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 Board pursuant to section 21(1) of the *Ontario Energy Board Act, 1998.*

INTERROGATORIES OF THE INDUSTRIAL GAS USERS ASSOCIATION ("IGUA") TO BOARD STAFF

1. Reference: Pacific Economics Group ("PEG") Report, Executive Summary, pp. (i) to (vii) inclusive
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

The evidence indicates that PEG is the advisor to Board Staff on Incentive Regulation ("IR") issues and that PEG's mandate is defined by Directives from Board Staff. The evidence refers to Board Staff January 5, 2007, Discussion Paper which is found in Union's evidence at Ex.B, Tab 1, Appendix A. The Board Staff Discussion Paper indicates that PEG was its adviser at the time the Discussion Paper was prepared. The Discussion Paper addresses many topics on the Issues List attached as Appendix A to Procedural Order No. 4. IGUA wishes to determine the extent to which the contents of the Board Staff Discussion Paper reflects advice and opinions PEG provided to Board Staff. In this context, please provide PEG's responses to the following questions:

(a) When did PEG first become the adviser to Board Staff with respect to IR issues?

(b) Did PEG express opinions to Board Staff which are reflected in the opinions described in the Discussion Paper which are attributed to Board Staff?

(c) Please describe the extent to which PEG participated in the drafting of the Discussion Paper.

(d) Using the list of each of the items in the Table of Contents of the Board Staff Discussion Paper found in Union's evidence at Ex.B, Tab 1, Appendix A and for each of the items and sub-items in Topic 2 "Underlying Principles", Topic 3 "Incentive Regulation Plan Design" and Topic 4 "Other Issues", provide PEG's opinion on each of the matters discussed and a brief description of PEG's rationale for its opinions on each of these subject matter items.

(e) Using the List of Questions contained in the Board's Issues List found at Appendix A to Procedural Order No. 4, please provide PEG's answers to each of the questions asked in items 1 to 14 inclusive, including a brief description of PEG's rationale for each response.

2. Reference: PEG Report, Executive Summary, pp. (iii) to (vii) inclusive
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

PEG's evidence contains summary tables of the Indexes computed by PEG for EGD and Union. Union's evidence at Ex.B, Tab 1, page 8 contains a Table summarizing Union's price cap plan proposal. EGD's evidence at Ex.B, Tab 1, Schedule 1, pp.1 to 3 contains a summary description of its proposal. IGUA wishes to understand the differences between the IR regimes being proposed by Union and EGD and PEG's recommendations for each utility. In this context, please provide responses to the following questions:

(a) Using Union's Table 1 as the point of departure, please revise the Table as required to show how Union's summary would differ if the Board accepted PEG's recommendations for Union.

(b) Does PEG recommend a Price Cap rather than a Revenue Cap for EGD?

(i) If the answer is yes, then please briefly explain the rationale for PEG's response;

(ii) If the answer is no, then please briefly explain the rationale for PEG's response and include therein an explanation of why, in PEG's view, the Board should consider approving IR regimes for Union and EGD which materially differ.

(c) Please provide an exhibit which summarizes PEG's understanding of EGD's IR proposal using the same parameter topic headings Union uses in its Table 1 and then provide a revision to that summary table to show how EGD's proposal would differ if the Board accepted PEG's recommendations for EGD.

3. Reference: PEG Report, Executive Summary, pp. (i) to (vii) inclusive, Board Staff Discussion Paper, Union evidence Ex.B, Tab 1, Appendix A
Issue Nos.: 1.2, 5.1 and 6.1
Issue:
1.2 What is the method for incentive regulation that the Board should approve for each utility?
5.1 What are the Y factors that should be included in the IR plan?
6.1 What are the criteria for establishing Z factors that should be included in the IR plan?

The evidence indicates that the IR Regime which PEG supports contemplates that a number of components of the regulated revenue requirements of Union and EGD will continue to be subject to some form of continuing Cost of Service ("COS") regulation for the duration of any

IR plan the Board might approve for each of these utilities. In this context, IGUA regards Y factors, including Deferral Accounts, and Z factors as continuing COS features of rate regulation. IGUA would like to obtain PEG's analysis of the extent to which the regulated revenue requirements of Union and EGD will continue to be subject to some form of continuing COS regulation over the duration of any IR plan the Board might approve for each utility. To this end, please provide, in separate schedules for Union and EGD, the following:

(a) PEG's understanding of the total base year regulated revenue requirement for Union and EGD;

(b) PEG's understanding of the total base year delivery-related regulated revenue requirement for Union and EGD;

(c) PEG's segregation of the total base year regulated revenue requirement for Union and EGD to be provided in response to question (a) between the following broad categories:

- Cost of gas, operations and maintenance expenses,
- Depreciation,
- Property taxes,
- Capital taxes,
- Return segregated as follows:
  - Equity return
  - Cost of debt
  - Income taxes

(d) Within each of these broad categories, list and provide PEG's quantification of any item of COS which, in whole or in part, falls within the categories of Y factors, including Deferral Accounts, and Z factors proposed by Union and EGD.

(e) Using information to be provided in response to the previous questions, please provide PEG's estimate of the following:

(i) the proportion of the total regulated revenue requirement of Union and EGD which will not be subject to some form of continuing COS treatment under the IR plans proposed by Union and EGD;

(ii) the proportion of the delivery-related revenue requirement of Union and EGD which will not be subject to some form of continuing COS treatment under the IR plans proposed by Union and EGD.

4. **Reference:** **PEG Report, Executive Summary, pp. (i) to (vii) inclusive**
Issue Nos.: **1.1 and 1.2**
Issue:
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?

IGUA wishes to have PEG provide Schedules which will illustrate the incremental revenues, over and above the base year revenue requirement, which will be available to Union and EGD in an illustrative 1% price cap scenario for Union and EGD for each of the years 2008 to 2012 inclusive.

For Union, please make the following assumptions:

- a 2007 rate base of $3.4B
- a composite depreciation rate of 3%
- a 2007 revenue requirement, including cost of gas of $2B, with the delivery-related component thereof in an amount of $900M
- over the years 2008 to 2012 inclusive, the addition of 20,000 residential customers per year

For EGD, please make the following assumptions:

- a 2007 rate base of $3.7B
- a composite depreciation rate of 4.5%
- a 2007 revenue requirement, including the cost of gas of $3.1B, with the delivery-related revenue requirement component thereof being in an amount of $925M
- over the years 2008 to 2012 inclusive, the addition of 50,000 residential customers per year

If further assumptions need to be made to provide the illustrations, then please have PEG make the further assumptions which it considers to be reasonable.

Under these assumptions, please provide exhibits which will show, for Union and EGD separately, the following:

(a) The incremental revenues, over and above the base year revenue requirement, which a 1% price cap for each of the years 2008 to 2012 will produce in each of those years;

(b) The estimated amount of capital spending which the 1% price cap will accommodate in each of the years 2008 to 2012 inclusive; and

(c) For EGD, provide a schedule which will show the incremental revenues, over and above the base year revenue requirement, which EGD's proposed revenue per customer cap of 2% per year will produce for each of the years 2008 to 2012 inclusive, along with the estimated amount of capital spending which EGD's revenue per customer cap of 2% per year will support in each of those years.

5. Reference: PEG Report, Executive Summary, pp. (i) to (vii) inclusive, Staff Discussion Paper, Union Ex.B, Tab 1, Appendix A

Issue Nos.: 11.1, 11.2 and 11.3

Issue: 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-annually or annually)?

