500 Consumers Road
North York ,ON M2J 1P8
P.O. Box 650
Scarborough, ON
M1K 5E3

Lesley Austin
Regulatory Coordinator, Regualtory Affairs
Tel 416-495-6505
Fax 416-495-6072
Email: Lesley.Austin@enbridge.com

ENBRIDGE

November 16, 2011

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge") – Interrogatory Responses
2012 Rate Adjustment Application ("Application")
Ontario Energy Board ("Board") File Number EB-2011-0277

As directed in the Board's October 13, 2011, Procedural Order No. 1, enclosed please find Enbridge's responses to Interrogatories received from Intervenors in the above noted proceeding.

Exhibit I, Tab 1, Schedules 1 to 18;
Exhibit I, Tab 2, Schedules 1 and 9;
Exhibit I, Tab 3, Schedules 1 to 9;
Exhibit I, Tab 4, Schedules 1 to 14;
Exhibit I, Tab 5, Schedules 1 to 8;
Exhibit I, Tab 6, Schedules 1 to 13;
Exhibit I, Tab 7, Schedule 1; and
Exhibit I, Tab 8, Schedules 1 to 15.

Also attached please find the following updated and new exhibits:

Exhibit A, Tab 1, Schedule 1, page 1 and 4;
Exhibit A, Tab 4, Schedule 2; and
Exhibit B, Tab 1, Schedule, page 4.

This submission has been filed through the Board's Regulatory Electronic Submission System ("RESS"), and two hard copies are being sent to the Board as directed. Enbridge's filing for this proceeding can be found on the Enbridge website at: www.enbridgegas.com/ratecase.

If you have any questions, please contact the undersigned.

Sincerely,

Lesley Austin
Regulatory Coordinator, Regulatory Affairs

cc: Mr. F. Cass, Aird & Berlis LLP (via email and courier)
All Interested Parties EB-2011-0277 (via email)

EXHIBIT LIST

APPLICATION FOR 2012 RATE ADJUSTMENT

Exhibit	Tab	Schedule	Contents	Witness(es)
A – ADMINISTRATIVE				
A	1	1	Exhibit List	R. Bourke
	2	1	Application	F. Cass
	3	1	Approvals Requested	R. Bourke
	4	1	Curriculum Vitae	R. Bourke
		2	Curriculum Vitae	R. Bourke
	5	1	Draft Issues List	R. Bourke
B – 2012 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION				
B	1	1	2012 Rate Adjustment Summary	R. Bourke
		2	2012 Revenue per Customer Cap Determination	K. Culbert A. Kacicnik D. Small
		3	Inflation Factor	S. Murray
		4	Customer Additions	F. Ahmad
		5	Gas Volume Budget	R. Lei
		6	Budget Degree Days	S. Murray H. Sayyan
		7	Average Use Forecasting Model and Economic Assumptions	S. Murray H. Sayyan
	2	1	Y Factor Power Generation Projects	S. Murray J. Sim
		2	Y Factor DSM Program	K. Culbert

EXHIBIT LIST

Exhibit	Tab	Schedule	Contents	Witness(es)
D – 2010 ACTUAL RESULTS				
D	1	1	2010 Historical Year Review EB-2011-0008	K. Culbert
E – REFERENCE MATERIAL				
E	1	1	Settlement Agreement – EB-2007-0615 dated February 4, 2008	R. Bourke
	2	1	Customer Care and CIS Settlement Template (the "True-Up" Template) – EB-2007-0615 Rate Order, Appendix F dated May 15, 2008	R. Bourke K. Culbert
	3	1	Return on Equity	S. Murray
I – INTERROGATORIES				
I	1	1 - 18	Board Staff Interrogatories	EGD
	2	1 - 9	BOMA Interrogatories	EGD
	3	1 - 9	CCC Interrogatories	EGD
	4	1 - 14	CME Interrogatories	EGD
	5	1 - 8	Energy Probe Interrogatories	EGD
	6	1 - 13	FRPO Interrogatories	EGD
	7	1	Just Energy Interrogatories	EGD
	8	1 – 15	VECC Interrogatories	EGD

CURRICULUM VITAE OF
ANDREW MANDYAM

Experience: Enbridge Gas Distribution Inc.

Manager, Marketing and Energy Efficiency
2011

Manager, Demand Side Management and Portfolio
2010

Customer Information System Replacement Project Business Manager
2007 - 2009

Manager, Customer Care and Customer Information System Program Operations
2006

Manager, Information Technology Solutions and Support
2005

Senior Project Manager, Information Technology Solutions and Support
2003

Oracle Corporation

Practice Manager
1997 – 2003

Compaq Canada

Program Manager
1995 – 1997

Ontario Hydro

Associate Engineer
1990 - 1995

Education: B.A.Sc. Mechanical Engineering
University of Toronto
1990

Memberships: Professional Engineers of Ontario
Project Management Institute

CURRICULUM VITAE OF
STEVE MCGILL

Experience: Enbridge Gas Distribution Inc.

Manager, Strategic Projects & Market Analysis
2003

Manager, Customer Support & Advocacy
2000

Manager, Customer Accounting Projects
1995

Manager, Large Volume Billing
1992

Manager, Industrial Sales, Metropolitan Toronto
1990

Manager, Rate & Contract Administration
1987

Rate Research Analyst
1985

Market Analyst
1981

Distribution Planner
1979

TransCanada Pipelines Limited

Junior Statistician

Junior Draftsman

Education: Bachelor of Arts (Honours Geography), University of Toronto, 1978

Miscellaneous short courses in Public Utility Management,
General Management, and Accounting

Appearances: (Ontario Energy Board)
EB-2011-0226
EB-2007-0615
EB-2005-0001
RP-2003-0203
RP-2002-0133
RP-2001-0032
RP-2000-0040
EBRO 497-01
EBRO 497
EBRO 495
EBRO 492
EBRO 490
EBRO 487
EBO 179-14/15

of $28.1 million as allowed within the EB-2008-0346 guidelines, is included into the 2012 total revenue outside of the incentive escalation formula at Row 20. /c

8. Row 6 removes the 2011 Board Approved CIS/Customer Care costs of $97.4 million (exclusive of bad debt) (shown at Appendix F in the EB-2007-0615 Rate Order). This adjustment is necessary as the base distribution revenue upon which the incentive escalation formula is to be applied should exclude CIS/Customer Care costs. The 2012 Approved CIS/Customer Care costs are included into the 2012 distribution revenue, outside of the incentive escalation formula, and are further outlined at Row 21.

9. Row 7 removes the 2011 Board Approved power generation related Y factor revenue requirement amount of $3.5 million from the base subject to escalation. The inclusion of an updated 2012 revenue requirement amount of $6.6 million is shown at Row 22. The power generation project cost treatment was approved to be handled outside of the escalation portion of the incentive formula.

10. Row 8 shows the distribution revenue sub-total of $830.1 million inclusive of all of the above noted adjustments. This is the exact amount of the Board Approved formula portion of 2011 rates as shown at Appendix A, page 1, Column 1, Row 18 of the EB-2010-0146 Rate Order.

11. Row 9 incorporates an incremental reduction to base rates of $4.6 million, which is the 2012 ratepayer amount relating to incremental tax rate and rule change expectations, agreed to be shared equally between ratepayers and the Company. Within the EB-2011-0008 proceeding, the Company filed and the OEB approved evidence which updated the previous approved tax savings and sharing agreement.

Witnesses: K. Culbert
A. Kacicnik
D. Small

I – Interrogatory Responses

1 – Board Staff

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Ref: Ex. B /Tab 1/ Sch 2 /

Please confirm that there have been no departures from the terms of the EB-2007-0615 settlement for the calculation of the 2012 revenue requirement, assignment of the revenue requirement to the rate classes, and the derivation of the 2012 rates. If there were departures, please identify and describe the nature of any departures.

RESPONSE

EGD confirms there have been no such departures.

Witnesses: K. Culbert
A. Kacicnik
D. Small

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Ref: Ex. B /Tab 1/ Sch 4 /

Please provide a table of new customer additions, comparing Board-approved with actual, for each of the past 5 years. Please also include the 2012 forecast.

RESPONSE

Please see EGD's response to VECC Interrogatory 1, part b) at Exhibit I, Tab 8, Schedule 1.

Witness: F. Ahmad

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Ref: Ex. B /Tab 1/ Sch 5/

(a) Please provide a table of historic and forecast gas volumes, in a similar format to the example shown below, broken down by general service and contract that shows the Board-approved versus the actual volumes for the 5-year period 2007 through 2011. Please also include the 2012 Budget. Additionally, please include the average number of customers.

Example

	Year 1		Year 2		Year 3, etc.	
	Board-approved	Actual	Board-approved	Actual	Board-Approved	Actual
General Service						
Contract						
Total Volume						
No. Customers (avg.)						

(b) Please also provide a table in a format similar to part a. above showing weather-normalized volumes.

Witnesses: R. Lei

RESPONSE

a) Table 1 on page 3, provides the requested information for un-normalized volumes.

b) Table 2 on page 4, illustrates the requested information for weather normalized volumes. In order to compare the year over year variance between actual and Board Approved normalized numbers on the same basis, each year actual results have to be normalized to the corresponding Board Approved degree days for that year.

During the requested time period, distribution volumes were influenced by many events that have had an impact on annual use.

Some of these events include:

a. Fluctuations in natural gas prices;
b. Rate switching and migration between rate classes;
c. The economic downturn and extended recovery that began in the fall of 2008; and
d. Declining residential average use.

Table 1 - Weather Un-Normalized Volumes and Customers

(Volumes in 10^6m^3)

	2006		2007		2008		2009		2010		2011		2012
	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Estimate	Budget
General Service	7,932.8	7,490.5	7,642.2	8,314.8	8,288.0	8,806.0	9,083.2	9,129.2	9,083.5	8,757.0	9,283.4	9,419.8	9,356.7
Contract	4,387.9	3,996.4	4,134.3	3,758.5	3,355.2	3,101.5	2,316.6	2,205.6	2,008.6	2,183.6	2,022.9	2,039.2	1,943.4
Total Volumes	12,320.7	11,486.9	11,776.5	12,073.3	11,643.2	11,907.5	11,399.8	11,334.8	11,092.1	10,940.6	11,306.3	11,459.0	11,300.1
No. Customers (avg.)	1,792,615	1,782,813	1,823,258	1,824,789	1,864,047	1,865,020	1,906,437	1,887,605	1,931,528	1,926,294	1,965,538	1,957,733	1,984,734

Table 2 - Weather Normalized Volumes and Customers

(Volumes in 10^6m^3)

	2006		2007		2008		2009		2010		2011		2012
	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Estimate	Budget
General Service	7,932.8	7,901.9	7,642.2	8,037.9	8,288.0	8,369.7	9,083.2	8,833.7	9,083.5	8,479.5	9,283.4	9,419.8	9,356.7
Contract	4,387.9	4,119.1	4,134.3	3,739.8	3,355.2	3,099.6	2,316.6	2,191.4	2,008.6	2,175.7	2,022.9	2,039.2	1,943.4
Total Volumes	12,320.7	12,021.0	11,776.5	11,777.7	11,643.2	11,469.3	11,399.8	11,025.1	11,092.1	10,655.2	11,306.3	11,459.0	11,300.1
No. Customers (avg.)	1,792,615	1,782,813	1,823,258	1,824,789	1,864,047	1,865,020	1,906,437	1,887,605	1,931,528	1,926,294	1,965,538	1,957,733	1,984,734

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: Ex. B /Tab 2/ Sch 5

Please report the pension plan's annual investment returns for the last 5 years and compare them to the annual investment returns of a group of peers of comparable size and scale operating in Canada.

RESPONSE

Please see the table provided below.

	2006	2007	2008	2009	2010
EGD RPP	10.6%	1.0%	-18.4%	16.7%	9.8%
Comparable Peers*					
90th percentile	14.3	8.9	-11.7	19.2	12.7
75th percentile	13.0	7.7	-13.2	17.3	11.6
50th percentile	11.4	3.7	-14.7	13.9	10.3
25th percentile	8.7	1.7	-19.6	12.1	8.7
10th percentile	7.2	0.1	-24.3	4.4	7.9

*Based on companies on the TSX composite with pension assets between $100M - $2B

Witnesses: S. Kancharla
R. Lei
A. Patel

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Ref: Ex. B /Tab 2/ Sch 5

(a) Does EGD directly manage the plan or is it managed by another entity?

(b) Please name the corporate entity managing the plan.

(c) Does the plan include only the employees and retirees of EGD or are there other members (such as employees of affiliated companies) included in the plan? If so, please provide details as to the numbers of any such employees and the identity of the affiliates.

RESPONSE

a) EGD does not directly manage the plan.

b) The plan is managed by the Pension Administration Group at Enbridge Inc. under the direction of the Pension Committee, which sets the plan goals and asset mix policy, while the investments are managed by various investment managers. EGD has seat a on the Pension Committee.

c) The EGD RPP plan includes Enbridge Gas Distribution Inc., and two affiliates, Gazifère Inc. and Enbridge Gas New Brunswick Inc. However, the cash contribution requested in the Z factor only pertains to Enbridge Gas Distribution Inc.

The EGD SERP and EGD SSERP only includes Enbridge Gas Distribution Inc.

Member details by plan and affiliate are:

	Enbridge Gas Distribution Inc.	Enbridge Gas New Brunswick Inc.	Gazifere Inc.
EGD RPP	3,477	143	101
EGD SERP	29	N/A	N/A
EGD SSERP	5	N/A	N/A

Witnesses: S. Kancharla
R. Lei
A. Patel

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Ref: Ex. B /Tab 2/ Sch 5

Under EGD's Z factor proposal, does the shareholder assume any of the financial responsibility, or is the request that 100% of the underfunding be recovered from the ratepayer?

RESPONSE

EGD has requested the pension funding based on the X factor criteria of:

i. The event must be causally related to an increase/decrease in cost;
ii. The cost must be beyond the control of the Company's management and is not a risk in respect of which a prudent utility would take risk mitigation steps;
iii. The cost increase/decrease must not otherwise be reflected in the per customer revenue cap;
iv. Any cost increase must be prudently incurred; and
v. The cost increase/decrease must meet the materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event).

Since EGD believes the funding fits the above criteria, 100% of the funding is being requested to be recovered from ratepayers.

Witnesses: S. Kancharla
R. Lei
A. Patel

BOARD STAFF INTERROGATORY #7

INTERROGATORY

Ref: Ex. B /Tab 2/ Sch 5

Paragraph 12 notes that EGD would need to make contributions to the RPP and SERP plans in 2012 in the amount of $16.6 million.

(a) Please comment on whether it is typical practice in the Canadian pension plan industry that when a plan is in a deficit position, its members' contributions are adjusted to account for the shortfall.

(b) What is the role of the corporation or plan sponsor overseeing the pension fund when a plan is in a deficit position and requires additional funding? Does the plan sponsor typically contribute to the funding shortfall? If so, what percentage of the shortfall is typically funded by the plan sponsor?

RESPONSE

a) Whether a plan requires member contributions is up to the plan sponsor and in 2001 EGD chose not to have its members make contributions.

It is a requirement, however, in the Canadian pension plan industry for plan sponsors (or members if so chosen by the plan sponsor) to make contributions to the plan if it is in a deficit position. The funding requirement EGD is facing is in accordance with actuarial standards/rules and legislative requirements from the Financial Services Commission of Ontario.

b) The funding requirements EGD is facing is determined by an external professional actuarial firm, Mercer (Canada) Ltd., and is calculated in accordance with actuarial standards/rules and legislative requirements from the Financial Services Commission of Ontario. If the plan is in deficit, there are legislative requirements that determine the minimum contributions to be made to the plan. 100% of the minimum contributions are required to be made by the plan sponsor. EGD confirms that the amount of $16.6M represents the minimum contributions as required by legislation.

Witnesses: S. Kancharla
R. Lei
A. Patel

BOARD STAFF INTERROGATORY #8

INTERROGATORY

Ref: Ex. B /Tab 2/ Sch 5/Appendix B Mercer Report dated October 3, 2011

Please indicate whether EGD's external auditor has reviewed the Mercer Report. If so, does the report reflect the auditor's comments? If not, when will the external auditor's review take place?

RESPONSE

EGD's external auditors have not yet reviewed the Mercer Report. EGD's external auditors will review the report in 2012 with the commencement of cash contributions as this is when it would impact EGD's financial statements.

Witnesses: S. Kancharla
R. Lei
A. Patel

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Ref: Ex. B /Tab 2/ Sch 5/Appendix B Mercer Report page 5 of 32

On page 5 of the evidence (page 2 of the actual Mercer report), paragraph 3 states:

> "We have also conducted an actuarial valuation for management information purposes as at December 31, 2010 that was not filed with FSCO or CRA. This valuation is the basis for the projections contained herein."

Please indicate whether the above-referenced "actuarial valuation for management purposes" has been reviewed by EGD's external auditor.

RESPONSE

This actuarial valuation has not yet been reviewed by EGD's external auditors as it was finalized in September 2011. This valuation will be reviewed by them in March of 2012 when they conduct the year end pension audit for the year ended December 31, 2011

Witnesses: S. Kancharla
R. Lei
A. Patel

BOARD STAFF INTERROGATORY #10

INTERROGATORY

Ref: Ex. C /Tab 1/ Sch 5

What basis of accounting is being used for the calculation of the proposed 2012 rates?

RESPONSE

Canadian GAAP is being used for the calculation of the proposed 2012 rates.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

BOARD STAFF INTERROGATORY #11

INTERROGATORY

Ref: Ex. C /Tab 1/ Sch 5

Please specify which accounting presentations will be filed in association with EGD's formal earnings sharing filings for 2011 and 2012?

RESPONSE

Earnings sharing filings for 2011 and 2012 will be performed and presented using CGAAP.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

BOARD STAFF INTERROGATORY #12

INTERROGATORY

Ref: Ex. C /Tab 1/ Sch 5

Please file a copy of the application made by EGD to the relevant Canadian securities regulator requesting authorization to use USGAAP.

RESPONSE

Please find attached a copy of the application made by EGD.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

Enbridge Inc.
3000 Fifth Avenue Place
425 – 1st Street S.W.
Calgary, AB T2P 3L8
Canada
www.enbridge.com

Debra J. Poon
Senior Legal Counsel

Tel: 403 767-3642
Fax: 403 231-7380
debra.poon@enbridge.com

November 10, 2010

VIA COURIER AND EMAIL

Alberta Securities Commission
4th Floor, 300 – 5th Avenue SW
Calgary, AB T2P 3C4

Attention: Director, Corporate Finance
Email: legalapplications@seccom.ab.ca

Ontario Securities Commission
Suite 1903, Box 55
20 Queen Street West
Toronto, ON M5H 3S8

Attention: The Secretary to the Commission
Email: applications@osc.gov.on.ca

Dear Sirs/Mesdames:

Re: Application Pursuant to Section 9.1 of National Instrument 52-107 *Acceptable Accounting Principles, Auditing Standards and Reporting Currency* to Permit the Filing of US GAAP Financial Statements for Affiliates of an SEC Issuer

Application is hereby being made by Enbridge Inc. ("**EI**"), Enbridge Gas Distribution Inc. ("**EGD**"), Enbridge Pipelines Inc. ("**EPI**"), Enbridge Income Fund ("**EIF**") and Enbridge Income Fund Holdings Inc. ("**EIFH**") to the securities regulator or regulatory authority (as applicable) in the Provinces of Alberta, British Columbia, Saskatchewan, Manitoba, Quebec, Nova Scotia, New Brunswick, Prince Edward Island and Newfoundland and Labrador (the "**Passport Jurisdictions**") and to the Ontario Securities Commission ("**OSC**") for exemptive relief pursuant to section 9.1 of National Instrument 52-107 *Acceptable Accounting Principles, Auditing Standards and Reporting Currency* ("**NI 52-107**") and section 5.1 of National Instrument 52-107 *Acceptable Accounting Principles and Auditing Standards* ("**New NI 52-107**") from the requirements of sections 3.2 of New NI 52-107 to permit the preparation and filing by EGD, EPI, EIF and EIFH (collectively, the "**Affiliates**") of US GAAP financial statements for financial years commencing on or after January 1, 2012. EI and the Affiliates are collectively referred to as the "**Filers**".

This is a dual application made to the Alberta Securities Commission ("**ASC**") as the principal regulator for the Passport Jurisdictions and to the OSC. The OSC is the principal

regulator for EGD as its head office is located in Ontario. However the Filers request that the ASC be designated as the principal regulator for this application as it is the principal regulator of all of the other Filers (including EI, of which EGD is an indirect wholly-owned subsidiary), which have their head office in Alberta. Please consider this a written request pursuant to section 3.7 of National Policy 11-203 *Process for Exemptive Relief Applications in Multiple Jurisdictions* ("**NI 11-203**") for a change in principal regulator in respect of EGD for this application only.

Notice that section 4.7(1) of MI 11-102 *Passport System* is being relied upon for the Passport Jurisdictions is hereby given to the ASC as principal regulator. The exemption for which relief is sought is from the requirements of sections 3.2 of New NI 52-107 (expected to come into force on January 1, 2011) in respect of the financial statements of the Affiliates.

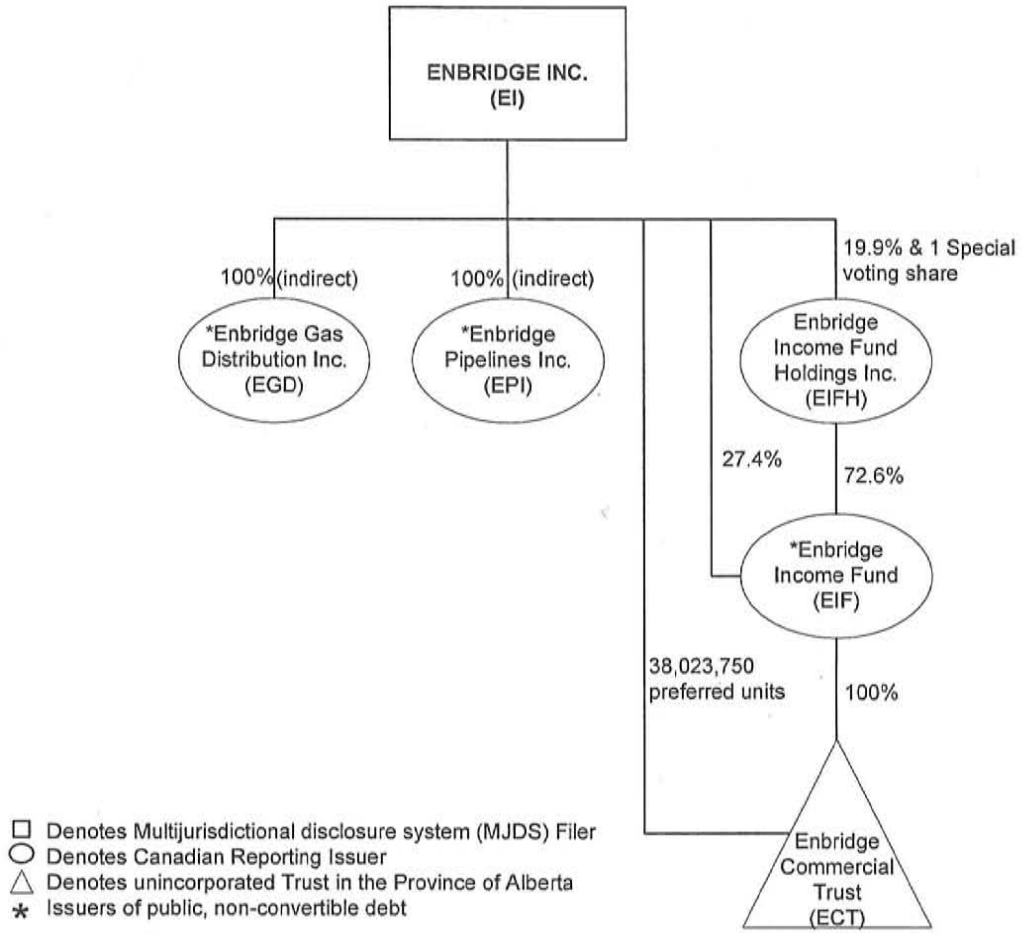
The Filers are also seeking confidentiality of this application, the supporting materials and the decision pursuant to section 5.4 of NI 11-203. Confidentiality is being sought as the Filers have not yet publicly announced their intention to implement US GAAP pending the outcome of this application. Accordingly, we request confidentiality be extended until the earlier of (a) the date the Filers announce to the public that they will be transitioning to US GAAP; (b) the date the Filers advise the principal regulator that there is no longer any need for the application and this decision to remain confidential; and (c) 90 days following the date of the decision. We submit that maintaining the confidentiality requested will not be prejudicial to the public interest.

Facts

EI and all of the Affiliates with the exception of EIFH are reporting issuers in the Passport Jurisdictions and Ontario. EGD and EPI are indirect wholly-owned subsidiaries of EI and have public holders of non-convertible debt securities. EIFH will become a reporting issuer following completion of an arrangement ("**Arrangement**") involving EIF and EIF unitholders ("**Unitholders**"), as described in the EIF information circular dated March 31, 2010 (filed on SEDAR on April 7, 2010). The Arrangement is being effected primarily due to changes to Canadian federal income tax legislation relating to specified investment flow-through trusts and is expected to be completed on or about December 15, 2010. The activities of EIFH will be restricted to investment in EIF following completion of the Arrangement. EI and EIFH will be the only holders of EIF units and the Unitholders and EI will be the shareholders of EIFH. The Toronto Stock Exchange has conditionally approved the listing of the EIFH shares following completion of the Arrangement.

Following the Arrangement, EI will own 27.4% of the EIF units and 19.9% of the EIFH shares. Together with these interests and its preferred unit investment in Enbridge Commercial Trust (a wholly-owned subsidiary of EIF), EI holds a combined direct and indirect economic interest in EIF of 72%. EIF will continue to be a reporting issuer following completion of the Arrangement as it will still have public holders of non-convertible debt securities.

The summarized organizational structure depicting EI's direct and indirect ownership of the Affiliates following the effective date of the Arrangement is set out below. Note that for ease of reference, we have omitted wholly-owned direct and indirect non-reporting issuer subsidiaries of EI that are between EI and EGD and EI and EPI.



Each of EI and the Affiliates are or will be a "qualifying entity" and intend to rely on the optional one-year deferral from International Financial Reporting Standards ("**IFRS**") specified in section 5.4 of the New NI 52-107 to prepare and file Canadian GAAP (pre-changeover) financial statements for the financial year commencing January 1, 2011 and ending December 31, 2011.

EI is required to file reports with the United States Securities and Exchange Commission ("**SEC**") under section 15(d) of the *United States Securities Exchange Act of 1934* (the "**1934 Act**") and the common shares of EI are also listed and posted for trading on the New York Stock Exchange.

The Affiliates are not currently "SEC Issuers" and therefore do not file reports with the SEC. Further facts relating to the Filers are set forth in the enclosed draft Decision

Submissions

EI is an "SEC Issuer" as defined in New NI 52-107 and accordingly, may rely on sections 3.7 and 3.8 of New NI 52-107 to prepare and file US GAAP financial statements for the financial years commencing on or after January 1, 2012.

The consolidated financial statements of EI include the accounts of the Affiliates, which must be prepared using the same basis of accounting as EI. However, as the Affiliates are not SEC Issuers, section 3.7 of New NI 52-107 is not available to enable the Affiliates to file US GAAP financial statements to comply with the continuous disclosure obligations under Canadian securities laws (the "**Legislation**").

While the New NI 52-107 is not yet in effect, the conversion to US GAAP is a significant and complex undertaking which will require considerable time to complete. EI and the Affiliates are therefore seeking exemptive relief in advance of New NI 52-107 taking effect. We respectfully submit that the Affiliates should not be required to prepare two sets of financial statements using different accounting principles and should be permitted to prepare and file US GAAP financial statements to comply with the Legislation for the reasons set forth below.

1. There is continuing uncertainty with respect to the application of IFRS to the rate regulated operations of the Filers, which are pervasive and central to its business model and a key driver of financial performance. Management of the Filers believe that US GAAP articulates more guidance than IFRS and faithfully represents the economic realities of its regulated businesses; providing a well recognized, accepted and comprehensive basis of accounting and financial reporting. As NI 52-107 already permits SEC Issuers to file US GAAP financial statements in satisfaction of Canadian reporting requirements, the Canadian investor base understands and can interpret US GAAP.

2. There is likely to be confusion if the financial statements of EI and the Affiliates filed on SEDAR and made available to public stakeholders and Industry Regulators are not on a consistent basis as the differences between IFRS and US GAAP are pervasive. For example, the Affiliates would be required to write-off regulatory assets and liabilities in the absence of any specific guidance under IFRS, whereas US GAAP permits the recognition of such assets and liabilities. Publishing the financial results of the Filers in the public domain under different accounting principles detracts from the objectives of providing relevant and transparent financial reporting and does not serve the best interests of stakeholders.

3. Significantly greater resources and expense will be required on a continuous basis to prepare, review and audit two different sets of financial statements for each Affiliate in addition to supplemental financial information required by industry

regulators ("**Industry Regulators**"), including without limitation, the National Energy Board and the Ontario Energy Board. The differences between IFRS and US GAAP are extensive and maintaining two sets of financial statements would drastically increase the cost and complexity of the Affiliates' financial statement reporting process with no perceived benefit to users of those financial statements.

4. Rate regulated accounting is well established in Canada and the US and EI already complies with ASC 980 Regulated Operations, the US GAAP standard on rate regulated accounting. As EI has reconciled its consolidated financial statements to US GAAP for many years, users of its financial statements will have a consistent basis of reference when analyzing EI on a historical basis.

5. EI, through its subsidiaries and affiliates (including the Affiliates), has significant assets and operations in the US, the primary market for securities of EI outside of Canada is the US and US GAAP would enhance comparability with many industry peers.

6. EI's related US public issuers, Enbridge Energy Management, L.L.C. and Enbridge Energy Partners, L.P. are also registered with the SEC and currently prepare and file US GAAP financial statements pursuant to the 1934 Act and under both US GAAP and IFRS will be required to consolidate its financial statements into EPI's which in turn will consolidate its financial statements into EI's.

7. Although it may be possible for the Affiliates to be eligible to file US GAAP financial statements by becoming "SEC Issuers", we respectfully submit that the Affiliates should not be required to incur the significant expense involved in registering and making filings with the SEC, as well as assuming additional regulatory and PCAOB audit obligations, merely to comply with the Legislation.

Authorities

This application may be considered "novel" as New NI 52-107 was only recently published and is not expected to come into force until January 1, 2011. However, there are many decisions whereby the ASC, OSC and other Canadian securities regulatory authorities have granted relief from the requirements of NI 52-107 and in particular, the requirement to file the form of financial statements mandated by NI 52-107, including:

1. *In the Matter of Nortel Networks Limited*, OSC April 15, 2010;

2. *In the Matter of Brookfield Asset Management Inc.,* OSC August 25, 2008;

3. *In the Matter of Potash Corporation of Saskatchewan Inc.*, OSC August 6, 2010;

4. *In the Matter of IESI-BFC Ltd.*, OSC September 3, 2010;

5. *In the Matter of SXC Health Solutions Corp.*, OSC July 14, 2008;

6. *In the Matter of DaimlerChrysler Canada Finance Inc. and DaimlerChrysler AG*, OSC June 30, 2005; and

7. *In the Matter of Total Capital S.A. and Total Capital Canada Ltd.*, OSC June 16, 2010.

In *Nortel*, the applicant was a reporting issuer and a wholly-owned direct subsidiary of a reporting issuer that was an SEC Issuer. Similar to the Affiliates, the applicant had outstanding debt securities held by the public which were not listed on any stock exchange. Both the applicant and parent had prepared and filed US GAAP financial statements. Relief was granted to permit the applicant to continue to prepare and file US GAAP financial statements even though it ceased to be an "SEC issuer" and was therefore not eligible to continue to use the exemption in NI 52-107 to permit it to prepare and file US GAAP financial statements.

In *Brookfield*, the OSC granted relief to permit the early filing (for financial periods beginning on or after January 1, 2009) of IFRS-IASB financial statements by a reporting issuer which was also an SEC Issuer that had subsidiaries which were both Canadian reporting issuers and SEC registrants "subject to a diverse set of financial reporting requirements". The applicant submitted that the adoption of IFRS-IASB would be in the its best interest as it would result in additional information that would enhance shareholders' understanding of its results of operations and financial position and reduce the number of bases of accounting prepared by the applicant. The headnote to the decision stated that the applicant wished to "reduce the complexity of its financial statement preparation process". We respectfully submit that the rationale in *Brookfield* applies to this application. It is the Filers' opinion that US GAAP currently presently offers a better alternative for rate regulated entities than IFRS in enhancing the readers' understanding of the Filers' operations and financial position.

The rationale in *Brookfield* has been accepted in more recent decisions, such as *Potash* in which the applicant represented that the adoption of IFRS-IASB would be in its best interests and that of users of its financial statements as it would simplify its financial statements by possibly eliminating the requirement to reconcile to US GAAP, and the use of a single set of accounting principles throughout the applicant's subsidiaries and significant investees would reduce the cost and complexity of its financial statement preparation process.

The applicant in *IESI-BFC* was a reporting issuer which had adopted US GAAP. Relief was granted from a number of requirements in NI 52-107 in respect of financial disclosure relating to the acquisition of an entity which did not use Canadian GAAP as the basis of its accounting and financial reporting and as a result of the acquisition, became part of the applicant's consolidated business. It was stated that the applicant had adopted US GAAP as the comprehensive basis of accounting and financial reporting and as such a Canadian GAAP reconciliation was not necessary in order for investors to have a consistent basis of accounting for the applicant's financial disclosure and financial statements. Similar relief

was granted in *SXC Health*. Both of these decisions support our submission that there should be one consistent basis of accounting for businesses consolidated into a parent entity.

The Legislation provides financial reporting exemptions, including for the filing of financial statements, to reporting issuers that are wholly-owned subsidiaries and/or issuers of credit rated debt securities only. It also recognizes and accepts financial statements prepared in accordance with US GAAP in certain circumstances, such as in Part 13 of National Instrument 51-102 *Continuous Disclosure Obligations* ("**NI 51-102**"). For example, section 13.4 of NI 51-102 provides relief, including from the obligation to file financial statements, to a wholly-owned credit support reporting issuer if certain conditions are met, including that only credit rated debt securities are issued. If the parent credit supporter is an "SEC Issuer" or not a reporting issuer in Canada, it can instead file the parent's financial statements and documents required to be filed by the SEC or under U.S. laws. A number of decisions have been issued by the securities regulatory authorities granting relief in circumstances where the applicants did not technically comply with the requirements of section 13.4 of NI 51-102. In both *Daimler* and *Total*, relief was granted as the parent was not organized or incorporated under U.S. laws (but was an SEC filer) and as the debt securities did not technically fall within the definition of "designated credit support securities". Further, relief was granted in *Total* despite its subsidiary not being wholly-owned by Total or Total's affiliates.

Although the present circumstances do not involve a credit support or guarantee by EI of the securities of its Affiliates, we respectfully submit that similar policy considerations apply. The exemption is based on the fact that the parent has sufficient financial strength such that its guarantee enables the securities of its subsidiary(ies) to obtain a credit rating. The rationale for the exemption should turn on the credit rating and not on whether a parental guarantee is provided. If US GAAP financial statements can be filed by a reporting issuer offering credit approved debt in Canada that has been guaranteed by a parent subject to SEC filing obligations, the filing of US GAAP statements should also be available for a reporting issuer offering credit approved debt (whose parent is also subject to SEC filing obligations) regardless of whether a parental guarantee is required to obtain a credit rating. Investors are only concerned with receiving the financial statements of the entity which has the obligation to repay the debt, which does not drive the presentation of the financial statements. Therefore, the basis of the exemption must be that the subsidiary reporting issuer or the SEC parent filer should not be required to incur the expense of preparing an additional set of financial statements (under Canadian GAAP) to comply with the Legislation and that US GAAP financial statements are considered an acceptable alternative.

Given that Canadian securities regulators have granted broad based relief to permit a reporting issuer that is a subsidiary of a foreign issuer to file its parent's US GAAP financial statements, we suggest that it is not prejudicial to the public interest to permit a subsidiary of a Canadian SEC issuer to file its **own** financial statements prepared in accordance with US GAAP.

The *Total* decision is also a precedent for the confidentiality sought for this application and the decision.

Please find enclosed:

1. draft Decision;

2. Verification Statement;

3. to the ASC only, a cheque payable to the ASC in the sum of $750; and

4. to the OSC only, a cheque payable to the OSC in the sum of $3,250.

Please do not hesitate to contact the writer if you have any questions or require anything further. Please note that as significant lead time will be required to identify and implement the procedures necessary to effect a conversion of the Filers' financial statements and financial reporting, we would very much appreciate your early response.

Yours truly,

Debra J. Poon
Senior Legal Counsel

Encls.

VERIFICATION STATEMENT

We authorize the making and filing of the attached application by Debra J. Poon, Senior Legal Counsel, Enbridge Inc. and confirm the truth of the facts contained therein.

DATED at Calgary, Alberta this 10th day of November, 2010.

ENBRIDGE INC.

Per: _____
J. Richard Bird, Executive Vice President,
Chief Financial Officer & Corporate Development

ENBRIDGE MANAGEMENT SERVICES INC.
as Administrator of **ENBRIDGE INCOME FUND**

Per: _____
Colin K. Gruending, Chief Financial Officer

ENBRIDGE INCOME FUND HOLDINGS INC.

Per: _____
Wanda Opheim, Director

DATED at Edmonton, Alberta this 10th day of November, 2010.

ENBRIDGE PIPELINES INC.

Per: _____
William G. Ross, Vice President, Finance

DATED at Toronto, Ontario this 10th day of November, 2010.

ENBRIDGE GAS DISTRIBUTION INC.

Per: _____
Narin Kishinchandani, Vice President, Finance

BOARD STAFF INTERROGATORY #13

INTERROGATORY

Ref: Ex. C /Tab 1/ Sch 5 / Page 1 & 2

- Addendum to the Report of the Board – Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment
- OSC Decision regarding Exemptive Relief for EGD Inc, EGD and EGD Pipelines dated February 25, 2011

Preamble:

The Board, under its International Financial Reporting Standards ("IFRS") initiative, has issued a number of documents including guidance for rate regulated utilities that are transitioning to IFRS. On June 13, 2011, the Board issued an Addendum to the Report of the Board ("Addendum") setting out additional regulatory policy regarding Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment.

