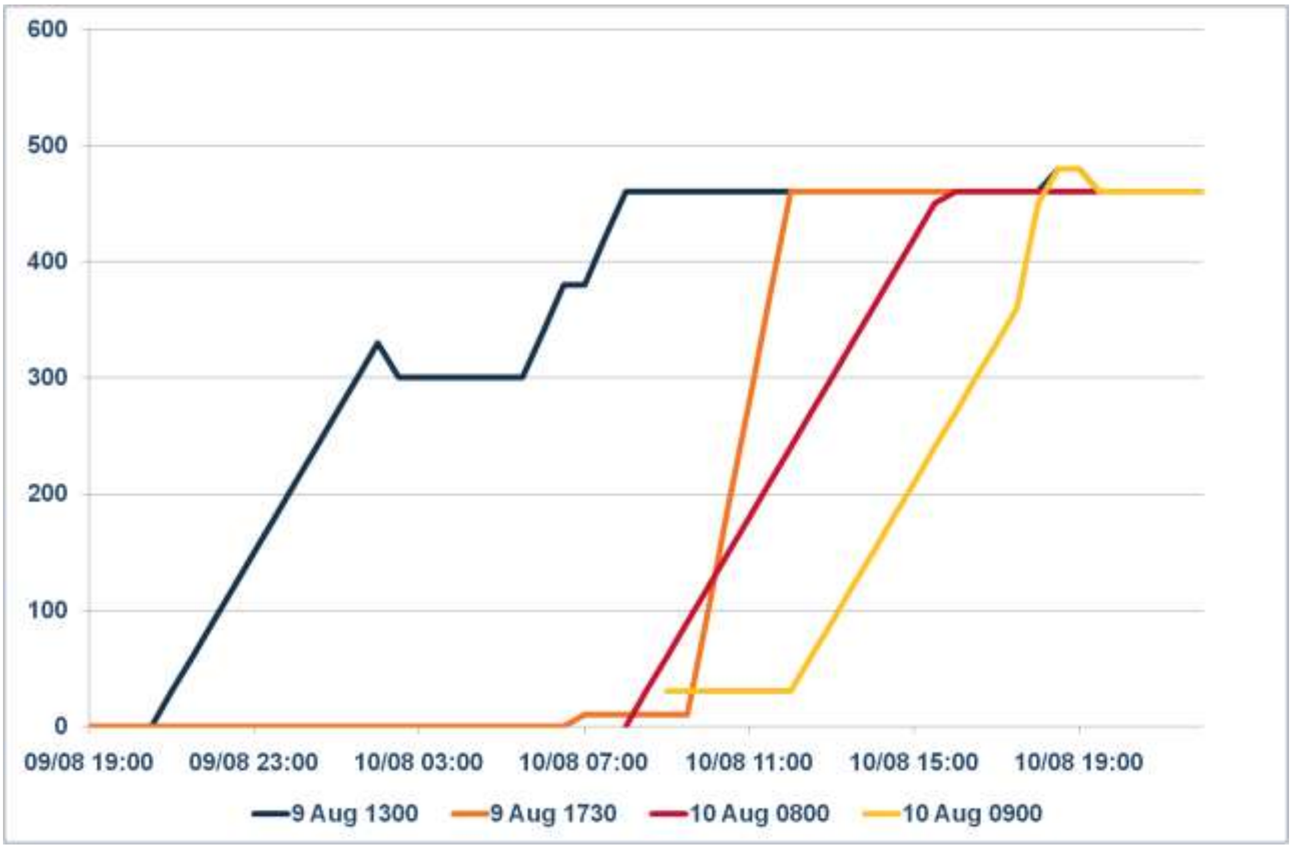
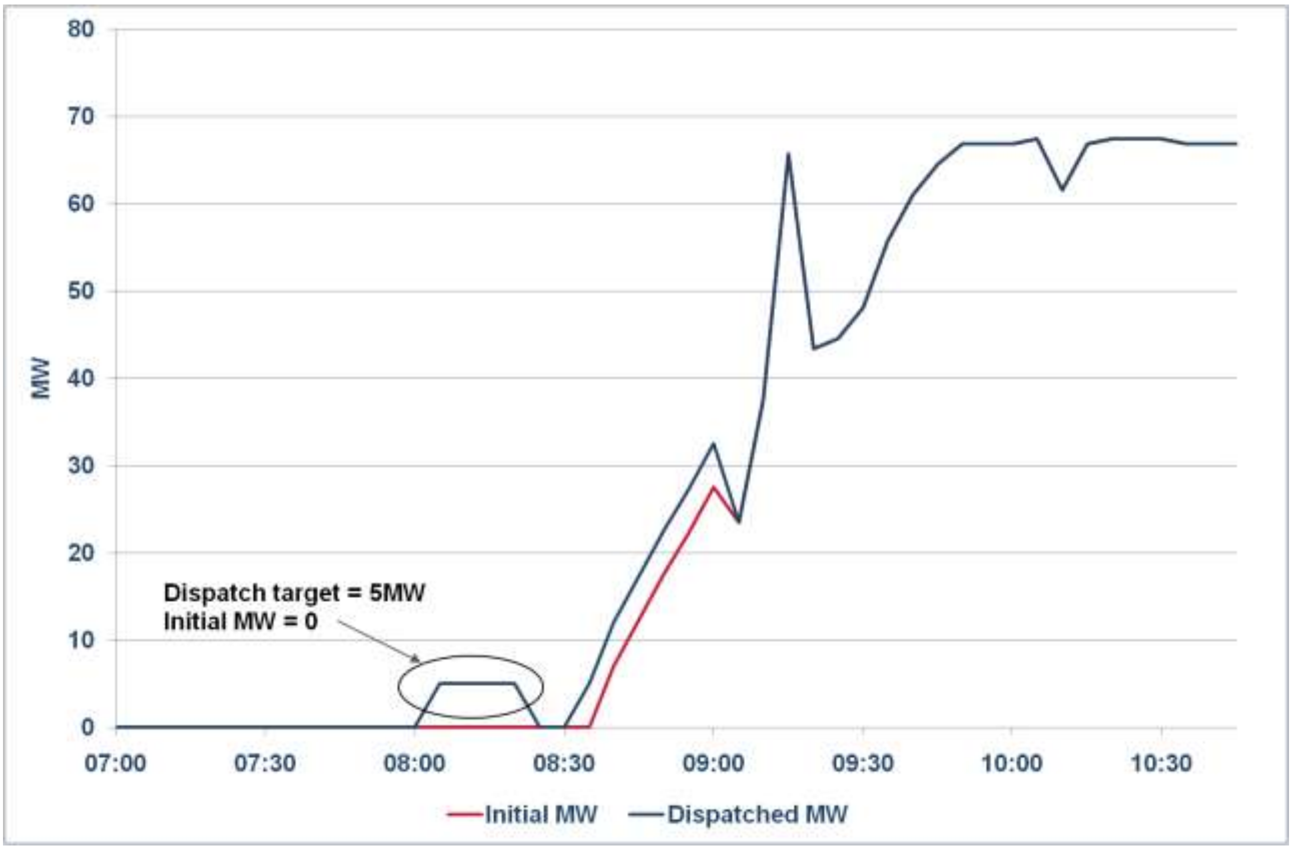


Figure 3 WW7 Dispatch Targets and Initial MW – 10 August 2010



Rebids were received at 1647 hrs on 9 August 2010 for WW7 to be available for the dispatch of 10 MW from the start of TI ending 0700 hrs on 10 August 2010. On the day, a rebid was received at 0625 hrs for WW7 to be available for 500 MW from TI ending 0830 hrs. Another rebid was received at 0814 hrs, for dispatch from 0830 hrs.

- The predispatch run at 1300 hrs on 9 August indicated that WW7 would be dispatched to 30 MW during TI ending 2100 hrs that evening, and would be fully dispatched to 460 MW during the event (TIs ending 08:30–09:00hrs on 10 August).
- The predispatch run at 1730 hrs on 9 August indicated WW7 would be dispatched to 10 MW from TI ending 0700 hrs on 10 August.
- The predispatch run at 0800 hrs on 10 August indicated WW7 would be dispatched to 30 MW, then 60 MW for TIs ending 0830 hrs and 0900 hrs respectively.

2.3 Switching Operations and Limits for WW7 Return to Service

At 0810 hrs TransGrid advised AEMO that WW7 would be returning to service shortly, which would require switching at Mt Piper and Wallerawang that would reduce the available ratings of the 70 line. At 0814 hrs TransGrid advised AEMO that WW7 would be synchronised in 5 minutes. The unit was reoffered to 0 MW for the remainder of TI 08:30hrs, with maximum capacity offered as available for dispatch for TI ending 0900 hrs (i.e. from DI ending 0835 hrs onwards).