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

IGUA wishes to obtain PEG's opinions on the appropriate reporting requirement features of an IR regime for Union and EGD. The quarterly surveillance reporting requirements which the National Energy Board ("NEB") follows are reflected in a copy of the year end quarterly surveillance report filed by TransCanada PipeLines Limited ("TCPL"). In the context of this attachment, please provide PEG's responses to the following questions:

(a) Please describe the extent to which U.S. utilities are subject to the same kind of surveillance reporting requirements which TCPL and other NEB regulated utilities are required to follow.

(b) What advice, if any, did PEG provide Board Staff with respect to the reporting requirements issue?

6. Reference: **PEG Report, Executive Summary, pp. (i) to (vii) inclusive, Board Staff Discussion Paper**

Issue Nos.: **12.1, 12.1.1 and 12.1.2**

Issue: **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?

What are PEG's recommendations with respect to frequency with which changes should be made to rates on account of Y and Z factors?

7. Reference: **PEG Report, Executive Summary, pp. (i) to (viii) inclusive, and pp. 2 and following re: X factor components**

Issue Nos.: **1.1 and 3.2**

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

3.2 What are the appropriate components of an X factor?

The evidence indicates that the X factor is an offset to inflation in the adjustment formula to be applied to rates or to the revenue requirement of a particular utility. Consultatives with respect to the X factor issue have revealed that its statistically derived components are controversial and its judgmentally determined components are equally controversial. In this context, please provide responses to the following questions:

(a) Does a negative X factor imply negative productivity?

(b) Does PEG agree that regulators ought not to countenance negative productivity?

Please include a brief rationale for PEG's response to this question.

(c) What simplified approaches to the X factor component of the adjustment mechanism did PEG consider? For example, did PEG consider the rate freeze approach or a percentage of inflation approach as simplified approaches to the adjustment mechanism? Please explain the extent to which simplified approaches were considered and the results of PEG's consideration of each approach considered.

8. Reference: PEG Report, Executive Summary, pp. 2 and 15 to 17
Issue Nos.: 4.1, 4.2 and 4.3
Issue:
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 calculate?
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)?

The evidence discusses the average use factor as an adjustment to the X factor. The IR plans which Union and EGD propose contemplate that Demand Side Management ("DSM") matters will be a Y factor adjustment. The evidence also indicates that DSM measures and declines in average use are inter-related. In this context, please provide PEG's response to the following questions:

(a) Is there any reason why declines in average use could not be included within the ambit of the Board's consideration of matters pertaining to a Y factor for DSM or as a separate average use Y factor?

(b) Please revise the Tables in the Executive Summary of PEG's evidence at (iii), (iv) and (v) to exclude the average use factor as an adjustment to the X factor.

9. Reference: PEG Report, Executive Summary, Board Staff Report
Issue Nos.: 5.1 and 5.2, 6.1 and 6.2, 9.1 and 9.2, 10.1 and 10.2
Issue:
5.1 What are the Y factors that should be included in the IR plan?
5.2 What are the criteria for disposition?
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?
9.1 Should an off-ramp be included in the IR plan?
9.2 If so, what should be the parameters?
10.1 Should an ESM be included in the IR plan?
10.2 If so, what should be the parameters?

IGUA is interested in obtaining PEG's views on matters pertaining to the appropriateness of including or excluding an Earnings Sharing Mechanism ("ESM") as a feature of an IR plan for

Union and EGD. In this context, please provide PEG's responses to the following questions:

(a) In PEG's view, does a regulator have a continuing obligation over the duration of an IR regime to monitor the rates being charged to assess whether they remain within just and reasonable limits and are not producing unreasonable returns for utility shareholders?

(b) In PEG's view, is an ESM feature of an IR plan equivalent to treating a portion of equity return, in excess of the utility allowed return, as a Y factor or a Z factor adjustment to rates?

(c) Is the excessive return "off-ramp" equivalent to a 100% ESM mechanism in favour of the ratepayers?

10. Reference: PEG Report, Executive Summary, page (iv), pp. 64 to 67
Issue Nos.: 3.1 and 3.2
Issue: 3.1 How should the X factor be determined?
3.2 What are the appropriate components of an X factor?

The evidence indicates that the Price Cap Index for EGD's non-residential customer classes would be 0.32% and for Union's non-residential customer would be 0.08%, and that the Price Cap Index for residential service groups will be higher when a negative average use adjustment factor is included in the X factor. Please provide responses to the following questions with respect to this evidence:

(a) Are these service group PCIs for the non-residential customers of Union and EGD shown in Table (iv) of the PEG Report indicative of the Price Caps that would apply to determine the 2008 Rates for EGD and Union? If the answer is no, then please indicate the year for which these Price Cap Indeces would be applicable. For example, are they the Price Caps that would apply to determine Union and EGD rates for 2007, using a 2006 revenue requirements and rates as the base?

(b) What do the Price Cap Indeces for the residential rate classes become if the average use adjustment factor is treated as a Y factor, rather than as an adjustment which reduces the X factor?

(c) What are the statistical confidence levels for the service group Price Cap Indeces which PEG recommends?

(d) What other regulators have adopted service group Price Cap Indeces in the IR plans for the utilities they regulate?

11. Reference: Union Evidence, Ex.B, Tab 1, page 36
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

Union's evidence criticizes the PEG evidence with respect to service group PCIs. Please provide responses to the following questions with respect to Union's criticisms of PEG's evidence:

(a) Please have PEG provide a list of each of the criticisms Union makes of PEG's evidence and a summary of PEG's response to each of those criticisms.

12. Reference: EGD Evidence, Ex.B, Tab 1, Schedule 1, pp. 3-22, Ex.B, Tab 3, Schedules 1, 2 and 3
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

There are a number of criticisms of PEG's Report contained in EGD's evidence. Please provide responses to the following questions with respect to EGD's criticisms of PEG's Report:

(a) Please have PEG provide a list of each of the criticisms which EGD makes of its report and a summary of PEG's response to each of those criticisms.

13. Reference: PEG Report
Issue No.: 10.1
Issue: Should an ESM be included in the IR plan?

The evidence indicates that the Price Cap Mechanism and Rate Cap Mechanism can be designed so that the expected benefits of improved performance are shared equitably between utilities and their customers:

(a) Does PEG agree that implementation of an ESM is a method whereby the benefits of improved performance can be shared equitably between utilities and their customers? If not, why not?

(b) Please set out the advantages and disadvantages of ESMs from the perspective of the shareholder and the customer.

(c) Please provide copies of all research and presentations prepared by PEG that address ESMs in a North American setting.

14. Reference: PEG Report, p. (iii)
Issue No.: 3.1
Issue: How should the X factor be determined?

PEG states that the higher X factor for EGD is chiefly due to its greater opportunities to realize scale economies. Please produce and explain the factors and evidence considered by PEG in coming to this conclusion.

15. Reference: PEG Report, p. (iv)
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

PEG states that rate design can be addressed periodically in hearings much like it is today.

(a) In PEG's experience, is rate design normally addressed during the term of the IR plan, or alternatively, at the end of the IR plan?

(b) What are the advantages and disadvantages of allowing for rate design changes during the term of the IR plan?

(c) If rate design changes are permitted during the term of the IR plan, will this necessitate an adjustment to the PCIs or Revenue Cap Indexes ("RCI") set out in the PEG Report? Please explain.

