Ontario

EB-2011-0354

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 Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

DECISION ON SETTLEMENT AGREEMENT AND PROCEDURAL ORDER NO. 5

October 15, 2012

Enbridge Gas Distribution Inc. ("Enbridge") filed an application on January 31, 2012 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.The Board assigned file number EB-2011-0354 to the application and issued a Notice of Application dated March 2, 2012 (the "Notice"). The application was filed on the basis of US Generally Accepted Accounting Principles.

The Board issued its Decision on Preliminary Issue and Procedural Order No. 2 on May 16, 2012 which provided for, among other things, a settlement conference to be held between September 11 and 21, 2012. The Board directed that any settlement proposal arising from the settlement conference be filed on September 28, 2012. The Board is in receipt of a settlement agreement dated October 3, 2012 (the “Settlement Agreement”). The Settlement Agreement is attached as Appendix “A”.

The Settlement Agreement

The Board has reviewed the Settlement Agreement and notes that all of the issues have been completely settled, with the exception of the following:

- Issue D11 [Partial Settlement]
  Is the proposal for the Open Bill Access Program appropriate?

- Issue E1 [Partial Settlement]
  Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

- Issue E2 [No Settlement]
  Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

The Settlement Agreement states that Issue E2 is expected to proceed to hearing and that parties may take a position on Issue E1 when Issue E2 is considered by the Board.

The Board notes that the partial settlement of the Open Bill matter (Issue D11) includes a commitment to advise the Board of any resolution of the contract terms in the Open Bill Agreement by the end of October. The partial settlement on Issue D11 also includes an agreement to form a consultative group by November 15, 2012 to consider the proposal for an on-bill financing program for DSM measures.

The Board has considered the Settlement Agreement and accepts it with the exception of one settled item which is the matter of the Pension True-up Variance Account (the “PTUVA”). The settlement of Issue D1, “Is the 2013 O&M budget appropriate?” includes a description of the creation of a new variance account that would allow Enbridge to recover its actual pension costs in 2013 and in successive years. The Board will accept the establishment of the PTUVA for 2013, but does not accept the account’s on-going nature as described in the settlement. The matter of pension recoverability has broad implications and therefore the Board is not prepared at this time to approve on-going recoverability on the basis of a negotiated settlement. The Board is prepared to accept the settlement of Issue D1 provided that the wording in the paragraphs that relate to the future recoverability of pension costs beyond 2013 is struck as provided in the revised paragraphs attached as Appendix “B”.

If the parties agree to continue the settlement with the revised wording on Issue D1, the Board directs Enbridge to file a revised settlement agreement incorporating the new wording relating to the PTUVA by October 26, 2012. If the parties do not agree or consider that there should be other changes to the Settlement Agreement as filed, the Board directs Enbridge to advise the Board by October 26, 2012.

The Board notes that the Settlement Agreement proposes that interim rates be established for January 1, 2013 on the basis that final rates would be set once the Board hears and determines cost of debt and capital structure issues (Issues E1 and E2). The Settlement Agreement refers to a Draft Rate Order (the “Draft Rate Order”) for circulation by October 26, 2012 with comments from parties to be provided on November 7, 2012. The Board will consider the appropriateness of the Draft Rate Order with a view to issuing an Interim Rate Order to allow for new rates commencing January 1, 2013.

Experts’ Conference

The Board has determined that it will require the experts for all parties to participate in an expert pre-hearing conference (the “Experts’ Conference”) in accordance with section 13A of the Board’s *Rules of Practice and Procedure* (the “Rules”). The Experts’ Conference will be focussed on Enbridge’s request to increase the equity component of its capital structure from its existing level of 36% to 42%. The testimony relevant to this matter is that of Concentric Energy Advisors who prepared evidence for Enbridge, and Dr. Laurence Booth, who prepared evidence for the Canadian Manufacturers and Exporters (CME), the Consumers Council of Canada (CCC), the School Energy Coalition (SEC) and the Vulnerable Energy Consumers Coalition (VECC) (collectively, the “Consortium”).

The purpose of the Experts’ Conference is to identify, scope, and narrow the relevant issues and sub-issues, identify the points on which the views of the experts differ and are in agreement, and prepare a joint written statement to be filed as evidence at the oral hearing of this matter (the "Joint Written Statement").

The Board will restrict attendance at the Experts' Conference to the expert witnesses (Jim Coyne and Julie Lieberman of Concentric Energy Advisors, and Dr. Laurence Booth), one legal counsel representing Enbridge, one legal counsel representing the Consortium, a facilitator (including any support staff of the facilitator) retained by Board staff to facilitate the conference and to assist the experts in reaching the objectives of the conference, and Board staff. The Board wishes to advise counsel to Enbridge and to the Consortium that their participation is to be limited to ensuring that the objectives of scoping and narrowing the issues, and producing a joint statement of the experts, can be achieved.

The Joint Written Statement is required to outline the key issues, the points of agreement and disagreement on those issues, and the reasons for any disagreement. To assist with the Joint Written Statement, Board staff has attached at Appendix "C" a list of discussion points that should be considered by the experts at the start of the Experts' Conference. This list is intended to provide a starting point for discussions and may be modified in the Experts' Conference as necessary. For reference purposes only, the Board is also attaching at Appendix "D" an example of a previously filed joint written statement filed by experts following an Experts' Conference held in a different matter before this Board.

The Board will require a presentation of the Joint Written Statement at the oral hearing. At the hearing, the experts for both Enbridge and the Consortium will appear together as a concurrent expert witness panel for the purposes of answering questions from the Board and other parties, as may be permitted by the Board, and providing comments on the views of the other experts on the same panel.

As this is a new process at this Board, the Board is inviting all parties to file submissions with respect to the most appropriate procedure for the oral hearing of the concurrent expert witness panel in light of the objectives of the Board as expressed herein and in Rule 13A of the Board's Rules.

All previously announced hearing dates are hereby cancelled and replaced with the dates in this order.

THE BOARD ORDERS THAT:

1. An Experts' Conference will be convened at 9:00 a.m. on **October 22, 2012 and October 23, 2012** in the Board's offices at 2300 Yonge Street Toronto.

2. Enbridge shall file any revised Settlement Agreement by **October 26, 2012**.

3. The Joint Written Statement of the experts shall be filed with the Board and delivered to all parties on or before **October 31, 2012**.

4. Parties may file submissions with respect to process for the oral hearing of the evidence of the concurrent experts witness panel by **November 2, 2012**.

5. The oral hearing will commence at 9:30 a.m. in the Board's hearing room at 2300 Yonge Street Toronto on **November 19, 2012** and will continue on **November 20, 2012.**

6. An updated case timetable is attached as Appendix "E".

All filings to the Board must quote file number **EB-2011-0354**, be made through the Board's web portal at www.pes.ontarioenergyboard.ca.eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address, telephone number, fax number and e-mail address.

All filings shall use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca**.** If the web portal is not available the document may be emailed to BoardSec@ontarioenergyboard.ca. Persons who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Persons who do not have computer access are required to file seven paper copies. If a document has been submitted through the Board's web portal an e-mail is not required. For all electronic correspondence and materials related to this proceeding, parties must include in their distribution the Case Manager, Colin Schuch at colin.schuch@ontarioenergyboard.ca and Senior Legal Counsel, Kristi Sebalj at kristi.sebalj@ontarioenergyboard.ca.

All communications should be directed to the attention of the Board Secretary and be received no later than 4:45 p.m. on the required date.

ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON   M4P 1E4
Attention: Board Secretary

E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto October 15, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX "A"
Enbridge Gas Distribution Inc.

EB-2011-0354

Settlement Agreement

SETTLEMENT AGREEMENT

Enbridge Gas Distribution 2013 Rate Application

October 3, 2012

TABLE OF CONTENTS

PREAMBLE

This Settlement Agreement is filed with the Ontario Energy Board (the “OEB” or the “Board") in connection with the Application of Enbridge Gas Distribution Inc. (“Enbridge” or the “Company”), for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

In Procedural Order No. 2, the Board established the process to address the application, and in a Decision and Order dated June 15, 2012, the Board established the Issues List for this application.

A Settlement Conference was held between September 11 and 20, 2012. Ken Rosenberg acted as the OEB-appointed facilitator for the Settlement Conference. This Settlement Agreement arises from the Settlement Conference.

Enbridge and the following intervenors, as well as Ontario Energy Board technical staff (“Board Staff”), participated in the Settlement Conference:

ASSOCIATION OF POWER PRODUCERS OF ONTARIO (APPrO)
BUILDING OWNERS AND MANAGERS ASSOCIATION TORONTO (BOMA)
CANADIAN MANUFACTURERS & EXPORTERS (CME)
CONSUMERS COUNCIL OF CANADA (CCC)
DIRECT ENERGY MANAGEMENT LIMITED (Direct Energy)
ENERCARE INC. (EnerCare)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
FEDERATION OF RENTAL-HOUSING PROVIDERS OF ONTARIO (FRPO)
GREEN ENERGY COALITION (GEC)
HEATING, VENTILATION, AND AIR CONDITIONING COALITION (HVAC)
JUST ENERGY ONTARIO LP (Just Energy)
LOW-INCOME ENERGY NETWORK (LIEN)
POLLUTION PROBE (Pollution Probe)
SCHOOL ENERGY COALITION (SEC)
SUMMITT ENERGY (Summit)
VISTA CREDIT CORP. (Vista)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Agreement deals with all of the issues on the Issues List. Each of these issues from the Issues List is listed in the Table of Contents, above.

All intervenors listed above participated in part or all of the Settlement Conference and subsequent discussions. Certain of the intervenors participated only in the “open bill” issue (Issue D11) and not in discussions on any other issues. Those intervenors are referred to herein as the “open bill issue participants”. The “open bill issue participants” are Direct Energy, EnerCare, GEC, HVAC, Just Energy, LIEN, Pollution Probe, Summitt and Vista. (As noted in Issue D11, other intervenors also participated in Issue D11. Those other intervenors also participated in the other issues, and are therefore not listed as “open bill issue participants”.)

Any reference to "parties" in this Settlement Agreement is intended to refer to Enbridge and the intervenors listed above, with one exception. That exception relates to the fact that the "open bill issue participants" only participated in the negotiation of Issue D11, and did not participate in the negotiation of any other issue. Therefore, within the "Issues" section of this Settlement Agreement (Issues B1 to O6), references to "all parties" are intended to refer to Enbridge and all intervenors listed above, except for (and not including) the open bill issue participants. .

Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Agreement. Enbridge and all intervenors listed above have agreed to the settlement of the issues as described on the following pages. The open bill issue participants have only participated in the negotiation of Issue D11, and take no position on any other issue.

Best efforts have been made to identify all of the evidence that relates to each issue. The supporting evidence for each issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit B1, Tab 3, Schedule 1 is referred to as B1-3-1. The identification and listing of the evidence that relates to each settled issue is provided to assist the Board.

The Settlement Agreement describes the agreements reached on the issues. The Settlement Agreement provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties are of the view that the evidence provided is sufficient to support the Settlement Agreement in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board does not accept the proposed settlement of any issue, then subject to the parties' agreement on non-severability set out in the final paragraph below, further evidence may be required on the issue for the Board to consider it fully.

According to the Board's *Settlement Conference Guidelines* (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

None of the parties can withdraw from the Settlement Agreement except in accordance with Rule 32 of the *Ontario Energy Board Rules of Practice and Procedure*. Finally, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions parties might take with respect to the same issue in future proceedings, unless explicitly stated otherwise.

The parties agree that all positions, negotiations and discussion of any kind whatsoever that took place during the Settlement Conference and all documents exchanged during the conference that were prepared to facilitate settlement discussions are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Agreement.

It is fundamental to the agreement of the parties that none of the provisions of this Settlement Agreement are severable. If the Board does not, prior to the commencement of the hearing of the evidence in this proceeding, accept the provisions of the Settlement Agreement in their entirety, there is no Settlement Agreement (unless the parties agree that any portion of the Settlement Agreement that the Board does accept may continue as a valid Settlement Agreement).

OVERVIEW

Through the Settlement Conference, and as set out in this Settlement Agreement, the parties (except for the open bill issue participants, who take no position on any issue except for D11) have reached agreement on 53 of the 56 issues in Enbridge's 2013 rate rebasing application (referred to herein as the "Settled Issues").

The overall impact of the Settled Issues is to reduce the revenue deficiency from the as-filed amount of $92.9 million (Exhibit M2, Tab 1, Schedule 2) to an amount of approximately $17.9 million. The revenue requirement and deficiency impact of the Settled Issues are set out in the ADR Financial Statements attached to this Settlement Agreement as Appendix A (Exhibit N1, Tab1, Schedule 1, Appendix A, part 1).

As noted above, all parties agree that the Settled Issues are a package. This means that none of the components of the Settlement Agreement should be considered in isolation, but instead they should be considered as a complete package. All parties agree that the package of Settled Issues represents a fair and reasonable agreement that is in the public interest.

There are three outstanding issues (the "Unsettled Issues").

One of these Unsettled Issues, relating to the Open Bill Access Program (Issue D11), is listed as "Partially Settled" because the aspects of the issue with ratemaking implications are settled, while one aspect of the issue with no ratemaking impact remains unsettled (related to the terms of the Open Bill Agreement for 2013).

The other two Unsettled Issues, related to equity thickness and cost of capital under a new thickness (Issues E1 and E2), have a potential revenue deficiency impact of up to $21.9 million. This means that if Enbridge is successful in its request for an increase in equity thickness from the current 36% level to the requested 42% level, then the final 2013 revenue deficiency will be approximately $17.9 million. If Enbridge is not completely successful in this regard, then the 2013 revenue deficiency will be reduced by up to $21.9 million, depending on the level of equity thickness and associated capital structure approved by the Board.

All parties agree that Enbridge should implement interim rates on January 1, 2013 that reflect the impact of the Settled Issues. For the purpose of interim rate implementation, all parties have agreed that Enbridge will use the current level of equity thickness (36%). All parties agree that the agreement to use the current level of equity thickness (36%) and associated capital structure ratios for implementation of interim rates is not intended as an indication or suggestion to the Board that 36% is the appropriate level of equity thickness for Enbridge in 2013. That issue is to be determined by the Board based upon the evidence and argument presented.

The revenue requirement and deficiency impact of the agreement for interim rates is set out in the ADR Financial Statements attached to this Settlement Agreement as Appendix A (Exhibit N1, Tab1, Schedule 1, Appendix A, part 2). The overall result of the implementation of the Settled Issues is a revenue sufficiency of approximately $4.0 million (using the current 36% level of equity thickness). This Agreement also includes Appendix B (Gas Costs) and Appendix C (Average Use Forecasts). All of the Appendices are incorporated into and form part of this Settlement Agreement.

The Appendices were prepared by Enbridge for the assistance of the Board and the other parties. The parties to this Agreement, other than Enbridge, are relying on the accuracy and completeness of the Appendices in entering into this Settlement Agreement.

All parties agree that any financial impact of the determination of the Unsettled Issues (Issues E1 and E2) should be implemented as part of Enbridge's first QRAM Application following the Board's decision on those matters.

THE ISSUES

B: RATE BASE

1. Is Enbridge's forecast level of capital spending in 2013 appropriate?

[Complete Settlement]

All parties agree that Enbridge's capital budget for 2013 is appropriately set at $387 million. Amounts to be spent in relation to the GTA Reinforcement and Ottawa Reinforcement projects, which projects will be considered by the Board in separate Leave to Construct Applications, will, if approved, be in addition to the $387 million capital budget. Those two projects have no rate impact in 2013.

This 2013 capital budget is approximately $97 million less than the as-filed budget of $483.9 million, to take account of the assumed $46 million impact from the agreed-upon $23 million property, plant and equipment related reduction to 2013 rate base (set out in Issue B2 below), as well as the fact that the forecast $51 million to be spent in 2013 on the GTA and Ottawa Reinforcement projects (Exhibit B1, Tab 3, Schedule 3) is outside of the $387 million budget.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A2-1-2	Benchmarking Study
A2-2-1	2013 Regulatory Budget Assumptions and Guidelines Directive
B1-2-1	Rate Base – Capital Budget
B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000
B1-2-3	Comparison of Capital Expenditures 2007 to 2013
B1-3-1	Asset Plan
B1-3-2	Asset Plan and 2013 Capital Budget
B1-3-3	Leave to Construct Projects

B1-4-1	Information Technology Capital Budget
B1-5-1	Storage Capital Expenditure
B2-2-1	EGD Asset Plan 2012 to 2021
B3-2-1	Utility Capital Expenditures Comparison 2013 Test Year and 2012 Estimate
B3-2-2	2013 Capital Expenditures by Project (Projects Exceeding $500,000)
B3-2-4	System Expansion Monitoring - 2013 Test Year
B4-2-1	Utility Capital Expenditures Comparison 2012 Bridge Year and 2011 Historical Year
B4-2-2	2012 Capital Expenditures by Project (Projects Exceeding $500,000)
B4-2-4	System Expansion Monitoring - 2012 Bridge Year
B5-2-1	Utility Capital Expenditures Comparison 2011 Historic and 2007 Board Approved
B5-2-2	2011 Capital Expenditures by Project (Projects Exceeding $500,000)
B5-2-4	System Expansion Portfolio - 2011 Historic Year
I-B1-1.1 to 20.4	Interrogatories on Issue B1
I-B2-4.4 and 4.5	CME Interrogatories #4 and 5
I-B2-8.1	FRPO Interrogatory #1
I-B3-1.1 to 14.1	Interrogatories on Issue B3
I-B4-1.1 to 14.1	Interrogatories on Issue B4
I-B5-1.1 to 20.1	Interrogatories on Issue B5
I-B6-8.1 to 14.1	Interrogatories on Issue B6
I-B7-5.1 to 20.1	Interrogatories on Issue B7
I TR 5 to 80	Evidence at Technical Conference (September 5, 2012)
JT1.1 to 1.9	Undertakings from Technical Conference (September 5, 2012)

2. Is the proposed Test Year Rate Base appropriate?

[Complete Settlement]

All parties agree that Enbridge's 2013 utility rate base, on an average of averages basis, is appropriately set at $4,162.0 million, as compared to the amount of $4,174.2 million set out at Exhibit M2, Tab 1, Schedule 3). This amount is derived as follows.

First, it reflects an agreed-upon reduction of $23 million in the average of averages 2013 rate base related to property, plant and equipment (i.e. $3,935.1 million, as compared to the amount of $3,958.1 million set out at Exhibit M2, Tab 1, Schedule 3, which was part of an overall rate base of $4,174.2 million).

Second, it reflects an increase in rate base of $10.2 million that results from the agreed-upon changes to depreciation rates set out at Issue D7 below.

Third, it reflects an increase in rate base of $0.6 million that results from a change in working capital, as discussed at Issue B7 below.

The updated Test Year Rate Base, reflecting the impact of these changes, is seen in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at pages 2 through 5.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Rate Base Evidence and Summaries
B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000
B1-2-3	Comparison of Capital Expenditures 2007 to 2013

B3-1-1	Ontario Utility Rate Base – Comparison of 2013 Test Year to 2012 Bridge Year
B3-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2013 Test Year
B4-1-1	Ontario Utility Rate Base – Comparison of 2012 Bridge Year to 2011 Historical Year
B4-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2012 Bridge Year
B5-1-1	Ontario Utility Rate Base – Comparison of 2011 Historic to 2007 Board Approved
B5-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2011 Historic Year
I-B1-1.4 and 1.6	Board Staff Interrogatories #4 and 6
I-B1-2.1	APPrO Interrogatory #1
I-B1-3.1	BOMA Interrogatory #1
I-B1-4.1 to 4.2	CME Interrogatories #1 and 2
I-B1-5.3- 5.4 and 5.11-5.14 and 5.16	CCC Interrogatories #3 and 4 and 11 to 14 and 16
I-B1-7.1to 7.2 and 7.4	Energy Probe Interrogatories #1, 2 and 4
I-B1-14.1	SEC Interrogatory #1
I-B1-20.1	VECC Interrogatory #1
I-B2-1.1 to 8.1	Interrogatories on Issue B2
I-B4-5.1	CME Interrogatory #1
I-B6-8.1 to 14.1	Interrogatories on Issue B6

3. Is the proposed Information Technology Capital Budget appropriate?

[Complete Settlement]

See Issue B1, above. The Information Technology Capital Budget is part of the overall agreed-upon capital budget of $387 million for 2013.

