DECLARED WHOLESALE GAS MARKET (VIC)

INVESTIGATION OF AN UNINTENDED SCHEDULING RESULT

Gas Day 29 June 2010

PREPARED BY: Market Performance

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Disclaimer

This report has been prepared by the Australian Energy Market Operator Limited (AEMO) for the sole purpose of an investigation of an unintended scheduling result in accordance with Rule 218 of the National Gas Rules

Investigation of an Unintended Scheduling Result on 29 June 2010

Background

In accordance with rule 218(1)(b) of the National Gas Rules, on 12 July 2010, AEMO published a notice that it had, on its own initiative, commenced an investigation into whether an *unintended scheduling result* occurred on 29 June 2010.

This Report includes AEMO's decision and the analysis and reasons for its decision in accordance with rule 218(3) of the National Gas Rules.

Decision

AEMO has determined that an *unintended scheduling result* occurred in the 2pm, 6pm and 10pm schedules on 29 June 2010.

On gas day 29 June 2010 there was an increase in forecast demand to the highest level this winter, exceeding 1200TJ. In the 2pm reschedule, maximum hourly flow Supply Demand Point Constraints (SDPCs) were applied to the Iona and SEA Gas injection points in accordance with the Gas Scheduling Procedures. These SDPCs were applied to limit the aggregate flow in the South West Pipeline (SWP) to its maximum transportation capacity and were applied to ensure the correct flows from each injection point.

Given the SDPCs, gas injection bids at 2pm and 6pm for both the Iona and SEA Gas were such that only injection bids priced at $0/GJ were scheduled. However, analysis undertaken in this investigation found that the Market Clearing Engine (MCE) did not respond as expected or as intended. Different *response times* specified in the *accreditation of controllable quantities* applying to gas bids for the SEA Gas injection point from different market participants, caused a quantity of gas that was offered on an equally beneficial basis at $0GJ in the 2pm schedule to be de-scheduled while other equally priced gas was scheduled to continue flowing. At 6pm a quantity of a new gas bid, at $0/GJ and supported by AMDQ on an equally beneficial basis as other gas scheduled, was not scheduled.

AEMO has concluded that an *unintended scheduling result* occurred on 29 June 2010 in the 2pm and 6pm reschedules in accordance with the criteria specified in the National Gas rules:

- Rule 217(1)(a): In the 2pm schedule, equally beneficial bids at the SEA Gas injection point and at the same bid price $0/GJ were not scheduled to the same extent. In the 6pm schedule, equally beneficial bids at the SEA Gas injection point, at the same bid price of $0/GJ and supported by AMDQ Credit Certificates, were not scheduled to the same extent.
- Rule 217(2)(a)(vii)&((ix): The SDPCs were applied in accordance with Scheduling Procedures for the 2pm and subsequent schedules and set the correct aggregate hourly flow rates at the Iona and SEA Gas injection points and thus the total flow rate into the South West Pipeline. These SDPCs were intended to control overall flow rates and not to cause the unintended scheduling outcomes for individual participants as summarised above; and
- Rule 217(4): The total financial impact in terms of market imbalance payments was in the order of $30,000, excluding GST, and for one market participant exceeded the $20,000 threshold required for an unintended scheduling result.

Actions to deal with potential future occurrences

As an interim solution to mitigate the risk of a recurrence of this scheduling issue, AEMO has issued a market notice in accordance with the Scheduling Procedures indicating that on days where an SDPC is applied at an injection point, accredited constraint response times will be set equal to the gas supply with slowest response time. This will ensure that all gas bids are treated on an equal basis.

In the longer term AEMO will review the Accreditation process and develop a paper with options to deal with this scheduling issue, and commence consultation on the solutions through the Gas Wholesale Consultative Forum.

Analysis of SEA Gas Schedules on 29 June 2010

SEA Gas Schedules: 6am and 10am

29 June 2010 was an extremely cold day and operational issues were compounded by a SDPC also being applied at the Longford injection point to reflect an ongoing part plant outage. The reduction in supply from Longford caused flows in the South West pipeline to be scheduled initially near to and later at the maximum capacity of the South West Pipeline (Iona to Melbourne) while relying on LNG from the Dandenong storage facility as the last available gas supply to meet system demand.

