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**By Electronic Filing and By Email**

October 22, 2007

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Ms Walli

**Combined Proceeding**
**Enbridge Gas Distribution Inc. and Union Gas Limited Rates for 2008**

| | |
|---|---|
| **Enbridge Gas Distribution Inc. ("EGD")** | **Union Gas Limited ("Union")** |
| **Board File No.: EB-2007-0615** | **Board File No.: EB-2007-0606** |

**Our File No.: 302701-000411**

Please find attached Intervenor Evidence submitted on behalf of the Industrial Gas Users Association ("IGUA") in the above-noted combined proceeding.

The required paper copies will follow shortly.

Yours very truly

Peter C.P. Thompson, Q.C.

\slc
enclosure
c. Interested Parties EB-2007-0606 and EB-2007-0615
Murray Newton (Industrial Gas Users Association)

OTT01\3314816\1

**EB-2007-0606**
**EB-2007-0615**

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

**AND IN THE MATTER OF** an Application by Union Gas Limited for an Order or Orders approving or fixing a multi-year incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas effective January 1, 2008;

**AND IN THE MATTER OF** an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing rates for the distribution, transmission and storage of natural gas effective January 1, 2008;

**AND IN THE MATTER OF** a combined proceeding before the Board pursuant to section 21(1) of the *Ontario Energy Board Act, 1998*.

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# EVIDENCE OF THE INDUSTRIAL GAS USERS ASSOCIATION ("IGUA")

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October 22, 2007

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**Attachments**: **Tab Nos.**

## I. INTRODUCTION

1. The following evidence is submitted on behalf of the Industrial Gas Users Association ("IGUA") with respect to the Incentive Regulation ("IR") proposals made by Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("EGD"). The member companies of IGUA are listed in the document attached at **Tab 1**.

2. Murray Newton, the President of IGUA, will testify at the hearing to support this evidence. Mr. Newton may be accompanied by one or more representatives from IGUA member companies served by Union and EGD. The curriculum vitae of IGUA's witnesses will be provided shortly before they testify.

3. The issues which the Ontario Energy Board (the "Board" or "OEB") has identified for adjudication in these proceedings are listed under twelve (12) topic headings in the Issues List attached to Procedural Order No. 4. A copy of the Issues List is attached at **Tab 2**.

4. Matters pertaining to IR were discussed by the Board in its Report dated March 30, 2005, entitled "Natural Gas Regulation in Ontario; a Renewed Policy Framework - Report on the Ontario Energy Board Natural Gas Forum", hereinafter referred to as the "NGF Report".

5. The Board's Natural Gas Forum ("NGF") was not an adjudicative proceeding. A copy of page 13 of the NGF Report describing the NGF process is attached at **Tab 3**. Representatives of the Pacific Economics Group ("PEG") acted as advisers to the Board in the NGF process. None of the information presented to the Board during the course of the NGF process was subject to cross-

examination. The Board's conclusions with respect to matters pertaining to an IR framework based on its consideration of untested information are contained in its NGF Report at pages 14 to 36 inclusive attached at **Tab 4**. The Board's plan to implement the conclusions of the NGF Report is described at pages 74 to 81 inclusive thereof attached at **Tab 5**.

6. The Board directed its staff to take the lead in undertaking research, commissioning expert advice, and consulting with stakeholders on the further development of an IR framework for natural gas utilities in Ontario. As a result, Board staff, with the assistance of consultants from PEG, conducted a series of meetings with stakeholders and eventually circulated a Staff Discussion Paper on an IR framework for natural gas utilities dated January 5, 2007 ("Staff Discussion Paper"), which EGD has filed as Exhibit D, Tab 1, Schedule 1. The Staff Discussion Paper was followed by PEG's initial draft of its Price Cap Index ("PCI") designed for Ontario's natural gas utilities ("PCI Report") released to stakeholders on March 30, 2007. A Technical Conference was held on April 18, 2007, to permit stakeholders to ask questions of PEG with respect to the March 30, 2007 draft of its PCI Report.

7. By letter dated May 3, 2007, the Board requested Union and EGD to file Applications for Rates commencing January 1, 2008. Union and EGD filed their respective Applications on May 11, 2007. The Board issued its Notice of Applications and Combined Proceeding on May 25, 2007.

8. Board Staff circulated the final PEG PCI Report dated June 20, 2007. On June 27, 2007, the Board issued the first of a series of Procedural Orders

pertaining to the filing of the June 20, 2007 PEG PCI Report as evidence; the submission of Interrogatories with respect to the PCI Report and the evidence filed by Union and EGD; responses thereto; and the scheduling of a Technical Conference pertaining to those Interrogatory Responses. This Technical Conference with respect to the Interrogatory Responses provided by PEG/Board Staff, Union and EGD was held from October 3 to October 5, 2007. Responses to Undertakings, given during the course of the Technical Conference, were delivered by PEG/Board Staff, Union and EGD on or about October 11, 2007.

9. IGUA's evidence with respect to matters in issue reflects the evidence of PEG, Union, and EGD filed to date. IGUA is aware that evidence will be filed by other intervenors and recognizes that such evidence could influence the views which it has currently formed with respect to matters in issue in these proceedings.

## II. INCENTIVE REGULATION

10. Industrial gas users have always supported a healthy natural gas distribution infrastructure. Industrial gas users support the need for a balanced regulatory framework where both shareholder and customer interests are equally protected. A properly designed rate setting mechanism should provide utility shareholders with the opportunity to earn a fair return while providing their customers with the assurance of just and reasonable rates. This will continue to be the case under IR. Therefore, it is important that the OEB maintain its regulatory vigilance and oversight regardless of the mechanism used to determine the rates monopoly service providers charge their customers. As will be addressed in more detail below, the OEB must ensure all stakeholders are provided with the necessary

monitoring tools required to assess the continued appropriateness of any IR model ultimately implemented by Ontario's natural gas utilities. It is essential that stakeholders be given clear guidelines with respect to the specific future circumstances where it may be appropriate to exit the IR models.

11. IGUA wishes to emphasize, at the outset, that the Board's statutory mandate under the *Ontario Energy Board Act* (the "*OEB Act*") requires that the end result of whatever method of regulation the Board applies be "just and reasonable rates". Accordingly, the ultimate question to be asked and answered is whether the rates which a particular method of regulation produces each year are "just and reasonable".

12. In this context, a clear understanding of the criteria applied by regulatory tribunals and affirmed by the Courts to evaluate whether regulated rates are "just and reasonable" is fundamental.

13. Regulatory tribunals and the Courts have repeatedly stated that for rates to be just and reasonable, they must produce a return to the utility owner which, under the circumstances, is fair to the consumer on one hand, and on the other hand, secures for the company, a fair return for the capital invested. A utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on other business undertakings which are attended by corresponding risks and uncertainties. The utility has no right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. In IGUA's view, transparent and timely

disclosure of the return which regulated rates produce for the utility owner is fundamental to an evaluation of whether the rates are just and reasonable.

14. The Board determines a rate of return which it considers to be reasonable for the utilities it regulates. The equity return which the Board determines to be reasonable for the gas utilities it regulates is derived by adding a formula-based risk premium to consensus interest rate forecasts for a pre-determined mix of long and short term debt.

15. By definition, rates which produce a reasonable return recover the costs that need to be incurred to maintain quality utility service.

16. By definition, the equity rate of return and the overall rate of return determined by the Board to be reasonable are the returns which create an environment that is conducive to investment. They represent a level of return which satisfies the financial viability standard.

17. In order for ratepayers to be either better off or no worse off in terms of rates under an IR regime, compared to rates under a Cost of Service (“COS”) regime, the returns a utility owner realizes over the duration of an IR regime must be limited to a reasonable return.

18. An on-going comparison of the return level produced by regulated rates in normalized conditions to the rate of return which the Board has determined to be appropriate is essential to the evaluation of whether regulated rates for any particular year are just and reasonable.

19. Sustainable improvements which operate to produce a return in excess of a reasonable return should be allocable to ratepayers in every year in which they

occur. Otherwise, utility owners will be charging rates that are not just and reasonable.

20. Rates which consistently produce more than the allowed return are not just and reasonable. A regulator must protect utility ratepayers by preventing a utility from charging rates which are too high. Conversely, rates which consistently produce a rate of return which is less than the allowed return are not just and reasonable. A regulator must protect utility owners by approving increases in rates which consistently fail to produce the allowed return on a normal normalized basis.

21. In this context, IGUA considers an Earnings Sharing Mechanism ("ESM") feature of an IR plan to be an essential element necessary to assure that rates remain just and reasonable throughout the duration of the IR regime. In its RP-1999-0017 Decision with Reasons at page 151, the Board agreed that:

> ***"… an ESM is one way of mitigating the risk of earnings being unacceptably high or unacceptably low under a price cap plan."***

22. The potential for over-earnings was the rationale relied upon by the Board when including an ESM in its September 4, 2003 Decision in the RP-2003-0048 proceedings approving a 1.8% escalation factor increase in EGD's 2003 revenue requirement as EGD's 2004 revenue requirement. IGUA also notes that EGD considered a symmetric ESM to be an appropriate feature of the five (5) year Price Cap Plan it was proposing for the years 2004 to 2008 as Attachment 1 to Exhibit I, Tab 17, Schedule 1 shows.

23. In IGUA's view, an ESM, as a component of an IR plan, should not be excluded from the regime on the grounds that it blunts or dilutes the incentive effect of an IR regime on utility owners to maximize efficiency. What a properly designed

ESM assures is that the statutory pre-requisite of just and reasonable rates is met throughout the duration of any IR regime. The incentive effect of an ESM on utility owners is irrelevant.

24. The just and reasonable rates requirement is not a goal or objective of an IR regime. It is a statutory pre-requisite. Customers of regulated monopoly service providers will have no confidence in a regulatory regime which does not transparently disclose the actual and normalized returns a utility owner is earning, on an annualized basis, in relation to the Board determined allowed return levels.

25. The NGF Report, the Staff Discussion Paper, and the evidence of Union and EGD list a number of principles and objectives which an IR regime should achieve. One of the stated objectives of an IR plan is to enhance rate stability and predictability. Another factor to consider is the comprehensiveness of the plan.

26. The IR regimes proposed by Union and EGD are far from comprehensive in that they do not eliminate in their entirety a continuance of features of COS regulation. Every Y factor in an IR plan is a COS feature of regulation. Y factors fall outside the ambit of “incentive” rate-making. Every deferral account created for rate-making is a feature of COS regulation. Revenues and expenses which are subject to deferral account protection fall outside the ambit of incentive rate making. As well, every Z factor brought into account in determining rates is a COS feature rather than an incentive feature of rate-making.

27. Achieving greater stability and predictability in rates is very much dependent upon the extent to which Y factor, deferral account, and Z factor features of a particular IR mechanism are structured. Union's evidence at Exhibit C13.2 indicates that under its proposal, only 45% of its regulated revenue requirement will be subject to "incentive" rate-making. In EGD's case, the percentage is slightly less than 25% of the total revenue requirement as shown in Exhibit JTB.2. At best, the IR regimes proposed by Union and EGD are COS and IR plan hybrids.

28. The frequency of rate changes for Union and EGD will not change under the IR regimes they propose. Changes to rates will be considered four times a year in QRAM proceedings. Annual changes to rates will be considered to accommodate the clearing of the multitude of deferral accounts which Union and EGD propose to continue. The direction and magnitude of the rate changes triggered by these events are unpredictable. Accordingly, the specific IR regimes proposed by Union and EGD will not reduce or eliminate the frequency of rate changes or the unpredictability thereof.

29. Both Union and EGD seek to reserve the right to propose, during the operation of an IR regime, and to have the Board implement during the operation of an IR regime, changes to the methodologies that have been used to derive the base rates. For example, both Union and EGD seek the right to propose changes to the methodology the Board applies to determine Return on Equity ("ROE"). IGUA suggests that, if the costs of equity are to remain an open item, then

fairness considerations require that declines in the costs of debt occurring during the term of the price cap plan also be brought into account.

30. In addition, Union seeks to have the Board vary the weather normalization methodology it approved for the longer term in its March 18, 2004 Decision in the RP-2003-0063 proceedings, and thereby enhance Union's base year revenue requirement and rates by an amount of about $7M. IGUA considers these methodology change proposals to be incompatible with the IR goal of enhancing the stability and predictability of rate-setting. IGUA urges the Board to refrain from considering and implementing selective methodology adjustments favourable to utility owners, either at the outset of or during the term of an IR plan. Alternatively, any methodology change proposals which the Board might consider and approve during the term of an IR plan should not become effective until the plan expires.

31. Union and EGD appear to accept that another important feature of any IR plan to consider is its transparency. It is IGUA's view that any IR regime which does not require the utility owners to transparently report, on a continuing basis throughout the IR regime, the level of returns it is earning on the rates it charges, is a plan which lacks the transparency that is fundamental to a regulatory determination that the rates being charged continue to be just and reasonable. IGUA considers the resistance of Union and EGD to making this type of regular and transparent disclosure to be a material flaw in their respective IR proposals.

32. IGUA notes that, in the presentation made by the President of EGD to the North American investment community on October 3, 2007, at Exhibit JTB.25,

Attachment 2, page 5, EGD is forecasting the achievement of a ROE of almost 12% under its IR plan. Regulated rates which produce such a result on current financial conditions are not just and reasonable, and an appropriately structured ESM is required to assure that the regulated rates EGD charges over the duration of the IR regime remain just and reasonable.

33. Union and EGD appear to accept that IR plans should be reasonably simple to administer. The evidence indicates that there is likely to be considerable controversy over some or all of the appropriate conclusions and findings to be drawn from the statistical and non-statistical evidence pertaining to the components of the X factor. If the evidence, once tested, reasonably supports a conclusion that the components of the X factor are likely to be in an amount that approximates the anticipated rate of inflation, then simplicity considerations weigh in favour of Board approval for a rate freeze for service groups which are not contributors to the declining Average Use ("AU") phenomenon.

34. It is in the context of these general observations with respect to Incentive Regulation that IGUA outlines its concerns with the IR regimes proposed by Union and EGD, and suggests alternatives thereto which it requests the Board to consider.