On page 19 of the Addendum, the Board states that

> The Board must consider the general public interest in ensuring efficiency and consistency in utility regulation in Ontario, and will require utilities to explain the use of an accounting standard other than MIFRS for regulatory purposes.
>
> A utility, in its first cost of service application following the adoption of the new accounting standard, must demonstrate the eligibility of the utility under the relevant securities legislation to report financial information using that standard, include a copy of the authorization to use the standard from the appropriate Canadian securities regulator (if applicable) showing any conditions or limitations, and set out the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.
>
> The Board cautions utilities that the adoption of USGAAP as a short term solution may be counter-productive. If a utility is required to transition to IFRS for financial reporting purposes a few years after adopting USGAAP, certain transitional issues may not have been avoided, but delayed, and additional costs may be incurred if the utility changes its accounting standard twice. The Board will

> carefully scrutinize the costs incurred to accomplish two successive transitions if the utility seeks to recover these costs from ratepayers.
>
> In addition, the Board emphasizes to utilities that it retains the authority to require specific accounting standards and practices for regulatory purposes in any case where the Board finds that the public interest requires uniformity in those standards and practices among utilities. (Emphasis Added)

EGD requests approval to establish a deferral account to recognize and record the financial impacts which will occur in 2012 in relation to its required transition away from current Canadian General Accepted Accounting Principles ("CGAAP"). EGD also indicates that it is requesting the deferral account pending the explanations as required by the Board in the Addendum in its 2013 rate application.

Board staff notes that the Ontario Securities Commission ("OSC") has posted a decision relevant to EGD on its website. The Decision issued on February 25, 2011 grants exemptive relief to EGD to prepare its financial statements in accordance with United States General Accepted Accounting Principles ("US GAAP") commencing January 1, 2012 until December 31, 2014.

In view of the OSC Decision, this and following sets of Board staff interrogatories assumes that EGD will transition to US GAAP instead of IFRS for financial reporting purposes.

Questions/Requests:

a) Starting from January 1, 2012, Canadian public companies with activities subject to rate-regulation are required to adopt IFRS for public financial reporting purposes unless they can demonstrate qualification to adopt US GAAP. EGD indicated that it will transition away from current CGAAP in 2012 but has not identified the accounting standard.

   i) Please confirm that EGD will transition to US GAAP instead of IFRS for financial reporting purposes as EGD has already obtained exemptive relief from the OSC.
   ii) Please file a copy of the OSC Decision dated February 25 2011.
   iii) The OSC granted EGD limited exemptive relief for a period of 2012 to 2014. Please provide EGD's plan to address this limitation.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

b) EGD is requesting approval of a Transition Impact of Accounting Changes Deferral Account ("TIACDA") in its 2012 IRM rate application, indicating an intention to use US GAAP for both financial reporting and regulatory purposes. The Board has outlined a number of requirements in the Addendum regarding the use of an accounting standard other than MIFRS for rate regulation purposes.

   i) Please provide a detailed explanation of the benefits and potential disadvantages to the utility and especially to its ratepayers of using US GAAP instead of MIFRS for rate regulation purposes.

c) How does EGD plan to address the following matters:

   i) the IFRS transition costs that were recorded
   ii) the transition costs to US GAAP; and
   iii) the transition costs to IFRS that may be incurred in subsequent years, if conversion from US GAAP to IFRS occurs.

d) Please provide any regulatory precedent for the creation and disposition of the TIACDA account or similar deferral account.

e) Please indicate when EGD will request the disposition of the account balance and the period over which EGD proposes to recover the balance recorded in the TIACDA from ratepayers.

f) Please indicate whether EGD proposes to record carrying charges in relation to the amounts recorded in TIACDA, and if so, why this is appropriate and what rate of interest will be used.

RESPONSE

a) i) EGD confirms that it will transition to US GAAP for financial reporting purposes effective January 1, 2012.

   ii) Please see Attachment A.

   iii) EGD views the limited period exemption provided by the OSC being reflective of the uncertainty with regards to the treatment of rate-regulated operations under IFRS, recognizing that the US GAAP guidance on this front is better reflective of

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

the economic outcomes of the business. EGD expects to pursue a further exemption from the OSC at the end of the exemption period, unless IFRS guidance on this front, by that time, becomes largely aligned with that of US GAAP.

As an alternate, EGD will also likely have the ability to register with the Securities and Exchange Commission (SEC) in the US, so as to secure continued use of US GAAP for financial reporting purposes.

b) EGD will be using USGAAP for financial reporting purposes in 2012 but will be using CGAAP for regulatory purposes.

i)
Advantages of US GAAP over MIFRS

- Ensures continued alignment between financial reporting and regulatory basis of accounting

  EGD believes that it is important to have transparency and consistency between the accounting framework underlying external and OEB reporting. Through this consistency, there is a clear link between the audited financial statements and regulatory decisions. If there was a different basis of accounting, there would be additional EGD and OEB costs associated with the complexities of dual reporting and the reconciliations between them. This continued reconciliation would become increasingly complex and burdensome with every passing fiscal period.

- Better reflective of the economic realities of the underlying business

  EGD is of the view that users of its financial statements would prefer to have the financial statements reflect the economic realities of the regulated operations.

- Ensures relative consistency in earnings and revenue requirements

  Given that EGD does not expect any significant impact in annual earnings as a result of converting to USGAAP, there should be no significant limiting impacts to rates as a result of the conversion.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

- Circumvents the need for establishing principles based accounting justification (under IFRS) for each new regulatory event, thus limiting incremental administrative and audit costs.

  The Financial Accounting Standards Board issued FAS 71 in 1982 to permit the economic realities of rate regulation. These standards, subsequently re-codified as ASC 980, have proven to be a mature, reliable and an understandable set of accounting standards.

- Consistency with industry approach, thus enhancing comparability.

  There appear to be many Canadian regulated utilities which are adopting USGAAP or considering adopting USGAAP. Examples of such companies include: Emera, Fortis BC, AltaGas, TransCanada Pipelines, Union Gas and Hydro One. This would facilitate benchmarking with peer companies which will benefit EGD and its stakeholders.

  EGD is of the view that a complete harmonization of IFRS with USGAAP is not likely to occur in the foreseeable future. There continues to be strong resistance to adopting IFRS by rate regulated entities due to the fact that it does not contain any special treatment for rate regulated operations accounting. By allowing EGD to file under USGAAP, there would be the consistency in reporting which would continue to permit benchmarking and other comparative analysis.

- Not a material shift from CGAAP

  The most significant impact to EGD as a result of the adoption of MIFRS would be the increased costs which could no longer be capitalized to capital assets. These costs would be recorded as current Operating costs and cause a significant increase in revenue requirement.

<u>Disadvantages of US GAAP over MIFRS</u>

- An additional accounting framework for rate-making.

  Some utilities in Ontario may not have the option of converting to USGAAP; therefore there will be an inconsistent application of accounting principles between EGD and those entities. There could be an impact in the amount of time spent by the OEB in analyzing entities which have converted to USGAAP.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

The impact of this is likely lessened, however, as it appears that Union Gas will also be converting to USGAAP which means the two significant natural gas distribution companies in Ontario will be filing in USGAAP. In addition, some of the electric distribution companies in Ontario are considering filing in USGAAP.

- Potential uncertainty with regards to longevity of the solution.

  As previously indicated, EGD has been granted OSC relief for the 2012 to 2014 fiscal periods. While the Company expects that it will continue to utilize USGAAP after 2014, a final determination on this front has not yet been made.

- Training and education

  EGD is aware that USGAAP represents a new basis of accounting for its staff; therefore it will have to ensure that there is proper training in place. The OEB would also be impacted as the OEB would need to ensure its staff has a necessary level of knowledge pertaining to USGAAP.

c) i) EGD has recorded IFRS transition costs in the IFRSTCDA which were cleared previously. The company will be submitting a report provided by KPMG on the reasonableness of its IFRS and USGAAP conversion costs in total, as agreed to in the EB-2011-0008 Settlement Agreement (2010 Earnings Sharing). Any additional conversion costs above those already collected in relation to the IFRS conversion preparatory work will be brought forward in EGD's 2011 Earnings Sharing application in the spring of 2012.

ii) See response to part i)

iii) If at any time in the future EGD is required to convert to IFRS, it will bring forward a summary of potential implications and a plan to deal with such implications in a future proceeding.

d) As EGD has never had to transition away from using Canadian GAAP in the past it does not have a precedent for OEB approval of such a transition deferral account.

e) EGD will bring forward a proposal in its 2013 rate proceeding seeking a review and approval of amounts recorded in the TIACDA and the timing of the disposition of such amounts

f) EGD does not plan to record any carrying charges in relation to the amounts recorded in the TIACDA in 2012.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

Citation: Enbridge Inc., Re, 2011 ABASC 106 **Date: 20110225**

In the Matter of
the Securities Legislation of
Alberta and Ontario (the **Jurisdictions**)

and

In the Matter of
the Process for Exemptive Relief Applications in Multiple Jurisdictions

and

In the Matter of

Enbridge Inc., Enbridge Gas Distribution Inc.
and Enbridge Pipelines Inc. (the **Filers**)

Decision

Background
The securities regulatory authority or regulator in each of the Jurisdictions (the **Decision Maker**) has received an application from the Filers for a decision under the securities legislation of the Jurisdictions (the **Legislation**) exempting Enbridge Gas Distribution Inc. (**EGD**) and Enbridge Pipelines Inc. (**EPI**), (collectively, the **Affiliates**) from the requirements in subsection 3.2 of National Instrument 52-107 *Acceptable Accounting Principles and Auditing Standards* (**NI 52-107**) that financial statements be prepared in accordance with Canadian GAAP - Part I (the **Exemption Sought**) to permit the Affiliates to prepare their financial statements in accordance with United States generally accepted accounting principles (**US GAAP**).

Under the Process for Exemptive Relief Applications in Multiple Jurisdictions (for a dual application):

(a) the Alberta Securities Commission is the principal regulator for this application;

(b) the Filers have provided notice that subsection 4.7(1) of Multilateral Instrument 11-102 *Passport System* (**MI 11-102**) is intended to be relied upon in British Columbia, Saskatchewan, Manitoba, Québec, Nova Scotia, New Brunswick, Prince Edward Island and Newfoundland and Labrador (the **Passport Jurisdictions**); and

(c) the decision is the decision of the principal regulator and evidences the decision of the securities regulatory authority or regulator in Ontario.

Interpretation
Terms defined in National Instrument 14-101 *Definitions,* MI 11-102 and NI 52-107 have the same meaning if used in this decision, unless otherwise defined.

Representations
This decision is based on the following facts represented by the Filers:

Enbridge Inc.

1. Enbridge Inc. (**EI**) was incorporated under the *Companies Act* (NWT) on April 13, 1970 and continued under the *Business Corporations Act* (Canada) on December 15, 1987. The head office of EI is in Calgary, Alberta.

2. EI is a reporting issuer or equivalent in the Jurisdictions and each of the Passport Jurisdictions and, to its knowledge, is not in default of securities legislation in any jurisdiction in Canada.

3. The securities of EI are listed on the Toronto Stock Exchange (**TSX**) and the New York Stock Exchange (**NYSE**).

4. EI is an "SEC issuer" as that term is defined in NI 52-107 and can rely on subsection 3.7 of NI 52-107 to prepare and file with, or deliver to, a securities regulatory authority or regulator US GAAP financial statements.

Enbridge Pipelines Inc.

5. EPI was incorporated by Special Act of Canada on April 30, 1949 and continued under the *Business Corporations Act* (Canada) on June 2, 1980. The head office of EPI is in Calgary, Alberta.

6. EPI is a reporting issuer or equivalent in the Jurisdictions and each of the Passport Jurisdictions and, to its knowledge, is not in default of securities legislation in any jurisdiction in Canada.

7. EPI does not have any "exchange-traded securities" as that term is defined in National Instrument 21-101 *Marketplace Operation* **(NI 21-101)**.

8. EPI is a wholly-owned indirect subsidiary of EI and has issued and outstanding the following publicly-held debt (as at January 31, 2011) that is not convertible into equity securities of any issuer:

   $200,000,000 Series K Debentures at 8.20%
   $2,424,600,000 Medium Term Notes at rates ranging from 2.93% to 6.62%
   $25,500,000 in Commercial Paper

9. EPI is a rate-regulated entity whose business includes, through a wholly-owned subsidiary, 100% voting control of Enbridge Energy Management, L.L.C. (**EEM**), which holds an indirect 25.5% ownership interest in Enbridge Energy Partners, L.L.P. (**EEP**).

10. EEM and EEP are not reporting issuers or equivalent in any jurisdiction of Canada, but are registrants with the SEC and their securities are listed on the NYSE.

11. EEM and EEP prepare and file US GAAP financial statements with the SEC pursuant to the 1934 Act and, pursuant to US GAAP and International Financial Reporting Standards (**IFRS**), such financial statements must be consolidated into the financial statements of EPI, which will in turn be consolidated into the financial statements of EI.

12. EPI is not an "SEC issuer" as that term is defined in NI 52-107.

Enbridge Gas Distribution Inc.

13. EGD was incorporated by Special Act of Canada in 1848. EGD was continued under the *Corporations Act, 1953* (Ontario) and is now subject to the *Business Corporations Act* (Ontario). The head office of EGD is in Toronto, Ontario.

14. EGD is a reporting issuer or equivalent in the Jurisdictions and each of the Passport Jurisdictions, and to its knowledge, is not in default of securities legislation in any jurisdiction of Canada.

15. EGD does not have any "exchange-traded securities" as that term is defined in NI 21-101.

16. EGD is a wholly-owned indirect subsidiary of EI and has outstanding the following publicly-held debt (as at January 31, 2011) that is not convertible into equity securities of any issuer:

    $235,000,000 Debentures at rates of 9.85% and 10.80%; and
    $2,195,000,000 Medium Term Notes at rates ranging from 4.045% to 8.85%

17. EGD is a rate-regulated natural gas distribution utility.

18. EGD is not an "SEC Issuer" as that term is defined in NI 52-107.

General

19. Each of the Filers are rate-regulated entities and, accordingly, may rely on subsection 5.4 of NI 52-107 to prepare and file Canadian GAAP - Part V financial statements for the financial year commencing January 1, 2011 and ending December 31, 2011.

20. It was anticipated that the International Accounting Standards Board's (**IASB**) exposure draft would have provided direction regarding rate-regulated accounting under IFRS effective prior to the January 1, 2011 transition date to IFRS to assist rate-regulated issuers with their IFRS transition. However, due to divergent views on rate-regulated accounting at the IASB, a rate-regulated accounting standard has not been finalized. There continues to be significant uncertainty as to when, and if, rate-regulated accounting under IFRS will be clarified.

21. Rate-regulated accounting is well established in the United States and EI already complies with ASC 980 *Regulated Operations*, the US GAAP standard on rate regulated accounting. EI has reconciled its financial statements to US GAAP for many years.

22. NI 52-107 permits SEC issuers to file US GAAP financial statements in satisfaction of requirements under the securities legislation of the Jurisdictions and the Passport Jurisdictions and does not require any reconciliation of US GAAP financial statements to Canadian GAAP.

23. As an SEC Issuer, EI may rely on subsection 3.7 of NI 52-107 to prepare and file US GAAP financial statements and intends to do so for the financial years commencing on or after January 1, 2012.

24. The financial statements of the Affiliates are consolidated into the financial statements of EI. As the Affiliates are not SEC issuers, they cannot rely on subsection 3.7 of NI 52-107 to file US GAAP financial statements.

25. The Affiliates will certify their interim and annual US GAAP financial statements by filing the appropriate certificates in accordance with National Instrument 52-109 *Certification of Disclosure*.

Decision

Each of the Decision Makers is satisfied that the decision meets the test set out in the Legislation for the Decision Maker to make the decision.

The decision of the Decision Makers under the Legislation is that the Exemption Sought is granted for the financial years commencing January 1, 2012 until the financial year ending December 31, 2014 in respect of each Affiliate provided that:

(a) EI, directly or indirectly, remains the holder of all of the equity securities in respect of the Affiliate;

(b) the Affiliate does not issue any "exchange traded securities" as that term is defined in NI 21-101, and any securities convertible into equity securities of the Affiliate are held directly or indirectly by EI; and

(c) the financial statements of the Affiliate continue to be consolidated into the financial statements of EI.

Cheryl McGillivray, CA
Manager, Corporate Finance

BOARD STAFF INTERROGATORY #14

INTERROGATORY

Ref: Ex. C /Tab 1/ Sch 5 / Page 1 & 2

Preamble:

EGD is requesting approval to establish a 2012 TIACDA in its 2012 IRM rate application to recognize and record the financial impacts which will occur in 2012 in relation to EGD's transition to US GAAP.

Unlike IFRS (IFRS 1), US GAAP does not have a standard that provides exemption from full retrospective adoption. Without such a standard, transitioning to US GAAP requires full retrospective application of all applicable standards. In other words, the financial statements are prepared as if EGD had always been applying US GAAP.

Questions/Requests:

a) EGD requested a general deferral account for all financial impacts, but only specifically mentioned employee benefits. Please provide the reasons for this and list any other financial impacts resulting from transitioning to US GAAP.

b) Please provide a summary of all financial impacts expected by EGD to be recorded into TIACDA and any consequential impacts on 2012 rates. Please include the quantum of the impacts and the reasons underpinning the changes.

c) Please confirm that the financial statements as at and for the year ended December 31, 2012 will contain comparative figures for 2011 that are also in accordance with US GAAP.

d) Assuming the financial statements as at and for the year ended December 31, 2012 will contain comparative figures for 2011 that are also in accordance with US GAAP, the adjustment to retained earnings in those comparative financial statements would be to the opening retained earnings balance at January 1, 2011.

    i) In light of this, please clarify the date at which the requested charge to retained earnings in the TIACDA is being calculated.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

ii) Please provide the time period in which the financial impacts will be recorded in the TIACDA.

e) Please confirm whether EGD has completed its analysis of differences between Canadian GAAP and US GAAP and has identified the financial differences resulting in adjustments to retained earnings as at January 1, 2011. If the analysis is completed, please file it.

f) Please provide a copy of the opening balance sheet at the transition date (January 1, 2011) prepared in accordance with US GAAP and a reconciliation by line item to the balance sheet as at the same date prepared in accordance with Canadian GAAP.

g) Please describe the nature and extent of involvement of EGD's external auditors and/or other professional consultants with the transition to US GAAP. To the extent that written communications discussing the transition to US GAAP exist, please provide copies of such communications. If the external auditors have not completed audit procedures related to the opening balance sheet, please indicate the expected timeframe for this step.

RESPONSE

a) Based on the conversion work completed to-date, employee benefits is the only significant item impacting earnings in 2012. This is the reason why the evidence only specifically mentioned employee benefits.

b) EGD only expects to record the impacts relating to OPEB in the 2012 TIACDA. EGD will record the retained earnings adjustment relating to the write-off of the OPEB regulatory offset account (adjusted for the removal of the unamortized transitional amount) upon discontinuing CGAAP and the difference between the cash and accrual basis of accounting. The regulatory offset was approximately $83 million as at December 31, 2010 including the impact of the $16M unamortized transitional amount which is not allowed in USGAAP. In addition, the difference between the cash vs accrual method for 2012 is estimated to be approximately $3 million. There will be no impact on 2012 rates as EGD will provide evidence as part of the complete USGAAP application in the 2013 rates application and seek disposition treatment in that application.

c) Confirmed.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

d) i) The charge to retained earnings recorded in the TIACDA will be calculated as of January 1, 2010. EGD will be publicly filing its comparative financial statements for 2011 and 2010 in USGAAP.

ii) The amounts will be recorded upon approval of the establishment of the TIACDA.

e) EGD has a draft analysis of the differences between CGAAP and USGAAP and the related impacts on Earnings and Retained Earnings (filed as Attachment A to this interrogatory). It is EGD's opinion that the recognition of OPEB's is the only issue which will require a different treatment under USGAAP versus CGAAP. This different treatment would have been required even under IFRS. EGD's external auditors are in the process of reviewing the analysis and the positions taken by EGD. EGD's opinion, as indicated in responses to other Board Staff interrogatories, is that under either of USGAAP or IFRS, the Company is required to use an accrual basis of accounting for OPEB's as of 2012. EGD is seeking approval of the 2012 deferral account to provide it with the ability to retain the OPEB regulatory offset on its balance sheet. Without approval of the deferral account, EGD will not be able to record the impacts of the different treatment of OPEB's until such time as EGD can bring forward its completed analysis, which would immediately impact the capital structure of the business and potentially have a risk impact. EGD will file its completed and final analysis within its 2013 rate application.

f) See response to part e).

g) EGD has engaged its external auditors PWC to audit the comparative financial statements prepared in accordance with USGAAP. PWC expects to have completed the majority of their audit procedures in this regard no later than the first quarter of 2012.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

Significant CGAAP / USGAAP differences for EGD - DRAFT

Based on EGD's preliminary analysis of CGAAP vs. US GAAP differences, EGD has determined that the only significant difference between CGAAP and US GAAP is with respect to OPEB costs.

Under CGAAP the company accounts for OPEB costs on an accrual basis, but recognizes a regulatory offset for the difference between the cost on an accrual basis and the cash basis allowed for regulatory ratemaking purposes, having the net effect of recognition of OPEB cost on cash basis. However, per US GAAP a regulatory offset is not permitted for plans that are funded in rates on a pay-as-you-go basis, as EGD's OPEB plan is. For such plans, US GAAP requires that the costs be recognized on an accrual basis without a regulatory offset. Additionally, US GAAP guidance precludes the company from continuing to recognize the transitional obligation, which would be amortized as part of accrual OPEB expense. As a result of these differences under US GAAP, EGD is required to write-off the regulatory offset to retained earnings at Dec. 31, 2010, which amounts to approximately $83M gross of tax, including $16M of unamortized transitional obligation.

Please refer to Appendix 1 for a reconciliation of adjustments made to CGAAP balances in the conversion to US GAAP. Adjustments other than for Pension & OPEB do not impact the regulated operations of the company.

Significant CGAAP / IFRS differences for EGD

EGD has identified the following significant areas of difference between CGAAP and IFRS. In general, the primary reason for the significant differences is the fact that there is no specified guidance prescribed for rate regulated entities ("rate regulated accounting") and accordingly rate regulated entities must follow the definition of assets and liabilities per the conceptual framework of IFRS.

Regulatory Deferrals

Under CGAAP, EGD recognizes various regulatory deferrals (assets and liabilities) that account for the variance between the Company's financial accounting and regulatory accounting balances. Since IFRS does not prescribe rate regulated accounting and regulated assets and liabilities do not meet the IFRS criteria of assets and liabilities, the Company would no longer be able to recognize any of the regulatory balances recognized under CGAAP. Amounts currently recognized as regulatory deferrals would instead flow through the income statement, causing volatility in earnings. This would be undesirable for the Company and the ratepayers as it could result in unpredictable income statement impacts year-over-year and could also cause frequent and unpredictable changes in the amounts billed to customers. Under CGAAP, the Company accumulates variances in regulatory deferral accounts and recovers from or refunds to the ratepayers in rates once approved by OEB. For a majority of deferrals, this results in smoothing of the impacts to ratepayers.

Capital Assets

Under CGAAP, the Company capitalizes to its Property, Plant & Equipment (PP&E) costs as approved by the OEB for inclusion in the Company's regulatory asset base as such is allowed under CGAAP due to recognition of rate-regulated accounting. However, IFRS does not prescribe rate regulated accounting. Per IFRS IAS 16, only directly attributable costs can be capitalized, which would result in the Company having to recognize as O&M, costs that would have been normally capitalized to PP&E under CGAAP. The impact of this change (additional O&M) is estimated to be approximately $40 million per year. This additional O&M would result in additional revenue requirements and therefore a rate increase for the ratepayers.

Decommissioning Liabilities

The Company does not currently recognize a decommissioning liability under CGAAP, as there is no material legal obligation for the Company. Under IFRS, IAS 37 requires the Company to recognize constructive obligations in addition to legal obligations. A Constructive Obligation is defined as one that would result from a reasonable expectation of a third party based on a Company's current publicly disclosed policies or a specific public statement made by the Company. The Company is of the view that it would need to incur these costs when it would have to decommission its system, presumably when natural gas distribution is no longer required in the Company's franchise area. As a result, under IFRS the Company would be required to recognize a liability with an offsetting PP&E asset. The liability would be accreted annually at the weighted-average rate for the Company (used to discount the liability) and the asset would be depreciated over the life of the liability. The Company would seek to recover both the depreciation and the annual accretion through future rates (approximately $0.5M), resulting in higher rates for the ratepayers.

OPEB

Under CGAAP the Company accounts for the OPEB costs on an accrual basis in accordance with CGAAP guidance, however a regulatory offset is recognized for the difference between the cost on an accrual basis and the cash basis allowed for regulatory ratemaking purposes. Under IFRS, IAS 19 requires OPEB costs to be recognized in earnings based on the accrual basis with no regulatory offset since there is no prescribed rate regulated accounting.

Appendix 1 – DRAFT REPRESENTATION

Enbridge Gas Distribution Inc.
Canadian GAAP to US GAAP Reconciliation - Balance Sheet
December 31, 2010

	Reported C-GAAP	US GAAP Adjustments: Push Down Accounting (1)	US GAAP Adjustments: Pension/OPEB (Net of Tax)	US GAAP Adjustments: Deferred Financing Costs (2)	Reported US GAAP
(millions of Canadian dollars)					
Assets					
Current assets					
Accounts receivable and other	802				802
Gas inventories	400				400
	1,202	-	-	-	1,202
Property, plant and equipment, net	4,458	646			5,104
Investment in affiliate company	825				825
Deferred amounts and other assets	487	(4)	(229)	20	274
Intangible assets	167				167
	7,139	642	(229)	20	7,572
Liabilities and shareholders' equity					
Current liabilities					
Bank overdtaft	18				18
Short-term borrowings	332				332
Accounts payable and other	836		3		839
Current maturities of long-term debt	150				150
Deferred income taxes	5				5
	1,341	-	3	-	1,344
Long-term debt	2,267			20	2,287
Other long-term liabilities	1,058		(153)		905
Deferred income taxes	171	162	(26)		307
Loans from affiliate company	375				375
	5,212	162	(176)	20	5,218
Shareholders' equity					
Share capital					
Preferred shares	100				100
Common shares	1,071				1,071
Additional paid-in capital	202	929			1,131
Retained earnings	572	(449)	(56)		67
Accumulated other comprehensive loss	(18)		3		(15)
Total equity	1,927	480	(53)	-	2,354
Total Liabilities and Shareholder's Equity	7,139	642	(229)	20	7,572

(1) The push-down accounting adjustments are not part of the regulated opeartions of EGD and therefore have no impact on regulated earnings.

(2) This entry is a balance sheet reclass and therefore has no impact on net assets or earnings.

DRAFT REPRESENTATION

Enbridge Gas Distribution Inc.
Canadian GAAP to US GAAP Reconciliation - Income Statement
Year Ended December 31, 2010

		US GAAP Adjustments			
	Reported C-GAAP	**Push Down Accounting (1)**	**Pension/OPEB (Net of Tax)**	**Regulatory Deferral (2)**	**Reported US GAAP**
(millions of Canadian dollars)					
Gas commodity and distribution revenue	1,977			(201)	1,776
Transportation of gas for customers	390			5	395
	2,367	-	-	(196)	2,171
Gas commodity and distribution costs, excluding depreciation	(1,372)			206	(1,166)
Gas distribution margin	995	-	-	10	1,005
Other revenue	108				108
	1,103	-	-	10	1,113
Expenses					
Operating and administrative	393		3	10	406
Depreciation and amortization	270	22			292
Municipal and other taxes	44				44
Earnings sharing	19				19
	726	22	3	10	761
	377	(22)	(3)	-	352
Affiliate financing income	63				63
Interest expense	(186)				(186)
	254	(22)	(3)	-	229
Income taxes					
Current	(59)				(59)
Deferred	(2)	7	1		6
	(61)	7	1	-	(53)
Earnings	193	(15)	(2)	-	176
Preferred share dividends	(2)				(2)
Earnings attributable to the common shareholder	191	(15)	(2)	-	174

(1) The push-down accounting adjustments are not part of the regulated opeartions of EGD and therefore have no impact on regulated earnings.

(2) These adjustments have no net impact on earnings.

BOARD STAFF INTERROGATORY #15

INTERROGATORY

Ref: Ex. C /Tab 1/ Sch 5 / Page 1 & 2

- SEC Letter – February 23, 1995 (attached)

Preamble:

Conversion to US GAAP for employee future benefits generally requires full retrospective application of all relevant standards, reflecting the effective date of each individual standard and any related amendments. However, the SEC issued a letter dated February 23, 1995 permitting foreign issuers that cannot implement SFAS 87 as of the effective date specified in the standard due to unavailability of actuarial data, to adopt the standard as of a later date.

Questions/Requests:

a) Please confirm whether EGD will adopt the various standards under US GAAP for Pension and Other Post Employment Benefits (OPEB) as of the respective effective dates of the relevant standards. If EGD has elected a different effective date based on the letter issued by the SEC, please provide the effective date chosen and the reasons that EGD believes the exemption is applicable.

b) Please provide the amount of the transitional assets/liabilities resulting from the retrospective application of US GAAP which remain unamortized at the date of transition.

RESPONSE

a) EGD will adopt the various standards under USGAAP for Pensions and OPEB as of 2000, the year after which the most reliable information is available.

b) There are no unamortized transitional assets/liabilities resulting from retrospective application of USGAAP which remain unamortized at the date of transition. The unamortized amount recorded in EGD's financial statements relates to the adoption of CICA Section 3461 rather than the adoption of USGAAP.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

BOARD STAFF INTERROGATORY #16

INTERROGATORY

Ref: Ex. C / Tab 1 / Schedule 5 / Page 1 & 2 & Ex. B/Tab 2 /Sch 5 / Page 1

- OEB - Uniform System of Accounts prescribed for Class "A" Gas utilities paragraph 725

Preamble:

EDG states that it uses the cash basis for employee benefits where actual cash contributions are treated as costs for both financial reporting purposes under CGAAP and for rate making purposes. EGD also states that the cash basis accounting of the employee future benefit costs is enabled by special provisions related to accounting for rate regulated entities which have existed in various forms. The cash basis approach for rate making purposes stems from the Board's Uniform System of Accounts ("USoA") prescribed for Class "A" Gas utilities paragraph 725.

USoA paragraph 725 defines the account Employee Future Benefit as:

> "This account shall include amounts paid or contributed by the company towards all employee benefits. This account shall also include expenses to provide pension benefits in respect of employee past or current services."

EGD indicates that it will switch to an accrual basis of accounting commencing in 2012 as it transitions from CGAAP.

Questions/Requests:

a) USoA paragraph 725 does not specifically require the gas utility to use the cash approach for employee future benefits. Please explain the reasons that EGD considers USoA paragraph 725 as the basis of the regulatory treatment of employee future benefits.

b) Please provide a list of any Board Decision(s) and the relevant excerpt(s) from such Decision(s) showing that the cash basis approach of employee benefits has been approved by the Board.

c) Please explain in detail under CGAAP whether EGD accounts for employee future benefits using only the cash basis or whether it accounts for employee

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

future benefits using the accrual basis but achieves the effect of using the cash basis by also recording an offsetting regulatory asset or liability.

d) Please provide the relevant provisions under CGAAP to show that rate regulated entities can use the cash basis to account for employee future benefit costs for financial reporting purposes.

e) Given EGD is transitioning to US GAAP in 2012, please explain whether the cash basis of accounting for employee future benefits is allowed under US GAAP. Please provide the relevant provisions under US GAAP. Please explain pension and other post employment benefits separately.

f) Please explain the statement given at evidence reference C/1/5 paragraph 3 that "there will be a direct impact to earnings in the amount of the difference between a cash basis of accounting which EGD currently follows and an accrual basis of accounting required by EGD as of 2012".

   i) Please explain the reasons that there will be a direct impact to earnings, the cause of the impact, and the estimated quantum of the impact.
   ii) Please clarify whether this impact will be recorded in the TIACDA.

h) Historically EGD has used the cash basis for its employee future benefits for rate making purpose. Please clarify whether EGD is proposing the accrual basis approach for the employee future benefits for rate making purpose after it transitions to US GAAP and, if so,

   i) Please explain the costs and benefits to EGD and the ratepayers under the cash basis vs. the accrual basis for rate making purposes.
   ii) Please provide the estimated impacts to revenue requirements/rates and provide the quantum of the impacts under both the cash basis and the accrual basis. Please include an explanation of the reasons for the impacts.

RESPONSE

a) The passage contained in the first paragraph of EGD's evidence at Exhibit B, Tab 2, Schedule 5, page 1, intended to state that accounting for pension costs on a cash basis of accounting is acceptable for rate-making purposes and is allowed by the OEB's prescribed Uniform system of Accounts.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

b) Each of EGD's rate applications and evidence reviews for fiscal years up to and including 2007, contained O&M evidence and relevant financial statements which included OPEB's on a cash basis. EGD has not attempted to provide a list of Board Decisions and related passages which explicitly recognize that the OEB was approving of OPEB's on a cash basis approach.

c) Under CGAAP, EGD accounts for its employee future benefits using the accrual basis but as a result of recording a regulatory offset, the net effect is equivalent to accounting for the benefits on the cash basis.

d) There is no specific provision under CGAAP that expressly allows rate regulated entities to use the cash basis of accounting for financial reporting purposes. It is the Company's view that this basis of accounting, utilized in its 2009 to 2010 audited financial statements, is acceptable as a result of its interpretation of CICA Section 1100.

e) Similar to CGAAP, USGAAP does not permit the cash basis to be used as a basis of accounting for either pension or OPEB. However, under USGAAP, there are only limited circumstances in which an offsetting OPEB regulatory amount can be recorded. The specific provision under USGAAP that effectively prescribes the accrual basis of accounting is ASC 715-30-35-3 for pensions and ASC 715-60-35-7 for OPEB.

f) i. Absent approval of the TIACDA, there will be an earnings impact in 2012 as a result of the company being obliged to move away from CGAAP to either IFRS or USGAAP. Specifically, with the adoption of US GAAP for financial reporting purposes effective January 1, 2012, ASC 980-715-25-4 specifically states that if OPEB is included in rates on a "pay-as-you-go-basis" then a regulatory asset can no longer be recorded unless certain circumstances are met. The impact of this effectively results in recognizing OPEB expense on an accrual basis for financial reporting purposes but only recovering the cash contributions for rate making purposes.

ii. Yes, this impact will be recorded in the TIACDA.

h) During the current IR term, EGD will continue to use the cash basis approach but will be proposing to switch to the accrual basis under the new IR term beginning in 2013. The evidence to support switching to the accrual basis in 2013 will be filed with the 2013 rate application. The proposal will include information which is being requested in parts i) and ii).

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

BOARD STAFF INTERROGATORY #17

INTERROGATORY

Ref: Ex. C / Tab 1 / Schedule 5 / Page 1 & 2
- EGD, 2010 Audit Financial Statements

EGD has requested a deferral account TIACDA to record the accounting differences in 2012 due to its transition away from CGAAP. At paragraph 3 of the evidence, EGD explained the differences in relation to post employment benefits as follows:

> Under CGAAP, EGD recorded post employment benefits on the balance sheet representing the funded status plus the unamortized transitional assets less unamortized net actuarial gains with a corresponding regulatory offset, in the expectation that such costs would be allowed recovery or inclusion in future rates. In the absence of CGAAP, EGD cannot record a regulatory offset resulting in the entire balance being written off to retained earnings. Without the ability to record a regulatory offset as was permitted within CGAAP, there will be a direct impact to earnings in the amount of the difference between a cash basis of accounting which EGD currently follows and an accrual basis of accounting required by EGD as of 2012.

The following exhibit is reproduced from EGD's 2010 Audited Financial Statements (prepared under Canadian GAAP) Note 17 Post Employment Benefits for its defined benefit plans:

($million)	Pension		Other	
	2010	2009	2010	2009
Overfunded/(Underfunded) status at end of year	57	107	(83)	(81)
Contribution after measurement date	-	-	-	1
Unamortized past service costs	4	5	-	-
Unamortized transitional (asset)/obligation	(70)	(94)	16	19
Unamortized net actuarial loss/(gain)	228	184	(4)	(9)

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

Net amount recognized in the Consolidated Statement of Financial Position at end of year	219	202	(71)	(70)
Presented as follows:				
Deferred Amounts and Other Assets	222	205	-	-
Other Long – Term Liabilities	(3)	(3)	(71)	(70)

Questions/Requests:

a) Please provide a copy of EGD's 2010 Audited Financial Statements (AFS).

b) Please confirm that the "post employment benefits" referred by EGD includes Pension and Other Post Employment Benefits (OPEB).

c) To the extent that Pension and OPEB guidance under US GAAP provides accounting policy alternatives, will the accounting policy choices made by EGD under US GAAP be consistent with the corresponding accounting policies under CGAAP?

d) For each accounting policy choice that is not consistent (such as, but not limited to, actuarial valuation method, recognition of actuarial gains/losses, and expected return on plan assets), please list the accounting policy choice made under CGAAP and US GAAP and explain why the choice was made.

e) EGD states that "Under CGAAP, EGD recorded post employment benefits on the balance sheet representing the funded status plus the unamortized transitional assets less unamortized net actuarial gains with corresponding regulatory offset". Please clarify why unamortized past service costs are not included.

f) Please clarify the statement by EGD "In the absence of CGAAP, EGD cannot record a regulatory offset resulting in the entire balance being written off to retained earnings."

   i) In relation to the "regulatory offset" referred to by EGD, please clarify whether EGD is referring to any specific deferral/variance account approved by the Board. If so, please provide the account number and the relevant

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

references to and excerpts from Board Decisions. If not, please explain how the recording of the "regulatory offset" would impact the rates.

ii) Please explain why EGD cannot record a "regulatory offset" under US GAAP.

iii) Please clarify what comprises "the entire balance" that will be written off to retained earnings. Please provide the nature, and estimated quantum, of the components of the balance.

g) Please clarify whether the Unamortized past service costs, Unamortized transitional (asset)/obligation and Unamortized net actuarial loss/ (gain) for Pension and OPEB in Note 17 of EGD's 2010 AFSs will be written off to the opening retained earnings.

h) Please explain whether there is an ongoing difference between net pension benefit costs and net OPEB expenses in the use of CGAAP and US GAAP. Please outline the different accounting treatments and the reasons for these differences.

RESPONSE

a) A copy of EGD's 2010 Annual Financial Statement follows as Attachment A.

b) "Post employment benefits" refers to only OPEB.

c) To the extent that any policy alternatives under USGAAP chosen by the company are inconsistent with corresponding accounting policies under CGAAP, the company will provide details of such in its 2013 rates application.

d) Please see response to c) above.

e) With reference to the TIACDA, post employment benefits refer only to OPEB. There is no concept of unamortized past service costs relating to OPEB.

f)

i. The regulatory offset is not referring to a specific deferral account approved by the Board. Recognition of the regulatory offset would allow the company to continue effectively recognizing OPEB expense on a cash basis for financial reporting purposes.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

ii. Under ASC 980-715-25-4, if OPEB expense is included in rates on a "pay-as-you-go-basis" then no regulatory asset can be recorded.

iii. Please see EGD's response to Board Staff Interrogatory 14, part b), at Exhibit I, Tab 1, Schedule 14.

g) For pension, the unamortized amounts will be written off against the regulatory offset. For OPEB, the unamortized transitional obligation will be written off against opening retained earnings and the unamortized net actuarial loss/gain will be written off against Other Comprehensive Income (OCI).

h) Yes, there will a difference between the use of CGAAP and US GAAP. With respect to OPEB, ordinarily, it will be recognized on an accrual basis under US GAAP without a regulatory offset, whereas under CGAAP, it was effectively accounted for on a cash basis due to the regulatory offset. Pension benefit costs under CGAAP and US GAAP will be consistent in 2012 for regulatory and financial reporting purposes.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

ENBRIDGE GAS DISTRIBUTION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2010

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE GAS DISTRIBUTION INC.

