THE LONDON PROPERTY MANAGEMENT ASSOCIATION ("LPMA"), THE WHOLESALE GAS SERVICE PURCHASERS GROUP ("WGSPG"), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA ("BOMA") #1

INTERROGATORY

Ref: PEG Report, page ii

Issue Number: 3.1
Issue: How should the X factor be determined?

The evidence indicates that the sample period for the Enbridge and Union indexing work was limited to 2000 – 2005.

a) Please update all relevant portions of the PEG Report to reflect the use of 2000 – 2006 data for Enbridge and Union. Please provide tables showing the Summary Price Cap Indexes, Service Group PCIs and Revenue Cap Indexes for Enbridge and Union comparing the results using the 2000 – 2005 data and using the 2000 – 2006 data. Please provide explanations for all changes.
b) Please update all relevant portions of the PEG Report to reflect the use of 2001 – 2006 data for Enbridge and Union. Please provide tables showing the Summary Price Cap Indexes, Service Group PCIs and Revenue Cap Indexes for Enbridge and Union comparing the results using the 2000 – 2005 data and using the 2001 – 2006 data. Please provide explanations for all changes.

RESPONSE

a) and b) The requested updates would require significant new work to be conducted by PEG, including the gathering of the 2006 data. These updates might produce materially different estimates of the TFP and rate trends of the two companies and might have a modest effect on the IPD. However, it should be noted that PEG is not purposing to use the TFP trends of the companies in the X factor calculations. They are just there to appraise the reasonableness of the external targets.

Witness: Mark Lowry

PEG cannot provide the results of these updates within the timelines of the interrogatories' responses. However PEG anticipates that if the utilities provide the data in a timely manner after receiving the data request, results of these updates will be available prior to the commencement of ADR.

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”) #2

INTERROGATORY

Ref: PEG Report, page ii

Issue Number: 3.1
Issue: How should the X factor be determined?

The evidence indicates that the sample period for US work was 1994 - 2004.

a) Please update all relevant portions of the PEG Report to reflect the use of the 2000 – 2005 sample period for the US work (If 2005 data is not available, use the sample period 1999 – 2004). Please provide tables showing the Summary Price Cap Indexes, Service Group PCIs and Revenue Cap Indexes for Enbridge and Union comparing the results using the sample period 1994 – 2004 for the U.S. work as filed and using the 2000 – 2005 (or 1999 – 2004) sample period for the U.S. work. Please provide explanations for all changes.

b) Please explain why PEG used a sample period of 1994 – 2004. What are the possible implications of using a different sample periods? Does the business cycle have any impact on the results depending on the years used? Please explain.

RESPONSE

a) The requested update would require significant new work to be conducted by PEG and would have little or no benefit to the proceeding. A period shorter than 10 years for the estimation of the econometric model has two problems: First, the model would not reflect the long term trend in the TFP. Second, a reduction in the number of data points will reduce the precision of the estimates of the cost elasticities that we use in various X factor calculations. Therefore PEG will not conduct the requested update.

b) A ten year sample period is appropriate for capturing the long term trend in the TFP of the sampled gas utilities. A ten year sample period is also desirable for the development of accurate elasticity estimates using econometric methods. The business cycle is a germane consideration since delivery volumes (especially those to industrial customers) in a given year display a modest sensitivity to the position in the cycle. However, the 1994-2004 period poses no particular problems in this regard since both the start and the end dates are years of rebound from a recent recession.

THE LONDON PROPERTY MANAGEMENT ASSOCIATION ("LPMA"), THE WHOLESALE GAS SERVICE PURCHASERS GROUP ("WGSPG"), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA ("BOMA") #10

INTERROGATORY

Ref: PEG Report, page 22

Issue Number: 3.1
Issue: How should the X factor be determined?

a) What is the potential impact of the PEG estimates of using "rough estimates" for net salaries and wages, pension and other benefits costs for Enbridge?

b) Please recalculate the Summary Price Cap Indexes, Service Group PCIs and Revenue Cap Indexes found in the tables in the Executive Summary if the rough estimates used for Enbridge are excluded from the analysis.

c) Has PEG attempted to obtain the level of detail from Enbridge that it was able to obtain from Union? If so, please provide the explanation provided by Enbridge for not providing the information.

RESPONSE

a) Rough estimates of EGD labour costs will materially distort our estimates of the quantity subindexes for the labour and materials & services input categories. However, these distortions are substantially offsetting and produce net distortions in our estimates of TFP and the productivity of O&M inputs only to the extent that they result in inappropriate weights for the subindexes.

b) The requested recalculation requires that Enbridge provides the above mentioned data. PEG anticipates that if Enbridge provides the data in a timely manner after receiving a new data request, results of this recalculation will be available prior to the commencement of ADR

c) PEG made concerted efforts to obtain this information. Enbridge in essence responded that the requested data were not readily available and that their personnel were busy with other duties.

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”) #11

INTERROGATORY

Ref: PEG Report, page 23

Issue Number: 3.1
Issue: How should the X factor be determined?

What is the impact on the analysis of changing the 65/35 weighting of debt and equity to the current Board approved weighting of 64/36 for each of the utilities?

RESPONSE

This change would have only a slight effect on the analysis because the change in the weighting is slight.

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION ("LPMA"), THE WHOLESALE GAS SERVICE PURCHASERS GROUP ("WGSPG"), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA ("BOMA") #13

INTERROGATORY

Ref: PEG Report, page 24

Issue Number: 4.2
Issue: How should the impact of changes in average use be calculated?

The evidence states that the treatment of DSM savings was undertaken in the ***hope*** that the Picks would not compensate the utilities for their DSM activities.

a) Can PEG confirm that the approach taken will not result in double counting through the PCI and the Lost Revenue Adjustment Mechanism for DSM activities.

b) If actual normalized use was used, including the impact of DSM, instead of adjusting actual normalized use for the DSM savings, in the calculation of the average use adjustment factor, would this approach eliminate any potential for double counting? Please explain.

c) Please redo the analysis using the approach suggested in part (b) above and provide the resulting PCI components for both utilities.

RESPONSE

a) Yes.

b) No. The AU factor would be more negative and the utilities would be compensated during the IR period for the historical slowdown in volume growth due to DSM even if they have already been compensated for lost revenue.

c) The requested recalculation would require significant new work to be conducted by PEG. As explained in b), this approach would not eliminate any potential for double counting, therefore PEG will not redo this analysis.

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION ("LPMA"), THE WHOLESALE GAS SERVICE PURCHASERS GROUP ("WGSPG"), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA ("BOMA") #14

INTERROGATORY

Ref: PEG Report, page 27-28

Issue Number: 3.1
Issue: How should the X factor be determined?