Evidence: The evidence in relation to this issue includes the following:

B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000
B1-4-1	Information Technology Capital Budget
I-B1-20.2	VECC Interrogatory #2
I-B2-1.14 to 1.16	Board Staff Interrogatories #14 to 16
I-B3-1.1 to 14.1	Interrogatories on Issue B3
I-B6-8.1 to 14.1	Interrogatories on Issue B6
I TR 66 to 71	Evidence at Technical Conference (September 5, 2012)
JT1.8	Undertaking from Technical Conference (September 5, 2012)

4. Is the proposed budget for Storage Capital Expenditure appropriate?

[Complete Settlement]

See Issue B1, above. The Storage Capital Expenditure Budget is part of the overall agreed-upon capital budget of $387 million for 2013.

Evidence: The evidence in relation to this issue includes the following:

B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000

B1-5-1	Storage Capital Expenditure
I-B4-1.1 to 14.1	Interrogatories on Issue B4
I TR 5 to 43	Evidence at Technical Conference (September 5, 2012)
JT1.1 to 1.5	Undertakings from Technical Conference (September 5, 2012)

5. Is the forecast of Customer Additions appropriate?

[Complete Settlement]

All parties agree that Enbridge's forecast of 38,896 customer additions for 2013, as set out at Exhibit B3, Tab 2, Schedule 3, is appropriate for capital budget purposes.

Evidence: The evidence in relation to this issue includes the following:

B2-1-1	Economic Feasibility Procedure and Policy
B3-2-3	Gross Customer Additions and Average Cost per Customer Addition Budget 2013 and 2012 Estimate
B4-2-3	Gross Customer Additions and Average Cost per Customer Addition 2012 Estimate and 2011 Historic
B5-2-3	Gross Customer Additions and Average Cost per Customer Addition Actual 2011 and 2011 Board Approved
I-B5-1.1 to 20.1	Interrogatories on Issue B5

6. Is the allocation of the cost and use of capital assets between utility and non-utility ("unregulated") operations appropriate?

[Complete Settlement]

All parties agree to the overall 2013 capital and O&M budgets (as set out at Issues B1 and D1), which include the impact of allocations of costs between utility and non-utility ("unregulated") storage operations.

In relation to the EB-2012-0055 case (Enbridge's 2011 ESM case), all parties agree that because this Settlement Agreement does not result in any change to Enbridge's approach to the allocation of costs between regulated and unregulated storage activities that, when applied to the 2011 allocations would affect the 2011 ESMDA, there is no need for any adjustment to the 2011 ESMDA in relation to allocation of storage costs. (Reference, OEB Decision and Order on Settlement Agreement in EB-2012-0055, dated September 17, 2012 at page 2).

It is agreed that EGD will not raise any procedural objection if any party seeks approval of different methodologies for allocation of the cost and use of capital assets or O&M allocations between utility and non-utility storage operations in the 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000
B1-5-1	Storage Capital Expenditure
D2-5-1	Regulated Unregulated Storage Cost Allocation – Black & Veatch
I-B4-5.1	CCC Interrogatory #1
I-B5-5.3	CCC Interrogatory #3
I-B6-8.1 to 14.1	Interrogatories on Issue B6
C1-1.2-1	Board Staff Interrogatory #2
I TR 5 to 43	Evidence at Technical Conference (September 5, 2012)
JT1.1 to 1.5	Undertakings from Technical Conference (September 5, 2012)
2 TR 25 to 39 and 197 to 202	Evidence at Technical Conference (September 6, 2012)
JT2.1 and 30	Undertakings from Technical Conference (September 6, 2012)

7. Is the proposed working capital allowance appropriate?

[Complete Settlement]

All parties agree that the proposed 2013 working capital allowance of $216.1 million (as set out at Exhibit M2, Tab 1, Schedule 3, page 1) will be increased by $0.6 million, to take account of two settled items.

First, there is an increase in working cash allowance of $1.5 million that results from the agreed-upon changes to the overall O&M budget amount, as discussed at Issue D1 below. This outcome results from the fact that the net lag day credit within the working cash calculation will be applied to a lower level of O&M budget as compared to the pre-filed evidence.

Second, there is a decrease in gas in storage of $0.9 million to take account of the agreed-upon changes to the gas volume budget, as discussed at Issue C2 below.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Rate Base Evidence and Summaries
B3-1-3	Working Capital Components of Average of Monthly Averages 2013 Test Year
B4-1-3	Working Capital Components of Average of Monthly Averages 2012 Bridge Year
B4-1-3	Working Capital Components of Average of Monthly Averages 2013 Historic Year
I TR 72 to 74	Evidence at Technical Conference (September 5, 2012)
JT1.9	Undertaking from Technical Conference (September 5, 2012)

C: OPERATING REVENUE

1. Is Enbridge's revenue forecast appropriate?

[Complete Settlement]

Subject to changes set out below related to Gas Volume Forecast (Issue C2) and Transactional Services (Issue C6), all parties agree that Enbridge's revenue forecast is appropriate. The updated revenue forecast, reflecting the impact of these changes, is seen in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at page 6.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A2-2-1	2013 Regulatory Budget Assumptions and Guidelines Directive
C1-1-1	Operating Revenue Summary
C1-2-1	Revenue Forecast
C1-4-1	Transactional Services
C1-5-1	Other Service and Late Payment Penalty Revenue
C3-1-1	Utility Operating Revenue 2013 Test Year
C3-1-2	Comparison of Utility Operating Revenue Budget 2013 and Estimate 2012
C3-2-1	Customers, Volumes and Revenues by Rate Class - 2013 Budget
C3-2-2	Comparison of Average Customer Numbers by Rate Class 2013 Budget and 2012 Estimate
C3-3-1	Details of Other Revenue Budget 2013 and Estimate 2012
C3-4-1	Transactional Services 2013 Test Year Budget Revenue and Cost Components
C3-5-1	NGV Rate of Return 2013 Test Year
C4-1-1	Utility Operating Revenue 2012 Bridge Year
C4-1-2	Comparison of Utility Operating Revenue 2012 Estimate and 2011 Historic
C4-1-3	Comparison of Utility Operating Revenue 2012 Estimate and Board 2007 Budget Approved
C4-2-1	Customers, Volumes and Revenues by Rate Class - 2012 Estimate
C4-2-2	Comparison of Average Customer Numbers by Rate Class 2012 Estimate and 2011 Historic
C4-3-1	Details of Other Revenue 2012 Estimate and 2011 Historic
C4-3-2	Details of Other Revenue 2012 Estimate and 2007 Board Approved
C4-4-1	Transactional Services 2012 Bridge Year Estimate vs. 2007 Board Approved Budget Revenue and Cost Components
C4-5-1	NGV Rate of Return 2012 Bridge Year
C5-1-1	Utility Operating Revenue 2011 Historic (Estimate)
C5-1-2	Comparison of Utility Operating Revenue 2011 Historic Year and 2007 Board Approved
C5-2-1	Customers, Volumes and Revenues by Rate Class –2011 Historic
C5-3-1	Details of Other Revenue 2011 Historic vs. 2007 Board Approved
C5-4-1	Transactional Services 2011 Historic vs. 2007 Board Approved Budget Revenue and Cost Components
C5-5-1	NGV Rate of Return 2011 Historic Year
I-C1-1.1 to 5.1	Interrogatories on Issue C1
I-C5-1.1 to 20.1	Interrogatories on Issue C6
I-C5-1.1 to 20.1	Interrogatories on Issue C7

2. Is Enbridge's gas volume forecast appropriate?

[Complete Settlement]

All parties agree that Enbridge will increase its forecast number of customers (active customer meters, or "unlocks") for 2013 by 4,500 from the estimate set out at Exhibit C1, Tab 3, Schedule 2 (page 1), such that the forecast total customers for 2013 will be 2,025,462. This change arises from the agreement of all parties that Enbridge's forecast of customers for 2012 was understated by 4,500, which agreement results in an increase to the forecast starting number of customers for 2013. This change has no impact on the customer additions forecast for 2013, which is settled under Issue B5 above.

All parties also agree that Enbridge's gas volume forecast for 2013 will be updated to take account of the changes to degree day forecasts in Issue C3 (below).

Enbridge's updated gas volume forecast reflecting the changes noted above is seen in the updated Summary of Gas Costs to Operations attached as Appendix B (Exhibit N1, Tab 1, Schedule 1, Appendix B).

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Gas Volume Budget
C1-3-2	2013 Gas Volume Budget Update
C2-3-1	Budget Degree Days
C2-3-2	Updated 2013 Budget Degree Days
C4-2-3	Comparison of Gas Sales and Transportation Volume by Rate Class 2012 Estimate and 2011 Historic
C4-2-4	Comparison of Gas Sales and Transportation Revenue by Rate Class 2012 Estimate and 2011 Historic
C4-2-5	Comparison of Gas Sales and Transportation Volume by Rate Class 2012 Estimate and 2007 Board Approved
C5-2-2	Comparison of Gas Sales and Transportation Volume by Rate Class 2011 Historic and 2010 Historic
C5-2-3	General Service System-Wide Normalized Average Use
C5-2-4	Comparison of Gas Sales and Transportation Volume by Rate Class 2011 Historic and 2007 Board Approved
C5-2-5	General Service Average Uses Historical Normalized Actual and Board Approved Fiscal and Calendar Years
C5-2-6	Large Volume (Contract) Customer Demand Historical Normalized Actual and Board Approved Fiscal and Calendar Years
D2-6-1	Unaccounted For Gas Study
D3-4-1	Unbilled and Unaccounted-for Gas Volumes
D4-4-1	Unbilled and Unaccounted-for Gas Volumes
D5-4-1	Unbilled and Unaccounted-for Volumes 2011 Historic vs. 2007 Board Approved
I-C1-4.1	CME Interrogatory #1
I-C2-5.1 to 11.1	Interrogatories on Issue C2
I-C3-7.1 to 20.1	Interrogatories on Issue C3
I-C4-1.1 to 20.2	Interrogatories on Issue C4
I-C5-1.1 to 20.2	Interrogatories on Issue C5
I-C5-1.1 to 20.2	Interrogatories on Issue C5

3. Is Enbridge's degree day forecast for each of the Company's delivery areas (EDA, CDA, and Niagara) appropriate?

[Complete Settlement]

All parties agree that Enbridge's degree day forecasts for 2013 for the Eastern Delivery Area and the Niagara Delivery Area, as set out in the Company's updated evidence at Exhibit C2, Tab 3, Schedule 2 (page 2), are appropriate.

All parties agree that for 2013, Enbridge will use the 10 year moving average model to forecast degree days for the Central Delivery Area. That agreement is based upon the Company's evidence in response to Exhibit I, Issue C3, Schedule 7.1 which indicates that the 10 year moving average model is currently the highest ranked forecasting model (using data up to and including 2011) for the Central Delivery Area. As set out in response to Exhibit I, Issue C3, Schedule 7.1 (page 3), this will result in a 2013 Environment Canada degree day forecast of 3,713 for the Central Delivery Area, which is 201 degree days higher than had been indicated the Company's updated evidence, which used the 20 year trend model.

It is agreed that no party will raise any procedural objection if Enbridge seeks approval of different degree day methodologies for any of its delivery areas in its 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

C2-3-1	Budget Degree Days
I-C3-7.1 to 20.1	Interrogatories on Issue C3
JT2.28 and 2.33 to 2.34	Undertakings from Technical Conference (September 6, 2012)
JT2-EP1	Supplementary Undertaking from Technical Conference (September 6, 2012)
2 TR 189 to 196 and 207 to 211	Evidence at Technical Conference (September 6, 2012)
JT2.28, 2.33 and 2.34	Undertaking from Technical Conference (September 6, 2012)

4. Is the Average Use forecast appropriate?

[Complete Settlement]

All parties agree that Enbridge's average use forecast for 2013, which has been updated to take account of the changes in degree day forecast as set out at Issue C3 above, is appropriate. The updated average use forecast is set out at Appendix C (Exhibit N1, Tab 1, Schedule 1, Appendix C).

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Gas Volume Budget
C5-2-6	Large Volume (Contract) Customer Demand Historical Normalized Actual and Board Approved Fiscal and Calendar Years
I-C4-1.1 to 20.2	Interrogatories on Issue C4
2 TR 202 to 206	Evidence at Technical Conference (September 6, 2012)
JT2.32	Undertaking from Technical Conference (September 6, 2012)

5. Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

[Complete Settlement]

For the purpose of settlement, all parties accept the level of UAF forecast by Enbridge.

Evidence: The evidence in relation to this issue includes the following:

D2-6-1	Unaccounted For Gas Study
D3-4-1	Unbilled and Unaccounted-for Gas Volumes
D4-4-1	Unbilled and Unaccounted-for Gas Volumes
D5-4-1	Unbilled and Unaccounted-for Volumes 2011 Historic vs. 2007 Board Approved
I-C5-1.1 to 20.2	Interrogatories on Issue C5
2 TR 155 to 189 and 196 to 197	Evidence at Technical Conference (September 6, 2012)
JT2.21 to 2.23; 2.25 to 2.26; and 2.29	Undertakings from Technical Conference (September 6, 2012)
	Supplementary Undertakings from Technical Conference (September 6, 2012)

6. Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

[Complete Settlement]

All parties agree to a change in Enbridge's Transactional Services (TS) sharing methodology for 2013. The changes are the following:

a. All TS net revenues (total storage and transportation TS revenues less associated costs) will be shared 90/10 between ratepayers and Enbridge's shareholder.

b. Enbridge will include a credit of $12 million in revenue requirement for 2013 related to an anticipated ratepayer share of TS net revenues, with a guarantee of $8 in ratepayer share.

c. The ratepayer share of 2013 TS net revenues will be tracked in the 2013 Transactional Services Deferral Account. In the event that the ratepayer share of 2013 TS net revenues exceeds $12 million, then such amounts over $12 million will be credited to ratepayers along with the clearance of the Company's other 2013 deferral and variance accounts. In the event that the ratepayer share of 2013 TS net revenues is less than $12 million, then Enbridge will be credited with the difference between the actual ratepayer share of 2013 TS net revenues and $12 million, to a maximum credit to Enbridge of $4 million.

It is agreed that no party will raise any procedural objection if Enbridge or any other party requests a different TS sharing methodology in Enbridge's 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

All parties agree that the acceptance of the inclusion of TS revenues related to FT long haul optimization in the determination of Enbridge's net TS revenues for 2013 is without prejudice to the position that any party may take on any issues related to the determination of Enbridge's net TS revenues within the 2011 and 2012 ESM proceedings, or in Enbridge's 2014 rate proceeding.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
C1-4-1	Transactional Services
C3-4-1	Transactional Services 2013 Test Year Budget Revenue and Cost Components
C4-4-1	Transactional Services 2012 Bridge Year Estimate vs. 2007 Board Approved Budget Revenue and Cost Components
C5-4-1	Transactional Services 2011 Historic vs. 2007 Board Approved Budget Revenue and Cost Components
I-C5-1.1 to 20.1	Interrogatories on Issue C6
I-DV1-8.2	FRPO Interrogatory #2

7. Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept Enbridge's forecast of other service and late payment penalty revenues, as set out at Exhibit C1, Tab 5, Schedule 1, including the methodologies used to cost and price those services.

Evidence: The evidence in relation to this issue includes the following:

C1-5-1	Other Service and Late Payment Penalty Revenue
C3-3-1	Details of Other Revenue Budget 2013 and Estimate 2012
C4-3-1	Details of Other Revenue 2012 Estimate and 2011 Historic
C4-3-2	Details of Other Revenue 2012 Estimate and 2007 Board Approved
C5-3-1	Details of Other Revenue 2011 Historic vs. 2007 Board Approved
I-C5-1.1 to 20.1	Interrogatories on Issue C7

D: OPERATING COSTS

1. Is the 2013 O&M budget appropriate?

[Complete Settlement]

In its prefiled evidence, Enbridge requested a total O&M budget of $438.1 million, comprised of five elements as set out below (Exhibit D1, Tab 3, Schedule 1):

Customer Care service charges	$89.4 million
DSM	$31.4 million
Pension costs	$37.3 million
RCAM	$32.1 million
All other O&M	$247.8 million
	$438.1 million

As set out below (Issues D9 and D13), the DSM and Customer Care costs already been approved in separate proceedings. All parties agree that the amounts for the RCAM and "All other O&M"

budgets will be combined, and that Enbridge will reduce this combined “All other O&M” budget for 2013 by $22.8 million. All parties agree, for the purposes of settlement, that Enbridge’s O&M budget for pension costs is accepted as filed, subject to the variance account treatment described below.

As a result, parties agree, for the purposes of settlement. that Enbridge’s 2013 O&M budget is appropriately set at $414.9 million, which represents a reduction of $22.8 million from the as-filed budget as set out in Impact Statement #2 (Exhibit M2). The budget is comprised of the following:

Customer Care service charges	$89.4 million
DSM	$31.4 million
Pension costs	$37.3 million
All other O&M	$256.8 million
	$414.9 million

The “All other O&M” amount is an envelope amount, and is not specifically allocated to any particular O&M expenses.

All parties agree that the 2013 pension costs amount is to be trued-up, such that Enbridge ultimately recovers in rates only the actual amount of its 2013 pension expense. To accomplish this, all parties agree to the creation of a Pension True-Up Variance Account (PTUVA) which will record any differences between the Company’s forecast pension expense and the actual pension expense (both determined on an accrual basis). All parties agree that the PTUVA will function so as to effect a true-up of pension expenses, as well as a smoothing of pension expense differences over future years in the event that the amounts recorded in the PTUVA are significant. To effect these outcomes, in future years the PTUVA will include any uncleared balances from previous years, as well as the difference between that year’s forecast and actual pension expenses (again, on an accrual basis). For the Test Year, the 2013 PTUVA will record differences between the forecast 2013 pension expense of $37.3 million and the actual 2013 pension expense. In the event that the balance (positive or negative) of the 2013 PTUVA is $5 million or less, then the entire amount will be cleared along with the Company’s other 2013 deferral and variance accounts. In the event that the balance (positive or negative) of the 2013 PTUVA is more than $5 million, then half of the accumulated balance will be cleared along with the Company’s other 2013 deferral and variance accounts and the remainder will be transferred to the next year’s PTUVA to be addressed in the same manner.

By way of example, if the actual pension expenses for 2013 exceed forecast pension expenses by $8 million, then that amount will be recorded in the 2013 PTUVA, and $4 million will be cleared to the credit of Enbridge, at the time that Enbridge’s 2013 deferral and variance accounts are cleared. The remaining balance of $4 million will be transferred to the 2014 PTUVA, which will also record the difference between 2014 forecast and actual pension expenses, After the end of 2014, the balance of the 2014 PTUVA (if it is less than $5 million) will be cleared. If the balance of the 2014 PTUVA is greater than $5 million, then half of the balance will be cleared and the other half will be transferred to the 2015 PTUVA.

All parties agree that a different approach to the clearance of balances in the PTUVA may be agreed upon in future proceedings considering the disposition of such balances, if the approach set out above is deemed to be inappropriate in the circumstances.