16. Reference: PEG Report, p. (iv)
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

PEG states that, when an RCI is used, a balancing account commonly ensures that the allowed revenue requirement is exactly recovered. Please identify the various categories of costs which are commonly included in such a balancing account:

17. Reference: PEG Report, p. (vi)
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

PEG states that the evidence indicates that declining average use is being experienced by many gas utilities in North America. Please provide copies of all of the evidence relied upon in making this statement.

18. Reference: PEG Report, p. (vii)
Issue Nos.: 3.1 and 3.2
Issue: 3.1 How should the X factor be determined
3.2 What are the appropriate components of an X factor?

PEG refers to research it has previously conducted for Board Staff to develop an IR Plan for power distributors in which it was concluded that the average explicit stretch factor approved for energy utilities in rate escalation indexes was around 0.50%. Please provide a copy of that research.

19. Reference: PEG Report, p. (vii)
Issue Nos.: 3.1 and 3.2
Issue: 3.1 How should the X factor be determined
3.2 What are the appropriate components of an X factor?

PEG refers to incentive power research it undertook for Board Staff that suggests a stretch factor of 0.42% for EGD and Union. Please provide a copy of that incentive power research.

20. **Reference:** **PEG Report, p. (vii)**
Issue Nos.: **3.1 and 3.2**
Issue: **3.1 How should the X factor be determined**
3.2 What are the appropriate components of an X factor?

PEG states that no evidence has been brought to their attention concerning the recent operating efficiency of EGD or Union, and accordingly, PEG has no basis for adjusting the X factor for this consideration. Were EGD and Union given an opportunity to provide evidence relevant to the determination of a stretch factor? If the answer is yes, please explain the opportunities provided to EGD and/or Union and produce all related correspondence.

21. **Reference:** **PEG Report, page 2**
Issue Nos.: **1.1 and 1.2**
Issue: **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?

PEG states that Board Staff initially directed PEG to undertake index research that would support the design of PCIs for EGD and Union, and subsequently, Board Staff requested the development of RCIs and PCIs for particular search groups. Please provide a copy of all written directions and correspondence between Board Staff and PEG.

22. **Reference:** **PEG Report**
Issue Nos.: **1.1 and 1.2**
Issue: **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?

Throughout its report, PEG refers to information provided by EGD and Union. Please provide all correspondence between PEG and EGD or Union, including any correspondence between EGD and Union to and from Board Staff that relates to the work undertaken by PEG.

23. **Reference:** **PEG Report, page 21**
Issue No.: **1.2**
Issue: **What is the method for incentive regulation that the Board should approve for each utility?**

In describing the primary sources of data used in its research on the index trends of Ontario gas utilities, PEG states that there are inconsistencies in the data that EGD and Union made available.

(a) Were Union and EGD requested to provide the same data? If not, why not?

(b) Once it became apparent that inconsistencies in the data existed, did PEG make a further request to EGD and/or Union to provide further information? If not, why not? If so, please provide a copy of all related correspondence.

24. **Reference:** **PEG Report, page 21**
Issue No.: **1.2**
Issue: **What is the method for incentive regulation that the Board should approve for each utility?**

PEG states that "other sources of data" were also used in the Ontario indexing research. Please provide copies of all "other sources of data" relied upon by PEG.

25. **Reference:** **PEG Report, page 23**
Issue No.: **1.1**
Issue: **What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?**

PEG computed the indexes on the cost of funds for EGD and Union using a 65/35 weighting of debt and equity. The debt to equity ratio currently approved for EGD and Union is 64/36. Please re-calculate your PCIs and RCIs using the 64/36 debt to equity ratio.

26. **Reference:** **PEG Report, page 26**
Issue No.: **1.1**
Issue: **What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?**

In computing output quantity indexes for EGD and Union, PEG added to the weather normalized volumes certain estimates, provided by Union and EGD, of their DSM savings. Please provide the DSM savings provided to PEG by Union and EGD.

27. **Reference:** **PEG Report, page 32**
Issue No.: **1.1**
Issue: **What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?**

PEG observes that the Partial Factor Productivity Index for EGD fell by more than 11% in 2003 and did not subsequently regain much of that lost ground. The year 2003 was the first following the conclusion of EGD's targeted IR Plan for O&M inputs. PEG further observed that there is no evidence that this plan produced lasting benefits for EGD customers.

(a) What steps can be taken to assure that EGD and Union achieve sustainable productivity gains?

28. **Reference:** **PEG Report, page 47**
Issue No.: **4.1**

Issue: **Is it appropriate to include the impact of changes in average use in the annual adjustment?**

The evidence indicates that the weather-normalized trends computed by PEG were similar to the companies in the case of Union but not in the case of EGD. Moreover, the figures calculated by PEG suggest average use declines for EGD that are conservatively less severe than those calculated by EGD.

(a) Please set out the methodology used by PEG to compute the weather normalized trends for both Union and EGD.

(b) If the Board approved weather normalization methods for each company are changed, will this affect PEG's calculation of the Average Use Factor, or any other component of the PCIs or RCIs?

(c) If the Board approves the weather normalization methodology requested by Union at Ex.B, Tab 2, how will this affect PEG's calculation of the Average Use Factor, or any other component of the PCI or RCI?

29. Reference: **PEG Report, page 61, Union Evidence, Ex.B, Tab 1, page 32 of 48**
Issue No.: **3.1**
Issue: **How should the X factor be determined?**

PEG states that a stretch factor used in the determination of an X factor will facilitate the sharing between utilities and customers of any benefits that are expected to result from the stronger performance incentives generated by the Plan. At Exhibit "B", Tab 1, p. 32 of 48, Union claims there is no justification for a stretch factor during the next IR Plan and that the stretch factor proposed by PEG is purely an "ad hoc add on".

(a) Does PEG agree that the proposed stretch factor of 0.5% is "purely an ad hoc add on"? If not, why not?

(b) In the absence of a stretch factor, how are benefits shared with customers?

(c) If there is no stretch factor, should there then be an ESM?

(d) Under what circumstance, if any, is it appropriate for an IR Plan to have no stretch factor and no ESM?

30. Reference: **PEG Report, pp. (v) and 61, Union Evidence, Ex.B, Tab 1, pp. 32 to 34 of 48**
Issue No.: **3.1**
Issue: **How should the X factor be determined**

Union's evidence sets out a number of factors in an attempt to justify the absence of a stretch factor. At page (v) of the PEG Report, PEG states that utilities should demonstrate superior performance with convincing benchmark evidence if they wish to receive special rate treatment with respect to inclusion [or exclusion] of a stretch factor. In PEG's opinion, do the factors identified in Union's evidence demonstrate superior performance such that they ought to receive special rate treatment and have no stretch factor applied to the calculation of their X factor? If not, why not?

31. Reference: Union Evidence, Ex.B, Tab 1, page 10 of 48
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

Union has requested that certain adjustments be made to the 2000 Base Rates, including:

(a) Items from previous Board Decisions:

(i) Splitting the M2 rate class into two rate classes (M1 and M2);

(ii) Adjustments for the 2008 GDAR capital costs;

(iii) Treatment of S&T deferral accounts;

(iv) DSM;

(b) A one-time adjustment to reflect the 20-year trend weather normalization method.

If these adjustments are approved by the Board, would they necessitate any adjustments to the PCIs and RCIs contained in the PEG Report? If the answer is yes, then provide details of the necessary adjustments

32. Reference: Union Evidence, Ex.B, Tab 1, page 17 of 48
Issue No.: 12.3
Issue: 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?