## III. UNION'S PROPOSALS

### A. IR Plan

35. A summary of Union's proposed IR plan is contained in Exhibit C13.1, a copy of which is attached at **Tab 6**.

(i) Plan Type - Price Cap and Service Group Price Caps

36. IGUA can see some benefits associated with a Price Cap model for Union. IGUA appreciates that declining average uses by Union's residential and small general service classes is a continuing problem which needs to be addressed. IGUA also agrees that the declining AU problem is confined to Union's residential and smaller general service ratepayers. Accordingly, addressing the AU problem requires that service groups be separated into the residential and general service class which is subject to the declining AU phenomenon and the remaining rate classes and that separate and appropriate PCIs for each service group be determined.

(ii) <u>Adjustment Mechanism</u>

(a) <u>Inflation</u>

37. IGUA accepts Gross Domestic Product Price Index ("GDPPI") as the statistical base for determining the inflation component of a PCI. IGUA will explore at the hearing whether "updated" GDPPI statistics should be considered.

(b) <u>X Factor</u>

38. IGUA does not accept Union's stretch factor proposal of zero basis points. The fact that Union has essentially operated under the auspices of a rate freeze for several years and, over those years, has consistently earned more than its allowed ROE on a normalized basis demonstrates that the sum of all the components of the X factor for Union exceeds the rate of inflation.

39. IGUA notes that the PCI which PEG derives for the service groups other than the residential and small general service groups, at a GDPPI of 1.86 and a stretch factor of 50 basis points, is 0.08. At a GDPPI of 2.04, PEG's PCI for such service groups would increase to 0.26. With a stretch factor of 75 or more basis

points, a PCI of zero or a rate freeze results. In the RP-1999-0017 proceeding, the Board determined that Union's stretched productivity factor should be 140 basis points.

40. If the IR plan does not include an ESM, then IGUA suggests that a stretch factor significantly in excess of 50 basis points will be required to assure that the rates charged for utility services over the duration of the IR plan satisfy the statutory just and reasonable pre-requisite.

(iii) Declining AU as an Element of the X Factor for Residential and General Service

41. IGUA accepts that one way of addressing the declining AU problem is to make an upward adjustment to the PCI for the residential and small general service groups as PEG proposes. IGUA wishes to explore, at the hearing, whether there are others ways of dealing with the problem such as whether a dollar amount for the appropriate AU adjustment can be calculated annually at the same time that the DSM Y factor amount is calculated. Obviously, any AU adjustment factor must exclude the AU declines which are being accounted for in the Y factor calculation for DSM.

(iv) Y Factors

42. IGUA accepts that cost of gas and upstream transportation costs are appropriate items to be included in the Y factor. IGUA also accepts that DSM costs and other DSM effects are appropriate to be included in the calculation of the Y factor, provided they are not also being reflected in the AU adjustment.

43. IGUA wishes to explore, at the hearing, whether Union has adequately or fairly considered the elimination of both revenue and expense deferral accounts.

(v) Z Factors

44. As long as an ESM is a feature of the IR plan for Union, then IGUA accepts that a particular dollar amount can be established as a threshold which needs to be exceeded before any Z factor adjustments can be claimed.

45. If the IR plan does not include an ESM, then, in IGUA's view, normalized earnings and the rate of return being earned by the utility needs to be considered when determining the amount of a Z factor claim threshold that must be exceeded before considering an increase in rates on account of a Z factor claim.

(vi) Plan Term

46. The degree of uncertainty surrounding most cost and revenue components of the proposed IR plan causes IGUA to prefer a shorter term for the proposed IR plan. Therefore, IGUA recommends the IR plan should be restricted to a term of three (3) years duration rather than the five (5) years proposed by Union. The number of uncertainties associated with the statistical evidence and the risks of misspecifying the parameters of the plan and the resulting negative implications for consumers support the adoption of a plan term shorter than five (5) years.

(vii) ESM

47. IGUA considers an ESM to be a mandatory pre-requisite of an IR plan in order to assure that the rates being charged for regulated services comply with the mandatory statutory requirement that rates be just and reasonable. IGUA's preliminary view is that a graduated ESM around a narrow deadband above and below the Board's formula-based ROE is required to comply with the just and reasonable rates statutory requirements.

(viii) Reporting

48. Transparent and quarterly reporting of all relevant regulatory information, including annualized equity returns, in a format comparable to the surveillance reporting model required by the National Energy Board ("NEB"), should be required of Union.

(ix) Rebasing

49. The rebasing rules should not be established on an assumption that a return to COS regulation at the end of the IR plan is precluded. Rather, rebasing rules should be established on an assumption that a return to COS is an option to be implemented either for the purposes of re-setting base rates, or for the continuance of a COS regime beyond the re-basing year. In this context, Union should be directed to keep records over the duration of the IR plan of the linkage between its regulated rates and allocated costs.

(x) Marketing Flexibility

50. In IGUA's view, changes to rate "tilt" during the IR plan should be avoided, if possible. Any changes to rate tilt Union wishes to implement during the term of the IR plan should be subject to prior Board approval.

51. Any new services, together with the treatment of the revenues generated by such new services, Union proposes to introduce during the term of the IR plan should be subject to prior Board approval.

(xi) Non-Energy Services

52. IGUA accepts that charges for these services need not change in accordance with the PCI on the understanding that revenues from these charges are utility

revenues and that any changes to the charges will be subject to prior Board approval.

**B. Base Rate Adjustments**

(i) Items from previous Board Decisions

53. IGUA accepts that adjustments to Base Rates should be made for items arising from previous Board Decisions. However, one significant item which Union fails to address is the appropriateness of its allocation of rate base to its non-utility storage services business. Union only allocates 21% of the integrated storage assets to non-utility storage services, even though 33% of the volumetric storage capacity is ear-marked for ex-franchise storage services. This allocation is transparently unreasonable and should be increased to 33%. The base year revenue requirement and rates should be reduced by an amount of about $8.37M shown in Exhibit JTA.28 to properly adjust for this under-allocation of storage assets to the non-utility storage services business.

(ii) Possible True-Up of Base Rates to Reflect Normalized 2007 ROE of 8.54%

54. Union needs to disclose its estimated normalized 2007 ROE so that it can be determined whether a true-up of base rates is required.

(iii) Weather Normalization Adjustment and Methodology Changes Generally

55. Adherence to the predictability and stability of rates objective should operate to preclude any changes in the methodology used by the Board to derive the base rates, and preclude methodology changes from being implemented during the term of the IR regime. Any methodology changes should only be implemented when the IR plan expires.

### C. Interim Rates

56. Any interim rates approved for Union should reflect a proper volume-based allocation of storage assets to the non-utility storage services business and the extent to which normalized base rates for 2007 produce a ROE in excess of 8.54%. Since a rate freeze is an option which the evidence appears to support and because methodology changes pertaining to weather normalization are incompatible with the Board's prior Decision in RP-2003-0063 proceeding, as well as the predictability and stability of rates objective of an IR plan, there should be no interim rate increases with respect to either the weather normalization adjustment or the PCI Union proposes.

## IV. EGD'S PROPOSALS

### A. IR Plan

57. A summary of EGD's proposed IR plan is contained in Exhibit I, Tab 17, Schedule 1, a copy of which is attached at **Tab 7**, along with a copy of Exhibit C, Tab 4, Schedule 1, page 5, which contains a numerical illustration of the manner in which EGD's proposal will operate.

#### (i) Plan Type - Revenue Per Customer Cap

58. IGUA has significant concerns with the system-wide revenue per customer cap plan EGD proposes. Any revenue per customer cap plan which IGUA might be prepared to consider would need to first be segregated by rate classes, or by service groups, with one of the service groups being the residential and small general service customers for which declining AU is problematic, and the other service group being all other customer classes.

59. The evidence at Exhibit JTB.1 indicates that, at best, EGD's revenue per customer cap only covers slightly less than 25% of EGD's total revenue requirement. The calculations EGD has provided at Exhibit C, Tab 4, Schedule 1, page 5 at lines 7 and 15 indicate that for 2008, EGD's proposal will produce a revenue requirement increase of $40M, excluding any revenue requirement changes pertaining to the following:

(a) Capital expenditures related to system, safety and integrity and applications for leave to construct;

(b) DSM program costs;

(c) CIS/Customer Care costs;

(d) Incremental gas costs associated with upstream transportation, storage and supply mix costs;

(e) An adjustment related to the embedded carrying costs of gas and storage and working cash related to gas costs; and

(f) Changes in costs related to certain deferral and variance accounts.

In addition, EGD reserves the right to seek increases in the level of equity return the Board currently allows.

As already noted, if the costs of equity are to remain an open item, then declines in the costs of debt occurring during the plan term must be brought into account.

60. Based on the foregoing, most of EGD's revenue requirement remains subject to COS regulation. As a result, EGD's proposal appears to be a "targeted" rather than a "comprehensive" IR proposal. IGUA considers EGD's proposed plan to be inappropriate because of its lack of comprehensiveness.

61. It is unclear to IGUA why EGD has abandoned its support for a price cap plan. Its disputes with PEG concerning the conclusions to be drawn from the statistical evidence should not effect a determination of whether or not a price cap plan is appropriate. As already noted, uncertainties with respect to the statistical evidence and the risks of misspecifying plan parameters are best mitigated by adding an ESM feature to the IR plan.

62. It appears to IGUA that the IR plan types which might reasonably balance the interests of EGD's ratepayers and its shareholder include the following:

(a) A PCI model of the type IGUA proposes for Union, or

(b) A revenue per customer plan segregated by rate class or customer groups with no Y factor protection for capital expenditures.

The other option is to continue to adhere to full forward test year rate regulation where EGD's proposed rates and underpinning costs can be examined in a transparent and open manner.

63. IGUA will wish to explore at the hearing the implications of these alternatives for EGD. EGD currently refuses to answer any discovery questions pertaining to models other than the particular revenue per customer cap model it proposes.

(ii) <u>The Adjustment Mechanism</u>

(a) <u>Inflation</u>

64. As with Union, IGUA accepts GDPPI as the statistical base for determining inflation. Once again, IGUA wishes to leave open and explore at the hearing whether updated GDPPI information should be considered.

(b) X Factor

65. As with Union, IGUA does not accept EGD's proposed stretch factor of zero basis points and that the sum of all components of the X factor, excluding any AU adjustment, is -0.77 as EGD asserts.

66. In view of the fact that EGD's escalation factor only covers less than 25% of its total revenue requirement and that all other components thereof will be subject to some form of continuing COS regulation, IGUA suggests that a very significant stretch factor is required and particularly so if an ESM feature is not added to the plan.

67. IGUA expects that when all of the disputed evidence with respect to the individual components of the X factor and the sum of all of its components has been tested, it is likely to support, as reasonable, a conclusion that, for those rate classes for which declining AU is not an issue, the sum of all of the components of the X factor for EGD approaches the current rate of inflation of about 2.04%. Therefore, IGUA will be urging the Board to find that a rate freeze for those rate classes for which declining AU is not an issue is appropriate for EGD and that the $40M increase in revenue requirement which EGD seeks through application of its revenue per customer cap proposal, excluding revenue requirement changes with respect to about 75% of its revenue requirement, is grossly excessive and unreasonable.

(iii) Y Factors

68. As with Union, IGUA accepts that cost of gas, upstream transportation, and DSM cost changes are appropriate Y factors.

69. Again, as with Union, IGUA wishes to explore, at the hearing, whether EGD has adequately or fairly considered reducing the deferral account protection it currently enjoys.

70. IGUA suggests that the capital expenditure cost Y factor which EGD proposes related to system safety and integrity and applications for leave to construct is inappropriate. IGUA suggests that leaving EGD's capital expenditure plans with respect to system safety and integrity and leave to construct applications as an open COS item is incompatible with the recent Board Decision with respect to EGD's overall capital expenditures in EB-2005-0001/EB-2005-0437 dated February 9, 2006. The relevant excerpts from this Decision are attached at **Tab 8**.

71. With respect to EGD's system expansion plans and the feasibility thereof, IGUA notes that there is a material disconnect between the depreciation rates EGD recovers in its revenue requirement and the revenue horizon it uses to forecast the feasibility of attaching additional customers. For the residential and smaller general service rate classes, EGD uses a 40 year revenue horizon in evaluating the economic feasibility of expansion. Such a revenue horizon implies a composite depreciation rate of about 2.5%. Yet, EGD recovers in rates a composite depreciation rate in excess of 4.5%.

72. IGUA suggests that if EGD is going to recover in rates a composite depreciation rate in excess of 4.5%, then it should constrain its system expansion to projects which are economically feasible over a time horizon of 22 to 23 years. If EGD continues to assess the economic feasibility of system expansion for residential

and small general service customers over a 40 year time horizon, then the depreciation rate it recovers in rates should be considerably less than 4.5%. In this regard, IGUA notes that the composite depreciation rate Union currently recovers from its customers is about 3%. One way or another, the Board should refrain from requiring EGD's existing customers to subsidize what is uneconomic system expansion.

(iv) Z Factors

73. As with Union, IGUA can accept a particular dollar amount as a threshold for determining Z factor eligibility, as long as there is an ESM feature in the IR plan. Without an ESM, the normalized returns which the rates are producing needs to be considered when determining the appropriate threshold amount to be exceeded to obtain Z factor eligibility.

(v) Plan Term

74. As with Union, IGUA prefers a plan term of three (3) years rather than five (5) years, particularly where the plan does not include an ESM.

(vi) ESM

75. As with Union, IGUA considers an ESM to be a mandatory pre-requisite of an IR plan for EGD in order to assure that the rates being charged for regulated services comply with the mandatory statutory requirement that they be just and reasonable.

76. As already noted, IGUA's preliminary view is that a graduated ESM around a relatively narrow deadband above and below the Board's formula-based ROE is required to comply with the just and reasonable rates statutory requirements.

(vii) Reporting

77. As with Union, transparent and quarterly reporting of all relevant regulatory information, including annualized equity returns, in a format comparable to the surveillance reporting model required by the National Energy Board ("NEB"), should be required of EGD. IGUA does not accept EGD's rejection of these reporting requirements.

(viii) Rebasing

78. As with Union, the rebasing rules for EGD should not be established on an assumption that a return to full COS regulation at the end of the IR plan is precluded. Rather, the rebasing rules should be established on an assumption that a return to full COS is an option to be implemented for the purposes of re-setting base rates, or for the continuance of a COS regime beyond the re-basing year. In this context, EGD should be directed to keep records of the linkage between its regulated rates and allocated costs over the duration of the IR plan.

(ix) Non-Energy Services

79. As with Union, IGUA accepts that charges for these services need not change in accordance with the IR plan on the understanding that revenues from these charges are utility revenues and that any changes to the charges will be subject to prior Board approval.