The updated O&M budget, reflecting the impact of these changes, is seen in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at page 6.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A2-1-2	Benchmarking Study
A2-2-1	2013 Regulatory Budget Assumptions and Guidelines Directive
D1-1-1	Operating Cost Summary
D1-3-1	Operating Maintenance Costs
D1-3-2	Employee Expenses and Workforce Demographics
D1-4-1	Corporate Cost Allocation (“CAM”)
D1-4-2	Updated Corporate Cost Allocation (“CAM”)
D1-24-1	Regulatory Adjustments and Eliminations – CAM Elimination to Adjust for RCAM
D1-24-2	Updated Regulatory Adjustments and Eliminations - CAM Elimination to Adjust for RCAM
D1-7-1	Demand Side Management Budget
D1-9-1	Open Bill Access
D1-10-1	Finance Department - O&M Budget
D1-12-1	CIS / Customer Care – A Review of the Treatment of CIS/Customer Care Costs as a Result of the ADR Settlement in EB-2011-0226
D1-13-1	Energy Supply, Storage Development and Regulatory – O&M Budget
D1-14-1	Law Department – O&M Budget
D1-15-1	Operations – O&M Budget
D1-16-1	Information Technology – O&M Budget
D1-17-1	Business Development and Corporate Strategy
D1-18-1	Human Resources – O&M Budget
D1-20-1	Pipeline Integrity and Safety – O&M Budget
D1-21-1	Public and Government Affairs – O&M Budget
D1-22-1	Non Departmental Expenses – O&M Budget
D2-3-1	Compensation Study – A Comparison of the EGDI Compensation Program
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D3-2-2	Operating and Maintenance Expense by Department 2013 Test Year
D3-2-3	Operating and Maintenance Expense by Cost Type - 2013 Test Year vs. 2012 Bridge Year
D3-2-4	Salaries and Wages and FTE Forecast 2013 Test Year
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D4-2-3	Operating and Maintenance Expense by Department 2012 Estimate
D4-2-4	Operating and Maintenance Expense by Cost Type 2012 Estimate and 2011 Historic
D4-2-5	Salaries and Wages and FTE Estimate 2012 Bridge Year
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
D5-2-2	Operating and Maintenance Expense by Department 2011 Historic
D5-2-3	Operating and Maintenance Expense by Cost Type 2011 Historic and 2007 Board Approved
D5-2-4	Salaries and Wages and FTE 2011 Historic
D5-2-5	O&M Variances 2007 - 2011
I-D1-1.1 to 20.5	Interrogatories on Issue D1
I-D2 to D26	Other Interrogatories on D series issues
I TR 82 to 160	Evidence at Technical Conference (September 5, 2012)
JT1.11 to 1.22	Undertakings from Technical Conference (September 5, 2012)
2 TR 182 to 184	Evidence at Technical Conference (September 6, 2012)
JT2.27	Undertaking from Technical Conference (September 6, 2012)

2. Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs, when updated to take account of the updated gas volume budget (Issue C2).

The impact of the updated gas volume budget on Enbridge's gas supply requirements can be seen in the updated Summary of Gas Costs to Operations (Exhibit N1, Tab 1, Schedule 1, Appendix B) and the impact to Enbridge's gas costs are seen in the ADR Financial Statements (Exhibit N1, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at page 6.

All parties agree that the acceptance of Enbridge's 2013 gas supply plan is without prejudice to the position that parties may take in Enbridge's 2014 rates proceeding, or in Enbridge's 2011 and 2012 ESM proceedings, in relation to the issue described above at Issue C6 related to FT long haul optimization in the determination of Enbridge's net TS revenues.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D1-2-1	Gas Costs, Transportation and Storage
D1-2-2	Status of Transportation Contracts
D1-2-4	Curtailment Compliance Report
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D3-3-1	Summary of Gas Cost to Operations
D3-3-2	Summary of Storage and Transportation Costs Fiscal 2013
D3-3-3	Peak Day Supply Mix
D3-3-4	Monthly Pricing Information
D3-3-5	Gas Supply/Demand
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D4-3-1	Summary of Gas Cost to Operations 2012 Bridge Year
D4-3-2	Summary of Storage & Transportation Costs Fiscal 2012
D4-3-3	Peak Day Supply Mix – 2012 Forecast
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
D5-3-1	Summary of Gas Cost to Operations 2011 Historic Year
D5-3-2	Summary of Storage & Transportation Costs Fiscal 2011 Historic
D5-3-3	Canadian Peak Day Supply Mix 2011 Historic
I-D2-1.1 to 8.10	Interrogatories on Issue D2
I-D6-20.2	VECC Interrogatory #2
I-DV1-7.2	Energy Probe Interrogatory #2
2 TR8 to 91	Evidence at Technical Conference (September 6, 2012)
JT2.2 to 2.11	Undertakings from Technical Conference (September 6, 2012)

3. Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

[Complete Settlement]

In its prefiled evidence (at Exhibit D1, Tab 2, Schedule 3), Enbridge applied to increase its peak gas day design criteria (PGDDC) to utilize updated design criteria using a 1 in 10 recurrence interval. For the purposes of settlement, all parties agree that Enbridge will increase its PGDDC to utilize the updated design criteria set out at Exhibit D1, Tab 2, Schedule 3 using a 1 in 5 recurrence interval. As set out at Tables 1 and 5 (pages 7 and 16) to Exhibit D1, Tab 2, Schedule 3, this will result in an increase of heating degree days (HDDs) for the Company's three weather zones as follows:

	Current Design Criteria	Updated Design Criteria
Central Weather Zone	39.5	41.4
Eastern Weather Zone	45.1	48.2
Niagara Weather Zone	36.3	38.8

All parties agree that Enbridge will phase in the change to HDDs equally over the 2013 and 2014 years, as follows:

	Current	1st 'Step'	2013	2nd 'Step'	2014
Central Weather Zone	39.5	0.9	40.4	1.0	41.4
Eastern Weather Zone	45.1	1.6	46.7	1.5	48.2
Niagara Weather Zone	36.3	1.3	37.6	1.2	38.8

In order to meet the increased requirements resulting from the 2013 and 2014 increases to PGDDC, the Company will have to acquire increased transportation capacity. All parties agree that the cost consequences of unutilized transportation capacity related to this incremental transportation capacity will be recorded in the 2013 and 2014 Design Day Criteria Transportation Deferral Account (DDCTDA). Enbridge estimates that the cost consequences of unutilized transportation capacity will be approximately $5 million in 2013 and $15 million in 2014. The balances in the 2013 and 2014 DDCTDAs , together with carrying charges, will be disposed of in a manner determined by the Board in a future rate hearing.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
D1-2-3	Design Criteria Evidence
D2-4-1	Gas System Design Criteria Analysis For Enbridge Gas Distribution
D2-4-2	Analysis of Peak Gas Day Design Criteria
I-D2-4.1	CME Interrogatory #1
I-D2-8.5 to 8.9	FRPO Interrogatory #5 to 9
I-D3-1.1 to 20.1	Interrogatories on Issue D3
2 TR 4 to 8; 39 to 63; 67 to	Evidence at Technical Conference (September 6, 2012)

72 ;and 76 to 91	
JT2.2 to 2.5 and 2.10 to 2.11	Undertakings from Technical Conference (September 6, 2012)

4. Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

[Complete Settlement]

All parties agree that the recovery of Pension and Other Post-Employment Benefits expense on an accrual basis commencing January 1, 2013 is appropriate. All parties further agree that Enbridge shall recover the Other Post-Employment Benefits (OPEB) expenses described at Exhibit A2, Tab 3, Schedule 1 equally over a twenty year period commencing January 1, 2013. The OPEB expenses of $90 million will be recorded in the Transition Impact of Accounting Changes Deferral Account (TIACDA), and will be cleared to the credit of Enbridge at the rate of $4.5 million per year (no interest will be applicable to the amounts recorded in the TIACDA).

Evidence: The evidence in relation to this issue includes the following:

A2-3-1	Change in Accounting Methodology – Other Post Employment Benefits ("OPEB")
A2-3-2	Change in Accounting Methodology – Pension Expense
I-D1-1.6	Board Staff Interrogatory #6
I-D4-1.1 to 14.2	Interrogatories on Issue D4
I-DV2-1.1 to 4.1	Interrogatories on Issue DV2
I TR 138 to 153	Evidence at Technical Conference (September 5, 2012)
T1.23	Undertaking from Technical Conference (September 5, 2012)

5. Is the corporate cost allocation ("RCAM") appropriate?

[Complete Settlement]

See Issue D1, above. The RCAM corporate cost allocation for 2013 is part of the overall agreed-upon "All other O&M budget" of $256.8 million. It is agreed that no party will raise any procedural objection if any party requests changes to RCAM in Enbridge's 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Corporate Cost Allocation ("CAM")
D1-4-2	Updated Corporate Cost Allocation ("CAM")
D1-24-1	Regulatory Adjustments and Eliminations – CAM Elimination to Adjust for RCAM
D1-24-2	Updated Regulatory Adjustments and Eliminations - CAM Elimination to Adjust for RCAM

D2-1-1	Regulatory Corporate Cost Allocation ("RCAM") Update - MNP
I-D1-1.12	Board Staff Interrogatory #12
I-D1-1-20.5	VECC Interrogatory #5
I-D5-1.1 to 20.5	Interrogatories on Issue D5
I-D12-14.2	SEC Interrogatory #2
I-D15-14.3 and 14.4	SEC Interrogatories #3 and 4
I TR 108 to 117 and 121 to 123	Evidence at Technical Conference (September 5, 2012)
JT1.17 to 1.19	Undertakings from Technical Conference (September 5, 2012)

6. Are the affiliate charges appropriate?

[Complete Settlement]

See Issue D1 above. The financial impact of affiliate charges for 2013 is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

A1-9-1	List of Affiliate Charges
I-D6-20.1 to 20.2	Interrogatories on Issue D6
I-D14-5.3	CCC Interrogatory #3
I-D14-7.1	Energy Probe Interrogatory #1
I-D14-14.1	SEC Interrogatory #1
I-D18-5.1 to 5.2	CCC Interrogatories #1 and 2
I-D19-14.2	SEC Interrogatory #2
I TR 135 to 138	Evidence at Technical Conference (September 5, 2012)
JT1.21	Undertaking from Technical Conference (September 5, 2012)

7. Are the proposed depreciation rate changes appropriate?

[Complete Settlement]

All parties accept Enbridge's proposed depreciation rates for 2013, as set out at Exhibit D2, Tab 5, Schedule 1 and Exhibit D2, Tab 2, Schedule 1 (Gannett Fleming Depreciation Study), with two exceptions.

First, the service lives for 475.20 Distribution Mains – Plastic will be increased from 55 to 65 years.

Second, the service lives for 473/474 Distribution Services & Meter Installations will be increased from 40 to 45 years.

All parties agree that the use of the depreciation rates set out in the Gannett Fleming Depreciation Study, as modified for the two adjustments set out above, is appropriate for ratemaking purposes for 2013 (including for determination of rate base) and that Enbridge shall be entitled to adopt such adjusted depreciation rates for purposes of financial accounting. The impact of this change for 2013 is to reduce depreciation expense by $20.3 million.

It is agreed that no party will raise any procedural objection if Enbridge files a new depreciation study, and seeks approval of updated depreciation rates based upon such new study, in its 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

D1-5-1	Depreciation Rate Change
D2-2-1	Depreciation Study – Gannett Fleming
D2-2-2	Schedule Depreciation Rates
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
I-D1-1.2	Board Staff Interrogatory #2
I-D5-2.1 to 5.1	Interrogatories on Issue D7
I TR 103 to 108	Evidence at Technical Conference (September 5, 2012)
JT1.13 to 1.14	Undertakings from Technical Conference (September 5, 2012)

8. Is the municipal taxes expense appropriate?

[Complete Settlement]

All parties agree that Enbridge will reduce its municipal taxes forecast by $800,000, such that the 2013 municipal tax amount to be included in operating costs is $39.3 million.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D1-6-1	Municipal Taxes
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
I-D8-1.1 to 20.1	Interrogatories on Issue D8

9. Is the demand side management budget appropriate?

[Complete Settlement]

All parties agree that Enbridge's demand side management budget for 2013 is $31.4 million, as set out in the Board-approved Settlement Agreement in the EB-2011-0295 proceeding. This amount is part of the overall O&M budget set out at Issue D1.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Demand Side Management Budget
I-D1-1.12	Board Staff Interrogatory #12
I-D9-1.1	Board Staff Interrogatory #1

10. Is the income tax expense forecast appropriate?

[Complete Settlement]

All parties agree that Enbridge's income tax expense forecast is appropriate, subject to adjustments to be made to reflect the changes between Enbridge's pre-filed evidence (as set out in Impact Statement #2 at Exhibit M2) and the Settled Issues in this Settlement Agreement. The revised income tax expense is reflected in the ADR Financial Statements (Exhibit N1, Tab 1, Schedule 1, Appendix A, parts A and B at page 8).

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
I-D10-1.1 to 1.4	Interrogatories on Issue D10
I TR 123 to 132	Evidence at Technical Conference (September 5, 2012)
JT1.20	Undertaking from Technical Conference (September 5, 2012)

11. Is the proposal for the Open Bill Access Program appropriate?

[Partial Settlement]

All parties, as well as the open bill issue participants, agree to the resolution of the Open Bill Access issue on the following terms.

Enbridge will continue to offer open bill services in 2013, under the terms of the Board-approved Settlement Agreement in EB-2009-0043 subject to the following two changes:

a. The Fees to be charged for Billing Services will be updated as set out at Table 4 of Exhibit D1, Tab 9, Schedule 14.

b. The Costs to be used for determining net income amounts for the purpose of sharing between Enbridge and ratepayers will be updated as set out at Table 4 of Exhibit D1, Tab 9, Schedule 14.

The terms of the OBA Agreement that governs the relationship between Enbridge and Billers are being discussed between Enbridge and the open bill issue participants. These parties hope to be able to reach resolution on the terms of contract by the end of October 2012, and will advise the Board in that regard. In the event that no agreement can be reached, then these parties may ask the Board to consider and determine issues related to the terms of the OBA Agreement, as contemplated in Procedural Order No. 4.

All parties, as well as the open bill issue participants, agree that as of January 1, 2013 Enbridge will continue to use the current form of OBA Agreement until such time as either: (i) Enbridge and the open bill issue participants agree on an updated form of OBA Agreement; or (ii) the Board makes a determination on any outstanding issues related to the OBA Agreement.

All parties, as well as the open bill issue participants, agree that if Enbridge wishes to continue to offer open bill services beyond December 31, 2013, then Enbridge must make application to the Board to do so. It is expected that such application (which might be part of a rates application, or might be a stand-alone application), will set out the terms upon which Enbridge proposes to continue the open bill program over a longer term or the terms upon which Enbridge proposes to wind down the program. Enbridge agrees that it will meet with all interested parties (including open bill issue participants) at least one month before it files the application contemplated in this paragraph. The purpose of such meeting is to provide information about Enbridge's plans and intentions to interested parties and to allow Enbridge to receive comments from those parties that may be relevant in the preparation of Enbridge's application.

In response to a proposal made by certain open bill issue participants to have Enbridge initiate an on-bill financing program for DSM measures (such as energy efficient equipment and building envelope upgrades), all parties, as well as the open bill issue participants, agree to the following next steps to work towards the possibility of offering on-bill financing for DSM measures with the intention of starting in January 2014:

a. By November 15, 2012, a consultative group will be formed to further consider the proposal. Any intervenor participating in this EB-2011-0354 case or in the ongoing DSM consultative would be eligible to participate in the consultative group.

   The consultative group will have at least three meetings in 2012, with the stated goal of creating a project plan setting out how Enbridge would offer on-bill financing for DSM measures at the lowest feasible interest rates.
b. In creating a project plan, the consultative group will consider the appropriate program design for an on-bill financing program for DSM measures to allow for such a program to be feasible, viable and effective. Items that may be considered include, but are not limited to, the following items which have been proposed by certain open bill issue participants:

   a. Whether and, if appropriate, how to issue an RFP seeking one or more financiers to offer financing to underpin the on-bill financing program activities involving the on-bill financing DSM consultative.

b. Whether and, if appropriate, how to ensure that the DSM on-bill financing program will only provide financing for DSM measures, with the goal of having such products sold and installed by reputable professionals.

c. Whether and, if appropriate, how to ensure that an accurate energy rating system (e.g., NRCan's EnerGuide Rating system) is used to: a) forecast; and b) measure the post-installation actual savings of DSM measures that are financed by the DSM on-bill financing program.

d. Whether and, if appropriate, how to ensure that DSM on-bill financing charges can be transferred to a new homeowner or tenant.

c. Once the project plan is completed, which is anticipated by early 2013, Enbridge will then lead the execution of the project plan.

All parties, as well as the open bill issue participants, acknowledge that Enbridge has not yet made any determination as to whether it plans to continue open bill services beyond 2013 or whether Enbridge will seek to wind down the program at that time. All parties, as well as the open bill issue participants further acknowledge that while the continuation of Enbridge's open bill services is not a pre-requisite to offering DSM on-bill financing, the question of whether open bill services continue in 2014 may impact on the feasibility and viability of offering DSM on-bill financing. In that regard all parties, as well as the open bill issue participants, acknowledge that Enbridge has not yet made any determination about whether it will proceed with on-bill financing for DSM measures in 2014 and acknowledge that such determination is contingent, at least in part, on the DSM on-bill financing program being feasible and viable to implement. If the decision is made to proceed with on-bill financing for DSM measures, Enbridge will aim to launch the DSM on-bill financing program in January 2014.

Evidence: The evidence in relation to this issue includes the following:

D1-9-1	Open Bill Access
I-D11-1.1 to 20.11	Interrogatories on Issue D11
I-D11-23.1 to 24.17	Supplementary Interrogatories on Issue D11

12. Is the proposed O&M budget for Finance appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Finance is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-10-1	Finance Department - O&M Budget
I-D12-5.1 to 14.3	Interrogatories on Issue D12

13. Has Enbridge properly implemented the revenue requirement associated with the Customer Care and CIS Settlement Agreement (per EB-2011-0226)?

[Complete Settlement]

All parties agree that Enbridge has properly implemented the revenue requirement associated with the Customer Care and CIS ("CC/CIS") Settlement Agreement (per EB-2011-0226).

All parties agree that the 2013 Customer Care O&M component of $89.4 million within the total CC/CIS revenue requirement is part of the overall O&M budget set out at Issue D1.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
D1-12-1	CIS / Customer Care – A Review of the Treatment of CIS/Customer Care Costs as a Result of the ADR Settlement in EB-2011-0226
D1-12-2	EB-2011-0226 Settlement Agreement Enbridge Customer Care and CIS Costs 2013 to 2018 - September 2, 2011
I-D1-1.12	Board Staff Interrogatory #12
I-D13-1.1	Board Staff Interrogatory #1

14. Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Energy Supply, Storage Development and Regulatory is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-13-1	Energy Supply, Storage Development and Regulatory – O&M Budget
I-D14-1.1 to 20.1	Interrogatories on Issue D14
1 TR 116 to 120	Evidence at Technical Conference (September 5, 2012)

15. Is the proposed O&M budget for Law appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Law is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-14-1	Law Department – O&M Budget
I-D15-1.1 to 14.4	Interrogatories in Issue D25

16. Is the proposed O&M budget for Operations appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Operations is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-15-1	Operations – O&M Budget
I-D16-1.1 to 14.4	Interrogatories on Issue D16

17. Is the proposed O&M budget for Information Technology appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Information Technology is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-16-1	Information Technology – O&M Budget
I-D17-1.1 to 14.3	Interrogatories on Issue D17

18. Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada (“ETIC”) related amounts, appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada (“ETIC”) related amounts, is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-17-1	Business Development and Corporate Strategy
I-D18-1.1 to 20.1	Interrogatories on Issue D18

19. Is the proposed O&M budget for Human Resources appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Human Resources is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-18-1	Human Resources – O&M Budget
I-D19-1.1 to 20.1	Interrogatories on Issue D19

20. Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Pipeline Integrity & Safety is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-20-1	Pipeline Integrity and Safety – O&M Budget
I-D20-1.1 to 14.5	Interrogatories on Issue D20

21. Is the proposed O&M budget for Public and Government Affairs appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Public and Government Affairs is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-21-1	Public and Government Affairs – O&M Budget
I-D1-1-14.9	SEC Interrogatory #9
I-D21-5.1 to 14.2	Interrogatories on Issue D21

22. Is the proposed O&M budget for Non-Departmental O&M Expenses appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Non-Departmental O&M Expenses is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-22-1	Non Departmental Expenses – O&M Budget
I-D22-1.1 to 14.1	Interrogatories on Issue D22

23. Is the forecast of Provision for Uncollectable Amounts for 2013 appropriate?

[Complete Settlement]

See Issue D1, above. The Provision for Uncollectable Amounts for 2013 is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-3-1	Operating Maintenance Costs
I-D1-1.9	Board Staff Interrogatory #9
I-D1-1-14.3	SEC Interrogatory #3

24. Is the allocation of O&M costs between utility and non-utility ("unregulated") operations appropriate?

[Complete Settlement]

See Issue B6, above.

Evidence: The evidence in relation to this issue includes the following:

A1-9-1	List of Affiliate Transactions for the 2013 Test Year, 2012 Bridge Year and 2011 Historic Year
I-D18-1.1	Board Staff Interrogatory #1
I-D24-1.1 to 5.1	Interrogatories on Issue D24
1 TR 132 to 135	Evidence at Technical Conference (September 5, 2012)

DV: DEFERRAL AND VARIANCE ACCOUNTS

1. Are Enbridge's existing and proposed deferral and variance accounts appropriate?

[Complete Settlement]

Subject to the exceptions set out below, all parties agree to the establishment of Enbridge's deferral and variance accounts, on the basis as described in evidence at Exhibit D1, Tab 8, Schedule 1.