Union claims that it should have the ability to adjust the Fixed Monthly Charge and the Variable Charge on a revenue neutral basis annually. Union claims that with the ability to adjust the Fixed Monthly Charge and the Variable Charge on a revenue neutral basis, there would be no need to adjust the fixed monthly charge as part of the Price Cap formula.

(a) Is it appropriate to adjust the Fixed Monthly Charge and Variable Charge during the IR term? Please provide an explanation.

(b) Would these adjustments impact Union's business risks?

(c) If Union is provided with the ability to adjust the Fixed Monthly Charge and the Variable Charge during the term of the IR period, would there be a need to adjust the PCIs or RCIs calculated by PEG? Please explain.

33. Reference: Union Evidence, Ex.B, Tab 1, page 18 of 48
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

Union states that a Price Cap Mechanism should be used because it better addresses the two items that matter most to customers: the price and quality of the service they receive. Does PEG agree that a Price Cap Mechanism addresses these two items better than a Revenue Cap Mechanism? Please explain.

34. **Reference:** **Union Evidence, Ex.B, Tab 1, page 36 or 48**
Issue No.: **4.1**
Issue: **Is it appropriate to include the impact of changes in average use in the annual adjustment?**

Union states that it does not understand how PEG can calculate separate Service Group PCIs for each Rate Class that contains residential customers without doing a productivity study by Rate Class. Does PEG agree that a productivity study by Rate Class is necessary to determine Service Group PCI's? If not, why not?

35. **Reference:** **Union Evidence, Ex.B, Tab 1, page 36 of 4**
Issue No.: **4.1**
Issue: **Is it appropriate to include the impact of changes in average use in the annual adjustment?**

Union recommends an alternative to PEG's calculation of Service Group PCI's which is calculated by adjusting the company-wide Average Use Factor by the combined revenue share of the General Service Rate classes. Does PEG agree with Union's proposed approach to calculating the Average Use Factor applicable to the General Service Rate classes? If not, why not?

36. **Reference:** **Union Evidence, Ex.B, Tab 1, page 40 of 48**
Issue No.: **6.1**
Issue: **What are the criteria for establishing Z factors that should be included in the IR plan?**

Union lists as an example of a possible Z factor the return on equity formula.

(a) Does PEG agree that a change in the Return on Equity Formula during the IR term is an appropriate Z factor? If not, why not?

(b) If a Return on Equity Formula is changed during the IR term, would this necessitate a change in any of the components of the PCIs or RCIs as calculated by PEG? If so, please provide an explanation.

37. **Reference:** **Union Evidence, Ex.B, Tab 1, Schedule 1, page 5 of 22**
Issue No.: **1.2**
Issue: **What is the method for incentive regulation that the Board should approve for each utility?**

EGD alleges that the following objectives cannot be satisfied by a plan that does not adequately compensate the utility for the cost escalation and growth pressures it faces:

(a) Maintain a safe and reliable system;

(b) Meet service quality requirements;

(c) Retain incremental ROE resulting from efficiency improvement initiatives; and

(d) Respond to the continuing demand for new customer attachment, recently at a pace of 45,000 to 50,000 new customers per year.

In PEG's opinion, can these objectives be satisfied by both a PCI and an RCI? Please explain.

38. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 1, page 2 of 37
Issue No.: 3.1
Issue: How should the X factor be determined?

EGD's analysis of the X factor focussed only on the geometric decay method and ignores the use of the cost of service method. Is it appropriate to ignore the cost of service method? If not, why not?

39. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 1, pp. 8 to 10 of 37
Issue No.: 3.1
Issue: How should the X factor be determined?

EGD provides evidence in Tables 3, 4 and 5, as well as in the corresponding text about its Output Quantity Index, Input Quantity Index, and Historical Cost Weighted TFP:

(a) Did PEG have access to this information when it prepared its report?

(b) If the answer to (a) is no, did PEG request this information from EGD?

(c) Does this information alter PEG's opinion on the appropriate X factor to be used in the Revenue Cap Index ("RCI") and PCI applicable to EGD?

40. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 1, page 25 of 37
Issue No.: 3.1
Issue: How should the X factor be determined?

EGD has identified what it claims are viable alternatives for establishing the productivity target which include:

(a) Use of the California Department of Rate Payer Advocates replicated PEG model presented in July 2007 for the U.S. as a whole, adjusted for the Canadian-U.S. productivity gap;

(b) Use of the California Department of Rate Payer Advocates replicated PEG model presented in July 2007 for the Northeast Sector, adjusted for the Canadian-U.S. productivity gap.

(i) Does PEG agree that either of these adjusted models are viable alternatives for establishing the productivity target for EGD? If not, why not?

41. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 8 of 24
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

Dr. Carpenter alleges that based on data currently available, the companies that make up the peer groups that PEG has chosen for EGD do not have business characteristics that are similar to EGD's. Does PEG agree with this statement? If not, why not?

42. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 11 of 24
Issue No.: 3.1
Issue: How should the X factor be determined

Dr. Carpenter observes that in Dr. Lowry's April 2007 testimony in California, Dr. Lowry reported that the average annual growth in TFP during 1994 to 2004 was 0.63%. In Dr. Lowry's June 2007 Ontario report he reported an average annual growth rate in TFP for that same time period for the U.S. sample as 1.18%.

(a) Please explain the reasons for the different growth rates in the annual TFP between Dr. Lowry's April, 2007 testimony and the June, 2007 report.

43. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 14 of 24
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

Dr. Carpenter states that PEG's Ontario model can only be considered robust and unbiased if it includes all of the variables that explain Gas Distribution Costs, and that one of those variables is Customer Density.

(a) Does PEG agree with this statement? If not, why not?

(b) Does PEG's Ontario model take into consideration Customer Density? If not, why not?

44. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 18 of 24
Issue No.: 3.1
Issue: How should the X factor be determined

Dr. Carpenter states that PEG's reasoning that the prospects for the realization incremental scale economies by EGD is inversely related to initial operating scale is faulty. Dr. Carpenter states that at some point scale economies will plateau or be exhausted, particularly when incremental customers and volumes require the construction of greater miles of new distribution main per customer. Does PEG agree with these assertions? If not, why not?

45. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 18 of 24

Issue No.: **3.1**
Issue: **How should the X factor be determined?**

Dr. Carpenter states that number of customers is by far the single most important determinate of costs in PEG's model, and that under PEG's reasoning the positive and significant quadratic number of customers variable should lead to an opposite conclusion regarding the ability of companies the size of EGD to realize future scale economies. Does PEG agree with this assertion? If not, why not?

46. Reference: **EGD Evidence, Ex.B, Tab 3, Schedule 2, page 19 of 24**
Issue No.: **3.1**
Issue: **How should the X factor be determined?**

Dr. Carpenter states that PEG does not appear to have considered a Northeast Regional approach to its econometric model, even though that was the approach PEG took in the model's estimation for Boston gas in 2003.

(a) Did PEG consider a Northeast Regional approach to its econometric model? If not, why not?

(b) If PEG did consider this approach, did it apply any regional dummy variables to test for Northeast Regional effects? If not, why not?

(c) If the answer to (b) is no, please explain why PEG employed a dummy variable in the sample utilities located in the Northeast U.S. in its models estimation for Boston gas in 2003, but has not done so in Ontario in 2007.

47. Reference: **EGD Evidence, Ex.B, Tab 3, Schedule 2, page 21 of 24**
Issue No.: **3.1**
Issue: **How should the X factor be determined**

In addressing EGD's cast iron replacement program, Dr. Carpenter alleges that it is "patently unreasonable" for PEG to reject any adjustment for a known and important cost driver over the plan for EGD on the basis of "a statistically unconfirmed null hypothesis" associated with sample data that may not even reflect such programs.