Financial Reporting
Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are not officers or employees of the Company, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Audit, Finance & Risk Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the Company's Board of Directors, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

Janet A. Holder
President, Gas Distribution

(Signed)

Narinder K. Kishinchandani
Vice President, Finance

February 18, 2011

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
North American Centre
5700 Yonge Street, Suite 1900
North York, Ontario
Canada M2M 4K7
Telephone +1 416 218 1500
Facsimile +1 416 218 1499

Independent Auditor's Report

To the Shareholders of Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2010 and 2009 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes including a summary of significant accounting policies.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2010 and 2009 and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants, Licensed Public Accountants
February 18, 2011
Toronto Ontario

"PricewaterhouseCoopers" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership, or, as the context requires, the PricewaterhouseCoopers global network or other member firms of the network, each of which is a separate legal entity.

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Gas Commodity and Distribution Revenue	**1,977**	2,346
Transportation of Gas for Customers	**390**	449
	2,367	2,795
Gas Commodity and Distribution Costs Excluding Depreciation *(Note 19)*	**(1,372)**	(1,770)
Gas Distribution Margin	**995**	1,025
Other Revenue	**108**	108
	1,103	1,133
Expenses		
Operating and administrative *(Note 19)*	**393**	385
Depreciation and amortization	**270**	254
Municipal and other taxes	**44**	49
Earnings sharing *(Note 3)*	**19**	19
	726	707
	377	426
Affiliate Financing Income *(Note 19)*	**63**	63
Interest Expense *(Notes 9 and 19)*	**(186)**	(190)
	254	299
Income Taxes *(Note 16)*		
Current	**(59)**	(51)
Future	**(2)**	(27)
	(61)	(78)
Earnings	**193**	221
Preferred Share Dividends	**(2)**	(3)
Earnings Applicable to the Common Shareholder	**191**	218

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Earnings	**193**	221
Other Comprehensive (Loss)/Income		
Change in fair value of cash flow hedges, net of tax	**(13)**	1
Reclassification to earnings of realized (losses)/gains on cash flow hedges, net of tax	**(2)**	2
Change in foreign currency translation adjustment	**(1)**	(3)
Other Comprehensive Loss	**(16)**	-
Comprehensive Income	**177**	221

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Preferred Shares *(Note 11)*	**100**	100
Common Shares *(Note 11)*	**1,071**	1,071
Contributed Surplus	**202**	202
Retained Earnings		
Balance at beginning of year	**596**	566
Earnings applicable to the common shareholder	**191**	218
Common share dividends declared	**(215)**	(188)
Balance at End of Year	**572**	596
Accumulated Other Comprehensive Loss		
Balance at beginning of year	**(2)**	(2)
Other comprehensive loss	**(16)**	-
Balance at End of Year	**(18)**	(2)
Total Shareholders' Equity	**1,927**	1,967

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Operating Activities		
Earnings	**193**	221
Depreciation and amortization	**270**	254
Future income taxes	**2**	27
Other	**2**	2
Changes in operating assets and liabilities *(Note 18)*	**31**	467
Settlement recoverable *(Note 3)*	**5**	-
	503	971
Investing Activities		
Additions to property, plant and equipment	**(345)**	(309)
Additions to intangible assets	**(20)**	(61)
Change in construction payable	**-**	(11)
Other	**-**	(3)
	(365)	(384)
Financing Activities		
Net change in short-term borrowings	**(182)**	(367)
Issue of short-term note payable to affiliate company *(Note 19)*	**2**	6
Repayment of short-term note payable to affiliate company *(Note 19)*	**(3)**	(6)
Debenture and term note issues	**402**	-
Debenture and term note repayments	**(150)**	(102)
Preferred share dividends	**(2)**	(4)
Common share dividends	**(208)**	(181)
Other	**(2)**	(1)
	(143)	(655)
Increase in Bank Overdraft	**(5)**	(68)
(Bank Overdraft)/Cash and Cash Equivalents at Beginning of Year	**(13)**	55
Bank Overdraft at End of Year	**(18)**	(13)
Supplementary Cash Flow Information		
Income taxes paid	**59**	113
Interest paid *(Note 9)*	**185**	187

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2010**	2009
(millions of Canadian dollars)		
Assets		
Current Assets		
Accounts receivable and other *(Notes 4 and 19)*	**802**	801
Gas inventories	**400**	396
	1,202	1,197
Property, Plant and Equipment, net *(Note 5)*	**4,458**	4,290
Investment in Affiliate Company *(Note 19)*	**825**	825
Deferred Amounts and Other Assets *(Note 6)*	**487**	487
Intangible Assets *(Note 7)*	**167**	179
	7,139	6,978
Liabilities and Shareholders' Equity		
Current Liabilities		
Bank overdraft	**18**	13
Short-term borrowings *(Note 9)*	**332**	515
Accounts payable and other *(Notes 8 and 19)*	**836**	781
Current maturities of long-term debt *(Note 9)*	**150**	150
Future income taxes *(Note 16)*	**5**	5
	1,341	1,464
Long-Term Debt *(Note 9)*	**2,267**	2,015
Other Long-Term Liabilities *(Note 10)*	**1,058**	972
Future Income Taxes *(Note 16)*	**171**	185
Loans from Affiliate Company *(Notes 9 and 19)*	**375**	375
	5,212	5,011
Shareholders' Equity		
Share capital		
Preferred shares *(Note 11)*	**100**	100
Common shares *(Note 11)*	**1,071**	1,071
Contributed surplus	**202**	202
Retained earnings	**572**	596
Accumulated other comprehensive loss	**(18)**	(2)
	1,927	1,967
Commitments and Contingencies *(Notes 19 and 20)*		
	7,139	6,978

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

Janet A. Holder
President, Gas Distribution

(Signed)

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 3)*; allowance for doubtful accounts *(Note 4)*; depreciation rates and carrying values of property, plant and equipment *(Note 5)*; amortization rates of intangible assets *(Note 7)*; fair values of financial instruments *(Notes 13 and 14)*; income taxes *(Note 16)*; post-employment benefits *(Note 17);* contingencies *(Note 20);* and fair value of asset retirement obligations. Actual results could differ from these estimates.

BASIS OF PRESENTATION
The consolidated financial statements include the accounts of the Company and its subsidiaries. Investments are accounted for according to their classification (see Financial Instruments).

REGULATION
The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and rate-making and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

REVENUE RECOGNITION
The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

FINANCIAL INSTRUMENTS
The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, other financial liabilities or derivatives in qualifying hedging relationships. The Company has not classified any financial assets or liabilities as held to maturity.

Held for Trading
Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings. The Company has classified Cash and Cash Equivalents and Bank Overdraft as held for trading.

Available for Sale
The Company classifies its investment in the preferred shares of IPL System Inc. as an available for sale financial asset. Such instruments are periodically created by the Company and its affiliated companies to meet the current and future financing requirements of either the Company or its affiliated companies and no external market for the instrument exists. As this investment originated in a related party transaction and has no quoted market price in an active market, it is carried at cost and a fair value has not been determined. Dividends received from this investment are recognized in earnings when the right to receive payment is established *(Note 19)*.

Loans and Receivables
Loans and receivables, which include Accounts Receivable and Other, are initially recognized at fair value and subsequently measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

Other Financial Liabilities
Other financial liabilities are measured at amortized cost using the effective interest rate method and include Short-Term Borrowings, Accounts Payable and Other, Long-Term Debt and Loans from Affiliate Company.

Derivatives in Qualifying Hedging Relationships
The Company uses derivative financial instruments to manage changes in natural gas prices and interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges.

Cash Flow Hedges
The Company uses cash flow hedges to manage changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other Comprehensive Income (OCI) and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

The majority of St. Lawrence's derivatives relate to the management of natural gas prices. Given that St. Lawrence is subject to rate regulation, the effective portion of changes in the fair value of these derivatives is deferred as an asset or liability until they are settled and an offsetting asset or liability is recorded on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to customers in subsequent period rates.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES
The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

FOREIGN CURRENCY TRANSLATION
The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. This operation is self-sustaining and is translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of this operation are included in the foreign currency translation adjustment component of Accumulated Other Comprehensive Loss (AOCL).

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of ninety days or less upon issuance.

GAS INVENTORIES
Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred for future collection or refund by the Company to the customers, as approved by the Regulators. Actual cost of natural gas for St. Lawrence includes the effect of natural gas price risk management activities.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2010, $102 million of natural gas was held on behalf of transportation service customers (December 31, 2009 - $164 million). These transactions have no impact on the Company's consolidated earnings, cash flows or financial position.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment are recorded at cost, including associated operating costs and an allowance for interest during construction at current arm's length interest rates.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation.

Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved the by Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets include costs that the Regulators have permitted, or are expected to permit, to be recovered through future rates, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS
Intangible assets consist primarily of the Customer Information System (CIS) and software costs, which are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS
Asset retirement obligations (AROs) associated with the retirement of long-lived assets would be measured at fair value and recognized as Other Long-Term Liabilities in the period in which they could be reasonably determined. The fair value would approximate the cost a third party would charge to perform the tasks necessary to retire such assets and would be recognized at the present value of expected future cash flows. AROs would be added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability would be accreted over time through charges to earnings and would be reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of

changes in cost estimates and regulatory requirements.

It is not possible to make a reasonable estimate of AROs for the Company due to the indeterminate timing of the asset retirements.

POST-EMPLOYMENT BENEFITS

The Company maintains non-contributory pension plans that provide defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants.

The Company's post-employment benefits are determined as follows:

- The cost of pensions and OPEB earned by employees is actuarially determined using the projected benefit method pro-rated on service and management's best estimate of the expected plan investment performance, salary escalation, retirement ages of employees and expected health-care and insurance costs.
- Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific asset mix within the pension plan. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.
- The excess of the cumulative unrecognized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets is amortized over the expected average remaining service lives of employees.
- Pension costs under the defined benefit pension plans have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages. Adjustments arising from plan amendments, actuarial gains and losses, and changes to assumptions are amortized over the expected average remaining service lives of the employees.
- The transitional asset and obligation is amortized over the expected average remaining service lives of employees. The transitional asset relates to the pension plans and is the fair value of the plan assets less the accrued benefit obligation at October 1, 2000, amortized over 13 years. The transitional obligation relates to OPEB and is equal to the accrued benefit obligation at October 1, 2000, amortized over 15 years.

The regulated utility operations of the Company recover pension and OPEB expense based on the amounts paid. This is in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension and OPEB regulatory liability and asset has been recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year's consolidated financial statement presentation.

2. CHANGES IN ACCOUNTING POLICIES

FUTURE ACCOUNTING POLICY CHANGES

International Financial Reporting Standards

First-time adoption of Part I – International Financial Reporting Standards (Part I) of the Canadian Institute of Chartered Accountants (CICA) Handbook is mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and it will continue to present its financial statements in accordance with Part V – Pre-changeover Accounting Standards of the CICA Handbook during the 2011 deferral period.

Business Combinations
CICA Handbook Section 1582, *Business Combinations*, replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. The adoption of this standard will impact the Company's accounting treatment of any future business combinations occurring on or after January 1, 2011.

Consolidated Financial Statements and Non-Controlling Interests
The CICA issued Handbook Sections 1601, *Consolidated Financial Statements* and 1602, *Non-controlling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards is not expected to have a material impact to the Company's consolidated earnings or cash flows. The revised standards are effective January 1, 2011.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, "Enbridge Gas Distribution" refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas "St. Lawrence" refers specifically to St. Lawrence Gas Company, Inc.

RATE APPROVAL
Enbridge Gas Distribution's annual rates are currently set using a revenue per customer cap Incentive Regulation (IR) methodology. This IR methodology adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The cost of natural gas is passed on to customers as a flow-through.

St. Lawrence's rates for each year are set using a Cost of Service (COS) methodology that allows the revenues to be set to recover forecast costs and to earn a rate of return on common equity. Forecast costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of St. Lawrence to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken. The cost of natural gas is passed on to customers as a flow-through.

APPROVED RATES

Enbridge Gas Distribution
Enbridge Gas Distribution's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2010 (2009 – 8.39%) based on a 36% (2009 – 36%) deemed common equity component of capital for regulatory purposes.

To align the interests of customers with the Company's common shareholder, an earnings sharing mechanism forms part of the Settlement Agreement (the Settlement) with customer representatives approved by the OEB in February 2008. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive). To the extent the actual utility return on the approved equity level represented by normalized earnings (i.e., excluding the effects of weather) (ROE) exceeds the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings are shared with customers. The common shareholder retains the first 100 basis points of ROE above the NROE, while earnings represented by the ROE in excess of 100 basis points above the NROE are shared equally with customers.

St. Lawrence
St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.50% for the year ended December 31, 2010 (2009 – 8.89%) based on a 50% (2009 – 51.5%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11.0% (2009 – 9.6%) are shared equally with customers. The calculation of such earnings is cumulative over the three-year period commencing

January 1, 2010 and ending December 31, 2012, and resulted in no sharing impact as at December 31, 2010 (2009 - $nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company generally would not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Long-term regulatory liabilities are recorded in Other Long-Term Liabilities and current regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ from those recorded.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2010**	2009	Consolidated Statements of Financial Position Location**	Estimated Recovery/ Settlement Period (years)	Earnings Impact[1] **2010**	Earnings Impact[1] 2009
(millions of Canadian dollars)						
Regulatory Assets/(Liabilities)						
Enbridge Gas Distribution						
Future income taxes [2]	**164**	174	DA/OLTL	*	**(7)**	-
OPEB [3]	**68**	62	DA	*	**1**	4
Unaccounted for gas variance [4]	**18**	10	AR	1	**5**	6
Settlement recoverable [5]	**15**	20	AR/DA	2	**(3)**	-
Shared Savings Mechanism [6]	**11**	14	AR	*	**-**	-
Average use true-up variance [7]	**4**	3	AR	*	**1**	4
Deferred rate hearing costs [8]	**3**	6	AR/DA	2	**(2)**	-
Future removal and site restoration reserves [9]	**(753)**	(692)	OLTL	*	**-**	-
Pension plans [10]	**(222)**	(205)	OLTL	*	**6**	(6)
Purchased gas variance [11]	**(144)**	(227)	AP	1	**-**	-
Earnings sharing deferral [12]	**(38)**	(25)	AP	1	**-**	-
Transactional services deferral [13]	**(14)**	(14)	AP	1	**-**	-
Other regulatory assets and liabilities	**10**	10	***	*	**-**	(3)
	(878)	(864)			**1**	5
St. Lawrence						
Other regulatory assets and liabilities	**3**	(2)	***	*	**3**	(1)
	3	(2)			**3**	(1)
	(875)	(866)			**4**	4

* Refer to the footnote for details.
** AR – Accounts Receivable and Other
AP – Accounts Payable and Other
DA – Deferred Amounts and Other Assets
OLTL – Other Long-Term Liabilities
*** Dependent on the nature of the item.

1. The increase/(decrease) in the Company's after-tax reported earnings as a result of the rate regulation recognition of the item, excluding any additional earnings sharing impact. This includes the impact from recovery or refund, during the current year, of items outstanding at the end of the prior year.

2. The future income taxes balance represents the regulatory offset to future income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.

3. The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover OPEB expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and OPEB expense would be charged to earnings based on the accrual basis of accounting.

4. Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.

5. Settlement recoverable deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts are being recovered from customers over a five-year period, which commenced in 2008. In the absence of rate regulation, these costs would be expensed as incurred.

6. Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.

7. Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual normalized average use for general service customers. The amount will be recovered

from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the variance would be included in earnings in the year incurred.

8. Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, these costs would be expensed as incurred.

9. Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

10. The pension plans' balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover pension expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would be charged to earnings based on the accrual basis of accounting.

11. Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation, the actual cost of natural gas would be included in commodity costs and commodity revenue would be adjusted by an equal and offsetting amount as the right to collect the revenue has been established.

12. Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to customers and represents 50% of normalized earnings (i.e., excluding the effects of weather) represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2010 balance relates to the years ended December 31, 2010 and 2009. The December 31, 2009 balance relates to the years ended December 31, 2009 and 2008. There would be no change in the treatment of this item in the absence of rate regulation.

13. Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

Operating Cost Capitalization

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2010, costs relating to this services contract of $124 million (2009 - $112 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2010, the net book value of these costs was $111 million (2009 - $124 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. In the absence of rate regulation, the actual price of natural gas purchased would be recorded in gas inventories.

Included in gas inventories at December 31, 2010 is $43 million (2009 - $41 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred.

Depreciation

In the absence of rate regulation, depreciation rates would not have included a provision for future removal and site restoration costs.

4. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2010**	2009
(millions of Canadian dollars)		
Trade receivables	**422**	391
Unbilled revenues	**231**	222
Agent billing and collection receivable	**86**	105
Regulatory assets *(Note 3)*	**61**	67
Due from affiliates *(Note 19)*	**11**	15
Taxes receivable	**14**	33
Prepaid expenses	**5**	8
Other	**23**	17
Allowance for doubtful accounts	**(51)**	(57)
	802	801

5. PROPERTY, PLANT AND EQUIPMENT

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Gas mains	**4.2%**	**2,505**	**484**	**2,021**
Gas services	**4.6%**	**2,036**	**628**	**1,408**
Regulating and metering equipment	**3.8%**	**691**	**224**	**467**
Storage	**2.8%**	**240**	**79**	**161**
Land and right-of-way	**2.6%**	**77**	**29**	**48**
Computer technology	**19.8%**	**33**	**4**	**29**
Under construction	**-**	**66**	**-**	**66**
Other	**3.5%**	**259**	**76**	**183**
		5,907	**1,524**	**4,383**
Unregulated storage	**3.6%**	**52**	**2**	**50**
Construction materials inventory	**-**	**25**	**-**	**25**
		5,984	**1,526**	**4,458**

December 31, 2009	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Gas mains	4.2%	2,373	440	1,933
Gas services	4.4%	1,961	594	1,367
Regulating and metering equipment	3.7%	677	216	461
Storage	2.8%	228	73	155
Land and right-of-way	2.5%	68	27	41
Computer technology	19.5%	27	3	24
Under construction	-	71	-	71
Other	3.4%	247	79	168
		5,652	1,432	4,220
Unregulated storage	4.1%	48	1	47
Construction materials inventory	-	23	-	23
		5,723	1,433	4,290

Total depreciation expense, including amounts collected for future removal and site restoration costs, for property, plant and equipment was $238 million for the year ended December 31, 2010 (2009 - $225 million).

6. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2010**	2009
(millions of Canadian dollars)		
Regulatory assets *(Note 3)*	**252**	259
Pension asset *(Note 17)*	**222**	205
Long-term portion of derivative assets *(Note 14)*	**-**	4
Other	**13**	19
	487	487

7. INTANGIBLE ASSETS

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**20.1%**	**100**	**44**	**56**
CIS	**10.0%**	**127**	**16**	**111**
		227	**60**	**167**

December 31, 2009	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	20.5%	107	52	55
CIS	10.5%	127	3	124
		234	55	179

Intangible assets include $9 million of work-in-progress for the year ended December 31, 2010 (2009 - $9 million). Total amortization expense for intangible assets was $32 million for the year ended December 31, 2010 (2009 - $29 million).

8. ACCOUNTS PAYABLE AND OTHER

December 31,	2010	2009
(millions of Canadian dollars)		
Operating accrued liabilities	**282**	240
Regulatory liabilities *(Note 3)*	**204**	295
Budget billing plan payable	**92**	64
Security deposits	**73**	57
Dividends payable	**54**	47
Trade payables	**43**	25
Taxes payable	**34**	9
Interest payable	**29**	29
Due to affiliates *(Note 19)*	**3**	4
Current derivative liabilities *(Note 14)*	**1**	3
Other	**21**	8
	836	781

9. DEBT

December 31,	Weighted Average Interest Rate	Maturity	2010	2009
(millions of Canadian dollars)				
Debentures	10.46%	2011-2024	**235**	385
Medium-term notes	5.54%	2014-2050	**2,195**	1,795
Commercial paper and credit facility draws, net			**333**	508
Other			**6**	12
Deferred debt issue costs			**(20)**	(20)
Total Debt			**2,749**	2,680
Current Maturities			**(150)**	(150)
Short-Term Borrowings	1.13%		**(332)**	(515)
Long-Term Debt			**2,267**	2,015
Loans from Affiliate Company			**375**	375

Debenture and term note maturities for the years ending December 31, 2011 through 2015 are $150 million, $nil, $nil, $400 million, and $nil, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2011 through 2015 are $138 million, $130 million, $130 million, $124 million and $109 million, respectively.

INTEREST EXPENSE

Year ended December 31,	2010	2009
(millions of Canadian dollars)		
Debentures and medium-term notes	**149**	151
Loans from affiliate company *(Note 19)*	**27**	27
Commercial paper and credit facility draws	**2**	4
Other interest and finance costs	**11**	14
Capitalized	**(3)**	(6)
	186	190

In 2010, total interest paid to third parties was $158 million (2009 - $160 million) and total interest paid to affiliated companies was $27 million (2009 - $27 million).

CREDIT FACILITIES

In 2010, the Company elected to reduce its committed credit facilities and commercial paper program limit by $100 million. The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not

exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

December 31, 2010	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	**700**	**325**	**375**
St. Lawrence Gas Company, Inc.	**12**	**8**	**4**
Total Credit Facilities	**712**	**333**	**379**

1. Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

Credit facilities carried a weighted average standby fee of 0.60% per annum from January to July 2010 and 0.38% per annum from August to December 2010 on the unused portion and draws bear interest at market rates.

10. OTHER LONG-TERM LIABILITIES

December 31,	**2010**	2009
(millions of Canadian dollars)		
Regulatory liabilities *(Note 3)*	**984**	897
OPEB liabilities *(Note 17)*	**71**	70
Pension liability *(Note 17)*	**3**	3
Other	**-**	2
	1,058	972

11. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preferred shares.

COMMON SHARES

December 31,	**2010**		2009	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)				
Balance at beginning of year	**141**	**1,071**	141	1,071
Common shares issued	**-**	**-**	-	-
Balance at End of Year	**141**	**1,071**	141	1,071

PREFERRED SHARES

December 31, 2010 and 2009	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preferred shares in millions)			
Group 1	**0.2**	**Nil**	**-**
Group 2, Series A - C, Cumulative Redeemable Retractable	**6**	**Nil**	**-**
Group 2, Series D, Cumulative Redeemable Convertible	**4**	**Nil**	**-**
Group 3, Series A - C, Cumulative Redeemable Retractable	**6**	**Nil**	**-**
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	**4**	**4**	**100**
Group 4	**10**	**Nil**	**-**
Group 5	**10**	**Nil**	**-**
			100

Cumulative cash dividends on the Group 3, Series D preferred shares were payable at a fixed yield rate of 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder's option, into Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

12. STOCK OPTION AND STOCK UNIT PLANS

Certain employees and senior officers of the Company are granted stock-based compensation from Enbridge through its three long-term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

During the year ended December 31, 2010, 180,500 stock options (2009 – 244,350 options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $46.59 in 2010 (2009 - $39.61) and a grant date fair value of $6.56 (2009 - $6.73).

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan that includes the Company's senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average common share price and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two, if Enbridge performs within the highest range of its performance targets. The 2008, 2009, and 2010 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's growth in earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

During the year ended December 31, 2010, 9,100 PSUs (2009 – 6,900) were issued to employees of the Company.

RESTRICTED STOCK UNITS

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price multiplied by the units outstanding on the maturity date.

During the year ended December 31, 2010, Enbridge granted 58,750 RSUs (2009 – 61,800) to certain employees of the Company.

STOCK-BASED COMPENSATION EXPENSE

The Company is charged an expense for stock-based compensation which includes a direct charge for ISOs, PSUs and RSUs issued to employees of the Company and an allocation of such costs with respect to employees of Enbridge who provide services to the Company. For the year ended December 31, 2010, the direct charge totaled $6 million (2009 – $5 million) and the allocation totaled $5 million (2009 – $4 million). These costs are included in operating and administrative expenses.

13. RISK MANAGEMENT

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in interest rates, foreign exchange rates and natural gas prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt (commercial paper). Floating to fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.8%.

At December 31, 2010, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have caused a $3 million increase (2009 - $15 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2010, and a $nil effect (2009 - $4 million decrease) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2010 assuming the variable rate debt outstanding had been outstanding for the entire period.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is $nil (2009 - $nil).

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Only St. Lawrence manages the exposure to natural gas price risk by entering into fixed price natural gas contracts. Other than St. Lawrence, the Company no longer manages natural gas price risk exposure, in compliance with the directive of the OEB. Fluctuations in natural gas prices are borne by the customers.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

December 31, 2010	2011	2012	2013	2014	2015	Thereafter
Natural gas *(10^6m^3)*	17	6	-	-	-	-
Interest rate contracts *(millions of Canadian dollars)*	279	111	-	-	-	-
Net Cash Flows	296	117	-	-	-	-

The Company does not have any credit-risk related contingent features associated with its derivative instruments.

The Company estimates that $3 million of AOCL related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. Any gains or losses from natural gas derivatives are borne by customers. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 24 months at December 31, 2010.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 19 and 20)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 9)* with a diversified group of banks and institutions which, if necessary, would enable the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2010. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt and loans from affiliate company *(Notes 9 and 19)*.

For the years ending December 31, 2011 through 2015, and thereafter, the Company has estimated that the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

	2011	2012	2013	2014	2015	Thereafter
(millions of Canadian dollars)						
Cash inflows	-	-	-	-	-	-
Cash outflows	(1)	-	-	-	-	-
Net Cash Flows	(1)	-	-	-	-	-

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 14, Fair Value of Financial Instruments.

The change in the allowance for doubtful accounts in respect of accounts receivable is detailed below.

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Balance at beginning of year	**(57)**	(50)
Additional allowance	**(23)**	(29)
Amounts used and reversed	**29**	22
Balance at End of Year	**(51)**	(57)

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 21 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate. Under IR, these estimated costs recovered through distribution rates relate to the base year of the IR plan (2007) and are escalated by the approved formula during the IR term.

Entering into derivative financial instruments can also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. At December 31, 2010, the Company has a maximum exposure to credit risk of $nil (2009 - $3 million) related to its derivative counterparties.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Accounts receivable and other	**-**	**-**	**722**	**-**	**-**	**80**	**802**	**722**
Investment in affiliate company	**-**	**825**	**-**	**-**	**-**	**-**	**825**	**N/A**
Deferred amounts and other assets	**-**	**-**	**-**	**-**	**-**	**487**	**487**	**-**
Liabilities								
Bank overdraft	**18**	**-**	**-**	**-**	**-**	**-**	**18**	**18**
Short-term borrowings	**-**	**-**	**-**	**332**	**-**	**-**	**332**	**332**
Accounts payable and other	**-**	**-**	**-**	**597**	**1**	**238**	**836**	**598**
Long-term debt	**-**	**-**	**-**	**2,417**	**-**	**-**	**2,417**	**2,775**
Loans from affiliate company[2]	**-**	**-**	**-**	**375**	**-**	**-**	**375**	**N/A**

December 31, 2009	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Accounts receivable and other	-	-	691	-	2	108	801	693
Investment in affiliate company	-	825	-	-	-	-	825	N/A
Deferred amounts and other assets	-	-	-	-	4	483	487	4
Liabilities								
Bank overdraft	13	-	-	-	-	-	13	13
Short-term borrowings	-	-	-	515	-	-	515	515
Accounts payable and other	-	-	-	474	3	304	781	477
Long-term debt	-	-	-	2,165	-	-	2,165	2,445
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

1 *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market (Note 19).*

2 *Loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined (Note 19).*

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps and natural gas swaps for which observable inputs can be obtained.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed

methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates.

When possible the estimated fair value is based on quoted market prices, and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and the nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and natural gas) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

December 31, 2010	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets:				
Current derivative assets	**-**	**-**	**-**	**-**
Long-term derivative assets	**-**	**-**	**-**	**-**
Financial liabilities:				
Current derivative liabilities	**-**	**(1)**	**-**	**(1)**
Long-term derivative liabilities	**-**	**-**	**-**	**-**
Total Net Derivative Liability	**-**	**(1)**	**-**	**(1)**

December 31, 2009	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets:				
Current derivative assets	-	2	-	2
Long-term derivative assets	-	4	-	4
Financial liabilities:				
Current derivative liabilities	-	(3)	-	(3)
Long-term derivative liabilities	-	-	-	-
Total Net Derivative Asset	-	3	-	3

15. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCL), long-term debt (including intercompany debt, excluding transaction costs), short-term borrowings and bank overdraft less cash and cash equivalents.

The Company's capital is calculated as follows:

December 31,	**2010**	2009
(millions of Canadian dollars)		
Bank overdraft	**18**	13
Short-term borrowings	**332**	515
Long-term debt (includes current portion)	**2,437**	2,185
Loans from affiliate company	**375**	375
Shareholders' equity	**1,945**	1,969
Cash and cash equivalents	**-**	-
	5,107	5,057

The Company's objectives when managing capital are to maintain flexibility among: enabling the business to operate at the highest efficiency while maintaining safety and reliability; providing liquidity for growth opportunities; maintaining a capital structure that is in alignment with the deemed equity ratio of 36%; and providing acceptable returns to the common shareholder. These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital in light of changes in the economic and regulatory environment and the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to the common shareholder, issue new shares or issue new debt. Dividend payments are determined with the objective of maintaining a capital structure that is in alignment with the deemed equity ratio of 36%.

Due to the seasonal nature of the Company's business and continuing growth in the asset base, cash receipts do not typically match the Company's requirements for capital expenditures, dividends, long-term debt retirement and inventory replenishment. Generally, cash shortfalls are financed initially through the issuance of short-term debt. The Company maintains a balanced capital structure by periodically refinancing short-term debt with long-term debt.

The Company's borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as Canadian GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of debt issue costs and intercompany interest expense, less gains on asset dispositions divided by the annual interest requirements. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2010, the Company was in compliance with these covenants.

16. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Earnings before income taxes	**254**	299
Combined statutory income tax rate	**31.0%**	33.0%
Income taxes at statutory rate	**79**	99
Increase/(decrease) resulting from:		
Non-taxable dividend income from affiliated companies	**(19)**	(21)
Future income taxes related to regulated operations	**7**	-
Other	**(6)**	-
Income Taxes	**61**	78
Effective Income Tax Rate	**24%**	26%

The future income taxes recorded in current liabilities of $5 million (2009 - $5 million) arise primarily from temporary differences relating to regulatory deferral accounts.

At December 31, 2010, the Company had a future income tax liability of $164 million (2009 - $174 million) related to regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset to the extent that the future income tax liability is expected to be included in regulator-approved future rates and recovered from future customers.

17. POST-EMPLOYMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees. The management selected measurement date of December 31, 2010 was used to determine the plan assets and the accrued benefit obligation.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average

remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuation and the next required actuarial valuation are as follows:

Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
December 31, 2009	December 31, 2012

The defined benefit pension plans' costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

Post-employment Benefits Other than Pensions
OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

DEFINED BENEFIT PLANS
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plan using the accrual method.

	Pension Benefits		OPEB	
December 31,	**2010**	2009	**2010**	2009
(millions of Canadian dollars)				
Change in Accrued Benefit Obligation				
Benefit obligation at beginning of year	**588**	579	**81**	83
Service cost	**12**	13	**1**	1
Interest cost	**39**	39	**5**	6
Actuarial loss/(gain)[1]	**79**	(12)	**5**	(6)
Benefits paid	**(31)**	(31)	**(3)**	(3)
Net transfer in/(out)	**15**	-	**(2)**	-
Benefit obligation at end of year	**702**	588	**87**	81
Change in Plan Assets				
Fair value of plan assets at beginning of year	**695**	700	**-**	-
Transfer to the defined contribution component	**(2)**	(1)	**-**	-
Actual return on plan assets[1]	**78**	26	**-**	-
Employer's contributions	**4**	1	**7**	3
Benefits paid	**(31)**	(31)	**(3)**	(3)
Net transfer in	**15**	-	**-**	-
Fair value of plan assets at end of year	**759**	695	**4**	-
Funded Status				
Benefit obligation	**(702)**	(588)	**(87)**	(81)
Fair value of plan assets	**759**	695	**4**	-
Overfunded/(Underfunded) status at end of year	**57**	107	**(83)**	(81)
Contribution after measurement date	**-**	-	**-**	1
Unamortized prior service cost	**4**	5	**-**	-
Unamortized transitional (asset)/obligation	**(70)**	(94)	**16**	19
Unamortized net actuarial loss/(gain)	**228**	184	**(4)**	(9)
Net amount recognized in the Consolidated Statement of Financial Position at end of year	**219**	202	**(71)**	(70)
Presented as follows:				
Deferred Amounts and Other Assets *(Note 6)*	**222**	205	**-**	-
Other Long-Term Liabilities *(Note 10)*	**(3)**	(3)	**(71)**	(70)

1 *Includes revaluing plan assets and liabilities for December 31, 2010.*

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
Discount rate	**5.70%**	6.60%	**5.70%**	6.60%
Average rate of salary increases	**3.50%**	3.50%	**5.00%**	5.00%

Net Benefit Costs Recognized

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
(millions of Canadian dollars)				
Benefits earned during the year	**12**	13	**1**	1
Interest cost on projected benefit obligations	**39**	39	**5**	6
Actual return on plan assets	**(78)**	(26)	**-**	-
Actuarial loss/(gain)	**79**	(12)	**5**	(6)
Differences between costs arising in the year and costs recognized in the year:				
Return on plan assets	**29**	(22)	**-**	-
Prior service costs	**1**	1	**-**	-
Transitional (asset)/obligation	**(24)**	(25)	**3**	3
Actuarial (loss)/gain	**(64)**	25	**(5)**	6
Net defined benefit costs on an accrual basis	**(6)**	(7)	**9**	10
Defined contribution benefit costs	**2**	1	**-**	-
(Credits)/costs on an accrual basis	**(4)**	(6)	**9**	10

Costs related to the period on an accrual basis are presented above and are initially expensed. However, there is a partially offsetting adjustment due to the regulatory mechanism in place. As a result, the net expense is comprised of plan contributions and actual OPEB benefit costs paid, which is consistent with the recovery of such costs in rates. Such costs totaled $4 million for pension benefits and $7 million for OPEB for the year ended December 31, 2010 (2009 - $1 million and $3 million, respectively).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
Discount rate	**6.60%**	6.70%	**6.60%**	6.70%
Average rate of return on pension plan assets	**7.14%**	7.25%	**-**	-
Average rate of salary increases	**3.50%**	5.00%	**5.00%**	5.00%

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	9.13%	4.50%	2029
Other Medical and Dental	4.50%	4.50%	2029

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $12 million in the accumulated post-employment benefit obligations and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $10 million in the accumulated post-employment benefit obligations and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

Major Categories of Plan Assets

	Pension Benefits		
	2010		2009
As at December 31,	Allocation	Amount	Allocation
(millions of Canadian dollars)			
Equity securities	**58%**	**439**	55%
Fixed income securities	**41%**	**313**	41%
Other	**1%**	**7**	4%
Total Assets	**100%**	**759**	100%

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

The Company manages the investment risk of its defined benefit pension plans by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

Target Mix for Plan Assets	
Equity securities	52.5%
Fixed income securities	42.5%
Other	5.0%

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
(millions of Canadian dollars)				
Total contributions	**4**	1	**7**	3
Contributions expected to be paid in 2011	**5**		**4**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2011	2012	2013	2014	2015	2016-2020
(millions of Canadian dollars)						
Expected future benefit payments	38	39	41	43	45	255

18. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Accounts receivable and other	**3**	187
Gas inventories	**(4)**	260
Accounts payable and other	**32**	20
	31	467

19. RELATED PARTY TRANSACTIONS

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
IPL System Inc.		
Dividend income	**63**	63
Interest expense	**27**	27
Enbridge Inc.		
Purchase of treasury and other management services	**32**	28
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**30**	44
Vector Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**27**	29
Vector Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**1**	1
Alliance Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**25**	24
Alliance Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**17**	18
Enbridge Commercial Services Inc.		
Purchase of information services	**2**	2

The Company had related party balances as follows:

December 31,	**2010**	2009
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company		
Enbridge (U.S.) Inc.	**6**	7
Note receivable from affiliate company		
Enbridge (U.S.) Inc.	**-**	4
Accounts receivables/(payables)		
Enbridge Inc.	**(1)**	(2)
Gazifère Inc.	**5**	4

Financing Transactions
The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2010, the investment of $825 million (2009 - $825 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2010, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2010, interest paid amounted to $27 million (2009 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

Treasury and Other Management Services
Enbridge provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services.

Wholesale Service
These services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services
The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2011 - $67 million, 2012 to 2013 - $133 million, 2014 to 2015 - $114 million and thereafter - $nil.

Information Services
The Company purchases access to a few of its customer care information systems from Enbridge Commercial Services Inc. (ECS), an affiliate under common control. ECS charges the Company amounts under a service level agreement designed to recover the cost of providing the service.

Trade Receivables and Payables
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

20. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has entered into long-term contracts and future payments under the contracts are as follows:

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Services contract [1]	22	7	13	2	-
Customer care service contracts [2]	71	57	14	-	-
CIS contracts [3]	9	6	3	-	-
Total Contractual Obligations	102	70	30	2	-

1. In 2003, the Company signed a service agreement with Accenture Inc., for a period of ten years, to provide management assistance and information technology solutions for work and asset management and field force transformation. These services relate to system improvement and expansion related construction activities performed by the Company and its construction contractors.
2. In 2007, the Company signed five-year customer care services contracts with third party service providers for meter reading, billing, billing administration, call handling, and collections.
3. In 2007, the Company signed contracts with third party service providers for CIS integration services, software maintenance and support.

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the

discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2011 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

Bloor Street Incident

The Company had been charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The decision was appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge's decision and ordered a new trial to be conducted before a different judge. The Company commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed the Company's motion, meaning that the Superior Court's decision ordering a new trial will stand. At this time it is not certain when a new trial of the charges will commence. Management does not believe any fines that may be levied will have a material financial impact on the Company.

TAX MATTERS

The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATON

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

CORPORATE INFORMATION

TRUSTEE AND REGISTRARS

Debentures
9.85% and 10.80% debentures

BNY Mellon Trust Company
Corporate Trust Services
320 Bay Street, P.O. Box 1
Toronto, Ontario, M5H 4A6
and in Halifax, Montreal, Winnipeg, Regina, Calgary and Vancouver

For each of the above group of debentures, BNY Mellon Trust Company is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium Term Notes
Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street, 5th Floor
Toronto, Ontario, M5J 2W5

TRUSTEE

Medium Term Notes
BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, P.O. Box 1
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preferred Shares
Computershare Investor Services Inc.
100 University Avenue
Toronto, Ontario, M5J 2Y1

Corporate Governance

The size of the Board of Directors of the Company is currently set at six (6) members, two (2) of whom are considered to be independent directors.