The evidence indicates that the shares of each billing determinant in revenue served as weights in the output quantity indexes and that both utilities provided PEG with highly detailed data on billing determinants and the corresponding revenues.

a) Please provide all such data in electronic format.

b) Please provide all calculations used to estimates the weights used in the indexes and used in the calculation of the indexes.

c) How was the data used adjusted to reflect any increase in the fixed monthly charges and/or demand charges over the period for which data was used? If no adjustment was made, please explain why.

d) Have the revenue weights been adjusted to reflect the Board approved fixed charges and/or demand charges that have been approved for the fiscal 2007 base year? If not, why not?

e) Would a change in the monthly fixed charges and/or demand charges in the base year fiscal 2007 have an impact on the calculation of the weights used in the output quantity indexes? If not, why not?

f) If the answer to part (e) is yes, please redo the analysis and provide the analysis and results that would flow from using the current fixed/variable rates as approved by the Board for the 2007 base year.

g) Union Gas proposes to have the flexibility to adjust the fixed and variable components of rates using different percentages. Would this flexibility have any impact on the appropriate weights to be used in calculating the indexes if these weights are changed during the IR period? Please explain.

<u>RESPONSE</u>

a) See the working papers prepared in PEG's response to question 2 of EGD's interrogatories. Please note that access to some portions of the working papers requires the signing of a confidentiality agreement.

b) See the working papers prepared in PEG's response to question 2 of EGD's interrogatories. Please note that access to some portions of the working papers requires the signing of a confidentiality agreement.

c) and d) The revenue-weighted output indexes are based on 2005 since 2005 data were the latest for which data were provided. Additionally, it is our understanding that the EGD final rate orders for 2007 base year have yet to be approved.

e) Yes

f) PEG cannot provide the results of these updates within the timelines of the interrogatories' responses. However PEG anticipates that if the utilities provide the data in a timely manner after receiving the data request, results of this recalculation will be available prior to the commencement of ADR.

g) Yes. A redesign of weights can place more weight on customer charges, and thereby bolster revenue insofar as customer growth is more rapid than output growth. This can affect the pertinent X factor, which is specific to the revenue shares of Enbridge and Union.

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”) #16

INTERROGATORY

Ref: PEG Report, page 27

Ref: PEG Report, page 28

Issue Number: 3.2
Issue: What are the appropriate components of an X factor?

The evidence indicates that the input index for Union also includes a subindex for gas used in system operations.

a) Does the inclusion of a subindex for gas used in system operations mean that any change in gas volumes should not be a Y or Z factor adjustment? Please explain.

b) Does the inclusion of a subindex for gas used in system operations mean that any change in gas prices should not be a Y or Z factor adjustment? Please explain.

RESPONSE

a & b) No. This index covers only gas consumed by the company in its utility operations. The PCI thus does not adjust rates for changes in the price of gas and the quantities of Union’s gas sales services.

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”) #23

INTERROGATORY

Ref: PEG Report, page 27 - 28

Issue Number: 3.1
Issue: How should the X factor be determined?

The evidence indicates that index theory suggests that flexible weights are generally more accurate than fixed weights for calculating the revenue weights.

a) Please explain why PEG decided to use the fixed weights.

b) Please explain how this fixed weight has been determined. Please provide all the data and calculations and assumptions used to calculate these fixed weights.

c) Does the fixed weight calculation take into account the higher monthly customer charges approved by the Board in the 2007 base rates? If not, please update the evidence to reflect this change.

RESPONSE

a) PEG fixed the weights in order to simulate the inability for companies to adjust rates among volumetric and fixed charges in the future IR plan.

b) The fixed weights take the revenue in 2005 derived from each category (eg. Volumetric charge of Rate 1) and divide this by the total revenue of all the categories. For the data and calculations of these revenue weights see PEG’s response to question 2 of EGD’s interrogatories.

c) The calculations do not reflect the Board approved 2007 base rates. Please see Exhibit R-PEG, Tab5, Schedule 14 (f).

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”) #24

INTERROGATORY

Ref: PEG Report, Table 10

Issue Number:
Issue:

Please update Table 10 to reflect actual 2006 data.

RESPONSE

To fully reflect actual 2006 data in table 10, we would need to include 2006 data in the econometric model that determine Please refer to Exhibit R-PEG, Tab 6, Schedule 1.

The requested update would require significant new work to be conducted by PEG. It would require gathering data for all the 36 US gas utilities for the years 2005 and 2006 and redoing the econometric analysis. PEG is of the view that the inclusion of two years in a ten year database has only a modest impact on results. Therefore PEG will not conduct the requested update.

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION ("LPMA"), THE WHOLESALE GAS SERVICE PURCHASERS GROUP ("WGSPG"), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA ("BOMA") #30

INTERROGATORY

Ref: PEG Report, page 61

Issue Number: 3.2
Issue: What are the appropriate components of an X factor?

a) Did PEG take into account the historic precedent of Union's trial PBR plan that was in place in 2001 through 2003 when setting the stretch factor? If not, why not?

b) Please confirm the following from Union's trial PBR plan as approved and implemented:

Component/Year	2001	2002	2003
GDPPI	3.9%	2.5%	0.2%
IPD	1.1%	1.1%	1.1%
Stretched PD	1.4%	1.4%	1.4%
Price Cap	1.4%	0.0%	-2.3%

c) Please confirm that during Union's trial PBR plan there was an earnings sharing mechanism in place.

d) Please confirm the following during Union's trial PBR plan:

ROE/Year	2001	2002	2003
Approved *	9.66%	9.62%	9.37%
Normalized Actual	11.45%	12.36%	12.08%
Difference	1.79%	2.74%	2.71%

* Approved based on the draft guideline formula and used for earnings sharing purposes.

e) The PEG report recommends an overall X factor of 0.52, only one-fifth of the X factor approved by the Board in RP-1999-0017. With an X factor of 2.5%, Union has able to earn a significant premium, even with an earnings sharing

Witness: Mark Lowry

mechanism in place. In light of this, does PEG believe that a low X factor, as recommended, and no earnings sharing mechanism is appropriate, in light of the historical precedent of Union's trial PBR plan. Please explain fully.

f) Please present the performance predicted by the incentive power model that would have been predicted for Union's trial PBR plan. Please provide all inputs and assumptions used in modeling the expected performance improvement.

g) Is PEG aware of any IR plans that have a variable stretch factor that can be adjusted during the plan of a term? If yes, please provide a summary of the number and types of adjustments that are made.

<u>RESPONSE</u>

a) Yes.

b) 2001: From "Decision with Reasons" in Docket RP-1999-0017 (Union's 2001 GRC)

- The IPD was set at 1.1% 2001-2003.
- The table accurately reflects the stretched productivity factor: fixed at 1.4% from 2001-2003, giving an X-factor of 2.5% (p. 89).
- The GDPPI for 2001 was indeed set at 3.9%, based on the annual change 1999 Q2 - 2000 Q2 (p. 90).

2002: From "Decision with Reasons" in Docket RP-2001-0029 (2002 rate review)

- The inflation index adopted by the Board for 2002 was 2.0% rather than 2.5% as shown in the table. Thus we believe that the price cap index for 2002 was (I-X) = (2.0%-2.5%) = -0.5%, rather than 0.0% as shown in the table (p.71).