(a) Is PEG aware of any U.S. utilities where an adjustment for a cast iron main replacement program has been incorporated into a PCI or RCI? If yes, please provide details.

(b) Please provide PEG's response to the allegation that it is patently unreasonable to reject any adjustment for a known and important cost driver over the plan period for EGD.

48. Reference: **EGD Evidence, Ex.B, Tab 3, Schedule 3, page 5 of 64**
Issue Nos.: **3.1 and 13.1**
Issue: **3.1 How should the X factor be determined?**
13.1 What information should the Board consider and stakeholders be provided with at the time of rebasing?

Dr. Bernstein states that since the IR Plan under the OEB involves price rebasing at the end of the IR plan, it is redundant to include a positive stretch factor. Does PEG agree with this statement? If not, why not?

49. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 12 of 64
Issue No.: 3.1
Issue: How should the X factor be determined?

Dr. Bernstein states that omitting an X factor component designed to measure future changes in infrastructure expenditures that differ from past trends will lead to an incorrect X factor.

(a) Does PEG agree with this statement? If not, why not?

(b) In PEG's view, if X factors should be designed to measure future infrastructure expenditures, then should X factors also measure all other non-infrastructure-related future changes? Please explain.

50. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 22 of 64
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

Dr. Bernstein states that PEG's AU effect does not in fact account for the prevailing and prospective declines in service usage, which differ from past trends. As a consequence, the PCI and RCI developed by PEG are deficient. Does PEG agree with this conclusion? If not, why not?

51. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 23 of 64
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

Dr. Bernstein states that since future prices will be rebased at the end of the forthcoming IR period, that rebasing procedure transfers productivity improvements to consumers and eviscerates the rationale for a stretch factor. Does PEG agree with this proposition? If not, why not?

52. Reference: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 27 of 64
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

Dr. Bernstein states that PEG's analysis and calculation of its specific X factors must be rejected on the basis of its arbitrary calculation and flawed analytical development. Does PEG agree that its calculation of the service specific X factors were arbitrary and were flawed? If not, why not?

53. **Reference:** **EGD Evidence, Ex.B, Tab 3, Schedule 3, page 29 of 64**
Issue No.: **4.1**
Issue: **Is it appropriate to include the impact of changes in average use in the annual adjustment?**

Dr. Bernstein states that the sample period for the IPD component differs from the PD component of PEG's analysis. Dr. Bernstein states that this is inconsistent and could lead to sample "cherry picking". Does PEG agree? If not, why not?

54. **Reference:** **EGD Evidence, Ex.B, Tab 3, Schedules 1, 2 and 3**
Issue No.: **3.1**
Issue: **How should the X factor be determined?**

Does the evidence provided by EGD with respect to the X factor change PEG's opinion on the PCI or RCI set out in the PEG Report?

TransCanada PipeLines Limited
Canadian Mainline
NEB Quarterly Surveillance Report

For the Year Ended December 31, 2006

The NEB Quarterly Surveillance Report is a special purpose financial summary intended for the use of the National Energy Board and its staff. The Report is provided to enable the Board to monitor the Company's utility operations in comparison with the revenues and expenditures approved for the test year.

Pursuant to Guide BB of the Board's Filing Manual TransCanada submits its year end report for 2006.

The report has been prepared assuming final tolls for 2006 pursuant to Board Order TG-05-2006.

CONTENTS

TransCanada PipeLines Limited
Canadian Mainline
INCOME SUMMARY
For the Year Ended December 31, 2006
($000)

Schedule 1.0

Line No.	Particulars	NEB Accounts	Period Actual	Decision	Variance (c) - (d)	Note
	(a)	(b)	(c)	(d)	(e)	
	Revenues					
1	Net Revenues (Schedule 1.1)		1,824,080	1,824,080	0	
2	Amortization of 2006 Revenue Surplus		13,207	13,207	0	
3	Net Revenues		1,837,287	1,837,287	0	
4	Return on Rate Base Deferral		(2,640)	0	(2,640)	(1)
5	TCPL Share - Performance Incentive Envelope	301	9,540	0	9,540	(2)
6	TCPL Share - Interest Rate Management Program	301	2,723	0	2,723	(3)
7	Net Revenue Including Deferred Items		1,846,910	1,837,287	9,623	
	Operating Expenses					
8	Compensation (Schedule 4; Line 15)	301	75,843	n/a	n/a	
9	Other Operations, Maintenance & Administrative	301/302	98,358	174,163	n/a	
10	OM&A Equalization	301/302	0	0	0	
11	OM&A	301/302	174,201	174,163	38	
12	Compressor Repair and Overhaul	301/302	38,711	38,711	0	
13	Regulatory Proceeding Costs	301	1,000	1,000	0	
14	Pipe Integrity and Insurance Deductible	301	31,804	31,804	0	
15	Transmission by Others	301	313,553	313,553	0	
16	Electric Costs & Tax on Fuel	301	91,604	91,604	0	
17	Storage Operating Costs	301	13,970	13,970	0	
18	NEB Cost Recovery	301	10,719	10,719	0	
19	Depreciation	303/304	402,339	402,339	0	
20	Municipal & Provincial Capital Tax	305	123,839	123,839	0	
21	Regulatory Amortizations	301	(198,981)	(198,981)	0	
22	Performance Incentive Envelope	301	7,500	7,500	0	
23	Income Taxes	306	189,953	189,573	380	
24	Total Operating Expenses		1,200,212	1,199,794	418	
25	Operating Income		646,698	637,493	9,205	
26	Financial Charges	320-323	408,650	399,456	9,194	(4)
27	**Net Income Applicable to Common Equity**		238,049	238,037	11	
28	Rate Base		7,416,512	7,438,655	(22,143)	
29	Return on Rate Base		8.72%	8.57%		
30	Return on Common Equity		8.92%	8.88%		

Note:

(1) Lower average rate base is primarily due to the actual 2006 opening GPIS balance being lower than the forecast opening GPIS reflected in the Decision.

(2) TCPL's share of the Performance Incentive Envelope determined in accordance with Appendix "D" of the 2006 Tolls Settlement. (See Schedule 11.0)

(3) TCPL's share of the enduring Interest Rate Management Program. (See Schedule 9.0)

(4) Interest costs on long-term debt are higher than the amount included in tolls principally as a result of a prefunded capital structure.

