Ontario Energy Board

EB-2007-0606

EB-2007-0615

Enbridge Gas Distribution

Issues Day

August 10, 2007

Issues 1.2 and 1.3

1. Board Secretary's letter dated May 3, 2007 to Enbridge Gas Distribution
2. Section 36 of the *Ontario Energy Board Act, 1998*
3. *Northwestern Utilities Limited v. City of Edmonton*, [1929] S.C.R. 186 at pages 192-93

Issue 1.4

4. Ontario Energy Board, *2007-2010 Business Plan*, December 2006, at page 8
5. Ontario Energy Board, Decision with Reasons – Phase 1, July 5, 2007 at pages 65-66

Issue 3.3

6. Enbridge's Pre-filed Evidence, Exhibit B-3-1, page 25, paras. 58 and 59
7. Enbridge's Pre-filed Evidence, Exhibit B-3-1, page 37, para. 91
8. Enbridge's Pre-filed Evidence, Exhibit B-3-1, page 2, para. 3
9. Enbridge's Pre-filed Evidence, Exhibit B-3-1, pages 30-34
10. Enbridge's Pre-filed Evidence, Exhibit B-3-1, page 31

Issues 3.3 and 14

11. Ontario Energy Board, *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, March 30, 2005 at pages 3 and 21

Scheduling

12. Enbridge's Exhibit A-1-1, page 2

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Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

BY EMAIL ONLY

May 3, 2007

Patrick Hoey
Director, Regulatory Affairs
Enbridge Gas Distribution Inc.
P.O. Box 650
Scarborough ON M1K 5E3

Re: Enbridge Gas Distribution Inc. – Fiscal 2008 Rates

Dear Mr. Hoey:

As you are aware, it is the Board's intention to implement rates for Enbridge Gas Distribution Inc. and Union Gas Limited under a multi-year incentive ratemaking framework for 2008. The Board therefore requests that you file an application for rates that will commence January 1, 2008.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board Act, 1998

S.O. 1998, c. 15, Sched. B

Amendments

- 1999, c. 6, § 48: *Amendments Because of the Supreme Court of Canada Decision in M. v. H. Act, 1999*
- 2000, c. 26, Sched. D, § 2: *Red Tape Reduction Act, 2000*
- 2001, c. 9, Sched. F, § 2: *Government Efficiency Act, 2001*
- 2002, c. 1, Sched. B: *Reliable Energy and Consumer Protection Act, 2002*
- 2002, c. 17, Sched. F, Table: *Municipal Law Amendment Act, 2002*
- 2002, c. 23, § 4: *Electricity Pricing, Conservation and Supply Act, 2002*
- 2003, c. 3, §§ 2-90: *Ontario Energy Board Consumer Protection and Governance Act, 2003*
- 2003, c. 8: *Ontario Energy Board Amendment Act (Electricity Pricing), 2003.*
- 2004, c. 8, § 46, Table: *Public Accounting Act, 2004*
- 2004, c. 17, § 32: *Audit Statute Law Amendment Act*, 2004
- 2004, c. 23, Sched. B: *Electricity Restructuring Act, 2004*
- 2005, c. 5, § 51: *Spousal Relationship Statute Law Amendment Act, 2005*
- 2006, c. 3, Sched. C: *Energy Conservation Responsibility Act, 2006*
- 2006, c. 21, Sched. F, § 136(1): *Access to Justice Act, 2006*
- 2006, c. 32, Sched. C, § 42: *Municipal Statute Law Amendment Act, 2006*
- 2006, c. 33, Sched. X: *Budget Measures Act, 2006 (No. 2)*
- 2006, c. 35, Sched. C, § 98: *Public Service of Ontario Statute Law Amendment Act, 2006*

respect to all or any part of the subject-matter of the order, rule or code. 1998, c. 15, Sched. B, s. 34 (2); 2003, c. 3, s. 29 (2).

No further petition

(3) If the Board has acted in accordance with the direction of the Lieutenant Governor in Council under clause (1) (b), the decision of the Board is not subject to petition under this section. 1998, c. 15, Sched. B, s. 34 (3).

Limitation

(4) This section does not apply to orders of the Board under Part IV or in respect of a licence for the retailing of electricity under Part V. 1998, c. 15, Sched. B, s. 34 (4).

Question referred to Board

35. The Minister may require the Board to examine, report and advise on any question respecting energy. 1998, c. 15, Sched. B, s. 35.

PART III
GAS REGULATION

Order of Board required

36. (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract. 1998, c. 15, Sched. B, s. 36 (1).

Order of Board re Smart Metering Entity

(1.1) Neither the Smart Metering Entity nor any other person licensed to do so shall conduct activities relating to the metering of gas except in accordance with an order of the Board, which is not bound by the terms of any contract. 2006, c. 3, Sched. C, s. 3.