2003: From "Settlement Agreement" in Docket RP-2002-0130 (2003 rate review)

- The table accurately reflects the inflation index of 0.2% adopted in the settlement agreement, and corresponding price cap of -2.3% (p. 9).

c) From "Decision with Reasons" in Docket RP-1999-0017 (Union's 2001 GRC): The 2001-2003 PBR plan included an earnings sharing mechanism with the following specifications: symmetric, based on actual earnings, with a deadband around Board-approved ROE of one percentage point after taxes, and sharing of any earnings variance on a 50:50 basis between the ratepayer and shareholder (p. 152).

d) We are able to confirm some, but not all, of the figures presented in this table.

e) The 2.5% X factor chosen by the Board in RP-1999-0017 is at the high end of the range that has been approved for North American energy utilities. It reflected a sizable 1.1% input price differential that was sensitive to the decline in bond yields that slowed materially in the mid-1990s. The stretched productivity factor of 1.4% was far above the recent productivity trend of Union. In choosing the 1.4% figure the Board did not clearly acknowledge the need to subtract the productivity trend of the economy.

The fact that Union prospered under this plan may reflect special circumstances such as the following:

- Unusually strong demand for its services
- Favorable movements in input prices
- Less pronounced average use declines than it faces today

f) Details of the incentive power research are attached to our response to Enbridge question 45. Examination of the table that summarizes incentive power results suggests that Union's PBR plan, with a four year term (including three out years) and earnings sharing would produce substantially weaker incentives than the plan approved by Board staff. Please note that access to the code for our incentive power model requires the signing of a confidentiality agreement.

g) We have not done a systematic review of this issue but believe that some approved plans have involved increasing X factors. An example is the plan recently approved in Massachusetts for the power distribution services of NSTAR electric and gas. This plan did not involve a specific stretch factor.

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONOTO AREA (“BOMA”) #32

INTERROGATORY

Ref: PEG Report, page 64

Issue Number: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

The evidence states that the notional PCI change for each company is similar to the trend in their actual rates during the 2000-2005 period.

a) Please provide the Board Approved rates for all rate classes that were in place for Union for 2000.

b) Please provide the Board Approved rates for all rate classes that were in place for Enbridge for 2000.

c) Please provide the Board Approved rates for all rate classes that were in place for Union for 2005.

d) Please provide the Board Approved rates for all rate classes that were in place for Enbridge for 2005.

RESPONSE

(a)(b)(c) Copies of Board approved rates for Union 2000, Union 2005, and Enbridge 2000 will be provided shortly. Historical rate information for Union Gas from 1997 to 2007 is available through the following link to Union’s website: http://www.uniongas.com/aboutus/regulatory/rates/summary/ratesummary.asp

(d) The Enbridge final rate order, RP-2003-0063, with all Board approved rates for 2005 is attached.

Witness: Mark Lowry

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Ontario

BY PRIORITY POST 1

December 22, 2004 2

Mr. Patrick Hoey 3
Director, Regulatory Affairs
Enbridge Gas Distribution Inc.
500 Consumers Road
Toronto, Ontario
M1K 5E3

Dear Mr. Hoey: 4

Re: **Enbridge Gas Distribution Inc.** 5
Rate Order
Board File No. RP-2003-0203

The Board has today issued its Rate Order in the above matter, and an executed copy is enclosed. 6

You are directed: 7

1. to immediately serve a copy of this Rate Order, either personally by courier or by registered mail, upon each intervenor and observer of record in RP-2003-0203; 8

2. to file with the Board affidavit evidence proving the above service immediately upon completion, with a copy of the Order and the original Post Office Registration Receipts (where applicable) and/or courier slips attached as appendices. 9

Yours truly, 10

11

John Zych
Board Secretary

DocID: OEB: 13DFR-0

1

RP-2003-0203

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15 (Schedule B); 2

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission, and storage of gas commencing October 1, 2004. 3

BEFORE: 4

Bob Betts 5
Presiding Member

Paul Sommerville 6
Member

Pamela Nowina 7
Member

FINAL RATE ORDER ARISING FROM THE 2005 TEST YEAR DECISION WITH REASONS RP-2003-0203 8

Enbridge Gas Distribution Inc.("EGDI", the "Company") filed an application dated December 17, 2003 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas for EGDI's 2005 fiscal year commencing October 1, 2004. The Board assigned file number RP-2003-0203 to the Application. 9

The Board issued a Partial Decision with Reasons on August 31, 2004 and directed that several rate design changes be implemented on October 1, 2004, including the removal of rate seasonality, except for Rate 135, and an increase in the monthly Rate 1 customer charge to $11.25 per customer. 10

On September 3, 2004, EGDI filed its proposal for an interim rate order. The Board issued an Interim Rate Order on September 27, 2004, and noted that a final rate order would be approved after the Board had dealt with the remaining unsettled issues in a forthcoming Decision with Reasons. 11

On November 1, 2004, the Board issued its RP-2003-0203 Decision with Reasons which included the Board's findings regarding the unsettled issues of Transactional Services, Gas Transportation and Storage Costs, Risk Management, Deferred Taxes and Fiscal Year-End Change. 12

With regard to rate implementation impact of the RP-2003-0203 Decision, the Board required that ... 13

> "... the Company reflect the changes brought about by this Decision, and the Settlement Proposal, including an updated ROE, in revised financial schedules similar to the "N1, Tab 2" exhibits. These exhibits shall be filed with the Board as soon as possible." (RP-2003-0203 Decision/ para. 7.1.1) 14

and directed that... 15

> " In order to implement the new rates as quickly as practicable...the Company [to] file a Draft Final Rate Order with the Board as soon as possible. Given the timing of this Decision, the Board expects the new rates would be effective January 1, 2005." (RP-2003-0203 Decision/ para. 7.1.2) 16

On November 22, 2004, EGDI filed its proposal for a final rate order to be effective January 1, 2005. The proposal included the following elements: 17

- Restated 2005 Test Year financial statements ("N1, Tab 2" exhibits) indicating a sufficiency of $9.5 million and a corresponding reduction in rates; 18
- Unit rates for the one-time adjustment (customer credit) for the period October 1, 2004 to December 1, 2004; 19
- Unit rates for the one-time adjustment (customer credit) for the disposition of the 2004 deferral account balances for Transactional Services, Unaccounted for Gas and Earnings Sharing. 20

The Industrial Gas Users Association, the School Energy Coalition, the Vulnerable Energy Consumers Coalition and the Consumers Council of Canada filed submissions, dated December 3, 2004, December 9, 2004, December 10, 2004 and December 9, 2004, respectively, with the Board. The submissions expressed disagreement with EGDI's calculation of the amount of 2004 over-earnings to be shared with ratepayers. 21

For purposes of this final rate order, the Board will pass through the earnings sharing total as 22
currently proposed by EGDI so as to not unduly delay the implementation of the related customer credit. Regarding the single remaining issue relating to the inclusion of a customer service cost component in the earnings sharing calculation, the Board makes no determination at this time. The Board issued a Letter of Direction, dated December 10, 2004, which set out a timetable for submissions on the issue and recognized that any adjustment resulting from the process would not be ready for inclusion in the January 2005 billing cycle. Once submissions are complete, the Board will determine this issue and make any further orders that may be necessary at that time.