## V. IGUA PROPOSALS

### A. Union

80. IGUA expects that after all of the evidence currently filed and to be filed with respect to the price cap IR plan proposed by Union has been tested, it will likely support a conclusion that, for the contract rate classes whose consumption is not

subject to the declining AU problem, a three (3) year rate freeze satisfies the fairness, alignment, earnings opportunities, efficiency, comprehensive, rates predictability and stability, flexibility and accountability objectives Union urges the Board to consider.

81. The addition of a graduated ESM operating around a narrow deadband above and below the Board's ROE will assure Union's shareholder and its ratepayers that the rates being charged for utility services over the duration of the plan term will satisfy the statutory just and reasonable standard.

## B. <u>EGD</u>

82. While the implications for EGD of a price cap plan by service group and a revenue cap per customer plan by rate class and/or service group need to be further explored at the hearing, IGUA expects that when all of the evidence with respect to matters in issue has been fully tested, it will likely support a conclusion that, for the contract rate classes and service groups whose consumption is not subject to the declining AU problem, a three (3) year rate freeze satisfies the nine (9) IR principles listed in the Staff Discussion Paper which EGD accepts and urges the Board to apply.

83. As with Union, the addition of a graduated ESM operating around a narrow deadband above and below the Board's ROE will assure EGD's shareholder and its ratepayers that the rates being charged for utility services over the duration of the plan term will satisfy the statutory just and reasonable standard.

# TAB 1

# Members/Membres

## Pulp & Paper/ Pâtes et papier

| | Qué. | Ont. | Man. |
|---|---|---|---|
| Abitibi-Consolidated Inc. | x | x | |
| Atlantic Packaging Products Ltd. | | x | |
| Bowater Canadian Forest Products Inc. | x | x | |
| Cascades Inc. | x | x | |
| Domtar inc. | x | x | |
| Grant Forest Products Inc. | | | |
| Les Entreprises Tembec Inc. | x | x | |

## Metals/Métaux

| | Qué. | Ont. | Man. |
|---|---|---|---|
| Alcan Primary Metal Group | x | | |
| Alcoa Primary Metals | x | | |
| Dofasco Inc. | | x | |
| Gerdau Ameristeel | | x | |
| Ivaco Rolling Mills | | x | |
| Mittal Canada Inc. | x | x | |
| PanAbrasive inc. | | x | |
| QIT-Fer et Titane Inc. | x | | |

## Mining, Smelting & Refining/ Mines, fonderies et raffineries

| | Qué. | Ont. | Man. |
|---|---|---|---|
| Agrium | | x | |
| Cameco Corporation | | x | |
| CVRD Inco Limited | | x | |
| Sifto Canada Inc. | | x | |
| Xstrata Copper | | x | |
| Xstrata Nickel | | x | |
| Xstrata Zinc Canada | x | | |
| Zochem, Division of Hudson Bay Mining & Smelting Co., Ltd. | | x | |

## Chemicals/ Produits chimiques

| | Qué. | Ont. | Man. |
|---|---|---|---|
| Air Liquide Canada Inc. | x | x | |
| Cytec Canada Inc. | | x | |
| E.I. du Pont Canada Company | x | x | |
| Interquisa Canada s.e.c. | x | | |
| INVISTA (Canada) Company | | x | |
| KRONOS Canada, Inc. | x | | |
| NOVA Chemicals (Canada) Ltd. | x | x | |
| Petresa Canada Inc. | x | | |
| Recochem Inc. | x | x | |

## Other Industries/ Autres industries

| | Qué. | Ont. | Man. |
|---|---|---|---|
| Canadian Mist Distillers Limited | | x | |
| CertainTeed Gypsum North American Services, Inc. | x | x | x |
| CGC Inc. | x | x | |
| IKO Industries Ltd. | | x | |
| Sensient Flavors Canada Inc. | | x | |
| Suncor Energy Marketing Inc. | | x | |
| Tate & Lyle North American Sugars Ltd. | | x | |
| 3M Canada Co. | | x | x |
| VFT Inc. | | x | |
| Walker Industries Holdings Limited | | x | |

July 2007

juillet 2007

Industrial Gas Users Association/l'Association des consommateurs industriels de gaz
1201 – 99 Metcalfe Street, Ottawa, Ontario K1P 6L7
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# TAB 2

## APPENDIX A

## UNION GAS LIMITED
## ENBRIDGE GAS DISTRIBUTION INC.
## EB-2007-0606 / EB-2007-0615

## ISSUES LIST

### 1. Multi-Year Incentive Ratemaking Framework

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

1.2 What is the method for incentive regulation that the Board should approve for each utility?

1.3 Should weather risk continue to be borne by the shareholders, and if so what other adjustments should be made?

### 2. Inflation Factor

2.1 What type of index should be used as the inflation factor (industry specific index or macroeconomic index)?

2.1.1 Which macroeconomic or industry specific index should be used?

2.2 Should the inflation factor be based on an actual or forecast?

2.3 How often should the Board update the inflation factor?

2.4 Should the gas utilities ROE be adjusted in each year of the incentive regulation (IR) plan using the Board's approved ROE guidelines?

### 3. X Factor

3.1 How should the X factor be determined?

3.2 What are the appropriate components of an X factor?

3.3 What are the expected cost and revenue changes during the IR plan that should be taken into account in determining an appropriate X factor?

### 4. Average Use Factor

4.1 Is it appropriate to include the impact of changes in average use in the annual adjustment?

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

4.3 If so, how should the impact of changes in average use be applied (e.g., to all customer rate classes equally, should it be differentiated by customer rate classes or some other manner)?

## 5. Y Factor

5.1 What are the Y factors that should be included in the IR plan?

5.2 What are the criteria for disposition?

## 6. Z Factor

6.1 What are the criteria for establishing Z factors that should be included in the IR plan?

6.2 Should there be materiality tests, and if so, what should they be?

## 7. Natural Gas Electricity Interface Review (NGEIR) Decisions

7.1 How should the impacts of the NGEIR decisions, if any, be reflected in rates during the IR plan?

## 8. Term of the Plan

8.1 What is the appropriate plan term for each utility?

## 9. Off-Ramps

9.1 Should an off-ramp be included in the IR plan?

9.2 If so, what should be the parameters?

## 10. Earning Sharing Mechanism (ESM)

10.1 Should an ESM be included in the IR plan?

10.2 If so, what should be the parameters?

## 11. Reporting Requirements

11.1 What information should the Board consider and stakeholders be provided with during the IR plan?

11.2 What should be the frequency of the reporting requirements during the IR plan (e.g., quarterly, semi-annual or annually)?

11.3 What should be the process and the role of the Board and stakeholders?

## 12. Rate-Setting Process

12.1 Annual Adjustment

12.1.1 What should be the information requirements?

12.1.2 What should be the process, the timing, and the role of the stakeholders?

12.2 New Energy Services

12.2.1 What should be the criteria to implement a new energy service?
12.2.2 What should be the information requirements for a new energy service?

12.3 Changes in Rate Design

12.3.1 What should be the criteria for changes in rate design?

12.3.2 How should the change in the rate design be implemented?

12.3.3 What should be the information requirements for a change in rate design?

12.4 Non-Energy Services

12.4.1 Should the charges for these services be included in the IR mechanism?

12.4.2 If not, what should be the criteria for adjusting these charges?

12.4.3 What should be the criteria to implement new non-energy services?

12.4.4 What should be the information requirements for new non-energy services?

## 13. Rebasing

13.1 What information should the Board consider and stakeholders be provided with at the time of rebasing?

## 14. Adjustments to Base Year Revenue Requirements and/or Rates

14.1 Are there adjustments that should be made to base year revenue requirements and/or rates?

14.2 If so, how should these adjustments be made?

# TAB 3

Ontario

# Natural Gas Regulation in Ontario:

# A Renewed Policy Framework

## Report on the Ontario Energy Board

## Natural Gas Forum

**March 30, 2005**

## The Natural Gas Forum Process

The first Natural Gas Forum meeting took place in November 2003. At that one-day meeting, the Board heard stakeholders' views on the priority issues for natural gas regulation.[4] From that initial discussion, the Board identified the priority issues for the Natural Gas Forum:

- system supply
- storage and transportation
- rate regulation

To stimulate the review, the Board sponsored a discussion paper on each topic. The discussion papers contained market research, recounted the experiences of other jurisdictions and identified policy options. The Board received 24 initial written submissions in response to these discussion papers.

In the fall of 2004, the Board hosted a second Natural Gas Forum meeting. This six-day technical consultation provided an opportunity for stakeholders to present their views to the Board and for all participants to discuss these views. There were 31 oral presentations and 9 panel discussions. After completion of the technical consultations, the Board received 35 final written submissions. Appendix 2 lists the parties that made oral presentations and final submissions.

Because the Natural Gas Forum is a policy initiative, the Board's statutory power to grant cost awards in "proceedings" did not apply to the Forum. However, the Board made funding available from its own budget to facilitate the participation of a number of stakeholders, including residential customers and environmental groups.

The Board would like to thank all the Natural Gas Forum participants who took the time to make presentations during the technical consultations and who participated in the exchange of views that took place.

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[4] The *Report of the Ontario Energy Board Natural Gas Forum* (2003) is available on the OEB Web site under "Natural Gas Forum." Also available at that location are the discussion papers, initial and final written submissions, and slides of oral presentations referred to in the following paragraphs.

# TAB 4

# RATE REGULATION

## Background

For many years, the Board has employed the traditional cost-of-service ratemaking (COSR) methodology to set the rates for the gas utilities under its jurisdiction. In the late 1990s, the Board encouraged Union Gas Limited (Union) and Enbridge Gas Distribution Inc. (Enbridge) to bring forward applications for performance based regulation (PBR) plans. Each company did so, and the Board subsequently reviewed the plans and approved them for implementation.

Because these two plans involved the first PBR experience in the Ontario gas industry, they were viewed as trial plans of three years' duration. However, they did not have the same degree of comprehensiveness. Enbridge's plan covered only the operations and maintenance portion of its costs and was termed a "targeted" PBR, while Union's plan provided comprehensive PBR coverage for its full revenue requirement, with a price cap.

Upon the expiration of the trial PBR plans, the companies were asked to file new cost-of-service (COS) applications to set base rates for what were expected to be new PBR proposals. However, both companies chose not to update their PBR plans, and instead resumed filing applications based on traditional COS methods. At present, both utilities are operating under COS rates.

However, for some time stakeholders have expressed concerns about perceived inefficiencies in the current ratemaking framework, such as a resource-intensive hearing process and weak incentives for utilities to perform efficiently. As a result, the Natural Gas Forum focused on broad questions related to determining an appropriate ratemaking framework and, in particular, whether the current framework should be maintained or changed.

## The Regulatory Framework: Cost-of-Service Ratemaking or Performance Based Regulation?

Many of the submissions expressed a degree of support for PBR because of its incentive properties and the desirability of increasing utilities' efficiency. This support partly reflected the acknowledged weaknesses in the COSR model, including weak efficiency incentives and the high regulatory burden of annual rate hearings. However, endorsement of PBR was delivered with caution, particularly by the customer groups. A number of these groups expressed a preference for COSR at the present time, because, in their view, it has proven to be an effective methodology.

Many of the submissions (and the initial Board-sponsored discussion paper) commented on the experience of Enbridge's and Union's trial PBR plans. The reluctance of many stakeholders to endorse PBR is related to their dissatisfaction with these initial trial PBR plans. The PBR trials were widely considered unsuccessful, and the Board must consider this experience in determining future direction.

Stakeholders identified six factors to be considered in designing a ratemaking plan:

- whether the plan is targeted or comprehensive
- the sharing of benefits/earnings between ratepayers and shareholders
- the complexity of the rate adjustment mechanism
- the term of the plan
- transparency of information during the term of the plan
- the clarity of the Board's expectations for the plan

These six factors are discussed below.

**Whether the plan is targeted or comprehensive:** Most PBR plans are comprehensive, to create stronger and more balanced incentives. For example, a plan that focuses only on operating and maintenance expenses may weaken incentives to control capital costs, with the effect that overall performance incentives may not be improved. A plan that targets only certain areas may unintentionally create incentives for firms to allocate costs differently than they otherwise would. The targeted nature of the Enbridge PBR plan may have played a role in the general dissatisfaction for this type of plan. In particular, the outsourcing Enbridge undertook may have been less controversial if Enbridge's PBR had been more comprehensive.

**The sharing of benefits/earnings between ratepayers and shareholders:** Many ratepayer groups in particular criticized the Enbridge PBR plan because it did not contain explicit provisions to share benefits with its customers. The lack of this feature contributed to stakeholder perceptions that the Enbridge plan was poorly designed. It also elevated concerns about regulatory gaming with respect to Enbridge's outsourcing arrangements. Many customer groups were disappointed by what they saw as the absence of any explicit or tangible benefits resulting from the trial PBR plans, and they viewed earnings sharing mechanisms as a way to address this shortcoming. Rebasing at the end of the plan's term is another mechanism for ensuring that benefits flow to ratepayers. Rebasing also avoids the incentive-diluting effects of earnings sharing mechanisms during the term of the plan.

**The complexity of the rate adjustment mechanism:** Another factor that, it was felt, limited the effectiveness of the PBR plan was the acknowledged need for technical expert opinion and input on the specific parameters of the PBR mechanism. A number of stakeholders expressed concern that the technical debates related to the Union PBR plan were time consuming and expensive. Others pointed out the risk of arbitrary decisions on the parameters. The wish to avoid high costs and, more importantly, the risk of arbitrary regulatory decisions have contributed to a desire to implement a more simplified approach to PBR plans. All else being equal, simplicity in the design of PBR plans is seen as a virtue, but the Board must ensure that the resulting rates are just and reasonable.

**The term of the plan:** Both of the Ontario PBR trial plans had three-year terms, to reflect the plans' experimental nature. Typically, PBR plans are designed so that incentives are naturally strengthened as the PBR plan's term and the period between rate reviews increase. Generally, five-year plans are the standard in PBR regimes, but plans as long as 10 years have been implemented. The long terms allow utilities to implement long-term efficiency improvements.

**Transparency of information during the term of the plan:** Customer groups were concerned that the framework of PBR plans is less transparent than that of COS plans, and that, therefore, customers were more excluded from the PBR process than from the COS process. Also, stakeholders were concerned about the lack of public reporting of the utility's results. Stakeholders wanted this information to assess whether the regulatory framework was working.