Order re: rates

(2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas. 1998, c. 15, Sched. B, s. 36 (2).

Power of Board

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate. 1998, c. 15, Sched. B, s. 36 (3).

Contents of order

(4) An order under this section may include conditions, classifications or practices applicable to the sale, transmission, distribution or storage of gas, including rules respecting the calculation of rates. 1998, c. 15, Sched. B, s. 36 (4).

Deferral or variance accounts

(4.1) If a gas distributor has a deferral or variance account that relates to the commodity of gas, the Board shall, at least once every three months, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates. 2003, c. 3, s. 30.

Same

(4.2) If a gas distributor has a deferral or variance account that does not relate to the commodity of gas, the Board shall, at least once every 12 months, or such shorter period as is

prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates. 2003, c. 3, s. 30.

Same

(4.3) An order that determines whether and how amounts recorded in a deferral or variance account shall be reflected in rates shall be made in accordance with the regulations. 2003, c. 3, s. 30.

Same

(4.4) If an order that determines whether and how amounts recorded in a deferral or variance account shall be reflected in rates is made after the time required by subsection (4.1) or (4.2) and the delay is due in whole or in part to the conduct of a gas distributor, the Board may reduce the amount that is reflected in rates. 2003, c. 3, s. 30.

Same

(4.5) If an amount recorded in a deferral or variance account of a gas distributor is reflected in rates, the Board shall consider the appropriate number of billing periods over which the amount shall be divided in order to mitigate the impact on consumers. 2003, c. 3, s. 30.

Fixing other rates

(5) Upon an application for an order approving or fixing rates, the Board may, if it is not satisfied that the rates applied for are just and reasonable, fix such other rates as it finds to be just and reasonable. 1998, c. 15, Sched. B, s. 36 (5).

Burden of proof

(6) Subject to subsection (7), in an application with respect to rates for the sale, transmission, distribution or storage of gas, the burden of proof is on the applicant. 1998, c. 15, Sched. B, s. 36 (6).

Order, motion of Board or at request of Minister

(7) If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates for the sale, transmission, distribution or storage of gas by any gas transmitter, gas distributor or storage company are just and reasonable, the Board shall make an order under subsection (2) and the burden of establishing that the rates are just and reasonable is on the gas transmitter, gas distributor or storage company, as the case may be. 1998, c. 15, Sched. B, s. 36 (7).

Exception

(8) This section does not apply to a municipality or municipal public utility commission transmitting or distributing gas under the *Public Utilities Act* on the day before this section comes into force. 1998, c. 15, Sched. B, s. 36 (8).

Gas storage areas

36.1 (1) The Board may by order,

(a) designate an area as a gas storage area for the purposes of this Act; or

(b) amend or revoke a designation made under clause (a). 2001, c. 9, Sched. F, s. 2 (2).

Transition

(2) Every area that was designated by regulation as a gas storage area on the day before this section came into force shall be deemed to have been designated under clause (1) (a)

1929

CANADIAN CREDIT MEN'S TRUST ASSOCIATION LTD. v. HOFFAR LTD.

Mignault J.

The petition is therefore dismissed with costs.

Petition dismissed with costs.

Solicitors for the petitioner: *Griffin, Montgomery & Smith.*

Solicitor for the respondent: *R. W. Ginn.*

1928

*Oct. 24.

1929

*Feb. 5.

NORTHWESTERN UTILITIES, LIMITED ..... } APPELLANT;

AND

THE CITY OF EDMONTON AND BOARD OF PUBLIC UTILITY COMMISSIONERS OF ALBERTA..... } RESPONDENTS.

THE CITY OF EDMONTON.....APPELLANT;

AND

NORTHWESTERN UTILITIES, LIMITED, AND BOARD OF PUBLIC UTILITY COMMISSIONERS OF ALBERTA ..... } RESPONDENTS.

ON APPEAL FROM THE APPELLATE DIVISION OF THE SUPREME COURT OF ALBERTA

Public utilities—Public Utilities Act, Alta.—Hearings and investigations by Board of Public Utility Commissioners—Powers of Board—Obtaining of evidence—Absence of evidence—Order of Board fixing rates for gas supply in municipality by franchise holder—Return on investment—Inclusion in "rate base" of discount on sale of bonds—Appeal from Board's order—"Question of law."

The Board of Public Utility Commissioners of Alberta made an order in 1922 fixing rates chargeable for gas proposed to be supplied in the city of Edmonton by the predecessor of the appellant company. The Board fixed the rates on the basis of an allowance of 10% as a fair return on the investment in the enterprise, and in determining the "rate base" (the amount to be considered as invested in the enterprise) it included as a capital expenditure a sum which was the discount on the sale of the company's bonds. The rates were to continue in force for three years from the date on which gas was first

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*PRESENT:—Anglin C.J.C. and Mignault, Rinfret, Lamont and Smith JJ.