Upon reviewing the materials, the Board finds it appropriate to issue a final rate order effective 23
January 1, 2005 reflecting the Board's RP-2003-0203 Decision. The Board acknowledges that this rate order will be immediately superceded by another rate order, docket number RP-2003-0203/EB-2004-0492, also effective January 1, 2005, implementing the changes associated with the 2nd quarter Quarterly Rate Adjustment Mechanism ("QRAM"). The two orders provide an administrative path regarding the resulting rates.

THE BOARD ORDERS THAT: 24

1. The Financial Statements attached as Appendix "A" are accepted as the basis for the rates in this order. 25

2. The rates, attached as Appendix "B" and appearing under col. 5, to this order are hereby approved effective January 1, 2005. These rates will be immediately superceded by the interim rates resulting from the January 2005 QRAM decision. 26

3. The adjustment to applicable billed volumes during the period October 1, 2004 to December 31, 2004, shall be calculated using the unit rates included in the attached Appendix "C". 27

4. The 2004 Unaccounted for Gas variance account, the 2004 Transactional Services deferral account and the 2004 Earnings Sharing deferral account balances shall be cleared using the unit rates included in the attached Appendix "D". 28

ISSUED at Toronto, December 22, 2004 29

ONTARIO ENERGY BOARD

John Zych
Board Secretary

DocID: OEB: 13DFQ-0

APPENDIX "A" TO
ENBRIDGE GAS DISTRIBUTION INC.
RATE ORDER
BOARD FILE NO. RP-2003-0203
DATED: December 22, 2004
NOT AVAILABLE ELECTRONICALLY

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Utility Impact Summary

Line No.		Col. 1 Reference	Col. 2 ($Millions)
1.	Utility rate base	App.A.S3.P1	3,422.1
2.	Utility income	App.A.S4.P1	244.1
3.	Indicated rate of return	App.A.S5.P1	7.13%
4.	Requested rate of return	App.A.S5.P1	8.10%
5.	(Deficiency) in rate of return	App.A.S5.P1	(0.97)%
6.	Net (deficiency)	App.A.S5.P1	(33.2)
7.	Gross (deficiency)	App.A.S5.P1	(51.1)
8.	Revenue at existing rates	App.A.S6.P1	2,838.9
9.	Revenue requirement	App.A.S6.P1	2,890.0
10.	Gross revenue (deficiency)	App.A.S6.P1	(51.1)

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Utility Rate Base

Line No.		Col. 1 ADR 2004-06-17 N1.T2.S3 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Decision Utility Rate Base ($Millions)
	Property, plant, and equipment			
1.	Cost or redetermined value	4,381.5		4,381.5
2.	Accumulated depreciation	(1,481.0)		(1,481.0)
3.		2,900.5		2,900.5
	Allowance for working capital			
4.	Accounts receivable merchandise finance plan	0.3		0.3
5.	Accounts receivable rebillable projects	4.6		4.6
6.	Materials and supplies	19.9		19.9
7.	Mortgages receivable	1.1		1.1
8.	Customer security deposits	(31.3)		(31.3)
9.	Prepaid expenses	2.7		2.7
10.	Gas in storage	551.3	(0.7)	550.6
11.	Working cash allowance	(26.3)		(26.3)
12.	Total Working Capital	522.3	(0.7)	521.6
13.	**Utility rate base**	3,422.8	(0.7)	3,422.1

Note 1: Information from Col. 3 of Exhibit N1, Tab 2, Schedule 3, page 1, Updated: 2004-06-17.

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Explanation of Adjustments to Utility Rate Base

Line No. Adj'd	Adjustment ($Millions)	Explanation
10.	(0.7)	**Gas in storage** To reflect the impact of the OEB decision with respect to the gas storage contract between EGDI and Union Gas Limited. (Tr. Vol.1, 1092 - 1093)

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Working Capital Components - Working Cash Allowance

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,837.5	0.1	0.5
2.	Items not subject to working cash allowance		168.0		
3.	Gas costs charged to operations	App.A.S4.P1	2,005.5		
4.	Operation and Maintenance	App.A.S4.P1	301.3		
5.	Less: Storage costs		(6.5)		
6.	Operation and maintenance costs subject to working cash		294.8		
7.	Ancillary customer services		0.7		
8.			295.5	(33.9)	(27.4)
9.	Sub-total				(26.9)
10.	Storage costs		6.5	40.5	0.7
11.	Storage municipal and capital taxes		1.8	33.9	0.2
12.	Sub-total				0.9
13.	Goods and services tax				(0.3)
14.	Total working cash allowance				(26.3)

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Utility Income

Line No.		Col. 1 ADR 2004-06-17 N1.T2.S4 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Decision Utility Income ($Millions)
	Revenue			
1.	Gas sales	2,087.2		2,087.2
2.	Transportation of gas	750.2		750.2
3.	Transmission and compression & storage	1.6		1.6
4.	Other operating revenue	27.2		27.2
5.	~~Interest and property rental~~	-		-
6.	Other income	0.3		0.3
7.	**Total revenue**	2,866.5	-	2,866.5
	Costs and expenses			
8.	Gas costs	2,006.9	(1.4)	2,005.5
9.	Operation and maintenance	301.3		301.3
10.	Depreciation and amortization	193.5		193.5
11.	Fixed financing costs	1.2		1.2
12.	Recovery of notional deferred taxes	18.4	(6.1)	12.3
13.	Municipal and other taxes	51.5		51.5
14.	**Total costs and expenses**	2,572.8	(7.5)	2,565.3
15.	Utility income before income taxes	293.7	7.5	301.2
	Income taxes			
16.	Excluding interest shield	109.6	2.6	112.2
17.	Tax shield on interest expense	(55.1)	-	(55.1)
18.	Total income taxes	54.5	2.6	57.1
19.	**Utility net income**	239.2	4.9	244.1

Note 1: Information from Col. 3 of Exhibit N1, Tab 2, Schedule 4, page 1, Filed: 2004-06-17.

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Explanation of Adjustments to Utility Income

Line No. Adj'd	Adjustment ($Millions)	Explanation
8.	(1.4)	**Gas costs** To reflect the impact of the OEB decision with respect to the gas storage contract between EGDI and Union Gas Limited. The remaining $1.3 million of the $2.7 million Board decision impact with respect to the contract is realized through the Union Gas Deferral Account. (Tr. Vol.1, 1092 - 1093)
12.	(6.1)	**Recovery of notional deferred taxes** To reflect the impact of the OEB decision which allows the recovery of $23.9 million, after taxes, over a three year period commencing in fiscal 2005 instead of two years as reflected in calculations inherent within the ADR settlement agreement.
16.	2.6	**Income taxes - excluding interest shield** To reflect adjustments to utility income taxes as a result of the OEB decision.