Within the Purchased Gas Variance Account (PGVA), all parties have agreed to one methodology change. With respect to dispositions of long Banked Gas Account (BGA) balances, all parties agree that when a long BGA balance is purchased by Enbridge from a customer, Enbridge will credit the difference between the purchase price and the Empress price embedded in the PGVA to a load balancing component of the PGVA (rather than to the commodity component of the PGVA, which is the current methodology).

As set out in Issue C6 above, all parties agree to the changes described in determining amounts to be included in the 2013 Transactional Services Deferral Account (TSDA).

As set out in Issue D1 above, all parties agree to the creation of a 2013 Pension True-Up Variance Account (PTUVA).

As set out in Issue D3 above, all parties agree to the parameters described in determining amounts to be included in the 2013 and 2014 Design Day Criteria Transportation Deferral Account (DDCTDA).

Evidence: The evidence in relation to this issue includes the following:

A1-6-1	Accounting Orders
D1-8-1	Deferral and Variance Accounts
D1-8-3	Deferral and Variance Account Forecast Balances
I-DV1-5.1 to 20.1	Interrogatories on Issue DV1

2. Is Enbridge's request to recover from ratepayers an approximate $90 million forecasted balance as at December 31, 2012 in the 2012 Transition Impact of Accounting Changes Deferral Account ("TIACDA") appropriate?

[Complete Settlement]

See Issue D4, above.

Evidence: The evidence in relation to this issue includes the following:

D1-8-1	Deferral and Variance Accounts
D1-8-3	Deferral and Variance Account Forecast Balances
I-DV2-1.1 to 4.1	Interrogatories on Issue DV2
2 TR 138 to 153	Evidence at Technical Conference (September 6, 2012)

E: COST OF CAPITAL

1. Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

[Partial Settlement]

All parties agree with Enbridge's forecasts of the cost rates for 2013 long and medium term debt, short term debt and preference shares.

All parties also agree with the forecast of the cost of debt for the Test Year, based upon Enbridge's current 36% level of deemed common equity (as set out in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, part 2 at page 9). In that regard, if the OEB were to determine that no change to Enbridge's current 36% level of deemed common equity is appropriate, then it is agreed that the long term debt component of Enbridge's capital structure will increase to $2,461.9 million as a result of a required $400 million debt issuance, to occur in August 2013, at agreed upon forecast coupon and effective interest rates of 4.10% and 4.18%. As a result of the new debt issuance with interest rates that are lower than the average interest rate for Enbridge's existing outstanding debt, Enbridge's average long term debt cost rate is reduced to 5.80% from the forecast 5.90%.

In the event that the Board approves a different level of common equity from the current 36%, in response to Issue E2, then there is no agreement on the appropriate capital structure. This issue is to be heard by the Board. In particular, there is no agreement as to the mix of short and long term debt and preference shares, and the resulting cost of capital, in the event that the Board approves a different level of deemed common equity from the current 36%, in response to Issue E2. All parties are free to take whatever position they deem appropriate in relation to this question when Issue E2 is considered by the Board.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E3-1-2	Summary Statement of Principal and Carrying Costs of Term Debt 2013 Test Year
E3-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2013 Test Year
E3-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2013 Test Year
E3-1-5	Unamortized Preference Share Issue Expense Average of Monthly Averages 2013 Test Year
E4-1-1	Cost of Capital 2012 Bridge Year
E4-1-2	Summary Statement of Principal and Carrying Cost of Term Debt 2012 Bridge Year
E4-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2012 Bridge Year
E4-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2012 Bridge Year
E4-1-5	Unamortized Preference Shares Issue Expense Average of Monthly Averages 2012 Bridge Year
E5-1-2	Summary Statement of Principal and Carrying Cost of Term Debt 2011 Historic
E5-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2011 Historic
E5-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2011 Historic
E5-1-5	Unamortized Preference Share Issue Expense Average of Monthly Averages 2011 Historic
F3-1-1	Cost of Capital 2013 Test Year
I-E1-1.1 to 21.2	Interrogatories on Issue E1
I-E2-2.1	APPrO Interrogatory #1
2 TR 118 to 121 and 137 to 145	Evidence at Technical Conference (September 6, 2012)
JT2.15 to 2.17	Undertakings from Technical Conference (September 6, 2012)

2. Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

[No settlement]

All parties agree that this issue shall proceed to hearing. The attached ADR Financial Statements show the impact of this Settlement Agreement based upon a 42% equity thickness and a 36% equity thickness (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at pages 1 and 9.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A3-9-1	DBRS and S&P Reports
E1-2-1	Cost of Capital
E2-1-2	Capital Structure: Equity Ratio
E2-2-1	Concentric Energy Advisors : Equity Thickness Evaluation & Recommendation
L1-1-1	Business Risk And Capital Structure For Enbridge Gas Distribution Inc (EGDI) – Dr. Booth
I-E1-7.1 and 7.5	Energy Probe Interrogatories #1 and 5
I-E1-20.1 and 20.3	VECC Interrogatories #1 and 3
I-E1-21.1 and 21.2	CME et al Interrogatories #1 and 2
I-E2-1.1 to 21.12	Interrogatories on Issue E2
I-E2-22.1 to 22.52	EGD Interrogatories to Dr. Booth
2 TR91 to 155	Evidence at Technical Conference (September 6, 2012)
JT2.12 to 2.20	Undertakings from Technical Conference (September 6, 2012)

3. Is the proposal to use the Board's formula to calculate return on equity appropriate?

[Complete Settlement]

All parties agree that Enbridge will use the Board's formula from the December 2009 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities to calculate return on equity (ROE). All parties agree that, as set out in that Report, the calculation of ROE to be used for the purpose of setting rates for 2013 shall be determined using Consensus October 2012 inputs, which are based on September data, once such information is available in October 2012. As set out at Issue O6 below, if timing permits Enbridge will implement the updated ROE as part of the draft Rate Order process in November 2012, so that this becomes part of the interim rates to be implemented on January 1, 2013. If that timing is not possible, then the updated ROE will be implemented as part of final rates.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
E2-1-1	Return on Equity Calculation for 2013
I-E3-1.1 to 21.3	Interrogatories on Issue E3

F: REVENUE SUFFICIENCY / DEFICIENCY

1. Is the revenue requirement and revenue deficiency or sufficiency for the Test Year calculated correctly?

[Complete Settlement]

All parties agree that the revenue deficiency for the Test Year arising from the Settled Issues, as set out in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2), is calculated correctly.

Evidence: The evidence in relation to this issue includes the following:

A2-4-1	Drivers of Deficiency / (Sufficiency)
E3-1-1	Revenue Deficiency Calculation And Required Rate Of Return 2013 Test Year
E5-1-1	Revenue Sufficiency Calculation And Required Rate Of Return 2011 Historical Year (Estimate)
F1-1-1	Revenue (Deficiency) / Sufficiency Summary
F3-1-1	Cost of Capital 2013 Test Year
F3-1-2	Utility Income 2013 Test Year
F3-1-3	Utility Rate Base 2013 Test Year
F4-1-1	Revenue Sufficiency Calculation and Required Rate of Return 2012 Bridge Year
F4-1-2	Utility Income 2012 Bridge Year
F4-1-3	Utility Rate Base 2012 Bridge Year
F5-1-1	Revenue Sufficiency and Recalculated Rate of Return 2011 Historic
F5-1-2	Utility Income 2011 Historic
F5-1-3	Utility Rate Base 2011 Historic
M1-1-1	Impact Statement No. 1
M1-1-2	Change in Revenue Requirement 2013 Test Year
M1-1-3	Utility Rate Base 2013 Test Year
M1-1-4	Utility Income 2013 Test Year
M1-1-5	Ontario Utility Capital Structure 2013 Test Year
I-F1-5.1 to 20.1	Interrogatories on Issue F1

2. Is the overall change in revenue requirement reasonable given the impact on consumers?

[Complete Settlement]

The overall changes in revenue requirement arising from the Settled Issues assuming a 36% and a 42% equity thickness is set out in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2). All parties agree that the overall change in revenue requirement is reasonable given the impact on consumers.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
I-F2-4.1 to 20.1	Interrogatories on Issue F2

G: COST ALLOCATION

1. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgements used and the proposed application of that study with respect to Test Year rates, appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept Enbridge's utility Cost Allocation Study, including the methodologies and judgements used and the proposed application of that study with respect to Test Year rates.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	2013 Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study - 2013 Test Year
G2-2-1	Revenue to Cost/Rate of Return Comparisons
G2-2-2	Revenue to Cost/Rate of Return Comparisons Excluding Gas Supply Commodity
G2-3-1	Functionalization of Utility Rate Base
G2-3-2	Functionalization of Utility Working Capital
G2-3-3	Functionalization of Utility Net Investments
G2-3-4	Functionalization of Utility O&M
G2-4-1	Classification of Rate Base
G2-4-2	Classification of Net Investment
G2-4-3	Classification of O&M Costs
G2-5-1	Allocation of Rate Base
G2-5-2	Allocation of Return & Taxes
G2-5-3	Allocation of Total Cost of Service
G2-6-1	Rate Base Functionalization Factors
G2-6-2	Classification of Gas Costs to Operations
G2-6-3	Allocation Factors
G2-6-4	Allocation of DSM Program Costs General Costs Including Fringe Benefits and A&G
G2-7-1	Tecumseh – Functionalization and Classification of Rate Base
G2-7-2	Tecumseh – Functional Allocation of Cost of Service - 2013 Test Year
G2-7-3	Tecumseh – Classification of Cost of Service 2013 Test Year
G2-7-4	Tecumseh Gas Rate Derivation 2013 Test Year
G2-7-5	Tecumseh Gas Isolation of Transmission Related Rate Base 2013 Test Year
G2-7-6	Tecumseh Gas Isolation of Transmission Related Operating Cost 2013 Test Year
G2-7-7	Functionalization of Short Cycle Net Revenues to In/Ex Franchise Customers 2013 Test Year
I-G1-2.1 to 20.1	Interrogatories on Issue G1

2. Are the Cost Allocation Study methodology relating to Customer Care and CIS costs appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept the Cost Allocation methodology relating to Customer Care and CIS costs.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	2013 Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study - 2013 Test Year

3. Are the principles applied in the utility Cost Allocation Study consistent where appropriate with the principles applied in allocating costs between utility and non-utility (“unregulated”) businesses?

[Complete settlement]

See Issue B6, above.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	2013 Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study - 2013 Test Year
D2-5-1	Regulated Unregulated Storage Cost Allocation – Black & Veatch
G2-7-1	Tecumseh – Functionalization and Classification of Rate Base
G2-7-2	Tecumseh – Functional Allocation of Cost of Service - 2013 Test Year
G2-7-3	Tecumseh – Classification of Cost of Service 2013 Test Year
G2-7-4	Tecumseh Gas Rate Derivation 2013 Test Year
G2-7-5	Tecumseh Gas Isolation of Transmission Related Rate Base 2013 Test Year
G2-7-6	Tecumseh Gas Isolation of Transmission Related Operating Cost 2013 Test Year
G2-7-7	Functionalization of Short Cycle Net Revenues to In/Ex Franchise Customers 2013 Test Year

H: RATE DESIGN

1. Are the rates proposed for implementation effective January 1, 2013 and appearing in Exhibit H just and reasonable?

[Complete Settlement]

See Issue O6, below.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	2013 Proposed Rates
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook
H2-7-1	Annual Bill Comparison

2. Are the proposed levels of customer charges, including the fixed/variable split, appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept the fixed/variable split of customer charges, and agree with the process set out in response to Issue O6 for the implementation of interim rates as of January 1, 2013.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	2013 Proposed Rates
H2-6-1	Rate Handbook
H2-7-1	Annual Bill Comparison

O: OTHER ISSUES

1. Has Enbridge responded appropriately to all relevant Board directions from previous proceedings, including any commitments from prior settlement agreements?

[Complete Settlement]

All parties accept Enbridge's evidence that it has responded appropriately to all relevant Board directions from previous proceedings.

Evidence: The evidence in relation to this issue includes the following:

A1-13-1	Status of Board Directives from Previous Board Decisions and/or Board Orders
I-O1-8.1	FRPO Interrogatory #1

2. Are Enbridge's economic and business planning assumptions for the Test Year appropriate?

[Complete Settlement]

In relation to the Settled Issues, no party takes issue with whether Enbridge's economic and business planning assumptions for the Test Year are appropriate.

Any party is free to take whatever position they deem appropriate about the economic and business planning assumptions applied by Enbridge in relation to Issues E1 and E2.

Evidence: The evidence in relation to this issue includes the following:

A2-2-1	2013 Regulatory Budget Assumptions and Guidelines Directive
B2-1-1	Economic Feasibility Procedure and Policy
C2-1-1	Key Economic Assumptions
I-B1-5.15	CCC Interrogatory #15
I-C2-11.2	Energy Probe Interrogatory #2
I-O2-5.1 to 5.2	CCC Interrogatories #1 and 2

3. Are sustainable productivity and efficiency gains achieved under incentive regulation appropriately reflected in Enbridge's Cost of Service estimates?

[Complete Settlement]

All parties agree that Enbridge's 2013 cost of service rates, as agreed through the Settled Issues in this Settlement Agreement, reflect productivity and efficiency gains that have been achieved from the incentive regulation term. The parties accept the estimates of productivity and efficiency gains prepared by Enbridge in response to JT1.28. Enbridge agrees that, as part of its 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology), it will address ways to establish and maintain records of productivity and efficiency initiatives that would be useful for the Board in a subsequent rebasing application or other proceeding where such information would be useful.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A2-1-2	Benchmarking Study (Concentric)
A2-1-3	Analytical Review of the September 2011 PEG-R Report (PSE)
I-O3-1.1 to 20.1	Interrogatories on Issue O3
I TR 160 to 200	Evidence at Technical Conference (September 5, 2012)
JT1.25 to 1.28	Undertakings from Technical Conference (September 5, 2012)

4. Are Enbridge's Conditions of Service (i.e. customer service policies including security deposits, late payment penalty, etc.) compatible with Board directives?

[Complete Settlement]

No party takes issue with whether Enbridge's Conditions of Service are compatible with Board directives. As indicated in response to JT1.24, Enbridge will update its Conditions of Service to address low-income customer service policy amendments, as required in the EB-2010-0280 proceeding.

Evidence: The evidence in relation to this issue includes the following:

A1-14-1	Conditions of Service
I-O4-5.1 to 5.2	Interrogatories on Issue O4
I TR 156 to 158	Evidence at Technical Conference (September 5, 2012)
JT1.24	Undertaking from Technical Conference (September 5, 2012)

5. Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified, and reflected in the appropriate manner in the application, the revenue requirement for the Test Year, and the proposed rates?

[Complete Settlement]

See Issue B4 above.

Evidence: The evidence in relation to this issue includes the following:

Procedural Order #2	Decision on Preliminary Issue, May 16, 2012
A1-6-2	Accounting for Rate Regulated Operations Current and Future Changes
I-O5-1.1 to 1.4	Clearance of Deferral and Variance Account Balances

6. How should the Board implement the rates relevant to this proceeding if they cannot be implemented on or before January 1, 2013?

[Complete Settlement]

All parties agree that the revenue requirement and rate impact of the Settled Issues should be implemented into rates as of January 1, 2013, using an assumed 36% equity thickness. The overall change in revenue requirement arising from the Settled Issues assuming a 36% equity thickness is set out in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, part 2). As noted in the Overview, all parties agree that the agreement to use the current level of equity thickness (36%) and associated capital structure ratios for implementation of interim rates is not intended as an indication or suggestion to the Board that 36% is the appropriate level of equity thickness for Enbridge in 2013. That issue is to be determined by the Board based upon the evidence and argument presented.

Enbridge will provide a draft Rate Order (setting out the interim rates reflecting the Settled Issues) to all parties on or before Friday, October 26, 2012. Parties will provide comments on the draft Rate Order by Wednesday, November 7, 2012. Enbridge will then provide any required response and updates, in order to allow the Board to consider the draft Rate Order shortly thereafter. Assuming that the Board approves the draft Rate Order before the end of November 2012, then the interim rates reflecting the Settled Issues will be implemented in conjunction with Enbridge's January 1, 2013 QRAM Application. If timing permits, Enbridge will implement the updated ROE (see issue E3, above) as part of the draft Rate Order process in November 2012. That would allow for the updated ROE to become part of the interim rates to be implemented on January 1, 2013. If that timing is not possible, then the impact of the updated ROE will be implemented as part of final rates, as described below.

The rates to be implemented on January 1, 2013 will be interim rates, to be adjusted subsequently to take account of the full year effect of the determination of Issue E2 (Enbridge's request to increase deemed common equity component from 36% to 42%), and any related impacts from Issue E1 (cost of debt). If necessary, the interim rates will also be adjusted to reflect the updated ROE that will be determined in November 2011 in accordance with process described at Issue E3, above). All parties agree that any financial impact of the determination of Issues E1 and E2 (and Issue E3, if necessary) shall be implemented as part of Enbridge's first QRAM Application following the Board's decision (or if time does not permit, as part of the following QRAM Application).

Evidence: The evidence in relation to this issue includes the following:

N1-1-1, App. A to C	Appendices to Settlement Agreement

CHANGE IN REVENUE REQUIREMENT
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted ADR Impact Statement	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 ADR Impact Statement EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	4,103.7	(12.2)	4,091.5	70.5	4,162.0
2.	Required rate of return	7.19	-	7.19	6.44	7.18
3.		295.1	(0.9)	294.2	4.6	298.8
	Cost of service					
4.	Gas costs	1,307.9	34.9	1,342.8	-	1,342.8
5.	Operation and maintenance	348.3	(22.8)	325.5	89.4	414.9
6.	Depreciation and amortization	288.1	(21.5)	266.6	12.7	279.3
7.	Fixed financing costs	2.3	-	2.3	-	2.3
8.	Debt redemption premium amortization	-	-	-	-	-
9.	Company share of IR agreement tax savings	-	-	-	-	-
10.	Municipal and other taxes	40.1	(0.8)	39.3	-	39.3
11.		1,986.7	(10.2)	1,976.5	102.1	2,078.6
	Miscellaneous operating and non-operating revenue					
12.	Other operating revenue	(38.3)	(6.0)	(44.3)	-	(44.3)
13.	Interest and property rental	-	-	-	-	-
14.	Other income	(0.7)	-	(0.7)	-	(0.7)
15.		(39.0)	(6.0)	(45.0)	-	(45.0)
	Income taxes on earnings					
16.	Excluding tax shield	73.7	12.8	86.5	9.0	95.5
17.	Tax shield provided by interest expense	(35.8)	(0.2)	(36.0)	(0.9)	(36.9)
18.		37.9	12.6	50.5	8.1	58.6
	Taxes on sufficiency / (deficiency)					
19.	Gross sufficiency / (deficiency)	(81.9)	75.0	(6.9)	-	(6.9)
20.	Net sufficiency / (deficiency)	(60.2)	55.1	(5.1)	-	(5.1)
21.		21.7	(19.9)	1.8	-	1.8
22.	**Sub-total revenue requirement**	2,302.4	(24.4)	2,278.0	114.8	2,392.8
23.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(4.6)	(4.6)
24.	**Total revenue requirement**	2,302.4	(24.4)	2,278.0	110.2	2,388.2
	Revenue at existing Rates					
25.	Gas sales	1,923.9	45.6	1,969.5	80.2	2,049.7
26.	Transportation service	294.9	4.9	299.8	19.0	318.8
27.	Transmission, compression and storage	1.7	-	1.7	-	1.7
28.	Rounding adjustment	-	0.1	0.1	-	0.1
29.	Revenue at existing rates	2,220.5	50.6	2,271.1	99.2	2,370.3
30.	**Gross revenue sufficiency / (deficiency)**	(81.9)	75.0	(6.9)	(11.0)	(17.9)

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 2, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 3 of Exhibit F3, Tab 1, Schedule 1, Page 2, Filed: 2012-01-31.