TransCanada PipeLines Limited
Canadian Mainline
SUMMARY OF REVENUE BY CLASS OF SERVICE
For the Year Ended December 31, 2006
($000)

Line No.	Particulars	Period Actual	Decision	Variance (b) - (c)
	(a)	(b)	(c)	(d)
	Transportation Service			
1	Firm Service	1,532,704	1,528,298	4,406
2	Firm Transportation - Non Renewable	2,357	2,370	(13)
3	Energy Deficient Gas Allowance	340	0	340
4	Sales Meter Station Charges	65	75	(10)
5	Diversion	35,976	13,000	22,976
6	Short Term Firm Transportation	158,847	72,200	86,647
7	Storage Transportation Service	32,882	32,998	(116)
8	STS Overrun	252	1,000	(748)
9	Interruptible Service	199,049	278,000	(78,951)
10	Interruptible Backhaul	1,247	1,500	(253)
11	Parking and Loan Service	717	1,800	(1,083)
12	Balancing Fees	1,381	2,500	(1,119)
13	FT RAM Credit	(165,107)	(130,000)	(35,107)
14	Total Transportation	1,800,710	1,803,741	(3,031)
	Other Operating Revenue			
15	Delivery Pressure Charge	25,365	20,339	5,026
16	Total Revenue	1,826,075	1,824,080	1,995
	Deferred Revenues			
17	Firm Service	(4,407)	0	(4,407)
18	Discretionary	7,638	0	7,638
19	Non-discretionary	(5,226)	0	(5,226)
20	Total Deferred Revenues	(1,995)	0	(1,995)
21	Net Revenues	1,824,080	1,824,080	0

TransCanada PipeLines Limited
Canadian Mainline
AVERAGE PIPELINE RATE BASE
For the Year Ended December 31, 2006
($000)

Line No.	Particulars	Period Actual	Decision	Variance (b) - (c)	Note
	(a)	(b)	(c)	(d)	
	Utility Investment				
1	Net Plant	7,350,560	7,376,777	(26,217)	(1)
2	Contributions in Aid of Construction	(21,804)	(21,804)	0	
3	Total Plant	7,328,756	7,354,973	(26,217)	
	Working Capital				
4	Cash	22,157	19,949	2,208	(2)
5	Goods & Services Tax , Net	(7,298)	(5,036)	(2,262)	(3)
6	Materials and Supplies	27,087	26,574	513	
7	Transmission Linepack	42,962	42,834	128	
8	Storage Gas	12,543	12,543	0	
9	Prepayments and Deposits	1,223	1,920	(697)	
10	Total Working Capital	98,674	98,784	(110)	
	Deferrals				
11	Miscellaneous Deferred Items	32,411	32,431	(20)	
12	Operating and Debt Service Deferrals	(94,535)	(96,216)	1,681	(4)
13	Surplus Pension/Post Employment Benefits	51,206	48,683	2,523	(5)
14	Total Deferrals	(10,918)	(15,102)	4,184	
15	**TOTAL RATE BASE**	7,416,512	7,438,655	(22,143)	

Note:

(1) Variance is primarily due to the actual 2006 opening GPIS balance being lower than the forecast opening GPIS reflected in the Decision.

(2) Cash working capital is higher than the decision amount primarily due to increased pipe integrity and repair and overhaul costs.

(3) Net GST variance is due to higher GST payments related to increased revenues.

(4) The operating deferral component of rate base was fixed in accordance with the 2006 Tolls Settlement. The variance is a result of reflecting the actual operating deferral component.

(5) Variance is due to higher pension funding requirement.

TransCanada PipeLines Limited
Canadian Mainline
THROUGHPUT DETAIL
For the Year Ended December 31, 2006
(TJ)

Line No.	Particulars	Period Actual	Decision	Variance (b) - (c)	% Variance	Note
	(a)	(b)	(c)	(d)		
	CANADIAN SERVICE					
	Firm Service					
1	Firm Service	1 047 382	1 291 067	(243 685)	(19)	(1)
	Discretionary Services					
2	Diversion	76 623	50 487	26 136	52	(1)
3	Short Term Firm Service	165 155	57 090	108 065	189	(1)
4	Interruptible Service	326 556	310 763	15 793	5	(1)
	Non-Discretionary					
5	Storage Transportation Service	63 540	85 279	(21 739)	(25)	(2)
6	Total Canadian	1 679 256	1 794 686	(115 430)		
	EXPORT SERVICE					
	Firm Service					
7	Firm Service	863 018	1 030 807	(167 789)	(16)	(1)
	Discretionary Services					
8	Diversion	87 077	68 189	18 888	28	(1)
9	Short Term Firm Service	120 188	51 050	69 138	135	(1)
10	Interruptible Service	355 313	256 371	98 942	39	(1)
	Non-Discretionary					
11	Storage Transportation Service	3 143	2 304	839	36	(2)
12	Firm Transportation - Non Renewable	17 724	19 760	(2 036)	(10)	(3)
13	Total Export	1 446 463	1 428 481	17 982	1	
14	**TOTAL THROUGHPUT**	3 125 719	3 223 167	(97 448)	(3)	

Note:

(1) Throughput associated with FT commodity and discretionary services are dependent on customer contracting behaviours which are not easily predictable and therefore can show variances from original estimates.

(2) Decrease in domestic STS commodity volumes is primarily due to lower deliveries to Gaz Metro - East and Centra Gas - Manitoba. Increase in export STS commodity volumes is a result of higher deliveries to Philipsburg and Cornwall.

(3) Decrease in FT-NR commodity volumes as a result of a lower load factor for deliveries than in the Decision.

TransCanada PipeLines Limited
Canadian Mainline
THROUGHPUT DETAIL
For the Year Ended December 31, 2006
(TJ)

Line No.	Particulars	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
	CANADIAN SERVICE														
1	Firm Service	102 580	92 830	94 440	80 240	83 422	78 122	78 976	81 624	79 425	85 259	93 062	97 402	1 047 382	
2	Diversion	6 100	5 283	6 990	11 799	10 784	5 209	4 394	6 220	4 668	3 496	4,115	7,565	76 623	
3	Short Term Firm Service	20 587	17 685	18 867	21 134	18 362	19 425	14 885	8 044	9 821	8 383	3,591	4,371	165 155	
4	Storage Transportation Service	13 055	15 361	10 497	2 561	1 451	647	1 188	1 431	806	3 504	5,797	7,242	63 540	
5	Interruptible Service	31 053	29 378	30 817	11 803	22 267	30 779	25 501	18 919	30 072	33 102	30,004	32,861	326 556	
6	Total Canadian	173 375	160 537	161 611	127 537	136 286	134 182	124 944	116 238	124 792	133,744	136,569	149,441	1 679 256	
	EXPORT SERVICE														
7	Firm Service	75 848	71 139	77 023	70 044	70 259	72 876	78 311	75 256	65 761	68 117	67 859	70 525	863 018	
8	Diversion	7 859	7 432	9 524	5 750	5 034	7 943	9 484	8 913	7 490	6,060	5,113	6,475	87 077	
9	Short Term Firm Service	19 812	15 503	15 778	17 875	22 025	5 399	3 692	8 274	4 918	3,107	993	2,812	120 188	
10	Storage Transportation Service	613	942	822	117	4	0	5	18	12	148	119	343	3 143	
11	Firm Transportation - Non Renewable	1 668	1 551	1 616	1 736	1 910	1 769	1 822	1 949	1 804	1,899	-	-	17 724	
12	Interruptible Service	23 643	24 714	26 920	22 203	18 408	24 986	25 371	27 385	25 731	42,250	44,408	49,294	355 313	
13	Total Export	129 443	121 281	131 683	117 725	117 640	112 973	118 685	121 795	105 716	121,581	118,492	129,449	1 446 463	
14	**TOTAL THROUGHPUT**	302 818	281 818	293 294	245 262	253 926	247 155	243 629	238 033	230 508	255,325	255,061	278,890	3 125 719	(1)

Note:

(1) Based on volumes invoiced by class of service.