AEMO gave permission for the switching operations to proceed immediately on the basis that power system security could be managed without the need to delay the return to service of the unit[4]. This required a reduction in the ratings of the Mt Piper to Wallerawang 70 and 71 lines. The rating of this line during the event is shown in Figure 4.

[4] A forced delay in WW7's return to service would have required AEMO to issue either an instruction or direction to the Generator not to synchronise. However, AEMO can only issue such an instruction or direction

The rating information is manually entered by AEMO on advice from TransGrid. Although ramping toward the limit, either through a constraint equation or by manually changing the limit, may have lessened the market impact, this would have delayed synchronisation of WW7 and AEMO has no ability to do this other than for reasons of system security. Further analysis, discussed in section 6.2, indicates that in this instance applying ramping to the line ratings would have needed to dealy the WW7 unit's synchronization by a period of 1.5 – 2 hours in order to have any material impact on price outcomes. Both the outage and the system normal constraint equations violated during DIs ending 0820 hrs to 0835 hrs and the 5-minute dispatch prices were set at the MPC.

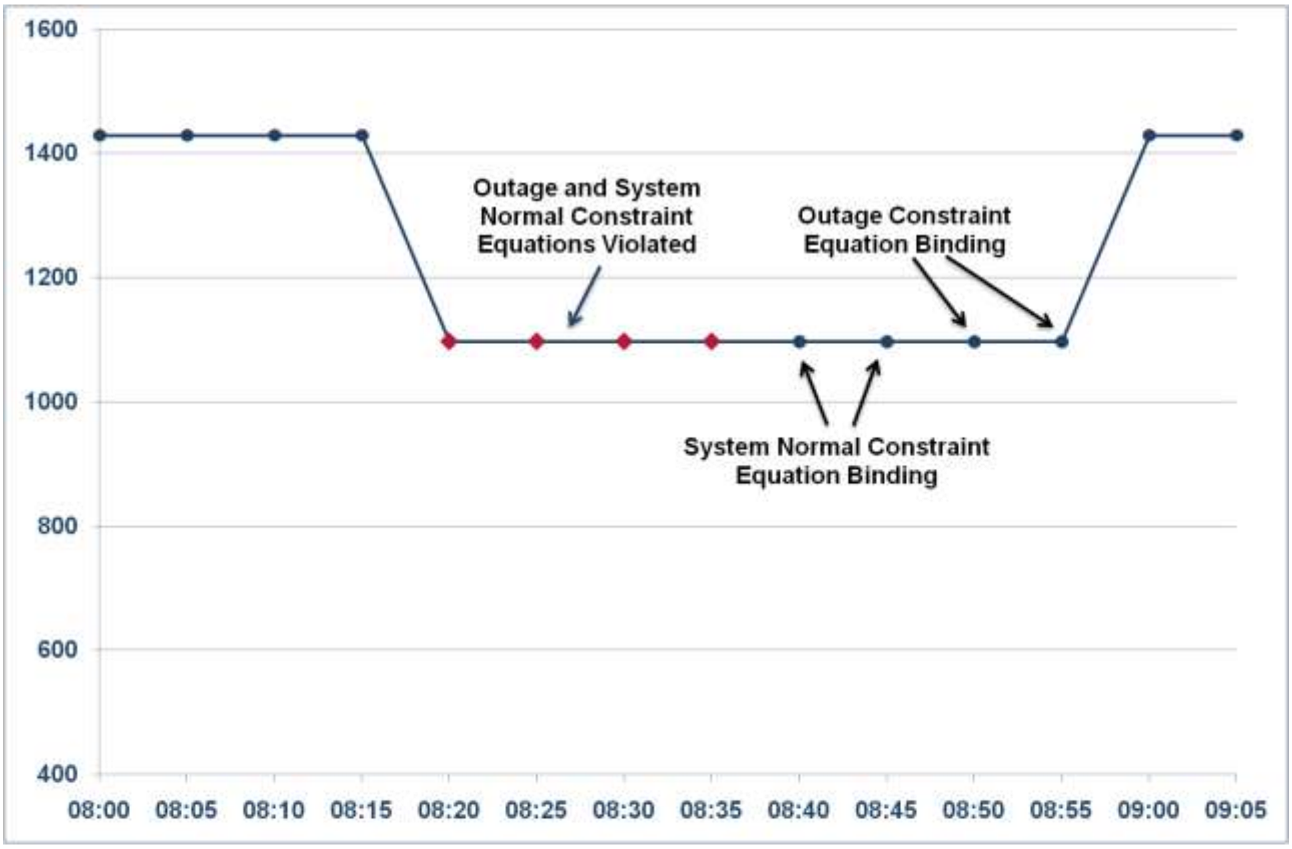
In DIs ending 0840 hrs and 0845 hrs the system normal constraint bound and in DIs ending 0850 hrs and 0855 hrs the outage constraint bound. The two constraints have similar right hand side calculations, although it would be unusual for them to bind (but violate) at the same time. This would have had a minor impact on the dispatch of some generation.

At 0900 hrs, following synchronisation of WW7 and reinstatement of the operational arrangement, market prices returned to normal levels.

Market notices 32589, 32591 and 32592, issued at 0833 hrs, 0857 hrs and 0900 hrs respectively are relevant to the event. In hindsight, AEMO considers that it may have been beneficial to have issued additional market notices in advance of the WW7 return to service giving notice that a lower line rating could be expected to be applied for a short period. AEMO uses this approach for expected system conditions such as bushfires and lightning activity.

This incident was not a reviewable operating incident as defined in clause 4.8.15(a) of the National Electricity Rules (NER), because although the constraint equations violated, post contingency line ratings (and therefore power system security) were not exceeded for more than 30 minutes.

Figure 4 Mt Piper–Wallerawang Line 70 Rating



where power system security is threatened and AEMO did not have a power to require a delay to the unit return to service.

2.4 After the event

On 13 August 2010, TransGrid advised through AEMO Communication No. 417 that it had completed the majority of the work to remove restrictions (including the need for the operational solution) that were limiting the ratings of the 70 and 71 transmission lines.

From 26 August 2010, 500 kV commissioning work was completed with former Mt Piper–Marulan 330 kV lines commissioned as 500 kV lines between Mt Piper, Bannaby and Marulan switchyards.

3 Generator Response

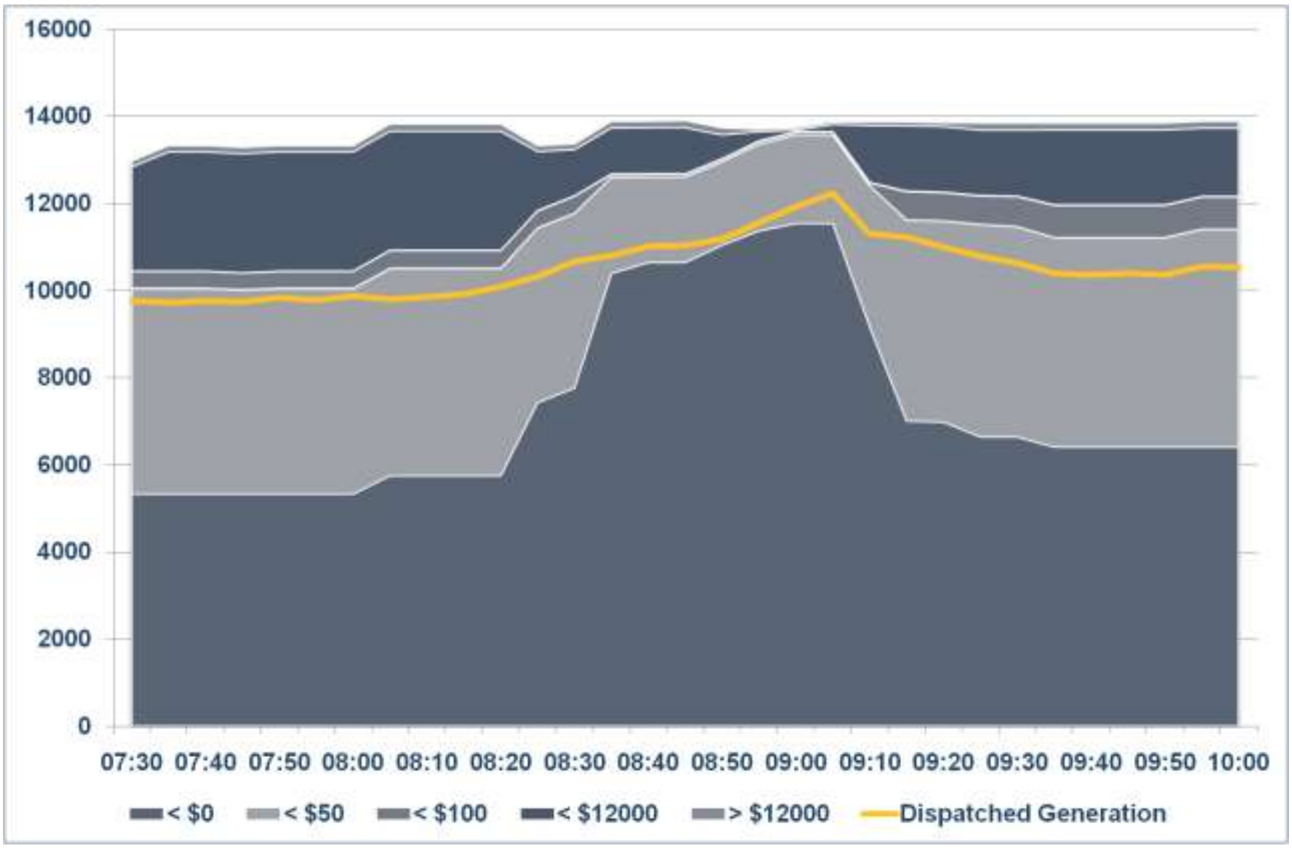
3.1 Rebidding by New South Wales Generators

A number of rebids of generating units in New South Wales were received immediately following the first high price at 0820 hrs. This resulted in an additional 1680 MW of generation capacity being offered at negative prices, bringing the total amount of negatively priced generation to 7437 MW, some 56% of total capacity offered.