**The clarity of the Board's expectations for the plan:** Stakeholders perceived a lack of direction from the Board and exhibited a degree of scepticism in the trial PBR process. The submissions indicated that greater understanding and consensus on PBR would likely emerge if the Board clearly articulated its views about the purpose, application and most appropriate design of PBR plans. Several parties contrasted the gas experience with that in electricity, noting that in the case of electricity the Board took an active role in evaluating PBR options and in working with stakeholders to arrive at a preferred PBR model. These parties observed that, in contrast, the natural gas PBR plans were based on company proposals, with subsequent input from intervenors, Board hearings and then the Board's ultimate decisions.

There was widespread agreement that the Board should develop guidelines to outline its ratemaking expectations of all parties, irrespective of the model it chooses. The rationale was that, due to the expected longer term of the new ratemaking regime, clear and consistent long-term policies are needed to reduce the regulatory risk and to ensure that productivity targets are understood and met.

### The Board's Conclusions

The Board believes that the level of scepticism is due in part to the different expectations held by utilities and customers, which in turn are due to the absence of a clearly articulated ratemaking framework. The Board will establish a firm framework to ensure that consistent expectations are held by both utilities and customers.

As a first step, the Board must take account of its legislated objectives, and in particular, the following:

- to protect the interests of consumers with respect to prices and the reliability and quality of gas service
- to facilitate rational expansion of transmission and distribution systems and rational development and safe operation of gas storage
- to facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas

To fulfil these statutory objectives, the Board must determine the most effective ratemaking framework. Accordingly, it has determined that the gas rate regulation framework must meet the following criteria:

- establish incentives for sustainable efficiency improvements that benefit both customers and shareholders
- ensure appropriate quality of service for customers
- create an environment that is conducive to investment, to the benefit of both customers and shareholders

The Board believes that a ratemaking framework that meets these criteria will ensure that the statutory objectives of consumer protection, infrastructure development and financial viability will be met, and that rates will be just and reasonable. Each of the above criteria is discussed further below.

**Sustainable efficiency improvements:** It is important that the rate regulation framework creates incentives for the implementation of sustainable efficiency improvements and that it is structured to ensure that ratepayers share the benefits of these efficiencies. Traditional COSR plans generally provide only limited incentives for efficiencies. A PBR framework, on the other hand, is generally recognized to provide efficiency incentives.

The challenge is to ensure that the efficiencies do not result just in short-term shareholder benefits, but rather sustainable improvements that benefit ratepayers through lower utility costs and lower rates. A properly designed ratemaking framework will provide incentives for utilities to find cost efficiencies, and thereby to increase their earnings over the course of the plan. A properly designed plan will also ensure that customers benefit from efficiency gains both during the plan's period, through an appropriate adjustment or earnings sharing mechanism, and upon rebasing for the next plan period. The Board recognizes the importance of ensuring that customers achieve benefits from the beginning of the plan's term.

**Appropriate quality of service:** Appropriate quality of service is at the core of consumer protection. It is generally believed that the gas utilities provide good customer service. There is a risk that the introduction of strong incentives to implement efficiencies could result in reduced quality of service. To meet its objective to protect consumer interests, the Board must address this issue. At the same time, the Board recognizes that some efficiencies may involve finding more effective ways to deal with customer issues. Further, the Board must be open to arguments that it may be reasonable to reduce some service levels if they are not cost effective to maintain.

**An environment conducive to investment**: The Board is committed to creating a predictable and stable regulatory environment that encourages continued investment in the sector. A strong, financially viable sector will help to sustain a robust gas market in Ontario, which will benefit consumers in terms of price and security of supply. In the Board's view, while Ontario's natural gas sector does not now suffer from an overall lack of investment, it is important to examine the incentives for investment to ensure they create a stable financial base for the utilities.

In particular, the Board is concerned about the infrastructure needs associated with the expected increase in gas-fired power generation, the changing flow patterns that may result with market developments (for example, if there were a liquefied natural gas terminal in eastern Canada) and the need to maintain Ontario as a location with a strategically important natural gas hub. Infrastructure is addressed in detail in the section of this report called "Storage and Transportation," but infrastructure needs are an underlying element that must also be considered in developing the overall rate regulation framework.

Given the criteria set out and explained above, a fundamental issue for the Board is whether COSR or some form of PBR should be implemented to regulate the rates of the gas utilities, or whether the Board should consider the range of options available on the continuum that runs between the COSR and PBR frameworks. COSR, as it has been applied in Ontario, presents fewer risks in some respects, but it also lacks strong incentives to increase operating efficiencies and to reduce costs. The regulatory burden of annual or bi-annual rate cases associated with COSR is also high. In contrast, PBR can be designed to create strong performance incentives and to reduce regulatory costs, by extending the term of the plan to three years or more. However, PBR involves issues related to the ongoing transparency of costs and the need to ensure that customers share the benefits of the efficiencies implemented. These issues, and the six factors (discussed earlier) that were identified as a result of the experience with the Union and Enbridge trial PBR plans, need to be addressed for PBR to be successful.

In North America, PBR plans have been encouraged and implemented in several jurisdictions, including Ontario. Outside North America, many regulators addressing market restructuring have chosen PBR instead of COSR, so that PBR is now a widely used form of energy utility regulation in the world. PBR is also employed in other regulated industries, most notably telecommunications.[5]

In the Board's view, it is the parameters of the framework that will determine whether the framework meets the criteria. For example, the COSR framework could be refined to

[5] Further information on the experience with PBR in other jurisdictions is available in the discussion paper "Rate Regulation in Ontario," prepared for the Natural Gas Forum and available on the OEB Web site under "Natural Gas Forum."

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.

***The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet its criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities – to the benefit of customers and shareholders. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario. The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan.***

A related matter is whether the IR framework should be comprehensive or targeted – in other words, whether the plan should apply to all costs or only some costs. The targeted approach was tried with the Enbridge plan. The comprehensive approach was used for Union and for Ontario's local electricity distribution companies, and it is the more common approach in other jurisdictions. The Board's view is that the targeted approach did not work effectively because it diluted and distorted the incentives, and that a comprehensive model is preferable. Although a comprehensive approach may involve greater regulatory costs to implement and may be considered by some to involve greater risks, it offers more balanced incentive properties and may be expected to reduce the overall regulatory burden.

Similarly, the Board concludes that the utilities should not alternate between a COSR and an IR framework. Switching between rate frameworks could make robust benefit sharing harder to achieve and introduce confusion and mistrust.

With respect to concerns that incentive regulation should not be used until a stable environment exists, we acknowledge that the industry continues to experience change, but we do not believe that this situation is inconsistent with an IR framework. Rather, the Board is of the view that a properly constructed IR framework should address expected changes and establish a balance of risks and rewards for the utilities.

A further related matter is the treatment of the utilities' role in and policies for conservation and demand management. It will be necessary to ensure that the rate regulation framework and the conservation and demand management policies are compatible. The Board expects that this issue can be addressed in the rate application process.

The following key parameters of the ratemaking framework are addressed below:

- annual adjustment mechanism
- rebasing
- earnings sharing mechanism
- the term of the plan
- off-ramps, z-factors and deferral or variance accounts
- service quality monitoring
- financial reporting
- filing guidelines
- the role of alternative dispute resolutions

## Annual Adjustment Mechanism

The annual adjustment mechanism is the means by which rates are changed each year within the term of the plan. In many respects, this feature is the most important one in the plan. The adjustment mechanism captures expected annual changes in costs (such as inflation) and the utility's productivity improvements. The choice of the productivity factor has been controversial in past rate cases, as discussed earlier, but it is one of the ways that the benefits of efficiency improvements can be shared with customers during the term of the plan. The issue is how rates should be adjusted within the term of an IR plan.

### Stakeholders' Views

Stakeholders offered a variety of views. Enbridge said that it would be appropriate to use the Ontario consumer price index (CPI) to adjust rates annually, along with a discount factor to reduce the forecast inflation number. This plan would have no separate productivity factor. Union said that setting an accurate productivity factor can be a controversial process, and suggested that adopting an earnings sharing mechanism with no deadband would act as a form of implicit productivity factor.

Other suggestions included a rate freeze in the second and third years of a three-year plan, which would eliminate the need for controversial issues such as inflation and productivity factors. Another suggestion was to use 50 per cent of the Ontario CPI in each year, with the remaining 50 per cent being deemed to cover all other adjustments, such as productivity, stretch factors and so on.

**The Board's Conclusions**

In a multi-year IR plan, the annual adjustment mechanism embodies the combined assessment of cost changes and productivity improvements. Various methods can be used to evaluate these trends (inflation factors, industry productivity factors, and so on), and the resulting adjustment mechanism could be a complex formula or it could be a single factor, taking the form of an increase, a decrease or a rate freeze. The Board understands that determining an appropriate productivity factor may be challenging. It concludes, however, 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. As stated above, the Board believes that ensuring that customers share in the benefits of efficiencies is a key criterion for an effective rate regulation framework.

Some stakeholders submitted that separate earnings sharing mechanisms could be used instead of specific productivity factors. The Board does not believe that using an earnings sharing mechanism is the appropriate approach. Its reasons are discussed in the section below on earnings sharing.

***The Board will hold a generic hearing to determine the appropriate basis for setting the annual adjustment mechanism. The Board expects that once the generic methodology is determined, its application to each utility may result in different specific adjustments.***

## Rebasing

Rebasing is the exercise that takes place at the expiry of an IR plan in preparation for setting rates for the subsequent period. Essentially, it is a review of the utility's financial position on both an historic and prospective basis, including an examination of the efficiency improvements realized under the IR plan. In a practical sense, rebasing reviews are very similar to traditional COSR reviews, except that they include a focus on the achievements reached in the IR plan. Rebasing also provides some assurance that there is an up-to-date and meaningful relationship between costs and rates. The issue addressed here is whether rebasing should occur.

### Stakeholders' Views

Most stakeholders, with the exception of Union and Enbridge, submitted the view that rebasing is an essential component of an incentive-based ratemaking framework. The Canadian Manufacturers & Exporters submission made the point that rebasing should take account of actual performance in the final year of the plan. Enbridge asserted that the development of the second-generation PBR plan should be negotiated with stakeholders without rebasing, and that utilities' periodic information filings should be adequate to satisfy the Board that the relationship between costs and rates is reasonable.

### The Board's Conclusions

***Each IR plan must begin with a robust set of cost-based rates, based on a thorough and transparent review. 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 their 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.***

As described above, the benefits of efficiencies can be shared with customers in two ways – during the term of the plan, through the adjustment mechanism, and in the base rates for the subsequent plan. With robust rebasing, all of the efficiency improvements achieved during the term of a plan would be built into the base rates for the subsequent plan. In this way, shareholders retain the benefits of any efficiency gains (that is, any achieved over and above the productivity factor) during the term of the initial plan, and all of the benefits flow to customers during the term of subsequent plans.

During rebasing, the Board will be particularly interested in determining whether the efficiency improvements achieved by the utility are temporary or sustainable, and it will expect to receive a thorough analysis of this issue. For example, the Board will be interested in the relationship between operation, maintenance and administration costs and capital expenditures, the timing of capital expenditures and the associated impacts on shareholders and customers. The Board will also expect to see, during the plan's term, measures that are designed to improve the utility's productivity on a sustained basis – not temporary, unsustainable budget cuts. The Board's determination of the new base rates and forward plan will reflect its assessment of all of these factors. The Board also cautions that it will take an unfavourable view of sudden and significant increases in costs at the time of rebasing, unless thoroughly justified.

## Earnings Sharing Mechanisms

Earnings sharing mechanisms (ESMs) are sometimes employed in incentive-based ratemaking schemes to provide for the sharing of earnings in excess of a pre-established level between the utility's shareholders and ratepayers, usually during the term of the plan. That is, ESMs are intended to return some of the productivity improvements to ratepayers during the term of the plan.[6] ESMs are generally tied to the utility's return on equity (ROE), although the specific features of the ESM may vary from plan to plan. The features include the level at which sharing takes place, the ratio of sharing between shareholders and ratepayers and whether the ESM is symmetrical (that is, whether it

[6] In this discussion, the Board is not referring to the earnings sharing associated with transactional services, storage and transportation services or demand-side management.

applies when earnings are both above and below the target ROE). The issues we address here are whether there should be an ESM in the IR plans and, if so, what form it should take.

**Stakeholders' Views**

Stakeholders were divided on this issue. A number of stakeholders, primarily customer groups, were of the view that an ESM assures customers that they will benefit from the productivity gains made by the utilities. For example, the Consumers Council of Canada and the Vulnerable Energy Consumers Coalition suggested that earnings sharing could be incorporated into a COSR framework over a multi-year period. London Property Management Association and Wholesale Gas Service Purchasers Group made the point that an asymmetrical ESM applicable only to earnings above the target ROE would provide utilities with a significant incentive to increase efficiencies.

Union and Enbridge took the view that a symmetrical ESM could be developed around a benchmark ROE.

Others took the view that an ESM should not be adopted, because it would reduce the efficiency incentives of a PBR plan.

**The Board's Conclusions**

Customers can benefit from productivity improvements during the term of an IR plan in two ways: through the productivity factor in the price adjustment mechanism and/or through an ESM. If the productivity factor is low, customers may be dissatisfied with the expected level of benefits, and may view earnings sharing as an appropriate means by which to realize benefits within the plan's term. Stakeholders may also rely on an ESM as a way to mitigate the effects of an incorrect or uncertain productivity factor (which may be the result of utilities and stakeholders not having the same information).

In addition to the benefits that would accrue during the plan's term, customers could also benefit from productivity improvements through robust rebasing at the beginning of the next plan, as has already been described.

The regulatory challenge is to provide strong incentives to promote efficiency, while at the same time achieving customers' acceptance of the IR plan by ensuring that the benefits of the efficiencies flow to them. In the Board's view, ESMs would reduce the utility's productivity incentives and introduce a potentially costly additional regulatory process – results that are not in accordance with the Board's criteria for the regulatory framework. The Board recognizes that, without an ESM, the determination of the adjustment factor will be particularly important to ensure that customers benefit from productivity gains during the plan's term. For this reason, as noted earlier in this report, the Board has concluded that a generic hearing should be held to determine the annual adjustment mechanism.