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Utility Taxable Income and Income Tax Expense

Line No.		Col. 1 ADR 2004-06-17 N1.T2.S4.P3 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Decision Utility Tax ($Millions)
1.	Utility income before income taxes	293.7	7.5	301.2
	Add Backs			
2.	Depreciation and amortization	193.5		193.5
3.	Large corporation tax	6.5		6.5
4.	Other non-deductible items	1.2		1.2
5.	Total Add Back	201.2	-	201.2
6.	Sub total	494.9	7.5	502.4
	Deductions			
7.	Capital cost allowance - Federal	146.8		146.8
8.	Capital cost allowance - Provincial	146.7		146.7
9.	Items capitalized for regulatory purposes	32.1		32.1
10.	Deduction for "grossed up" Part VI.1 tax	5.7		5.7
11.	Amortization of share/debenture issue expense	1.8		1.8
12.	Amortization of cumulative eligible capital	0.1		0.1
13.	Amortization of C.D.E. and C.O.G.P.E	0.3		0.3
14.	Total Deduction - Federal	186.8	-	186.8
15.	Total Deduction - Provincial	186.7	-	186.7
16.	Taxable income - Federal	308.1	7.5	315.6
17.	Taxable income - Provincial	308.2	7.5	315.7
18.	Income tax provision - Federal	64.7	1.5	66.2
19.	Income tax provision - Provincial	43.1	1.1	44.2
20.	Income tax provision - combined	107.8	2.6	110.4
21.	Part V1.1 tax			1.9
22.	Investment tax credit			(0.1)
23.	Total taxes excluding tax shield on interest expense			112.2
	Tax shield on interest expense			
24.	Rate base			3,422.1
25.	Return component of debt			4.60%
26.	Interest expense			157.4
27.	Combined tax rate			35.00%
28.	Income tax credit			(55.1)
29.	Total income taxes			57.1

Note 1: Information from Col. 3 of Exhibit N1, Tab 2, Schedule 4, page 3, Filed: 2004-06-17.

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Utility Capital Structure

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	1,900.0	55.52	7.86	4.36
2.	Short term debt	225.3	6.58	3.59	0.24
3.		2,125.3	62.10		4.60
4.	Preference shares	99.1	2.90	5.00	0.15
5.	Common equity	1,197.7	35.00	9.57	3.35
6.		3,422.1	100.00		8.10
7.	Utility income	($Millions)			244.1
8.	Utility Rate base	($Millions)			3,422.1
9.	Indicated rate of return				7.13%
10.	(Deficiency) in rate of return				(0.97)%
11.	Net (deficiency)	($Millions)			(33.2)
12.	Gross (deficiency)	($Millions)			(51.1)
13.	Revenue at existing rates	($Millions)			2,838.9
14.	Revenue requirement	($Millions)			2,890.0
15.	Gross revenue (deficiency)	($Millions)			(51.1)

Enbridge Gas Distribution Inc.
OEB Approved 2005 Test Year
Change in Revenue Requirement

Line No.		Col. 1 OEB Decision ($Millions)	Col.2 ADR 2004-06-17 N1.T2.S6 (Note 1) ($Millions)	Col.3 Change (Col.1-Col.2) ($Millions)
	Cost of capital			
1.	Rate base	3,422.1	3,422.8	
2.	Required rate of return	8.10%	8.14	
3.		277.2	278.6	(1.4)
	Cost of service			
4.	Gas costs	2,005.5	2,006.9	
5.	Operation and maintenance	301.3	301.3	
6.	Depreciation and amortization	193.5	193.5	
7.	Fixed financing costs	1.2	1.2	
8.	Notional utility account recovery	12.3	18.4	
9.	Municipal and other taxes	51.5	51.5	
10.		2,565.3	2,572.8	(7.5)
	Miscellaneous operating and non-operating revenue			
11.	Other operating revenue	(27.2)	(27.2)	
12.	Interest and property rental	-	-	
13.	Other income	(0.3)	(0.3)	
14.		(27.5)	(27.5)	-
	Income taxes on earnings			
15.	Excluding tax shield	112.2	109.6	
16.	Tax shield provided by interest expense	(55.1)	(55.1)	
17.		57.1	54.5	2.6
	Taxes on sufficiency / (deficiency)			
18.	Gross sufficiency / (deficiency)	(51.1)	(60.6)	
19.	Net sufficiency / (deficiency)	(33.2)	(39.4)	
20.		17.9	21.2	(3.3)
21.	**Revenue requirement**	2,890.0	2,899.6	(9.6)
	Revenue at existing Rates			
22.	Gas sales	2,087.2	2,087.2	
23.	Transportation service	750.2	750.2	
24.	Transmission, compression and storage	1.6	1.6	
25.	Sub-total	2,839.0	2,839.0	-
26.	Rounding adjustment	(0.1)	-	(0.1)
27.	Revenue at existing rates	2,838.9	2,839.0	(0.1)
28.	**Gross revenue sufficiency / (deficiency)**	(51.1)	(60.6)	9.5

Note 1: Information from Col. 1 of Exhibit N1, Tab 2, Schedule 6, page 1, Filed: 2004-06-17.

APPENDIX "B" TO
ENBRIDGE GAS DISTRIBUTION INC.
RATE ORDER
BOARD FILE NO. RP-2003-0203
DATED: December 22, 2004
NOT AVAILABLE ELECTRONICALLY