The NSW bid stack, showing the amount of generation offered at negative prices during the period of interest, is shown in Figure 5. At 0850 hrs, more than 11,000 MW of generation was offered at negative prices with high ramp-up and low ramp-down rates of change.

The offer changes resulted in a rapid increase of 1,830 MW in the amount of generation dispatched in New South Wales from DIs ending 0820 hrs to 0900 hrs, with a corresponding change in interconnector flows. With excess generation[5] in Queensland, the energy offers of -$1,000 per MWh could not be cleared in full and became marginal offers during the DIs ending 0820 hrs to 0840 hrs.

Figure 5 New South Wales Bid Stack



5 Excess generation is defined in the National Electricity Rules as aggregate self dispatch level of self-committed generation which is in excess of the quantity needed to meet the expected power system demand and reserve requirements.

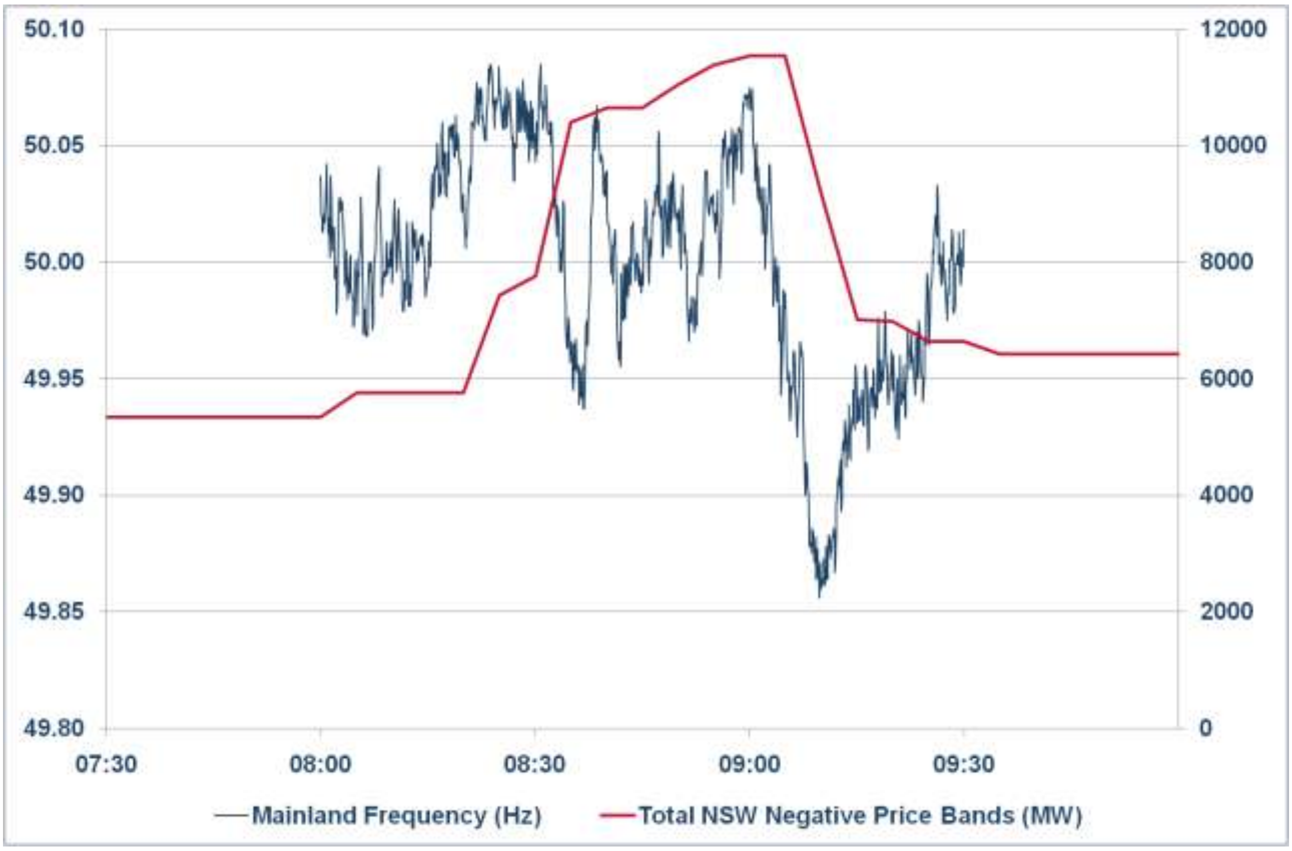
3.2 Power System Operations

Generators in NSW generally responded to dispatch instructions. The four fast-start units at Colongra Power Station received instructions to start from DI ending 0820, although two units did not respond initially, resulting in a discrepancy between dispatch targets and actual output of up to 276 MW at 0835 hrs. One of those units started 20 minutes later while the other unit was subsequently rebid unavailable. However, the discrepancies did not meet AEMO's criteria to be declared non-conforming.

The overall response of generating units had an impact on power flows within New South Wales and the mainland power system frequency. The mainland frequency and the total New South Wales capacity bid in negative priced bands is shown in Figure 6. Frequency swings between 0820 and 0835 hrs relate to initial rebidding activities, while those after 0900 hrs relate to rebidding after the prices had returned to normal levels.

While the power system was secure in the strict technical sense, large responses to market price signals en-masse result in a number of physical changes to generating units and the network, which AEMO considers will increase the chance of a multiple contingency event occurring during or immediately after pricing events. They also have the potential to increase the impact of a contingency event where power system conditions are changing significantly within a 5-minute interval. AEMO's submission to the Transmission Frameworks Review[6] discussed the physical impacts of this event in more detail.

Figure 6 – Mainland Frequency and NSW Negative Priced Capacity



[6] Available at http://www.aemc.gov.au/Media/docs/AEMO-b64b3c62-db16-4a2b-aa28-316545eb4b38-0.pdf, refer Appendix E.

4 Pricing and Mis-pricing Outcomes

This section provides facts about price outcomes, forecasts and mis-pricing[7] during the event. The implications of these outcomes are discussed later in the report.