1929

NORTH-WESTERN UTILITIES LTD. v. CITY OF EDMONTON.

Lamont J.

appeal is that the Board in making a reduction in the rate of return did so for two reasons, one of which was the "altered conditions of the money market," and that of this no evidence was adduced before the Board. The company contends that, without hearing evidence upon the point, and without giving it an opportunity to establish that the conditions of the money market had remained unaltered since 1922, the Board was without jurisdiction to make the reduction. This contention was not stated in this form in the order granting leave to appeal to the Appellate Division, but the fixing of the rate of return at 9% only, was there set out as an error of the Board in respect of which leave to appeal was granted.

Whether or not the Board can properly base an order (in part at least) on the existence of a state of fact of which no evidence was adduced before it at the hearing and as to which the party affected has not had any opportunity of being heard is, in my opinion, a question of law which depends for its answer upon the construction to be placed upon the *Public Utilities Act*.

I am, therefore, of opinion that the company had a right to appeal.

The question involved in this appeal is: Had the Board jurisdiction to find as a fact how the conditions of the money market had altered between November, 1922, and July, 1927, without any witness testifying at the hearing that an alteration had taken place.

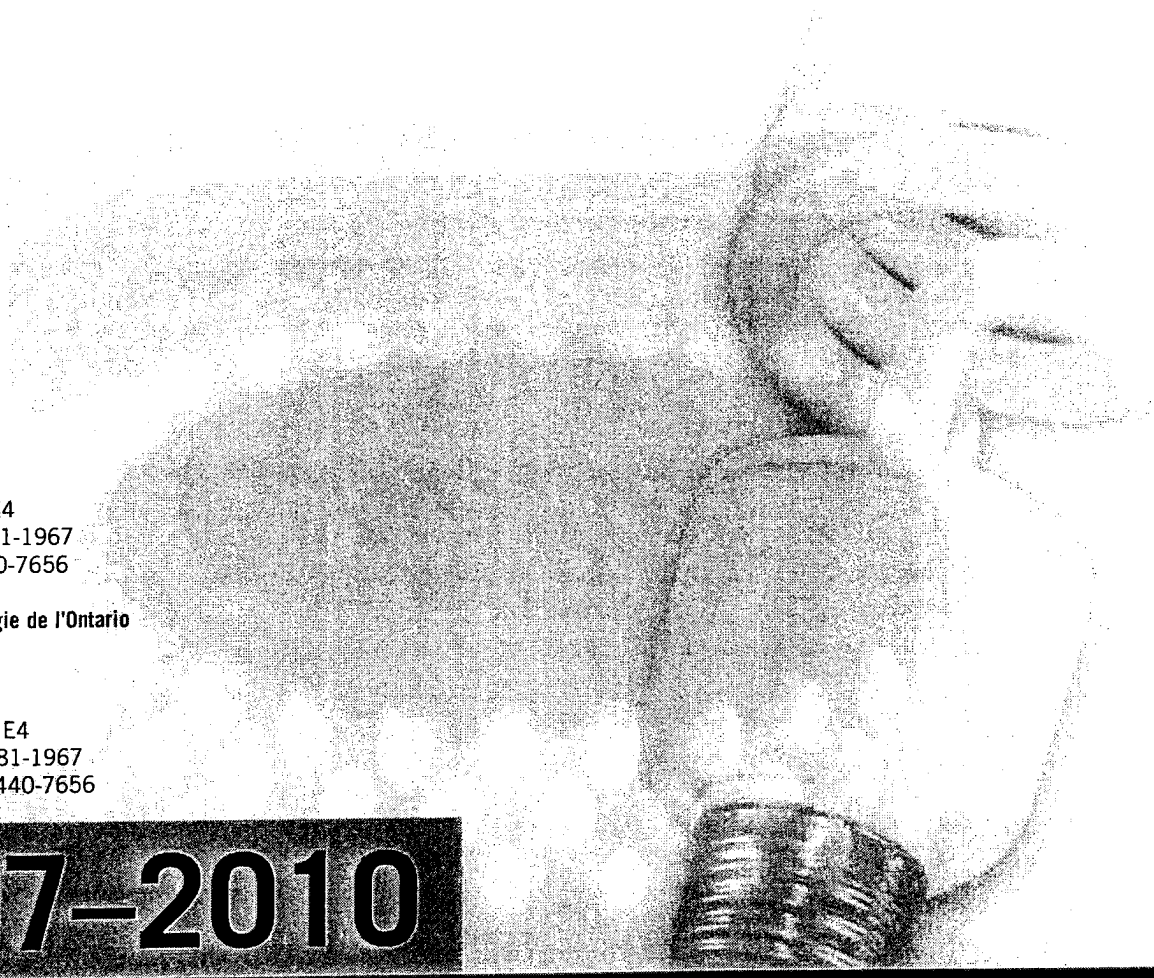
As the Board was determining what would be a fair return on the capital invested by the company in the enterprise, and as it reduced the return from 10% to 9%, it can, I think, be taken that by "the altered conditions of the money market" the Board meant that the returns for money invested in securities in which moneys were ordinarily invested had decreased during the period in question. In other words, that the rate of interest obtainable for moneys furnished for investment was, generally speaking, lower by a certain percentage in 1927 than it was in 1922. That, in my opinion, is all that is involved in the finding.