TransCanada PipeLines Limited
Canadian Mainline
PAYROLL STATISTICS
TOTAL COMPENSATION AND EMPLOYEE BENEFITS (1)
For the Year Ended December 31, 2006
($000)

Line No.	Particulars (a)	Period Actual (b)
	SALARIES	
1	Field Operations	41,168
2	Engineering	17,974
3	Operations & Engineering Support	17,546
4	Commercial & Regulatory	24,860
5	Business Services	38,060
6	Information Systems	20,423
7	Total Regular Salaries (2)	160,031
8	Ancillary & Other	12,018
9	Total Gross Salaries	172,049
	ALLOCATED MAINLINE	
10	Base Salaries	55,282
11	Ancillary & Other	4,392
12	Charged to Construction & Other (3)	(14,537)
13	Net Salaries	45,137
14	Incentive Compensation (Short and Long Term)	30,706
15	Total Compensation	75,843
	EMPLOYEE BENEFITS	
16	Actuarial Pension Plan & Retiree Expenses	35,360
17	Pension & Benefit Plan Administration	2,741
18	Provincial Health Insurance	1,664
19	Employee Insurance & Savings Plan	12,702
20	Workers' Compensation	198
21	Employment Insurance, CPP, QPP	5,463
22	Other Benefits	1,750
23	GROSS BENEFITS	59,878
	ALLOCATED MAINLINE	
24	Mainline Base Salaries (per line 10)	55,282
25	Benefits Applied at Standard Rate (38%)	21,011
26	Pension/Benefit Adjustment	(294)
27	Total Benefits	20,717

Note:

(1) Compensation and benefits information was not specified in the $174.2 million aggregate OM&A amount approved in the 2006 Tolls Settlement. Therefore, variances between actual results and the 2006 Tolls Settlement cannot be determined.

(2) Consists of salaries related to the Mainline, Alberta System, BC System, Foothills Sytem as well as TransCanada's Corporate areas.

(3) Salaries are charged to Construction & Other at standard labour rates that include a benefit component.

TransCanada PipeLines Limited
Canadian Mainline
PAYROLL STATISTICS
AVERAGE EMPLOYEE ALLOCATION [1]
For the Year Ended December 31, 2006

Line No.	Particulars	Actual
	(a)	(b)
1	Total Employees [2]	1,808
	Less:	
2	Charged to Non-Mainline	1,160
3	Allocated Mainline Employees	648
4	Charged to Mainline Construction and Other	128
5	Employees Charged to OM&A	520

Note:

(1) Average employee allocation information is implicit in the fixed OM&A amount approved in the 2006 Tolls Settlement. Therefore, Decision amounts and corresponding variances cannot be determined.

(2) Consists of employees related to the Mainline, Alberta System, BC System, Foothills System as well as TransCanada's Corporate areas.

TransCanada PipeLines Limited
Canadian Mainline
DEFERRED BALANCES
For the Year Ended December 31, 2006
($000)

Line No.	Particulars	Period Actual
	(a)	(b)
	Flow-Through Deferrals	
	Cost Deferrals	
1	TBO Costs	(23,198)
2	Storage Operating Costs	(167)
3	Pipeline Integrity and Insurance Deductible	13,783
4	NEB Cost Recovery	(950)
5	Return on Rate Base	(2,751)
6	Income Taxes	(11,376)
7	Depreciation Expense	(709)
8	Gas Related and Electric Costs	(3,441)
9	Municipal and Other Tax	(5,195)
10	Performance Incentive Envelope	(7,829)
11	Compressor Repair & Overhaul	7,643
12	Regulatory Proceedings Costs	753
13	Total Cost Deferrals	(33,437)
	Revenues	
14	Firm Service	(4,564)
15	Discretionary	5,934
16	Non - Discretionary	(5,415)
17	Total Revenue Deferrals	(4,045)
	Other	
18	Foreign Exchange on U.S. $ Debt Interest	(3,172)
19	Foreign Exchange on U.K. £ Debt Interest	(1,060)
20	Total Other Flow-Through Items	(4,232)
21	Total Flow-Through Deferrals	(41,714)
	Incentive-Based Deferrals	
22	Interest Rate Management Program	(2,768)
23	Performance Incentive Envelope	9,803
24	Total Incentive-Based Deferrals	7,035
25	2006 Surplus Variance	(2,987)
26	2005 Regulatory Amortization Balance	1,681
27	Total Deferred Balances (1)	(35,985)

Note:

(1) Balances include carrying charges.

TransCanada PipeLines Limited
Canadian Mainline
PERFORMANCE MEASURES
(2002 - 2006)

Ln. No.	Description	2002	2003	2004	2005	2006
1	Revenue Requirement/Throughput-km ($/$10^6m^3$-km)	$12.98	$14.31	$15.24	$12.58	$10.88
2(a)	Total Operating Expenses (Excluding Inc. Taxes)/Throughput-km ($/$10^6m^3$-km) (1)	$6.89	$7.94	$8.39	$6.45	$6.06
2(b)	Selected Operating Expenses (Excluding Inc. Taxes)/Throughput-km ($$10^6m^3$-km) (2)	$5.59	$6.45	$7.17	$5.46	$5.02
3(a)	Total Operating Expenses (Excluding Inc. Taxes)/Gross Plant (%)	8.99%	9.83%	9.48%	8.73%	8.21%
3(b)	Selected Operating Expenses (Excluding Inc. Taxes)/Gross Plant (%)	7.30%	7.98%	8.10%	7.40%	6.80%
4	Admin. and General Expenses/Employee ($)	$166,195	$166,532	$182,735	$191,803	$208,720
5	Admin. and General Expenses/Throughput km ($/$10^6m^3$-km)	$0.83	$0.89	$0.91	$0.73	$0.81
6	Net Plant /Throughput km ($/$10^6m^3$-km)	$54.06	$54.99	$57.62	$46.01	$43.86
7	Throughput-km/Employee (10^6m^3-km)	199,075	187,559	201,739	263,579	258,620
8	Average Salary/Employee ($) (3)	$75,788	$78,930	$82,017	$85,191	$88,513
9	Employee Benefits/Employee ($) (3)	$22,425	$28,020	$30,920	$32,142	$33,122
	Statistics - Rate of Return on Common Equity & Rate Base					
10	Actual Rate of Return on Common Equity	9.95%	10.18%	9.83%	9.66%	8.92%
11	Approved Rate of Return on Common Equity	9.53%	9.79%	9.56%	9.46%	8.88%
12	Actual Rate of Return on Rate Base	9.46%	9.40%	9.25%	8.99%	8.72%
13	Approved Rate of Return on Rate Base	9.27%	9.28%	8.97%	8.90%	8.57%

Note:

(1) Total operating expenses (excluding income taxes) including amounts which the Company may influence.

(2) Selected operating expenses (excluding income taxes) over which the Company has little influence.

(3) Average salary and associated benefits for a TransCanada employee.

TransCanada PipeLines Limited
Canadian Mainline
INTERCORPORATE TRANSACTIONS
For the Year Ended December 31, 2006

- Summary Receipts -

Contracting Party	Nature of Service	($000)	Ref. Sch.#
TransCanada Calibrations	Lease Agreement	366	8.2
Total		**366**	

TransCanada PipeLines Limited
Canadian Mainline
INTERCORPORATE TRANSACTIONS
For the Year Ended December 31, 2006

- Summary Payments -

Contracting Party	Nature of Service	($000)	Ref. Sch.#
Great Lakes Gas Transmission Company	Gas Transportation	171,265	8.3
Trans Quebec & Maritimes Pipeline Inc.	Gas Transportation	79,757	8.3
NOVA Gas Transmission Ltd. (NGTL)	Gas Balancing	1,000	8.3
TransCanada Energy Ltd.	Purchase of Electricity, Construction and Linepack Gas	68,338	8.3
TransCanada Turbines	Repair and Overhaul	15,246	8.3
TransCanada Calibrations	System Maintenance	218	8.3
Total		**335,824**	

TransCanada PipeLines Limited
Canadian Mainline
INTERCORPORATE TRANSACTIONS
For the Year Ended December 31, 2006
($000)

- Receipts -

Contracting Party: TransCanada Calibrations

Nature Of Service: Lease Agreement

Description: Rent, electricity, warehouse costs charged to TransCanada Calibrations for usage of property and warehouse space at Station 41.