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 does not intend for earnings sharing mechanisms to form part of IR plans.***

## The Term of the Plan

### Stakeholders' Views

On the issue of the optimal term for the ratemaking plan, stakeholders were generally divided into two camps – customer groups generally favoured short terms of two to three years, while the utilities and the School Energy Coalition (SEC) favoured longer terms of five years or more.

Union submitted its view that the term of a plan should be long enough to provide the utility with incentives to pursue productivity improvements, and noted that the "payoff" for some productivity improvement measures may not be realized for some time. In recognition of these factors, the minimum term of plans approved in some jurisdictions is five years, with some terms as long as 10 years.

The Industrial Gas Users Association (IGUA) suggested that the term be one of the elements negotiated by the parties. IGUA indicated a preference for a shorter term, but said that a longer term may be acceptable if provision were made for an automatic review or reopening of the issue under defined circumstances. SEC proposed an initial five-year term, subject to a single off-ramp. SEC also proposed that, at the end of four years and before any rebasing application, the Board hold a hearing to determine whether it would be appropriate to extend the incentive plan for a further period of up to five years or to require a rebasing exercise.

**The Board's Conclusions**

The Board's view, shared by most stakeholders, is that the current system of annual rate cases is inefficient – it is costly and time consuming. The challenge for the Board is to implement a regulatory model that contains incentives for utilities to make productivity improvements and that reduces the annual regulatory burden, while ensuring both that customers benefit from productivity improvements and that an appropriate level of transparency is maintained. The Board believes that IR plans must contain longer rate-approval periods to ensure an incentive for utility shareholders to make productivity improvements and to benefit from them.

***The Board expects that the term of IR plans will be between three and five years. The Board's view is that three years represents the minimum term that may be expected to give rise to productivity incentives, and its preference is for a plan of five years. The Board is reluctant to approve a term greater than five years at this time, given the importance of ensuring that productivity gains are passed on to customers in subsequent periods. The term of the plan will be determined in the generic hearing on the annual adjustment mechanism.***

The Board is of the view that a plan should not be reopened during its term except for the most compelling reasons. Off-ramps are addressed below.

## Off-Ramps, Z-Factors and Deferral or Variance Accounts

Various mechanisms can be established as part of the overall ratemaking framework, but designed to operate outside the plan itself. An *off-ramp* is a pre-defined set of conditions under which the plan would be terminated before its end date, usually because of some unforeseen event. A *z-factor* provides for a non-routine rate adjustment intended to safeguard customers and the utility against unexpected events outside of management control. *Deferral accounts* are formalized accounts that track an amount that cannot be forecast. *Variance accounts* are formalized accounts that track a variance around a forecast. These mechanisms are often called risk-mitigation tools, as they create a regulatory "buffer" against unforeseen circumstances.

**Stakeholders' Views**

Most stakeholders advocated limits on the use of off-ramps, z-factors and deferral or variance accounts. In their view, these mechanisms inappropriately mitigate the utility's risk in an incentive-based system. In general, customer groups would like to see utilities assume more risk by consenting to PBR agreements that eliminate deferral or variance accounts, as well as any side agreements that shelter the utility from unforeseen events. It is recognized that a balance exists between eliminating these mechanisms and allowing shareholders to reap the benefits of good performance. Striking this balance was viewed as more in keeping with the objectives of incentive-based ratemaking.

Union, on the other hand, argued that off-ramps are designed to protect both customers and the utility, and that customers benefit from being served by a financially viable utility. In Union's trial PBR, off-ramps were restricted to a serious decline or significant improvement in Union's financial position. Enbridge's view was that deferral or variance accounts and z-factors provide justifiable regulatory relief from cost elements beyond the control of management.

**The Board's Conclusions**

The Board's view of off-ramps, z-factors and deferral or variable accounts is guided by the need for an appropriate balance of risks and rewards in the incentive regulation model. As stated earlier, the Board believes that it is appropriate for the utility's shareholders to retain all earnings during the plan's period. The Board believes that this is a very strong incentive. The Board also believes that, as a balancing factor, the utility should assume an appropriate level of business and financial risk.

***In the Board's view, an appropriate balance of risk and reward in an IR framework will result in reduced reliance on deferral or variance accounts, and reliance on off-ramps or z-factors in limited, well-defined and well-justified cases only.***

## Service Quality Monitoring

When a regulated utility seeks cost-saving (efficiency) initiatives under an incentive plan, there is a danger that the quality of service experienced by its customers will suffer. The Board has identified appropriate quality of service as one of its criteria for the ratemaking framework. Service quality indicators (SQIs) have been used in Ontario, but they have been limited to measures such as telephone response time, emergency response and pipeline corrosion surveys. The issue before the Board is how a service quality framework should be developed and regulated.

**Stakeholders' Views**

Stakeholders generally agreed that quality of service is an important matter. Union suggested that SQIs should relate to those aspects of the utility's service that are important to customers, and that SQI targets should be derived from the historical performance levels of the utility. Enbridge also generally supported SQIs, noting that they provide assurance that operating efficiencies are not achieved at the expense of either customer service or the safe operation of the distribution system.

Union maintained that performance rewards and penalties would be inappropriate. In its view, SQIs are intended to ensure that minimum standards are maintained in an environment where the utility has incentives to improve productivity, not to give the utility an incentive to offer higher service standards than customers may need or want. Enbridge, on the other hand, indicated that it was open to considering service incentives with SQIs.

### The Board's Conclusions

In keeping with the Board's consumer protection goal for the rate regulation framework, it considers quality of service of great importance. While service quality measures and standards could be developed as part of the IR plans, the Board believes that there is merit in setting the service quality measures and standards first. Then the IR plans can be developed with the knowledge that the service quality aspect is fixed.

***The Board will develop the service quality framework, and will undertake a consultation to finalize the measures, standards and reporting mechanism. The Board expects to use its rule making tools to implement this framework.***

At this point, the Board does not foresee incorporating direct financial incentives into the service quality framework. However, the Board will monitor performance, and the utilities will be subject to the Board's compliance process. In the event of substandard performance, the compliance process may involve negotiated solutions or, potentially, enforcement action, either of which could include penalties.

## Financial Reporting

Financial reporting refers to the flow of information from the utility to the Board (and, potentially, stakeholders) during the term of an IR plan. The Board needs to consider issues related to financial reporting in its development of the regulatory framework, keeping in mind the appropriate level of transparency and the current rules for financial reporting and record keeping.

**Stakeholders' Views**

Union and Enbridge expressed dissatisfaction with the high level of financial monitoring and the associated costs. Customer groups maintained, however, that increased financial scrutiny is needed, especially for an incentive-based plan, arguing that incentive-based regulation would presumably involve a more light-handed approach to regulation, and, hence, there was a risk of a reduced emphasis on financial monitoring.

Customer groups stated that the utilities need to provide financial information as a matter of course. Some suggested that cost and revenue data should be filed on a quarterly basis.

**The Board's Conclusions**

The Board has concluded that regular financial reporting by the utilities is necessary, and must be made available to stakeholders. The purpose of this reporting and the associated analysis is to allow the Board to discharge its responsibilities respecting the financial viability of the utilities and the transparency and the ongoing information about costs that are required by the IR framework. Rather than establishing a separate financial reporting system, the Board will use the Gas Reporting and Record Keeping Requirements (RRRs) to ensure that the objectives of transparency and financial viability are met.

***The Board will consult with stakeholders and modify the Gas Reporting and Record Keeping Requirements (RRRs) as necessary to meet the requirements for financial reporting in the new ratemaking framework. While the Board intends to conduct this consultation and modify the RRRs before the development of the first IR plan, it expects that the RRRs may be further refined in the context of specific IR plan development.***

The Board will ensure that appropriate financial information is accessible to stakeholders, but it does not intend to institute a formal process for reviewing this information within the term of the IR plans. The Board may consider whether to use informal stakeholder conferences.

## Data Filing Guidelines

It has been 15 years since the Board has undertaken a review of rate application filing requirements. Over the years, due to changing circumstances, the utilities have departed from the guidelines, a situation that has led to some confusion and difficulty in understanding the rate filings, particularly among intervenor stakeholders.

### Stakeholders' Views

Virtually all of the stakeholders indicated that the Board needs to standardize the filing requirements to ensure that the appropriate data are available to all parties early in the rate setting process. Union and Enbridge supported the concept of developing filing guidelines. In addition, it was noted that the rate hearing process would be less burdensome on all parties, less costly and less adversarial if Enbridge's and Union's filings were identical to the extent possible.

### The Board's Conclusions

The Board concludes that standardizing the data filing requirements will assist in streamlining the regulatory process and in ensuring the appropriate level of transparency with respect to costs and utility operations.

***The Board will undertake a review of the gas utility data filing guidelines for rate hearing processes, and then develop a set of draft filing guidelines, which it will distribute for consultation. Wherever possible, the Board will seek to develop consistent guidelines for Union and Enbridge, and will consider issues such as electronic filings.***

## The Role of Alternative Dispute Resolutions

Alternative dispute resolution (ADR) is a key feature of the Board's current natural gas rate hearing process. In an ADR, stakeholders attempt to resolve as many issues as possible through negotiation, although the Board must approve the ADR settlement for it to take effect. The ADR process aims to reduce the number and complexity of issues that the Board must determine at a hearing. Although the Board did not specifically request stakeholder comments on the ADR process, it did ask for general comments about the ratemaking process, and a number of stakeholders addressed ADR. The Board must determine the role of ADR in an IR framework and whether changes should be implemented in the interim, while a COS framework is in place.

**Stakeholders' Views**

The great majority of stakeholders felt that some form of ADR would be a useful part of the process. However, stakeholders disagreed about exactly what form the ADR should take. Some parties advocated minor changes to the current process, while others favoured substantial changes. The suggestions included the following:

- Fewer parties should participate in ADR. Nominating only one party to represent each interest would avoid duplication.
- The ADR should occur at the beginning of the process, before the formal discovery process.
- A technical conference should precede the ADR, to clarify the evidence and issues following the receipt of interrogatory responses.
- Intervenor funding should create incentives for intervenors to settle issues.
- The mediator should have in-depth knowledge of the subject matter and the authority and skills to use whatever methods are deemed most appropriate to reach a negotiated settlement.
- The Board should accept comprehensive settlements without requiring further evidentiary support where parties representing a broad range of interests reach an agreement.
- An effective monitoring and evaluation system would ensure the ongoing success of the program.

**The Board's Conclusions**

***The Board is mindful of the concerns stakeholders have expressed and the efforts they have made to propose improvements to the ADR process. The Board will not decide at this time the precise structure of the ADR process for the utility-specific IR plans. The***

***Board has already undertaken a review of the ADR process, and it will consider the submissions made through the Natural Gas Forum before releasing its conclusions in the ADR review. The Board expects that the ADR process will evolve further in the process leading to the first IR applications.***

## Conclusions on Rate Regulation

The Board has set out its expectations for an IR framework. A number of issues must be addressed before this framework can be implemented and plans approved:

- service quality framework
- financial reporting framework
- data filing guidelines
- base rates for each utility
- the annual adjustment mechanism and the term of the plan

The Board's implementation plan for the IR framework, and the specific steps involved, are set out in the "Implementation" section of this report.

# TAB 5

# IMPLEMENTATION

This section begins with a description of the Board's key processes and then presents the Board's plan to implement the conclusions of this report.

## The Board's Processes

The Board's implementation plan will rely on orders, rules and guidelines. These regulatory instruments, the processes by which they are implemented and the ways in which they will be used to implement the conclusions of this report are discussed briefly below.

### Orders

The conventional way in which the Board has decided issues in the natural gas sector has been through formal orders. Subsection 19(2) of the *Ontario Energy Board Act, 1998* (the Act), provides that the Board "shall make any determination in a proceeding by order." As a result, orders result from proceedings, which are adjudicative and largely subject to court-like procedural requirements set out in the Act and in the *Statutory Powers Procedure Act.* Proceedings are used to, among other things, fix rates for gas distribution, storage and transportation (section 36 of the Act), consider the designation of storage areas (sections 37–40 of the Act) and determine whether the Board should refrain from regulation (section 29 of the Act).

### Rules and Guidelines

Rules and guidelines are established by the full Board, not by a panel in a hearing. Rules may be issued under section 44 of the Act in relation to a very broad range of issues. The Board has passed several rules in the gas sector, including rules governing the conduct of gas marketers (the Gas Marketers Code of Conduct) and gas distributors in relation to affiliates (the Affiliate Relationships Code) and gas vendors (the Gas Distribution Access Rule or GDAR). The Board's rules in the gas sector are similar to the codes issued by the Board in the electricity sector, where the practice has been more extensive.

Rules are fundamentally different from orders; as Evans, Janisch, Mullan and Risk state in *Administrative Law: Cases, Text and Materials*, "The essence of a rule, as opposed to an adjudication, is that the former lays down a norm of conduct of general application while the latter deals only with the immediate parties to a particular dispute."[21] As a result, rules are useful tools for implementing policy.

Rules are developed by the Board under section 45 of the Act through a notice-and-comment process. Because the Board initiates the rule making process, it is necessarily more proactive in developing the substance of a rule than it is in proceedings where a party commences an application. In the rule making process, the Board drafts a rule and circulates it, often with a discussion paper, for comment by interested parties.