The Board has an Audit, Finance & Risk Committee comprised of the following directors:

J. L. Braithwaite
D.A. Leslie
J. R. Bird

The Audit, Finance & Risk Committee's key responsibilities include the review of the consolidated financial statements, systems of internal financial and compliance control.

The governance of the Company is the responsibility of the Board of Directors and the Audit, Finance & Risk Committee of the Board, who are also responsible under law for the supervision of the management of the Company's businesses and affairs and have the statutory authority and obligation to act honestly and in good faith with a view to the best interests of the Company.

The Board makes independent decisions and also receives recommendations from the following committees of the Enbridge Inc. Board of Directors, who act in an advisory capacity to the Board of Directors of the Company:

- Governance Committee
- Human Resources & Compensation Committee
- Corporate Social Responsibility Committee

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the Statement of *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 29, 2010), which is incorporated herein by reference.

BOARD STAFF INTERROGATORY #18

INTERROGATORY

Ref: Ex. E /Tab 3/ Sch 1

Please provide the calculation details underpinning the ROE for 2012.

RESPONSE

Please see EGD's response to VECC Interrogatory #13, at Exhibit I, Tab 8, Schedule 13.

Witness: S. Murray

2 - BOMA

BOMA INTERROGATORY #1

INTERROGATORY

Ex B, T2, Sch 6, pp 1-19

Enbridge states at page 6 that, starting in 2009 and 2010, it "began to create and implement a program to take preventative steps to address cross-bore issues, and reduce the chances of any serious incidents in its franchise area". What did these steps consist of? Please discuss.

RESPONSE

In the last quarter of 2009 Enbridge launched a pilot response plan in the Niagara region franchise to ensure a workable plan both for Enbridge and the municipalities who own the sewer facilities. In preparation for this pilot, Enbridge created the appropriate education/awareness communication materials, and created and entered into agreements with and trained a service provider and Enbridge staff on response protocols. Enbridge also worked with Ontario One Call to establish protocols and call types to facilitate the dispatching of this new work type to the appropriate service provider. Niagara Region municipal sewer operators, plumbers and drain cleaners were invited to education sessions to learn about Enbridge's new Sewer Safety Program.

As a result of this pilot and working with Municipal sewer operators in the Niagara Region, the response plan and protocols were revised to facilitate a more operationally effective program. The communication materials were revised to reflect the amended processes and the response plan was rolled out to the remainder of the Enbridge franchise areas in 2010.

There are five areas of focus in the plan:

New procedures for addressing blocked sewer lines
Public education / awareness and response campaign
New construction procedures when trenchless technologies are to be utilized
Legacy investigations (to seek to identify existing cross bores), and
Records management, research and development (to develop better installation records and safer construction and locate procedures).

Witnesses: C. Clark
L. Lawler

BOMA INTERROGATORY #2

INTERROGATORY

When did Enbridge begin to take precautionary actions with respect to new construction procedures to avoid cross-bore issues with service lines; when did they commence legacy investigations; when did they begin activities to enhance public, municipal, government and trades awareness of the cross-bore risk?

RESPONSE

Updated construction procedures were implemented in 2008.

Legacy investigations commenced in 2008.

Education/Awareness and Response commenced in Q4 of 2009 in the Niagara Region and was rolled out in the rest of Enbridge's service territory in 2010.

Witnesses: C. Clark
L. Lawler

BOMA INTERROGATORY #3

INTERROGATORY

Enbridge states that it encountered and repaired approximately forty-four sewer lateral cross-bores since 2007. What was the approximate cost of the work? Please provide details on how the cost was calculated.

RESPONSE

First, the cross bores have to be identified and then repaired. There are three ways that cross bores are identified.

1. Legacy Investigation. For 2010 to Year to Date ("YTD") 2011 costs for this part of the program have been approximately $0.6M.

2. The Sewer Safety Program (A customer, plumber or municipality calling Ontario One Call). At a cost of approximately $3.6M for 2010 and 2011 YTD.

3. Identified by the municipal sewer operator, plumber, or property owner outside of the Sewer Safety Program.

Repair costs when found average approximately $12,000 and are dependent on a number of factors such as location, restoration costs for property damage both internal and external, and type and size of gas plant. The costs are based on actual repair costs on a case by case basis.

Witnesses: C. Clark
L. Lawler

BOMA INTERROGATORY #4

INTERROGATORY

Please provide the minutes of the two meetings of TSSA Risk Reduction Group on Pipelines in March and June of 2011, referenced at B, 2, 6, p6, par 22.

RESPONSE

Copies of the minutes are attached as requested.

Witnesses: C. Clark
L. Lawler

FUELS SAFETY PROGRAM

Tel: (416) 734-3353
Fax: (416) 231-7525

March 7, 2011

Highlights of the
Risk Reduction Group (RRG) on PIPELINES MEETING
March 1, 2011
3300 BLOOR STREET WEST, Toronto

PRESENT:

Phippen,Chris	Utilities Kingston
Doug Lapp,	Enbridge Gas Distribution Inc. (part time),
Clifford Clark	Enbridge Gas Distribution Inc.
Bob Bacic	Union Gas Limited
Les Wojtanowski	Sun-Canadian PipeLine Company Limited
Orlo Cracknell	Imperial Oil Products and Chemical Division
Jason Hrycyshyn,	ELECTRICAL SAFETY AUTHORITY
Les Jones,	City of Kitchener, Utilities Operation Centre
Cecil Blair	TransCanada Pipelines
Kourosh Manoucheri	Technical Standards & Safety Authority (TSSA)
Zenon Fraczkowski	TSSA (part time)
Jorge Larez	TSSA (part time)
Muddassir Nazir	TSSA (part time)
Oscar Alonso	TSSA

Absent:

Zora Crnojacki	Ontario Energy Board
Ken McGillivray	Nova Chemicals (Canada) Ltd.

Opening Remarks

The chairman welcomed all in attendance and suggested self-introduction of members. The membership list was updated (attached).

L:\FSESB\
COMMITTEE\PIPELIN

Draft

The term of reference for the RRG-Pipelines was briefly discussed. A copy of the document is attached below:

L:\FSESB\OA\RRG terms of reference, 2

1. Approval of the agenda.

The agenda was approved as presented.

2. Approval of the previews minutes

The minutes were approved as distributed.

3. Business arising from the minutes of previous meeting (October 11, 2007)

The group briefly reviews of the minutes. A short discussion follows on the main items of the minutes. No further actions were required.

4. New Business

4.1 Proposed adoption of the new edition of the CSA Z662-11. Discussion of the proposed Directors' Order for the CAD.

The previously distributed Director's Order draft was reviewed. The CSA Z662-11would be published in July, 2011 and the intention was to have the new code and the Ontario additions or changes in effect by the end of the year or early 2012. A draft CSA Z662 used for balloting was also attached to the agenda and it was clarified that some changes have been introduced at the Technical Committee meeting held in Vancouver on February 9/11, 2011. However, the changes would only affect a small percentage of clauses.

The draft Director's Order was modified to reflect the observations, clarifications or errors that the participant noted. The new draft is attached below:

L:\FSESB\OA\ Director's Order, Z66

The chairman invited the members to further review the document and suggest any other changes or additions.

4.2 Review of Advisory on Clearing Blocked Sewer Service Lines.

Draft

The wording has been incorporated in the CAD, Item (14).

4.3 Implementation of OQ programs.

Oscar Alonso emphasized the need to demonstrate that the competency and training of personnel as required in Annex N, item 7, Operator Qualification (OQ) or similar programs. The person performing designated (covered) tasks (particularly in the field) should have available a credential to show that he or she has been trained and is entitled to perform the work. The certificate could be something similar to a driver's license, showing as a minimum:

a) Name of the person,
b) Work type or designation
c) Expiry date, and
d) The signature and clarification of the company's official authorizing the certificate.

Alternatives to demonstrating the intent of this without it necessarily being a certificate, (such as a print out of the workers and their qualifications], may be acceptable.

4.4 Adoption of CSA Z246.1-09, Security Management for Petroleum and Natural gas Industry Systems.

The standard is included in Section 2.(1) of the CAD.

5. Next meeting

No specific date was established for the next meeting. I will be at the call of the chair or upon the request from members.

cc: RRG Pipelines
Gas Advisory Council
John Marshall

L:\FSESB\COMMITTE\PIPELINE\minutes\March 1, 2011 minutes.doc

Draft

Phippen,Chris
Utilities Kingston
1211 John Counter Blvd.
Kingston, ON K7L 4X7
Telephone: 613-546-1181 X2335
Fax: 613-542- 1463
E-Mail: cphippen@utilitieskingston.com

Doug Lapp, P.Eng.
Chief Engineer
Engineering Stnds & Tech Serv
Enbridge Gas Distribution Inc.,
500 Consumers rd.,
North York, ON M2J 1P8
Telephone: 416-495-3940
Fax: 416-495-5871
E-mail: doug.lapp@enbridge.com

Zora Crnojacki
Chair, Ontario Pipeline Coordination Commit.
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416-440-8104
Fax: 416-440-7656
E-mail: crnojazo@oeb.gov.on.ca

Bob Bacic
Senior Advisor, Integrity Management
Union Gas Limited
P.O. Box 2001, 50 Keil Drive North
Chatham, ON N7M 5M1
Telephone: 519 436 4687
Fax: 519 436 5292
E-mail: bbacic@uiniongas.com

Les Wojtanowski
Manager, Operations & Engineering
Sun-Canadian PipeLine Company Limited
P .O. Box 470
Waterdown ON L0R 2H0
Telephone: 905-690-5605 x5605
Cel: 416 873 8626
Fax: 905-689-1233
E-mail:lwojtanowski@Sun-canadian.com

Casey Steneker
Engineering, Maintenance and Projects Manager
Imperial Oil Products and Chemical Division
237 Fourth Ave. S. W.
Calgary AB T2P 3M9
Telephone: 403-237-3430
Fax: 403-237-2012
E-mail: casey.steneker@esso.ca
(Orlo Crackwell)

Jason Hrycyshyn, P.Eng
Electrical Distribution Safety Engineer
Technical Services and Compliance
ELECTRICAL SAFETY AUTHORITY
PHONE: 905-712-5654
FAX: 905-507-4572
jason.hrycyshyn@electricalsafety.on.ca

Les Jones, P.Eng.
Utilities Engineer
City of Kitchener
Utilities Operation Centre
83 Elmsdale Drive
Kitchener, ON
Telephone: 519 741 2826
Fax: 519 741 2638
E-mail: les.jones@kitchener.ca

Cecil Blair
Director, Eastern Canada Region
Transcanada Pipelines
11200 Weston Rd.,
Maple ON L6A 1S7
Telephone: 905-832-7301
Fax: 905-832-7391
Cell: 416 522-7075
E-mail: cecil_blair@transcanada.com

Ken McGillivray
Pipeline Coordinator
Nova Chemicals (Canada) Ltd.
P. O. Box 3060,
Sarnia, ON N7T 8C7
Telephone: 519-862-2911 x 2392
Fax: 519-481-2701
Cell: 519 331 4236
E-mail: MCGILLKE@novachem.com

Kourosh Manoucheri *Fuels Safety Engineer* *Technical Standards & Safety Authority* *14th Floor, Centre Tower* *3300 Bloor Street West* *Toronto ON M8X 2X4* *Telephone: 416-734-3356* *Fax: 416-231-7539* *E-mail: kmanoucheri@tssa.org*	***Oscar Alonso*** *Fuels Safety Engineer* *Technical Standards & Safety Authority* *14th Floor, Centret Tower* *3300 Bloor Street West* *Toronto ON M8X 2X4* *Telephone: 416-734-3353* *Fax: 416-231-7525* *E-mail: oalonso@tssa.org*
Zenon Fraczkowski *Engineering Manager, Fuels Safety* *TSSA*	***Srikanth Mangalam*** *Risk Manager* *TSSA*

I:\fsesb\committe\pipeline\2011 RRG Oil & Gas Pipeline Committee

Purpose

In support of its strategic objective to improve safety outcomes and recognizing the need for industry input, the Technical Standards and Safety Authority (TSSA) actively solicits the technical advice of the key stakeholders from the respective industries that it regulates through a number of industry specific risk reduction groups (RRGs). Industry members are invited to work with TSSA in the development of resolutions to identified safety gaps, adopting codes, implementing regulatory/code requirements, etc. Participation of stakeholder representatives on the RRGs is very much appreciated by TSSA.

Reporting

The collective mandate of the RRGs is to discuss and provide input to TSSA on safety, code adoption, regulatory implementation and interpretation issues. As a means to ensure that the views represented by the RRG members are reflective of their industry sector, the chair of the RRG will provide progress updates to the appropriate industry advisory councils. This may be accomplished through formal presentations at council meetings and/or via electronic distribution of meeting minutes.

This reporting structure ensures overall coordination of industry input, facilitates endorsement of RRG recommendations by the council and reinforces TSSA's commitment to transparency and public accountability.

Structure

RRGs are established to address a safety gap, code adoption, regulatory implementation or specific risk management issue. RRGs and issues requiring safety solutions are established by TSSA. The RRG process is to formally solicit input from the statutory directory on safety and interpretation issues. The final decision regarding the resulting action resides with the statutory director. Council members are invited to submit issues for consideration. Issues will be assessed and RRGs established and prioritized using risk-informed methodology. RRG discussions and resultant guidance for the resolution of specific issues will be based on risk management principles and communicated to the applicable councils. RRG updates will be standing items on all council agendas. RRG members operate under their own terms of reference.

Membership

Membership of the RRGs will be reflective of the stakeholders in the respective industries. TSSA will strive to manage RRG membership so that input is balanced and, to the extent appropriate, represents the industry as a whole as well as the end user/consumer. TSSA may not restrict membership in order to gain the most input on an issue and the RRG process may also allow communication of new regulatory, code or safety requirements.

Members will be invited to participate by TSSA or industry stakeholders. Any member wishing to participate may do so.

RRGs will be chaired by TSSA; however, where appropriate, TSSA will delegate the chair position to a member of industry. In addition to the chair, TSSA will appoint a coordinator to support RRG initiatives through the scheduling of meetings, preparation of agendas and meeting minutes and maintenance of records, where appropriate and beneficial.

Membership on the RRG is voluntary and, as such, there will be no retainers or fees paid to RRG members by TSSA. Any expenses incurred will be the responsibility of the participating individual / organization / association.

Qualifications of Members

Appointees to the RRGs will be relevant topic/technical experts in their respective organization/association who are committed to represent their industry sector's position on safety issues. TSSA may consider participants who are not experts if they have a specific interest in the issue or may be impacted by the issue.

Meetings

The RRGs shall meet as often as is deemed necessary so as to develop appropriate solutions to identified safety issues/topics.

Meeting agendas and supporting material will be sent to each member in advance of the meeting date. Minutes will be distributed within two weeks of the meeting. Meeting minutes will also be distributed to all members of the appropriate industry advisory council.

Confidentiality

Every employee of TSSA is required to safeguard the confidentiality of proprietary or sensitive information, audit findings and industry records. This obligation extends to RRG members, and to information or records related to RRGs (e.g. agendas, minutes, etc.).

Conflict of Interest

It is recognized that members of the RRGs may ultimately derive either direct or indirect benefit from the outcome of specific deliberations of the RRGs. All members are required to refrain from using their position to gain benefit from or influence any other member, organization or industry sector.

Fuels Safety Program	Ref. No.: FS--11	Rev. No.:
DIRECTOR'S ORDER	Date: December 14, 2011	Date:

IN THE MATTER OF:
THE TECHNICAL STANDARDS AND SAFETY ACT, 2000,
S.O. 2000, c. 16

- and -

ONTARIO REGULATION 223/01 (Codes and Standards Adopted by Reference)
made under the Act
- and -
ONTARIO REGULATION 210/01 (Oil and Gas Pipeline Systems)
made under the Act

Subject: Amendment to the Oil and Gas Pipeline Systems Code Adoption Document
Sent to: Gaseous Fuels Advisory Council, Pipeline RRG, Posted on TSSA's Web-Site

The Director of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems) pursuant to section 8 of Ontario Regulation 223/01 (Codes and Standards Adopted by Reference) hereby provides notice that the Oil and Gas Pipeline Systems Code Adoption Document published by the Technical Standards & Safety Authority and dated June 1, 2001, is amended as follows:

All sections of the Code Adoption Document (Sections 1 to 5) are revoked and replaced with the following:

Section 1

REFERENCE PUBLICATIONS
(1) The reference publications as set forth herein are approved by the Director and adopted as part of this Document and the standards, procedures and requirements therein, as applicable to this Document, shall be complied with by operating companies as well as anyone engaged in the design, construction, erection, alteration, installation, testing, operation or removal of a pipeline, for the transmission of oil or gas or the distribution of gas.

Government of Ontario
Technical Standards & Safety Act, Boilers and Pressure Vessels Regulation

Canadian Standards Association
Service Regulators for Natural Gas, CSA 6.18-02

Draft

Section 2

GENERAL REQUIREMENTS

2. (1) The Standards issued by the Canadian Standards Association entitled Oil and Gas Pipeline Systems Z662-11, Security Management for Petroleum and Natural Gas Industry Systems CSA Z246.1-09 and CSA Z276-11 Liquefied Natural Gas (LNG) – Production, Storage and Handling and the standards, specifications, codes and publications set out therein as reference publications insofar as they apply to the said Standards are adopted as part of this Document, with the following changes for the CSA-Z662-07 Standard:

(2) Clause **1.2** is amended by adding the following item:
(h) pipelines that carry gas to and from a well head assembly of a designated storage reservoir.

(3) Clause **1.3** is amended by adding the following items:
(p) digester gas or gas from landfill sites
(q) multiphase fluids
(r) gathering lines
(s) offshore pipeline systems
(t) oil field steam distribution pipeline systems oil field water services
(u) carbon dioxide pipeline systems.

(4) Clause **4.1.7** is revoked and the following substituted:
4.1.7 Subject to prior review by the Director, it shall be permissible for steel oil and gas pipelines to be designed in accordance with the requirements of Annex C, provided that the designer is satisfied that such designs are suitable for the conditions to which such pipelines are to be subjected.

(5) Clause 4.3.4 is amended by adding the following clauses: (new)

4.3.4.9 Identification of a high consequence area
Operating companies, in accordance to the definitions in this document, shall identify the high consequence areas and determine which segments of oil and gas transmission pipeline system are subjected to these additional requirements. The operator must describe in its integrity management program the method it is applying and include the potential impact radius when utilized to establish a high consequence area. For this purpose, the operator shall:

(1) *Identified sites.* The operator shall identify an identified site, for purposes of this clause, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning response agencies, local municipalities' planning department or other relevant agencies.
(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

(i) Visible marking (*e.g.*, a sign); or
(ii) The site is licensed or registered by a federal, provincial, or local government agency; or
(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a federal, provincial or local government agency and available to the general public.
(3) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in this subsection, the operator must complete the evaluation using
method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

4.3.4.10. Operator Responsibility to implement this subsection
a) An operator of a covered pipeline segment must develop and follow a written program (part of the Pipeline Integrity Management Program (IMP)) that contains all the elements described in the IMP and that addresses the risks on each covered transmission pipeline segment.
(b) *Implementation Standards.* In carrying out this subsection, an operator must follow the requirements of this Subsection and other pertinent documents referenced in CSA Z662-11 and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property.
The following definition applies to this section:
Assessment is the use of testing techniques as allowed in this section to ascertain the condition of a covered pipeline segment.
Covered segment or covered pipeline segment means a segment of oil or gas transmission pipeline located in a high consequence area. The terms "oil", "gas" and "transmission" are defined in the O. Reg. 210/01. For the purpose of this document, transmission lines includes lines with a MOP of 30% or more of the SMYS.

High consequence area means
a) for a gas transmission pipeline, an area established by one of the methods described in paragraphs (1) or (2) as follows:
(1) An area defined as—
(i) A Class 3 location under CSA Z662-11, Clause 4.3.3; or
(ii) A Class 4 location under Clause 4.3.3; or
(iii) Any area in a Class 1 or Class 2 location where, and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.
(2) The area within a potential impact circle containing—
(i) 20 or more buildings intended for human occupancy, or
(ii) An identified site.

b) for an oil pipeline, an area containing,
(1) A *commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists;

(2) A *high population area*, which means an urbanized area, as defined and delineated by the latest Statistics Canada Census, that contains 50,000 or more people and has a population density of at least 385 people per square Km;

(3) An *other populated area,* which means a place, as defined and delineated by the latest Statistics Canada Census, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area;

(4) An *unusually sensitive area,* as defined in company's PIM.

Identified site means each of the following areas:
(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities,
camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or
(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office
buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or
(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle *(natural gas or HVP products)* is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius **(PIR)** means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d 2)), where
'r' is the radius of a circular area in feet surrounding the point of failure,
'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and
'd' is the nominal diameter of the pipeline in inches.
NOTE: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion.

4.3.4.11. Risk Assessment
The operator shall conduct a risk assessment that follows Annex B Guidelines for risk assessment of pipelines of CSA Z662-11 for each covered segment. The risk assessment shall include the high consequence areas and determine if additional preventive or mitigative measures are needed.

The operator shall prioritize the covered pipeline segments according to the risk.

4.3.4.12. Remediation
The operator shall establish the required repair or mitigation activity to take on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to,

a) establishing shorter inspection intervals,
b) installing emergency flow restricting devices (EFRDs) on the oil pipeline segment,
c) modifying the systems that monitor pressure and detect leaks for oil pipelines,

d) providing additional training to personnel on response procedures,
e) conducting drills with local emergency responders and adopting other management controls.

Evacuation procedures shall take into consideration the PIR. For LVP products segments located in high consequence areas, the operating company shall review with the Ontario Ministry of natural Resources (MNR) and the Ontario Ministry of Environment (MOE) the company' contingency plan in case of potential leaks or spills.

(6) Clause **7.10.3.2** is revoked and the following substituted:
7.10.3.2 For HVP and for sour service pipeline systems, all butt welds shall be inspected by radiographic or ultrasonic methods, or a combination of such methods, for 100% of their circumferences, in accordance with the requirements of clause 7.10.4.

(7) Clause **10.5.2** is amended by adding the following clauses:
10.5.2.7 Emergency Communication Meetings
The operator shall conducts meetings with local authorities, inviting police, fire fighting authorities, Ontario Ministry of Transport (MTO), MNR, MOE, local conservation authorities and TSSA to explain the authorities the characteristics of the pipeline system the operator operates, the type of fuels being transported and the typical behaviour of this fuels in case of uncontrolled leaks or spills, the capabilities and the coordination required to respond to pipeline emergencies.

These meetings shall be conducted at intervals not exceeding 5 years and at different sites, following the operating company prioritization of the covered pipeline segments according to the risk.

10.5.2.8 Operating companies shall prepare an emergency response plan and make it available on request to local authorities.

(8) Clause **10.6** is amended by adding the following clause:
10.6.5 Right-of-Way Encroachment

10.6.5.1 It shall be prohibited to install patios or concrete slabs on the pipeline right-of-way or fences across the pipeline right-of-way unless written permission is first obtained from the operating company.

10.6.5.2 It shall be prohibited to erect buildings including garden sheds or to install swimming pools on the pipeline right-of-way. Storage of flammable material and dumping of solid or liquid spoil, refuse, waste or effluent, shall be also forbidden.

10.6.5.3 Operating companies shall be allowed to erect structures required for pipeline system operation purposes on the pipeline right-of-way.

10.6.5.4 No person shall operate a vehicle or mobile equipment except for farm machinery and personal recreation vehicles across or along a pipeline right-of-way unless written permission is first obtained from the operating company or the vehicle or mobile equipment is operated within the travelled portion of a highway or public road.

10.6.5.5 Operating companies shall develop written procedures for periodically determining the depth of cover for pipelines operated over 30% of SMYS. Such written procedures shall include a

rationale for the frequency selected for such depth determinations. Where the depth of cover is found to be less than 60 cm in lands being used for agriculture, an engineering assessment shall be done in accordance with clause 10.11.2 and a suitable mitigation plan shall be developed and implemented to ensure the pipeline is adequately protected from hazards.

(9) Clause **10.3** is amended by adding the following items:

10.3.10 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if:

a) the operating company or person makes an application to the Director under Section 18(1) 1, 18(1) 3 and 16 (6) of the Regulation.

b) the Director has reasons to believe that the design, construction, operation or abandonment of a pipeline, or any part of a pipeline is or may cause

i. a hazard to the safety of the public or to the employees of the operating company

ii. an adverse effect to the environment or to property, or

c) the Director wishes to assess the operating company's pipeline integrity management program.

10.3.11 For the protection of the pipeline, the public and the environment, an operating company shall develop a pipeline integrity management program for steel pipelines with a MOP of 30% or more of the SMYS. The pipeline integrity management program shall contain:

a) a management system;

b) a working records management system;

c) a condition monitoring program, and

d) a mitigation program.

10.3.12 When developing the pipeline integrity management program, an operating company shall consider CAN/CSA-Z662-11, Oil and Gas Pipeline Systems, Annex N, Guidelines for Pipeline Integrity Management Programs.

(10) Clause **10.3.7** is revoked and the following substituted:

10.3.7.1 Prior to a change in service fluid, including sweet to sour, the operating company shall conduct an engineering assessment to determine whether it would be suitable for the new service fluid. The assessment shall include consideration of the design, material, construction, operating, and maintenance history of the pipeline system and be submitted to the Director for approval.

(11) Clause **10.15.1.2** is amended by adding the following items:

(e) maintain warning signs and markers along the pipeline right-of-way;

(f) maintain existing fences around above ground pipeline facilities; and

(g) empty tanks and purge them of hazardous vapours.

(12) Clause **12.4.11.1** is renumbered as clause **12.4.11.1.1**. Clause **12.4.11** is amended by adding the following clauses:

12.4.11.1.2 All new and replacement natural gas service regulators shall comply with the requirements of CSA 6.18-02 standard, Service Regulators For Natural Gas, including the Drip and Splash Test contained in Appendix A of the said Standard. Where a regulator – meter set installation or supplemental protective devices as providing equivalent protection against regulator vent freeze up passes a successful test in accordance to Appendix C of the said Standard, the requirements of Appendix A (Drip and Splash Test) and those contained in Clause 14.15 (Freezing

Rain Test) of the Standard are waived. Evidence of test made in accordance with Appendix C, shall be kept by the operating Company as permanent records.

12.4.11.1.3 Regulator-meter set configurations shall be included in the operating company's operating and maintenance procedures.

(13) Clause **12.4.15.6** is amended by replacing the reference to CAN/CSA-B149.1 to "Table 5.2 of CAN/CSA B149.1-10, Natural Gas and Propane Installation Code".

(14) Clause 12.6.13
Clause 12.6.13 is amended by adding the following clause:

12.6.13.8 Natural gas distributors shall incorporate in their Distribution Pipeline Integrity Program Management an action plan that includes:

a) Description of the steps to mitigate the potential of penetration of sewer lines by a natural gas line during trenchless installation,
b) Raising awareness of the potential safety issue that could arise when attempting to clear a blocked sewer service line beyond the outside walls of a building,
c) An assessment of potential risks and a plan to mitigate these risks.

(15) Clause **12.10.11** is amended by adding the following:
12.10.11(e) For polyethylene piping installed in Class 1 and Class 2 location, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of Clause 12.4.2; and

12.10.11(f) For polyethylene piping installed in Class 3 and Class 4 location, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of clause 12.4.2 with a combined design factor and temperature derating factor (F x T) of 0.32, unless the operating company conduct an engineering assessment to determine whether it would be suitable for the existing polyethylene piping to be operated at the new pressure. The assessment shall include consideration of the design, material, construction, operating, and maintenance history of the pipeline system and be submitted to the Director for approval.

(16) Clause **12** is amended by adding the following:
12.10.15 Operating companies shall establish effective procedures for managing the integrity of pipeline systems with a MOP less than 30% of SMYS (Distribution Systems) so that they are suitable for continued service, following as applicable, the requirements of sub item (9) of this documents.

Section 3

POLYETHYLENE PIPE CERTIFICATION

3. (1) Polyethylene piping and fittings that are used in a polyethylene gas pipeline shall be certified by a designated testing organization accredited by the Standards Council of Canada as conforming to the CAN/CSA-B137.4-09. Polyethylene Piping Systems for Gas Services.

Section 4

WELDER QUALIFICATION
Welds shall not be made in any steel pipe that forms or is intended to form a part of a steel oil or gas pipeline or a component of a steel pipeline unless the welding procedures has been approved and the welder is qualified to make the weld in accordance with the requirements of the Standard adopted under section 2 of this document and is the holder of the appropriate authorization issued under the Boilers and Pressure Vessels Regulation, made under the Technical Standards & Safety Act.

Section 5

(1) Where there is a conflict between a standard, specifications, code or publication adopted in sections 1, 2 and 3 of this document, this document prevails.

(2) Any person involved in an activity process or procedure to which this document applies – shall comply with this document.

(3) This Director's Order is effective January 1, 2012.

Dated at Toronto this XX day of November, 2011.

_____
John Marshall
Statutory Director
O.Reg. 210/01 (Oil and Gas Pipeline Systems)
made under the Technical Standards & Safety Act

l/fsesb/oa/Director's Order, Z662-11, rev 1.doc

Draft

FUELS SAFETY PROGRAM

Tel: (416) 734-3353
Fax: (416) 231-7525

June 14, 2011

Highlights of the
MEETING on CROSS BORE
June 10, 2011
3300 BLOOR STREET WEST, Toronto

PRESENT:

Jamie Milner,	Enbridge Gas Distribution Inc.,
Clifford Clark	Enbridge Gas Distribution Inc.
Michael Shannon	Union Gas Limited
Jeff Hodgins,	Union Gas Limited
Walter Malcolm	City of Kitchener, Utilities Operation Centre
John Marshall	Technical Standards & Safety Authority (TSSA)
Elizabeth Nielsen	Consumers Advisory Council
Rick Delaney	Link-Line (By teleconference)
Oscar Alonso	TSSA

Absent:

Zenon Fraczkowski	TSSA

Opening Remarks

The chairman welcomed all in attendance and suggested self-introduction of members.

Approval of the agenda.

The agenda was approved as presented.

E:\Agenda, RRG-Pipelines, June 1

Review of Advisory on Clearing Blocked Sewer Service Lines.

…2

Draft

Jamie Milner presented a summary of the AGA and CGA status on actions on Cross Bore:

E:\Risk Reduction Group AGA and CGA

In addition, the following documents were sent by Clifford Clark, at the request of the members, the White Papers issued by AGA and CGA:

E:\AGA White Paper Cross Bore Preventio

E:\CGA-White Paper on Sewer Lateral Cro

Resolution on the actions to be taken on Cross Bore

It was resolved that the proposed advisory on Cross Bore included in the agenda, be changed to a TSSA Director's Order. The proposed Order is attached below:

E:\Director's Order on Cross Bore.doc

Clarification on RRG-Pipeline scope

Oscar Alonso offered a clarification regarding the term of reference for the RRG-Pipelines. This committee involves stakeholders from the Oil and Gas industry pipelines, within the scope of the O. Reg. 210/01. A copy of the Term of Referenced is attached below:

L:\FSESB\OA\RRG terms of reference, 2

Next meeting

No meeting may be required. A conference call before issuance of the Order will be considered.

cc: **RRG Pipelines**
Gas Advisory Council

Draft

Draft

Risk Reduction Group (PIPELINES)

Cross Bore

PROPOSED AGENDA

June 10, 2011, from 9:00 A.M. to 11:00 A. M. Room 1606

TSSA, 16th. FLOOR, Centre Tower
3300 BLOOR STREET WEST
ETOBICOKE, ONTARIO

1. **Welcome and introductions-all**

2. **Approval of the agenda**

3. **White Paper - Jamie Milner**

4. **RRG membership and chair - Oscar Alonso**

L:\FSESB\
COMMITTEE\PIPELIN

5. **Edited Clearing Blocked Sewer Service Lines**

L:\FSESB\OA\
Advisory on Clearing

6. **Next steps and Meeting - all**

6. **Adjournment.**

l:\users\fsesb\committee\pipeline\agenda\June 10, 2011

Risk Reduction Group (RRG) COMMITTEE (PIPELINES)
February 2011

Chris Phippen,
Utilities Kingston
1211 John Counter Blvd.
Kingston, ON K7L 4X7
Telephone: 613-546-1181 X2335
Fax: 613-542- 1463
E-Mail: cphippen@utilitieskingston.com

Doug Lapp, P.Eng.
Chief Engineer
Engineering Stnds & Tech Serv
Enbridge Gas Distribution Inc.,
500 Consumers rd.,
North York, ON M2J 1P8
Telephone: 416-495-3940
Fax: 416-495-5871
E-mail: doug.lapp@enbridge.com

Zora Crnojacki
Chair, Ontario Pipeline Coordination Commit.
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416-440-8104
Fax: 416-440-7656
E-mail: crnojazo@oeb.gov.on.ca

Bob Bacic
Senior Advisor, Integrity Management
Union Gas Limited
P.O. Box 2001, 50 Keil Drive North
Chatham, ON N7M 5M1
Telephone: 519 436 4687
Fax: 519 436 5292
E-mail: bbacic@uiniongas.com

Les Wojtanowski
Manager, Operations & Engineering
Sun-Canadian PipeLine Company Limited
P .O. Box 470
Waterdown ON L0R 2H0
Telephone: 905-690-5605 x5605
Cel: 416 873 8626
Fax: 905-689-1233
E-mail:lwojtanowski@Sun-canadian.com

Casey Steneker
Engineering, Maintenance and Projects Manager
Imperial Oil Products and Chemical Division
237 Fourth Ave. S. W.
Calgary AB T2P 3M9
Telephone: 403-237-3430
Fax: 403-237-2012
E-mail: casey.steneker@esso.ca
(Orlo Crackwell)

Jason Hrycyshyn, P.Eng
Electrical Distribution Safety Engineer
Technical Services and Compliance
ELECTRICAL SAFETY AUTHORITY
PHONE: 905-712-5654
FAX: 905-507-4572
jason.hrycyshyn@electricalsafety.on.ca

Les Jones, P.Eng.
Utilities Engineer
City of Kitchener
Utilities Operation Centre
83 Elmsdale Drive
Kitchener, ON
Telephone: 519 741 2826
Fax: 519 741 2638
E-mail: les.jones@kitchener.ca

Cecil Blair
Director, Eastern Canada Region
Transcanada Pipelines
11200 Weston Rd.,
Maple ON L6A 1S7
Telephone: 905-832-7301
Fax: 905-832-7391
Cell: 416 522-7075
E-mail: cecil_blair@transcanada.com

Ken McGillivray
Pipeline Coordinator
Nova Chemicals (Canada) Ltd.
P. O. Box 3060,
Sarnia, ON N7T 8C7
Telephone: 519-862-2911 x 2392
Fax: 519-481-2701
Cell: 519 331 4236
E-mail: MCGILLKE@novachem.com

Kourosh Manoucheri *Fuels Safety Engineer* *Technical Standards & Safety Authority* *14th Floor, Centre Tower* *3300 Bloor Street West* *Toronto ON M8X 2X4* *Telephone: 416-734-3356* *Fax: 416-231-7539* *E-mail: kmanoucheri@tssa.org*	***Oscar Alonso*** *Fuels Safety Engineer* *Technical Standards & Safety Authority* *14th Floor, Centret Tower* *3300 Bloor Street West* *Toronto ON M8X 2X4* *Telephone: 416-734-3353* *Fax: 416-231-7525* *E-mail: oalonso@tssa.org*
Zenon Fraczkowski *Engineering Manager, Fuels Safety* *TSSA*	***Srikanth Mangalam*** *Risk Manager* *TSSA*

I:\fsesb\committe\pipeline\2011 RRG Oil & Gas Pipeline Committee

Fuels Safety Program	Ref. No.: FS-176-10	Rev. No.:
ADVISORY	Date: October 15, 2010	Date:

Subject: Clearing Blocked Sewer Service Lines
Sent to: Posted on Web-Site and Distributed to Gas Council and Gaseous Fuels RRG, Natural Distribution Companies.

A potential safety situation could arise when home owners or administrators of commercial, institutional or industrial buildings attempt (by themselves or by calling a contractor) to clear a blocked sewer service line beyond the outside wall of the building. The issue is that natural gas lines installed using trenchless practices may have inadvertently penetrate the sewer line.

A natural gas line that has penetrated a sewer line may be undetected for a long period of time. Clearing the sewer service line with rotating equipment or water jet equipment could damage the gas line and result in a leak of natural gas into the sewer line, posing an immediate safety risk.

For this reason, natural gas distributors shall submit to the Director by September 30, 2010 an action plan that includes:

a) Description of the steps to mitigate the potential of penetration of sewer lines by a natural gas line during trenchless installation,
b) Raising awareness of the potential safety issue that could arise when attempting to clear a blocked sewer service line beyond the outside walls of a building,
c) An assessment of potential risks and a plan to mitigate these risks.

l/fsesb/oa/Advisory on Clearing Blocked Sewer Lines.doc

Draft

Risk Reduction Group (Pipelines) Cross Bores June 10, 2011 AGA & CGA White Papers

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 2, Schedule 4, Attachment B, Page 8 of 48

American Gas Association white paper

ENBRIDGE

- Contents
  - Discussion of issues related to trenchless pipeline installation in the vicinity of sewer lines
  - Ownership of sewer lines and lack of availability of records and locates
  - Suggested damage prevention partnership between gas utilities and sewer owner/operators
  - Risk mitigation through communication and education of stakeholders
    - Non prescriptive
    - Each stakeholder develop own strategy to mitigate assessed risk
  - Focus is to minimize the creation of new cross bores
  - Legacy investigation and response issues not dealt with

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 2, Schedule 4, Attachment B, Page 9 of 48

Canadian Gas Association white paper

- Contents
  - Summary of current conditions
  - Considerations for assessing and mitigating risk
  - Guidelines not prescriptive
  - Four key areas of focus
    - Communication/Education and Awareness
    - Minimize the creation of new cross bores
    - Existing installations where trenchless technologies were used
    - Continuous improvement
  - Industry coordinated awareness, communication, education and response
  - Provides insights into how gas utilities can work with other stakeholders in getting sewer lines located and marked on a going-forward basis

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 2, Schedule 4, Attachment B, Page 10 of 48

North American Society for Trenchless Technology (NASTT)
No-Dig Show 2011

Washington, D.C.
March 27-31, 2011

Paper A-1-04

AGA WHITE PAPER: NATURAL GAS PIPELINES AND UNMARKED SEWER LINES – A DAMAGE PREVENTION PARTNERSHIP

AGA Distribution Construction & Maintenance Committee[1]

[1] American Gas Association, Copyright © 2010, All Rights Reserved, April 2010, See Notice and Disclaimer on Final Page

ABSTRACT:

The purpose of this white paper is to provide a discussion of the issues related to trenchless pipeline installations in the vicinity of sewer lines. This paper includes reference to existing material related to damage prevention with an emphasis on sewer mains and lateral lines that are not marked. This paper does not imply acceptance of any responsibility or liability of any owner/operator to locate and mark sewer lines; it simply accepts whatever the current condition is in each location and offers guidelines to minimize existing exposure.