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

Item No.	Rate No.	Col. 1	Col. 2 Rate Block m³	Col. 3 Interim EB-2004-0428 cents *	Col. 4 Rate Change cents * (1)	Col. 5 Final RP-2003-0203 cents *
	RATE 1 **					
1.01		Customer Charge		$11.25	$0.0000	$11.25
1.02		Delivery Charge	first 30	9.6171	($0.1299)	9.4872
~~1.03~~			~~next 55~~	~~9.0060~~	~~($0.1299)~~	~~8.8761~~
1.04			next 85	8.5271	($0.1299)	8.3972
1.05			over 170	8.1706	($0.1299)	8.0407
1.06		Gas Supply Load Balancing		1.1070	($0.0042)	1.1028
1.07		Gas Supply Transportation		4.7240	$0.0000	4.7240
1.08		Gas Supply Commodity - System		28.5724	$0.0000	28.5724
1.09		Gas Supply Commodity - Buy/Sell		28.5551	$0.0000	28.5551
	RATE 6 **					
2.01		Customer Charge		$22.00	$0.0000	$22.00
2.02		Delivery Charge	First 500	8.5578	($0.0675)	8.4903
2.03			Next 1050	6.5579	($0.0675)	6.4904
2.04			Next 4500	5.1579	($0.0675)	5.0904
2.05			Next 7000	4.2580	($0.0675)	4.1905
2.06			Next 15250	3.8580	($0.0675)	3.7905
2.07			Over 28300	3.7580	($0.0675)	3.6905
2.08		Gas Supply Load Balancing		1.1534	($0.0044)	1.1490
2.09		Gas Supply Transportation		4.7978	$0.0000	4.7978
2.10		Gas Supply Commodity - System		28.6818	$0.0000	28.6818
2.11		Gas Supply Commodity - Buy/Sell		28.6646	$0.0000	28.6646
	RATE 9 **					
3.01		Customer Charge		$200.00	$0.0000	$200.00
3.02		Delivery Charge	first 20000	8.9559	($0.1949)	8.7610
3.03			over 20000	8.3955	($0.1949)	8.2006
3.04		Gas Supply Load Balancing		0.0746	($0.0002)	0.0744
3.05		Gas Supply Transportation		4.1995	$0.0000	4.1995
3.06		Gas Supply Commodity - System		28.4469	$0.0000	28.4469
3.07		Gas Supply Commodity - Buy/Sell		28.4297	$0.0000	28.4297
	RATE 100 ***					
4.01		Customer Charge		$100.00	$0.0000	$100.00
4.02		Delivery Charge	first 14,000	5.0780	($0.0405)	5.0375
4.03			next 28,000	3.7190	($0.0405)	3.6785
4.04			over 42,000	3.1600	($0.0405)	3.1195
4.05		Gas Supply Load Balancing		0.9471	($0.0035)	0.9436
4.06		Gas Supply Transportation		4.5354	$0.0000	4.5354
4.07		Gas Supply Commodity - System		28.5148	$0.0000	28.5148
		Gas Supply Commodity - Buy/Sell		28.4975	$0.0000	28.4975
	RATE 110 ***					
5.01		Customer Charge		$500.00	$0.0000	$500.00
5.02		Demand Charge (Cents/Month/m³)		20.0000	$0.0000	20.0000
5.03		Delivery Charge	first 500,000	0.4321	($0.0174)	0.4147
5.04			next 500,000	0.4321	($0.0174)	0.4147
5.05			over 1,000,000	0.2821	($0.0174)	0.2647
5.06		Load Balancing Commodity		0.3141	($0.0013)	0.3128
5.07		Gas Supply Transportation		4.2900	$0.0000	4.2900
5.08		Gas Supply Commodity - System		28.4469	$0.0000	28.4469
5.09		Gas Supply Commodity - Buy/Sell		28.4297	$0.0000	28.4297

NOTE : * Cents unless otherwise noted.
** The Gas Supply Load Balancing and Transportation Charges are included in the Delivery Charge on the applicable Rate Schedules.
*** The Transportation Charge is included in the Gas Supply Load Balancing Charge on the applicable Rate Schedules.
(1) Adjustment to reflect RP-2003-0203 Final Decision.

Filed 2004-11-22
RP-2003-0203
Final Board Order
Appendix B
Schedule 1
Page 2 of 4

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 Interim EB-2004-0428 cents *	Col. 4 Rate Change cents * (1)	Col. 5 Final RP-2003-0203 cents *
	RATE 115 ***					
1.01		Customer Charge		$500.00	$0.0000	$500.00
1.02		Demand Charge (Cents/Month/m³)		20.0000	$0.0000	20.0000
1.03		Delivery Charge	first 500,000	0.2134	($0.0070)	0.2064
1.04			next 500,000	0.2134	($0.0070)	0.2064
1.05			over 1,000,000	0.1134	($0.0070)	0.1064
1.06		Load Balancing Commodity		0.1180	($0.0004)	0.1176
1.07		Gas Supply Transportation		3.5201	$0.0000	3.5201
1.08		Gas Supply Commodity - System		28.4469	$0.0000	28.4469
1.09		Gas Supply Commodity - Buy/Sell		28.4297	$0.0000	28.4297
2.00	RATE 125					
		Delivery Charge (Cents/Month/m³ of Contract Dmnd)		8.2125	$0.0000	8.2125
3.00	RATE 135 ***	DEC - MAR				
3.01		Customer Charge		$100.00	$0.0000	$100.00
3.02		Delivery Charge	first 14,000	6.4871	($0.0089)	6.4782
3.03			next 28,000	5.2871	($0.0089)	5.2782
3.04			over 42,000	4.8871	($0.0089)	4.8782
3.05		Gas Supply Load Balancing		0.0354	($0.0001)	0.0353
3.06		Gas Supply Transportation		3.1736	$0.0000	3.1736
3.07		Gas Supply Commodity - System		28.5563	$0.0000	28.5563
		Gas Supply Commodity - Buy/Sell		28.5390	$0.0000	28.5390
3.08	RATE 135 ***	APR - NOV				
3.09		Customer Charge		$100.00	$0.0000	$100.00
3.10		Delivery Charge	first 14,000	1.7871	($0.0089)	1.7782
3.11			next 28,000	1.0871	($0.0089)	1.0782
3.12			over 42,000	0.8871	($0.0089)	0.8782
3.13		Gas Supply Load Balancing		0.0354	($0.0001)	0.0353
3.14		Gas Supply Transportation		3.1736	$0.0000	3.1736
3.15		Gas Supply Commodity - System		28.5563	$0.0000	28.5563
		Gas Supply Commodity - Buy/Sell		28.5390	$0.0000	28.5390
4.00	RATE 145 ***					
4.01		Customer Charge		$100.00	$0.0000	$100.00
4.02		Delivery Charge	first 14,000	3.2794	($0.0205)	3.2589
4.03			next 28,000	1.9204	($0.0205)	1.8999
4.04			over 42,000	1.3614	($0.0205)	1.3409
4.05		Gas Supply Load Balancing		0.5047	($0.0024)	0.5023
4.06		Gas Supply Transportation		4.5354	$0.0000	4.5354
4.07		Gas Supply Commodity - System		28.5491	$0.0000	28.5491
		Gas Supply Commodity - Buy/Sell		28.5318	$0.0000	28.5318
5.00	RATE 170 ***					
5.01		Customer Charge		$200.00	$0.0000	$200.00
5.02		Demand Charge (Cents/Month/m³)		3.0000	$0.0000	3.0000
5.03		Delivery Charge	first 1,000,000	0.3730	($0.0054)	0.3676
5.04			over 1,000,000	0.1730	($0.0054)	0.1676
5.05		Gas Supply Load Balancing		0.2013	($0.0010)	0.2003
5.06		Gas Supply Transportation		3.8467	$0.0000	3.8467
5.07		Gas Supply Commodity - System		28.4469	$0.0000	28.4469
		Gas Supply Commodity - Buy/Sell		28.4297	$0.0000	28.4297

NOTE :

* Cents unless otherwise noted.

*** The Transportation Charge is included in the Gas Supply Load Balancing Charge on the applicable Rate Schedules.

(1) Adjustment to reflect RP-2003-0203 Final Decision.