Guidelines do not necessarily have a statutory basis, nor are they established through a statutory process. Like rules, guidelines are also concerned with conduct. However, unlike rules, guidelines are not binding. As Professor Hudson Janisch states in the work cited above:

> Terminology here is very fluid as "policy" may include "manuals," "guidelines," "standards" and the like. Nothing turns on the precise term employed. The important thing is that unless an agency is given legislative authority to make binding rules, it must always consider exceptions to its general approach.[22]

The courts have encouraged agencies to adopt policy guidelines in the absence of express statutory authority to bring about greater predictability in decision making. The Supreme Court of Canada upheld the authority of the Canadian Radio-television and Telecommunications Commission to issue policy guidelines, despite the lack of specific statutory authority, as part of its role in implementing the Government of Canada's broadcasting policy. According to Chief Justice Laskin: "An overall policy is demanded

[21] J.M. Evans, H.N. Janisch, David J. Mullan and R.C.B. Risk, *Administrative Law: Cases, Text and Materials* (Toronto: Emond Montgomery, 2003), at 675. See Chapter 8 for a discussion of rule making.
[22] Ibid., at 266.

in the interests of prospective licensees and of the public under such a public regulatory regime as is set up by the *Broadcasting Act.* Although one could mature as a result of a succession of applications, there is merit in having it known in advance."[23]

Other agencies have also adopted policy guidelines without specific statutory authority, the most well-known of which are the guidelines issued under the *Competition Act (Canada)* respecting matters such as mergers, predatory pricing and price discrimination. Again, these guidelines are not legally binding, but a regulatory innovation that serves the goals of clarity and predictability. As the Federal Court of Appeal put it in reviewing these guidelines:

> In addition, the possibility that a reviewing court may not agree with an agency's view of the law is an inevitable risk associated with the administrative practice of issuing non-binding guidelines and other policy documents to shed light on agency thinking and to assist those subject to the regulatory regime it administers. The risk should deter neither the courts from deciding what the law is, nor the agencies from engaging in the often useful exercise of administrative rule making.[24]

As the above comments indicate, there are no statutory procedural requirements for the establishment of guidelines, while the Board can satisfy the statutory requirements for establishing rules by inviting written comments. However, the Board's practice with respect to establishing rules has been to encourage a level of stakeholder participation well beyond statutory requirements. For example, on occasion (for example, in developing the GDAR) the Board has asked parties to appear before it and to make oral submissions on particular issues, and has considered the records of those proceedings as part of its deliberations. However, hearings are not considered to be the only, or even the primary, way of obtaining stakeholder input.

[23] *Capital Cities Communications Inc.* v. *Canadian Radio-television and Telecommunications Commission*, [1978] 2 S.C.R. 141 at 171.
[24] *Canada (Commissioner of Competition)* v. *Superior Propane Inc.*, [2001] 3 F.C. 185, para. 146.

The use of non-hearing processes for rule making has been commented on by a number of observers. For example, the *Final Report of the Ontario Task Force on Securities Regulation,* which made recommendations about the role of rule making in the context of securities regulation, specifically did not advocate that a hearing be a mandatory component of the notice-and-comment procedure. Professor Ron Daniels, who authored the report, would only go so far as to endorse "the use of public hearings to the extent they may enhance the development of certain policy instruments in appropriate circumstances."[25]

Others have been more critical of the use of public hearings in rule making. Professor David Mullan, commenting on the history in the United States, where rule making is used much more extensively than in Canada,[26] stated:

> The anxious experimentation with more detailed procedures by Congress and the agencies themselves has demonstrated that the rule-making process should seldom, if ever, be surrounded by all the procedural requirements which attend a court-like adjudication.[27]

Similarly, Professor Hudson Janisch has identified and analyzed the following reasons why rule making (whether through a binding process or through non-binding guidelines) is preferable to an "*ad hoc* order":[28]

- public participation
- legitimacy
- visibility
- comprehensibility

[25] Ontario Task Force on Securities Regulation, *Responsibility and Responsiveness: Final Report of the Ontario Task Force on Securities Regulation* (Toronto: Queen's Printer for Ontario, 1994), at 36.
[26] For a discussion of the American experience, see K.C. Davis, *Administrative Law of the Seventies* (Rochester and San Francisco: LCP BW Publishing, 1976).
[27] D.M. Mullan, "Rule-Making Hearings: A General Statute for Ontario?" prepared for the Commission of Freedom of Information and Individual Privacy, 1979, at 11. See also the discussion at 156–157, where Professor Mullan quotes from the Administrative Conference's recommendation that it "emphatically believes that trial-type procedures should never be required for rule-making except to resolve issues of specific fact."
[28] H. Janisch, "The Choice of Decision-Making Method: Adjudication, Policies and Rule Making" (1992), *Law Society of Upper Canada Lectures* 259 at 266. Professor Janisch is referencing A.E. Bonfield, "State Administrative Policy Formulation and the Choice of Law Making Methodology" (1990), 42 Admin L.R. 121 at 122–131.

- efficiency
- abstraction
- appropriate factual basis
- initiative
- easier participation
- prospective application
- consistency

As a result, the Board, like many tribunals, faces a number of challenges and opportunities in developing new types of policy instruments. The Board firmly believes that stakeholder consultation is important, and it will continue to pursue innovative ways to facilitate it. The implementation of this report will involve a variety of procedures, as set out in the implementation plan described below.

## Implementation Plan

The conclusions in this report will require implementation in an orderly manner over the next few years. This implementation plan groups the processes required to implement these changes into four categories of issues: (1) infrastructure; (2) rate setting; (3) gas supply and transportation; and (4) miscellaneous. The following describes the processes involved in each of these categories of issues.

### 1. Infrastructure Issues

There are two main processes that will involve a review of infrastructure issues: The Gas-Electricity Interface Review and the Storage Proceeding. These two are related because the result of the review of the requirements for gas-fired power generation could have a significant impact on the issues that have to be addressed in determining the best way to regulate gas storage. The process contemplated for each is set out below.

#### (i) Gas-Electricity Interface Review

The Board will hold a review to determine the impact of increased gas-fired power generation on storage and transportation infrastructure and services in order to ensure a reliable supply of electricity and gas. This review may lead to a formal proceeding resulting in orders setting rates, granting leave to construct or other remedies. The details and timing of this review will be provided shortly so that the review may commence as soon as possible.

### (ii) Storage Regulation

The Board will hold a proceeding to determine whether, or to what extent, it should refrain from regulating the rates for gas storage services. This determination will take into account traditional concerns respecting allocation of cost of service storage and whether market rates are appropriate from the perspective of ratepayers and utilities. In addition to this, the Board's storage proceeding will also be informed by the review of gas infrastructure in the context of the gas-electricity interface review. As a result, the storage proceeding will commence after the implications from the gas-electricity interface review become clearer.

## 2. Rate Setting Issues

There are several interconnected processes that will combine to permit the implementation of the incentive regulation plan. To make this incentive regulation plan enduring, there are a number of prior decisions that must be determined. These decisions involve determining the allocation of costs between distribution and supply; setting a cost of service base for regulated delivery activities; setting the service levels; determining the financial reporting requirements that must be met during the term of the IR plan; and determining the appropriate annual adjustment mechanism and the term of the IR plan. The process for each of these is discussed below.

### (i) Generic Proceeding on Cost Allocation of Regulated Gas Supply

The Board will hold a generic cost allocation proceeding to ensure proper costing of regulated gas supply. As part of this hearing, the Board will also assess whether further unbundling is required and how any further unbundling will be implemented. This will determine the base regulated delivery activity for the term of the IR Plan. This determination will be made by mid-2006.

### (iii) Develop Filing Guidelines for Rate Applications and Setting Base Rates

The cost of the base regulated delivery activity must be established. This requires both clear direction on the information that should be filed to provide an evidentiary basis to set the cost of service base and a hearing to determine the appropriate base. Generic filing requirements will be established using a consultation process and completed by the end of 2006. Decisions on the appropriate base for each of the utilities will be made in separate proceedings and be provided by the end of 2007.

### (iii) Service Quality Monitoring and Financial Reporting

All parties must have a clear understanding of both the service levels and the financial reporting requirements that must be met during the term of the IR plan. The Board will develop the service quality and financial reporting frameworks through consultative processes. The Board expects to use its rule making authority to implement these frameworks. This will be completed by the end of 2006.

### (iv) Generic Proceeding on the Annual Adjustment Mechanism

The final terms of the IR plan will be set after the processes outlined above are completed. The Board will determine the appropriate annual adjustment mechanism and the term of the IR plan following a hearing. This will be completed by the end of 2008.

## 3. Gas Supply and Transportation

The two interconnected issues in this area are the review of the quarterly rate adjustment mechanism (QRAM) methodology and the treatment of utility long-term gas supply and transportation contracts.

### (i) Standardize Quarterly Rate Adjustment Mechanism Methodology

The Board will develop guidelines that will ensure a consistent and formulaic approach across utilities in calculating the Reference Prices and the purchased gas variance account (PGVA), and for disposing of the PGVA balances. The consultation process on these guidelines will also consider the underlying price. This process, as well as the related process for long-term contracting is expected to be completed in 2006.

### (ii) Develop Prior Review Process for Long-Term Contracts

The Board will develop guidelines to consider applications for prior approval of long-term supply and/or transportation contracts. This process, as well as the related process for QRAM pricing is expected to be completed in 2006.

## 4. Miscellaneous

### (i) Practice Direction on Alternative Dispute Resolution (ADR)

The Board has already undertaken a review of the ADR process. However, it will consider the submissions made through the NGF before releasing its conclusions of that review. The Board expects to publish any changes to the ADR process in 2005.

### (ii) Develop New Independent Gas Storage Filing Guidelines

The Board will develop guidelines on new independent gas storage (i.e., those storage operators that have no affiliation with gas distributors or transmitters). These guidelines will be distributed for stakeholder comment. The development of these guidelines is expected to take place in 2005.

# TAB 6

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

*Reference: Ex.B, Tab 1, page 8, Table 1*

*Issue 1.2 - What is the method for incentive regulation that the Board should approve for each utility?*

***Question:***

*IGUA wishes to understand the differences between the IR regime being proposed by Union and the recommendations of Pacific Economics Group ("PEG") for Union. In this context, please provide responses to the following questions:*

*(a) Please revise Table 1 to show how Union's summary would differ if the Board accepted PEG's recommendations for Union.*

---

**Response:**

a) Please see Attachment.

**Table 1 – Revised per Exhibit C13.1**
**Union Price Cap Plan Proposal Summary**

<table>
<tr><th>Parameter</th><th>Evidence Section</th><th>Proposal</th></tr>
<tr><td>Summary PCI</td><td>5.7</td><td><table>
<tr><td></td><td>Union</td><td>PEG</td></tr>
<tr><td>Productivity Differential</td><td>0.52</td><td>0.52</td></tr>
<tr><td>Input Price Differential</td><td>0.22</td><td>0.22</td></tr>
<tr><td>Average Use Factor</td><td>-0.72</td><td>-0.72</td></tr>
<tr><td>Stretch Factor</td><td>0.00</td><td>0.50</td></tr>
<tr><td>X Factor [A = sum of above]</td><td>0.02</td><td>0.52</td></tr>
<tr><td>Recent GDP IPI FDD Trend [B]</td><td>1.86</td><td>1.86</td></tr>
<tr><td>PCI [B-A]</td><td>1.84</td><td>1.34</td></tr>
</table></td></tr>
<tr><td>Base Rate Adjustments</td><td>5.1</td><td>Adjust the 2007 Board approved rates for:<br>▪ items from previous Board Decisions, and<br>▪ a one-time adjustment to reflect the 20-year trend weather normalization method</td></tr>
<tr><td>Plan Term</td><td>5.2</td><td>5 year term beginning January 1, 2008</td></tr>
<tr><td>Marketing Flexibility</td><td>5.3</td><td>Continue to have the flexibility to:<br>▪ Adjust fixed/variable rates on a revenue neutral basis<br>▪ Develop, on a timely basis, new services and change existing services when required</td></tr>
<tr><td>Price Cap vs. Revenue Cap</td><td>5.4</td><td>Price Cap</td></tr>
<tr><td>Inflation Factor</td><td>5.6</td><td>▪ GDP-IPI FDD Canada index (average of annualized quarterly changes of the last four quarters).<br>▪ Adjusted annually.</td></tr>
<tr><td>Service Group PCIs</td><td>5.7.5</td><td><table>
<tr><th>Union</th><th>Recent GDP IPI FDD Trend</th><th>X Factor Excluding Stretch and AU</th><th>Adjusted AU Factor</th><th>Net X Factor</th><th>PCI</th></tr>
<tr><td>General Service</td><td>1.86</td><td>0.74</td><td>-1.12</td><td>-0.38</td><td>2.24</td></tr>
<tr><td>All other</td><td>1.86</td><td>0.74</td><td>0.00</td><td>0.74</td><td>1.12</td></tr>
<tr><td>PEG</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Rate M2</td><td>1.86</td><td>1.24</td><td>-1.37</td><td>-0.13</td><td>1.99</td></tr>
<tr><td>Rate 01</td><td>1.86</td><td>1.24</td><td>-1.37</td><td>-0.13</td><td>1.99</td></tr>
<tr><td>Nonresidential</td><td>1.86</td><td>1.24</td><td>0.54</td><td>1.78</td><td>0.08</td></tr>
</table></td></tr>
<tr><td>Y Factors</td><td>5.8</td><td>▪ Cost of gas and upstream transportation costs<br>▪ DSM cost increases and other affects<br>▪ Elimination of long-term storage deferral account<br>▪ Other deferral accounts</td></tr>
<tr><td>Z Factors</td><td>5.9</td><td>▪ Criteria as listed in Table 4 including a threshold of $1.5M<br>▪ Specific examples include: return on equity formula; late payment penalty litigation and damages; and permit fees</td></tr>
<tr><td>Non-Energy Services</td><td>5.10</td><td>▪ Outside of price cap</td></tr>
<tr><td>Off Ramps</td><td>5.11</td><td>▪ No off ramps required</td></tr>
<tr><td>Reporting</td><td>6.0</td><td>▪ Data filing guidelines<br>▪ Service quality requirements<br>▪ Rate setting filings<br>▪ Reporting at rebasing</td></tr>
</table>

# TAB 7

## IGUA INTERROGATORY #1

### INTERROGATORY

Reference: EGD Evidence, Ex.B, Tab 1, Schedule 1, pp. 1 to 3

Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

EGD's evidence summarizes its Incentive Regulation ("IR") plan proposal. IGUA wishes to understand the differences between the IR regimes being proposed by Union Gas Limited ("Union") and EGD, and the recommendations of the Pacific Economics Group ("PEG") for each utility. In this context, please provide responses to the following questions

(a) Please prepare a Table comparable to Table 1 in Union's evidence at Ex. B, Tab 1, page 8, summarizing EGD's revenue cap IR proposal.

(b) Please revise the Table to be provided in response to question (a) to show the different results that would ensue if PEG's recommendations relevant to a revenue cap IR plan are adopted.

(c) Please revise the Table to be provided in response to question (a) to show the results that would ensue if PEG's price cap recommendations for EGD were to be approved by the Board.

(d) A few years ago, EGD was attempting to persuade stakeholders to subscribe to a multi-year IR plan. Please provide a summary description of the comprehensive IR plan EGD was then asking stakeholders to endorse and indicate whether it was a revenue cap or price cap plan.

### RESPONSE

a) The table follows on the next page.
b) This request should be directed to Board Staff.
c) This request should be directed to Board Staff.
d) The plan that was presented to (and not supported by) stakeholders, was a price cap. A summary is attached.