On December 30, 2004, AGA published an Engineering Technical Note: "*Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry.*" Attached in the appendix of this document, it shares specific guidelines and practices, which can be considered by natural gas utilities to improve safety. This particular paper seeks to build upon that information by providing insights into how natural gas utilities can collaborate with other stakeholders in getting sewer lines marked on a going-forward basis and in finding ways to effectively deal with existing sewer lines.

INTRODUCTION:

Unlike gas, electric, water and telecommunications lines, cross-bored sewer laterals can go undetected for extended periods. These cross-bored sewer laterals are typically found when someone is attempting to unclog a sewer lateral and discovers the bored line inside the sewer lateral. Educating the public, regulatory bodies, sewer operators, developers, and plumbing associations of their roles in getting sewer lines marked will be essential in reducing the dangers associated with unmarked sewer lines. Information and support may also be provided by the local One-Call Agency. The need for this paper is based upon the elevated risk associated with unmarked sewer lines and the increased use of trenchless technology.

The Regulatory Environment

All states have One-Call system(s) to distribute planned excavation information to utilities and most state One-Call laws have some type of penalty for non-compliance. However, since each state's enforcement mechanism varies as defined by its particular law, the effectiveness of enforcement varies widely, ranging from extremely active and effective to non-existent. An additional concern is that some states exempt all or portions of sewer systems from

their regulations. Some state regulatory agencies are even precluded from assessing fines or penalties on a municipality that may be operating a sewer system.

Some state and local governments own and operate the sewer lines only from the property line to the waste water treatment facility. As a result, sewer lines on private property may either be owned by the property owner or owned and/or operated by the municipality.

From a municipality's perspective, there may be political implications associated with these regulatory and ownership issues. Elected officials are often faced with priorities associated with keeping sewer rates and taxes as low as possible, while simultaneously protecting the safety of their constituencies and the public.

Regardless of future changes in the regulatory environment, each sewer line operator must adhere to all current laws and regulations related to the location and marking of underground facilities in the particular state and locality where the project is located.

A Partnership Model

Natural gas owner/operators and sewer line owner/operators have shared interests:

- Safety of the general public and their customers
- Providing the service at the lowest cost
- Preventing damage to their infrastructure

Sewer line owners/operators face some challenges as portions of their systems can predate piped water or natural gas systems and most are not electronically locatable. Legacy sewer installation records are often inadequate, incomplete, or non-existent and the organizations that support those systems vary in size. Their resources may also vary according to the size of the systems.

Sewer and natural gas utilities should explore mutual damage prevention efforts and sewer system owner/operators may be able to learn from the natural gas utilities that have successfully addressed similar challenges in the past. Both should seek to understand each other's operating policies, practices, requirements and priorities. For example,

- What is the mark-out policy?
- Who owns the service line laterals?
- Who operates and maintains the service line laterals, on and off the public right of way?
- How are sewer lines located?
- What can be done to ensure that all sewer lines (whether new or replacement installations) are constructed in a manner that allows them to be electronically locatable?
- What is the level of involvement in the One Call process?
- Who is responsible for locates of buried facilities on private property?
- What communications, if any, are sent to customers to alert them, especially if they have a responsibility in marking customer-owned facilities under the local state statute?
- Will the sewer owner/operator install an outside cleanout on a homeowner's line if one is not available? (this is sometimes at a cost to the customer)
- How can the sewer owner/operator and the natural gas utility share information on sewer locations?
- What is the sewer owner/operator's typical response to a blocked sewer lateral?

The remainder of this paper focuses on other important steps that may be considered by the natural gas utility and the local sewer owner/operator.

Communication and Education with Other Stakeholders

In some circumstances, a communication and education strategy may be appropriate to help mitigate risk. The natural gas owner/operator can develop their own strategy based upon the unique requirements of each situation. It may be appropriate to encourage sewer system owner/operators (municipalities, city, etc.) to develop their own communication and education strategy to mitigate the risks that may exist for them in relation to their facilities regarding the use of trenchless technologies. **Specific communication examples are listed below, but the list is**

not intended to be all-inclusive, and not all of the suggestions listed below may be appropriate in all situations.

- Communicate with and educate municipalities, public works departments, owner/operators of private sewer systems, plumbing industry, companies that rent rotary cutting tools, trade unions, contractors, state regulatory boards, homeowners, and the public.
- Include the trenchless technology topic related to sewer laterals and mains in mailings, letters, and/or bill inserts.
- Work cooperatively with the local One-Call Center to identify a list of locating firms that are available to stake privately owned underground facilities. This will provide property owners a reasonable method to fulfill any responsibility they may have to mark their buried facilities.
- Provide contact information for the facility owner and ask for notification prior to reaming sewer lines.
- As part of an operator's Public Education Program, network with plumbers, equipment rental businesses, owners of private sewer systems (e.g.- mobile home parks, commercial campuses, school complexes, hospitals), and state regulatory boards to develop best practices for investigating blocked sewer lateral lines.
- Work with state licensing boards to ensure that a thorough understanding of unmarked sewer line issues is required of individuals who are endeavoring to obtain or renew a business, plumbing, or contractor's license.

Practices to Consider in Using Trenchless Technologies

The 2004 technical note *"Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry,"* identified practices that should be considered when using trenchless technology. The practices will not be applicable or effective for all utilities.
For example:

- Some states and municipalities require a plumber's license to access sewer systems; these licenses are generally not held by the natural gas distribution companies.
- Natural gas distribution companies may have difficulty accessing non-customer premises which are outside of the utility easement in which a trenchless technology was used.
- In many parts of the country, the sewer lateral is owned by the homeowner up to the sewer main and there is no information available for mark-out purposes.
- Many of the practices identified in the 2004 technical note apply to directional drilling, and not to other forms of trenchless technology.

When trenchless technology is used by a contractor working for a natural gas distribution company, additional safety language may be appropriate in the contract to clearly convey that the contractor needs to exercise prudent steps in assuring that all utility lines have been located. Additional insurance requirements may also be considered to ensure the appropriate levels of liability insurance are maintained to cover associated risk. Actual insurance requirements should be reviewed by appropriate personnel.

For simple work efforts where the natural gas distribution company or its contractor is the only entity involved in the construction, the practices outlined in the 2004 technical note *"Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry"* may be sufficient when using trenchless technology. For more complex work efforts or for when there are multiple companies, agencies, or municipalities involved, the 2004 technical note and the following additional practices may be considered by natural gas operators and sewer operators during the planning and installation effort:

1. **Planning**

The following are some additional practices for consideration during the planning stages for use of trenchless technology:

- Proper Engineering Design, determining a path of installation which will reduce the likelihood of utility interference
- Use of sub-surface utility engineering methods
- Participation in utility coordinating committees
- Participation in municipal coordinating committees
- Depending on the size and complexity of a project or activity, hold pre-bid / construction meetings with utilities and public works officials, prior to the start and during construction
- Use experienced contractors

2. Installation

Reminder: Follow applicable state one-call and dig-safe laws.

Below are some additional practices for consideration during a natural gas installation project that uses trenchless technology. (The local sewer operator may be able to assist.)

- Consider pre-location of sewer laterals where an exterior clean-out is available:
  - Measure the depth of the sewer line lateral. Caution should be taken because a sewer lateral may not have consistent grade or path from the building entrance to the sewer main.
  - Run a fish tape down through the exterior clean-out, use a line locator in the conductive mode, and verify location and depth by pothole; or
  - Insert a sonde in the exterior clean-out and use a drill head locator to verify location and depth; or
  - Pre-camera through the exterior clean-out to verify location and depth.
- Pot hole along the path, as appropriate for conditions
  - Establish criteria for which every sewer line must be pot holed (such as privately owned sewer systems including trailer parks, schools, college campuses, shopping malls, etc.)
  - Establish criteria for spaced verification of sewer laterals including:
    - Conditions that allow the practice (long, known depth sewer mains, etc.)
    - Verification at some set distance (for example, every 200' when laterals are 4' deep or every 400' when laterals are 6' deep)

3. Post-installation Records and Metrics

The following practice is for consideration during the documentation stages when using trenchless technology:

- Natural gas pipelines installed with trenchless technology can be identified on field work orders or company mapping systems as such.

NOTE: This technical note is a suggested guide only, and the use of these Guidelines or any variation thereof, shall be at the sole discretion and risk of the user parties. ***See Notice and Disclaimer on final page.***

DEFINITIONS

Cross Bore: A utility cross bore is an intersection of an existing underground utility or underground structure by a second utility installed by trenchless technology that results in direct contact between the transactions of the utilities that compromises the integrity of either utility or underground structure.

Sewer Line: Includes any system to remove waste water from a structure including the sanitary sewer lateral, sewer main, or septic system line. This also includes combined sanitary sewer and storm water systems.

Trenchless Technology: includes use of the following:
1. Directional drills
2. Piercing tools (hogs, moles, missiles, etc.)
3. Water boring equipment

4. Augur boring equipment, including pipe jacking
5. Plowing
6. Insertion or pipe-splitting

Verify: To determine or test the accuracy of, as by comparison, investigation or reference.

REFERENCES

Available resources include: i) federal, state and local laws and regulations; ii) guidelines from Common Ground Alliance, American Gas Association, and other organizations; iii) various industry articles; and iv) manufacturer equipment instructions. Although the references listed below may be designed for directional drilling, many of the practices are applicable for other types of trenchless installation procedures.

This section provides specific reference material and sites. References range from general statements, guidelines and practices to specific recommendations. It is designed to provide the reader with a range of material depending on the needs and requirements.

American Gas Association (AGA) Technical Note, December 30, 2004
"Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry"www.aga.org
Above document provides detailed recommendations and specific references to sewer lateral lines and recommended processes. **Note: It is included in the appendix of this document.**

Common Ground Alliance Best Practices Version 6.0
March 2009 "Excavation Practice Statements and Description"http://commongroundalliance.com
Above document is a reference guide with very general statements. No specific reference to sewer lateral lines.

Cross Bore Safety Association www.crossboresafety.org. This site has a multitude of information.

Distribution Contractors Association DCA Position Paper – Marking Sewer Laterals November 16, 2006
http://dca-online.org

HDD Consortium 2001, 2004, 2008 "Horizontal Directional Drilling – Good Practice Guidelines"
Retail literature through North American Society for Trenchless Technology
http://www.nastt.org/store/good_practices.html. This manual is very detailed with specific recommendations and minimum guidelines. It is specifically related to directional drilling technology with references to preventative measures around sewer facilities.

National Underground Contractors Association NUCA Position Paper – Locating and Marking Service Laterals
September 26, 2006 www.nuca.org

Office of Pipeline Safety August 1999 "Study of One-Call Systems and Damage Prevention Best Practices"
Excavation Task Team Best Practices http://commongroundalliance.com
Above document is a reference guide with very general statements. No specific reference to sewer lateral lines.

Appendix

Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry

Copyright © 2004 American Gas Association, All Rights Reserved
See Notice and Disclaimer on final page.

December 30, 2004
AGA Distribution, Construction & Maintenance Committee

DCM – 2004 – 4-1

DIRECTIONAL DRILLING DAMAGE PREVENTION GUIDELINES FOR THE NATURAL GAS INDUSTRY

PURPOSE

The purpose of this paper is to provide general guidelines for natural gas operators to use in the enhancement of their company's damage prevention programs for directional drilling operations. This paper provides parameters for protecting existing natural gas facilities from damage during directional drilling activities, as well as includes general guidance on underground damage prevention procedures when installing new natural gas facilities by directional drilling.

Each natural gas operator is responsible for developing their own damage prevention program with guidelines, policies and procedures that are specific to the application of directional drilling within the region of their facilities. The information in this document is not intended to replace local, state, federal or private company rules or regulations. These guidelines are a suggested guide only, and the use of these guidelines or any variation thereof, shall be at the sole discretion and risk of the user parties.

BACKGROUND

The background of the need for the development of these safety guidelines is based on suggestions from two governmental agencies associated with the natural gas pipeline industry and a request from a natural gas industry association:

- National Transportations Safety Board (NTSB) Safety Recommendation P-99-1, dated April 28, 1999, which directed that the Research & Special Programs Administration (RSPA) ensure that the natural gas operators' damage prevention programs include actions to protect their facilities when directional drilling operations are conducted in proximity to those facilities.

- In follow-up to this advisory, RSPA issued a Pipeline Safety Advisory Bulletin ADB-99-04, dated August 23, 1999 to all owners and operators of hazardous liquid and natural gas pipeline facilities. This advisory urged these operators to review, and amend if necessary, their written damage prevention program to minimize the risks associated with directional drilling and other trenchless technology operations near buried pipelines. Its purpose was to ensure that pipeline operators take actions to recognize the dangers associated with directional drilling and other trenchless technology operations, and to ensure that underground pipeline facilities are adequately located and protected from inadvertent damage.

- The American Gas Association (AGA) Operating Section Managing Committee requested that general safety guidelines for directional drilling operations in the proximity of natural gas facilities be developed.

RESOURCES

There are numerous articles, guidelines and instructions on the practice of directional drilling from various trade associations and manufacturers of equipment. Those documents are excellent resources for understanding the full extent of safe directional drilling practices. Though this paper will incorporate many of the already documented practices for safe directional drilling, its main purpose is to highlight the appropriate safety practices for natural gas operators to ensure that their underground facilities are adequately located and protected from damage.

The sources used for this paper include excerpts from materials prepared by the directional drilling trade associations, along with suggested practices that are in-development and in-place by member companies of the AGA.

DESCRIPTION OF PROCESS

Directional drilling is a trenchless method of installing underground facilities that can reduce the expense and difficulties that are experienced in open trench construction practices. The usage of directional drilling will be determined by the operator based on many factors. Some of these factors may include the site conditions, size of job, soil conditions, environmental considerations, subsurface interference, traffic disruption, and disruption to the public. It is typically used on river or stream crossings, railroad crossings, highway crossings, well-developed areas and environmentally sensitive areas.

The typical technique for installing pipe by directional drilling uses a surface mounted drill rig that launches drill rods creating a string of rods (called the drill string) below the ground guided by a drill head that is directionally controlled by the drill operator. The direction of the drill is along a pre-determined path (called the drill path) based upon the above ground and below ground, pre-construction investigations of the site. A locating device is used during the drill to track the location of the drill head so that the operator may make adjustments as necessary. A small diameter pilot hole is drilled from the entrance point (typically in a sending pit) to the desired exit point (receiving pit). It is necessary to use a drilling fluid during drilling to lubricate and protect the pipe, and to maintain the size of the hole being opened. Following the exit of the pilot drill bit, the hole is then enlarged by the use of a backreamer attached to the end of the drill string which is pulled back through the pilot hole. As the backreaming takes place, the pipe being installed is also pulled into the hole. Directional drilling may require the use of a casing pipe to protect the carrier pipe where required and/or dictated by an outside agency.

DIRECTIONAL DRILLING GUIDELINES

General

The listed guidelines are general in nature and contain some suggested procedures. Precautions recommended by manufacturers of trenchless technology equipment should be reviewed prior to construction. Applicable state and local requirements for damage prevention should be followed.

Employee Safety

- Directional drilling, whether by the operator in installing new natural gas pipelines or by a third party installing facilities in the proximity of natural gas pipelines, should follow normal construction safety practices that are in accordance with local and federal safety guidelines.

- In addition, all recommended safety practices by directional drilling equipment manufacturers should be adhered to.

- The primary safety issue for field personnel is striking underground utilities. Proper planning and adequate protective measures will provide a safe work environment for the crews and minimize utility damage.

- Employees involved in any aspect of a directional drilling project should wear the appropriate protective equipment based on the conditions they are operating in and required by federal, state, local and company regulations. Appropriate personal protective equipment for directional drilling operations may include, but is not limited to, the following items: hard hat, gloves, safety glasses, hearing protection, flagger/traffic vests, dust masks, and electrical-protection gloves and boots.

- All drill machines should be equipped with an electrical strike detector in the event that the drill rods strike an energized underground utility. Field personnel should make sure that the strike detector is fully operational prior to the start of any directional drilling activities. The strike detector shall be entered into the ground prior to setting the anchor stakes into the ground.

- The drilling machine shall be properly grounded to assure operator protection in the event that the drill rod hits an electric line. Should the alarm go off, the operator should remain on the grounded machine until the drill rod is disconnected from the electrical line or the electric line is shut down.

- Only employees who have been trained and qualified should be permitted to operate the drilling equipment. Personnel should familiarize themselves with any safety concerns addressed in the operator's manual.

Planning

- If directional drilling must be used in streets with parallel runs of gas transmission mains, electric transmission lines, hazardous liquid pipelines, fiber optic lines and other similar facilities, it is advised that a minimum separation between the various underground facilities be established that ensures the safety of the facilities.

- The separation between the gas pipeline and other facilities must be sufficient to allow for maintenance activities on both utilities. Be sure to check local regulations for the minimum separation distances between the gas pipeline and the other facilities.

- Design and installation of metallic structures should be done in such a manner to minimize and mitigate damage from stray current and to prevent interference with existing cathodic protection current distribution on adjacent or crossed facilities.

- Drill paths that are parallel to within 3 feet of any utility, including gas lines, should be avoided. However, when deemed necessary to drill within 3 feet of a utility, the drill head should be physically located at regular intervals dependent on soil type and surrounding conditions.

- Drilling contractor should have a plan in place in the event of a utility strike. This plan should also include the notification of the utility owner.

Site Investigation

- Establish a proposed drill path and visually inspect the potential site for suitability for directional drilling by walking the area.

- Be alert to any obstructions and indications of the presence of other underground facilities or structures such as catch basins, sewers, water boxes, manhole covers, valve box covers, meter pits, telephone and cable television boxes, electrical transformers, conduit or drop lines from utility poles, pavement patches, previous locate marks, ditch line depressions, out buildings that may have unmarked utilities serving them, underground shutoffs, etc.

- Consider talking with local residents who may have knowledge of subsurface activities in the area.

- Review available underground facility maps.

- Depending on the scope of the project, most directionally drilled natural gas main installations should be straight, with a 3 feet minimum cover, and not vary by more than 2 feet horizontally. However, each utility will need to determine the appropriate minimum cover based on their company's operating specifications as well as the actual physical operating conditions where the pipe is installed.

- Establish a site where there is sufficient room for entrance and exit tie-in pits, drill equipment, and safe operation.

- After determining the proposed drill path and delineating the work area with white paint, contact the appropriate utility One-Call provider to ensure that all underground facilities are located and marked accordingly by their owners. Request through the One-Call provider the location of other underground utilities. If possible, identify the presence of utilities not located through One-Call and attempt to determine their location by contacting the owner(s) of those facilities or employing other means to identify the path in which they are running. Note: not all One-Call Centers will send mark-out requests for design purposes.

- In locating facilities, it should be noted that One-Call providers will only help to notify owners of active utility services. Since there may be abandoned and private services that are not located, it is worthwhile to check with utility companies or local residents to determine if their knowledge will reveal any helpful information for critical situations.

- In finalizing the drill path, determine the depth and location of all underground facilities along that path to the extent practicable. Test holing should be considered.

- Establish locations of all entrance and exit pits to ensure that there are not any aboveground or subsurface structures that would interfere with the drilling equipment's operation. Ensure that there is adequate clearance of overhead electric, telephone or cable lines for these locations.

- Establish by test holes or from experience the suitability of soil conditions for directional drilling along the proposed drill path. Directional drilling may not be suitable if the subsoil is composed of large grain material (e.g., gravel and cobble fragments, rock, buried debris, abandoned foundations).

Pre-construction

- Call the local One-Call provider with sufficient advance notice to ensure that all underground facilities are marked, or verified that they are not in the location of the proposed work.

- Notification to all underground utilities through the local One-Call provider must be typically made 48 to 72 hours prior to the start of any directional drilling, depending on the requirements in the state where work is taking place.

- Notify residential and business neighbors, along with privately owned services (e.g., gas, water, and electric) in the area of impending work.

- Proper jobsite setup and layout are essential to ensure safe directional drilling operations. The following should be considered when preparing the jobsite: work area protection, flagger requirements, barricades or other methods to safeguard the public and employees, applicable safety and excavation requirements, marking and locating hazards, verifying One-Call markings, checking location and depth of underground facilities, checking for signs of venting associated with underground tanks, etc.

- There should be a briefing for all employees on the jobsite prior to beginning operations and periodically during the project. The briefing should include:
  - Overview of project plans and identification of field supervision
  - Location and access to local emergency facilities
  - Location and type of buried services and overhead obstructions
  - Jobsite safety: warnings, barriers, emergency procedures, personal protective equipment

- Review the selected locations for the boring machine and the entrance/exit pits to ensure that there are no subsurface or aboveground interferences.

- A visual inspection should be made for the proposed drill path just prior to the drilling operation to ensure that all utilities are marked and that there are no subsurface interferences.

- Expose all underground utilities that are perpendicular or parallel to the bore path, and verify the depth of the facilities. Efforts to locate the existing facility may utilize such techniques as electronic location devices, hand digging, pot holing when practical, vacuum excavation methods, use of pressurized air or water, pneumatic hand tools or other noninvasive methods. Note: some HDD methods use slurry, and digging void in the drill path causes the drill slurry to rise to the surface.

- Existing underground facilities should be exposed with sufficient space around the facility so that the drilling operation can be visually checked to ensure that it will not impact the facility.

- If in the course of excavation the location of the existing facility is found to be incorrect, the facility owner should be contacted so they can correct their records.

- The crew leader should visually inspect the planned drill path, just prior to proceeding with the drilling operation, to ensure that all utility services and underground structures have been identified and test holes made as required.

- Avoid sinking anchor stakes for the boring machine within 24 inches of any utility. If this requirement is impossible to meet, then test holes should be made at a depth equal to 12 inches deeper than the length of the anchor stakes to ensure no strike will occur when anchoring the machine.

Construction

- Parallel installations: Test holes should be excavated at intervals along the existing underground facility closest to the drill path to positively locate and inspect this facility throughout drilling operations to assure no direct or incidental contact. Test holes should be a minimum of 12" deeper than the desired depth of the facility that is to be installed. The minimum intervals for these test holes are dependent on the proximity of the existing facility to the drill path, as well as the type of facility being paralleled. The drilling path should be continuously monitored and it is suggested that the location of the drill head is marked at least every 10 feet.

- Paralleling gas installations: For existing gas facilities, a typical suggestion is to excavate a test hole every 50 feet if the drill path is within 5 feet of a distribution gas pipeline. If an existing gas pipeline that is being paralleled crosses under pavement, the pipeline should be exposed at each curb for monitoring. The intervals for the test holes will be dependent on the proximity of the existing pipeline to the drill path, as well as the type of gas pipeline in operation.

- Crossing installations: Consider excavating test holes at all crossing locations to the extent practicable. The existing facility should be completely exposed with sufficient visual area so that it can be assured that the drilling operations do not impact the facility. A typical practice is to excavate at least 12 inches below the existing facility and 24 inches on either side of the located position of the facility to be crossed. The 24 inches on either side is in addition to the facility width marked by the line locator.

- The test holes can be used to observe the drill head as it passes exposed substructures. Test holes are also used to ensure adequate clearance for the back-reamer (pull-back head). Note that the backreaming process will be a larger hole size and should be taken into consideration when specifying minimum separation distances from existing facilities.

- Establish, check and maintain proper radio communication between the operator and locator at all times before and during directional drilling operations. Communication between the drill operator, locator and operating personnel is critical. Adequate communications should be established between the operator of the drill rig and the crew member that is tracking the location of the drill string during these operations. Appropriate hand signals should be agreed upon in case the electronic communication fails.

- Appropriate locate and guidance equipment for steering and maintaining accurate location of the drilling head should be used during all drilling operations. Using electronic locating equipment, the location of the drill head during the drilling operation should be continuously monitored to ensure that the drill path follows the design profile. Locations should be marked or staked as required. The drill head should be inspected at test holes previously made at substructure locations to ensure adequate clearance.

- If possible, maintain a minimum separation of 12" when crossing gas facilities; however, if facilities are fully exposed, then a separation of less than 12" may be considered where regulations allow.

- The aboveground drill path should be sufficiently accessible to allow the locator to be able to monitor the progress of the drill head. Overhead structures or wire lines may present potential problems in the accuracy of the electronic locator along the drill path. Steel-reinforced concrete (e.g., sidewalks, driveways, roads, etc.), invisible dog fences, underground power cables and fiber optic cable can also present problems and may interfere in use of the locator. Walking the drill path with the locator prior to the drill string being started can reveal interference problems.

- The horizontal and vertical position of the drill head should be closely monitored as the drilling progresses. The location of the reaming tool should also be closely monitored during the backreaming process to ensure that the reaming tool follows the path of the pilot hole.

- Directional drilling crews should perform periodic sweeps of the area during the project to further ensure that all possible attempts to avoid damage to marked and unmarked facilities have been made.

- Cease drilling operations if an unidentifiable, abnormal or unanticipated resistance or sudden movement of the drill string is encountered. Also, cease operations if other conditions develop (lightning, etc.) that could affect the safe operation of the equipment and personnel. Proceed only after the source of the disturbance has been identified and/or eliminated. Particular care should be taken to ensure that existing substructures are not penetrated. If any underground facility is known to be damaged during the project, notify the appropriate operator and/or emergency response personnel immediately, as appropriate.

- If determined to be needed following the completion of a directional drill near an existing gas pipeline, perform a leak survey of the pipeline to ensure that it was not impacted by the new installation.

Directional Drilling in Proximity of Sewer Facilities

- Sewer systems are especially vulnerable to damage from directional drilling operations for the following reasons:
  - Lines are often non-metallic, making them difficult to locate.
  - Clean-outs or other indications of laterals may be hidden or non-existent.
  - Damage may not be readily apparent when a sewer, particularly a gravity flow system, is pierced by a drilling machine.

- Additional efforts should be considered in determining whether sewer lines and laterals are within the proposed construction area of a directional drilling project. Some of these efforts may include the following:
  - Contact the city, building owners, local plumbers, and other persons that can provide assistance with identifying the existence and location of sewer lines.
  - Obtain maps and drawings of the sewer system from the city or other entity. Maps can provide the depth of the sewer lines and other valuable information that can assist in determining the location of the sewer lines within the proposed drill path.
  - Visually check the job site for sewer cleanouts, manhole covers, and any markings on curbs or gutters that may exist for sewer facilities.
  - Use internal camera systems, if available, that travel down the main sewer line and allow the laterals to be located visually.
  - Use electronic technology, if available, to track a locating transmitter inserted into a sewer and/or lateral to determine its path and depth.
  - Use ground penetrating radar, if available, to assist in locating sewer lines and laterals.

- In determining the depth of the sewer and laterals, the following guidelines should be considered:

- If a sewer line is located, check the direction of the flow of the water and the direction of the pipe. The flow direction will tell the grade of the sewer. It will help judge whether the sewer will be shallower or deeper where the drill is being made.
- Access manhole covers and measure the depth of the main sewer line.
- Access outside clean-outs and measure the depth of the sewer line lateral. Caution should be taken because a sewer lateral may not have a consistent grade from the building entrance to the sewer line.
- Obtain access to buildings that do not have an outside clean-out and visually identify where the sewer exits the structure. Visually determine the depth of the sewer lateral by identifying where the lateral exits the building versus the depth of the sewer main at the street.

- If known sewer facilities cannot be positively located, then consider the following alternatives:
  - Do not use directional drilling or other trenchless equipment for installing the gas main or service.
  - Use the directional drilling equipment and perform a post-construction camera inspection of possibly affected sewer lines.
  - Use directional drilling equipment only in those areas where the location and depth of sewer lines have been determined to be safely outside the drill path and use open trench equipment for areas where the sewer line conflicts have not been ruled out.
  - Use a sewer listening device where sewer lines are not physically exposed. It is important that a person monitoring the sewer for penetration be alert to any unusual noise and immediately communicates the information to the equipment operator. It is possible that the drill penetration will coincide with a resistance felt by the operator.

NOTE: These "Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry" are a suggested guide only, and the use of these Guidelines or any variation thereof, shall be at the sole discretion and risk of the user parties. ***See Notice and Disclaimer on final page.***

SOURCES

- National Transportations Safety Board (NTSB) Safety Recommendation P-99-1, dated April 28, 1999
- RSPA Pipeline Safety Advisory Bulletin ADB-99-04, dated August 23, 1999
- GPTC Guide for Gas Transmission and Distribution Piping Systems: 2003 Edition - Guide Material Appendix G-192-6 - "Subsurface Damage Prevention Guidelines for Directional Drilling and Other Trenchless Technologies"
- "Common Ground: Study of One-Call Systems and Damage Prevention Best Practices", August 1999
- HDD Consortium, "Horizontal Directional Drilling - Good Practice Guidelines", May 2001
- Directional Crossing Contractors Association, "Horizontal Drilling Safe Operations Guidelines", 2000
- Various member companies of the American Gas Association - specifications, operations guidelines, procedures manuals, etc.

Notices and Disclaimer

This document was prepared by the American Gas Association's (AGA) Distribution Construction & Maintenance Committee based on suggestions from the National Transportations Safety Board and the Research & Special Programs Administration and the request of the AGA Operating Section Managing Committee.

The AGA and its member companies disclaim liability for any personal injury, property or other damages of any nature whatsoever, whether special, indirect, consequential or compensatory, directly or indirectly resulting from the publication, use of, or reliance on the this document; for any violation of any federal, state or municipal regulation with which this document may conflict; or for the infringement of any intellectual property rights from the use of this document.

The AGA does not take position with respect to the validity of any patent rights asserted in connection with any items which are mentioned in or are the subject of the document, and the AGA disclaims liability for the infringement of any patent resulting from the use of or reliance on the document. Users of the document are expressly advised that determination of the validity of any such patent rights, and the risk of infringement of such rights is entirely their own responsibility.

Efforts have been made to ensure the accuracy and reliability of the data contained in the herein; however, the document is provided "as is" and neither AGA nor its employees or agents make any representations, warranties or guarantees of any kind, either express or implied, including, but not limited to, any warranty that the document will fulfill any particular purpose or needs and the implied warranties merchantability, quality, accuracy or fitness for a particular purpose. Neither AGA nor its employees or agents make any warranty as to the results that may be obtained from the use of the document.

In issuing and making the document available, the AGA is not undertaking to render professional or other services for or on behalf of any person or entity. Nor is the AGA undertaking to perform any duty owed by any person or entity to someone else. Anyone using this document should rely on his or her own independent judgment or, as appropriate, seek the advice of a competent professional in determining the exercise of reasonable care in any given circumstances. Information on the topics covered by the document may be available from other sources, which the user may wish to consult for additional views or information not covered by the document.

The AGA has no power, nor does it undertake, to police or enforce compliance with the contents of the document. Nor does the AGA list, certify, test, or inspect products, designs, or installations for compliance with the document. Any certification or other statement of compliance with the document shall not be attributable to the AGA and is solely the responsibility of the certifier or maker of the statement.

It may become necessary to make revisions to this document in the future. Whenever any revisions are advisable, recommendations should be forwarded to the American Gas Association, 400 N. Capitol Street, NW, 4th Floor, Washington, DC 20001, USA.

NOTICES AND DISCLAIMER:

The American Gas Association (AGA) coordinated the creation of this document. While AGA provides administrative services, it does not independently test, evaluate, or verify the accuracy or soundness of any statements contained in this document.

This document is based on information that has not been verified or audited. The AGA and its member companies disclaim liability for any personal injury, property or other damages of any nature whatsoever, whether special, indirect, consequential or compensatory, directly or indirectly resulting from the publication, use of, or reliance on this document; for any violation of any federal, state or local regulation with which this document may conflict; or for the infringement of any intellectual property rights from the use of this document

The AGA does not take position with respect to the validity of any patent rights asserted in connection with any items which are mentioned in or are the subject of this document, and the AGA disclaims liability for the infringement of any patent resulting from the use of or reliance on this document. Users of this document are expressly advised that determination of the validity of any such patent rights, and the risk of infringement of such rights is entirely their own responsibility.

Efforts have been made to ensure the accuracy and reliability of the data contained herein; however, this document is provided "as is" and neither the AGA nor its employees or agents make any representation, warranty or guarantee in connection with this document, express or implied, including, but not limited to, any warranty that this document will fulfill any particular purpose or needs of the User and any implied warranties of merchantability, quality, accuracy, or fitness for a particular purpose. Neither the AGA nor its employees or agents make any warranty as to the results that may be obtained from the use of this document.

Nothing contained in this document should be viewed as an endorsement or disapproval of any particular service provider, product or methodology.

In issuing and making this document available, neither the AGA nor its member companies are undertaking to render professional or other services for or on behalf of any person or entity. Nor are they undertaking to perform any duty owed by any person or entity to someone else. Anyone using this document should rely on his or her own independent judgment or, as appropriate, seek the advice of a competent professional in determining the exercise of reasonable care in any given circumstances.

Users of this document should consult applicable federal, state and local laws and regulations. The AGA does not, by the publication of this document, intend to urge action that is not in compliance with applicable laws, and this document may not be construed as doing so. Information on the topics covered in this document may be available from other sources, which the User may wish to consult for additional views or information not covered in this document.

AGA has no power, nor does it undertake, to police or enforce compliance with the contents of this document. Nor does the AGA list, certify, test, or inspect products, designs, or installations for compliance with this document. Any certification or other statement of compliance with this document shall not be attributable to the AGA and is solely the responsibility of the certifier or maker of the statement.

The information contained in this document is not intended as legal advice or as an opinion on specific facts. For information about these issues, the User should consult the User's employer or seek the advice of a competent professional.

All questions, requests for revisions, or other communications relating to this document should be sent to: American Gas Association, Attention: AGA Operating Section, 400 N. Capitol St., N.W., Suite 450, Washington, D.C. 20001

Copyright © 2010 American Gas Association, All Rights Reserved.

DRAFT
2010-08-19

CGA White Paper

Natural Gas Pipelines and Sewer Lines

The Cross Bore Issue

DRAFT

Executive Summary:

A utility cross bore is defined as an unintended intersection of an existing underground utility by a second utility that can occur during construction that uses trenchless technologies. Utility cross bores are a bigger issue than just gas lines intersecting sewer lines. This is a broad industry issue. Water lines, electrical cables and communications lines are generally installed using the same trenchless methods employed in the natural gas industry. All of these utilities have the potential of intersecting a sewer line during the installation process. The cross bores that involve natural gas utility mains and services and sewer lines result in direct contact of both facilities that can compromise the integrity of the gas line, sewer line or both structures.
A cross bore represents a potentially serious safety risk. In and of itself, the cross bore does not create a hazard. However, some can lead to blocked sewers which require tools to be inserted to clear the blockage. These tools can pierce or cut the utility that has intersected the sewer line and in the case of gas lines, can lead to the escape of gas into buildings and the potential for fire or explosion.

This white paper provides the reader with a discussion of the potential risks and safety issues that may exist due to the use of trenchless technologies to install natural gas mains and services and the unintentional intersection of a sewer line that may have resulted. Unless a natural gas line that intersects a sewer line is damaged, it does not pose an immediate safety risk. This paper provides guidelines, suggestions and practices that Canadian Utilities may consider in assessing and mitigating the safety implications of sewer cross bores. These guidelines and suggestions are intended to enhance public and worker safety and the reliability of the infrastructure.

The guidelines and suggestions have been grouped into four key areas of focus:

1. Communication/Education and Awareness
2. Eliminate the Creation of New Cross Bores (risk reduction)
3. Existing Installations where Trenchless Technologies were used
4. Continuous Improvement

This paper also provides a summary of the current issues related to trenchless natural gas pipeline installations in the vicinity of sewer This white paper is not intended to be prescriptive in how these suggestion, practices and guidelines may be utilized by any natural gas utility, municipal organization or regulatory agency.

DRAFT

Purpose:

The purpose of this paper is to provide a summary of the current issues related to trenchless natural gas pipeline installations in the vicinity of sewer lines and identifies mitigation opportunities to address those issues. The paper is not intended to be prescriptive in how these guidelines may be utilized by any natural gas utility, regulatory agency, or municipal organization.

This paper provides guidelines that Natural Gas Utilities may follow when installing gas lines using any type of trenchless technology, and what Natural Gas Utilities may consider when assessing or mitigating the risks of existing trenchless installations.

Finally, this paper provides insights into how Natural Gas Utilities can partner with other key stakeholders in getting sewer lines located and marked on a going-forward basis and in finding ways to effectively deal with existing sewer lines.

Industry Overview:

Cross bores, the intersection of gas and other utilities with a sewer line can present a serious risk to utility owners, sewer operators, the plumbing community, building owners/occupants and the public. The risk can be described as low frequency, high consequence. Risk of fire/explosion occurs when a natural gas line that was cross bored through a sewer line is pierced during clearing operations. Assessing the risk and the appropriate mitigation strategies are the responsibility of the utility owner and is a specific subset of subsurface infrastructure damage prevention.

There are two basic issues:

- Prevention of new cross bores by properly locating and marking sewer lines before construction so that new cross bores do not occur, and
- Prevention of damage of legacy/existing cross bores in which natural gas pipe has been unintentionally installed through sewer mains and services, but no one knows where they are or even that it happened

While potential safety issues related to cross bores have been known for some time, in recent years the importance and urgency of the cross bore issue has grown significantly. In the past several years, there have been tragic incidents involving other utilities. There have been 22 explosions in the United States – in both warm and cold weather states - that have resulted from cross bore situations involving natural gas lines. Many of these incidents have caused serious personal injury and property damage. Most of these incidents have occurred within the last 10 years.

In the United States, efforts are accelerating to increase industry and public awareness of the need to require the locating and marking of sewer mains and services prior to any

type of construction that involves excavating or disturbing the ground in any way. In some states, legislation has been passed requiring sewer mains and services to be located by the municipal sewer operator. A number of organizations and associations in the United States have identified the issue and are addressing it through either standing or ad hoc committees. These include but are not limited to the North American Society of Trenchless Technology (NASTT), the Common Ground Alliance (CGA), the American Gas Association (AGA), and the Distribution Contractors Association (DCA).

In February of 2008, the first AGA conference on "Managing the Threat of Sewer Facilities on Trenchless Installations" was held. This audio conference and further discussions with other utility representatives demonstrated that there were many different levels of recognition and response to this issue.

The Canadian Perspective - Current Conditions:

In Canada, the issue is just coming to the forefront and is currently being addressed by The Ontario Regional Common Ground Alliance (ORCGA) and this Canadian Gas Association (CGA) task force.

There have not been any documented incidents in Canada that have resulted in personal injury or significant property damage. However, there are many confirmed cases of cross bores in various regions of the country that have been identified by third parties such as municipal sewer operators and the plumbing and drain cleaning industry.