UTILITY RATE BASE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 2	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted ADR Impact Statement Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,645.6	(23.3)	6,622.3	127.1	6,749.4
2.	Accumulated depreciation	(2,758.0)	10.5	(2,747.5)	(56.6)	(2,804.1)
3.		3,887.6	(12.8)	3,874.8	70.5	3,945.3
	Allowance for Working Capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
6.	Materials and supplies	31.9	-	31.9	-	31.9
7.	Mortgages receivable	0.2	-	0.2	-	0.2
8.	Customer security deposits	(68.7)	-	(68.7)	-	(68.7)
9.	Prepaid expenses	1.8	-	1.8	-	1.8
10.	Gas in storage	249.3	(0.9)	248.4	-	248.4
11.	Working cash allowance	0.3	1.5	1.8	-	1.8
12.	Total Working Capital	216.1	0.6	216.7	-	216.7
13.	Utility Rate Base	4,103.7	(12.2)	4,091.5	70.5	4,162.0

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 3, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2012-01-31.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	(23.3)	Cost or redetermined value Change is the result of the settlement of issues B1 through B7 and related descriptions contained within the Agreement.
2.	10.5	Accumulated depreciation Change is the result of the settlement of issue D7 and the related description contained within the Agreement.
10.	(0.9)	Gas in storage Change is the result of the settlement of issue B7 and the related description contained within the Agreement.
11.	1.5	Working cash allowance Change is the result of the settlement of issue B7 and the related description contained within the Agreement.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2013 TEST YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,350.9	4.0	14.8
2.	Items not subject to working cash allowance (Note 1)		(8.1)		
3.	Gas costs charged to operations	M2.T1.S4.P1.Col.3	1,342.8		
4.	Operation and Maintenance	M2.T1.S4.P1.Col.3	325.5		
5.	Less: Storage costs		(7.9)		
6.	Operation and maintenance costs subject to working cash		317.6		
7.	Ancillary customer services		-		
8.			317.6	(18.7)	(16.3)
9.	Sub-total				(1.5)
10.	Storage costs		7.9	62.5	1.4
11.	Storage municipal and capital taxes		2.2	24.4	0.1
12.	Sub-total				1.5
13.	Harmonized sales tax				1.8
14.	Total working cash allowance				1.8

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

GAS IN STORAGE
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2013 TEST YEAR

Line No.		Volume	Col. 1 Impact Statement Number 2	ADR Adjustments	Col. 2 ADR Adjustments	Adjusted Volume	Col. 3 Adjusted ADR Impact Statement
		10*6 M*3	($Millions)	10*6 M*3	($Millions)	10*6 M*3	($Millions)
1.	January 1	1,425.1	328.4	(0.1)	(0.1)	1,425.0	328.3
2.	January 31	872.6	211.7	(33.0)	(7.3)	839.6	204.4
3.	February	446.8	120.1	(8.2)	(3.9)	438.6	116.2
4.	March	95.9	51.7	30.8	2.3	126.7	54.0
5.	April	44.4	50.2	25.2	1.8	69.6	52.0
6.	May	330.9	105.4	19.4	1.4	350.3	106.8
7.	June	720.0	178.2	13.9	0.9	733.9	179.1
8.	July	1,241.2	272.1	8.2	0.6	1,249.4	272.7
9.	August	1,763.8	366.3	2.3	0.1	1,766.1	366.4
10.	September	2,141.1	437.3	(3.2)	(0.4)	2,137.9	436.9
11.	October	2,246.7	462.6	(9.0)	(0.8)	2,237.7	461.8
12.	November	1,957.2	412.2	(36.1)	(5.2)	1,921.1	407.0
13.	December	1,478.4	318.6	(2.6)	(0.6)	1,475.8	318.0
14.	Avg. of monthly avgs.	1,109.4	249.3	0.7	(0.9)	1,110.1	248.4

UTILITY INCOME
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 2	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted ADR Impact Statement Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	1,923.9	45.6	1,969.5	80.2	2,049.7
2.	Transportation of gas	294.9	4.9	299.8	19.0	318.8
3.	Transmission, compression and storage revenue	1.7	-	1.7	-	1.7
4.	Other operating revenue	38.3	6.0	44.3	-	44.3
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.7	-	0.7	-	0.7
7.	Total operating revenue	2,259.5	56.5	2,316.0	99.2	2,415.2
8.	Gas costs	1,307.9	34.9	1,342.8	-	1,342.8
9.	Operation and maintenance	348.3	(22.8)	325.5	89.4	414.9
10.	Depreciation and amortization expense	288.1	(21.5)	266.6	12.7	279.3
11.	Fixed financing costs	2.3	-	2.3	-	2.3
12.	Debt redemption premium amortization	-	-	-	-	-
13.	Company share of IR agreement tax savings	-	-	-	-	-
14.	Municipal and other taxes	40.1	(0.8)	39.3	-	39.3
15.	Interest and financing amortization expense	-	-	-	-	-
16.	Other interest expense	-	-	-	-	-
17.	Total costs and expenses	1,986.7	(10.2)	1,976.5	102.1	2,078.6
18.	Ontario utility income before income taxes	272.8	66.7	339.5	(2.9)	336.6
19.	Income tax expense	37.9	12.6	50.5	8.1	58.6
20.	Utility net income	234.9	54.1	289.0	(11.0)	278.0

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 4, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 2, page 1, Filed: 2012-01-31.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	45.6	Gas sales Change is the result of the settlement of issues C1 through C5 and related descriptions contained within the Agreement.
2.	4.9	Transportation of gas Change is the result of the settlement of issues C1 through C5 and related descriptions contained within the Agreement.
4.	6.0	Other operating revenue Change is the result of the settlement of issues C6 and C7 and related descriptions contained within the Agreement.
8.	34.9	Gas costs Change is the result of the settlement of issues C1 through C5 and D2 & D3 and related descriptions contained within the Agreement.
9.	(22.8)	Operation and maintenance Change is the result of the settlement of issues C1 through C5 and D2 & D3 and related descriptions contained within the Agreement.
10.	(21.5)	Depreciation and amortization expense Change is due to the settlement of issues D1, D5, D9, D11 through D24 and related descriptions contained within the Agreement.
14.	(0.8)	Municipal and other taxes Change is the result of the settlement of issues D8 and the related description contained within the Agreement.
19.	12.6	Income tax expense Change is due to the impact on taxable income as a result of the settlement of all the issues identified above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted ADR Impact Statement Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes (M2, T1, S3, P1)	272.8	66.7	339.5
	Add			
2.	Depreciation and amortization	288.1	(21.5)	266.6
3.	Accrual based pension and OPEB costs	42.1	-	42.1
4.	Other non-deductible items	2.2	-	2.2
5.	Total Add Back	332.4	(21.5)	310.9
6.	Sub total	605.2	45.2	650.4
	Deduct			
7.	Capital cost allowance - Federal	234.8	(3.1)	231.7
8.	Capital cost allowance - Provincial	234.8	(3.1)	231.7
9.	Items capitalized for regulatory purposes	46.3	-	46.3
10.	Deduction for "grossed up" Part VI.1 tax	5.0	-	5.0
11.	Amortization of share/debenture issue expense	3.6	-	3.6
12.	Amortization of cumulative eligible capital	0.4	-	0.4
13.	Amortization of C.D.E. and C.O.G.P.E	0.4	-	0.4
14.	Cash based pension and OPEB costs	42.6	-	42.6
15.	Total Deduction - Federal	333.1	(3.1)	330.0
16.	Total Deduction - Provincial	333.1	(3.1)	330.0
17.	Taxable income - Federal	272.1	48.3	320.4
18.	Taxable income - Provincial	272.1	48.3	320.4
19.	Income tax rate - Federal	15.00%	0.00%	15.00%
20.	Income tax rate - Provincial	11.50%	0.00%	11.50%
21.	Income tax provision - Federal	40.8	7.3	48.1
22.	Income tax provision - Provincial	31.3	5.5	36.8
23.	Income tax provision - combined	72.1	12.8	84.9
24.	Part V1.1 tax			1.7
25.	Investment tax credit			(0.1)
26.	Total taxes excluding tax shield on interest expense			86.5
	Tax shield on interest expense			
27.	Rate base (M2.T1.S2.P1)			4,091.5
28.	Return component of debt (M2.T1.S4.P1)			3.32%
29.	Interest expense			135.7
30.	Combined tax rate			26.50%
31.	Income tax credit			(36.0)
32.	Total income taxes			50.5

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 4, page 3, Filed: 2012-09-12.

UTILITY CAPITAL STRUCTURE
2013 TEST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and medium term debt	2,312.8	56.53	5.90	3.335
2.	Short term debt/(investment)	(39.7)	-0.97	2.00	(0.019)
3.		2,273.1	55.56		3.316
4.	Preference shares	100.0	2.44	3.20	0.078
5.	Common equity	1,718.4	42.00	9.03	3.793
6.		4,091.5	100.00		7.187
7.	Utility income	($Millions)			289.0
8.	Rate base	($Millions)			4,091.5
9.	Indicated rate of return				7.063%
10.	(Deficiency) in rate of return				(0.124)%
11.	Net (deficiency)	($Millions)			(5.1)
12.	Gross (deficiency)	($Millions)			(6.9)
13.	Customer Care/CIS deficiency	($Millions)			(11.0)
14.	Total gross (deficiency)	($Millions)			(17.9)
15.	Revenue at existing rates	($Millions)			2,370.3
16.	Revenue requirement	($Millions)			2,388.2
17.	Total gross revenue (deficiency)	($Millions)			(17.9)

CHANGE IN REVENUE REQUIREMENT
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted ADR Impact Statement	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 ADR Impact Statement EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	4,103.7	(12.2)	4,091.5	70.5	4,162.0
2.	Required rate of return	7.19	(0.34)	6.85	6.44	6.85
3.		295.1	(14.8)	280.3	4.6	284.9
	Cost of service					
4.	Gas costs	1,307.9	34.9	1,342.8	-	1,342.8
5.	Operation and maintenance	348.3	(22.8)	325.5	89.4	414.9
6.	Depreciation and amortization	288.1	(21.5)	266.6	12.7	279.3
7.	Fixed financing costs	2.3	-	2.3	-	2.3
8.	Debt redemption premium amortization	-	-	-	-	-
9.	Company share of IR agreement tax savings	-	-	-	-	-
10.	Municipal and other taxes	40.1	(0.8)	39.3	-	39.3
11.		1,986.7	(10.2)	1,976.5	102.1	2,078.6
	Miscellaneous operating and non-operating revenue					
12.	Other operating revenue	(38.3)	(6.0)	(44.3)	-	(44.3)
13.	Interest and property rental	-	-	-	-	-
14.	Other income	(0.7)	-	(0.7)	-	(0.7)
15.		(39.0)	(6.0)	(45.0)	-	(45.0)
	Income taxes on earnings					
16.	Excluding tax shield	73.7	12.7	86.4	9.0	95.4
17.	Tax shield provided by interest expense	(35.8)	(2.3)	(38.1)	(0.9)	(39.0)
18.		37.9	10.4	48.3	8.1	56.4
	Taxes on sufficiency / (deficiency)					
19.	Gross sufficiency / (deficiency)	(81.9)	96.9	15.0	-	15.0
20.	Net sufficiency / (deficiency)	(60.2)	71.2	11.0	-	11.0
21.		21.7	(25.7)	(4.0)	-	(4.0)
22.	**Sub-total revenue requirement**	2,302.4	(46.3)	2,256.1	114.8	2,370.9
23.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(4.6)	(4.6)
24.	**Total revenue requirement**	2,302.4	(46.3)	2,256.1	110.2	2,366.3
	Revenue at existing Rates					
25.	Gas sales	1,923.9	45.6	1,969.5	80.2	2,049.7
26.	Transportation service	294.9	4.9	299.8	19.0	318.8
27.	Transmission, compression and storage	1.7	-	1.7	-	1.7
28.	Rounding adjustment	-	0.1	0.1	-	0.1
29.	Revenue at existing rates	2,220.5	50.6	2,271.1	99.2	2,370.3
30.	**Gross revenue sufficiency / (deficiency)**	(81.9)	96.9	15.0	(11.0)	4.0

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 2, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 3 of Exhibit F3, Tab 1, Schedule 1, Page 2, Filed: 2012-01-31.

UTILITY RATE BASE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1) ($Millions)	Col. 2 ADR Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Impact Statement Number 2 ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Total Adjusted ADR Impact Statement Rate Base Including CIS ($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,645.6	(23.3)	6,622.3	127.1	6,749.4
2.	Accumulated depreciation	(2,758.0)	10.5	(2,747.5)	(56.6)	(2,804.1)
3.		3,887.6	(12.8)	3,874.8	70.5	3,945.3
	Allowance for Working Capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
6.	Materials and supplies	31.9	-	31.9	-	31.9
7.	Mortgages receivable	0.2	-	0.2	-	0.2
8.	Customer security deposits	(68.7)	-	(68.7)	-	(68.7)
9.	Prepaid expenses	1.8	-	1.8	-	1.8
10.	Gas in storage	249.3	(0.9)	248.4	-	248.4
11.	Working cash allowance	0.3	1.5	1.8	-	1.8
12.	Total Working Capital	216.1	0.6	216.7	-	216.7
13.	Utility Rate Base	4,103.7	(12.2)	4,091.5	70.5	4,162.0

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 3, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2012-01-31.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	(23.3)	Cost or redetermined value Change is the result of the settlement of issues B1 through B7 and related descriptions contained within the Agreement.
2.	10.5	Accumulated depreciation Change is the result of the settlement of issue D7 and the related description contained within the Agreement.
10.	(0.9)	Gas in storage Change is the result of the settlement of issue B7 and the related description contained within the Agreement.
11.	1.5	Working cash allowance Change is the result of the settlement of issue B7 and the related description contained within the Agreement.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2013 TEST YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,350.9	4.0	14.8
2.	Items not subject to working cash allowance (Note 1)		(8.1)		
3.	Gas costs charged to operations	M2.T1.S4.P1.Col.3	1,342.8		
4.	Operation and Maintenance	M2.T1.S4.P1.Col.3	325.5		
5.	Less: Storage costs		(7.9)		
6.	Operation and maintenance costs subject to working cash		317.6		
7.	Ancillary customer services		-		
8.			317.6	(18.7)	(16.3)
9.	Sub-total				(1.5)
10.	Storage costs		7.9	62.5	1.4
11.	Storage municipal and capital taxes		2.2	24.4	0.1
12.	Sub-total				1.5
13.	Harmonized sales tax				1.8
14.	Total working cash allowance				1.8

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

GAS IN STORAGE
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2013 TEST YEAR

			Col. 1		Col. 2		Col. 3
Line No.		Volume	Impact Statement Number 2	ADR Adjustments	ADR Adjustments	Adjusted Volume	Adjusted ADR Impact Statement
		10*6 M*3	($Millions)	10*6 M*3	($Millions)	10*6 M*3	($Millions)
1.	January 1	1,425.1	328.4	(0.1)	(0.1)	1,425.0	328.3
2.	January 31	872.6	211.7	(33.0)	(7.3)	839.6	204.4
3.	February	446.8	120.1	(8.2)	(3.9)	438.6	116.2
4.	March	95.9	51.7	30.8	2.3	126.7	54.0
5.	April	44.4	50.2	25.2	1.8	69.6	52.0
6.	May	330.9	105.4	19.4	1.4	350.3	106.8
7.	June	720.0	178.2	13.9	0.9	733.9	179.1
8.	July	1,241.2	272.1	8.2	0.6	1,249.4	272.7
9.	August	1,763.8	366.3	2.3	0.1	1,766.1	366.4
10.	September	2,141.1	437.3	(3.2)	(0.4)	2,137.9	436.9
11.	October	2,246.7	462.6	(9.0)	(0.8)	2,237.7	461.8
12.	November	1,957.2	412.2	(36.1)	(5.2)	1,921.1	407.0
13.	December	1,478.4	318.6	(2.6)	(0.6)	1,475.8	318.0
14.	Avg. of monthly avgs.	1,109.4	249.3	0.7	(0.9)	1,110.1	248.4

UTILITY INCOME
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 2	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted ADR Impact Statement Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	1,923.9	45.6	1,969.5	80.2	2,049.7
2.	Transportation of gas	294.9	4.9	299.8	19.0	318.8
3.	Transmission, compression and storage revenue	1.7	-	1.7	-	1.7
4.	Other operating revenue	38.3	6.0	44.3	-	44.3
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.7	-	0.7	-	0.7
7.	Total operating revenue	2,259.5	56.5	2,316.0	99.2	2,415.2
8.	Gas costs	1,307.9	34.9	1,342.8	-	1,342.8
9.	Operation and maintenance	348.3	(22.8)	325.5	89.4	414.9
10.	Depreciation and amortization expense	288.1	(21.5)	266.6	12.7	279.3
11.	Fixed financing costs	2.3	-	2.3	-	2.3
12.	Debt redemption premium amortization	-	-	-	-	-
13.	Company share of IR agreement tax savings	-	-	-	-	-
14.	Municipal and other taxes	40.1	(0.8)	39.3	-	39.3
15.	Interest and financing amortization expense	-	-	-	-	-
16.	Other interest expense	-	-	-	-	-
17.	Total costs and expenses	1,986.7	(10.2)	1,976.5	102.1	2,078.6
18.	Ontario utility income before income taxes	272.8	66.7	339.5	(2.9)	336.6
19.	Income tax expense	37.9	10.4	48.3	8.1	56.4
20.	Utility net income	234.9	56.3	291.2	(11.0)	280.2

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 4, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 2, page 1, Filed: 2012-01-31.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	45.6	Gas sales Change is the result of the settlement of issues C1 through C5 and related descriptions contained within the Agreement.
2.	4.9	Transportation of gas Change is the result of the settlement of issues C1 through C5 and related descriptions contained within the Agreement.
4.	6.0	Other operating revenue Change is the result of the settlement of issues C6 and C7 and related descriptions contained within the Agreement.
8.	34.9	Gas costs Change is the result of the settlement of issues C1 through C5 and D2 & D3 and related descriptions contained within the Agreement.
9.	(22.8)	Operation and maintenance Change is the result of the settlement of issues C1 through C5 and D2 & D3 and related descriptions contained within the Agreement.
10.	(21.5)	Depreciation and amortization expense Change is due to the settlement of issues D1, D5, D9, D11 through D24 and related descriptions contained within the Agreement.
14.	(0.8)	Municipal and other taxes Change is the result of the settlement of issues D8 and the related description contained within the Agreement.
19.	10.4	Income tax expense Change is due to the impact on taxable income as a result of the settlement of all the issues identified above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted ADR Impact Statement Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes (M2, T1, S3, P1)	272.8	66.7	339.5
	Add			
2.	Depreciation and amortization	288.1	(21.5)	266.6
3.	Accrual based pension and OPEB costs	42.1	-	42.1
4.	Other non-deductible items	2.2	-	2.2
5.	Total Add Back	332.4	(21.5)	310.9
6.	Sub total	605.2	45.2	650.4
	Deduct			
7.	Capital cost allowance - Federal	234.8	(3.1)	231.7
8.	Capital cost allowance - Provincial	234.8	(3.1)	231.7
9.	Items capitalized for regulatory purposes	46.3	-	46.3
10.	Deduction for "grossed up" Part VI.1 tax	5.0	-	5.0
11.	Amortization of share/debenture issue expense	3.6	0.2	3.8
12.	Amortization of cumulative eligible capital	0.4	-	0.4
13.	Amortization of C.D.E. and C.O.G.P.E	0.4	-	0.4
14.	Cash based pension and OPEB costs	42.6	-	42.6
15.	Total Deduction - Federal	333.1	(2.9)	330.2
16.	Total Deduction - Provincial	333.1	(2.9)	330.2
17.	Taxable income - Federal	272.1	48.1	320.2
18.	Taxable income - Provincial	272.1	48.1	320.2
19.	Income tax rate - Federal	15.00%	0.00%	15.00%
20.	Income tax rate - Provincial	11.50%	0.00%	11.50%
21.	Income tax provision - Federal	40.8	7.2	48.0
22.	Income tax provision - Provincial	31.3	5.5	36.8
23.	Income tax provision - combined	72.1	12.7	84.8
24.	Part V1.1 tax			1.7
25.	Investment tax credit			(0.1)
26.	Total taxes excluding tax shield on interest expense			86.4
	Tax shield on interest expense			
27.	Rate base (M2.T1.S2.P1)			4,091.5
28.	Return component of debt (M2.T1.S4.P1)			3.52%
29.	Interest expense			143.9
30.	Combined tax rate			26.50%
31.	Income tax credit			(38.1)
32.	Total income taxes			48.3

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 4, page 3, Filed: 2012-09-12.