Witnesses: R. Campbell
P. Hoey

**Enbridge Gas Distribution**
**Revenue per Customer Cap Proposal**

| **Parameter** | **Ref** | **Proposal** |
|---|---|---|
| **Plan Type** | B-1-1 | Revenue per Customer Cap |
| **Summary: Revenue per Customer Cap Adjustment** | B-3-1 | Productivity Differential -1.43 %<br>Input Price Differential 0.22<br>Average Use Factor 0.00<br>Stretch Factor 0.00<br>**X Factor** [A=sum of above] **- 0.77 %**<br>Recent GDP IPI FDD [B] 2.04 %<br>**Revenue Cap Adjustment** [B-A] **2.81 %** |
| **Plan Term** | B-1-1 | • 5 Years beginning January 1, 2008 |
| **Renewal or Extension** | B-1-1 | • if the subject of an Agreement of Stakeholders and approved by the Board |
| **Inflation Factor** | B-2-1 | • GDP-IPI Final Domestic Demand Canada<br>• average of the annualized quarterly changes of the last four quarters<br>• adjusted annually |
| **Y Factors** | B-4-1<br>B-4-2<br>B-5-1 | • capital expenditure costs related to system safety and integrity and applications for leave to construct<br>• DSM program costs<br>• CIS/customer care costs<br>• incremental gas costs associated with upstream transportation, storage and supply mix costs and an adjustment related to the embedded carrying cost of gas in storage and working cash related to gas costs<br>• certain deferral and variance accounts |
| **Z factors** | B-1-1 | • on application by the Company; costs beyond management control, of at least $1.5 million, related to statutory and regulatory changes, changes in accounting reporting requirements and costs related to litigation and uninsured losses.<br>• an adjustment to the embedded ROE if there is a change in the Board "Guidelines". |
| **Non-Energy Services** | B-6-1 | • outside of the revenue cap |

Witnesses: R. Campbell
P. Hoey

| Parameter | Ref | Proposal |
|---|---|---|
| **Marketing Flexibility** | B-6-1 | • develop new services and change existing services by application to the Board |
| **Off Ramps** | B-1-1 | • on application by the Company if significant and unexpected developments threaten the sustainability of the plan |
| **Reporting** | B-6-1<br>B-7-1 | • Regulatory Reporting Requirements<br>• Service Quality Indicator Reports<br>• Annual Rate Filings<br>• Rebasing Filing Requirements |

Witnesses: R. Campbell
P. Hoey

**Key Elements of a Proposed CPBR Plan**
**Enbridge Consumers Gas** **Nov 2001**

| | |
|---|---|
| **CPBR Mechanism**: | Price Cap |
| **Base**: | 2003 Board Approved Rates |
| **Term of Plan**: | 5 years, 2004 to 2008 |
| **Price Cap Escalator**: | Ontario CPI; no input price differential |
| **Growth Factor**: | None |
| **Earnings Sharing**: | Symmetrical, 50/50 around benchmark ROE |
| **Dead Band**: | None: Immediate Sharing |
| **Productivity Offset**: | None |
| **Rebasing**: | None |
| **SQIs**: | Similar to TPBR SQIs plus an indicator of customer mobility (to be developed post OEB GDAR decision). |
| **Pricing Flexibility**: | As required to meet market needs and to adjust rates to desired revenue-cost ratios |
| **Pass-Throughs**: | System integrity costs (capital)<br>Commodity costs, through QRAM |
| **Z Factors**: | Changes in legislative, regulatory requirements and to generally accepted accounting principles that have cost impact greater than $2 million. |
| **Off Ramp**: | Serious financial difficulty due to a significant and unanticipated event |
| **DSM**: | Incentive mechanism outside of price cap to be negotiated in 2002/03 rates case process:<br>• LRAM: potential enhancements in calculation methodologies to be determined<br>• SSM: utility share to be determined for the term of the plan |
| **System Expansion**: | Continue within EBO188 Guidelines |

# 2008 REVENUE PER CUSTOMER CAP DETERMINATION

Enbridge's proposed revenue per customer cap calculation for 2008, as shown at page 6 of this exhibit, determines a 2008 total revenue requirement to be collected through rates through the completion of the following process. (Formula amounts and %'s being referred to below are all found in column 1 of p. 5)

## Process

1. Row 1, $3119.8 million, the starting point of the calculation, is the 2007 Total Board Approved revenue requirement as per the EB-2006-0034 Draft Rate Order. (App. A, Schedule 5, Column 1, Line 22 or revenue at existing rates plus deficiency at Lines 28 + 29)

2. Row 2, eliminates the gas cost of $2,174.6 million embedded within that total approved revenue requirement to arrive at Row 3, the 2007 Board Approved distribution revenue requirement ("DRR") of $945.2 million. Removal of this gas cost is necessary as it was based on a July 1, 2006 gas cost reference price of $381.692 /$10^3m^3$ and was relative to 2007 approved volumes[1]. The elimination is required in order to establish a base DRR upon which the incentive escalation formula can be applied exclusive of gas costs. A 2008 forecast gas cost, outside of the incentive escalation formula, is included into the 2008 total revenue requirement and at row 24, and is explained later in this evidence.

3. Row 3, shows the 2007 Board Approved DRR of $945.2 million to which the following further adjustments are required in order to calculate a DRR upon which the incentive escalation formula can be applied within the context of Enbridge Gas Distribution's proposed revenue per customer cap model.

4. Row 4, shows a further elimination of $59.5 million which is the embedded carrying cost on gas in storage and working cash related to gas costs in the 2007 Board Decision which are eliminated and explained at row 2 above. Similar to row 2, this elimination is required in order to remove the carrying cost on gas in storage and gas cost working cash embedded in the 2007 Board Approved DRR which was based on 2007 approved volumes and a July 1, 2006 gas cost reference price of $381.692 /$10^3m^3$. The elimination is necessary in order to establish a base DRR upon which the incentive escalation formula can be applied exclusive of carrying

[1] That reference price has been replaced within rates throughout each quarter in 2007 through the QRAM process. The latest requested reference price at Oct. 1, 2007 is $323.347/$10^3m^3$.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

costs on 2007 gas in storage and gas cost working cash amounts related to 2007 approved volumes and gas cost prices. A carrying cost on gas in storage and gas cost working cash for 2008, outside of the incentive escalation formula, is included into the 2008 total revenue requirement and explained at row 16 later in this process. (Ref. Exhibit C-4-1, Appendix A, pg.1)

5. Row 5, removes the 2007 Board Approved DSM operating costs of $22.0 million as established within the EB-2006-0021 Decision. This adjustment is necessary as the 2008 DSM operating cost budget has already been approved in the above mentioned proceeding, therefore the base DRR upon which the incentive escalation formula can be applied needs to exclude the 2007 approved amounts. The 2008 Board Approved DSM operating costs, outside of the incentive escalation formula, are included into the 2008 total revenue requirement at row 17.

6. Row 6, removes the 2007 Board Approved CIS/Customer Care cost of $90.8 million (exclusive of bad debt). Again, this adjustment is necessary as the 2008 CIS/Customer Care cost will be determined by the associated true-up mechanism and CIS/Customer Care revenue requirement template as established in the EB-2006-0034 proceeding. Therefore the base DRR upon which the incentive escalation formula is to be applied should exclude CIS/Customer Care costs. The 2008 allowable CIS/Customer Care costs are included into the 2008 total revenue requirement and explained at row 18.

7. Row 7, as a result of all of the above noted adjustments, now contains the base DRR of $772.9 million, upon which the Company's incentive escalation formula can be applied.

8. Row 8, provides the 2007 Board Approved average number of customers of 1,823,258 (from EB-2006-0034, Ex.C3, Tab 2, Schedule 1, Item 5) which is used in the next step of this process to calculate the base DRR dollar/customer before Y and Z factors.

9. Row 9, which is a 2007 base of $423.91 DRR per customer, is derived by dividing the row 7 base DRR of $772.9 million by the 2007 approved average customers of 1,823,258.

10. Row 10, 2.04%, is the GDP IPI inflation factor component of the proposed incentive escalation formula as explained in evidence at Exhibits B-2-1.

11. Row 11, (0.77%), is the X-factor productivity challenge component of the proposed incentive escalation formula as explained in evidence at Exhibit B-3-1.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

12. Row 12, 102.81% (or a multiplier of 1.0281) is a base of 100% plus the adjustment factor of 2.81% which is required in the next step to arrive at an escalated average DRR dollar per customer amount. The 2.81% is calculated as the GDP IPI inflation factor of 2.04% minus the X-factor or productivity factor of (0.77%).

13. Row 13, $435.82, is the 2008 DRR per customer which is calculated by multiplying the 2007 base DRR at row 9 of $423.91 by 102.81% or a multiplier of 1.0281.

14. Row 14, provides the 2008 forecast average number of customers of 1,864,047 which is found in evidence at Exhibit C-2-1, Appendix A.

15. Row 15, $812.4 million, is the 2008 base DRR which is calculated by multiplying the 2008 DRR per customer amount of $435.82 by the forecast 2008 average number of customers of 1,864,047. This 2008 base DRR is further adjusted in rows 16 through 24 to arrive at a 2008 total revenue requirement for which 2008 rates will be developed.

16. Row 16, increases the $812.4 base DRR by $43.1 million for carrying costs on 2008 gas in storage and gas cost working cash. As explained in the row 4 narrative, just as the carrying costs embedded in the Board's 2007 approved DRR need to be removed from a DRR to apply an incentive escalation formula, a 2008 carrying cost on gas in storage and gas cost working cash related to 2008 forecast volumes and the current Oct. 1, 2007 gas cost reference price needs to be included in a 2008 total revenue requirement. This is required in order to allow for the development of rates which would include 2008 volumetric forecasts and current gas price implications. (Ref. Exhibit C-4-1, Appendix A, p. 2)

17. Row 17, increases the $812.4 million base DRR by $23.1 million, which is the 2008 Board approved DSM operating costs as established in the EB-2006-0021 Decision. This is required to include a 2008 DSM amount into the 2008 total revenue requirement to replace the previously removed 2007 DSM operating costs as explained in the narrative for row 5.

18. Row 18, will increase the $812.4 million base DRR by the 2008 amount of CIS/Customer Care costs which, as previously mentioned in the row 6 narrative, will be determined through the template and true-up mechanism established in the EB-2006-0034 proceeding. This amount will not be known until the Company's incentive regulation formula to be used in the CIS/Customer Care cost template is determined, the true-up mechanism process is complete and the CIS revenue requirement treatment is determined. The schedule at page 5 of this exhibit

includes an amount of $89.2 million for illustrative purposes only. This amount is shown as an illustration amount in EB-2006-0034, Exhibit N1, Tab 1, Schedule 1, Appendix F, page 25, Column B, Line 23 and in this proceeding at Exhibit D-7-5.

19. Row 19, is the sum of rows 16, 17 & 18.

20. Rows 20 and 21, $1.0 million and $(0.3) million represent the amounts proposed for inclusion in the 2008 total revenue requirement with respect to Y-factor capital expenditure amounts for safety & reliability and leave to construct projects. The leave to construct revenue requirement now encompasses all leave to construct projects including any system reinforcement & expansion and power generation projects. The calculations of these revenue requirement amounts are now filed in evidence at Exhibit C-7-2, Safety & Reliability Y-Factor and Exhibit C-7-3, Leave to Construct Y-Factor Filed: 2007-09-25.

21. Row 22, $0.7 million, is the sum of the Y-factor capital expenditure revenue requirement calculations for rows 20 through 21.

22. Row 23, $968.5 million, pending the finalizing of the amount in row 19, represents a 2008 Board Approved DRR.

23. Row 24, $1,929.0 million, is the 2008 forecast gas cost which is required to be included into the 2008 total revenue requirement to replace the previously removed 2007 gas cost value embedded within the starting 2007 Total Board approved revenue requirement as explained in the narrative for row 2.

24. Row 25, $2,897.5, pending the finalizing of the amount in row 19, is the Company's 2008 total revenue requirement following the application of the sum of all of the elements of its proposed incentive escalation formula. 2008 rates will be designed to recover this entire amount based on the forecast of 2008 volumes inherent in the formula and revenue requirement derivation.

25. Row 26, $23.3 million, pending the finalizing of the amount in row 19, is equal to row 23 minus row 3 and represents the change in the Distribution Revenue Requirement.