Natural Gas Utilities have used trenchless installation methods since as early as 1970, and they became common place in the 1980's. Coincidentally the peak growth and expansion of infrastructure for many Canadian natural gas utilities occurred from the 1970's onward. Trenchless technologies have led to operational efficiencies as installation is fast, creates little traffic disruption, and is cost effective as it results in less damage to property, roadways and tree roots. Trenchless installations of gas lines and other utilities are used primarily in established neighbourhoods and urban areas where open trench work would be expensive and intrusive. There are numerous types of these technologies employed today.

It has been found that on occasion, trenchless gas line installations have unintentionally led to cross bores through sewer lines. It is often difficult for the facility owner to obtain or provide accurate sewer locates due to the quality of existing sewer facility records. The challenge for many sewer owner/operators is that existing records often contain unreliable information with respect to installation practices for the sewer mains and services. The standards for sewer line installations have varied considerably – from both geographical and generational perspectives.

Typically the municipality owns the sewer main and service up to the property line and the property owner owns the remaining portion to the building. Most homeowners do not know where their portion of the sewer service is buried, nor do they have the expertise to locate it.

In northern climates, sewer trunk and lateral lines are generally installed deeper than natural gas lines, to avoid the freeze-thaw issues. This has resulted in the belief there should be no conflict of facility locations. However, there may be some instances where the sewer mains and services have been installed at shallower depths or gas lines have been installed at deeper depths. This could result in the unintended intersection of the two utilities. Installation standards for sewer mains and services vary considerably from area to area and over time according to many variables.

In many cases, a gas line can remain in a sewer main or service without creating an immediate problem. It may remain undetected for years. The potential danger from a natural gas line through a sewer main or service arises when work is done on the sewer and the worker does not know that a natural gas line is there. Gas line locates are not typically requested by those working on the sewer lines, as no excavation is taking place when sewer lines are cleaned using various in line technologies. If an individual working on a sewer line blockage utilizes rotating, water jetting or any similar type of equipment to clear the sewer line, and a natural gas cross bore is present, the natural gas line could be damaged.

If the damage breaches the line, the natural gas could fill the sewer mains and services, entering the building(s) connected to the sewer system. If the gas to air mixture is in a range of 5% to 15% gas in air and a source of ignition is present, an explosion and/or fire may occur.

DRAFT

The Regulatory Environment

The CAN CSA Z662-07 Annex M.8.1 states "Gas distribution companies should identify and document hazards that can lead to a failure or damage incident with significant consequences". Although annex M is only informative, the industry should consider cross bores as a potential hazard and have procedures in place that reduce the potential risk associated with sewer line cross bores.

Some areas of some provinces have a One-Call system to distribute planned excavation information to utilities. Some have penalties for noncompliance, but enforcement alone is not effective. These regulations are under the purview of each province and are not consistent. One-Call systems are not mandatory in Canada and usually exclude many of the municipally operated utilities such as sewer systems. Many municipal and regional governments own and operate the sewer lines only from the property line to the waste water treatment facility. Some sewer lines on private property are owned by the property owner or condominium corporation.

Natural Gas Utilities recognize that there are potential municipal, administrative and political implications of the "sewer facility locate". Increased service fees, taxes or permit fees may be a result of the provision of sewer locates to those that may request them. While it is in our collective interests to minimize costs, safety is the priority.

Regardless of future changes in the regulatory environment, each natural gas operator and sewer line operator must adhere to all current laws related to the location and marking of underground facilities in the province where a project is located. In some jurisdictions the regulatory agencies are supportive of efforts to implement a plan to address the cross bore issue.

DRAFT

Definitions:

Cross Bore: A utility cross bore is an unintended intersection of an existing underground utility by a second utility that can occur during construction that uses trenchless technologies. The cross bores that involve natural gas utility pipelines and sewer lines result in direct contact of both facilities that compromises the integrity of the gas line, the sewer line, or both.

Sewer Line: A piping system used to move either sanitary waste or storm water. These can include the sanitary sewer lateral, the sanitary sewer main, septic system lines, and storm water systems.

Utility Locate: The provision of location information by an underground facility owner or their agent in the form of ground surface markings and/or facility location documentation, such as drawings, mapping, numeric descriptions or other written documents.

Trenchless Technology (including any of the following):

1. Directional Drill
2. Piercing Tools (torpedoes, moles, rockets,etc)
3. Water Boring Equipment
4. Auger Boring Equipment – including pipe jacking
5. Ploughing

DRAFT

Resources / Reference:

- Stakeholder interviews / focus groups
- Various member companies of the Canadian Gas Association - specifications, operations guidelines, procedures manuals, etc.
    - Enbridge Gas Distribution - pilot and test results
- Various member companies of the American Gas Association - specifications, operations guidelines, procedures manuals, etc.
- AGA – American Gas Association Damage Prevention Partnership White Paper
- CGA – Common Ground Alliance
- "Common Ground: Study of One-Call Systems and Damage Prevention Best Practices", August 1999
- Cross Bore Safety Association (www.crossboresafety.org)
- National Transportations Safety Board (NTSB) Safety Recommendation P-99-1, dated April 28, 1999
- RSPA Pipeline Safety Advisory Bulletin ADB-99-04, dated August 23, 1999
- Minnesota Department of Public Safety Alert Notice, May 10, 2010
- GPTC Guide for Gas Transmission and Distribution Piping Systems: 2003 Edition - Guide Material Appendix G-192-6 - "Subsurface Damage Prevention Guidelines for Directional Drilling and Other Trenchless Technologies"
- HDD Consortium, "Horizontal Directional Drilling - Good Practice Guidelines", May 2001
- Directional Crossing Contractors Association, "Horizontal Drilling Safe Operations Guidelines", 2000
- NASTT – North American Society for Trenchless Technology

DRAFT

Recommendations:

The objectives of the task force are to make recommendations:

1. That provide guidelines that Natural Gas Utilities may consider when installing gas lines using any type of trenchless technology, and
2. What Natural Gas Utilities may consider when assessing or mitigating the risks of existing trenchless installations, and
3. How Natural Gas Utilities can partner with other key stakeholders to drive continuous improvement relative to current practices.

The following recommendations are a combination of existing industry best practices and ideas gathered from key stakeholders through a series of discussions in early 2010.

The recommendations have been grouped into four areas of focus:

1. Communication & Education / Awareness
2. New Construction using trenchless technology
    a. Pre-Construction
    b. Construction
    c. Post Construction
3. Existing installations where trenchless technologies were used
4. Continuous Improvement

Each of the Canadian Natural Gas Utilities is responsible for developing its own program with policies, processes and procedures that are specific to the application of trenchless technologies within the region of their facilities. The information in this document is not intended to replace local, provincial, federal or private company rules or regulations. These recommendations are a suggested guide only, and the use of these guidelines or any variation thereof, shall be at the sole discretion and risk of the individual Utility.

DRAFT

1. Communication and Education / Awareness

In some circumstances, a communication and education strategy may be appropriate to help mitigate the risk of existing cross bores. The Natural Gas Utility can develop their own strategy based upon the unique requirements of each situation.

It may also be appropriate to encourage sewer system owner/operators (municipalities, city, etc.) to develop their own internal communication and education strategy to mitigate the risks that may exist for them in relation to the operation and maintenance of their facilities where trenchless technologies have been utilized.

Note: not all of the suggestions listed below may be necessary or appropriate in all jurisdictions and situations.

Natural Gas Utilities can communicate with and educate the key stakeholders. These groups would include municipalities, provincial safety regulators, public works departments, owner/operators of private sewer systems, the plumbing and drain cleaning industry, companies that rent rotary cutting tools for the purpose of drain / sewer cleaning, pipeline contractors, trade unions, third party locate firms, and emergency service responders. Targeting associations may be an effective way to educate many of these stakeholders.

Methods of communications and education that may be considered for these stakeholders include, but are not limited to:

- Information Packets
- Websites
- Face to face meetings
    - Open houses
    - Workshops
    - Conference presentations / participation
    - Association presentations / participation

Natural Gas Utilities may also communicate with and educate their customers and the general public.

Methods of communications and education that may be considered for the homeowners, businesses, and the public include, but are not limited to:

- Bill inserts
- Direct mailings
- Door to door handouts
- Newspapers
- Websites / Google Ads

- Sewer clearing equipment rental agencies

2. New Construction using trenchless technology

Natural Gas Utilities, working with other key stakeholders can significantly reduce the risk of new cross bore occurrences through the identification and implementation of industry practice guidelines at the various stages of construction:

- Pre-Construction
- Construction
- Post Construction

a) Pre-Construction

- Establish a proposed pipeline installation path and visually inspect the potential site for suitability for a trenchless installation by walking the area.

- Be alert to any obstructions and indications of the presence of other underground facilities or structures such as catch basins, sewers, water boxes, manhole covers, valve box covers, underground shutoffs, etc.

- Notify residential and business neighbors, along with privately owned services (e.g., sewer, gas, water, and electric) in the area of impending work.

- After determining the proposed drill path and marking the work area (some areas use white paint to mark the work area), contact the appropriate utility One-Call provider to ensure that all underground facilities are located and marked accordingly by their owners. If possible, identify the presence of utilities not located through One-Call and attempt to determine their location by contacting the owner(s) of those facilities or employing other means to identify the path in which they are running. This includes all sewer mains and laterals.

- Additional efforts should be considered in determining whether sewer lines and laterals are within the proposed construction area of a directional drilling project. Some of these efforts may include the following:
    - Contact the city, building owners, local plumbers, and other persons that can provide assistance with identifying the existence and location of sewer lines.

- Obtain maps and drawings of the sewer system from the city or other entity. Maps can provide the depth of the sewer lines and other valuable information that can assist in determining the location of the sewer lines within the proposed drill path.

- Visually check the job site for sewer cleanouts, manhole covers, and any markings on curbs or gutters that may exist for sewer facilities.

- Consider pre-location of sewer laterals where an exterior clean-out is available:
    - Measure the depth of the sewer line lateral. Caution should be taken because a sewer lateral may not have consistent grade or path from the building entrance to the sewer main.
    - Run a fish tape down through the exterior clean-out, use a line locator in the conductive mode, and verify location and depth by pothole; or
    - Insert a sonde in the exterior clean-out and use a drill head locator to verify location and depth; or
    - Pre-camera through the exterior clean-out to verify location and depth.

- Use internal camera systems, if available, that travel down the main sewer line and allow the laterals to be located visually.

- Use electronic technology, if available, to track a locating transmitter inserted into a sewer and/or lateral to determine its path and depth.

- Use ground penetrating radar, where effective (i.e. sandy soils), to assist in locating sewer lines and laterals.

- In determining the depth of the sewer and laterals, the following guidelines may be considered:
    - If a sewer line is located, check the direction of the flow of the water and the direction of the pipe. The flow direction will indicate whether the grade of the sewer is rising or falling. This will help judge whether the sewer will be shallower or deeper where the drill is being made.
    - Access manhole covers and measure the depth of the main sewer line.
    - Access outside clean-outs and measure the depth of the sewer line lateral. Caution should be taken because a sewer lateral may not have a consistent grade from the building entrance to the sewer line.
    - Obtain access to buildings that do not have an outside clean-out and visually identify where the sewer exits the structure. Visually determine the depth of the sewer lateral by identifying where the lateral exits the building versus the depth of the sewer main at the street.
    - Document results of visual assessment and method(s) used to physically locate the sewer line.
    - Document the criteria by which the lack of conflict was established for all addresses/locations where this method was used.

- If known sewer facilities cannot be positively located, then the following alternatives may be considered:
    - Do not use directional drilling or other trenchless equipment for installing the gas main or service.

  - Use directional drilling equipment only in those areas where the location and depth of sewer lines have been determined to be safely outside the drill path and use open trench equipment for areas where the sewer line conflicts have not been ruled out.

- In finalizing the installation path, determine the depth and location of all underground facilities along that path to the extent practicable. Pot holing should be considered.

- The following are some additional practices for consideration during the planning stages for use of trenchless technology:

  - Proper Engineering design, determining the path of installation with the least likelihood of utility interference
  - Participation in utility coordinating committees
  - Participation in municipal coordinating committees
  - Depending on the size and complexity of a project or activity, hold pre-bid / construction meetings with utilities and public works officials, prior to the start and during construction or use of sub-surface utility engineering methods

DRAFT

b) Construction

Review construction procedures/standards before starting work – including all applicable dig-safe legislation.

Below are some additional industry practices for consideration during a natural gas installation project that uses trenchless technology. (The local sewer operator may be able to assist.)

- Pot hole along the path, as appropriate for conditions
    - Establish criteria for which every sewer line must be pot holed (such as privately owned sewer systems including trailer parks, schools, college campuses, shopping malls, etc.)
    - Establish criteria for spaced verification of sewer laterals including:
        - Conditions that allow the practice (long, known depth sewer mains, etc.)
        - Verification at some set distance (for example, every 200' when laterals are 4' deep or every 400' when laterals are 6' deep)

- Existing underground facilities should be exposed with sufficient space around the facility so that the drilling operation can be visually checked to ensure that it will not impact the facility.

- If in the course of excavation the location of the existing facility is found to be incorrect, the facility owner should be contacted so they can correct their records.

- The crew leader should visually inspect the planned drill path, just prior to proceeding with the drilling operation, to ensure that all utility services and underground structures have been identified and test holes made as required.

- Crossing installations: Consider excavating pot holes at all crossing locations to the extent practicable. The existing facility should be completely exposed with sufficient visual area so that it can be assured that the trenchless installation does not impact the facility. A typical practice is to pothole and expose the sewer service lateral /main at the gas crossing; the cutting/drill head must be visible in the pothole. The recommendation is to document the address and the distance between the drilling head and the sewer pipe at all addresses/locations where this method was used. This record should be retained for the life of the pipeline. [NTD: don't we specify a requirement to daylight to the depth of the gas install any utility crossing independent of the crossed utility's depth?]

- If possible, maintain a minimum vertical separation of 12" when crossing facilities; however, if facilities are fully exposed, then a separation of less than 12" may be considered where regulations allow.

- Installation crews should perform periodic sweeps of the area during the project to further ensure that all possible attempts to avoid damage to marked and unmarked facilities have been made.

- Cease pipeline installations if an unidentifiable, abnormal or unanticipated resistance or sudden movement of the drill, mole, plow, etc is encountered. Proceed only after the source of the disturbance has been identified and/or eliminated. Particular care should be taken to ensure that existing substructures are not penetrated. If any underground facility is known to be damaged during the project, notify the appropriate operator and/or emergency response personnel immediately, as appropriate.

c) Post Construction

The following are some practices for consideration during the documentation stages when using trenchless technology:

- Installation method for natural gas pipelines installed with trenchless technology can be identified on field work orders or company mapping systems, and records kept for the life of the pipeline.
- Post trenchless construction video inspection can be used to verify any locations where a cross bore may have occurred, and records kept for the life of the pipeline.
- Notify customers that trenchless technology was the method of installation used for the natural gas pipeline – if the sewer lines were not visually inspected or verified by a camera that a cross bore did not occur. Include contact information for the Natural Gas Utility for notification prior to any cleaning of sewer lines.

DRAFT

3. Existing installations – where trenchless technologies were used.

- See the "communication and education" regarding the Natural Gas Utility's Stakeholder and Public Education Program.
    - Ensure there is an awareness and knowledge to request gas line locates when completing sewer line operations & maintenance / repairs.

    - Develop a Natural Gas Utility Response protocol when a sewer line is to be maintained / repaired / cleaned.
        - Accept a request for a gas line locate if a sewer line is to be repaired, maintained
        - Provide a natural gas facility locate
        - Provide a telephone enquiry process if a potential conflict exists
        - Perform investigation
        - Resolve conflicts
        - Determine appropriate cost recovery for utility/homeowner

- Options to actively determine if legacy/ existing installations are clear or if cross bores exist in identified high risk areas
    - Visual determination
    - Proximity test
    - In sewer camera inspection
    - Overlay facility information
    - Previous occurrences
    - Targeted public communication

    - Develop a common approach to risk assessment
        - Is there a sewer system in the area of the installation
        - Previous occurrences
        - Use of trenchless technology
        - Pipeline material
        - Sewer clearing equipment
        - Locating practices
        - Topography
        - Building construction types
        - Sewer installation standards
        - Overlay facility information (sewer elevation information)
        - Property assessment data to determine basement elevation

DRAFT

4. Continuous Improvement

Partnership:

Natural Gas Owner/Operators and Sewer Line Owner/Operators have shared interests:

- Safety of the public, customers and workers
- Providing the most cost effective service
- Preventing damage to their infrastructure

By way of developing and implementing a **Partnership Model** , the sewer and natural gas owner/operators may explore mutual damage prevention efforts. Both parties should seek to understand each other's operating policies and practices, requirements and priorities. For example

- What is the locate policy
- How are sewer lines located
- Who owns and is responsible for the sewer lateral lines
- How can the sewer owner/operator and utility share information
- What is the sewer owner/operator's typical response to a blocked sewer main or service lateral

Provide insights into how natural gas utilities can partner with other stakeholders in getting sewer lines located and marked on a going-forward basis and in finding ways to effectively deal with existing sewer lines

- Joint pursuit of legislative changes to make sewer lines locatable
- Sharing of information
- Presentations at municipal association conferences
- Investigate pilot project to cooperatively share video inspection data
- Clarity of accountabilities (ownership of facilities)
- Participation in One Call programs, Common Ground Alliances, and Utility Coordinating Committees

It is important to note that where the partnership approach is not successful to drive improvement and to implement best practices, the natural gas utilities may choose to drive legislative changes on their own - without the support of the impacted stakeholders. An example of this approach currently exists in Ontario where there is an inability to "partner" with all underground facilities owners to be members of a One Call system for damage prevention – resulting in the major members of the Ontario Regional Common Ground Alliance now lobbying government directly to make One Call membership mandatory in Ontario.

DRAFT

Reporting and Risk Assessment:

Where feasible, Natural Gas Utilities may record the actual number of sewer line conflicts that are experienced, and other pertinent data directly related to the incident. The information that is recorded could be used to create a database – both at the utility level and possibly nationally – to assist in the identification of common variables. If trends emerge, then both the natural gas utilities and the sewer line owners & operators may be able to better target their education and awareness efforts, as well as implement procedures that will better mitigate the potential risks of gas/sewer line cross bores.

If cross bore data were to be collected from – and shared with - all CGA members, there could also be a common approach to a risk assessment developed and implemented across the CGA membership.

The CGA Distribution Integrity Tool may be a mechanism to track and report on cross bore incidents. Further investigation is required to determine if this is the best approach, or if other options should be considered. A pilot should be explored for a three year period and reviewed for its usefulness in determining coincidence factors to assist with the identification of high risk situations. The numbers will be small and the overall effort to enter the information will be small.

Other:

Work cooperatively with the local One-Call Center to identify a list of locating firms that are available to stake privately owned (i.e. trailer parks, commercial plazas, universities, institutions, etc) underground facilities. This will provide property owners a reasonable method to fulfill their responsibility to mark their buried facilities.

Work with provincial and federal trade licensing boards to ensure that a thorough understanding of unmarked sewer line issues is required of individuals who are endeavoring to obtain/renew a plumbing trade, or contractor's license.

Work with municipal business licensing boards to ensure that a thorough understanding of the potential safety risk is required of individuals who are obtaining/renewing a business license.

DRAFT

Notices and Disclaimer

This document was prepared by the Canadian Gas Association (CGA) Cross Bore Safety Task Force at the request of the CGA Standing Committee on Operations.

This document is for information purposes only and does not constitute a standard. Information in the document should not be relied upon as the sole source of information relating to its content and no warranty, either express or implied, is made with respect to the information contained herein. The Canadian Gas Association, its members, respective employees and contractors are not responsible for any loss, inconvenience, damage (whether special or consequential) or claims arising out of the use of the information contained in this document.

DRAFT

Fuels Safety Program	Ref. No.: FS- -11	Rev. No.:
SAFETY ORDER	Date: Jun. 13, 2011	Date:

IN THE MATTER OF:
THE TECHNICAL STANDARDS AND SAFETY ACT, 2000,
S.O. 2000, c. 16

- and -

ONTARIO REGULATION 223/01 (Codes and Standards Adopted by Reference)
made under the Act
- and -
ONTARIO REGULATION 210/01 (Oil and Gas Pipeline Systems)
made under the Act

Subject: Clearing Blocked Sewer Service Lines
Sent to: Gas Advisory Council, Risk Reduction Group-Pipelines, Posted on TSSA's Web-Site

The Director of the Oil and Gas Pipeline Systems Regulation, pursuant to his authority as provided for in Section 36 (3) (c) of the Technical Standards and Safety Act, 2000, hereby orders the following:

A potential safety situation could arise when home owners or administrators of commercial, institutional or industrial buildings attempt (by themselves or by calling a contractor) to clear a blocked sewer service line beyond the outside wall of the building. The issue is that natural gas lines installed using trenchless practices may have inadvertently penetrated the sewer line.

A natural gas line that has penetrated a sewer line may be undetected for a long period of time. Clearing the sewer service line with rotating equipment or water jet equipment could damage the gas line and result in a leak of natural gas into the sewer line, posing an immediate safety risk.

For this reason, natural gas distributors shall submit to the Director by October 30, 2011 an action plan that includes:

a) Description of the steps to mitigate the potential of penetration of sewer lines by a natural gas line during trenchless installation,
b) Raising awareness of the potential safety issue that could arise when attempting to clear a blocked sewer service line beyond the outside walls of a building,
c) An assessment of potential risks and a plan to mitigate these risks.

This order is effective immediately.

Dated at Toronto this 10st.day of July, 2011.

APPROVED BY: _____
John Marshall,
Director, Gaseous Fuels Regulation
Technical Standards and Safety Act

Draft

Draft

Risk Reduction Group
Terms of Reference

Purpose

In support of its strategic objective to improve safety outcomes and recognizing the need for industry input, the Technical Standards and Safety Authority (TSSA) actively solicits the technical advice of the key stakeholders from the respective industries that it regulates through a number of industry specific risk reduction groups (RRGs). Industry members are invited to work with TSSA in the development of resolutions to identified safety gaps, adopting codes, implementing regulatory/code requirements, etc. Participation of stakeholder representatives on the RRGs is very much appreciated by TSSA.

Reporting

The collective mandate of the RRGs is to discuss and provide input to TSSA on safety, code adoption, regulatory implementation and interpretation issues. As a means to ensure that the views represented by the RRG members are reflective of their industry sector, the chair of the RRG will provide progress updates to the appropriate industry advisory councils. This may be accomplished through formal presentations at council meetings and/or via electronic distribution of meeting minutes.

This reporting structure ensures overall coordination of industry input, facilitates endorsement of RRG recommendations by the council and reinforces TSSA's commitment to transparency and public accountability.

Structure

RRGs are established to address a safety gap, code adoption, regulatory implementation or specific risk management issue. RRGs and issues requiring safety solutions are established by TSSA. The RRG process is to formally solicit input from the statutory directory on safety and interpretation issues. The final decision regarding the resulting action resides with the statutory director. Council members are invited to submit issues for consideration. Issues will be assessed and RRGs established and prioritized using risk-informed methodology. RRG discussions and resultant guidance for the resolution of specific issues will be based on risk management principles and communicated to the applicable councils. RRG updates will be standing items on all council agendas. RRG members operate under their own terms of reference.

Membership

Membership of the RRGs will be reflective of the stakeholders in the respective industries. TSSA will strive to manage RRG membership so that input is balanced and, to the extent appropriate, represents the industry as a whole as well as the end user/consumer. TSSA may not restrict membership in order to gain the most input on an issue and the RRG process may also allow communication of new regulatory, code or safety requirements.

Members will be invited to participate by TSSA or industry stakeholders. Any member wishing to participate may do so.

RRGs will be chaired by TSSA; however, where appropriate, TSSA will delegate the chair position to a member of industry. In addition to the chair, TSSA will appoint a coordinator to support RRG initiatives through the scheduling of meetings, preparation of agendas and meeting minutes and maintenance of records, where appropriate and beneficial.

Membership on the RRG is voluntary and, as such, there will be no retainers or fees paid to RRG members by TSSA. Any expenses incurred will be the responsibility of the participating individual / organization / association.

Qualifications of Members

Appointees to the RRGs will be relevant topic/technical experts in their respective organization/association who are committed to represent their industry sector's position on safety issues. TSSA may consider participants who are not experts if they have a specific interest in the issue or may be impacted by the issue.

Meetings

The RRGs shall meet as often as is deemed necessary so as to develop appropriate solutions to identified safety issues/topics.

Meeting agendas and supporting material will be sent to each member in advance of the meeting date. Minutes will be distributed within two weeks of the meeting. Meeting minutes will also be distributed to all members of the appropriate industry advisory council.

Confidentiality

Every employee of TSSA is required to safeguard the confidentiality of proprietary or sensitive information, audit findings and industry records. This obligation extends to RRG members, and to information or records related to RRGs (e.g. agendas, minutes, etc.).

Conflict of Interest

It is recognized that members of the RRGs may ultimately derive either direct or indirect benefit from the outcome of specific deliberations of the RRGs. All members are required to refrain from using their position to gain benefit from or influence any other member, organization or industry sector.

BOMA INTERROGATORY #5

INTERROGATORY

Summary of Costs: B2, T2, Sch 6, pp. 10-11.

(a) Explain the term "Work Volume" in column 3 and show how the expenditure cost, capital or O&M, was determined in each case where "Work Volume" is used, eg. in items like "Emergency Natural Gas Service Safety Inspection". How was the $2,377,500 cost arrived at? Explain. Provide the unit cost for each activity.

(b) Explain how each work number volume was estimated for each "expenditure description".

(c) (i) What costs for cross-bore was included in the base revenue requirement under Enbridge's IRM plan? (ii) What activities did these costs support? (iii) What costs were incurred in each of the years 2008, 2009, 2010, and 2011? (iv) What activities did these costs support?

RESPONSE

(a) The term work volume refers to the forecast number of calls that are expected to be received and will require a response. The $2,377,500 represents the total cost to respond to and perform the forecasted 5530 required “Emergency Natural Gas Sewer Safety Inspection”. Actual volumes from 2010 and 2011 were used to forecast volumes for 2012. The unit costs vary dependent on time of day, service area, volume and location. The unit costs range from $257 to $925.

(b) Work number volumes associated with Sewer Safety Inspections were forecast as explained in part (a) above. In all cases, actual numbers from 2010 and 2011 YTD were used with an increase to account for increased education and awareness regarding the Sewer Safety Program. Sewer lateral locate requirements for new construction programs are forecast based on projected work types in Enbridge’s capital construction program for 2012.

(c) Costs related to sewer lateral cross bores were not part of the 2007 base costs for rates leading into the IRM plan because the issues and associated costs were not well enough known at that time. In 2008 and 2009 cost tracking for cross bore related work was not well established. Costs for 2010 and 2011 YTD are as follows:

Witnesses: C. Clark
L. Lawler

Year	Cost	Activity
2010	$2.3M	O&M
	$1.2M	Capital
2011 YTD	$2.2M	O&M
	$1.1M	Captial

Supporting Sewer Safety inspections, education/awareness materials, legacy investigations, cross bore repairs, sewer lateral locates for construction and research and development.

Witnesses: C. Clark
L. Lawler

BOMA INTERROGATORY #6

INTERROGATORY

Action Plan.

(a) What percentage of new pipeline service construction work is done using the trenchless method (by dollar, by distance)?

(b) When was the Cross-Bore Safety Association founded? When did Enbridge join the Association? When did it become a "lead"? Please provide materials on the objectives, methods, and meeting agendas of the Association.

(c) When was the Ontario Regional Common Ground Alliance founded? Who are the members? When did Enbridge join? When did they adopt Best Practices for cross-bore detection and remediation? Please provide the "best practice" document.

(d) Provide a copy of CAN CSA Z662-07 Annex M.8.1. When was the sentence in quotation marks included in the above standard?

(e) When did the Minnesota and Virginia significant incidents occur? If information is readily available, when did the other 17 US incidents occur? When did the incident at St. Lawrence Gas occur?

(f) For how long has Enbridge been performing approximately 2,000 cross-bore investigations per year?

(g) Why does Enbridge have such a high number of cross-bore requests from the Niagara area, relative to other areas of the franchise?

(h) Please provide a copy of the natural gas installation code.

(i) When did Enbridge begin to take steps to address the risks posed by cross-bores?

Witnesses: C. Clark
L. Lawler

RESPONSE

(a) Trenchless technologies are utilized mostly for installation in improved areas. The amount (percentage) of pipe installed using trenchless technologies is sometimes a requirement of the municipal approval process and sometimes used for the convenience of the constructor to minimize impacts to existing physical features and reduce restoration costs. It is difficult to pre-determine the quantities until the exact location of the project is determined and a physical field review of the project is completed which will determine the optimal construction methods to be employed for the installation. 81% of the Company's capital program is spent on the installation of mains and services in improved areas and this represents approximately 36% of the total metres of pipe installed. At this time, Enbridge does not specifically track which sections of pipes were installed using trenchless technologies.

(b) The Cross Bore Safety Association was founded in 2007. An Enbridge representative was elected to the Board of Directors in October 2010. The Cross Bore Safety Association was formed to raise the awareness of the safety issues associated with the existence of cross bores, provide history and information relating to system integrity, risk evaluation, State regulations and rulings, information sources, industry best practices for cross bore prevention and other pertinent materials relating to the use of trenchless technologies and cross bore prevention. Refer to the Cross Bore Safety Association website for details. http://www.crossboresafety.org

(c) The Ontario Regional Common Ground Alliance ("ORCGA") was founded in 2003. There are over 400 members. Enbridge was a cofounder at its inception. The best practices related to cross bores were adopted in 2009. Please refer to the ORCGA website for the document and further details. http://www.orcga.com

(d) Annex M.8.1 is attached. It is not clear which sentence BOMA is requesting information on.

(e) There have been several significant incidents in Minnesota. The most recent was in February 2010. The remainder of the incidents in the US occurred between 1997 and 2008. The incident in St. Lawrence Gas occurred in 2004.

(f) Enbridge commenced legacy investigation work in 2008.

Witnesses: C. Clark
L. Lawler

(g) Because the Niagara Region was the pilot area for the rollout of the Sewer Safety Program, the awareness and recognition of the potential safety issues associated with cross bores is more mature than the remainder of the Enbridge service areas. Calling for a sewer safety inspection has been made mandatory by the Niagara Region municipal operations committee prior to clearing a blocked sewer lateral beyond the outside walls of a building whenever mechanical equipment is to be utilized.

(h) The CSA Z662 is available for purchase from the CSA.

(i) Steps to address the potential risks posed by sewer lateral cross bores were implemented in 2008.

M.6.3

Where evaluation of the knowledge and skills indicates that development is required, training should be arranged. Such training can include participation in

(a) formal training courses provided by educational institutions or industry organizations;
(b) workshops and conferences related to gas distribution system integrity;
(c) technical committees of industry and standards development organizations;
(d) research and development projects related to gas distribution system integrity; and
(e) supervised work experience.

M.7 Change management

M.7.1

Gas distribution companies should have a documented change management process to manage changes that can affect the integrity of their gas distribution system.

M.7.2

The change management process should have procedures in place to address and document, where applicable, items such as

(a) monitoring to identify anticipated and actual changes that can affect gas distribution system integrity;
(b) responsibilities for approving and implementing changes;
(c) analysis of implications and effects of the changes;
(d) communication of changes to affected parties;
(e) timing of changes; and
(f) reasons for the changes.

M.8 Hazard identification and control

M.8.1

Gas distribution companies should identify and document hazards that can lead to a failure or damage incident with significant consequences.

M.8.2

The methods and data used for hazard identification should be documented and should take into consideration the primary causes and any additional failure or damage incident causes that are relevant.

M.8.3

Where hazards that can lead to a failure or damage incident with significant consequences identified, the gas distribution company should perform the following:

(a) assess and document the risks associated with such hazards in accordance with the provisions of Clause M.9; or
(b) implement and document measures
    (i) for monitoring conditions that can lead to failure or damage incidents; and
    (ii) to eliminate or mitigate conditions that can lead to failure or damage incidents.

BOMA INTERROGATORY #7

INTERROGATORY

In EB-2009-0172, at Ex B, Tab 3, Sch 2, p1, Enbridge applied for Z-factor treatment (and a variance account) for its Sewer Lateral Initiative. At the Settlement Conference in that proceeding. Enbridge agreed to withdraw its request for Z-factor and deferral account treatment.

(a) Please confirm that the program proposed in this proceeding is substantially the same, that is, is composed of the same activities as the Sewer Lateral Initiative. Please discuss differences, if any.

(b) Please confirm that Enbridge carried out the activities it proposed to carry out, as part of the Sewer Lateral Initiative, in 2010 and 2011. If there were any elements of that proposal not carried out in either 2010 or 2011, please discuss.

RESPONSE

a) The activities have not changed substantially. The response to calls received for blocked sewers have changed from a two step to a one step process as a result of working with the municipal sewer operators in the pilot project in late 2009. This change improved the operational effectiveness of the response plan. The fundamental difference as of late 2011 is that Enbridge now has a regulatory requirement, arising from the TSSA Directive, to implement and proceed with the sewer lateral initiative.

b) All of the education, awareness, response, and legacy components were carried out in substantially the same format as outlined in EB-2009-0172. The research and development component also proceeded as outlined. Enbridge did not complete the system changes to track method of construction or completed sewer safety inspections due to a limitation on system changes because of the new GIS system. These will proceed in 2012. Enbridge is tracking completed sewer safety inspections on a separate data base which will be uploaded to the new GIS system.

Witnesses: C. Clark
L. Lawler

BOMA INTERROGATORY #8

INTERROGATORY

Ex B, Tab 2, Sch 5, pp 1-8 (Pension Funding Requirement).

(a) Please explain what the "annual employee service cost" is.

(b) Please provide copies of Enbridge's annual cost certificates for 2007, 2008, 2009, and 2010.

(c) Please provide a copy of Enbridge's Statement of Investment Policies and Procedures.

(d) Enbridge states in paragraph 21 that it was precluded from making contributions to the plan in recent years because the plan was in a surplus position (our emphasis). But at paragraph 7, Enbridge states that in the period prior to IR, Enbridge was in surplus, and as a result has not had to make contributions to the plan (our emphasis). Please explain the different answers.

(e) Please provide the after tax return of the assets in the pension plan for each of the years 2007, 2008, 2009, and 2010, as of November 1, 2011.

(f) What contributions, other than "employee service cost related" contributions, are included in the $17.7 million?

RESPONSE

a) Annual Employee Service Costs should read “Annual Employer Service Cost”. It is the present value of future benefits earned by employees in the current period.

b) See Attachment A for the December 31, 2010 annual cost certificate. While an annual cost certificate was required as of December 31, 2009 a full valuation was also required as of December 31, 2009 so a cost certificate was not prepared. This

Witnesses: S. Kancharla
R. Lei
A. Patel

approach was approved by the Financial Services Commission of Ontario ("FSCO"). The requirement for a cost certificate did not exist prior to 2009.

c) See attachment B.

d) When rates were set for the current IR in 2007, due to the huge surplus, EGD was precluded from making contributions for the next three years (2007, 2008, and 2009) because of CRA rules. By 2009, while the EGD plan was in a surplus, the surplus was not so large as to preclude EGD from making contributions per CRA rules, however, EGD was not required to make contributions at that time per FSCO legislation.

e) Registered pension funds do not pay tax so an after tax return cannot be provided. Plan asset returns were as follows:

	2006	2007	2008	2009	2010
EGD RPP	10.6%	1.0%	-18.4%	16.7%	9.8%

A return for year-to-date November 1, 2011 has not been provided as it will not provide a good comparison to prior years which are on a full year basis. In addition, a year-to-date return is not indicative of what will materialize at December 31, 2011 as there are many uncertainties surrounding the economic conditions that will prevail at that date.

f) Of the $17.7M, employer service costs were $17.1M for the EGD RPP. The remaining amount represents special payments to amortize the unfunded liability of the SERP.

Note that the $17.7M was subsequently revised to $16.6M in the updated filing in this application, EB-2011-0277, on October 3, 2011.

Witnesses: S. Kancharla
R. Lei
A. Patel

31 March 2011

Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates

Actuarial Cost Certificate as at January 1, 2011

MERCER

Canada Revenue Agency Registration Number: 0242016

Note to reader regarding actuarial valuations:

This report may not be relied upon for any purpose other than those explicitly noted in the Introduction or by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

To prepare this report, actuarial assumptions are used to model the results for a single scenario from a range of possibilities. The results of that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant. In addition, different assumptions or scenarios may also be within the reasonable range and results based on those assumptions would be different. Actuarial assumptions may also be changed from one valuation to the next because of changes in regulatory requirements, plan experience, changes in expectations about the future and other factors.

Furthermore, should the plan be wound up, the going-concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. Emerging experience, including the growth of wind-up liabilities compared to the plan's assets (including future contributions and investment returns), will affect the wind-up funded position of the plan assuming it is wound-up in the future. In fact, even if the plan were wound-up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Because actual plan experience will differ from the assumptions, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

Contents

1. Introduction 1

2. Valuation Results 3
- Going-concern Financial Position 3
- Reconciliation of Financial Status 4
- Solvency Financial Position 4
- Hypothetical Wind-up Financial Position 5
- Current Service Cost (December 31, 2009) 6
- Impact on Contribution Holidays 6

3. Actuarial Opinion 7

Appendix A: Plan Assets

Appendix B: Actuarial Methods and Assumptions

Appendix C: Employer Certification

1

Introduction

To Enbridge Gas Distribution Inc.

At the request of Enbridge Gas Distribution Inc. (the "Company"), we have estimated the financial position of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "Plan") as at January 1, 2011 on a going-concern basis and on a solvency basis. The purpose of our calculations was to provide the information required to be included in an actuarial cost certificate prepared pursuant to section 7.1 of the Ontario *Pension Benefits Act Regulations*. Note that the Plan is made up of defined contribution ("DC") and defined benefit ("DB") components.

The information presented is prepared for the internal use of the Company and for filing with the Financial Services Commission of Ontario ("FSCO"). This information presented is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2012, or as at the date of an earlier amendment to the Plan. Unless a new cost certificate is filed as of January 1, 2012 demonstrating that the Plan has sufficient surplus, employer current service cost contributions must resume in 2012.

Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and based on methods and actuarial assumptions that are consistent with actuarial standards of practice in Canada;

- As instructed by the Company, we have reflected a margin for adverse deviations in our going-concern valuation by reducing the going-concern discount rate by 0.59% per year; and,

- We have reflected the Company decisions for determining the solvency funded position. Certain excludable benefits were excluded from the solvency liabilities.

Our calculations reflect the provisions of the Plan as at December 31, 2009. Based on the information provided by the Company, no substantive amendments have been made to the Plan since that date. A summary of the plan provisions is provided in Appendix F of our Report on the Actuarial Valuation for Funding Purposes of the Plan as at December 31, 2009, dated September 30, 2010.

Our calculations are based on an extrapolation of a valuation performed using membership data as at December 31, 2009. The membership data used in our calculations was summarized in Appendix E of our Report on the Actuarial Valuation for Funding Purposes of the Plan as at December 31, 2009, dated September 30, 2010.