RECYCLED PAPER

ENBRIDGE

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 Interim EB-2004-0428 cents *	Col. 4 Rate Change cents * (1)	Col. 5 Final RP-2003-0203 cents *
1.00	RATE 200 ***					
1.01		Customer Charge		$0.00	$0.0000	$0.00
1.02		Demand Charge (Cents/Month/m³)		10.0000	$0.0000	10.0000
1.03		Delivery Charge	15 * CD	0.6641	($0.0161)	0.6480
1.04			10 * CD	0.6641	($0.0161)	0.6480
1.05			over 25 * CD	0.6641	($0.0161)	0.6480
1.06		Gas Supply Load Balancing		0.7083	($0.0031)	0.7052
1.07		Gas Supply Transportation		4.5354	$0.0000	4.5354
1.08		Gas Supply Commodity - System		28.4469	$0.0000	28.4469
		Gas Supply Commodity - Buy/Sell		28.4297	$0.0000	28.4297
2.00	RATE 300					
2.01		Customer Charge negotiated up to		$2,000.00	$0.0000	$2,000.00
2.02		Demand Chg (Cents/Month/m³)	first 100,000	18.0000	$0.0000	18.0000
2.03			next 100,000	12.0000	$0.0000	12.0000
			over 200,000	6.0000	$0.0000	6.0000
2.04		Delivery Charge	first 2,000,000	0.4605	($0.0074)	0.4531
2.05			next 2,000,000	0.4405	($0.0074)	0.4331
2.06			over 4,000,000	0.4205	($0.0074)	0.4131
3.00	RATE 305					
3.01		Customer Charge negotiated up to		$2,000.00	$0.0000	$2,000.00
3.02		Delivery Charge	first 2,000,000	0.4605	($0.0074)	0.4531
3.03			next 2,000,000	0.4405	($0.0074)	0.4331
			over 4,000,000	0.4205	($0.0074)	0.4131
	RATE 310					
4.00		Load Balance				
4.01		Demand Charge (Cents/Month/m³)		12.8779	($0.0318)	12.8461
		Delivery Charge		4.0517	($0.0100)	4.0417
	RATE 315					
5.00		Storage				
5.01		Storage Demand Chg (Cents/Month/m³)		12.6869	($0.1263)	12.5606
5.02		Space Demand Chg (Cents/Month/m³)		0.0419	($0.0016)	0.0403
		Delivery Charge		0.3854	$0.0000	0.3854 (1)
		(1) Note: Rate excludes fuel.				
6.00	RATE 320					
		Backstop	All Gas Sold	32.6679	($0.0064)	32.6615

NOTE :
* Cents unless otherwise noted.
*** The Transportation Charge is included in the Gas Supply Load Balancing Charge on the applicable Rate Schedules.
(1) Adjustment to reflect RP-2003-0203 Final Decision.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col. 1	Col. 2 Rate Block m³	Col. 3 Interim EB-2004-0428 cents *	Col. 4 Rate Change cents * (1)	Col. 5 Final RP-2003-0203 cents *
	RATE 325					
		Transmission & Compression				
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.1760 (2)	$0.0000	$0.1760
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		16.1020 (2)	($0.0448)	$16.0572 (2)
1.02		Commodity Charge		1.7400	$0.0000	$1.7400 (2)
		Storage				
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.2130	($0.0009)	$0.2121
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		19.5160	($0.0716)	$19.4444
1.05		Commodity Charge		0.6840	$0.0000	$0.6840
		(2) Note: These are UNBUNDLED Rates				
	RATE 330	Storage Service - Firm				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.00		Minimum		0.3890	($0.0009)	$0.3881
2.01		Maximum		1.9450	($0.0046)	$1.9404
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.02		Minimum		35.6180	($0.1164)	$35.5016
2.03		Maximum		178.0900	($0.5820)	$177.5080
		Commodity Charge				
2.04		Minimum		$2.4240	$0.0000	$2.4240
2.05		Maximum		$12.1200	$0.0000	$12.1200
		Storage Service - Interruptible				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.06		Minimum		$0.3890	($0.0009)	$0.3881
2.07		Maximum		$1.9450	($0.0046)	$1.9404
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.08		Minimum		$28.4944	($0.0931)	$28.4013
2.09		Maximum		$142.4720	($0.4656)	$142.0064
		Commodity Charge				
2.10		Minimum		$2.4240	$0.0000	$2.4240
2.11		Maximum		$12.1200	$0.0000	$12.1200
		Storage Service - Off Peak				
		Commodity Charge				
2.12		Minimum		1.0933	$0.0000	$1.0933
2.13		Maximum		42.3478	($0.0984)	$42.2494
	RATE 331	Tecumseh Transmission Service				
		Firm				
3.00		Demand Charge ($/Month/10³ m³ of Maximum Contracted Daily Delivery)		3.2050	($0.0100)	$3.1950
		Interruptible				
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.1260	$0.0000	$0.1260

NOTE :

* Cents unless otherwise noted.

(1) Adjustment to reflect RP-2003-0203 Final Decision.

APPENDIX "C" TO
ENBRIDGE GAS DISTRIBUTION INC.
RATE ORDER
BOARD FILE NO. RP-2003-0203
DATED: December 22, 2004
NOT AVAILABLE ELECTRONICALLY

RIDER: E	Revenue Adjustment Rider

The following adjustment is applicable to billed volumes during the period October 1, 2004 to December 31, 2004.

Rate Class	Sales and Transportation Service (¢/m³)
Rate 1	(0.1341)
Rate 6	(0.0719)
Rate 9	(0.1951)
Rate 100	(0.0440)
Rate 110	(0.0187)
Rate 115	(0.0074)
Rate 135	(0.0090)
Rate 145	(0.0229)
Rate 170	(0.0064)
Rate 200	(0.0192)
Rate 300	(0.0074)
Rate 305	(0.0074)

APPENDIX "D" TO
ENBRIDGE GAS DISTRIBUTION INC.
RATE ORDER
BOARD FILE NO. RP-2003-0203
DATED: December 22, 2004
NOT AVAILABLE ELECTRONICALLY