UTILITY CAPITAL STRUCTURE
2013 TEST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and medium term debt	2,461.9	60.17	5.80	3.490
2.	Short term debt/(investment)	56.7	1.39	2.00	0.028
3.		2,518.6	61.56		3.518
4.	Preference shares	100.0	2.44	3.20	0.078
5.	Common equity	1,472.9	36.00	9.03	3.251
6.		4,091.5	100.00		6.847
7.	Utility income	($Millions)			291.2
8.	Rate base	($Millions)			4,091.5
9.	Indicated rate of return				7.117%
10.	Sufficiency in rate of return				0.270 %
11.	Net sufficiency	($Millions)			11.0
12.	Gross sufficiency	($Millions)			15.0
13.	Customer Care/CIS deficiency	($Millions)			(11.0)
14.	Total gross sufficiency	($Millions)			4.0
15.	Revenue at existing rates	($Millions)			2,370.3
16.	Revenue requirement	($Millions)			2,366.3
17.	Total gross revenue sufficiency	($Millions)			4.0

Summary of Gas Cost to Operations
Year ended December 31, 2013

Item #		Col. 1 10^3m^3	Col. 2 \$(000)	Col. 3 $/10^3m^3$ (Col.2 / Col.1)	Col. 4 \$/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	2,062,200.2	232,482.7	112.735	2.991
1.3	Western - @ Nova - TCPL	938,105.2	112,398.0	119.814	3.179
1.4	Western Buy/Sell - with Fuel	1,849.7	225.9	122.138	3.241
1.5	Western - @ Alliance	954,694.8	119,568.5	125.243	3.323
1.6	Less TCPL Fuel Requirement	(70,759.0)	0.0		
1.	Total Western Canadian Supplies	3,886,090.9	464,675.1	119.574	3.173
2.	Peaking Supplies	37,998.7	9,406.9	247.560	6.568
3.	Ontario Production	730.0	144.4	197.809	5.248
4.	Chicago Supplies	1,832,109.7	253,812.3	138.536	3.676
5.	Delivered Supplies	1,553,462.5	221,208.9	142.397	3.778
6.	Total Supply Costs	7,310,391.8	949,247.6	129.849	3.445
	Transportation Costs				
7.1	TCPL - FT - Demand		232,978.8		
7.2	- FT - Commodity	2,931,396.1	15,884.3	5.419	0.144
7.3	- Parkway to CDA		3,238.4		
7.4	- STS - CDA		5,793.8		
7.5	- STS - EDA		4,687.0		
7.6	- Dawn to CDA		9,471.0		
7.7	- Dawn to EDA		22,582.0		
7.8	- Dawn to Iroquois		7,063.3		
7.9	Other Charges		0.0		
7.10	Nova Transmission		7,039.6		
7.11	Alliance Pipeline		42,819.4		
7.12	Vector Pipeline		24,970.4		
7.	Total Transportation Costs		376,528.0		
8.	Total Before PGVA Adjustment	7,310,391.8	1,325,775.6	181.355	4.812
9.	PGVA Adjustment		(175,419.3)		
10.	Total Purchases & Receipt	7,310,391.8	1,150,356.3	157.359	4.175

Summary of Gas Cost to Operations
Year ended December 31, 2013

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	7,310,391.8	1,150,356.3	157.359	4.175
11.	Storage Fluctuation	(50,729.1)	(7,982.7)		
12.	Commodity Cost to Operations	7,259,662.7	1,142,373.6	157.359	
13.	Storage and Transportation Costs		107,679.1		
14.	Gas Cost to Operations	7,259,662.7	1,250,052.7	172.192	4.569
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		92,706.0		
17.	Forecasted Gas Costs	7,259,662.7	1,342,758.8	184.962	4.907

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2013

Item #		
1.	Sendout To Operations	7,259,662.7
2.	T-Service Volumes	4,316,708.5
3.	Total Sendout	11,576,371.2
4.1	Residential Sales	4,095,952.3
4.2	Commercial Sales	2,499,322.9
4.3	Industrial Sales	437,628.5
4.4	T-Service	4,277,267.2
4.5	Rate 200 T-Service (Gazifere)	38,849.3
4.6	Rate 200 Sales (Gazifere)	124,230.8
4.7	Company Use	5,176.3
4.8	Unaccounted For (UAF)	73,092.0
4.9	Unbilled Forecast - Sales	496.3
4.10	Unbilled Forecast - T-Service	592.0
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,576,371.2

Summary of Storage & Transportion Costs
Fiscal 2013

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2013	Col. 2 Fiscal 2013 Storage Charges Recovered in Fiscal 2013	Col. 3 Fiscal 2012 Storage Charges Recovered in Fiscal 2013	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2013
	Storage				
1.1	Chatham D	132.3	74.6	57.3	131.9
1.2	Injection	122.7	38.1	87.8	126.0
1.3	Withdrawal	121.2	121.2	0.0	121.2
1.4	Market Based Storage	19,592.0	10,691.8	8,747.6	19,439.4
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	827.2	827.2	0.0	827.2
1.	Total Storage	20,795.4	11,752.9	8,892.8	20,645.7
2.	Total Transportation	65,550.7	35,832.5	29,496.5	65,328.9
	Dehydration				
3.1	Demand	1,001.1	547.2	450.5	997.7
3.2	Commodity	189.5	189.5	0.0	189.5
3.	Total Dehydration	1,190.6	736.8	450.5	1,187.2
4.	Total Storage & Other Costs	87,536.8	48,322.1	38,839.7	87,161.9
	Fuel Costs				
5.1	Tecumseh	3,411.2	2,235.0	1,349.4	3,584.4
5.2	Union Storage	1,074.3	696.0	413.6	1,109.6
5.3	Union Transportation	15,815.1	15,508.8	314.5	15,823.2
5.	Total Fuel Costs	20,300.6	18,439.9	2,077.4	20,517.3
6.	Total Storage & Transportation	107,837.3	66,762.0	40,917.1	107,679.1
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				107,679.1

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Historic Year	2012 Bridge Year Estimate	2013 As Filed	2013 ADR
Residential		2,975	2,869	2,844	2,831	2,786	2,716	2,680	2,670	2,640	2,593	2,562	2,523	2,492	2,491	2,568
	Change		-106	-25	-13	-45	-70	-36	-10	-30	-47	-31	-39	-31	-1	77
	% Change		-3.56%	-0.87%	-0.46%	-1.59%	-2.51%	-1.33%	-0.37%	-1.12%	-1.78%	-1.20%	-1.52%	-1.23%	-0.04%	3.09%
Apartment		79,237	79,588	80,512	81,828	81,783	78,307	85,577	99,377	123,734	141,644	161,844	150,684	159,642	151,222	154,877
	Change		351	924	1,316	-45	-3,476	7,270	13,800	24,357	17,910	20,200	-11,160	8,958	-8,420	3,655
	% Change		0.44%	1.16%	1.63%	-0.05%	-4.25%	9.28%	16.13%	24.51%	14.47%	14.26%	-6.90%	5.94%	-5.27%	2.42%
Commercial		17,249	17,042	17,001	17,000	16,877	16,470	16,614	17,066	17,931	18,530	19,203	19,461	19,772	19,648	20,230
	Change		-207	-41	-1	-123	-407	144	452	865	599	673	258	311	-124	582
	% Change		-1.20%	-0.24%	-0.01%	-0.72%	-2.41%	0.87%	2.72%	5.07%	3.34%	3.63%	1.34%	1.60%	-0.63%	2.96%
Industrial		57,075	54,320	51,791	54,856	50,563	51,424	53,620	58,779	73,938	88,264	106,163	108,872	113,866	108,350	109,481
	Change		-2,755	-2,529	3,065	-4,293	861	2,196	5,159	15,159	14,326	17,899	2,709	4,994	-5,516	1,131
	% Change		-4.83%	-4.66%	5.92%	-7.83%	1.70%	4.27%	9.62%	25.79%	19.38%	20.28%	2.55%	4.59%	-4.84%	1.04%

* All historical average uses are on a calendar-year basis and have been normalized to the 2013 Budget degree days as filed.

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Historic Year	2012 Bridge Year Estimate	2013 As Filed	2013 ADR
Rate 1		2,975	2,869	2,844	2,831	2,786	2,716	2,680	2,670	2,640	2,593	2,562	2,523	2,492	2,491	2,568
	Change		-106	-25	-13	-45	-70	-36	-10	-30	-47	-31	-39	-31	-1	77
	% Change		-3.56%	-0.87%	-0.46%	-1.59%	-2.51%	-1.33%	-0.37%	-1.12%	-1.78%	-1.20%	-1.52%	-1.23%	-0.04%	3.09%
Rate 6		21,565	21,221	21,093	21,275	20,970	20,447	20,960	22,243	24,871	26,685	28,873	29,007	29,941	29,132	29,878
	Change		-344	-128	182	-305	-523	513	1,283	2,628	1,814	2,188	134	934	-809	746
	% Change		-1.60%	-0.60%	0.86%	-1.43%	-2.49%	2.51%	6.12%	11.81%	7.29%	8.20%	0.46%	3.22%	-2.70%	2.56%

* All historical average uses are on a calendar-year basis and have been normalized to the 2013 Budget degree days as filed.

APPENDIX "B"
Enbridge Gas Distribution Inc.

EB-2011-0354

2013 Pension Costs

All parties agree that the 2013 pension costs amount is to be trued-up, such that Enbridge ultimately recovers in rates only the actual amount of its 2013 pension expense. To accomplish this, all parties agree to the creation of a Pension True-Up Variance Account (PTUVA) which will record any differences between the Company's forecast pension expense and the actual pension expense (both determined on an accrual basis). ~~All parties agree that the PTUVA will function so as to effect a true-up of pension expenses, as well as a smoothing of pension expense differences over future years in the event that the amounts recorded in the PTUVA are significant. To effect these outcomes, in future years the PTUVA will include any uncleared balances from previous years, as well as the difference between that year's forecast and actual pension expenses (again, on an accrual basis).~~ For the Test Year, the 2013 PTUVA will record differences between the forecast 2013 pension expense of $37.3 million and the actual 2013 pension expense. ~~In the event that the balance (positive or negative) of the 2013 PTUVA is $5 million or less, then the entire amount will be cleared along with the Company's other 2013 deferral and variance accounts. In the event that the balance (positive or negative) of the 2013 PTUVA is more than $5 million, then half of the accumulated balance will be cleared along with the Company's other 2013 deferral and variance accounts and the remainder will be transferred to the next year's PTUVA to be addressed in the same manner.~~

~~By way of example, if the actual pension expenses for 2013 exceed forecast pension expenses by $8 million, then that amount will be recorded in the 2013 PTUVA, and $4 million will be cleared to the credit of Enbridge, at the time that Enbridge's 2013 deferral and variance accounts are cleared. The remaining balance of $4 million will be transferred to the 2014 PTUVA, which will also record the difference between 2014 forecast and actual pension expenses, After the end of 2014, the balance of the 2014 PTUVA (if it is less than $5 million) will be cleared. If the balance of the 2014 PTUVA is greater than $5 million, then half of the balance will be cleared and the other half will be transferred to the 2015 PTUVA.~~

~~All parties agree that a different approach to the clearance of balances in the PTUVA may be agreed upon in future proceedings considering the disposition of such balances, if the approach set out above is deemed to be inappropriate in the circumstances~~.

APPENDIX “C”
Enbridge Gas Distribution Inc.

EB-2011-0354

List of Discussion Points

1. Understanding of the Board’s capital structure policy (as contained in the EB-2009-0084 Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities)

2. Application of the Fair Return Standard

3. Assessment of Business Risk

4. Assessment of Financial Risk

5. Regulatory tools to manage Financial Risk

6. Assessment of Capital Market Conditions

7. Credit Ratings agency reports and the assessment of the potential for a downgrade

8. Development and use of a list of comparable utilities

9. Selection of the recommended Equity Ratio for Enbridge

APPENDIX “D”
Enbridge Gas Distribution Inc.

EB-2011-0354

CANDAS Joint Written Statement
dated July 20, 2012

FMC LAW

Fraser Milner Casgrain LLP
77 King Street West, Suite 400
Toronto-Dominion Centre
Toronto, ON, Canada M5K 0A1

MAIN 416 863 4511
FAX 416 863 4592

FILED ELECTRONICALLY AND VIA COURIER

Helen T. Newland
Helen.Newland@FMC-law.com
DIRECT 416-863-4471

July 20, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
PO Box 2319, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: Application by Canadian Distributed Antenna Systems Coalition ("CANDAS"); Board File No.: EB-2011-0120

Pursuant to Procedural Order No. 11 dated June 19, 2012 and the Board's letter dated July 19, 2012, the Applicant, CANDAS, submits for filing on behalf of itself and Toronto Hydro Electric Systems Limited ("THESL"), the enclosed joint written statement of Patricia Kravtin, Johanne Lemay, Michael Starkey and Adonis Yatchew, with respect to policy and economic issues.

CANDAS and THESL regret the delay in the filing of the enclosed and apologise for any inconvenience that this may cause.

Yours very truly,

(signed) H.T. Newland

YMS/bac

cc: All Intervenors

EB-2011-0120

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 Canadian Distributed Antenna Systems Coalition for certain orders under the *Ontario Energy Board Act, 1998*.

Joint Written Statement

Johanne Lemay
Patricia Kravtin
Michael Starkey
Adonis Yatchew

July 20, 2012

TABLE OF CONTENTS

PREAMBLE

1. This joint written statement is filed by Patricia Kravtin, Johanne Lemay, Michael Starkey and Dr. Adonis Yatchew (collectively, the "**Experts**") with the Ontario Energy Board ("the **Board**") in connection with an application by the Canadian Distributed Antenna Systems Coalition ("CANDAS") on behalf of its members, received on April 25, 2011 and subsequently amended by letters dated May 3 and June 7, 2011 (Board Docket Number EB-2011-0120) (the "**Application**"), seeking the following orders of the Board:

> "(a) Orders under subsections 70(1.1) and 74(1) of the Ontario Energy Board Act, 1998 (the "Act"): (i) determining that the Board's RP-2003-0249 Decision and Order dated March 7, 2005 (the "CCTA Order") requires electricity distributors to provide "Canadian carriers", as that term is defined in the Telecommunications Act, S.C. 1993, c. 38, with access to electricity distributor's poles for the purpose of attaching wireless equipment, including wireless components of distributed antenna systems ("DAS"); and (ii) directing all licensed electricity distributors to provide access if they are not so doing;
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> (b) in the alternative, an Order under subsection 74(1) of the Act amending the licences of all electricity distributors requiring them to provide Canadian carriers with timely access to the power poles of such distributors for the purpose of attaching wireless equipment, including wireless components of DAS; …
>
> (e) an Order under subsections 74(1) and 70(2)(c) of the Act amending the licences of all licensed electricity distributors requiring them to include, in their Conditions of Service, the terms and conditions of access to power poles by Canadian carriers, including the terms and conditions of access for the purpose of deploying the wireless and wireline components of DAS, such terms and conditions to provide for, without limitation: commercially reasonable procedures for the timely processing of applications for attachments and the performance of the work required to prepare poles for attachments ("Make Ready Work"); technical requirements that are consistent with applicable safety regulations and standards; and a standard form of licensed occupancy agreement, such agreement to provide for attachment permits with terms of at least 15 years from the date of attachment and for commercially reasonable renewal rights;
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> (f) its costs of this proceeding in a fashion and quantum to be decided by the Board pursuant to section 30 of the Act; and
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> (g) such further and other relief as the Board may consider just and reasonable."

2. Pursuant to Procedural Order No. 11 dated June 19, 2012, the Experts met and conferred with respect to policy and economic issues. Mr. Ken Rosenberg acted as facilitator for the expert pre-hearing conference. Board staff and counsel for CANDAS and THESL also attended the expert pre-hearing conference.

3. The parties and Experts understand that the expert pre-hearing conference is subject to the rules relating to confidentiality and privilege contained in the Board's *Settlement Conference Guidelines* (the "**Guidelines**"). The parties understand this to mean that the documents and other information provided, and the discussion of each issue during the expert pre-hearing conference, are strictly confidential and without prejudice.

4. Outlined below is a summary of the Experts' positions on economic and policy issues.

SUMMARY OF POSITIONS

Lemay / Kravtin	**Starkey / Yatchew**
1. What are the guiding principles governing mandated access to utility poles?	
The relevant standard for regulation of monopoly pole assets is a public interest standard that achieves: (1) efficient use and avoids undesirable duplication of utility poles; (2) avoids cross-subsidy (as measured against the underlying cost of service and not the excessive "market" price the utility can extract, given its market power); and (3) technological and competitive neutrality, resulting in lower prices and greater innovation in telecommunications services deemed critical to society – including utility ratepayers. There is no workably competitive or well-functioning market for electric distributors' monopoly utility pole assets that can substitute for regulatory intervention.	Proper application of the essential facilities doctrine holds that utility distribution poles are an essential facility for wireline attachments. Distribution poles are not an essential facility for wireless attachments because wireless carriers have numerous siting alternatives. From a public interest perspective, at a time when there are enormous upward pressures on electricity costs, it is inappropriate for electricity customers to subsidize other entities by allowing them to pay below market rates for access to electricity industry assets.
2. What are the key characteristics of utility pole networks?	
The unique attributes of utility poles that make shared use necessary, efficient, and desirable (*i.e.*, essential) for the provision of telecommunications services, applies to all manner of needed carrier attachments. No other attachment sites possess the same attributes of poles, *i.e.*, ubiquity, even spacing, relatively uniform height, access to power and provision of contiguous/continuous corridors. Evolving small-cell wireless technologies (such as DAS technology), like the facilities used to provide wireless telecommunications and television services, require, from a technical and economic perspective, a network of lower, uniformly spaced support structures, i.e., utility poles.	The important attributes of utility distribution poles from the perspective of wireless networks are also available on other accessible structures.

3. Are there any close substitutes to pole attachments?

The mere existence of (or even the number of alternatives) is not relevant if they do not constrain the monopoly pole owner's market power over poles. Wireline telecommunications and cable television services may also be deployed without access to poles – but access to poles is nonetheless mandated. Were this standard applied consistently, telecommunications carriers or cable television providers too could have been denied mandated access to poles in Ontario or elsewhere.

The demand for, and supply of**,** wireless attachment sites have grown dramatically over the last decade. Existing mobile carriers currently attach more than 7,000 wireless antennas at more than 1,300 unique locations throughout Toronto - none of which are THESL utility distribution poles. There is no evidence that this market for siting wireless equipment requires regulatory intervention.

4. What are the relevant market definitions to inform appropriate regulatory treatment?

Poles are a vital *input* to the provision of telecommunications services (*i.e.* the final service or *output*). Definitions of both input and output markets come into play in evaluating electric distributors' market power over poles. Following accepted principles**,** Lemay/Kravtin define the relevant output market applicable to mobile broadband services as the convergent telecommunications market where all manner of wireline and wireless services compete. We define the relevant input market as the market for pole attachments. Alternatives to poles have to be sufficiently close substitutes to be included in the relevant input market.

The single most important market for the present proceeding is the market for siting of wireless facilities. The existence of multiple sites and a workable siting market strongly favours reliance and promotion of existing siting markets. Fair, reasonable and efficient attachment prices to utility distribution poles should be determined within these markets. The existence of freely negotiated contracts for non-essential pole attachments in other jurisdictions (and in Toronto) is consistent with a workably competitive siting market.

5. Is there a basis for differentiating between wireline and wireless attachments to utility poles?

For the multitude of reasons set forth in the Lemay/Kravtin comments in this report (as well as in their pre-filed Evidence), there is no sound basis to discriminate between wireline and wireless carriers for purposes of attachment to poles. That wireless companies have entered into agreements to attach their facilities to utility poles does not in any way provide evidence of the existence of a fair, workable, or well functioning market for poles.

Wireline and wireless attachments are fundamentally different. Utility distribution poles are essential facilities for the former but not for the latter. Our regulatory approach treats these in a non-discriminatory fashion: wireline attachments, regardless of ownership, pay regulated attachment rates. Non-wireline attachments pay rates determined in the market-place. It is essential to emphasize that THESL is not denying CANDAS or any other potential telecom attacher access to its utility distribution poles. It is simply asking that non-essential attachers pay rates determined by market forces.