Four market participants, denoted by A, B, C and D in this analysis, submitted $0 bids at SEA Gas. In three instances these $0 bids were partly or fully supported by AMDQ for the purpose of tie-breaking in the scheduling process.

In the 6am and 10am schedules total forecast demand was 1159 and 1172TJ respectively, with the market prices shown in Table 1 set in each schedule by a bid at Iona. There were no binding SDPCs and the pipeline system was not constrained.

Table 1 show the relevant bids and scheduled quantities for the 6am and 10am schedules. The figures shown are preliminary and are rounded to the nearest GJ or nearest dollar. The scheduling outcomes are as intended and no adjustments are required to scheduled quantities or changes to imbalance payments (Δ IP) as a result of the issues that arose in the subsequent schedules on the day.

Table 1. SEA Gas Schedules 29 June 2010 6am and 10am

6am	Mkt Price	$ 3.6307			Adjustments	
ID	Bid	Bid Price	AMDQ	Scheduled	Schedule	Δ IP
A	63,000.0	$0.0000	50,000	63,000	63,000	$0
B	5,000.0	$5.9200	10,000	0	0	$0
C	4,400.0	$0.0000	0	4,400	4,400	$0
D	5,000.0	$0.0000	6,875	5,000	5,000	$0
			Total	72,400	72,400	$0

10am	Mkt Price	$ 3.8749			Adjustments	
ID	Bid	Bid Price	AMDQ	Scheduled	Schedule	Δ IP
A	63,000.0	$0.0000	50,000	63,000	63,000	$0
B	5,000.0	$5.9200	10,000	0	0	$0
C	4,400.0	$0.0000	0	4,400	4,400	$0
D	5,000.0	$0.0000	6,875	5,000	5,000	$0
			Total	72,400	72,400	$0

SEA Gas Schedules: 2pm, 6pm and 10pm

In the 2pm and 6pm reschedules, forecast demand increased to 1211 and 1224TJ respectively, due to forecast colder weather. SDPCs as MHQ (hourly flow rate limits) were applied at the SEA Gas and Iona injection points. These SDPCs were binding constraints such that only $0/GJ gas bids were scheduled at the Iona, SEA Gas injection points. Only $0/GJ gas was scheduled elsewhere in the system except at the LNG storage facility. The market prices increased to $5.9142 and $5.9112/GJ respectively, as shown in Table 2. and were set by LNG bids.

LNG was scheduled in price merit order because it was the last available source of supply given that all other supplies were scheduled at their respective maximum deliverable flow rates set by the SDPCs. The pipeline system itself was technically not constrained because the SDPCs set at Iona and SEA Gas were, in aggregate, consistent with the South West Pipeline capacity/maximum flow rate.

The relevant SEA Gas injection bids, AMDQ support and scheduled quantities are shown in the 2nd to 5th columns of Table 2.

In the 2pm schedule Market Participant C's 4,400GJ $0 bid (no AMDQ) which had been previously fully scheduled was rescheduled down to 1,467GJ. The 1,467GJ is the quantity scheduled in scheduling intervals prior to 2pm and no flow was scheduled from 2pm onwards. In this instance this gas bid would be expected to be prorated to a lower flow rate along with other equally beneficial bids ($0, no AMDQ support) at the time the SDPC was applied. This unintended scheduling outcome occurred because Market Participant C's accredited response time of zero allowed its gas flow to be reduced immediately to meet the SDPC whereas Market Participant A's and D's flows could not respond immediately due to the non-zero accredited response times. The outcome arose due to inconsistent accredited response times at a time a binding SDPC was applied.

In the 6pm schedule Market Participant B's 5,000GJ rebid at $0GJ and supported by AMDQ was not scheduled on in full as expected because the $0 gas already flowing bid at the maximum rate afforded by the SDPC could not be reduced immediately due to a non-zero accredited response times. Again, this outcome arose due to inconsistent accredited response times at a time a binding SDPC was applied.

The conclusions above have been confirmed by ICF consultants (who AEMO engages to support the MCE and its algorithms used for scheduling).