The assumptions used in our calculations are described in Appendix B. We have used the same going-concern valuation assumptions and methods as were used for the valuation as at December 31, 2009, except for the discount rate, which has been updated to reflect market conditions on January 1, 2011. These changes have resulted in an increase of $21,645,000 in the estimated going-concern funding target and an increase of $768,000 in the employer current service cost. The solvency assumptions have been updated to reflect market conditions at the valuation date. Emerging experience will affect the funded position of the Plan.

After checking with representatives of Enbridge Gas Distribution Inc., to the best of our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation.

Comments made in our report on the actuarial valuation of the Plan as at December 31, 2009 regarding the Ontario Court of Appeal's decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* and Supreme Court of Canada dismissal of the appeal in Monsanto Canada Inc. versus Superintendent of Financial Services ("*Monsanto*"), as well as other similar decisions, continue to apply to this report.

2

Valuation Results

Going-concern Financial Position

The plan's estimated financial position as at January 1, 2011 on a going-concern basis, in comparison with that shown in the last filed actuarial valuation at December 31, 2009, are summarized as follows:

	01.01.2011	12.31.2009
Assets		
Market value of assets	$734,426,000	$698,698,000
Going-concern funding target		
▪ active and suspended members	$356,767,600	$308,389,300
▪ pensioners and survivors	$321,634,900	$326,142,300
▪ deferred pensioners	$7,593,000	$7,003,400
Total	$685,995,500	$641,535,000
Funding excess (shortfall)	$48,430,500	$57,163,000
Assets over funding targets	107%	109%

Reconciliation of Financial Status

Funding excess (shortfall) as at previous valuation	$57,163,000
Interest on funding excess (funding shortfall) at 6.00% per year	$3,429,800
DB contributions drawn from funding excess, with interest	($15,129,500)
DC contributions drawn from funding excess, with interest	($1,446,500)
Net investment return different than expected	$26,058,700
Impact of changes in assumptions and methods	($21,645,000)
Funding excess (shortfall) as at current valuation	$48,430,500

Solvency Financial Position

The plan's estimated solvency position as at January 1, 2011, in comparison with that shown in the last filed actuarial valuation at December 31, 2009, are summarized as follows:

	01.01.2011	12.31.2009
Assets		
Market value of assets	$734,426,000	$698,698,000
Termination expense provision	($600,000)	($600,000)
Solvency assets	$733,826,000	$698,098,000
Solvency liabilities before exclusion of benefits:		
▪ active and suspended members	$437,831,700	$380,226,900
▪ pensioners and survivors	$378,050,800	$384,153,400
▪ deferred pensioners	$9,113,600	$8,726,600
Total solvency liabilities before exclusion of benefits	$824,996,100	$773,106,900
Value of excluded benefits	($126,131,200)	($107,030,000)
Solvency liabilities	$698,864,900	$666,076,900
Surplus (shortfall) on a market value basis	$34,961,100	$32,021,100
Transfer ratio	0.89	0.90

Hypothetical Wind-up Financial Position

The plan's estimated hypothetical wind-up position as at January 1, 2011, in comparison with that shown in the last filed actuarial valuation at December 31, 2009, are summarized as follows:

	01.01.2011	12.31.2009
Assets		
Market value of assets	$734,426,000	$698,698,000
Termination expense provision	($600,000)	($2,000,000)
Wind-up assets	$733,826,000	$696,698,000
Hypothetical wind-up liabilities:		
▪ active and suspended members	$437,831,700	$380,226,900
▪ pensioners and survivors	$378,050,800	$384,153,400
▪ deferred pensioners	$9,113,600	$8,726,600
Total wind-up liability	$824,996,100	$773,106,900
Wind-up excess (shortfall)	($91,170,100)	($76,408,900)

Current Service Cost (December 31, 2009)

Based on the results of the last actuarial valuation filed as at December 31, 2009 and adjusted for the impact of the change in discount rate, the employer's DB current service cost until the next valuation date is set at 12.07% of members' pensionable earnings.

As such, the estimated employer DB current service cost for 2011 is as follows:

Estimated DB Current Service Cost

	2011
Estimated members' pensionable earnings	$132,322,700
Employer's DB current service cost as a percentage of members' pensionable earnings	12.07%
Estimated employer's DB current service cost	$15,977,500

Impact on Contribution Holidays

In accordance with Sections 7(3.1) and 7(3.2) of the *Ontario Pension Benefits Act Regulations*:

- Surplus identified in the most recently filed actuarial valuation can only be used to reduce contributions for current service cost if an administrator files, within the first 90 days of the fiscal year, an actuarial cost certificate for the fiscal year; and,
- The maximum amount of any surplus identified in the most recently filed actuarial valuation report that can be used in such manner is equal to the lesser of:
  - The amount, if any, by which the going concern assets reported in the actuarial cost certificate filed for the fiscal year exceed the sum of the estimated going-concern funding target liabilities as reported in the certificate ($48,430,500); and,
  - The amount, if any, by which the solvency assets reported in the actuarial cost certificate filed for the fiscal year exceed the sum of the estimated solvency liabilities as reported in the certificate ($34,961,100).

As the estimated employer DB current service cost (i.e. $15,977,500) is lower than the lesser of these two amounts (i.e. $34,961,100), in accordance with Section 7(3) of the *Ontario Pension Benefits Act Regulations* the contribution holiday can continue.

In addition, since the DB component of the Plan is fully funded on both going concern and solvency bases, subject to the *Ontario Pension Benefits Act Regulations,* the Plan terms and any collective or employment agreement, the Company may apply DB assets in satisfaction of its contribution requirements for the DC component of the Plan. DC contribution requirements for 2011 are estimated to be $1,439,900.

3

Actuarial Opinion

In our opinion, for the purpose of determining the estimated funded status of the Plan as at January 1, 2011:

- The membership data are sufficient and reliable.
- The assumptions are appropriate.
- The methods employed are appropriate and consistent with accepted actuarial practice in Canada.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada except that it does not include the following disclosures which were not required to be provided under our terms of the engagement with the Company:

- Sensitivity of the valuation results to a 1% decrease in the discount rate; and,
- The solvency incremental cost.

This report has been prepared in accordance with the funding and solvency standards set by the *Ontario Pension Benefits Act*.

Chris Heller
FCIA, FSA

March 31, 2011
Date

Allen Hornung
FCIA, FSA

March 31, 2011
Date

Appendix A

Plan Assets

The DB assets of the Plan are held in trust by CIBC Mellon. We have relied upon the unaudited fund statements provided by CIBC Mellon, for the period from December 31, 2009 to January 1, 2011.

The pension fund transactions for the period from December 31, 2009 to January 1, 2011 are summarized as follows:

Reconciliation of Plan Assets (Market Value)

	2010
January 1	$698,698,000
Adjustment to assets to reflect audited statements	$2,364,000
	$701,062,000
PLUS	
Company contributions	
▪ Current service	$0
▪ Special payments	$0
Investment income	$69,592,000
	$69,592,000
LESS	
Pensions paid	$29,305,000
Lump-sum refunds	$1,051,000
Transfers to DC	$1,405,000
Investment expenses	$2,733,000
Other expenses	$1,734,000
	$36,228,000
December 31	$734,426,000

We have tested the pensions paid, the lump-sum refunds and the contributions for consistency with the membership data for the plan members who have received benefits or made contributions. The results of these tests were satisfactory.

Investment Policy

The plan administrator last revised its Statement of Investment Policies and Procedures effective May 2007. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the DB component of the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The constraints on the DB component asset mix and the actual asset mix at the valuation date are provided for information purposes:

	DB Investment Policy			Actual Asset Mix as at January 1, 2011
	Minimum	**Target**	**Maximum**	
Canadian equities	18.0%	21.0%	24.0%	22.0%
Foreign equities	22.5%	31.5%	40.5%	30.9%
Fixed income – universe	19.5%	32.5%	35.5%	41.0%
Fixed Income – real return	7.0%	10.0%	13.0%	
Infrastructure	2.0%	5.0%	8.0%	5.9%
Cash and short term assets	0.0%	0.0%	5.0%	0.2%
		100%		100%

Appendix B

Actuarial Methods and Assumptions

Actuarial Methods – Going-concern Basis

Valuation of Assets

For this valuation, we have continued to use the market value of assets.

Valuation of Actuarial Liabilities

We have continued to use the same actuarial valuation method as was used in the last actuarial valuation of the Plan and summarized in Appendix C of our Report on the Actuarial Valuation for Funding Purposes of the Plan as at December 31, 2009, dated September 30, 2010.

For the purposes of this report, going concern liabilities of the plan and the estimated service costs were calculated at December 31, 2009 using the assumptions described below and then rolled forward from December 31, 2009 to January 1, 2011 using the expected growth in liabilities as a result of new service accruals, and actual benefit payments between these two dates.

Actuarial Assumptions – Going-concern Basis

The actuarial value of benefits is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary.

For purposes of this report, we have lowered the discount rate to 5.75% from 6.00% at December 31, 2009. All other assumptions used in our calculations were the same as those used in the most recent actuarial valuation of the Plan as at December 31, 2009. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The assumptions used in the most recent actuarial valuation of the Plan as at December 31, 2009 are described in detail in our actuarial valuation report as at that date. The following is a summary of the rationale for the discount rate change since the last valuation at December 31, 2009.

Discount rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy.
- Additional returns assumed to be achievable due to active equity management (net of related expenses).
- Implicit provision for expenses determined as the expected rate of investment and administrative expenses to be paid from the fund in the future.
- A margin for adverse deviations, based on the proportion of the Plan assets invested in equities and the excess return expected on equities, over government bond yields.

The discount was developed as follows:

Assumed investment return	6.61%
Active management	0.23%
Implicit expense provision	(0.50%)
Margin	(0.59%)
Net discount rate	5.75%

The previous valuation assumed a discount rate of 6.00%.

Actuarial Methods and Assumptions – Solvency Basis

With the exception of the assumptions summarized in the table on the following page, the assumptions and methods used in our calculations were the same as those used in the most recent actuarial valuation of the Plan as at December 31, 2009.

Basis for benefits assumed to be settled through a lump sum	
Non-indexed interest rate:	3.70% per year for 10 years, 5.00% per year thereafter
Partially-indexed (50%) interest rate:	2.80% per year for 10 years, 3.70% per year thereafter
Partially-indexed (55%) interest rate:	2.70% per year for 10 years, 3.60% per year thereafter
Maximum pension limit:	▪ $2,552.22 per year of service for members over age 55 ▪ $2,552.22 per year of service, projected forward to the age which maximizes value at 2.77% for 10 years, and 3.54% per year thereafter, for members under age 55
Basis for benefits assumed to be settled through the purchase of an annuity	
Non-indexed interest rate:	4.48% per year
Partially-indexed (50%) interest rate:	2.77% per year
Partially-indexed (55%) interest rate:	2.60% per year
Maximum pension limit:	▪ $2,552.22 per year of service for immediate annuities ▪ $2,552.22 per year of service, projected forward to the age which maximizes value at 2.77% for 10 years, and 3.54% per year thereafter, for deferred annuities

For the purposes of this report, solvency liabilities of the plan were calculated at December 31, 2009 using the assumptions described above and then rolled forward from December 31, 2009 to January 1, 2011 using the expected growth in liabilities as a result of new service accruals, actual pay increases, actual cost-of-living (COLA) increases granted to pensioners, and actual benefit payments between these two dates.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3800 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for January 1, 2011 for benefits expected to be settled through a lump sum transfer in accordance with relevant portability requirements.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities. However, there is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. Therefore, we have relied upon preliminary guidance from the Canadian Institute of Actuaries regarding appropriate annuity proxy discount rates as at January 1, 2011.

We have not included a provision for adverse deviation in the solvency and hypothetical wind-up valuations.

Appendix C

Employer Certification

With respect to the estimate of the financial position of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates, as at January 1, 2011, I hereby certify that, to the best of my knowledge and belief:

- a copy of the official plan documents and of all amendments made up to January 1, 2011, were provided to the actuary;
- the valuation reflects Enbridge's decisions in regards to determining the solvency funding requirements;
- the asset information summarised in Appendix A is reflective of the Plan's assets;
- all events subsequent to December 31, 2009 that may have an impact on the results of the valuation have been communicated to the actuary.

March 29, 2011
Date

Signed

SONIA HÉROUX
Name

MERCER

Mercer (Canada) Limited
222 - 3rd Avenue South West
Suite 1200
Calgary, Alberta T2P 0B4
403 269 4945

Consulting. Outsourcing. Investments.

The Retirement Plan for the Employees of Enbridge Inc. and Affiliates

The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates

Statement of Investment Policies and Procedures

Effective: June 1, 2011

TABLE OF CONTENTS

1.0 INTRODUCTION ---------- 1

2.0 DESCRIPTION OF PLANS ---------- 1

3.0 INVESTMENT GOALS AND OBJECTIVES ---------- 2

4.0 ASSET MIX POLICY AND INVESTMENT OPTIONS ---------- 2

5.0 EXPECTED INVESTMENT RETURN AND RISK OF DB INVESTMENTS ----- 5

6.0 INVESTMENT CATEGORIES, LIMITS & CONSTRAINTS, LIQUIDITY AND MONITORING & REPORTING ---------- 6

7.0 CONFLICTS OF INTEREST POLICY ---------- 10

8.0 SECURITIES LENDING, VOTING RIGHTS, VALUATION OF INVESTMENT AND RELATED PARTY TRANSACTIONS ---------- 12

9.0 ROLES AND RESPONSIBILITIES ---------- 13

1.0 INTRODUCTION

1.1 This Statement of Investment Policy and Procedures (the "Statement" or "SIP&P") provides policy guidelines for the management and investment of the assets of The Retirement Plan for the Employees of Enbridge Inc. and Affiliates ("EI Plan") and The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates ("EGD Plan"), together referred to herein as the "Plans". Participating employers in the Plans are referred to herein as the "Employers".

1.2 Benefits under the DB provisions of the Plans are funded, by the Employers, through separate trusts (the "Trusts"). Each of the Trusts hold interests in either a pooled fund or in direct investments. The Trusts will be maintained and valued on a monthly basis by the trustee / custodian. The assets attributable to the Employers are invested in units of the Trusts. Benefits under the DC provisions of the Plans are funded, by the Employers, through separate member accounts (the "DC Accounts"). Together the Trusts and DC Accounts are referred to herein as the "Pension Funds".

1.3 The Pension Funds exist to help ensure that pension benefits will be paid. The Board of Directors of Enbridge Inc. (the "Board") and the Board of Directors of Enbridge Gas Distribution Inc. have delegated to the Human Resources and Compensation Committee of the Board (the "HRCC") the authority to review, approve or make recommendations to the Board with respect to policies governing the investment of the assets of the Pension Funds. This Statement has been adopted and approved by the HRCC to ensure that the assets of the Pension Funds are managed prudently and effectively. The Pension Committee of Enbridge Inc. is responsible for ensuring that the assets of the Pension Funds are managed in accordance with this Statement.

2.0 DESCRIPTION OF PLANS

2.1 The Plans have both a defined benefit ("DB") and a defined contribution ("DC") provision.

2.2 The DB provisions of the Plans are non-contributory. The Employers contribute to the DB provisions of the Plans amounts determined by the Plans' actuary, in accordance with applicable legislation. The DC provisions of the Plans are non-contributory. The Employers contribute to the DC provisions of the Plans an amount based on a percentage of the DC member's earnings.

2.3 The DB pension benefit is based on final average earnings. Therefore, DB liabilities for employee members are expected to grow directly with the level of earnings and indirectly with inflation. The DC pension benefit will depend on the value of the investments in the DC member's account.

2.4 The DB provisions of the Plans provide for automatic annual increases in pensions equal to 50% of the increase in the Consumer Price Index. As a result,

DB pensions for retired members and beneficiaries will increase as a function of inflation.

2.5 The DB liabilities are not dependent on the value of DB assets. The assets provide security that pension benefits will be paid. DB members have a direct interest in the funded status of the plan, but they have no direct interest in the funds' investment return. The Employers have a direct interest in investment return on the DB assets as the return influences the level of the Employers' contributions. The Employers are required to make up any funded status shortfall that may result. The risk of poor investment performance for DB assets is borne by the Employers. The risk of poor investment performance for DC assets is borne by DC members.

3.0 INVESTMENT GOALS AND OBJECTIVES

3.1 The goals of the Pension Funds with respect to DB investments are:

(a) to help ensure that pension benefits are secured over time;
(b) to minimize the Employers' pension contributions by maximizing the long-term investment return on assets; and
(c) to keep short-term fluctuations in pension contributions within a range which is acceptable to the Employers.

3.2 The objective of the Pension Funds is to earn a return on total DB assets which is greater than the rate of return assumed by the actuary in calculating the Employers' required contributions to the DB provision of the Plan.

3.3 The goals of the Pension Funds with respect to DC investments are:

(a) to provide a range of diversified investment options with materially different risk and return characteristics; and
(b) to allow DC members to direct the investment of their pension assets among these different options so as to achieve their individual retirement needs and savings objectives.

4.0 ASSET MIX POLICY AND INVESTMENT OPTIONS

Asset Mix Policy for DB Investments

4.1 The target asset mix policy of the Pension Funds with respect to DB investments has been adopted after consideration of the following factors:

(a) the nature and structure of the DB liabilities; including the attribution of such liabilities between active and retired members;
(b) the going concern funded status and cash flow requirement of the Plans;
(c) the solvency funded status of the Plans;
(d) the investment horizon of the Plans;

(e) the Employers' risk tolerance, i.e. the operating environment and financial situation of the Employers and their ability to withstand fluctuations in pension contributions; and

(f) the future outlook of the economy and capital markets with respect to investment returns, volatility of returns and correlation between assets.

4.2 Subject to further amendment by the HRCC or the Board, the DB assets of the Pension Funds shall be allocated among the investment categories indicated below so that on average over time the market value invested in each category, when measured as a percentage of the total market value of the funds, shall be expected to equal the following target asset mix:

The Retirement Plan for the Employees of Enbridge Inc. and Affiliates

Asset Class		Investment Policy Weighting (%)
Fixed Income	Nominal	20.0%
	Real Return	10.0%
	Cash and Short Term Assets	0.0%
	Subtotal	**30.0%**
Equities	Canadian	25.0%
	Global	20.0%
	Emerging Markets	7.5%
	Subtotal	**52.5%**
Real Assets	Infrastructure	10.0%
	Real Estate	7.5%
	Subtotal	**17.5%**
Total Assets		**100%**

The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates

Asset Class		Investment Policy Weighting (%)
Fixed Income	Nominal	30.0%
	Real Return	10.0%
	Cash and Short Term Assets	0.0%
	Subtotal	**40.0%**
Equities	Canadian	21.0%
	Global	17.0%
	Emerging Markets	6.5%
	Subtotal	**44.5%**
Real Assets	Infrastructure	9.0%
	Real Estate	6.5%
	Subtotal	**15.5%**
Total Assets		**100%**

4.3 The actual allocation of the DB assets of the Pension Funds at any point in time, measured in terms of the market value of assets in each investment category as a percentage of the total market value of the DB assets of the respective Pension Funds, may differ from the target asset mix specified above but shall remain within the following minimum and maximum ranges:

The Retirement Plan for the Employees of Enbridge Inc. and Affiliates-

Asset Class		Minimum	Maximum
Fixed Income	Nominal	17.0%	23.0%
	Real Return	7.0%	13.0%
	Cash and Short Term Assets	0.0%	5.0%
Equities	Canadian	22.0%	28.0%
	Global	17.0%	23.0%
	Emerging Markets	4.5%	10.5%
Real Assets	Infrastructure	7.0%	13.0%
	Real Estate	4.5%	10.5%

The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates-

Asset Class		Minimum	Maximum
Fixed Income	Nominal	27.0%	33.0%
	Real Return	7.0%	13.0%
	Cash and Short Term Assets	0.0%	5.0%
Equities	Canadian	18.0%	24.0%
	Global	14.0%	20.0%
	Emerging Markets	3.5%	9.5%
Real Assets	Infrastructure	6.0%	12.0%
	Real Estate	3.5%	9.5%

4.4 As the Plans' obligations are denominated in Canadian dollars, the allocation to Global Equities, Emerging Market Equities, Infrastructure and Real Estate may result in volatility to investment returns from fluctuations in the value of the Canadian dollar relative to foreign currencies. In order to reduce this volatility, 50% of the foreign currency exposure resulting from investments in publicly traded Global Equities and Emerging Market Equities, and 100% of the foreign currency exposure resulting from investments in Infrastructure and Real Estate will be subject to currency hedging where practical

4.5 Rebalancing among DB asset classes will be performed on an objective basis by the Pension Committee or its delegate as the asset mix percentages approach the range limits noted in paragraph 4.3 are reached. The frequency of this rebalancing will be variable depending on relative performance, but is designed to systematically, without prejudice or bias, re-align the asset class weightings back to those targeted in paragraph 4.2, when one or more asset classes

approach their minimum or maximum range. The result of such rebalancing, net of transactions costs, should be to both reduce portfolio performance volatility and enhance performance in volatile capital market periods.

Investment Options for DC Investments

4.6 The investment options with respect to the DC investments of the Plans have been chosen after consideration of the following factors:

(a) the options should have materially different risk and return characteristics to allow DC members to meet a variety of investment objectives ranging from long-term growth in pension assets to stability of capital;
(b) the level of investment knowledge of the majority of DC members and their degree of comfort in managing their pension investments;
(c) the investment management style neutrality, to mitigate short-term periods of gross underperformance;
(d) the cost and complexity of the investment program; and
(e) the administration and record-keeping function for the DC investments of the Plans.

4.7 The DC assets of the Pension Funds may be invested among the investment options in the following asset categories:

(a) Canadian Equities;
(b) Foreign Equities;
(c) Bonds;
(d) Short-term Assets; and
(e) Retirement Date Funds (Balanced Funds).

4.8 The allocation of DC assets among the different investment options shall be determined by DC members for their individual account. DC members shall be provided with the opportunity to change the allocation of their investment on a daily basis, if possible, but no less frequently than at least once a quarter.

4.9 DC member investment education is important. Regular assessments will be made by the Pension Committee in regard to the success of education programs delivered to date and areas for improvement. Specific provisions for the nature and extent of these programs are not explicitly noted in this Statement; however these provisions shall be appropriately robust, including industry best practices.

5.0 EXPECTED INVESTMENT RETURN AND RISK OF DB INVESTMENTS

5.1 If the DB assets of the Plans are invested according to the target asset mixes specified above, the nominal returns on total DB assets are expected to be 7.3% and 6.8% per year for the EI Plan and EGD Plan respectively. These exceed the return assumed by the actuary by 1.55% and 1.05% respectively. These returns

are expected over longer periods of time, generally in excess of four year moving periods.

5.2 The Plans' actuary currently uses a nominal valuation rate of 5.75% when calculating the value of benefits promised by the DB Plans and the required contributions by the Employers. If the Funds' nominal return, on a smoothed basis, is greater than 5.75% over a given period, the actuarial valuation will reveal a funding gain attributable to investment performance. Conversely, if the Funds' nominal return, on a smoothed basis, is less than 5.75% the actuarial valuation will reveal a funding loss attributable to investment performance. The excess returns noted above builds in funding conservatism, which acts to mitigate short-term periods of volatility and associated investment risk.

6.0 INVESTMENT CATEGORIES, LIMITS & CONSTRAINTS, LIQUIDITY AND MONITORING & REPORTING

6.1 This section sets forth investment constraints and limits, which are established in conjunction with risk management parameters. The constraints and limits are intended to be used as meaningful guidelines, rather than rigid rules. Investments made outside of the constraints and limits require prior approval of the Pension Committee and are continually reportable until remedied.

6.2 The Pension Committee has retained the services of specialist investment managers to invest the assets of the Pension Funds. The Pension Funds shall be managed, using both active and passive investment strategies, if available, for both DB and DC assets. The Pension Committee expects active investment strategies to add value in less efficient asset classes and recognizes that they may increase investment risk. The Pension Committee believes that the potential for higher investment returns in less efficient asset classes justifies the increase in investment risk. In more efficient asset classes, the Pension Committee believes that a combination of active and passive management should be used.

6.3 The Pension Funds shall be managed in accordance with applicable legislation including the Federal Pension Benefits Standards Act 1985 and Regulations, or the Ontario Pension Benefits Act and Regulations, as applicable, the Income Tax Act and all other applicable legislation as amended from time to time. The investments of the Pension Funds shall comply with the guidelines specified below. The guidelines apply to the total assets of the Pension Funds as well as the assets managed by each investment manager.

6.4 Each investment manager shall observe the CFA Institute Code of Ethics and Standards of Professional Conduct in managing the assets of the Pension Funds. In taking an investment action, the managers shall take into account: (a) the needs and circumstances of the Plans; (b) the basic characteristics of the investment involved; and (c) the basic characteristics of the Pension Funds.

Investment Categories

6.5 The Pension Funds may invest, either directly through segregated portfolios or indirectly through pooled funds, in the following investment categories, whether by way of market purchases, private placements, initial public offerings, or otherwise:

Equities

(a) common shares, preferred shares, and securities with equity characteristics, including, but not limited to, American Depository Receipts, Global Depository Receipts, participation notes and local access products;
(b) securities convertible into common shares;
(c) Exchange Traded Funds and Income Trusts;
(d) partly paid securities, subject to holding cash to cover the unpaid portion;
(e) securities in nonbenchmark countries, including but not limited to Emerging Markets countries;
(f) rights and warrants attached to permitted investments;
(g) other rights and warrants, but only after prior approval of the Pension Committee;

Real-Estate

(h) Indirect domestic or foreign real estate investment via independently managed pooled funds limited partnerships, specialist corporate structures, or real estate investment trusts (REITs);

Infrastructure

(i) Indirect domestic or foreign Infrastructure investment via independently managed pooled funds, limited partnerships, or specialist corporate structures;

Long-term Fixed Income

(j) bonds and debentures;
(k) mortgages and mortgage-backed securities;
(l) asset-backed securities;
(m) preferred shares;

Cash and Short-term Assets - with a maturity of one year or less

(n) cash on hand, demand deposits and term deposits;
(o) treasury bills and other government paper;
(p) short-term notes;
(q) bankers' acceptances;

(r) commercial paper; and
(s) guaranteed investment certificates.

6.6 The Pension Funds may use the following types of derivative instruments:

(a) futures and options contracts which trade on recognized exchanges and which are based on a security, index or currency related to the holdings of the Pension Funds;
(b) currency spot and forward contracts, and futures, options and options on futures on currencies;
(c) interest rate, equity and currency swap contracts; and
(d) equity linked notes.

These derivative instruments may only be used by an investment manager to replicate a passive investment in a market index, to manage the allocation of investments across assets, markets and currencies and to hedge Pension Fund currency and capital depreciation risk. They shall not be used: (a) for speculative purposes, (b) to create undue risk in the Pension Funds; and (c) unless they are more efficient and cost-effective than the equivalent transactions would be in the cash market.

For greater clarity, when used in an active currency hedge mandate, both long and short currency derivatives are required to reduce the exposure of the Plan assets to foreign currency movements. For all other purposes and uses, derivatives should be employed in a long investment strategy only, unless otherwise justified above.

6.7 The Pension Funds may hold any part of the portfolio in one or more pooled funds provided that such funds are expected to be operated within constraints reasonably similar to those described in this SIP&P. It is recognized that complete adherence to this SIP&P may not be entirely possible; at which point the investment guidelines or equivalent rules governing the pooled fund would override this SIP&P.

6.8 While the Pension Funds may hold units of pooled funds, which in turn hold shares of any of the Employers or their affiliates, the Pension Funds shall not otherwise directly invest in the securities of the Employers or their affiliates.

Investment Limits and Constraints

Equities

6.9 The market value of an investment in any one issuer, recognizing inter-company holdings and including both debt and equity, shall not exceed 7.5% of the market value of the total Pension Funds.

Fixed Income

6.10 The market value of fixed income securities of any one issuer (with the exception of securities issued or guaranteed by the Government of Canada or one of the Provinces of Canada) shall not exceed 5% of the total market value of all fixed income assets.

6.11 The market value of fixed income securities payable in a currency other than the Canadian dollar shall not exceed 20% of the total market value of all fixed income assets.

6.12 The market value of fixed income securities issued or guaranteed by the Government of Canada or a Province of Canada must not be less than 25% of the total market value of all fixed income assets.

6.13 The market value of municipal bonds shall not exceed 25% of the total market value of all fixed income assets.

6.14 The market value of corporate bonds shall not exceed 60% of the total market value of all fixed income assets. The market value of corporate bonds rated in the range BBB- to BBB+, by the Dominion Bond Rating Service or equivalent, shall not exceed 15% of the total market value of fixed income assets, on an individual manager mandate basis.

6.15 The Nominal Return Securities shall be managed with a target strategic weighting of 50% corporate bonds and 50% government bonds with a minimum and maximum of +/- 5% from this weighting. Rebalancing between corporate and government bonds will be performed on an objective basis as the bond percentages approach the +/- 5% range limits. The frequency of this rebalancing will be variable depending on relative performance, but is designed to systematically, without prejudice or bias, re-align the bond weightings back to the target strategic weighting. The Pension Committee can approve a deviation from the target strategic weighting, for example in instances where corporate spreads are at abnormally high or low levels, and it is deemed reasonable to assume corporate spreads will revert to more normal levels,

6.16 In addition to the 10% asset allocation to Real Return Securities for the Pension Funds, the market value of inflation-indexed or real return securities held in fixed income portfolios can be up to 10% of the total market value of all assets in fixed income portfolios.

6.17 The market value of private placements shall not exceed 15% of the total market value of all fixed income assets.

6.18 All securities must be rated BBB- or higher at the time of purchase by the Dominion Bond Rating Service or equivalent. The overall fixed income portfolio, on an individual manager mandate basis, must maintain a minimum rating of A.

6.19 Foreign fixed income securities must be rated by local rating services at levels comparable to those for Canadian fixed income securities specified above.

6.20 Mortgages must be National Housing Act (NHA) or similar insured mortgages unless prior approval has been given by the Pension Committee.

6.21 If an investment is downgraded, subsequent to its purchase or acquisition, to a rating level below BBB-, the manager must either receive the approval of the Pension Committee to continue to hold the downgraded security or sell the investment at the first reasonable opportunity.

Liquidity of Investments

6.22 Pension benefits are paid from the assets of the Pension Funds. The investment categories, limits and constraints above have been established with due regard for the need to maintain appropriate liquidity of investments for payment of pension benefits. Liquidity is provided by a) investing in readily marketable financial assets such as public equities and debt instruments, b) placing limits on illiquid investments, c) placing limits on private placements, and by d) placing constraints on the credit quality of fixed income securities.

Monitoring and Reporting

6.23 The Pension Committee shall submit an annual pension report to the HRCC, which outlines compliance with the terms of this Statement, the financial position of the Plans and investment performance attribution. During the year, information updates on any significant investment performance issues will be provided to the HRCC.

7.0 CONFLICTS OF INTEREST POLICY

7.1 This conflict of interest policy applies to:

(a) any employee of the Employers or an affiliated company involved in the management, administration or decision making process relating to the investments of the Plans and/or relating to the selection, appointment, review or replacement of the investment managers of the Plans; and

(b) an investment manager, with respect only to the investments of the Plans managed by the investment manager, or an employee or agent of the investment manager who is directly involved in the recommendation or selection of investments of the Plans.

7.2 A conflict of interest arises under the following conditions:

(a) when any person listed in Section 7.1:

(i) receives a material benefit from any investment, or from an actual or proposed contract with the issuer of any security, which is part of the investments of the Plans,

(ii) is a member of the board of directors, or similar body, or an officer or employee of an entity which is an issuer of any security which is part of the investments of the Plans, or

(iii) has material beneficial ownership of or control over any security or investment which is part of the investments of the Plans; or

(b) when any person listed in Section 7.1 (a) receives a material benefit from, or is a member of the board of directors, or similar body, or an officer or employee of an entity, or has any material beneficial ownership of or control over any investment manager of the Plans.

7.3 For the purposes of this conflict of interest policy:

(a) a security or investment shall be considered to be part of the investments of the Plan if: (i) it is already included in the investments of the Plans; or (ii) the decision to purchase or acquire the security or investment has been made;

(b) "material benefit" is one that could reasonably be expected to impair the ability of any person listed above to make unbiased and objective decisions with respect to the investments of the Plans;

(c) "material beneficial ownership or control" means either:

(i) ownership of or control over at least 10% of the issued and outstanding securities of a class or series of an issuer, the securities of which are included in the investments of the Plans, or either of them, or

(ii) ownership of or control over securities of which a class or series is included in the investments of the Plans, or either of them, comprising 10% or more of the assets beneficially owned or controlled by a person listed above in Section 7.1.

Notwithstanding the guidelines in (i) and (ii) above, a conflict of interest can exist if the extent of beneficial ownership or control is less than these percentage thresholds; and

(d) a security or investment is beneficially owned if it is owned by a person listed above or a member of his or her immediate family (spouse, children and dependent relatives) or if it is in a trust which includes as its beneficiaries that person or his or her immediate family.

7.4 Any person listed above who has a conflict of interest shall disclose the nature and extent of the conflict of interest in writing to the Pension Committee on first becoming aware of the conflict. The person disclosing the conflict shall not participate in the activities related to the issue in conflict without the express prior written consent of the Pension Committee.

7.5 The notification made by an individual with respect to a conflict of interest shall be considered a continuing disclosure of that conflict, subject to any future notification by that individual, for the purpose of the disclosure requirements of the conflict of interest policy, that he or she no longer has such conflict.

8.0 SECURITIES LENDING, VOTING RIGHTS, VALUATION OF INVESTMENTS AND RELATED PARTY TRANSACTIONS

Securities Lending

8.1 The Plans may enter into any securities lending agreement under which the loans are secured by cash or readily marketable investments having a market value of at least 102% for Canadian and US securities and 105% for non Canadian and non US securities. This amount must be maintained and marked-to-market on a daily basis.

Voting Rights

8.2 The investment managers are delegated the responsibility of exercising all voting rights acquired through the investment of the Plans' assets. Each manager shall exercise the voting rights with the intention of achieving the goals and objectives of the Plans.

8.3 The Pension Committee reserves the right to provide specific direction on the exercising of any voting rights. The investment managers are charged with the responsibility of bringing special voting matters to the attention of the Pension Committee as they arise.

Valuation of Investments

8.4 The valuation of investments held by the Plans that are regularly traded will be based on the market value.

8.5 The investment manager must notify the Pension Committee of any investments which are not regularly traded. For these investments the valuation will be based on fair value as determined by an independent pricing service or by the custodian. The fair value can be book value where deemed appropriate by the pricing service or custodian. Book value will be used where required by applicable legislation and regulatory policy.

Related Party Transactions

8.6 For the purpose of this section, a "related party" and a "transaction" in respect of the Plans have the meanings given to such terms in Schedule III of the Pension Benefits Standards Regulations, 1985 (Canada). The following related party transactions are permitted for the Plans:

(a) any transaction that is required for the operation or administration of the Plans, the terms and conditions of which are not less favourable to the Plans than market terms and conditions; and

(b) any purchase of securities of a related party, as allowed by Section 6.8, provided that those securities are acquired through the facilities of a public securities exchange recognized under the Pension Benefits Standards Act and Regulations, 1985 (Canada).

9.0 ROLES AND RESPONSIBILITIES

9.1 The duties of the HRCC, the Pension Committee and their respective agents are explicitly noted under separate Terms of Reference.

BOMA INTERROGATORY #9

INTERROGATORY

Mercer Report.

The Report states, on page 4, that the December 31 plan balance and minimum funding requirement for 2012 were estimated based on economic conditions at August 31, 2011. How would the study's conclusions change if the calculations were done based on economic conditions prevailing on October 31, 2011?

RESPONSE

As long as the plan is expected to be in a deficit position, which it is for October 31, 2011, the funding requirements in 2012 would not change. The funding requirements triggered are the minimum requirements which are equal to the service costs and the service cost is not dependant on the size of the deficit.

The service cost has been calculated using membership data from the 2010 Valuation. Therefore the funding requirements could change from the estimated $16.6M when the cost certificate is prepared using current membership data, however, it will not change due to the size of the deficit.

Witnesses: S. Kancharla
R. Lei
A. Patel

3 – CCC

CCC INTERROGATORY #1

INTERROGATORY

Please indicate if EGD has changed in any way the way in which it forecasts customer additions and average use relative to the last rate adjustment proceeding. If there have been changes please explain what they are, and the rationale for the changes.

RESPONSE

EGD's methods for forecasting customer additions and average use have not changed relative to the last rate adjustment proceedings.

Witness: F. Ahmad

CCC INTERROGATORY #2

INTERROGATORY

(B/T2/S5/p. 3)

Please explain, in detail, how EGD's ratepayers have benefited from the current pension reporting requirements.

RESPONSE

The EGD RPP has been in a surplus for an extended period of time which has meant that there has been no need for contributions to the plan thus eliminating the need to recover pension costs (arising from such contributions) in the revenue requirement.

Witnesses: S. Kancharla
R. Lei
A. Patel

CCC INTERROGATORY #3

INTERROGATORY

(B/T2/S5/p. 4)

Pension costs are a cost of operating the distribution business. Please explain why EGD's management has not been able to "control" this cost. Please explain why EGD has not been able to "manage a growing pension obligation due to employee services rendered."

RESPONSE

As outlined in Exhibit B, Tab 2, Schedule 5, paragraphs 19 and 20, EGD manages its pension plan over the long term. As a result it is unable to control the annual pension costs as managing pension costs on a short term basis would compromise the long term objects of the plan. Furthermore, the plan deficit primarily results from external economic factors that are not controllable by EGD.

The market forces of lower returns on invested assets and lower discount rates relating to future obligations has had the dual effect of retarding the growth of invested assets coupled with an increase in the present value of future obligations. The combined effect of this is the creation of a deficit, which in turn triggers a contribution requirement resulting in added costs.

Furthermore, due to a new regulation introduced on June 23, 2009 relating to the requirement for an annual cost certificate, EGD no longer has a guaranteed three year contribution holiday if the annual cost certificate shows a plan deficit. Since the plan is managed on a long term basis EGD does not have the ability to control costs as investment mandates are set with a long term view.

Witnesses: S. Kancharla
R. Lei
A. Patel

CCC INTERROGATORY #4

INTERROGATORY

(B/T2/S5/p. 8) Please provide on an annual basis for the years 2007-2011 the extent to which EGD's long term and short-term debt costs (embedded in rates) have varied from its actual debt costs.

RESPONSE

The attached Table 1 provides the financing costs as approved in 2007 and as incurred in 2008, 2009, and 2010. Actuals for 2011 are not available; an estimate of the costs will be filed in EGD's 2013 rate application.