A. THE KEY CHARACTERISTICS OF POLE NETWORKS

(1) Where utility distribution poles are the primary support structure, they

(i) are generally ubiquitous;

(ii) are relatively evenly spaced;

(iii) are of relatively uniform height;

(iv) are accessible for utility purposes;

(v) access to power is available; and

(vi) provide contiguous/continuous corridors.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
The key defining and unique characteristics of a utility pole network that render poles vital for telecommunications carriers, cable television providers and other public utilities, are true of pole networks anywhere, regardless of whether they are owned by the electric utility, or incumbent telephone company and regardless of the purpose for which such attachers seek a right of attachment. They are not affected by financial ownership arrangements, which can and in fact do shift over time.	While the above characteristics are common features of joint-use poles, it is important to keep in mind that pole networks are essential facilities for wireline attachments, but not generally for other types of attachments. As wireless technologies evolve, they are being designed to function across a wide spectrum of attachment environments, including those with varying heights and access to multiple backhaul options. It is for this reason that wireless carriers have been able to deploy extensive networks (including in Toronto) without access to utility distribution poles. As Mr. Starkey described in his evidence, wireless carriers as of August 2011 had installed 7,000 antennas in more than 1,300 unique location in Toronto. Mr. Starkey and Dr. Yatchew believe this evidence makes clear that the "unique nature of electricity distribution poles" as discussed above, are not "essential" to the placement of wireless attachments. That said, Mr. Starkey and Dr. Yatchew recognize that electricity distribution poles have value for the placement of wireless attachments. The primary disagreement between us and the CANDAS experts is how that value should be managed. We believe the CANDAS position transfers that value to CANDAS shareholders. We prefer allowing markets to establish the true value and to drive any proceeds to THESL ratepayers.

(2) Poles are ideally suited for the most efficient and least disruptive deployment of the high capacity fiber optic cabling that is an essential component of a DAS system capable of high speed data throughput.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
While the foregoing statement is true of fiber optic cables, it is also true for wireless facilities and in particular, for small-cell outdoor wireless technologies, including DAS. The notion espoused by Starkey/Yatchew that some attachments used to provide telecommunications services are essential attachments, while others are not, is logically flawed. This is most evident in the case of outdoor DAS technology, where the provision of ubiquitous broadband telecommunications services requires both wireline and wireless attachments.	Utility distribution poles are not an essential facility for wireless attachments. Poles are ideally suited for the most efficient and least disruptive deployment of above-ground wireline systems of various kinds, among them electricity distribution wires, telephone lines, cable company lines and fiber optic cable. Such wireline systems are essential to numerous industries. However, their essentiality does not confer mandated access to public pole systems for their non-essential attachments.

(3) THESL owns the overwhelming majority of utility distribution poles in Toronto.

[AGREEMENT]

(i) That network of poles generates market power in the supply of poles.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
	A claim that an entity has market power without a definition of the relevant market is not meaningful. For example, OPEC does not have market power per se. It has market power in the oil market, but not in the market for clothes-lines. Similarly, ownership of a network of poles generates market power in the market for wireline attachers (for which poles are essential facilities), but not necessarily in other markets.

(ii) That network of poles generates market power in the production of some good, *i.e.*, wireline attachments.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
While the foregoing statement is true with respect to wireline attachments, it is also true for wireless attachments, for example, for small-cell outdoor wireless technologies, including DAS. For example, if the pole owner may extract a rental rate for use of the asset that is one or two orders of magnitude, times the full cost-recovery based regulated rate, then, by standard economic measures of market power that would be sufficient evidence of substantial market power. The fact that wireless companies have entered into agreements with the utility to attach their facilities to utility poles does not in any way provide evidence of the existence of a fair, workable, or well functioning market.	In order to justify regulatory intervention on the basis of a market power argument, a finding of market failure would be critical. In considering prices, the relevant reference would be the market price for siting attachments, not a regulated price. Furthermore, it is not uncommon for workably competitive markets (including telecommunications markets) to display substantial price differentials for similar products. Such price differentials do not imply that regulatory intervention is required or even desirable. The existence of freely negotiated contracts for non-essential pole attachments in other jurisdictions (and now in Toronto) is consistent with a workably competitive siting market.

A.1 <u>KEY CHARACTERISTICS OF SITING OPTIONS OTHER THAN POLES</u>

(4) There are attachable facilities other than electricity distribution poles that are ubiquitous and available in a variety of spacings and heights. Wireless carriers currently and overwhelmingly use structures other than electricity distribution poles to which they attach wireless antenna and supporting equipment in Toronto and elsewhere. Those structures include the sides of buildings, rooftops, street furniture, self-erected structures and others. A list of thousands of wireless sites in Toronto is publicly available.[1]

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
There are no other attachable facilities other than utility poles – including electricity distribution poles – that are ubiquitous and evenly spaced and	The need for "ubiquity" in relation to wireless attachments depends in large part on the wireless technology in question. Macrocell technologies

[1] Starkey Evidence, pg. 27.

of relatively uniform height. Neither rooftops nor side walls of buildings, nor towers possess these attributes. Starkey/Yatchew do not deny this; indeed, as pointed out in the Starkey/Yatchew language above, facilities other than poles are of a variety of spacings and heights. Unless alternatives are sufficiently close substitutes in an economic sense in terms of actual or perceived physical and technical attributes, they do not constrain the pole owner's market power over the supply of poles. Furthermore, mounting antennas on building sides or walls is not feasible for the deployment of wireless or hybrid outdoor systems, such as DAS and WiFi. A similar rationale applies to the wireline networks of telcos and cablecos.	(the predominant method of providing wireless coverage), require an antenna every few kilometers depending upon topography and demand. "Ubiquity" in that context is clearly achievable by means other than utility distribution poles (indeed, electricity distribution poles do not provide necessary elevation for most macrocell applications). Further, in modern heterogeneous wireless networks,[2] a combination of macro and small cell technologies are employed in layers to provide broader coverage and capacity focused on high-demand areas. These newer architectures allow a carrier to use multiple attachment options to deploy and shape their networks. These options allow wireless carrier to consider utility distribution poles as but one alternative among many upon which to place their wireless equipment.

(5) There are multiple commercial wireless networks that are deployed without attachment to poles.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
The foregoing is true for both wireline and wireless carriers. The existing policy of mandating access to poles for the provision of telecommunications services does not require satisfaction of an absolute or impossibility standard, *i.e.*, a showing that commercial deployment is impossible without attachment to utility poles, to be in the public interest. For example, wireline networks are deployed and both telecommunications and television services are provided without the use of poles – but poles are nonetheless mandated for all in a competitively and technologically neutral manner. Moreover, from a practical perspective, while access to poles may not have been required for yesterday's mobile networks, it is required now	Wireline networks are deployed almost exclusively on poles or underground (conduit or direct buried). Wireless attachments clearly have a variety of siting options.

2 See Starkey Evidence, pgs. 33-35.

and in the future to provide ubiquitous mobile broadband services (*e.g.*, for the placement of antennas).[3]	

(6) DAS deployments require more antennas per fixed geographic area than macrocell deployments.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
See Lemay/Kravtin comment in A.1 (4).	The value of electricity distribution poles to CANDAS, because it has chosen a rather unique application of DAS across the metro area to provide "blanket coverage," may be higher than it is for other carriers who are pursuing more flexible network architectures. We do not fail to recognize this "private interest" value on the part of CANDAS relative to accessing THESL's electricity distribution poles. Where we disagree with CANDAS, is whether this <u>private</u> interest value is sufficient to warrant regulatory intervention on the part of the Board, to amend the distribution licences of every electricity distributor in Ontario.

(7) Structures to which wireless carriers in Toronto currently attach their wireless equipment vary in height.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
See comment in Lemay/Kravtin comment in A (2), A.1 (4) and A.1 (5).	

3 See the advantages of small-cell technologies including outdoor DAS for all mobile carriers as described in the July 26, 2011 Evidence of Johanne Lemay on pp. 20-21, which require utility poles to be efficiently deployed in a given area.

(8) Fiber optic cabling, access to power and the proper placement height for wireless antennas is available on structures in Toronto other than utility distribution poles.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
See Lemay/Kravtin comment to A(1)(4) and A(1)(5).	This statement is factual. COGECO (CANDAS' business partner) lights more than 500 buildings in Toronto with fiber and has more than 500 kilometers of fiber spread throughout Toronto. Likewise, Bell's policy is to light any building requiring more than 300 telephone lines.[4] Access to power is self-evident in the context of buildings and other structures (i.e., signage, etc.). Finally, wireless carriers today are using buildings and self-erected structure to attach multiple wireless technologies, both macrocell and others. Indeed, the proliferation of small cell technologies is accelerating, in part, because they are more flexible with regard to where they can be placed effectively. While the CANDAS experts may believe electricity distribution poles are superior for the CANDAS application with regard to these characteristics, we do not understand why this statement cannot be agreed to with that caveat.

B. THE SHARED USE OF UTILITY POLES (AND OF OTHER INFRASTRUCTURE) BY TELECOMMUNICATIONS ATTACHERS

(1) Electric and telephone utilities came to own pole networks by virtue of their historical incumbency, as a result of public policies to establish and promote the widespread availability of electric and phone services to the population at large, including grants of ownership rights or easements to public rights of way corridors.

[AGREEMENT]

[4] Starkey Evidence, pg. 47.

(2) From a public interest point of view the sharing of existing pole networks of incumbent electricity and telephone utilities is desirable, economically efficient and strongly encouraged by regulators**.**

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
The desirability of shared use of utility pole networks for telecommunications purposes holds true regardless of the particular type or types of facilities attached by the joint users. This is consistent with principles of non-discrimination and technological and competitive neutrality that apply to public good facilities such as utility pole networks. Applying these relevant principles, there is no distinction to be made between wireline and wireless carriers, subject only to their compliance with objective safety and engineering standards.	Sharing of pole networks has been encouraged by regulators for the placement of wireline facilities by electricity, telephone and cable companies.

(3) It is not practically or economically feasible, nor in the public interest, for a new entrant to install a duplicate pole network analogous to the existing utility network of poles. Therefore, the sharing of pole networks has been strongly encouraged by regulators.

[AGREEMENT]

(4) The alternatives available to telecommunications attachers to accessing existing utility pole networks, such as building their own stand alone networks or going underground are decidedly inferior vis-à-vis the former.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
See reasons set out in A (1), A (2), and A (3)(i) .	Attachment of wireline facilities occurs on poles or through underground conduits. However, in the overwhelming majority of cases, telecommunications companies place their non-wireline attachments, such as antenna, on structures other than utility distribution poles.

(5) Wireless companies have entered into commercial agreements to attach wireless facilities to utility distribution poles, and other types of poles, without a regulator mandating access or setting a price.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
The fact that wireless companies have entered into agreements with the utility to attach their facilities to utility poles does not in any way provide evidence of the existence of a fair, workable, or well functioning market for poles. In addition, it is not “self-evident” that the 1300 sites on which the antennas referred to in the Starkey/Yatchew comment are technically suitable or economically efficient for the deployment of the new small-cell technologies (that include outdoor DAS) in Toronto.	The statement above is broader than electricity distribution poles. As provided in Mr. Starkey's evidence, agreements have been reached between wireless carriers and utilities (including THESL), but also between wireless carriers and municipalities, as well as building owners and tower management companies. It seems self-evident that where multiple carriers have been able to place 7,000 antennas to date, without the intervention of the Board, a workable market exists.

C. EVOLUTION OF THE TELECOMMUNICATIONS INDUSTRY (TECHNOLOGIES AND MARKETS)

(1) The telecommunications marketplace is dynamic, i.e. characterized by significant and fast paced changes in underlying technological and market conditions.

[AGREEMENT]

(2) The telecommunications marketplace has become increasingly competitive over the past couple of decades with increasing competition among service providers offering an increasing array of products.

[AGREEMENT]

(3) The telecommunications marketplace has become increasingly convergent over the past couple of decades with telecommunications and cable television companies increasingly competing for the same customers in the telephone, video distribution, broadband data and wireless marketplaces. In some areas, electricity distribution companies or their affiliates increasingly compete for the same customers in the telephone, video distribution, broadband data and wireless marketplaces.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
Mobile wireless carriers compete in the same relevant output market (*i.e.*, the convergent telecommunications market) with incumbent wireline carriers (who also happen to be the largest mobile wireless players in the country). This has been repeatedly recognised by the federal telecommunications regulator, the Canadian Radio-television and Telecommunications commission.[5] Regulation remains "necessary" where an outcome approximating a competitive market outcome is not "possible".	Convergence in telecommunications markets does not imply that one or another telecommunications company should be accorded a below market price where a market exists. A fair, balanced and efficient policy would allow markets to determine prices wherever possible, and the regulator to determine prices where necessary.

(4) In an increasingly convergent marketplace, markets that were traditionally thought of as "separate" markets will no longer function as separate or independent markets.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
See Lemay/Kravtin comment in C(3).	While certain segments of telecommunications markets are becoming interrelated, the distinct products continue to exist with their own price structures determined in separate markets.

5 See for example, *Navigating Convergence,* Second Report (2011). Executive Summary: "Telecommunications and broadcasting are rapidly converging into a single world of communications that offers innovative services to consumers, delivers these services in new ways and disrupts current business models. Consumers expect to access the services or content they want at anytime, anywhere, using whichever device they choose." See also Section 2.1.1 on Broadband Networks, which states: "Similarly, successive improvements in wireless data transfer speeds have made truly mobile internet access available almost everywhere. in the future, access to the internet through wireless networks will rival wired access for the delivery of all but the most bandwidth-intensive applications."

(5) Wireless carriers provide similar services as other wireline telecom carriers. In many cases, particularly in the case of incumbents, the same companies provide wireline and wireless services.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
See Lemay/Kravtin comment in C (3) and C (4). An increasing proportion of consumers find mobile/wireless and wireline services substitutable. They are similar services. This is demonstrated by data from Statistic Canada showing that more Canadians are disconnecting their fixed phone line in favour of mobile phone service alone. [6]	Only minor disagreement exists with respect to this statement. Some consumers certainly use wireless rather than wireline services and find them to be acceptably similar (i.e., they are "substitutes"), others prefer to use both, depending upon the scenario (i.e., they are "complements"). In still other situations, one or the other simply is not acceptable. e.g., I cannot use my wireline while in my car, and I cannot, today, effectively use my wireless service to access extremely high-bandwidth. We believe this description is more accurate than simply to say the services are "similar." We do agree that it is often the case that the same companies offer both wireline and wireless services in the same geographic market.

(6) There is a convergence in service offerings and intermodal competition as well as substitutability between wireline and wireless/mobile services.

[AGREEMENT]

6 http://www.statcan.gc.ca/daily-quotidien/110405/dq110405a-eng.htm: "In 2010, 13% of households reported they used a cell phone exclusively, up from 8% in 2008.This was particularly the case for young households. In 2010, 50% of households in the 18-to-34 age bracket were using only cell phones, up from 34% two years earlier. Among all other households, 8% used a cell phone exclusively, up from 5%."

(7) The evolution of regulatory theory and practice has moved towards promoting competition where possible and regulation where necessary. This approach has been widely applied in telecommunications industries.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
Regulation remains as "necessary" today as ever before, where an outcome approximating a competitive market outcome (*i.e.,* lower prices, innovative service offerings, efficient use of societal or public good resources) is not "possible," such as exists in the market for poles. In theory and in practice, pro-competition policies as applied in the telecommunications industry and other historically regulated industries have always considered the market power of the incumbent monopoly provider, and the extent to which that provider can exert control over unfettered market outcomes to the detriment of the public interest.	

(8) As wireless radio and antenna technologies evolve, they are increasingly more flexible as to the structures to which they can be attached and/or where they can be placed.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
Wireless technologies are evolving to provide mobile broadband services, and small-cell technologies are a key to achieving this goal. These small-cell technologies, including outdoor DAS, emit at much lower power outputs and have much shorter transmission range than conventional macro cells. Thus, they require support structures that have the attributes of pole networks as highlighted in A. (1). We cannot corroborate the fact that small-cell technologies are being deployed today in Toronto for mobile services on any scale without access to utility poles. Where they are deployed on any scale, such as in Montreal , utility poles are the key support structure.	It is true that small cell technologies have lower power output and shorter transmission ranges. It is also true that small cell antennas and radios are generally smaller in size, and more flexible in the ways in which they can be elevated/attached to reach wireless customers. Utility distribution poles are but one option to which these antennas can be attached as evidenced by the fact that they are being deployed today in growing numbers without access to THESL's electricity distribution poles.

(9) Heterogeneous wireless networks use more than one technology to provide coverage in a given geographic area.

[AGREEMENT]

(10) Heterogeneous wireless networks rely upon a combination of macro and small cell technologies to address the needs of customers across a diverse topography.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
While the foregoing statement is true, it does not diminish the fact that a mobile carrier may have reason or be forced to exclusively deploy small-cell technologies such as outdoor DAS in any given area.	

(11) Wireless carriers have multiple technologies to choose from when determining how best to serve a geographic area, outdoor DAS is one such option.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
See also Lemay/Kravtin comment in C (8) and C (10)]	

(12) The trend in wireless backhaul is toward Internet Protocol ("IP")-based backhaul systems that are not necessarily reliant upon fiber optic cables connected to each antenna.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
The foregoing statement makes no sense and is not technically accurate. More importantly, from a policy and economic perspective, just because one can find examples of telecommunications and broadcasting services that are provided without access to poles does not fundamentally alter the unique attributes of pole networks. For every such example, there are examples, such as on the facts of this proceeding, of new technologies, such as small-cell wireless technologies, that do require access to poles. Given the rapid technological change that characterises our era, the public interest standard requires, among other things, a **technologically neutral** approach to regulation.	There is a strong trend in the industry to utilize IP backhaul options. IP need not rely solely upon fiber optic cable but can be transmitted via copper and coaxial cabling. Small cell technologies are being designed today to utilize these existing transmission mechanisms so as to obviate the need to access fiber where it does not exist, and as a result, increase the number of environments in which small cells can be placed/operated.[7] Mr. Starkey has clarified that he talking about any IP infrastructure available to commercial enterprises and is not limiting the discussion to DSL [Digital Subscriber Line] or cable modems.

D. <u>MARKET FAILURE</u>

(1) A central consideration in determining whether regulation is necessary is the identification of a market failure. A monopoly in the provision of a good or service can be the basis for regulatory intervention. The presence of existing or potential providers of a good or service can be the basis for regulatory forbearance.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
As discussed in sections A and A.1 above, poles are monopoly assets and there are no sufficiently close substitutes to constrain the pole owner's	

[7] See Starkey Evidence, pg. 37.

market power. As discussed here and in D.(2), Identification of market failure is only one of a number of public interest criteria that provide a basis for regulatory intervention.	

(2) A showing of market failure is not necessary under a public interest standard in order to justify regulation of pole access.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
The ultimate policy and economic question in this case is whether to apply the Board's *existing* regulation of pole attachment services in a non-discriminatory manner to all telecommunications carriers, consistent with a public interest standard, as more fully discussed in E (1) and E (2) below. A public interest standard for regulation takes into account multiple real-world criteria (*e.g.*, competitive and technological neutrality, efficient use of resources *etc.*) that are both independent of and highly interrelated to the theoretical concept of market failure.	The policy we propose is non-discriminatory: wireline attachers are charged regulated rates because of the absence of alternatives; wireless attachment rates are negotiated because of the presence of alternatives.

(3) The public utility's monopoly control over its distribution pole assets applies to all telecommunications carriers.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
Starkey/Yatchew's conclusion that the utility does not have monopoly power is based on an incorrect definition of the relevant input market, in which they incorrectly include alternatives that are not sufficiently close substitutes to poles. See the discussion of relevant input and output markets in G (1) and G (2) below. See also Lemay/Kravtin comments in A.1 (4) and A.1 (5) which discuss the inferiority, from both an economic and technical perspective, of other wireless siting options, as compared to poles.	(i) We would agree to the following statement: "The public utility's monopoly control over its distribution pole assets applies to all telecommunications carriers wishing to attach wireline facilities." (ii) Clearly, the public utility does not have monopoly control over wireless sites: most wireless antenna are not attached to utility distribution poles. (iii) As indicated earlier, the existence of market power or monopoly must be defined in relation to a specific market. Neither THESL nor any pole

	owner has monopoly power over the siting market for wireless attachments. Pole owners do have market power over wireline attachers, be they telecommunications companies, traditional cable companies or electricity companies.