The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other

hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. In fixing this net return the Board should take into consideration the rate of interest which the company is obliged to pay upon its bonds as a result of having to sell them at a time when the rate of interest payable thereon exceeded that payable on bonds issued at the time of the hearing. To properly fix a fair return the Board must necessarily be informed of the rate of return which money would yield in other fields of investment. Having gone into the matter fully in 1922, and having fixed 10% as a fair return under the conditions then existing, all the Board needed to know, in order to fix a proper return in 1927, was whether or not the conditions of the money market had altered, and, if so, in what direction, and to what extent.

For the city it was argued that, as one of the statutory powers of the Board was to deal with the financial affairs of local authorities (s. 20 (*d*)), and as this included the power to authorize the issue of new debentures by these authorities and to determine the rate of interest to be paid thereon and also the power to order a variation of the rate of interest payable upon any debt of the local authority (s. 103), the Board must necessarily be familiar with the rate of interest prevailing from time to time and therefore did not require to have witnesses called to furnish it with information which in the regular performance of its duty it was obliged to possess. In view of the powers and duties of the Board under the Act there is, in my opinion, considerable to be said for the city's contention. It is not necessary, however, to determine this question, for in the statute itself I find sufficient to justify the conclusion that the intention of the Legislature was to leave it largely to the discretion of the Board to say in what manner it should obtain the information required for the proper exercise of its functions.

ONTARIO ENERGY BOARD
COMMISSION DE L'ÉNERGIE DE L'ONTARIO



Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto ON M4P 1E4
Telephone: (416) 481-1967
Facsimile: (416) 440-7656

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto (ON) M4P 1E4
Téléphone : (416) 481-1967
Télécopieur : (416) 440-7656

2007–2010

Business Plan

December 2006

KEY INITIATIVES 2007-2010 Business Plan	PERFORMANCE MEASURES 2007-2010 Business Plan	DELIVERY PERIOD 2007-2010 Business Plan
Policy harmonization	The OEB has completed a review of weather normalization methodologies.	FY 2008–10
	The OEB has reviewed opportunities for policy harmonization within the natural gas sector.	FY 2009–10

Strategic Business Objective 2:

To Help Meet Ontario's Challenges for Renewal of Energy Infrastructure, Supply, and Conservation and Demand Management

Strategic context:

Ontario needs additional energy infrastructure, particularly in electricity generation and transmission. Record electricity demand continues to demonstrate the importance of electricity generation and transmission to the well-being of Ontarians. In addition, recent regulatory proceedings suggest that additional investment in existing electricity distribution infrastructure is needed.

To address Ontario's needs around electricity supply, transmission and demand management, the government has mandated the Ontario Power Authority (OPA) to develop an Integrated Power System Plan (IPSP). The OEB is tasked with reviewing the IPSP and with facilitating its implementation once it has been approved.

It is important for the regulator to understand the state of existing electricity distribution infrastructure to ensure that it is adequate. The Board must also examine issues pertaining to asset management, depreciation and working capital.

In the natural gas sector, the Board recently made a determination that storage services are subject to competition sufficient to protect the public interest. As a result, the OEB will now cease to regulate the prices charged for certain storage services. However, some implementation issues remain to be addressed.

With regard to conservation and demand management (CDM), the OPA has been directed by the Minister of Energy to coordinate the delivery and funding of CDM initiatives through electricity distributors in Ontario in the coming years. It is the Board's task to facilitate the implementation of government policy encouraging the development of a conservation culture. The Board remains committed to reducing barriers to the participation of electricity distributors in CDM programs. Demand side management (DSM) plans for natural gas distributors are also part of the Board's regulatory agenda.

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2006-0034

IN THE MATTER OF AN APPLICATION BY:

ENBRIDGE GAS DISTRIBUTION INC.

2007 RATES

DECISION WITH REASONS – PHASE 1

July 5, 2007

agreement by current debt holders and this will likely come at a cost. To be clear, the Company is not suggesting that this would be a reasonable remedy. It is unfortunate that these covenants pose such a high restriction. The Board notes that the Company is considering ways by which the existing covenants may be replaced in the longer run. The Board encourages the Company to pursue this initiative.