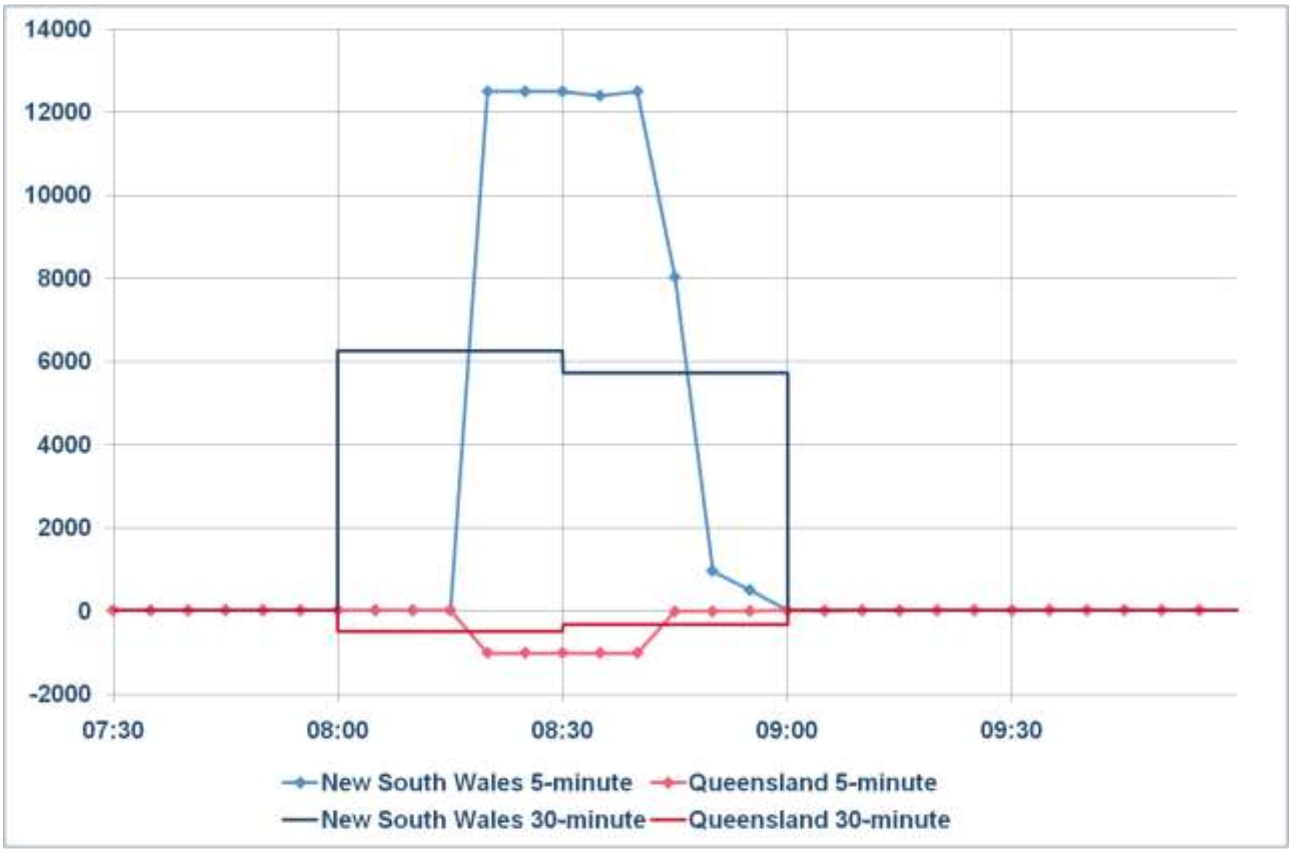
4.1 Energy Prices

The 30-minute trading interval energy prices for all NEM regions are shown in Table 2. Prices above $300 per MWh and below $0 per MWh are highlighted. The 5-minute dispatch interval energy prices for New South Wales and Queensland are shown in Table 3 of section 6.3 of this report. The 5-minute dispatch prices and 30-minute spot prices for New South Wales and Queensland are shown in Figure 7.

Table 2 Trading Interval Energy Prices in $ per MWh

	0800	0830	0900	0930
QLD	23.91	**-488.22**	**-326.88**	24.90
NSW	31.71	**6266.50**	**5738.78**	25.19
VIC	34.29	66.80	38.88	29.73
SA	35.87	68.74	40.50	32.45
TAS	31.16	58.51	33.94	26.81

Figure 7 New South Wales and Queensland Price Outcomes



A feasible dispatch solution could not be found for the New South Wales region during the DIs ending 0820 hrs to 0835 hrs and the network constraint equations N>>N-NIL_PRE36__S and N>>N-MNMP_ONE_1 violated. Dispatch prices reached the MPC in New South Wales for the four DIs. The price for DI ending 0835 hrs was subsequently revised to $12400 per MW·h under AEMO's over-constrained dispatch procedure.

[7] Mis-pricing is a defined term in the National Electricity Rules. See section 4.4 of this report.

The New South Wales price remained high in DIs ending 0840 hrs to 0855 hrs as some New South Wales generators were constrained off by the outage constraint equation, whilst others were either fully dispatched or ramp rate constrained. The situation was exacerbated as generation was being constrained-off during the peak morning demand period, with a New South Wales demand of approximately 11,000 MW.

4.2 Frequency Control Ancillary Services (FCAS) Prices

FCAS prices in all the NEM regions were not affected.

4.3 Predispatch Forecasts

AEMO publishes forecasts of prices through the predispatch and 5-minute predispatch schedules. Neither predispatch or 5-minute predispatch provided forecasts of the impact of the event on prices.

The first (30-minute) predispatch that used the lower line ratings was run at 0830 hrs (forecasting from TI ending 0900 hrs), where the forecast price in New South Wales was $553.76 per MWh and in Queensland was -$0.01 per MWh. The longer time intervals used by predispatch (30 minutes) compared to dispatch (5-minutes) meant that ramp rates have a smaller impact on prices.

The first 5-minute predispatch that used the lower line ratings was run at the same time as the central dispatch process (that is, from DI ending 0820 hrs). The effectiveness of the 5-minute predispatch to forecast dispatch prices was limited because:

- AEMO did not know exactly when the WW7 unit would be returned to service and as a result could not predict when the higher rating could be reinstated;
- Even if it had this information, 5-minute predispatch was not able to use a profile of expected available rating for this particular line. A single rating was used for dispatch and predispatch.

Given the short notice, AEMO did not assess whether the outage and the system normal constraint equations N>>N-MNMP_ONE_1 and N>>N-NIL_PRE36_S would be likely to bind or violate in dispatch[8].

4.4 Mis-pricing

The term “mis-pricing” is defined in the NER and describes the deviation in the “local” price at each generator connection point from the regional reference price (RRP) in the same region, due to the presence of network congestion[9].

In all eight DIs affected by this incident:

- The local price was either at the market floor price or significantly lower than the NSW RRP at Lower Tumut, Upper Tumut, Uranquinty, Liddell, Bayswater and Mount Piper Power Stations.
- The local price was at or near the NSW RRP at Colongra, Eraring, Munmorah, Vales Point and Tallawarra Power Stations and the Smithfield Energy Facility.
- The local price was either at the MPC or significantly above the RRP at Wallerawang Power Station.

[8] The effect of rebidding could also not be forecast or estimated.
[9] Refer AEMO “Guide to Mis-Pricing Information Resource”, available at http://www.aemo.com.au/electricityops/mispricing.html

5 Interconnector Outcomes

5.1 Interconnector flows

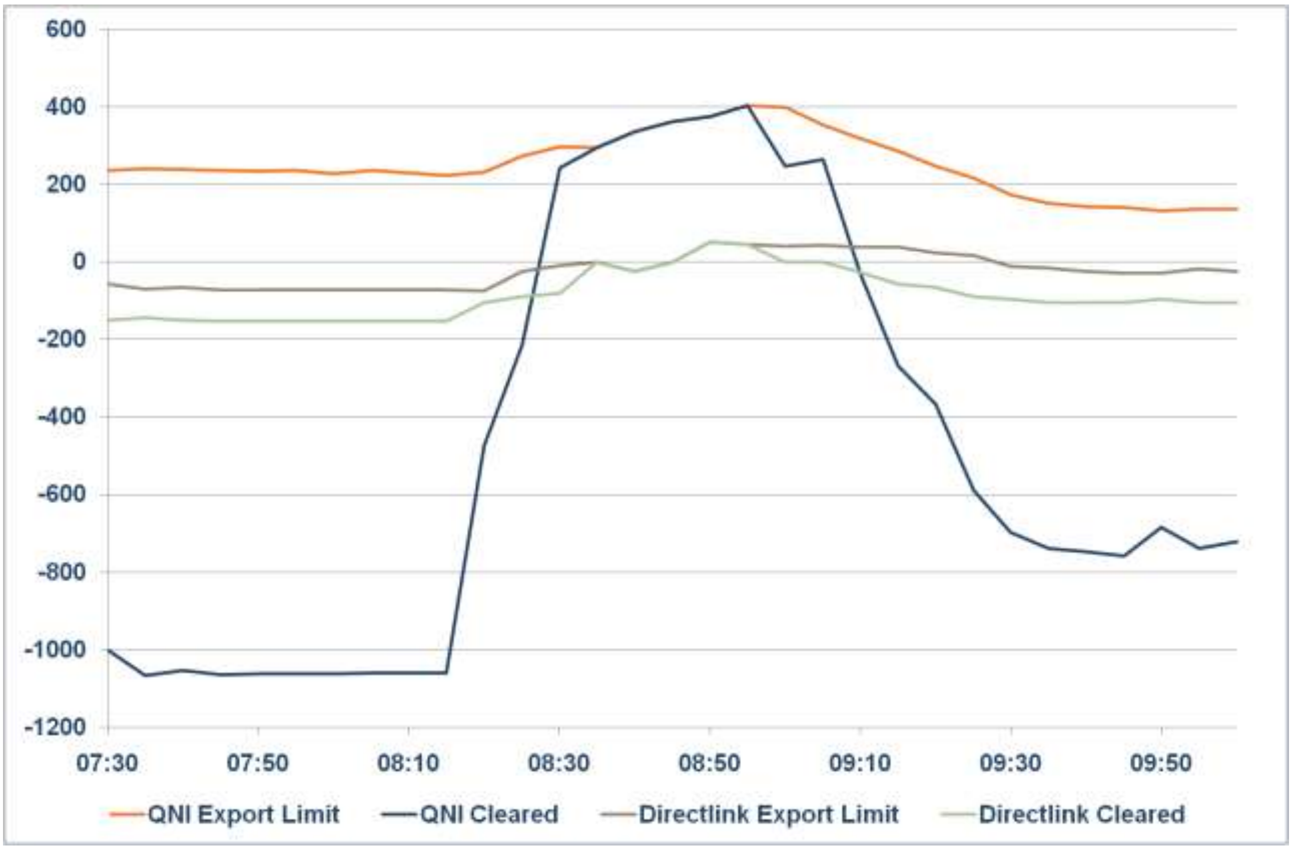
Interconnector cleared flows and limits for the NSW to Queensland interconnectors are shown in Figure 8, and for the Victoria to NSW interconnector are shown in Figure 9.