(4) A market failure exists where the owner of the asset is able to extract monopoly rent, *i.e.*, a price that is well in excess of the utility's incremental cost of providing access.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
Where a firm can limit access to or charge a supra-competitive price for an input (*i.e.*, poles) needed to provide a downstream or final service (*i.e*., telecommunications), market failure occurs in the form of reduced efficiency and the loss of economic welfare resulting from the less efficient use of resource. See also Lemay/Kravtin comment in D (5) below. Monopoly level rents are typically many order of magnitudes in excess of marginal cost. However, it is important to note that the OEB's regulated per-pole attachment rate for communications attachers is in fact based on a full cost-recovery standard, resulting in a rate that provides equal sharing of common costs and exceeds incremental cost by an order of magnitude. Especially in combination with make-ready charges and other fees paid by the attacher in addition to the regulated rate, the utility is ensured cost recovery well in excess of the incremental cost of attachment. This excess is pure contribution to the utility's core electric distribution service.	The idea that market failure exists and regulatory intervention is required whenever prices depart significantly from incremental costs is incorrect. It is unlikely that any telecommunications company could survive for long if it engaged in marginal cost pricing across its product offerings. In the present context, the relevant benchmark is the price determined in siting markets for wireless attachments.

(5) A market failure exists where the owner of the pole asset is able to dictate the mode and manner of an entrant's business plan by leveraging its monopolistic control over poles.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
By virtue of their market power over poles, incumbent electric distributors are in a position to delay, control, preclude or otherwise limit the range of deployment and technological options available to competitive telecommunications carriers. For example, in this case, Public Mobile had to completely redefine its network deployment plan to launch mobile voice and data services in Toronto. Public Mobile was forced to deploy using macro cell technologies on towers and rooftop and was prevented from fully executing its network deployment plans.	THESL is not in a position to dictate the business plans of telecommunications companies. THESL is required to attach the wireline facilities of cable and telecom entities and faithfully fulfills this obligation. THESL does not have monopolistic control of the siting market for non-wireline attachments and as such, poles do not constitute essential facilities for non-wireline attachments.

E. PUBLIC INTEREST STANDARD

(1) Sound regulatory policy should encompass principles of economic efficiency, fairness and competitive neutrality.

[AGREEMENT]

(2) In applying the public interest standard, sound regulatory policy takes into account:

(i) Technological neutrality;

(ii) Avoidance of impairment of competition;

(iii) Avoidance of unjust discrimination and undue preference;

(iv) Efficient use of public utility assets;

(v) Avoidance of undesirable duplication of pole networks;

(vi) Avoidance of cross-subsidy.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
A pole attachment fee in excess of an incremental	The list above is incomplete. The electricity

attacher's incremental costs would constitute a subsidy-free rate. This definition of a subsidy-free rate is well accepted in the economic and regulatory literature. The "commonly understood" definition referred to by Starkey/Yatchew is economically meaningful only where prices determined in the market-place approximate the price that would be achieved in an effectively competitive market, where market forces bid down price closer to cost. As explained in Lemay/Kravtin comment to D (4), the OEB's regulated per-pole attachment rate for communications attachers is in fact based on a full cost-recovery standard, resulting in a rate that provides equal sharing of common costs and exceeds incremental cost by an order of magnitude.	regulator also typically includes other considerations such as; 1. Environmental considerations. 2. Regulatory burden 3. Market solutions v. regulatory intervention 4. Public consultation 5. Impacts on electric utility customers 6. Appropriateness of a subsidy. CANDAS experts provide a narrow definition of subsidy-free rates. A more commonly understood definition of subsidy-free prices are prices which are not substantially below those determined in the market-place.

(3) Companies that compete directly in markets for their final services should face even-handed terms for access to shared resources.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
Competitive and technological neutrality require even-handed treatment of wireline and wireless carriers, regardless of who and what technologies they choose to use to deploy. Wireless carriers in particular, use a combination of wireline and wireless facilities, some of which may require attachment to poles in order to compete in the same final services market for convergent telecommunications services. See C (1) to C (6) above.	With the following clarification THESL experts could agree with this statement. An even-handed policy which applies equally to all telecommunications companies consists of two key elements: wireline attachment agreements are covered by regulation because utility distribution poles are essential facilities for such attachments; non-wireline attachment agreements are negotiated because poles are not essential facilities for such attachments.

(4) A regulatory policy that is competitively neutral is one that does not give one competitor in a given market an undue competitive advantage over another through preferential treatment, unrelated to that competitor's own efficiency in production or entrepreneurial skills.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
See Lemay/Kravtin comment in E (3) above.	The policy stated in E.(3) above with Starkey/Yatchew's clarification is competitively neutral.

(5) Access to poles should be mandated for all manner of telecommunications attachers for purposes of providing telecommunications services.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
See Lemay/Kravtin comment in E (3) above.	Mandated access to utility distribution poles is not driven by the industry within which a company participates, but by the essentiality of poles for certain types of attachments. Therefore as indicated in E.(3) above, including clarification, wireline facilities should receive mandated access; non-wireline facilities should not.

F. OTHER PUBLIC POLICY CONSIDERATIONS

(1) The same characteristics of poles that make access to poles necessary and efficient for the provision of telecommunications services using wireline facilities make it necessary and efficient for the provision of telecommunications services using wireless facilities and hybrid technologies, such as DAS.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
Poles are necessary and efficient for the provision of all manner of telecommunications and cable television services, for the reasons discussed in A	Poles are clearly not the efficient deployment platform for numerous wireless technologies. Companies using wireless technologies, including

(2), A (3) and A.1 (4). The mere existence of alternative support structures for both wireline and wireless telecommunications services in all of its many and varied forms, does not in and of itself constrain the market of the pole owner, owing to the unique attributes of poles identified in A(1). The same holds true for television services, which, depending on the technology chosen by the cable provider, could also be provided without access to poles.	DAS, routinely participate in siting markets to place their equipment. Neutral treatment of telecommunications companies would seem to require that CANDAS also participate in siting markets, of which utility distribution poles are only a portion.

(2) Pole networks are essential for the deployment of wireline systems belonging to electricity, cable and telecom companies. Pole networks are not essential for the attachment of wireless facilities belonging to telecom providers. Such facilities are routinely attached to a range of support structures such as buildings, towers and other street furniture.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
See Lemay/Kravtin comment above in F (1).	See prior comments in A.(1), (5), (9), etc.

(3) Workable or well functioning competitive markets are generally seen to be preferable to regulation. Regulation is a second best alternative to workable or well functioning markets. An important objective of a regulator is the promotion of competition and workable or well functioning markets where possible.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
Lemay / Kravtin would prefer “well-functioning” but can agree to keeping “workable and well-functioning”. See Lemay/Kravtin comment in B (5), C (7), and D (2) above. The foregoing statement is not categorically true without the important qualifier that if the market in question is subject to the exercise of market power, regulation may be required for the public good. A regulatory policy that is competitively and technologically neutral is fully consistent with and the best way to promote competition.	We believe that the terminology "workably competitive" markets is a standard commonly used by regulators.

(4) Definition of a public good: A public good has two defining characteristics. One party's consumption does not reduce the amount that could be available for someone else. And, no one can be excluded from its consumption. (Classic examples of public goods include national defense, police services and lighthouses.)

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
More relevant to the Board is an understanding of how this concept has been applied to utility poles. The CRTC, the FCC, and the Eleventh Circuit Court of Appeals in the U.S. have held that utility poles possess the essential characteristics of a public good and/or are appropriately classified as public goods pursuant to a public interest standard.[8]	

(5) A central public policy objective of the electricity regulator is the protection of the interests of electricity ratepayers as part of the overall application of a public interest standard.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
	We agree with this statement with the following clarification. In this context, it would seem appropriate for the electricity regulator to consider mandated access for non-essential facilities at rates that are far below market, against the pressures on electricity prices. In time, if non-essential attachers were to pay market rates, benefits to electricity rate-payers could be in the many millions of dollars.

8 See CRTC Decision 2008-17, FCC EB Docket 04-381, Order 07D-01 (2007), and *Alabama Power*, 311 F.3d at 1370.

(6) Proliferation of attachments on poles is a valid public policy consideration.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
Because of the nonrivalrous characteristic of utility poles, space on a typical pole can, as a matter of routine practice, accommodate multiple users and uses without any tangible loss to the owner. Concerns regarding "proliferation" are unsubstantiated and unwarranted.	Proliferation of attachments contributes to visual pollution and may be opposed by citizens for this and other reasons.

(7) In the past, the CRTC has been involved in the regulation of the use of towers and buildings for mounting antennas. The CRTC is in the process of phasing out its tariffs associated with the shared use of towers and cell sites.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
The statement is incorrect as it pertains to phone company poles within the jurisdiction of the CRTC. To the extent that it pertains to towers and cell sites, Ms Lemay and Ms Kravtin have no information that would be corroborative of the veracity of this statement.	It is our understanding that wireless providers seeking to attach antennas to towers and structures belonging to others must negotiate prices and other terms of access.

(8) THESL experts are not aware of specific CRTC Decisions regarding Distributed Antenna Systems.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
Ms Lemay and Ms Kravtin have no information to corroborate the accuracy of the foregoing statements. Moreover, we are not able to evaluate the basis of Starkey/Yachew's determination of relevancy.	A search of the CRTC Decisions over the last 5 years did not reveal any specific directions with respect to "distributed antenna systems" that are relevant to the issues in this case.

(9) CRTC recognizes the convergence of telecommunications markets.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
See comment in C (3) above.	

(10) CRTC has classified poles as public good facilities.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
See paragraphs 90 to 93 of Decision 2008-17 for the CRTC's determination to mandate access to the ILECs' poles, not because they are "essential" (see CRTC's definition at paragraph 36) *per se*, but because they can be considered "public good" facilities.[9]	

(11) Industry Canada CPC-2-0-03 includes a default public consultation process that must be followed when installing a new radio antenna site.

[AGREEMENT]

(12) New antenna sites placed on structure less than 15m in height are excluded from the Industry Canada default public consultation process.

[AGREEMENT]

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9 See Telecom Decision CRTC 2008-17, *Revised regulatory framework for wholesale services and definition of essential service*, online: http://www.crtc.gc.ca/eng/archive/2008/dt2008-17.htm.

(13) THESL utility distribution poles are generally less than 15m in height.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
	Starkey/Yatchew confirm based upon information provided by THESL.[10]

(14) It is anticipated that none of the CANDAS proposed antenna sites on THESL poles would have been subject to the Industry Canada default public consultation process.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
Telecommunications antenna proposals that are exempted from the default consultation process outlined in CPC-2-0-03 are required to comply with a municipal consultation process adopted by the City of Toronto. See paragraph 3(a) in City of Toronto, Telecommunications Tower and Antenna Protocol, adopted January 27 and 29, 2009.	We appear to agree that CANDAS equipment placed on THESL utility distribution poles would not be subject to the Industry Canada <u>public</u> consultation process. Instead, those wireless sitings are subject to a consultation process with Toronto City Planning Staff per Section 3(a) of the City of Toronto Telecommunication Tower and Antenna Protocol.

G. <u>IDENTIFICATION OF RELEVANT MARKETS</u>

(1) What are the relevant market definitions to inform appropriate regulatory treatment?

[DISAGREEMENT]

Lemay / Kravtin	**Starkey / Yatchew**
The market for convergent telecommunications services is the relevant output market.	The market for wireless services is the relevant output market. The market for siting of wireless facilities is the relevant input market.

[10] Affidavit of Mary Byrne (sworn September 1, 2011), para. 6 and Ex. A.

The market for utility pole attachments is the relevant input market. There are no other attachable facilities that possess the unique attributes of poles.	There are thousands of wireless sites operating in Toronto owned by entities other than THESL.

H. ACCESS TO UTILITY POLES

(1) Towers and rooftops are decidedly inferior substitutes to poles. As such, they do not serve to constrain the market power of the utility owner.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
See A (1) and Lemay/Kravtin comments in A.1 (4) and A.1 (5) for reasons why, from an economic perspective, poles are unique and other wireless siting options are decidedly inferior. Counting up the total number of antennas in Toronto is not a meaningful exercise. Regulators have not imposed an impossibility standard for telecommunications attachers that seek to attach to poles. Were this standard applied consistently, no telecommunications carriers or cable television providers they too could have been denied mandated access to poles in Ontario or elsewhere. The reality is that telecommunications technology is constantly evolving. Small-cell technologies, including outdoor DAS, are just one example of new and innovative deployment options being developed. Small-cells cannot be efficiently deployed from a technical standpoint on support structures other than utility poles. See Lemay/Kravtin comment in C (8). This is not a matter of serving the private interests of a single company's business plan. The deployment of small-cell technologies is becoming a necessity for all carriers. Owing to the unique characteristics of pole, all telecommunications attachers derive "value" from attaching to utility poles, but that does not obviate the public interest basis or need for regulatory intervention.	See prior comments at A(1), A.1.(6) and B(4) related to the number of existing wireless antenna and unique locations and the unique nature of the CANDAS business plan.

(2) In the telecommunications market today, depending on the specific application or technology, lack of access to poles could be a significant or complete barrier to entry.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
Starkey/Yatchew in effect, argue for discrimination on the basis of evolving telecommunications technology. At a minimum, this forecloses innovation and competition in downstream output markets. It also turns the principle of technological neutrality on its head. See also Lemay/Kravtin comment in C (12) above.	See discussion of H1 above. Multiple wireless carriers operate in Toronto today using multiple types of radio transmission technologies, including DAS. As discussed above, they operate extensively throughout the city and provide competing wireless services without accessing THESL utility distribution poles. Given this data, it is difficult to agree that allowing THESL to negotiate with wireless attachers for terms and conditions related to accessing its distribution poles, without regulatory intervention, erects "significant or complete barrier[s] to entry."

(3) In this case, THESL was able to leverage its monopoly power to dictate the mode and manner of Public Mobile's launch in the Toronto market.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
See Lemay/Kravtin comment above in D (5).	THESL is not in a position to 'dictate' to Public Mobile, or any other telecommunications carrier, how they develop their business plans. If such business plans require a subsidy through below market attachment rates for non-essential facilities, then it would seem unreasonable for THESL to acquiesce to such rates at the expense of its rate-payers.

(4) Access to electricity distribution poles is required for the widespread deployment of outdoor DAS to provide blanket coverage.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Disagree**
As discussed in Lemay/Kravtin's comment in H (1) above, access to poles will clearly have value to any attaching entity, but that value does not in any way diminish the need to mandate access to poles. To the contrary, it supports the need.	We cannot agree to this statement. As stated previously, we agree that where CANDAS, as part of its business model intends to rely solely on outdoor DAS technologies placed across a broad geographic footprint to provide "blanket coverage," access to electricity distribution poles at regulated rates would have substantial value to CANDAS members and their shareholders. However, we also note that multiple wireless operators and business models that do not hold solely to a single technology are not so heavily reliant upon electricity distribution poles - indeed, they operate today without access to electricity distribution poles at all.

(5) Public Mobile

(i) Public Mobile purchased spectrum in the 2008 auction. (It was high frequency, G-Block spectrum.)

(ii) Public Mobile has access to power poles in Montreal.

(iii) Public Mobile was able to launch its service in Toronto without access to utility distribution poles for the siting of their wireless antennas.

(iv) The Public Mobile network was "turned on" in Toronto approximately a month earlier than in Montreal.

(v) Public Mobile rate offerings are essentially the same in Montreal and Toronto.

[DISAGREEMENT]

Lemay / Kravtin Disagree	**Starkey / Yatchew Agree**
Ms Lemay and Ms Kravtin cannot corroborate all of the foregoing. [11]	

[11] See July 26, 2011 Evidence of Johanne Lemay on pp. 13, 14, 25 and 27.

I. OPERATIONAL AND SAFETY CONSIDERATIONS

(1) Operational and safety considerations are routinely addressed by utilities and third party wireless attachers in negotiated pole attachment agreements entered into between utilities and third party attachers.

[DISAGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew**
Starkey/Yatchew's specifically address allegedly unique safety/operational concerns in their pre-filed Evidence. Moreover, the foregoing statement is not intended to and does not address the technical merits of THESL's contentions that there are unique operational and safety considerations associated with wireless attachments that justify a "no wireless policy." Rather, Ms Lemay and Ms Kravtin are providing their understanding that in practice, operational and safety considerations are routinely and properly addressed through reasonable terms and conditions of attachment agreements, electricity safety codes, and other objective standards.	Pursuant to the Board's procedural order, we understood that the Expert Conference would be limited to public policy and economic issues. As such, THESL's witness on technical matters, Ms. Byrne, did not attend.

(2) Safety:

(i) Safety, operational or engineering considerations are routinely addressed in pole attachment agreements between utilities and third party attachers through adherence with electrical safety standards and other objective standards of access.

(ii) Utilities are adequately protected:

A. Agreements typically provide that any safety violations are remedied at the third party's expense.

B. Failure to comply is grounds for penalties and the ultimate removal of third party attachments at the expense of the third party.

(3) Operational:

(i) Electric utilities routinely accommodate third party attachments of varying shapes and sizes on their poles.

(ii) The only objective standards that limit the placement of attachments on poles are electrical safety standards.

(iii) Space on poles is not scarce. The make ready process is a normal routine practice of electric utilities by which additional space on poles can be readily attained through rearrangement of wires or change out of the pole to a higher or stronger pole.

(iv) Where a third party user may require pole modifications or change out of poles to accommodate its use, through the make ready process, that user will pay for the out of pocket costs incurred by the utility in connection with its attachment. The utility maintains full ownership of whatever improvements are made to the pole to accommodate the new attacher.

Lemay / Kravtin Agree	**Starkey / Yatchew**
	See response to I.(1)

(4) “Communication space” is a term of art with specific meaning in the industry.

[AGREEMENT]

Lemay / Kravtin Agree	**Starkey / Yatchew Agree**
The space referred to as “communications space” is a term of art referring generally to space below the power zone and above ground clearances. Its meaning in the industry is strictly in the context of electrical safety standards whose purpose historically has been to ensure the safety of communications workers. As long as safety requirements are met, the space that may be used for communications attachments can and is routinely expanded. Thus, the amount of space on a pole that can be used to accommodate communications attachments is a variable function of the size of the pole and the arrangement of attachments pursuant to required clearances for safety purposes. It is also common industry practice for communications equipment to be located above or below the space designated pursuant to safety standards as “communications space.” Furthermore, the evidence on the record of this	The term "communications space" is known in the industry to define space below the power space. Likewise, it is known to include a finite space of roughly 2 feet within which wireline attachments are generally placed. While it is true that equipment supporting wireline network(s) is sometimes found outside the communications space, that equipment is relatively sparse compared to the number of wireline attachments. Wireless attachments of the type contemplated by CANDAS would provide equipment outside the communications space with respect to every wireless attachment.

matter shows cable companies attach equipment outside of the communication space more frequently (5 times per square kilometre) than DAS providers (4 times per square kilometre). See Tormod Larsen Reply Evidence, Appendix "A", pages 3 and 5.	

J. CCTA DECISION

Ms Lemay and Ms Kravtin do not agree to have this section in this report. They have not been asked and have not reviewed the entirety of the record of the CCTA proceeding. In addition, that record speaks for itself.

(1) The Settlement Agreement in the 2004 CCTA proceeding which was accepted by the Board specifically sets aside consideration of wireless attachments.[12]

[DISAGREEMENT] [OBJECTION]

Lemay / Kravtin	**Starkey / Yatchew Agree**
See above.	

(2) The word "wireless" appears but twice in the 500 pages of transcripts for the hearing. The term distributed antenna system appears not at all.

[DISAGREEMENT] [OBJECTION]

Lemay / Kravtin	**Starkey / Yatchew Agree**
See above.	

***** END OF DOCUMENT *****

12 Canadian Cable Television Association Proceeding, Settlement Agreement, October 19, 2004, page 10.

APPENDIX "E"
Enbridge Gas Distribution Inc.

EB-2011-0354

Case Timetable
Date: October 15, 2012

	Event	Date
1.	Experts' Conference	October 22 and 23
2.	File any revised Settlement Agreement	October 26
3.	File experts' Joint Written Statement	October 31
4.	File proposals on process	November 2
5.	Oral Hearing	November 19 and 20