The Board agrees with the many intervenors who argued that the problem is or may be temporary. On the assumption of a continuing low interest rate environment, as debt matures and is replaced the lower interest charges would provide some relief. If interest rates increase, the relief may be quicker. Relief may well even come from weather.

In any event, like many intervenors the Board is not convinced that the Company's proposed remedy to what is or may be a temporary problem represents the least cost solution. The common equity component of Enbridge's capital structure is and should be a matter that is reviewed infrequently. The Company's proposal to increase the common equity thickness from 35% to 38% carries an annual cost of about $10 million to ratepayers. In view of that substantial cost, the Board must consider other remedies.

In consideration of all of the above, and on balance, the Board finds an increase in the common equity thickness from 35% to 36% to be reasonable. While this finding should alleviate somewhat the financial pressure currently experienced by the Company, it alone might not fully address the immediacy of the problem, if the problem continues indeed to exist. The Company therefore might need to engage in financing alternatives other than issuing of long term debt in the shorter term. This may involve a number of market instruments that are available to the Company, if indeed the Company cannot issue long term debt when it needs it. The Company must also be more wary of the impact of excessive payments to its affiliates on EBIT.

The Company's evidence was that, in the period 1993 to 2006, the Company lost $107 million in EBIT due to warmer-than-forecast weather and that the average impact of weather in either direction on EBIT was $35 million, which is two times more than the $16.8 million currently reflected in rates according to the Company's evidence. The

Board is of the view that, given the large influence of weather on EBIT, this risk may need to be removed from the utility.

The Board recognizes that a move to removing weather risk from the Company is a decision that has implications for all regulated gas utilities regulated by the Board, and perhaps for electricity utilities as well. The Board considers this to be worthy of evaluation in the near future.

economically generated efficiencies. In other words, all else equal, the greatest societal benefit is achieved when economic incentives are allowed to operate to their fullest extent. This is the essence of incentive regulation.

X-Factor Proposal

The Productivity Differential

56. As more detailed data becomes available through the interrogatory phase it is expected that the Company's witnesses will be able to provide more detailed estimates of the most appropriate X-Factor.

57. In the meantime, some viable alternatives for establishing the productivity target might include:

- Use of the California Department of Ratepayer Advocates' replicated PEG model presented in July 2007 for the U.S. as a whole, adjusted for the Canadian-U.S. productivity gap
- Use of the California Department of Ratepayer Advocates' replicated PEG model presented in July 2007 for the Northeast sector, adjusted for the Canadian-U.S. productivity gap

58. Unfortunately both of these alternatives still require reliance on detailed econometric models. Therefore, the Company proposes the Board consider using the Company's actual TFP history as the productivity target.

59. Using Company-specific historical data has a number of advantages. Most notably, using company-specific history doesn't rely on the challenges of modeling. It is not complicated and it is easy to replicate for future rebasing.

89. The Company's RCI, however, results in only 6 of 12 underestimates (6 of 11 excluding 2004). The Company's RCI estimate may exceed the long-term growth rate; however, this is justified in terms of the extremely tight business conditions that will prevail over the incentive regulation term.

Conclusion

90. With the release of the Pacific Economics Group ("PEG") report in late June that was fundamentally different from the previously issued report in March, the Company has done its best to quickly in assemble a response. In general, the process has been to attempt the replication and verification of PEG's results, as is standard econometric or scientific procedure. This process has been completed without the opportunity to seek clarification through interrogatories. To aid in the effort, the Company has retained the expert advice of The Brattle Group and Dr. Jeffrey Bernstein, who have provided preliminary comments in Exhibits B-3-2 and B-3-3, respectively. However, the Company's experts have indicated that they cannot provide a thorough evaluation of PEG's results until responses to interrogatories are provided. The Company is eager to play an informative and positive role in the formulation of an IR plan, and as such is keen to obtain a suitable X-Factor methodology that will provide for 'just and reasonable' rates.

91. Overall, the diagnosis is an expectation of reduced outputs in the face of increased input requirements going forward. Given the IR period is proposed to extend five years beyond the previous cost of service application (i.e. 2008-2012), these risks are compounded yearly. The future will be more difficult than the past. Analysis on past trends indicates a -0.15% is would lead to 'just and reasonable' rates. Therefore, to adequately address 'just and reasonable' rates going forward requires an X-Factor at least no less than past experience would reveal.

I. Introduction

3. The purpose of this evidence is to determine an appropriate X-Factor going into incentive regulation ("IR"). This determination should be well grounded in principle and must be supported by actual experience, both of which the Company undertakes to produce here. Ultimately, an appropriate X-Factor should pass the test of reasonableness when measured against historically approved revenue[1] increases, while also being reflective of the extraordinarily tight business conditions that will prevail over the IR term.