To determine the adjusted (revised) schedules shown in Table 2, the accredited response times were set equal the non-zero response times so that all gas competed on an equal basis in this context. The adjusted schedules and changes that occurred in imbalance payments (**Δ IP) excluding** GST are shown in the right-hand side columns of Table 2.

In the adjusted schedules in Table 2, all $0/GJ bids supported by AMDQ are scheduled in full while $0 bids without AMDQ are prorated by bid quantity, in accordance with the Scheduling Procedures, to use up the balance of injection capacity up to the maximum hourly flow rate set by the SDPC.

In the 10pm schedule, forecast demand reduced to 1193TJ due to less cold forecast overnight temperatures. The SDPC at SEA Gas was increased from 2,821GJ/h to an MHQ of 3005 GJ enabling increased SEA Gas injections which were was associated with scheduled withdrawals at Iona withdrawals. This increase in the SEA Gas SDPC enabled scheduling of some of Market Participant B's 5,000GJ $0 bid from 10pm. An Iona withdrawal bid set the market price of $2.2700/GJ. As occurred for the 6pm schedule, the different accredited response times did not allow this bid to be fully scheduled. The adjusted 10pm schedules and changes to imbalance payments are included so that the overall impacts on the day can be determined.

Table 2. SEA Gas Schedules 29 June 2010: 2pm, 6pm, and 10pm

2pm	Mkt Price	$ 5.9412	SDPC MHQ	2,821	Adjustments	
ID	Bid	Bid Price	AMDQ	Scheduled	Schedule	Δ IP
A	63,000.0	$0.0000	50,000	62,461	60,406	-$12,210
B	3,000.0	$9.9200	10,000	0	0	$0
C	4,400.0	$0.0000	0	1,467	3,522	$12,210
D	5,000.0	$0.0000	6,875	5,000	5,000	$0
			Total	68,927	68,927	$0

6pm	Mkt Price	$ 5.9112	SDPC MHQ	2,811	Adjustments	
ID	Bid	Bid Price	AMDQ	Scheduled	Schedule	Δ IP
A	63,000.0	$0.0000	50,000	62,341	56,580	-$21,904
B	5,000.0	$0.0000	10,000	0	5,000	$29,556
C	4,400.0	$0.0000	0	1,467	2,227	-$7,653
D	5,000.0	$0.0000	6,875	5,000	5,000	$0
			Total	68,807	68,807	-$2

10pm	Mkt Price	$ 2.2700	SDPC MHQ	3,005	Adjustments	
	Bid	Bid Price	AMDQ	Final Scheduled	Final Schedule	Δ IP
A	63,000.0	$0.0000	50,000	62,341	57,740	$2,633
B	5,000.0	$0.0000	10,000	1,552	5,000	-$3,523
C	4,400.0	$0.0000	0	1,467	2,620	$891
D	5,000.0	$0.0000	6,875	5,000	5,000	$0
			Total	70,359	70,359	$0

Financial impacts on the day

Table 3 summarises the changes to daily imbalance payments (excluding GST) for each market participant based on the adjusted schedules. Market Participants B and C were scheduled to flow 3,448GJ and 2,198GJ less gas on the day due to the unintended scheduling outcome. This reduced imbalance payments to them by $26,033 and $5,448 excluding GST, respectively. Market Participant A was scheduled flow more gas and achieved an increase in its imbalance payments on the day of $31,482 offsetting the reductions to Market Participants B and C exactly.

Table 3. Changes to Imbalance Payments for 29 June 2010

Gas Day Total		
ID	Δ IP	GJ retained
A	-$31,482	0
B	**$26,033**	**3,448**
C	**$5,448**	**1,153**
D	$0	0
Total	$0	

It should be noted that while Market Participants B and C did not receive the imbalance payments indicated above from the market, they do retain the value of the unscheduled gas for potential use in this market or another market in the future. In this context, the dollar amounts shown in Table 3 do not reflect the net financial impact on each of them.

Market Participants B and C were contacted in the days following the event and the issue and the potential financial impacts on them were discussed.

Market Participant A was scheduled to inject the gas and thus received imbalance payments at market price in accordance with their schedules for selling gas injected into the market. To the extent that Market Participant A varied from their schedule they were subject to deviation payments at the relevant market prices.