	Lease Agreement
Amount	366

TransCanada PipeLines Limited
Canadian Mainline
INTERCORPORATE TRANSACTIONS
For the Year Ended December 31, 2006
($000)

- Payments -

Contracting Parties: Great Lakes Gas Transmission Company (GLGT)

Nature Of Service: Gas Transportation

Description: Transportation services associated with the movement of gas on the GLGT system, billed in accordance with GLGT tolls

	Gas Transportation
Amount	171,265

Contracting Parties: Trans Quebec & Maritimes Pipeline Inc. (TQM)

Nature Of Service: Gas Transportation

Description: Transportation services associated with the movement of gas on the TQM system, billed in accordance with TQM tolls

	Gas Transportation
Amount	79,757

Contracting Parties: NOVA Gas Transmission Ltd. (NGTL)

Nature Of Service: Gas Balancing

Description: TransCanada Mainline has a Gas Balancing Agreement with NGTL to accommodate upstream storage.

	Gas Balancing
Amount	1,000

Contracting Parties: TransCanada Energy Ltd.

Nature Of Service: Purchase of Electricity, Construction and Linepack Gas

Description: Purchase of electricity to power compressor units and provide auxiliary power for compressor stations and purchase of construction and linepack gas.

	Purchase of Electricity	Purchase of Construction Gas	Purchase of Linepack Gas
Amount	67,517	267	554

Contracting Parties: TransCanada Turbines

Nature Of Service: Repair and Overhaul

Description: Repair and Overhaul of Compressor Units

	Repair and Overhaul
Amount	15,246

Contracting Parties: TransCanada Calibrations

Nature Of Service: System Maintenance

Description: System Maintenance

	System Maintenance
Amount	218

TransCanada PipeLines Limited
Canadian Mainline
INTEREST RATE MANAGEMENT PROGRAM
For the Year Ended December 31, 2006
($000)

Line No.	Particulars	Payable	Receivable	(Gain)/Loss
	(a)	(b)	(c)	(d)
1	Swaps	24,509	(29,954)	(5,445)
2	Premium on Swaptions	0	0	0
3	Total Gains	24,509	(29,954)	(5,445)
4	Incentive Based Deferred Amount @ 50%			(2,723)

TransCanada PipeLines Limited
Canadian Mainline
FUEL GAS INCENTIVE PROGRAM
For the Year Ended December 31, 2006

Line No.	Particulars	Winter Season Ended March 31, 2006 Amount ($10^6m^3/d$)	Summer Season Ended October 31, 2006 Amount ($10^6m^3/d$)
	(a)	(b)	(c)
	Actual Flows		
1	Actual Prairies Line Flow	190.76	168.74
2	Actual Northern Ontario Line Flow	103.66	93.81
	Target Fuel		
3	Actual Prairies Fuel Volume	3.144	2.214
4	Actual Northern Ontario Fuel Volume	3.664	3.052
5	Total Actual Fuel Volume	6.808	5.266
	Average Seasonal Fuel Savings		
6	Prairies Line	(0.074)	(0.011)
7	Northern Ontario Line	(0.144)	(0.179)
8	Fuel Volume Savings (Line 6 + Line 7)	(0.218)	(0.190)
		Amount ($000)	Amount ($000)
9	Seasonal Incentive Amount	0	0

TransCanada PipeLines Limited
Canadian Mainline
PERFORMANCE INCENTIVE ENVELOPE (PIE)
For the Year Ended December 31, 2006
($000)

Line No.	Particulars	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Fuel Ratio Accuracy and Timliness Incentive Program (FRATI)											
	Part A - Consumed Fuel Forecast											
1	Forecast Consumed Eastern Zone Fuel Ratio (%)	6.15%	5.29%	5.73%	7.11%	6.84%	5.24%	5.05%	5.25%	4.76%	4.84%	
2	Estimated Actual Consumed Eastern Zone Fuel Ratio (%)	6.20%	7.19%	6.64%	6.07%	5.32%	5.68%	5.10%	5.08%	4.18%	4.54%	
3	Difference (%)	0.05%	1.90%	0.91%	-1.04%	-1.52%	0.44%	0.05%	-0.17%	-0.58%	-0.30%	
4	TransCanada Incentive Payment	400	-	-	-	-	60	400	330	-	200	1,390
5	Bonus Payment	-	-	-	-	-	-	-	-	-	-	-
	Part B - Posted Fuel Forecast											
6	Posted Seasonal Eastern Zone Fuel Ratio (%)	7.86%	5.20%	5.40%	6.00%	6.00%	5.80%	6.50%	6.90%	4.70%	5.00%	
7	Posted Monthly Eastern Zone Fuel Ratio (%)	5.53%	5.01%	5.48%	7.00%	6.20%	5.10%	4.50%	4.90%	4.55%	4.80%	
8	Difference (%)	-2.33%	-0.19%	0.08%	1.00%	0.20%	-0.70%	-2.00%	-2.00%	-0.15%	-0.20%	
9	TransCanada Incentive Payment	-	400	400	-	400	-	-	-	400	400	2,000
10	Bonus Payment	-	-	-	-	-	-	-	-	-	-	-
11	Gross-Up Factor (12/10)	80	80	80	-	80	12	80	66	80	120	678
12	**TOTAL FRATI**	**480**	**480**	**480**	**-**	**480**	**72**	**480**	**396**	**480**	**720**	**4,068**
	GLGT TBO Management Incentive Program											
	Long-Term Releases Incentive Program											
13	Long Term Net TBO Cost Savings	86	1,097	549	301	477	1,084	942	672	1,014	1,330	7,553
14	TransCanada Incentive Payment (30%)	26	329	165	90	143	325	283	202	305	399	2,266
	Short-Term Releases Incentive Program											
15	Short Term Net TBO Cost Savings	491	0	0	27	30	0	3	177	319	83	1,130
16	TransCanada Incentive Payment (50%)	246	0	0	13	15	0	1	88	159	41	565
17	Marketing/Backstopping Costs			(11)			(1)	(23)				(35)
18	Gross-Up Factor (12/10)	54	66	31	21	32	65	52	58	93	88	560
19	**TOTAL GLGT TBO Management Incentive Program**	**326**	**395**	**185**	**124**	**190**	**389**	**313**	**348**	**557**	**529**	**3,356**
	Leak Detection and Repair Incentive Program (LDAR)											
20	Gas Emissions Saved (GJ/year)	32,093	44,698	154,324	115,028	1,695	4,343	0	9,533	21	0	361,735
21	TransCanada Incentive Payment											309
22	Gross-Up Factor (12/10)											62
23	**TOTAL LDAR Incentive Program**											**371**
	Municipal and Provincial Capital Tax Incentive Program											
24	Municipal and Provincial Capital Tax (2006 Actual)											118,990
25	Municipal and Provincial Capital Tax (2006 Tolls)											123,839
26	Variance											(4,849)
27	TransCanada Incentive Payment (30%)											1,455
28	Gross-Up Factor (12/10)											290
29	**TOTAL Municipal and Provincial Capital Tax Incentive Program**											**1,745**
30	**TOTAL TCPL Share - Performance Incentive Envelope**											**9,540**