4. The format of the analysis is modeled after PEG's X-Factor design, which consists of a productivity differential, an input price differential, and a stretch factor. To achieve the grounds for an effective comparison with PEG's submissions, the evidence focuses on a revenue cap design, where the X-Factor is defined as follows:

$$X = (TFP^{industry} - TFP^{economy}) + (\text{Input Prices}^{economy} - \text{Input Prices}^{industry}) + \text{Stretch}$$

5. Further, on the advice of the Company's expert witnesses (see Exhibit B-3-3), and to simplify the task at hand, the analysis is focused only on the Geometric Decay method ("GD") and ignores the use of the Cost of Service ("COS") method, both of which are described in PEG's report. It is hoped that further insights about the COS method can be obtained through the pending interrogatory phase.

6. The evidence begins by introducing the important, but overlooked, issue of the Canadian-U.S. productivity gap. After reviewing the Company's actual TFP history, an examination of PEG's X-Factor analysis follows, which ultimately leads to the Company's X-Factor proposal. Following a discussion regarding the future business context, the evidence concludes with commentary as to the reasonableness of the estimates.

there is no need to add back the growth term as PEG has defined in the Revenue Cap Index ("RCI") formula. Instead this amount would be recalibrated each year based on a forecast of customer additions and volumes and subject to stakeholder scrutiny. All else equal, the RCI and the RCCI are the same, except that one is calculated on a per customer basis. However, to establish a relative comparison of X-Factor proposals, the RCI's below are all calculated by adding back the growth term as per PEG's formula.

73. The table below summarizes the calculation of the ("RCI") X-Factor and compares this to PEG's analyses conducted in March 2007 and June 2007. As can be seen from the table above, the RCI X-Factor proposed by the Company is -0.15%.

Table 11: Summary RCI X-Factor Proposals

Summary RCI X-Factor Proposals	PEG March 2007 GD	PEG June 2007 GD	Enbridge Gas Distribution GD
$TFP^{industry}$	1.37	1.91	-0.60
$TFP^{economy}$	1.37	1.02	0.72
Productivity Differential	**0.00**	**0.89**	**-1.32**
Input $Prices^{economy}$	2.94	2.87	2.49
Input $Prices^{industry}$	3.10	2.02	1.32
Input Price Differential	**-0.16**	**0.85**	**1.17**
$Output^{revenue\text{-}weighted}$	0.00	0.00	0.00
$Output^{elasticity\text{-}weighted}$	0.00	0.00	0.00
Average Use Factor	**0.00**	**0.00**	**0.00**
Stretch Factor	**0.46**	**0.50**	**0.00**
X-Factor	**0.30**	**2.25**	**-0.15**

VI. Business Context Going Forward

74. While the analysis above looked at the historical features of total outputs relative to total inputs, the Board should also be mindful of the environment that will prevail

over the coming IR period. The factors that challenged TFP over the historical period are not likely to dissipate; in fact all indicators suggest that these challenges will only intensify.

Prospects for Outputs

75. By now the issue of declining residential and small commercial consumption is well documented. IndEco Research recently released a report that sought to study and understand the drivers of this reduced demand. That report can be found at Exhibit D, Tab 4, Schedule 1. Historically, the Company has seen annual average use declines of approximately 1.8% per year over the period 2000-2005. Higher and more volatile natural gas prices have been one of the key drivers for this decline. Other factors include the increasing efficiency with end use appliances and policies designed to regulate manufactured equipment efficiencies. In addition, new building techniques, such as improved thermal efficiencies and building codes, reduce the average energy footprint. DSM and other consumer conservation initiatives, including the Province's push for a culture of conservation, have likewise had a significant impact on volumetric declines. These issues will all remain prevalent throughout the upcoming IR period.

76. Another interesting phenomenon has been the trend towards multi-family residential dwellings, which, all else equal, demand less energy than their traditional detached counterparts do. Higher prices for new and pre-owned homes make the purchase of new semi-detached or town-homes relatively more affordable. A preference for smaller, more affordable multiple homes will likely cause further growth in this housing type and reduce average gas consumption further going forward. The Company has also experienced difficulty retaining water heater market penetration, which has suffered due to a variety of factors including customer desires for greater aesthetics, less floor space presence, and new technologies. New technologies are also gaining customer appeal for space heating. The demand for solar and ground-

source heating will only continue to rise as the costs of the technologies decline and consumer awareness increases.

77. Economists generally agree the housing sector has nowhere to go but down, which will take the pace of customer adds down with it as well. The primary drivers of reduced housing market activity are expected to be increased interest rates and higher overall housing prices.