In DI ending 0815 hrs, the cleared interconnector flow from Queensland to New South Wales was approximately 1,200 MW and from New South Wales to Victoria was 138 MW. The two constraint equations N>>N-NIL_PRE36__S and N>>N-MNMP_ONE_1 attempted to reduce power flowing into New South Wales by reversing flow into Queensland and increasing flow into Victoria.

In DI ending 0820 hrs, the two constraints equations could not be met. In both violating constraint equations, the coefficients for flows into Victoria are the lowest of all the controllable quantities available to the central dispatch engine[10]. As a result, this quantity was relaxed so a dispatch solution could be found for DIs ending 0820 hrs to 0835 hrs. This resulted in flows dispatched from Victoria to New South Wales until DI ending 0850 hrs.

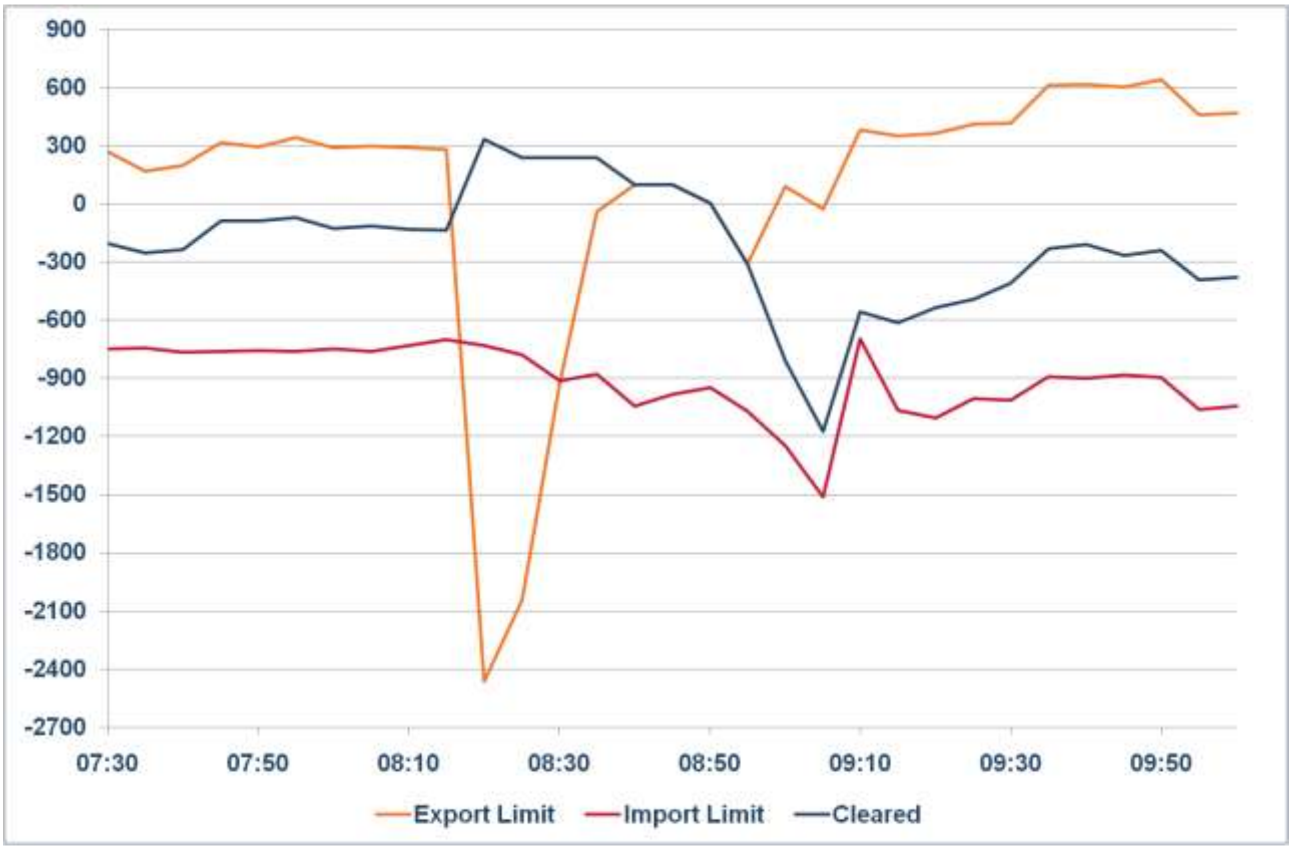
In DI ending 0830 hrs flow was reversed towards Queensland. This resulted in excess generation in Queensland and energy offers of -$1000 per MWh became marginal during DIs ending 0820 hrs to 0840 hrs.

Figure 8 MW Flow and Limits of QNI and Directlink Interconnectors



[10] Appendix A lists the coefficients of all controllable (that is, left hand side) variables in the two constraint equations.

Figure 9 MW Flow and Limits of Victoria to NSW Interconnector



5.2 Inter-regional settlements residues

In TI ending 0830 hrs, flow on the Victoria to New South Wales interconnector changed direction during the latter part of the interval with the overall energy flow being toward Victoria. However, because of the high prices in NSW in DI's ending 0820 to 0830 the NSW price was on average higher than Victoria. This resulted in a negative residue of -$85,748 accumulating on the directional interconnector from New South Wales to Victoria in TI ending 0830 hrs.

In TI ending 0900 hrs, flow on the NSW to Queensland interconnectors[11] was dispatched toward Queensland throughout the interval even through the price in NSW was high and the price in Queensland was negative. The counter-priced flow was a result of mis-pricing on the New South Wales side of the interconnection. This resulted in a negative residue of -$1,186, 284 accumulating on the directional interconnector from New South Wales to Queensland in TI ending 0900 hrs.

In all other TIs during the event, inter-regional settlements residues were positive.

Under arrangements that came into effect on 1 July 2010, negative settlements residue are recovered from a TNSP in the importing regions (Queensland and Victoria). This limits the impact of such events on the returns to holders of settlements residues rights. However, participants trading between Queensland and other regions (particularly generators in Queensland) could have experienced inter-regional financial loss that could not have been managed through the Settlements Residue Auction whenever interconnector flow is limited during price differentials between Queensland and New South Wales.

[11] That is, the combined flow on the QNI and Directlink interconnectors.

6 Scenarios Analysis

6.1 Predispatch

As noted earlier, neither predispatch nor the 5-minute predispatch accurately forecast the price outcomes for this event because configuration changes occurred in real time. Using off-line tools, AEMO recalculated PDS and 5-minute PDS results using the lower ratings applied from 0815 hrs.

The off-line tools used the same PDS and 5-minute PDS input data but also modelled the actual available line ratings.

Using the predispatch case run at 0830 hrs with the first solved interval being TI ending 0900 hrs and substituting the lower rating of 70 line for TI ending 0900 hrs, the price outcomes were:

- The NSW price increased to around $610 per MWh.
- The Queensland price decreased to around $5 per MWh.
- In all other regions, the price increased to around $200 per MW·h from between $25 per MWh and $30 per MWh in all regions.

The higher prices in all regions except Queensland is due to the overall reduction in lower cost generation that would have been required to manage the more restrictive network constraint.

Using the 5-minute predispatch case run at 0800 hrs and substituting the lower rating of 70 line from DI ending 0820 hrs to DE ending 0900 hrs, the NSW RRP increased to $12,500 per MWh and the Queensland RRP reduced to -$1,000 per MWh.

However, it should be noted that these results could not have been published in practice because ratings for the 70 line were being entered manually. Separate predispatch constraints with the lower rating or a mechanism for entering rating profiles[12] were not available at the time.

Predispatch will not generally be effective at forecasting transient price impacts from sub-30 minute changes in system conditions, because generating units can be moved much further in 30 minutes than in 5 minutes. Lower priced bands will in general be more likely to be fully cleared in predispatch compared to 5-minute predispatch or dispatch, and the price impacts will be less.

6.2 Ramping constraints

As mentioned in section 2.3 above, ramping of the line limit and flow was not possible because AEMO had no power to delay the unit's return to service.

AEMO commonly uses network constraint ramping for planned network outages[13]. The process sources data for an outage from the 30 minute PDS forecasts and ramps all constraint equations associated with an outage gradually to values forecast to apply when the outage commences.