RATE AND TYPE OF SALE

		COL. 1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11	COL. 12	COL. 13	COL. 14
		TOTAL (¢/m³)	SALES BUY/SELL AND WBT (¢/m³)	TOTAL SALES (¢/m³)	TOTAL ELIVERIES (¢/m³)	SALES BUY/SELL & WBT PEAK (¢/m³)	TOTAL BUNDLED PEAK (¢/m³)	SPACE (¢/m³)	DELIVE-RABILITY (¢/m³)	WINTER DELIVERIES (¢/m³)	DIRECT (¢/m³)	NUMBER USTOMERS (¢/m³)	RATE BASE (¢/m³)	EX-FRAN. DAILY (¢/m³)	EX-FRAN. ANNUAL (¢/m³)
RATE 1	- SYSTEM SALES	(0.4246)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0047	(0.0046)	(0.0125)	0.0000	0.0000	(0.1417)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.4246)			(0.2704)		0.0000	0.0047	(0.0046)	(0.0125)	0.0000	0.0000	(0.1417)		
	- WESTERN T-SERVICE	(0.4246)	0.0000		(0.2704)	0.0000	0.0000	0.0047	(0.0046)	(0.0125)	0.0000	0.0000	(0.1417)		
RATE 6	- SYSTEM SALES	(0.3578)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0051	(0.0050)	(0.0131)	0.0000	0.0000	(0.0743)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.3578)			(0.2704)		0.0000	0.0051	(0.0050)	(0.0131)	0.0000	0.0000	(0.0743)		
	- WESTERN T-SERVICE	(0.3578)	0.0000		(0.2704)	0.0000	0.0000	0.0051	(0.0050)	(0.0131)	0.0000	0.0000	(0.0743)		
RATE 9	- SYSTEM SALES	(0.7890)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0000	(0.0030)	(0.0151)	0.0000	0.0000	(0.5005)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.7890)			(0.2704)		0.0000	0.0000	(0.0030)	(0.0151)	0.0000	0.0000	(0.5005)		
	- WESTERN T-SERVICE	(0.7890)	0.0000		(0.2704)	0.0000	0.0000	0.0000	(0.0030)	(0.0151)	0.0000	0.0000	(0.5005)		
RATE 100	- SYSTEM SALES	(0.3219)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0039	(0.0035)	(0.0120)	0.0000	0.0000	(0.0399)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.3219)			(0.2704)		0.0000	0.0039	(0.0035)	(0.0120)	0.0000	0.0000	(0.0399)		
	- WESTERN T-SERVICE	(0.3219)	0.0000		(0.2704)	0.0000	0.0000	0.0039	(0.0035)	(0.0120)	0.0000	0.0000	(0.0399)		
RATE 110	- SYSTEM SALES	(0.3006)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0013	(0.0021)	(0.0088)	0.0000	0.0000	(0.0205)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.3006)			(0.2704)		0.0000	0.0013	(0.0021)	(0.0088)	0.0000	0.0000	(0.0205)		
	- WESTERN T-SERVICE	(0.3006)	0.0000		(0.2704)	0.0000	0.0000	0.0013	(0.0021)	(0.0088)	0.0000	0.0000	(0.0205)		
RATE 115	- SYSTEM SALES	(0.2869)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0001	(0.0015)	(0.0073)	0.0000	0.0000	(0.0078)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.2869)			(0.2704)		0.0000	0.0001	(0.0015)	(0.0073)	0.0000	0.0000	(0.0078)		
	- WESTERN T-SERVICE	(0.2869)	0.0000		(0.2704)	0.0000	0.0000	0.0001	(0.0015)	(0.0073)	0.0000	0.0000	(0.0078)		
RATE 135	- SYSTEM SALES	(0.2892)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0000	(0.0003)	(0.0062)	0.0000	0.0000	(0.0122)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.2892)			(0.2704)		0.0000	0.0000	(0.0003)	(0.0062)	0.0000	0.0000	(0.0122)		
	- WESTERN T-SERVICE	(0.2892)	0.0000		(0.2704)	0.0000	0.0000	0.0000	(0.0003)	(0.0062)	0.0000	0.0000	(0.0122)		
RATE 145	- SYSTEM SALES	(0.3097)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0036	(0.0018)	(0.0127)	0.0000	0.0000	(0.0283)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.3097)			(0.2704)		0.0000	0.0036	(0.0018)	(0.0127)	0.0000	0.0000	(0.0283)		
	- WESTERN T-SERVICE	(0.3097)	0.0000		(0.2704)	0.0000	0.0000	0.0036	(0.0018)	(0.0127)	0.0000	0.0000	(0.0283)		
RATE 170	- SYSTEM SALES	(0.2857)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0013	(0.0003)	(0.0092)	0.0000	0.0000	(0.0069)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.2857)			(0.2704)		0.0000	0.0013	(0.0003)	(0.0092)	0.0000	0.0000	(0.0069)		
	- WESTERN T-SERVICE	(0.2857)	0.0000		(0.2704)	0.0000	0.0000	0.0013	(0.0003)	(0.0092)	0.0000	0.0000	(0.0069)		
RATE 200	- SYSTEM SALES	(0.2966)	0.0000	0.0000	(0.2704)	0.0000	0.0000	0.0027	(0.0027)	(0.0118)	0.0000	0.0000	(0.0144)		
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
	- ONTARIO T-SERVICE	(0.2966)			(0.2704)		0.0000	0.0027	(0.0027)	(0.0118)	0.0000	0.0000	(0.0144)		
	- WESTERN T-SERVICE	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
RATE 325	- DAILY	0.0305												0.0305	0.0000
	- ANNUAL	0.0004												0.0000	0.0004
RATE 330	- DAILY	0.0252												0.0252	0.0000
	- ANNUAL	0.0003												0.0000	0.0003
RATE 331	- DAILY	0.0255												0.0255	0.0000

Note: (1) Unit Rates derived based on 2004 volumes (12 months Actuals)

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”) #33

INTERROGATORY

Ref: PEG Report, page 47

Issue Number: 4.2
Issue: How should the impact of changes in average use be calculated?

Please provide all the data, formulae and calculations used to estimate the components of the AU factor.

RESPONSE

See the working papers prepared in PEG’s response to question 2 of EGD’s interrogatories. Please note that access to some portions of the working papers requires the signing of a confidentiality agreement.

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”) #41

INTERROGATORY

Ref: Union Gas Evidence, Exhibit B, Tab 1, page 32

Issue Number: 3.2
Issue: What are the appropriate components of an X factor?

Union indicates that there is no justification for a stretch factor in its price cap. This proposal is based on their assertion that Union has had significant motivation to implement productivity improvements over the last 10 years.

a) Please comment on this rationale for not including a stretch factor.

b) Based on the information that PEG has related to price cap mechanisms that have been approved in other jurisdictions, please provide a summary of the number of plans on which it has detailed information on the calculation of the X factor and the number of those plans that do not include any stretch factor, directly or indirectly. For any approved price cap mechanism that does not include a stretch factor, please provide a brief summary of why no stretch factor was imposed.

RESPONSE

a) Please see our response to Exhibit R-PEG Tab 2 Schedule 54. We will provide additional comments in our answer to Exhibit R-PEG Tab 6 Schedule 12.

a) Please see our response in Exhibit R-PEG Tab 3 Schedule 44 for a useful summary table. Note that the absence of an explicit stretch factor is usually not an indication that a stretch factor was considered but rejected. More commonly, the X factor is implicitly stretched.

Witness: Mark Lowry

THE LONDON PROPERTY MANAGEMENT ASSOCIATION (“LPMA”), THE WHOLESALE GAS SERVICE PURCHASERS GROUP (“WGSPG”), AND THE BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”) #42

INTERROGATORY

Ref: Union Gas Evidence, Exhibit B, Tab 1, page 36 - 37

Issue Number: 4.2
Issue: How should the impact of changes in average use be calculated?

a) Please comment on the methodology proposed by Union in the calculation of the Adjusted AU Factor. In particular, is their use of the COS AU factor of -0.72 appropriate and is the use of the general service revenue share of 0.644 appropriate.
b) Unlike PEG, Union is not proposing any AU adjustment for rate classes that are not general service. Is this appropriate? Please explain.

RESPONSE

Please see our response to IGUA in Exhibit R-PEG Tab 5 Schedule 11.

Witness: Mark Lowry