26. Row 27, 2.46%, pending the finalizing of the amount in row 19, is row 26 expressed as a percentage of row 3 and represents the % change in the Distribution Revenue Requirement.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

2008 REVENUE CAP PER CUSTOMER, DISTRIBUTION REVENUE REQUIREMENT
AND TOTAL REVENUE REQUIREMENT DETERMINATION

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 |
|---|---|---|---|---|---|
| Row | Amount | Units | Revenue per Customer Cap model parameter | Exhibit & other reference(s) | Row Calculations |
| 1 | 3,119.8 | $m | 2007 Total Board Approved Revenue Requirement | EB-2006-0034 Draft Rate Order Appendix A | Input |
| 2 | 2,174.6 | $m | Gas Costs to operations (embedded above at Jul. 1, 2006 ref.price) | EB-2006-0034 Draft Rate Order Appendix A | Input |
| 3 | 945.2 | $m | Distribution revenue requirement ("DRR") - Board Approved 2007 Test Year | | R1-R2 |
| 4 | (59.5) | $m | 2007 embedded gas in storage & working cash carrying cost (Jul.1, 2006 ref.price) | EB-2006-0034 Decision & EB-2007-0615 C-7-6 | Input |
| 5 | (22.0) | $m | DSM 2007 Board Approved amount | EB-2006-0021 Decision | Input |
| 6 | (90.8) | $m | CIS / Customer Care 2007 Board approved amount ($90.8 M) | EB-2006-0034 N1-T1-S1, App. F, pg. 25 | Input |
| 7 | 772.9 | $m | DRR 2007 base (subject to the incentive escalation formula) | | R3 - (R4 + R5 +R6) |
| 8 | 1,823,258 | Avg. | 2007 Number of Customers (Average) | EB-2006-0034 C3-T2-S1, Item 5 | Input |
| 9 | $ 423.91 | $0.00 | 2007 Revenue Requirement per Customer | | ((R7 X 1,000,000) / R8) |
| 10 | 2.04% | % | GDP IPI | EB-2007-0615 B-2-1 | Input |
| 11 | -0.77% | % | X Factor | EB-2007-0615 B-3-1 | Input |
| 12 | 102.81% | % | 1.00 plus adjustment factor (calculated as inflation minus "X" factor) | = 1.00 + (GDP IPI - X Factor) | 1.00 + (R10 - R11) |
| 13 | $ 435.82 | $0.00 | 2008 Revenue Requirement per Customer | | R9 X R12 |
| 14 | 1,864,047 | Avg. | 2008 Number of Customers (Average) | EB-2007-0615 C-2-1 Appendix A | Input |
| 15 | 812.4 | $m | DRR 2008 base (resulting from the incentive escalation formula) | | (R13 X R14) / 1,000,000 |
| 16 | 43.1 | $m | 2008 gas in storage & working cash carrying cost (Oct.1, 2007 ref. price) | EB-2006-0034 Decision & EB-2007-0615 C-7-7 | Input |
| 17 | 23.1 | $m | DSM 2008 Board Approved amount | EB-2006-0021 Board Decision | Input |
| 18 | 89.2 | $m | CIS / Customer Care 2008 (EB-2006-0034 N1-T1-S1, App.F, pg. 25 illustrative) | (Note: 2008 final amount not yet available) | Input |
| 19 | 155.4 | $m | Sub-total - RR for GIS carrying cost, DSM and CIS/Customer Care | | Sum (R16 : R18) |
| 20 | 1.0 | $m | 2008 Safety & Reliability Y factor | EB-2007-0615 C-7-2 | Input |
| 21 | (0.3) | $m | 2008 Leave To Construct(s) Y factor | EB-2007-0615 C-7-3 | Input |
| 22 | 0.7 | $m | Sub-total - RR for Y Factors Capital Related | | Sum (R20 : R21) |
| 23 | 968.5 | $m | Distribution Revenue Requirement 2008 | | R15 + R19 + R22 |
| 24 | 1,929.0 | $m | 2008 Gas Costs to Operations (at Oct. 1, 2007 ref. price) | EB-2007-0615 C-1-1 | Input |
| 25 | 2,897.5 | $m | 2008 Total Revenue Requirement | | R23 + R24 |
| 26 | 23.3 | $m | Change in 2008 Distribution Revenue Requirement ($ millions) | | R23 - R3 |
| 27 | 2.46% | % | Change in 2008 Distribution Revenue Requirement (%) | | R26 / R3 (%'age) |

# TAB 8

Ontario Energy Board | Commission de l'Énergie de l'Ontario

Ontario

# EB-2005-0001/EB-2005-0437

## IN THE MATTER OF AN APPLICATION BY

## ENBRIDGE GAS DISTRIBUTION INC.

**2006 RATES**

## DECISION WITH REASONS

February 9, 2006

# 2. CAPITAL BUDGET

## 2.1 BACKGROUND

2.1.1 Enbridge proposed an increase in capital expenditures from the estimated $250.5 million in 2005 to $458.8 million for 2006. The Company claimed that it needs to address mounting demands on its gas distribution infrastructure being driven by requirements for pipeline integrity and remediation work, a need to support the provincial government in its effort to replace coal-fired electricity generation, new community attachments and new customers.

2.1.2 The major components of the capital budget are as follows:

- Customer related distribution plant expenditures of $172.8 million, representing an increase of $68.2 million over the 2005 estimate.

- System improvement and upgrade related expenditures of $235.3 million, representing an increase of $127.7 million over the 2005 estimate. This increase is mostly due to several major reinforcement projects and the accelerated bare steel and cast iron replacement program.

- General and other plant expenditures of $43.2 million, consisting of land, structures, and improvements ($5.5 million); office furniture, transportation heavy work tools and work equipment ($4.5 million); NGV compressor equipment ($0.1 million); and computers and communication equipment ($31.5 million).

- Capital expenditures for underground storage facilities of $6.9 million.

2.1.3 The requested capital budget would result in an increase in rate base of $174.1 million (net of accumulated depreciation and retirements) for the Test Year. The change in the forecast level of rate base is primarily a result of capital closeouts to rate base, capital expenditures and work in progress, changes in the value of the gas in storage inventory, and changes in working cash allowance requirement. Most of the rate base impact of the Company's proposed capital expenditures would occur in 2007, when most projects will be closed to rate base.

2.1.4 Enbridge described its approach to the budgeting process as a "bottom up" approach and explained that the capital budget is developed by assessing the needs of the business including customer growth, system reinforcement and infrastructure rehabilitation for safety and reliability needs.

2.1.5 Enbridge asserted that it has an ongoing legal obligation to address emerging legislative change in a timely manner. In this regard, the Company said that it has put into place certain policies and plans to respond to pipeline integrity legislation that has been introduced in Canada and the United States. As well, it is beginning to consider the appropriate response to distribution integrity related legislation that it expects will take effect in the near future.

2.1.6 Enbridge also requested Board approval of $31.5 million related to IT capital expenditures for computer, software and communications equipment. Enbridge submitted that its request for increased capital spending on IT is necessary to support EnVision (Work and Asset Management), EnTRAC (gas account tracking) and EnMar (meter management and large volume meter data processing) and to accommodate the integration of certain new customer care applications with the Company's existing applications. Enbridge maintained that the IT capital budget does not include any costs related to the implementation of new processes stemming from the Board's GDAR proceeding; nor does it include any expenditure for Strategic Information Management ("SIM") projects such as CIS.

2.1.7 Enbridge proposed an increase of $68.2 million in customer-related distribution plant expenditures. $36.3 million of this increase is earmarked as a placeholder for two potential power generation projects to be authorized by the Ontario government, pursuant to certain RFPs. Enbridge submitted that the provincial government's commitment to pursue new gas-fired electricity generation through the RFP process is evident in the fact that, at the time of filing, the government had already announced a 90MW plant for the Greater Toronto Airport Authority, and two 280MW plants for Mississauga. (One of these two 280MW plants has subsequently been withdrawn.) Enbridge reported that the government has recently indicated that it will be proceeding with another round of RFPs that will include a 1,000MW plant for "GTA West" and a 600MW plant for the downtown Toronto area. Enbridge submitted that Board approval of the requested amount would send a positive message that the natural gas industry is committed and ready to help address Ontario's electricity supply shortfall through the creation of appropriate infrastructure to serve such plants.

2.1.8 The capital expenditure budget proposed by the Company for system improvements and upgrades in the Test Year is $235.4 million and is comprised primarily of Total Improvement Mains of $146.2 million, representing an increase of $92.9 million above the amount in 2005. This increase is primarily due to several major reinforcement projects ($54.0 million) and the Company's accelerated bare steel and cast iron mains replacement program ($43.4 million). Enbridge submitted that the increased reinforcement main activity is driven primarily by the need to ensure adequate volumes and pressures across its distribution system in the face of the cumulative effects of years of new residential growth and commercial developments.

2.1.9 A number of intervenors argued that the proposed capital budget should not be approved and that a considerably lower budget should be approved. Intervenors cited a number of reasons for the Board to reduce the Company's capital budget proposal including:

- failure to provide evidence that adequately justifies major capital initiatives and individual programs;
- weaknesses in Enbridge's arguments linking increased capital requirements to any changed circumstances or new issues around safety, and
- new facts arising during the course of the rate proceeding that support lower capital requirements.

2.1.10 The intervenors proposed 2006 capital budgets ranging from $250 million to $300 million. In general, the intervenors argued that the Company should be able to manage within these levels, as these amounts are close to the Company's historic capital budget levels.

## 2.2 BOARD FINDINGS

2.2.1 It is not the Board's role in a rates case to micro-manage Enbridge's capital spending plans for any given year. Generally, Enbridge must determine for itself what level of spending is appropriate for a relevant period. This process within the Company must involve a thoughtful and programmatic assessment and prioritization of projects that have ripened to the extent that there is confidence that they can and should be accomplished within the period. This is particularly so in an environment that has seen significant increases in energy prices and where the Company is seeking a very substantial increase in overall capital spending. It may be that the Company will have to make choices about which projects are most critical, and which may have to await completion until future periods.

2.2.2 The Board's role is to ensure that the Enbridge's total spending program is balanced in that it is not so low as to threaten the orderly maintenance and development of the system, nor so high as to place undue upward pressure on rates, either in the test year or some future period. In fulfilling this role the Board attempts to place the capital spending plans within historical norms, which can be presumed to have found that appropriate balance. If spending well in excess of historic norms is proposed, the Board must assess whether the increase is justified through the presentation of evidence regarding the Company's analysis, prioritization, and judgement respecting budget components.

2.2.3 In the instant case, Enbridge has proposed an unprecedented increase in capital spending. The applied for amount represents an increase of over 80% of not only the previous year's budgeted amount, but also the average of the last five years. While the rate impact of this proposal in the Test Year may be modest, the implication of the budget for subsequent periods is significant. Over $400 million would be added to rate base for the 2007 rate year, which will result in a rate base impact of approximately 11% in that year.

2.2.4 In such a case the Board must examine Enbridge's proposal carefully to determine if such an unprecedented increase is balanced and justifiable or if the budget should be adjusted to enable the Company to make choices between programs of varying priority and at different stages of development.

2.2.5 To support the magnitude of the increase, Enbridge advanced the proposition that a number of extraordinary circumstances had come together at this time to create the need for this extraordinary capital spending budget. These circumstances are:

- extraordinary system expansion requirements;
- a pressing safety and reliability issue occasioned by cast iron and bare steel mains in Toronto; and,
- the advent of gas-fired merchant generation in its franchise area.

2.2.6 The Board is not convinced that Enbridge has proven that its environment has changed so markedly as to justify the proposed level of capital spending.

2.2.7 Looking first at the issue of expansion within Enbridge's system, the Board notes that the number of customer additions in 2006 is roughly the same as that for other years in the recent past. Enbridge suggested that there is not a linear relationship between customer additions in a given year and the capital expenditures necessary to accommodate them and that there is a point where the Company "catches up" for past years. This assertion by the Company is not supported by any direct evidence.

2.2.8 The Board notes that the rate of customer additions has been remarkably stable over the last number of years and considers that the capital budgets in each of those prior years should be presumed to, in aggregate, approximately accommodate the additions. In the Board's view, more compelling evidence is required before it can accept Enbridge's claim that this is an extraordinary year from a customer additions point of view and that such an unusually high level of capital spending is needed to accommodate them.

2.2.9 The acceleration of the bare steel and cast iron mains replacement program from 8 years to 3 years accounts for a significant portion of the increase in the capital budget for 2006. It is clear from the evidence that senior management intervened to accelerate the program and to increase the budget accordingly as a result of a change in its tolerance for the risks associated with managing this aging mains stock. The responsible engineering personnel had recommended a reduction in the spending amount for 2006. The technical challenges presented by the bare steel and cast iron mains did not change, nor did prevailing engineering practice. The existing program, which provides for a replacement of the bare steel and cast iron mains over an 8 year period, had been established by the Company's engineering staff and repeatedly presented and represented as being adequate to the risks associated with the mains. Nothing has intervened to change the adequacy of the 8 year replacement program, except senior management's risk tolerance.

2.2.10 Enbridge attempted to suggest that imminent changes in technical standards governing bare steel and cast iron pipe management would require an accelerated replacement program. In fact, Enbridge was unable to document or support this suggestion. No such change in the regulatory environment appears to be imminent.

2.2.11 Enbridge also suggested that an acceleration of the replacement program was justified because the anticipated decrease in the number of system leaks had not materialized. It looked to a study conducted by the American Gas Foundation to support this view. In fact, the AGF Study does not support or mandate the much more aggressive approach adopted by Enbridge for the purposes of this budget.

2.2.12 Similarly, Enbridge was unable to document any specific concerns on the part of the primary regulator of pipeline integrity in Ontario, the Technical Safety Standards Authority, with its 8 year replacement program. The Board also notes that Enbridge has not taken any steps to alert other public authorities, or its insurer, respecting a concern that the bare steel and cast iron mains now represent a previously underestimated danger to public safety.

2.2.13 What is clear from the evidence is that the acceleration of the bare steel and cast iron mains replacement program is the result of a change in senior management's risk tolerance, and not with any demonstrable change in the technical challenges presented by that pipeline stock. While it is laudable that the Company's senior management is focused on this program and determined to manage it aggressively, such a change in attitude without a change in the actual risk cannot justify an increase in the capital spending budget of the magnitude sought by the Company. Enbridge may choose, and perhaps, given Mr. Schultz' testimony, has already chosen, to afford the replacement program a priority beyond that which its own engineering forces identified, but it must do so within a budget that has not been unduly inflated to account for changes in mere risk tolerance.

2.2.14 Finally, Enbridge suggested that the prospect of new gas-fired electricity generation plants within its franchise territory justifies some extraordinary and significant increases in its capital spending budget. The increases are related to the construction of the infrastructure necessary to supply such plants with gas. This budget item references the prospect of gas-fired electricity generation and provides a "placeholder" for two potential generation plants in the Enbridge franchise area in 2006.

2.2.15 It is no secret that Ontario has identified a need for increased electricity generation. The Company has not provided any detail respecting imminent projects, and it would generally be considered unreasonable to insert placeholders in the budget without more substance. However, the Board, being mindful of the provincial imperative of developing more generation, is prepared to acknowledge that some provision should be made for as yet unspecified generation projects.

2.2.16 In conclusion, Enbridge has not demonstrated that circumstances exist which justify the extraordinary increase sought in the total capital budget. The Board does consider, however, that a case has been made for some increase in the budget over historical norms. While the Board is not convinced that the customer additions justify the extent of increase sought, it is prudent to make provision for some additional spending to ensure that system requirements are appropriately maintained. Similarly, while Enbridge has failed to support its claim for a radical acceleration of the bare steel and cast iron mains replacement program and the sharp increase in spending associated with it, some additional funds may be needed to adjust to developments in this area. The same kind of provision is appropriate for the development of infrastructure to support gas-fired generation projects and other system reinforcement.

2.2.17 Accordingly, the Board will approve a capital budget which is equivalent to the average for the five years 2001 to 2005 with an additional amount of $50 million to provide for the contingencies suggested by Enbridge in its evidence and general inflationary pressures. The total approved capital budget will therefore be $300 million.

2.2.18 In approving this budget amount, the Board leaves it to Enbridge's management to determine which projects it will pursue in the Test Year and at what pace it will pursue them. If the Company decides to accelerate the bare steel and cast iron mains replacement program, the Board would anticipate that claims for subsequent years would be reduced commensurately.