In practice, ramping is unlikely to have been an effective option in terms of reducing the price impacts. As shown in Figure 7, the price was high for 40 minutes (8 DIs) with a step change in line rating. Both the system normal and outage constraint equations violated for four DIs, resulting in dispatch prices of $12,500. Then the dispatch price in NSW stayed at the price cap and ramped down over the next four DIs.

For a ramping constraint to have been effective, it would need to reduce the line flow to the desired rating with a lower price impact. AEMO's analysis suggests the elapsed time to do this would have been at least doubled to 1.5 to 2 hours before WW7 could be given the clearance to synchronise. AEMO would not delay a unit return to service for that period unless there are clear security reasons for this.

[12] That is, to enter ratings for each half-hour or five-minutes over an extended period.
[13] Refer AEMO Operating Procedure "Generic Constraints due to Network Limitations" available at http://wwww.aemo.com.au/electricityops/3709.html.

Further, as the current outage ramping process requires a predispatch solution to be able to estimate the target ramp rate, this would have introduced a further 20 to 30 minutes delay to the unit return to service.

The network constraint ramping tool has been designed to be applied to constraint equations invoked in preparation for an outage. This event resulted from a change to a limit (rather than from the invocation of a constraint set), and the tool is not designed for this situation.

6.3 Dispatch Results with No Rebidding

The level of rebidding in Figure 6 suggested this may have had an impact on dispatch and pricing outcomes immediately following the initial price changes. To quantify this impact and to determine whether rebidding may have exacerbated market outcomes, AEMO calculated the outcomes for DIs ending 0815 hrs to 0900 hrs without any rebidding of capacity and generator ramp-down rates of change using its NEM simulator (DTS). The DTS uses the full network model, security applications and a complete market dispatch model, with simulated unit targets and line flows feeding into the initial conditions for the next NEMDE DI run.

The simulation assumes no rebidding by any participant after 08:00hrs. The effect of rebidding on spot prices is shown in Table 3. Price differences above $300 per MWh are shown in red.

The effects of rebidding on interconnector flows from Queensland to NSW are shown in Figure 10, and from Victoria to NSW are shown in Figure 11.

The rebidding resulted in up to a 1,400 MW reduction in New South Wales import from Victoria and a reduction of up to 600 MW in New South Wales import from Queensland for the TI ending 0900 hrs.

Due to the changes in the interconnector flows (reducing counter price flows from New South Wales), the “no rebidding” scenario had a reduced accumulation of negative inter-regional settlements residue (IRSR) on the VIC-NSW and NSW-QLD interconnectors.

Table 3 Energy Prices Without Rebidding

TI ending	DI ending	NSW	NSW: No rebidding	QLD	QLD: No rebidding	VIC	VIC: No rebidding
	08:05	$33.00	$32.37	$23.56	$20.54	$35.67	$34.95
	08:10	$33.00	$32.72	$23.56	$20.44	$35.70	$35.42
	08:15	$33.00	$33.00	$23.56	$20.42	$35.88	$35.43
	08:20	$12500	$12500	-$1000	-$1000	$97.86	$97.86
	08:25	$12500	$12500	-$1000	-$1000	$97.86	$97.86
	08:30	$12500	$12500	-$1000	-$1000	$97.86	$97.86
08:30		$6266.50	$6266.35	-$488.22	-$489.77	$66.80	$66.56
	08:35	$12400	$12500	-$1000	-$1000	$75.00	$97.86
	08:40	$12500	$12500	-$999.99	-$1000	$36.61	$97.86
	08:45	$8035.06	$8035.06	-$0.02	-$417.59	$36.13	$119.95
	08:50	$969.76	$8035.06	$4.78	-$0.03	$34.23	$99.98
	08:55	$509.55	$619.66	$13.67	$5.98	$28.95	$220.10
	09:00	$18.30	$103.97	$20.29	$102.86	$22.39	$99.98
09:00		$5738.78	$6965.63	-$326.88	-$384.80	$38.88	$122.62

Figure 10 Difference in Combined flow on N-Q-MNSP1 and NSW1-QLD1 Flow with No Rebidding

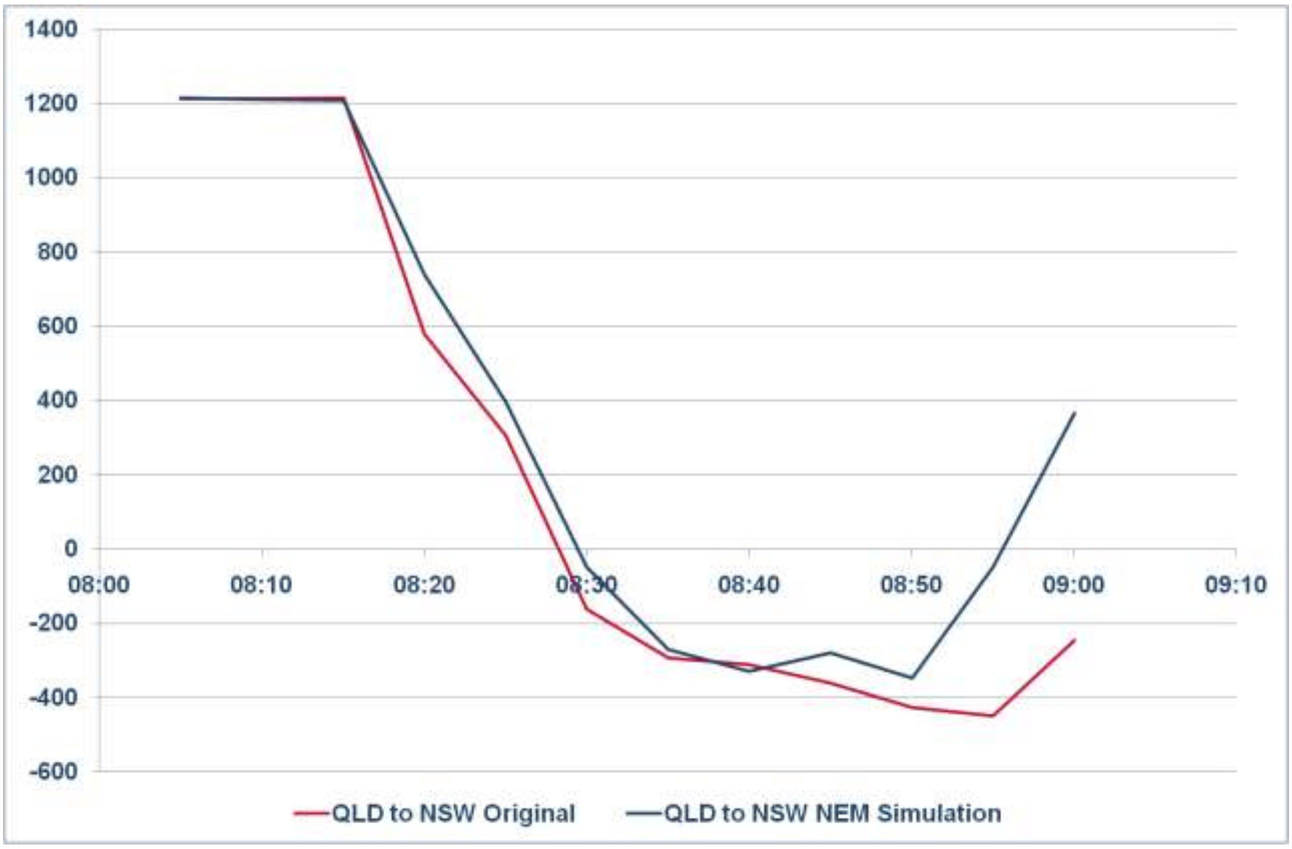
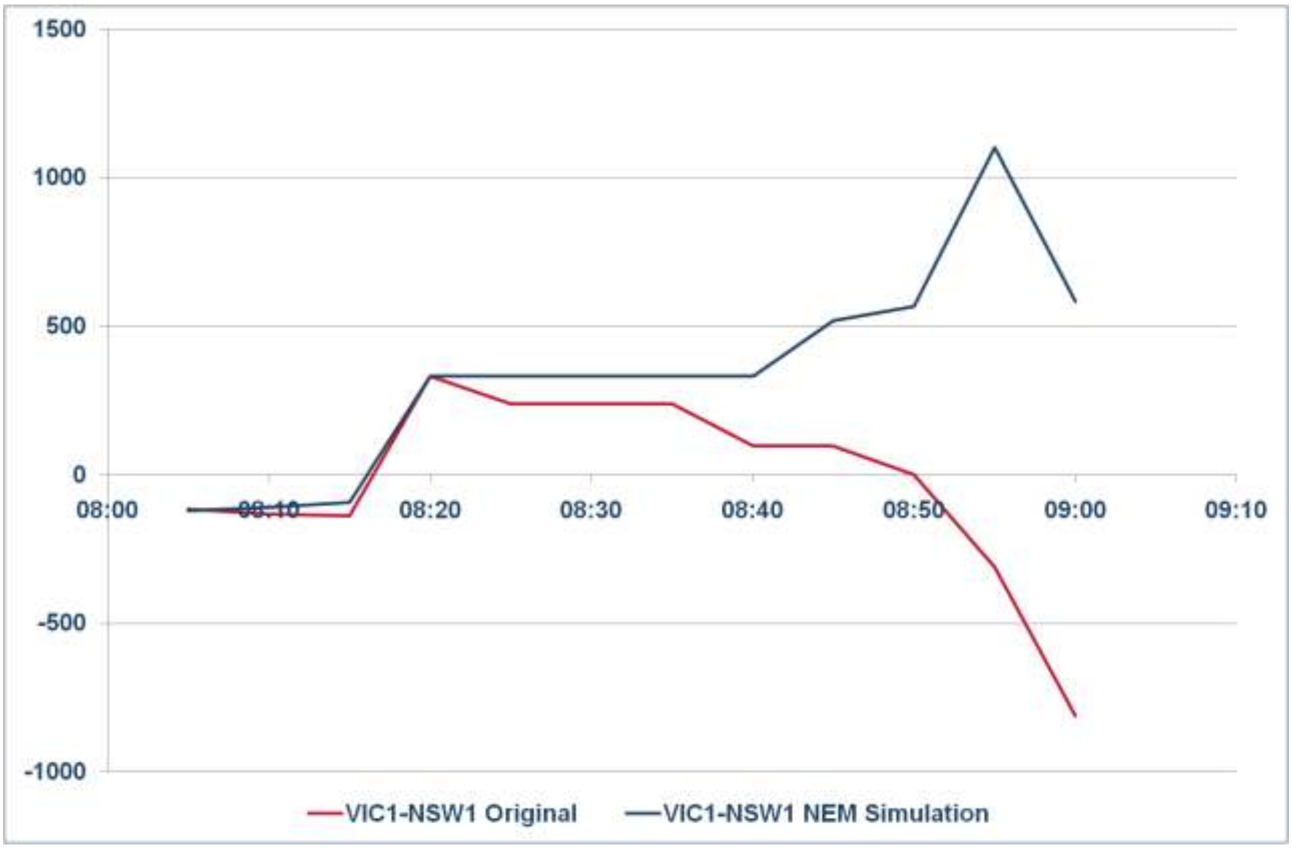