78. The destruction in industrial load has also seen widespread acknowledgement, and this is particularly true for the Company. As was shown above, the decline in the Company's "Other" volumes were 2.35% per year over the period 2000-2005. Ontario has traditionally been a hotbed for manufacturing activity; however, since the mid-1990s higher relative fuel prices have hurt this sector. Furthermore, industrial volumes are more significantly impacted by economic variables, such as exchange rates. Exchange rates have been increasing steadily since 2000 and the near parity condition between the Canadian and U.S. dollar that now exists has many firms closing, or threatening to close, their doors in Ontario. While interest rates have been historically low for the last several years, the prospects for increasing interest rates are high, with the Bank of Canada only recently increasing its key benchmark rate.

79. Going forward, the one bright spot for increasing output is the growing interest in gas-fired electricity generation. While these outputs may grow into the future, they must be considered high risk in the short term. First, it can take many years for the permitting and environmental assessment processes to take place, so there are no guarantees that significant volumes will actually be added in the very near term. Second, investing in a new generating facility is a huge capital commitment for a potential investor, and as interest rates and the exchange rate increase, the potential attractiveness of such a venture may decline.

Prospects for Inputs

80. On the inputs side, cost pressures continue to mount, driven chiefly by the aging of the Company's infrastructure. The Company has proposed that certain costs be classified as Y-Factors, however, regardless of their classification, the Company's capital constraints are only magnified by the requirement to replace aging infrastructure such as cast iron mains, bare steel mains, and protected steel mains whose cathodic protection has deteriorated.

81. Further, new demands to ensure safety and integrity are maintained reduce the capital envelope that can be dedicated to productivity enhancing projects. Anytime a project is geared toward regulatory or legal compliance or to meet a safety issue, it is given a high priority ranking. These projects add little in the way of enhanced productivity but they are necessary to remain a safe and reliable operator.

82. The Company's integrity management program is a perfect example. Arising out of a greater desire for information regarding system integrity, the TSSA will soon require that all gas distributors have a plan in place to address pipeline integrity. This involves costs to excavate a pipeline, install in-line inspection equipment, and conduct the necessary testing. This is a relatively new program that did not exist over the relevant TFP measurement exercise above, and it represents capital that is required but produces virtually no productivity benefits. The 10-year plan that has been provided to the TSSA represents greater than $50 Million dollars worth of capital spending requirements.

83. New technologies also present both opportunities and challenges going forward. To extend the integrity management illustration above, new technological processes, called pigging, enhance the information gathered throughout the integrity management process. With an obligation to respond to potential pipeline

weaknesses, enhanced information frequently means greater operational cost pressures to follow up on these. In other words knowing more about the integrity of the system necessitates greater operational spending. The societal benefits of this far outweighs the additional cost pressures, however, they are additional cost pressures that reduce the ability to invest in productivity enhancing projects.

84. As described above and elsewhere, the Company is also expected to respond to the large and growing need for gas-fired electricity generation to aid the Province's electricity needs. The sheer magnitude and uncertainty of these investments have the potential to significantly alter the Company's portfolio of capital spending. Even if these projects are classified as Y-Factors that will just reduce the uncertainty of the project. The total capital envelope will nevertheless be altered to accommodate the investment. In addition to these being significant investments, they also see payback periods that can extend for decades.

85. Finally, labour costs are a very significant portion of both the Company's O&M and Capital costs. These costs are expected to grow at a rate greater than inflation, while medical and dental benefits will increase at about 10% annually. Customer Care costs will increase proportional to the growth rate in customer numbers. Historically, this rate has been greater than the growth in inflation, and despite a forecast for a reduction in customer growth, it is anticipated to still grow at or near the growth rate in general inflation.

V. The Reasonableness of the Estimates

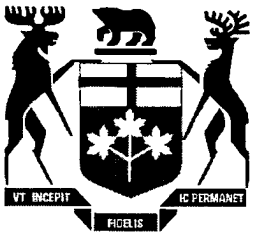
86. In PEG's March 2007 report, the reasonableness of their recommendation was measured against historical growth in the GDPIPI FDD over the period 1999-2005. PEG deemed the final recommendation was reasonable since rate escalations would increase similar to the historical rate of general inflation over this period. In PEG's June 2007 report, the reasonableness of their recommendation was

over the coming IR period. The factors that challenged TFP over the historical period are not likely to dissipate; in fact all indicators suggest that these challenges will only intensify.

Prospects for Outputs

75. By now the issue of declining residential and small commercial consumption is well documented. IndEco Research recently released a report that sought to study and understand the drivers of this reduced demand. That report can be found at Exhibit D, Tab 4, Schedule 1. Historically, the Company has seen annual average use declines of approximately 1.8% per year over the period 2000-2005. Higher and more volatile natural gas prices have been one of the key drivers for this decline. Other factors include the increasing efficiency with end use appliances and policies designed to regulate manufactured equipment efficiencies. In addition, new building techniques, such as improved thermal efficiencies and building codes, reduce the average energy footprint. DSM and other consumer conservation initiatives, including the Province's push for a culture of conservation, have likewise had a significant impact on volumetric declines. These issues will all remain prevalent throughout the upcoming IR period.