Figure 11 Difference in VIC1-NSW1 Flow with No Rebidding



Ignoring losses, the simulations showed:

- Rebidding did not appear to materially affect dispatch prices, except in one DI in NSW where rebidding appears to have reduced the price by $7000 per MWh and in one DI in Queensland where rebidding appears to have increased the negative price by around $400 per MWh.
- Rebidding did not appear to materially affect IRSR in TI ending 0830 (including the negative IRSR that accumulated on the NSW to Victoria direction interconnector).
- Rebidding appeared to increase negative IRSR on the NSW1-QLD1 directional interconnector by -$0.5 million to -$1 million in TI ending 0900 hrs.
- Rebidding appeared to reduce positive IRSR on the Victoria to NSW direction interconnector by $2 million to $0 in TI ending 0900 hrs (mostly a result of the higher simulated price in NSW in DI ending 0850 hrs).

7 Main Contributors

AEMO considers the main contributors to the pricing event were:

1. **Prior outages**: Prior outages of the Mt Piper–Marulan (36) 330 kV transmission line, and Wallerawang Power Station Units 7 and 8 generally increased flow on the lines from Mt Piper to Wallerawang. A WW7 return to service time was uncertain, limiting AEMO's ability to manage the impact of the return to service on the market. A further 1400 MW of generation in New South Wales was also unavailable, which could have reduced some of the impact of the outages.
2. **Operational arrangement**: The arrangement for making maximum use of line ratings between Mt Piper and Wallerawang was a temporary solution using manual entry of the rating depending on the switching arrangements.
3. **Violation of constraint equations**: Constraint equations violated resulting in a New South Wales price at the MPC and a negative Queensland price.
4. **Mis-pricing and rebidding**: Mis-pricing for a number of New South Wales generator units resulted in a local price being negative when the RRP was at the MPC. Subsequent rebidding by NSW Generators to move capacity into negatively priced bands, reduce ramp-down rates and increase ramp-up rates appears to have resulted in larger counter-price flows on interconnectors leaving New South Wales and prolonged the period during which the constraint equations violated, however, rebidding probably caused prices to recover to more normal levels one DI earlier.

Other factors that may have influenced the outcome but don't appear to have significantly contributed to the event were:

1. **No notice through predispatch or 5-minute predispatch**: The operational arrangement used a single manually entered rating, restricting AEMO's ability to use predispatch and 5-minute predispatch to forecast the price impacts of events such as this. Had systems been available, the effectiveness of predispatch would have been limited in any event by AEMO's decision not to delay the return to service of WW7.

   As discussed earlier, predispatch is also not as effective at forecasting transient price impacts of sudden changes to system conditions.
2. **No ramping constraint equations**: AEMO did not have the ability to use ramping constraint equations but could have achieved a similar result by manually ramping the change to the rating. The potential effectiveness of ramping would have been limited by a delay in clearance for the unit to return to service, which AEMO did not consider was appropriate for the power system conditions at the time.
3. **Use of system normal and outage constraints equations**: As both types of constraint equations violated initially, price outcomes are unlikely to have been affected by this factor. However, a change in dispatch outcomes would have resulted for some generating units.

4. **Generator responses to dispatch and fast start instructions**: Approximately 275 MW of generation that could have alleviated the constraint, mostly at Colongra Power Station, did not respond according to their fast-start inflexibility profiles.

Two factors, which are of a broader nature, are not considered here but will be either the subject of further review by AEMO or raised in submissions in other forums:

1. **Construction activities, line limitations and medium term generator unavailability:** AEMO is aware of submissions in the AEMC's Transmission Frameworks Review relating to the management of the network during construction activities. These comments particularly relate to the conversion of the 330 kV network between Marulan, Mt Piper and Bayswater to 500 kV, the subsequent issues identified with equipment ratings at Wallerawang and Mt Piper 330 kV switchyards, and the coincident issue of availability of plant at Wallerawang due to water limitations. AEMO intends to investigate this in more detail and will publish a separate report on this in due course.
2. **Market resilience to network congestion**: Unexpected network congestion, especially where constraint equations violate, can be a result of events such as contingencies, unplanned outages or switching, or changes to equipment ratings. It often results in significant generator mis-pricing (as happened in this event). Violations can result in the RRP being either the MPC ($12500 per MWh) or the MFP (-$1000 per MWh). Market responses vary depending on exposure to the spot price, but can include rebidding energy to higher or lower price bands, rebidding ramp rates, delays in following dispatch instructions and removal (tripping) units from service.

   AEMO believes that whatever arrangements are put in place to improve how transmission networks are planned and operated, congestion is an inevitable part of an electricity market. Disorderly responses such as these are common and indicate structural issues with the market design as well as opportunities to improve the network. Market design issues have an impact on the efficiency of the market, the effectiveness of risk management instruments such as the Settlements Residue Auction, result in substantial, unpredictable wealth transfers between participants, and expose non-market participants such as network users to these risks. AEMO has raised these issues for consideration by the AEMC in the context of their Transmission Frameworks Review.

8 Potential Actions

Areas for potential improvement by AEMO are:

- **Revoking system normal constraint equations during outages**: This is not AEMO's current policy as it involves risks due to human error that can affect market outcomes. A future project to automate constraint equations may partially address these risks.
- **Ramping constraints for system changes not involving outages**: This is likely to require substantial development effort and is not being considered at this stage. The need for such a process has reduced given that the operational arrangement at Wallerawang and Mt Piper is no longer in use.
- **Predispatch forecasts**: Separate predispatch constraint equations using the lower transmission element rating or a tool to allow profiling of manually entered quantities would improve AEMO's ability to forecast price events. As with ramping constraints, this is likely to require substantial effort and is not being considered at this stage. Because the unit was to be returned to service immediately, this would not have been effective for this particular event.
- **Market notices**: Additional market notices in advance of the WW7 return to service advising that a lower line rating could be expected to be applied for a short period will be provided in future. AEMO uses this approach for expected system conditions such as bushfires and lightning activity.

9 Conclusion

The market event of 10 August 2010 occurred because AEMO approved, and had no reason to delay, the immediate return to service of Wallerawang Power Station Unit 7 during a prior outage of a line between Mt Piper and Marulan. This in turn required a short-notice change in line ratings available for dispatch that caused constraint equations to violate, high prices in New South Wales, low prices in Queensland and a significant amount of rebidding by New South Wales generators.