76. Another interesting phenomenon has been the trend towards multi-family residential dwellings, which, all else equal, demand less energy than their traditional detached counterparts do. Higher prices for new and pre-owned homes make the purchase of new semi-detached or town-homes relatively more affordable. A preference for smaller, more affordable multiple homes will likely cause further growth in this housing type and reduce average gas consumption further going forward. The Company has also experienced difficulty retaining water heater market penetration, which has suffered due to a variety of factors including customer desires for greater aesthetics, less floor space presence, and new technologies. New technologies are also gaining customer appeal for space heating. The demand for solar and ground-



Ontario

Natural Gas Regulation in Ontario:

A Renewed Policy Framework

Report on the Ontario Energy Board

Natural Gas Forum

March 30, 2005

- create an environment that is conducive to investment, to the benefit of customers and shareholders

The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet these criteria. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario.

The following are the Board's conclusions on the key parameters:

In a multi-year IR plan, the **annual adjustment mechanism** embodies the combined assessment of cost changes and productivity improvements. The Board concludes that making an appropriate determination of this component will ensure that the benefits of efficiencies are shared with customers during the term of the plan. The Board will determine the methodology for the annual adjustment mechanism through a generic hearing.

The Board's view is that a thorough cost-of-service **rebasing** must occur at the end of each IR plan's term before a new plan is put in place. Rebasing is an important consumer protection feature. Through robust rebasing, efficiency improvements will be revealed and the benefits passed on to customers through base rates for the next period. The Board will determine the base rates through a hearing for each utility.

The Board does not intend for **earnings sharing mechanisms** to form part of IR plans. The Board views the retention of earnings by a utility within the term of an IR plan to be a strong incentive for the utility to achieve sustainable efficiencies. The Board will ensure that the benefits of efficiencies are shared with customers through the annual adjustment mechanism and thorough rebasing.

The Board expects that the **term** of IR plans will be between three and five years.

enhance the efficiency incentives by extending the term of the plan and to reduce regulatory costs by introducing process reforms. However, COSR requires a utility to forecast its costs and revenues. It is unlikely that a utility could make this forecast with an acceptable level of precision beyond two years, and a two-year term provides a limited efficiency incentive. Setting rates for any longer period would require the Board to consider external measures of cost inflation. As well, to ensure that customers share in the benefits when a utility outperforms its forecasts, some form of earnings sharing would be required.

If external measures of cost and some mechanism for benefit sharing were both added to the framework, the multi-year COSR plan would take on the characteristics of PBR. However, if this quasi-PBR framework were structured with an inadequate consideration of inflation and productivity potential, with z-factors (for non-routine rate adjustments intended to safeguard customers and the utility against unexpected events that are beyond management's control) and with an earnings sharing mechanism within the term of the plan, then the efficiency incentive would be reduced. Likewise, if onerous annual reviews were required, the regulatory costs could remain high. The resulting framework may be less satisfactory than that of a traditional COSR.

On the other hand, some forms of PBR may involve a de-linking of rates and costs, as well as a loss of transparent cost data and cost analysis. The Board does not support a complete de-linking of rates and costs, and it is not prepared to forgo the benefits of a transparent review of costs.

A rigorous multi-year framework can ensure that there is downward pressure on rates and that customers and shareholders benefit from efficiency improvements. The key determinant of success, though, is the particular parameters of the plan. The Board intends to adopt the best aspects of both the COSR and PBR approach. It will therefore focus on specifying its expectations for the specific parameters of the rate regulation framework.

EXHIBIT LIST

B – PRE-FILED EVIDENCE

Exhibit	Tab	Schedule	Contents	Witness(es)
B	6	1	Rate Filing Process and Report Requirements	K. Culbert A. Kacicnik
	7	1	Rebasing Filing Requirements	R. Bourke K. Culbert

C – OPERATING COSTS

C	1	1	Summary of Gas Cost to Operations	D. Small
	2	1	Customers and Volumes by Rate Class	I. Chan T. Ladanyi
		2	Degree Days	J. Denomy
		3	Average Use	J. Denomy
	3	1	Customer Additions	I. Chan T. Ladanyi
	4	1	2008 Revenue per Customer Cap Determination	I. Chan K. Culbert A. Kacicnik T. Ladanyi D. Small
	5	1	Cost Allocation / Rate Design	J. Collier A. Kacicnik
	6	1	Rate Schedules	J. Collier A. Kacicnik