The circumstances of the 500kV conversion works have been the subject of comment in other forums. AEMO will undertake its own review of these circumstances that covers the pricing events as a result of the commissioning program, management of the operational arrangement affecting lines between Mt Piper and Wallerawang, information available to AEMO concerning availability of critical generating plant during the program, and AEMO's ability to require additional works to mitigate market impacts from such programs.

To the extent that the construction program is now complete and equipment issues at Wallerawang and Mt Piper have been addressed, this event is a one-off and unlikely to happen again in this form. However, AEMO considers that congestion will continue to occur routinely in the NEM.

AEMO has identified some process improvements for consideration in the future.

Notwithstanding any outcomes of AEMO's review of the construction program, none of the improvements identified would have been effective at mitigating the market impacts of 10 August 2010, because:

- AEMO considered the changes to system conditions, including the potential for insecure operation of the power system would be recoverable within 30 minutes. This subsequently proved to be the case, with constraint equation violations lasting for 20 minutes.
- AEMO's present role does not permit delaying the return to service of a generating unit to avoid the potential for disruption to the market where power system security is not threatened. AEMO considers that actions to mitigate market impacts would have required a delay of the unit's return to service by 90 minutes to 2 hours.

This event has demonstrated a situation where network congestion in the NEM has resulted in bidding and pricing behaviour by generation that compounded dispatch and price risks faced by market participants. AEMO agrees with the Ministerial Council on Energy[14] that this should be further considered and addressed as part of the AEMC's Transmission Frameworks Review, and has submitted to that review to assist in this.

[14] "MCE Terms of Reference to AEMO Review of Transmission Frameworks", 20 April 2010, http://www.aemc.gov.au/Market-Reviews/Open/Transmission-Frameworks-Review.html, accessed 14 January 2011.

Appendix A. Violating Constraint Equations

A.1 Constraint equation N>>N-NIL_PRE36__S

Constraint description: Out= Nil, avoid Mt Piper to Wallerawang (70) O/L on Mt Piper to Wallerawang (71) trip; Feedback

Reason: Trip of Mt Piper to Wallerawang (71) line

LHS =

0.259 x Bayswater unit 1

0.259 x Bayswater unit 2

0.374 x Bayswater unit 3

0.374 x Bayswater unit 4

0.216 x Blowering hydro (3 aggregated units)

0.1 x Tallawarra CCGT

0.206 x Guthega hydro (2 aggregated units)

0.213 x Hume (NSW) hydro

0.25 x Hunter GT (2 aggregated units)

0.25 x Liddell unit 1

0.25 x Liddell unit 2

0.25 x Liddell unit 3

0.25 x Liddell unit 4

-0.212 x Lower Tumut pumps (3 aggregated pumps)

0.212 x Lower Tumut hydro (6 aggregated units)

0.25 x Redbank unit 1

0.723 x Mt Piper unit 1

0.723 x Mt Piper unit 2

0.12 x Shoalhaven hydro (aggregated Bendeela and Kangaroo Valley units)

-0.12 x Shoalhaven pumps (2 aggregated pumps)

0.214 x Uranquinty GT unit 1

0.214 x Uranquinty GT unit 2

0.214 x Uranquinty GT unit 3

0.214 x Uranquinty GT unit 4

0.212 x Upper Tumut hydro (8 aggregated units)

- Wallerawang unit 7

- Wallerawang unit 8

-0.235 x MW flow north on the Terranora Interconnector

-0.241 x MW flow north on the QNI AC Interconnector

0.212 x MW flow north on the Vic to NSW AC Interconnector

RHS =

1.873 x (NSW: 70 Mt. Piper-Wallerawang 330kV Sustained Emergency Rating

- MW flow on 70 330kV line at Mt Piper, Line end switched MW

- 0.92 x [MW flow on 71 330kV line at Mt Piper, Line end switched MW]

- 40 {Margin})

+ 0.212 x [MW flow north on the Vic to NSW AC Interconnector]

- 0.241 x [MW flow north on the QNI AC Interconnector]

- 0.235 x [MW flow north on the Terranora Interconnector]

+ 0.259 x [Bayswater unit 1]

+ 0.259 x [Bayswater unit 2]

+ 0.374 x [Bayswater unit 3]

+ 0.374 x [Bayswater unit 4]

+ 0.25 x [Liddell unit 1]

+ 0.25 x [Liddell unit 2]

+ 0.25 x [Liddell unit 3]

+ 0.25 x [Liddell unit 4]

+ 0.723 x [Mt Piper unit 1]

+ 0.723 x [Mt Piper unit 2]

- Wallerawang unit 7

- Wallerawang unit 8

+ 0.12 x [Shoalhaven hydro (aggregated Bendeela and Kangaroo Valley units)]

- 0.12 x [Shoalhaven pumps (2 aggregated pumps)]

+ 0.216 x [Blowering hydro (3 aggregated units)]

+ 0.25 x [Redbank unit 1]

+ 0.213 x [Hume (NSW) hydro]

+ 0.25 x [Hunter GT (2 aggregated units)]

+ 0.212 x [Upper Tumut hydro (8 aggregated units)]

+ 0.212 x [Lower Tumut hydro (6 aggregated units)]

- 0.212 x [Lower Tumut pumps (3 aggregated pumps)]

+ 0.206 x [Guthega hydro (2 aggregated units)]

+ 0.1 x [Tallawarra CCGT]

+ 0.214 x [Uranquinty GT unit 1]

+ 0.214 x [Uranquinty GT unit 2]

+ 0.214 x [Uranquinty GT unit 3]

+ 0.214 x [Uranquinty GT unit 4]

A.2 Constraint equation N>>N-MNMP_ONE_1

Constraint description: Out = Marulan to Mt.Piper (35 or 36) line, avoid Mt Piper-Wallerawang 30kV line (70) O/L on Mt Piper-Wallerawang 330kV line (71) trip; Feedback

Impact: NSW Generation + Interconnectors

Reason: Mt Piper-Wallerawang 330kV line (71) trip

LHS =

0.31 x Bayswater unit 1

0.31 x Bayswater unit 2

0.447 x Bayswater unit 3

0.447 x Bayswater unit 4

0.166 x Blowering hydro (3 aggregated units)

0.146 x Guthega hydro (2 aggregated units)

0.155 x Hume (NSW) hydro

0.299 x Hunter GT (2 aggregated units)

0.299 x Liddell unit 1

0.299 x Liddell unit 2

0.299 x Liddell unit 3

0.299 x Liddell unit 4

-0.153 x Lower Tumut pumps (3 aggregated pumps)

0.153 x Lower Tumut hydro (6 aggregated units)

0.299 x Redbank unit 1

0.869 x Mt Piper unit 1

0.869 x Mt Piper unit 2

0.158 x Uranquinty GT unit 1

0.158 x Uranquinty GT unit 2

0.158 x Uranquinty GT unit 3

0.158 x Uranquinty GT unit 4

0.153 x Upper Tumut hydro (8 aggregated units)

- Wallerawang unit 7

- Wallerawang unit 8

-0.281 x MW flow north on the Terranora Interconnector

-0.288 x MW flow north on the QNI AC Interconnector

0.154 x MW flow north on the Vic to NSW AC Interconnector

RHS =

2.021 x (NSW: 70 Mt. Piper-Wallerawang 330kV Sustained Emergency Rating

- MW flow on 70 330kV line at Mt Piper, Line end switched MW

- 0.925 x [MW flow on 71 330kV line at Mt Piper, Line end switched MW]

- 40 {Margin})

+ 0.154 x [MW flow north on the Vic to NSW AC Interconnector]

- 0.288 x [MW flow north on the QNI AC Interconnector]

- 0.281 x [MW flow north on the Terranora Interconnector]

+ 0.31 x [Bayswater unit 1]

+ 0.31 x [Bayswater unit 2]

+ 0.447 x [Bayswater unit 3]

+ 0.447 x [Bayswater unit 4]

+ 0.299 x [Liddell unit 1]

+ 0.299 x [Liddell unit 2]

+ 0.299 x [Liddell unit 3]

+ 0.299 x [Liddell unit 4]

+ 0.869 x [Mt Piper unit 1]

+ 0.869 x [Mt Piper unit 2]

- Wallerawang unit 7

- Wallerawang unit 8

+ 0.166 x [Blowering hydro (3 aggregated units)]

+ 0.299 x [Redbank unit 1]

+ 0.155 x [Hume (NSW) hydro]

+ 0.299 x [Hunter GT (2 aggregated units)]

+ 0.153 x [Upper Tumut hydro (8 aggregated units)]

+ 0.153 x [Lower Tumut hydro (6 aggregated units)]

- 0.153 x [Lower Tumut pumps (3 aggregated pumps)]

+ 0.146 x [Guthega hydro (2 aggregated units)]

+ 0.158 x [Uranquinty GT unit 1]

+ 0.158 x [Uranquinty GT unit 2]

+ 0.158 x [Uranquinty GT unit 3]

+ 0.158 x [Uranquinty GT unit 4]