Witnesses: K. Culbert
S. Murray

Table 1

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		2007 Board Approved			**2008 Actual**			**2009 Actual**			**2010 Actual**		
		Principal	Cost Rate	Interest Cost	Principal	Cost Rate	Interest Cost	Principal	Cost Rate	Interest Cost	Principal	Cost Rate	Interest Cost
		($M)	%	($M)	($M)	%	($M)	($M)	%	($M)	($M)	%	($M)
1.	Long term debt	2,234.4	7.31	163.3	2,311.8	6.98	161.4	2,180.4	6.90	150.4	2,190.7	6.77	148.3
2.	Short term debt	62.9	4.12	2.6	6.9	3.44	0.2	148.0	1.66	2.5	165.4	1.61	2.7
3.	Sub-total	2,297.3		165.9	2,318.7		161.6	2,328.4		152.9	2,356.1		151.0
4.	Fixed financing cost			0.5			0.7			6.5			4.8
5.	Total			166.4			162.3			159.4			155.8

CCC INTERROGATORY #5

INTERROGATORY

(B/T2/S6) Please provide any correspondence between EGD and Union Gas regarding Cross Bores/Sewer laterals. Specifically, please provide any correspondence between the two companies regarding Z-factor treatment of these costs.

RESPONSE

There has not been any correspondence between the two companies regarding the Z factor treatment of costs associated with Cross Bores/Sewer laterals. Enbridge and Union have shared communication materials and process information in order to ensure consistency of programs across our respective franchises.

Witnesses: C. Clark
L. Lawler

CCC INTERROGATORY #6

INTERROGATORY

(B/T2/S6/p. 5) What has been the cost to EGD of repairing the 44 sewer laterals? What has been the number of these repairs in each year since 2007?

RESPONSE

Please see the response to BOMA Interrogatory #5 at Exhibit I, Tab 2, Schedule 5.

Year	Number of Sewer Lateral/Cross Bore Repairs
2008	2
2009	4
2010	24
2011 YTD	11

Witnesses: C. Clark
L. Lawler

CCC INTERROGATORY #7

INTERROGATORY

B/T2/S6) For 2011 was the projected cost set out in EGD's 2011 rate adjustment application and what are the actual costs to date?

RESPONSE

Sewer Safety Program costs were not included in EGD's 2011 rate adjustment application. The actual costs to date are described in the response to BOMA Interrogatory #5 at Exhibit I, Tab 2, Schedule 5.

Witnesses: C. Clark
L. Lawler

CCC INTERROGATORY #8

INTERROGATORY

(B/T2/6/p. 13) Please provide a detailed explanation as to how the $2.377 million in was calculated. Please provide all assumptions.

RESPONSE

This number relates to “Emergency Natural Gas Sewer Safety Inspection”. Actual Sewer Safety Inspection requests from 2010 and 2011 by operating area were used to project the requests anticipated for 2012. The unit costs for each area in existing contractor service agreements vary by time of day service area, volume and location. An average cost was then multiplied by the forecasted call volume to arrive at the total projected cost.

Witnesses: C. Clark
L. Lawler

CCC INTERROGATORY #9

INTERROGATORY

(B/T2/S6) What is the projected annual cost to deal with the Cross Bore/Sewer Lateral issue for the next 5 years?

RESPONSE

The following table represents the forecast of O&M and capital expenditure costs associated with the cross bore / sewer lateral program for 2012 and 2013.

The Company respectfully declines to provide a forecast for the time period(s) beyond 2013.

Please note that this presentation is not on a revenue requirement basis.

Table 1

	2012	2013
O&M	3,681,707	3,725,887
Capital	2,091,118	1,350,793
	5,722,825	5,076,680

Witnesses: C. Clark
L. Lawler

CME INTERROGATORY #1

INTERROGATORY

FORECAST OF CUSTOMER ADDITIONS
Reference: Exhibit B, Tab 1, Schedule 2, page 1
Exhibit B, Tab 1, Schedule 4

Assume that each of the categories of Customer Additions used by EGD in its forecast has been underestimated by 5%. Please provide a schedule that will show the sensitivity of the 2012 delivery Revenue Requirement of $839.99M, shown at line 18 of Exhibit B, Tab 1, Schedule 2, page 1, to this reduced level of Forecast Customer Additions.

RESPONSE

The Company's proposed 2012 Distribution Revenue Requirement ("DRR") of $1,024.9 million would decrease or increase by approximately $0.4 million if the forecast customer additions underpinning the DRR was decreased or increased by 5%. Such a change in revenue requirement would have a negligible effect on the rate for all customer classes compared to those proposed at Exhibit B, Tab 3, Schedule 1, page 3.

Witnesses: K. Culbert
A. Kacicnik
D. Small

CME INTERROGATORY #2

INTERROGATORY

FORECAST OF CUSTOMER ADDITIONS
Reference: Exhibit B, Tab 1, Schedule 2, page 1
Exhibit B, Tab 1, Schedule 4

To what extent, if any, would the delivery rate impacts, shown at Exhibit B, Tab 3, Schedule 1, page 3, change with the foregoing reduced level of Forecast Customer Additions.

RESPONSE

As indicated in the response to CME Interrogatory #1 at Exhibit I, Tab 4, Schedule 4, the impact on the proposed 2012 revenue requirement resulting from the change in forecast customer additions would be a decrease of approximately $0.4 million. This would have a negligible effect on the rates for all customer classes compared to those proposed at Exhibit B, Tab 3, Schedule 1, page 3.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

CME INTERROGATORY #3

INTERROGATORY

POWER GENERATION Y FACTOR
Reference: Exhibit B, Tab 2, Schedule 1, page 1; Appendix A, pages 1 to 5

Is the list of Power Generation facilities described in paragraph 3 of Exhibit B, Tab 2, Schedule 1, at page 1 complete? If not, then list any other Power Generation facilities that fall within the ambit of the Y factor.

RESPONSE

Yes, the list is complete with respect to Y factor treatment.

Witnesses: K. Culbert
A. Kacicnik

CME INTERROGATORY #4

INTERROGATORY

POWER GENERATION Y FACTOR
Reference: Exhibit B, Tab 2, Schedule 1, page 1; Appendix A, pages 1 to 5

For each of the facilities that fall within the ambit of the Y factor, please provide details of the delivery service each facility acquires from EGD, and provide a schedule that will show the annual revenues that EGD has either received or expects to receive from each facility for each of the years 2008 to 2020 inclusive.

RESPONSE

EGD provides unbundled distribution service under Rate 125 (Extra Large Firm Distribution Service) to each power generation facility within the ambit of the Y factor.

The distribution revenues, in an aggregated format for the three facilities, are shown in the table below for the 2008 to 2012 period.

Year	2008	2009	2010	2011	2012
Total ($M)	1.8	3.1	3.9	3.8	6.3

Note: The pipeline serving the York Energy Centre will be in service for the entire 2012, which is reflected in the derivation of the Y factor amount for 2012. However, the facility will commence commercial operation on May 1, 2012 at which point it will start paying Rate 125 demand charges to EGD. This timeline for pipeline construction and commercial operation of the facility is committed to in the 20-year contract between the two parties. The time gap between the pipeline in-service date and the commercial operation of the power plant will allow the plant to test their equipment and processes. If the York Energy Centre power plant operated commercially for the entire 2012, the forecasted 2012 distribution revenues would then equal to $7.5 M.

The distribution revenues the Company will receive from the three power generation customers for the 2013 to 2020 period will be a function of the changes/increases in Rate 125 Contract Demand (“CD”) charges (i.e., the CD level for each facility is stipulated in its contract with EGD and remains fixed until the end of the 20-year contract). As an illustration only, should Rate 125 CD charge remain frozen at the 2012 level through 2020, then the Company would receive $7.5 M in distribution revenues

Witnesses: K. Culbert
A. Kacicnik
S. Murray
J. Sim

from the three customers in 2013 (i.e., in 2013 the York Energy centre will operate commercially for the entire year) and would continue to receive $7.5 M in each year between 2014 and 2020.

Witnesses: K. Culbert
A. Kacicnik
S. Murray
J. Sim

CME INTERROGATORY #5

INTERROGATORY

POWER GENERATION Y FACTOR
Reference: Exhibit B, Tab 2, Schedule 1, page 1; Appendix A, pages 1 to 5

Are all of the revenues EGD receives from each of the power facilities that fall within the ambit of the Y factor included in the Revenue Requirement calculations found at Exhibit B, Tab 2, Schedule 1, Appendix A, pages 1 to 5? If not, then please provide the rationale for their exclusion.

RESPONSE

No revenues are included in the derivation of the Y factor amounts for power generation projects or Y factors amounts for gas in storage related carrying costs, DSM, and CIS/Customer Care. Y factor amounts represent forecast revenue requirement, or costs, to be recovered in rates.

As highlighted above the Y factor for power generation projects derives the annual revenue requirement (i.e., costs) to be recovered in 2012 for these projects. The application of the IRM escalation formula together with Y and Z factor revenue requirement amounts determine the total level of 2012 revenue requirement as shown at Exhibit B, Tab 1, Schedule 2, page 1, Col. 1. Subsequently, through the rate design process, which adheres to the Board approved principles and conventions, rates and revenues are set to recover the total 2012 revenue requirement.

The 2012 Y factor revenue requirement, inclusive of allowed returns, for the Portlands Energy Centre, Thorold Cogen, and the York Energy Centre projects, equals $6.6 million as shown at Exhibit B, Tab 1, Schedule 2, page 1, Row 22, Col. 1.

The revenue from the three power generation customers from above is part of the $9.8 million in revenue the Company proposes to recover from five Rate 125 customers in 2012 as shown at Exhibit B, Tab 3, Schedule 5, page 1, Item 7, Col. 4.

The $9.8 million in Rate 125 revenues is part of the $2,544.3 million in total revenue the Company proposes to recover in 2012 as shown at Exhibit B, Tab 3, Schedule 5, page 1, Item 16, Col. 4.

Witnesses: K. Culbert
A. Kacicnik
S. Murray
J. Sim

The total 2012 revenue of $2,544.3 million equals the total 2012 revenue requirement of $2,544.3 million shown at Exhibit B, Tab 1, Schedule 2, page 1, Row 29, Col. 1.

The derivation of Y factor revenue requirement for power generation projects and the recovery of the same through rates are fully compliant with the Company's Incentive Regulation Settlement Agreement in EB-2007-0615.

Witnesses: K. Culbert
A. Kacicnik
S. Murray
J. Sim

CME INTERROGATORY #6

INTERROGATORY

POWER GENERATION Y FACTOR
Reference: Exhibit B, Tab 2, Schedule 1, page 1; Appendix A, pages 1 to 5

What economic feasibility analysis did EGD conduct with respect to its attachment of each of these Power Generation projects? For each facility, please provide calculations showing the Profitability Index ("PI") that results from an economic feasibility analysis of the attachment of each facility. Please include therein the time horizon used to evaluate the economic feasibility of attaching each facility to EGD's distribution network.

RESPONSE

The economic feasibility of the projects was conducted using the Discounted Cash Flow ("DCF") methodology as set out in the "Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario" and the "EBO 188: Natural Gas System Expansion, Report of the Board" dated January 1998.

The economic feasibility analysis for the Portlands Energy Centre yielded a Profitability Index (PI) = 1.0 after a contribution in aid of construction. The economic feasibility for Thorold Cogen yielded a Profitability Index (PI) = 1.0. The economic feasibility analysis for the York Energy Centre yielded Profitability Index (PI) = 1.0 after a contribution in aid of construction. The three projects satisfied the economic feasibility criteria in accordance with the Board's approved procedures as established in EBO 188: Natural Gas System Expansion, Report of the Board.

The economic feasibility analyses for the three projects were filed as part of Leave to Construct ("LTC") Applications. They are appended to this interrogatory response together with the Board's Decision and Order for each application.

The economic feasibility analysis for each of the projects was conducted over a 20 year horizon.

The economic feasibility of each project is updated once project costs are final to ensure a PI=1.0.

Witnesses: K. Culbert
A. Kacicnik
S. Murray
J. Sim

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0305

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order pursuant to Section 90(1) of the *Ontario Energy Board Act, 1998,* granting leave to construct natural gas pipelines in the City of Toronto.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Enbridge Gas Distribution Inc. ("Enbridge") filed an application with the Ontario Energy Board on December 7, 2006, under section 90 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c.15, Schedule B, for an Order for Leave to Construct natural gas pipelines for the purpose of supplying gas to the already approved Portlands Energy Centre generating station ("Portlands") in the City of Toronto. Construction is scheduled to start in the summer of 2007, with a planned in-service date of February 2008.

For the reasons set out below, the Board finds the construction of the proposed pipelines to be in the public interest and grants the Leave to Construct on the terms and conditions set out in this Decision.

Filed: 2011-11-16
EB-2011-0277
Exhibit I
Tab 4
Schedule 6
Attachment A
Page 2 of 21

The Proposed Pipelines

The project involves the construction of two sections of pipeline. The north section consists of approximately 6.5 kilometres of pipeline parallel to a portion of Enbridge's existing Don Valley Line. The south section consists of approximately 2.9 kilometres of pipeline that would interconnect the Don Valley Line at Enbridge's station B regulator station and end at Portlands.

The north section route is located primarily on land in the former Hydro One corridor currently owned by Enbridge (north of Sheppard Avenue to the north limit of Highway 401) and the Hydro One corridor presently owned by the Ontario Realty Corporation ("ORC") (from the south limit of Highway 401 to Eglinton Avenue). The majority of the south section is on land located on road allowances with the exception of certain locations owned by the City of Toronto Economic Development Corporation, the Toronto Port Authority and Ontario Power Generation Inc.

Maps showing the location of the two proposed pipelines are attached as Appendix "A".

The Parties

Three parties requested and were granted Intervenor status: Portlands Energy Centre, Toronto Economic Development Corporation ("TEDCO") and Union Gas Limited ("Union"). A late Intervenor status was granted to Mr. Paul Beatty, a resident of Scarborough, whose residence bordered to the eastern boundary of the northern section of the pipeline project. Mr. Beatty opposed the proposed location of the pipeline. The other Intervenors generally supported the project although TEDCO had concerns with certain aspects of the form of easement agreement. Both these matters are dealt with later in this Decision.

The Board granted Observer status to the City of Toronto ("the City"), Mr. John Butler and Mr. David Elder, both local residents. The City requested undertakings from Enbridge with respect to the type of drawings to be provided. That request will be dealt with later in this Decision.

Board Staff Counsel made written submissions on the legal test to be applied in Applications for Leave to Construct under sections 90 and 91 of the Act, which were circulated to the Applicant and all Intervenors. Board Staff Counsel also submitted proposed conditions of approval.

The Board also received a letter of comment from Mr. Peter Tabuns, MPP for Toronto-Danforth and Mr. Jack Layton, MP for Toronto-Danforth and the Toronto Energy Coalition ("TEC") and a letter of comment from Ms. Christine Becker, an affected resident. TEC requested that the Board deny the Application based upon the emissions that would be created by the generating facility. Ms. Becker commented on the public consultation and notification and on the proposed location of the pipeline.

The Public Interest Test

This is an Application under section 90 of the Ontario Energy Board Act seeking a Leave to Construct Order with respect to two natural gas pipeline projects. Section 96 of the Act provides that the Board shall make an Order granting leave if the Board finds that "the construction, expansion or reinforcement of the proposed work is in the public interest". When determining whether a project is in the public interest, the Board typically examines the need for the project, the economics of the project, the environmental impact and the impact on land owners. Each of these factors will be considered in turn.

The Need for the Project

Portlands is in the process of constructing a new 550 Megawatt high-efficiency natural gas fired generation plant and has signed a 20 year Accelerated Clean Energy Supply agreement with the Ontario Power Authority. The anticipated construction cost is $730 million with an initial in-service date of June 1, 2008. When fully complete, the Portlands facility will be capable of providing 25% of Central Toronto's electricity needs (Ex. A, Tab 3, Schedule 4, p. 2 of 4).

Enbridge and Portlands have entered into a 20 year gas delivery agreement (Ex. A, Tab 3, Schedule 5) based upon the Board approved Rate 125[1]. The hourly contract demand is 116 079 m^3 and the daily demand for the Portlands is 2 785 885 m^3. In addition, the customer requires a minimum pressure of 200 psi or 1379 kPa in order to operate its facility. The Gas Delivery Agreement requires Enbridge to deliver gas to Portlands on February 1, 2008 (Ex. A, Tab 3, Schedule 5, p. 56 of 58).

[1] *Enbridge Gas Distribution Inc.,* Decision with Reasons, EB-2005-0001, (February 9, 2006)

Ontario Energy Board
Filed: 2011-11-16
EB-2011-0277
Exhibit I
Tab 4
Schedule 6
Attachment A
Page 4 of 21

Enbridge's existing high pressure distribution system is supplied by the TransCanada Pipelines ("TCPL") system at the Victoria Square Gate Station. In 1971, a NPS 30 pipeline (the "Don Valley Line") was constructed from Victoria Square Gate Station to Enbridge's Station B located on Eastern Avenue (Ex. A, Tab 3, Schedule 2).

The Don Valley Line requires reinforcement, or looping to provide adequate pressure at Station B to meet Portlands' needs. In addition, the existing distribution system downstream of Station B does not have the ability to meet Portlands' requirements. Enbridge embarked on a process of developing a project that would meet the needs of Portlands in an environmentally acceptable and cost-effective manner.

The North Section: The maximum operating pressure of the Don Valley Line is 450 psi (3100 kPa). Station B has a minimum inlet pressure of 225 psi (1550 kPa). The minimum inlet pressure is required for the station to have the capability to supply natural gas in sufficient quantities and at sufficient pressures to the downstream distribution pipeline system. Without the Portlands load, the existing Don Valley Line is able to provide the required minimum inlet pressure at Station B with a Victoria Square Gate Station outlet pressure of 405 psi (2709 kPa) under Enbridge's system design conditions.

Enbridge examined the impact on pressures if the Portlands load is added and no reinforcement was undertaken. With an outlet pressure of 450 psi (3100 kPa) at Victoria Square Gate Station (the maximum operating pressure of the Don Valley Line) the pressure at Station B inlet pressure drops to 210 psi (1445 kPa) with the addition of the Portlands load. Unless reinforcement of the Don Valley Line was to occur, the Portlands load would remove any existing flexibility in the distribution system and the inlet pressure would be unacceptably low at Station B. As such, it was necessary for Enbridge to consider various alternatives to deliver gas in the required quantity and at the required pressure to Station B. Enbridge determined that the proposed North Section was the optimal choice.

After considering alternatives, Enbridge chose the North Section as the preferred alternative because the Environmental Assessment Reports identified the North Section as the preferred route. It also meets the contractual demands of Portlands and maintains the operational characteristics of the distribution system. In addition, it does not conflict with possible future use of the Hydro One corridor. It is lower in cost and it can meet the required timeline.

The South Section: Enbridge's current high pressure distribution system includes a NPS 24 pipeline approximately 3 500 m in length from Station B to the now abandoned R.L. Hearn Generating Station that was installed in 1971. This existing pipeline network downstream of Station B is not adequate to meet the requirements of Portlands as it currently operates with a maximum pressure of 125 psi (860 kPa). Portlands' minimum required delivery pressure is 200 psi (1378 kPa). Enbridge considered pressure elevating the existing piping infrastructure. The evidence (Ex. C, Tab 1, Schedule 1, pp. 4 - 6) described several issues with the pressure elevation option. In the end, the option to pressure elevate was not acceptable to Enbridge.

The evidence clearly supports a finding that there is a need for both north and south pipeline projects. The existing pipelines do not have the capacity to support Portlands' requirements. The need for new generation to meet the growing electricity requirements of Toronto is serious and well recognized.

The Proposed Routing

The routing of the northern section of pipeline was contested by Paul Beatty, a resident of the area. The proposed route as indicated in Appendix "A" is in a Hydro One transmission corridor. The current pipe is on the western side of the transmission corridor and Mr. Beatty argues that the new pipe should be in the east side of the corridor.

The Enbridge response was that Hydro One was not prepared to route the pipeline on the eastern side of the right-of-way because they wished to preserve that space for future development. Accordingly, locating the new pipe on the eastern portion of the Hydro One right-of-way was not something that was investigated further.

Mr. Beatty also argued that the proposed location was too close to properties on the western perimeter of the corridor. He noted that when the Board approved the original pipeline in 1971, it imposed a condition that the pipe be no closer than 35 feet to the property line.

With respect to the 35 ft. buffer that the Board mandated in 1971[2] Enbridge noted that the Technical Standards Safety Authority ("TSSA") does not provide any recommendation for set back on pipelines operating at less than 40% Specified Minimum Yield Strength ("SMYS") and therefore permits development up to edge of the

[2] *The Consumers' Gas Company,* Order Granting Leave to Construct, EBLO 142, (April 8, 1971)

pipeline right-of-way[3]. Accordingly, the proposed route which was reviewed as part of the Ontario Pipeline Coordinating Committee ("OPCC") process was endorsed by the TSSA:

> "We have reviewed the documentation related to the EB-2006-0305 Application received from Enbridge Consumers Gas and found that the design specifications for the pipeline meet or exceed the requirements of the Ontario Regulation on Oil and Gas Pipeline Systems. (O.Reg. 210/01). We also agree with the route selected, as it appears as the best alternative for the pipeline installation." (Ex. J.1, p. 22 of 99).

The Board appreciates the submissions made by Mr. Beatty, and the time spent compiling the materials that he shared with the Board. While the Board notes the concerns expressed by Mr. Beatty, the Board is satisfied that the evidence establishes that the route selected was the best alternative for the location of the northern section of the pipeline.

No intervernor objected to the location of the southern section of the pipeline. The Board is satisfied that the evidence establishes that the route selected was the best alternative for the location of the southern section of the pipeline.

Environmental Assessment

Both the North and South Pipeline Projects meet all the environmental assessment requirements. Enbridge was required to conduct a Category B Environmental Assessment pursuant to the Class Environmental Assessment Act for Management Board Secretariat and the Ontario Realty Corporation Act (April, 2004) because of the need to requirement an easement from the ORC.

Enbridge retained Dillon Consulting Ltd ("Dillon") and Stantec Consulting Ltd. ("Stantec") to undertake an environmental and socio-economic impact assessment to select preferred routes for north and south sections respectively. The assessment was carried out in accordance with the Board's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* (May 2003) (the "Board's Environmental Guidelines"). The results of the assessment are documented in "Toronto Portlands System Reinforcement Project: South Section", Stantec Consulting Ltd., December 2006 ("Stantec Report") (Ex. B, Tab 2, Schedule 4) and in "Updating Study-Environmental and Socio-economic Impact Assessment, Toronto

[3] PI-98/01 "Guidelines for Locating New Oil and Gas Pipeline Facilities", August 19, 1998.

Portlands System Reinforcement Pipeline: North End", Dillon Consulting Ltd., November 2006 ("Dillon Report") (Ex. B, Tab 2, Schedule 3).

Both the Stantec Report and the Dillon Report were reviewed by the OPCC.

Regarding the north section Mr. Guiseppe Muraca, the Environmental Consultant from Dillon, stated that the proposed route was environmentally acceptable and the environmental assessment was complete and it accords with the Board's Environmental Guidelines. Enbridge indicated that it was committed to implementing the mitigation recommended by Dillon.

With respect to the routing of the south section of the pipeline, Enbridge engaged an independent consultant, Stantec with extensive experience to develop the preferred route. Stantec undertook this work in compliance with the Board's Environmental Guidelines. As part of this process, Stantec undertook extensive consultation with government agencies and the public. Three public meetings were held to inform the public of the project and solicit input. Details of public consultation program may be found at section 4.0 of the Environmental Report prepared by Stantec. The Stantec Report indicates that nine pipeline segments were considered and in the end the route indicated in Appendix "A" was chosen because it was located in an existing roadway, minimized disruptions to socio-economic features and had public support. Mr. David Wesenger the Environmental Consultant from Stantec confirmed that the proposed route was an environmentally acceptable alternative using the proposed mitigation techniques included in the Stantec Report and rigid construction practice. Enbridge indicated that it was committed to implementing the mitigation measures in the Stantec Report.

Economics of the Project

Enbridge originally estimated that the project cost was $41.7 million but later advised that the cost had increased by $6.8 million due to an increase in the cost of acquiring land rights from the Ontario Realty Corporation and Hydro One. However, Enbridge advised that the economic feasibility of the project would not be impacted negatively because the increased costs would be added to the contribution in aid of construction made by Portlands.

The economic feasibility of the Project was determined in accordance with the Board's approved procedures as established in EBO 188 and the Board's approval in EB-2005-0001. The economic analysis indicated that a contribution in aid of construction is

required from Portlands in order for the net present value ("NPV") to equal zero or the profitability index ("PI") to equal one. A PI of 1.0 indicates that the Project is economic for Enbridge.

In order to ensure that the Project remains economic regardless of increases in cost, Enbridge has negotiated with Portlands a term in the Gas Delivery Agreement that provides that the "contribution in aid of construction will be re-calculated at the end of the Project based upon the actual cost of construction". Enbridge confirmed that the contribution in aid of construction will be re-calculated or increased to ensure that a PI of 1.0 is maintained. Accordingly, other ratepayers are not at risk and there is no concern with cross-subsidization. Put differently other ratepayers are not at risk for any costs overruns associated with this Project given the automatic adjustment clause that is found in the Gas Delivery Agreement (Ex. A, Tab 3, Schedule 5, p. 39 of 58, section (f)).

It is also important to note that the revenue stream from Portlands is not subject to variability because of variability in gas consumption by Portlands. The revenues to be earned by Enbridge are based on contract demand volumes, not actual consumption. This ensures Portlands' predicted revenues going forward and recovery over the 20 year horizon.

Enbridge has also secured financial assurances from Portlands in the form of guarantees from the parents of Portlands, that ensure that Enbridge is protected through to the conclusion of the Gas Delivery Agreement. In its argument, Enbridge filed a letter from Portlands responding to issues raised by the Board during a hearing. The letter confirmed the allocation of risk and Portlands' commitment to the Project.

Land Issues and Form of Easement

TEDCO is an Intervenor in this proceeding and participated in the oral hearing. Enbridge requires an easement from TEDCO with respect to three sections of land. Two sections are located immediately north and south of the shipping channel where Enbridge will be using a horizontal directional drill to cross underneath the shipping channel. The remaining easement required by Enbridge is within the Portlands generating facility where Enbridge currently has an existing distribution pipeline.

Section 97 of the OEB Act provides that a leave to construct will not be granted until the Applicant has satisfied the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board.

TEDCO asked the Board to modify the form of agreement proposed by Enbridge with respect to two clauses. First, TEDCO took issue with the environmental cause, (clause 7) in the Standard Form Agreement whereby the landowner represents and warrants that the lands do not contain hazardous substance. Enbridge responded that the Board should not be concerned about the specific terms of the form of easement at this point stating that the form was simply "a starting point" in the negotiations.

Enbridge submits that it is not the Board's role in a leave to construct proceedings to intervene in the negotiations between the Applicant and the landowners. In the event that the parties are unable to negotiate an agreement, then alternatives are considered which may include different routes or even expropriation. The OEB Act provides a mechanism to resolve such disputes through an expropriation proceeding. That mechanism provides for compensation under the Expropriation Act by the Ontario Municipal Board ("OMB") and not the OEB. Accordingly, Enbridge argues that the legislation limits this Board's role to the determination of whether expropriation of land is required, not to determine whether the amount of compensation is appropriate. Enbridge also points out that the form of easement being proposed in this proceeding was the form approved by the Board in Scarborough System Reinforcement Application EB-2006-0066[4] as well as the Goreway Station Application in EB-2005-0539[5].

With respect to the environmental clause, Enbridge says that the Transferor is in the best position to know the environmental condition of the property in question. Accordingly, to the extent that representation is false, the Transferor should be responsible for the removal of hazardous substances. With respect to the indemnity, Enbridge says that the landowner is free to negotiate additional terms with Enbridge and the absence of such clause in the proposed Agreement in no way prohibits TEDCO from negotiating such a clause.

Section 97 of the Ontario Energy Board Act reads:

> "In an application under section 90, 91 or 92, leave to construct shall not be granted until the applicant satisfies the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board."

---

4 *Enbridge Gas Distribution Inc.,* Decision and Order, EB-2006-0066, (November 30, 2006)

5 *Enbridge Gas Distribution Inc.,* Decision and Order, EB-2005-0539, (July 10, 2006)

In the course of cross-examination, Enbridge testified that:

- The form of easement agreement filed by Enbridge is offered to all landowners (Transcript Vol. 1, p.92);
- The standard form agreement filed by Enbridge is generally the same agreement that the utility files with the Board on every leave to construct application (Transcript Vol. 1, p. 96);
- The agreement is considered a 'benchmark' and is in all respects open to negotiation between the parties (Transcript Vol. 1, p. 97);
- In most cases changes are made as a result of negotiations (Transcript Vol. 1, pp. 98-99);
- The agreement filed by Enbridge does not contain an indemnification paragraph (Transcript Vol. 1, pp. 102-103);
- The agreement filed by Enbridge contains paragraphs which permit Enbridge to select the route and obtain an indemnity from the landowner for the removal of any hazardous substances found on the land (Transcript Vol. 1, pp. 99-100).

When considering the standard form agreement to be offered to affected landowners, the Board considers the agreement anew and in the context of the application in which it has been filed. The Board approves a standard form agreement which represents the initial offering to the affected landowner. Once the Board is satisfied with the standard form agreement, and in this case the Board is satisfied with the form as filed by Enbridge, the parties are free to negotiate whatever terms they believe to be necessary to protect their specific interests. The Board does not become involved in the detailed negotiation of the clauses in the agreements between one landowner and the Applicant. It is also accepted that a review by this Board under Section 97 does not extend to the amount of compensation or the structure of compensation arrangements.[6]

At the time of the hearing Enbridge had not finalized any of the landowner easement agreements but remained optimistic that they would be concluded well in advance of the planned construction start on July 1, 2007. The only possible exception was Studios of America. Enbridge advised the Board that the Board would be updated on the status of all easement agreements.

[6] *Union Gas Limited* , Decision and Order, EB-2005-0550, (June 12, 2006)

The Emissions Issue

The Board received a letter of public comment on February 7, 2007 from Mr. Peter Tabuns, (MPP Toronto-Danforth), Mr. Jack Layton, (MP Toronto-Danforth) and the Toronto Energy Coalition ("TEC"). TEC requested the Board to deny this Application based upon the potential environmental impacts of the Portlands generating facility. Enbridge asked the Board to disregard these comments because "a [belief] that the construction operation of a plant will result in emissions has nothing to do with the pipeline application before the Board".

A similar concern was raised in the Application by the Greenfield Energy Centre Limited in a Leave to Construct a natural gas pipeline in the Township of St. Clair, Ontario. In the Board's Decision Order dated January 6, 2006, the Board clearly separated the environmental aspects of the pipeline construction from those related to the power station itself. The Board stated:

> "To be clear, only those effects that are additive or interact with the effects that have already been identified as resulting from the pipeline construction are to be considered under cumulative effects."[7]

The Board further stated that it has no jurisdiction to consider the arguments of the Intervenors in this regard:

> "In the Board's view, the law is clear that the jurisdiction on environmental matters associated with the power station falls under the *Environmental Assessment Act* administered by the Ministry of the Environment, and not the Ontario Energy Board. The process under the provincial Environmental Assessment Act in relation to the GEC generating station has been concluded ." (pp. 17-18)

This Decision was upheld by the Divisional Court.[8]

The Board Staff Counsel filed as part of its argument draft conditions of approval. The last draft condition was unique to this proceeding and resulted from a request by the City of Toronto, an Observer in this case, that the condition be followed including:

---

[7] *Greenfield Energy Centre Limited Partnership,* Decision and Order, RP-2005-0022/EB-2005-0441/EB-2005-0442/EB-2005-0443/EB-2005-0444, (January 6, 2006) at p.10.

[8] *Power Workers' Union*, *CUPE Local 1000 v. Ontario Energy Board* (2006), 214 O.A.C. 208, [2006] O.J. No. 2997 (Div. Ct.)

Filed: 2011-11-16
EB-2011-0277
Exhibit I
Tab 4
Schedule 6
Attachment A
Page 12 of 21

> "That Enbridge Gas Distribution Inc. provide, within thirty (30) days of the completion of its construction (defined for the purposes of the public highway as the backfill and temporary patch of any excavation) to the City of Toronto and the property owners over which the pipeline will be built:
>
> - Drawings certified by an Ontario Land Surveyor accurately showing the location of the constructed pipeline; or
>
> - A record drawing as defined by the Association of Professional Engineers of Ontario accurately showing the location of the constructed pipeline."

Enbridge did not oppose a condition but noted that the cost of Ontario Land Surveyor would be approximately $240,000. Under the terms of the Gas Delivery Agreement this cost would become part of the project. As a result, neither Enbridge nor the ratepayers would incur the costs. Enbridge did state that they did not support the inclusion of this condition as a standard practice in other projects. Finally, Enbridge noted that the option for surveyor drawings, rather than engineer record drawings would appear to better meet the City of Toronto's request to tie the location of the pipeline into the property bars (Transcript Volume 1, p. 119).

While this additional cost may not be immediately borne by Enbridge or Enbridge's other ratepayers, in the long run such costs form part of utility's cost of service and are ultimately paid by ratepayers. There is not sufficient evidence before us to justify this additional cost. The interests of the City of Toronto can be protected through less costly means. It is significant that the City of Toronto did not appear at the hearing to support its position or present argument. In the circumstances the Board is not prepared to grant the request by the City of Toronto and directs that the last paragraph contained in the draft conditions of approval, filed by Board Staff Counsel, be removed.

Orders Granted

For the Reasons indicated, the Board finds that the two pipeline projects being proposed by Enbridge in this proceeding are in the public interest and grants the Leave to Construct subject to the conditions set out in Appendix "B".

Filed: 2011-11-16
EB-2011-0277
Exhibit I
Tab 4
Schedule 6
Attachment A
Page 13 of 21

THE BOARD ORDERS THAT:

1. Enbridge Gas Distribution Inc. is granted leave, pursuant to subsection 90 (1) of the Act, to construct approximately 6.5 kilometres of NPS 36 pipeline to parallel a portion of Enbridge's existing NPS 30 XHP Don Valley Line and approximately 2.9 kilometres of NPS 20 XHP steel pipeline that would interconnect the Don Valley Line at Enbridge's Station B regulator station and would terminate at the Portlands Energy Centre in the City of Toronto, subject to the conditions of approval set forth in Appendix "B".

2. Eligible intervenors who seek an award of costs incurred to date shall file their cost submissions in accordance with the *Practice Direction on Cost Awards* with the Board Secretary and with Enbridge Gas Distribution Inc. within 15 days of the date of this Decision. Enbridge Gas Distribution Inc. may make submissions regarding the cost claims within 30 days of the Decision and the intervenors may reply within 45 days of the Decision. A decision and order regarding cost awards will be issued at a later date. Upon receipt of the Board's cost award decision and order, Enbridge Gas Distribution Inc. shall pay any awarded costs with dispatch.

3. Enbridge Gas Distribution Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, June 1, 2007

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

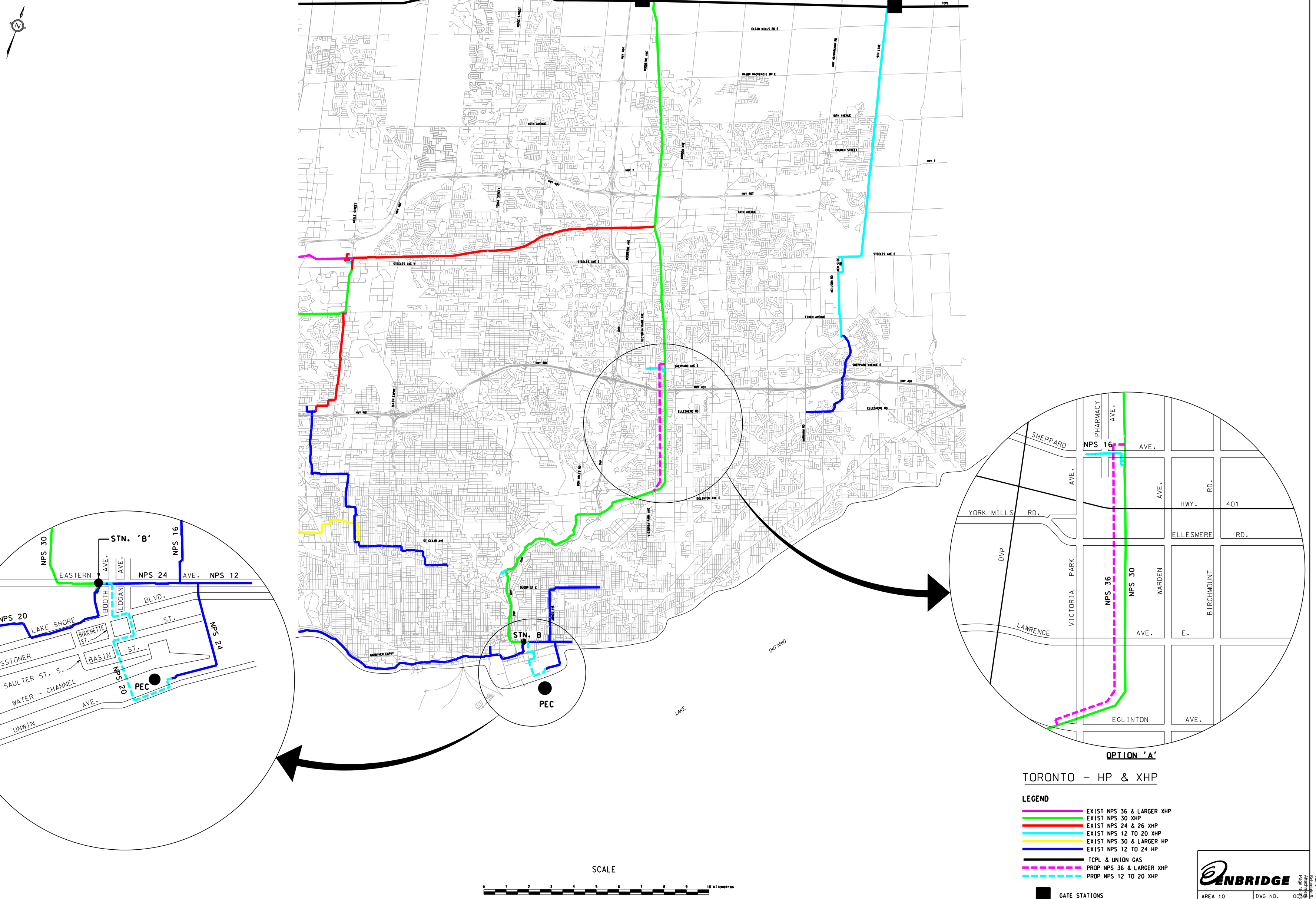
APPENDIX "A"

TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2006-0305

DATED June 1, 2007

MAPS OF THE PIPELINE ROUTES



OPTION 'A'

TORONTO - HP & XHP

LEGEND

- EXIST NPS 36 & LARGER XHP
- EXIST NPS 30 XHP
- EXIST NPS 24 & 26 XHP
- EXIST NPS 12 TO 20 XHP
- EXIST NPS 30 & LARGER HP
- EXIST NPS 12 TO 24 HP
- TCPL & UNION GAS
- PROP NPS 36 & LARGER XHP
- PROP NPS 12 TO 20 XHP
- GATE STATIONS

SCALE

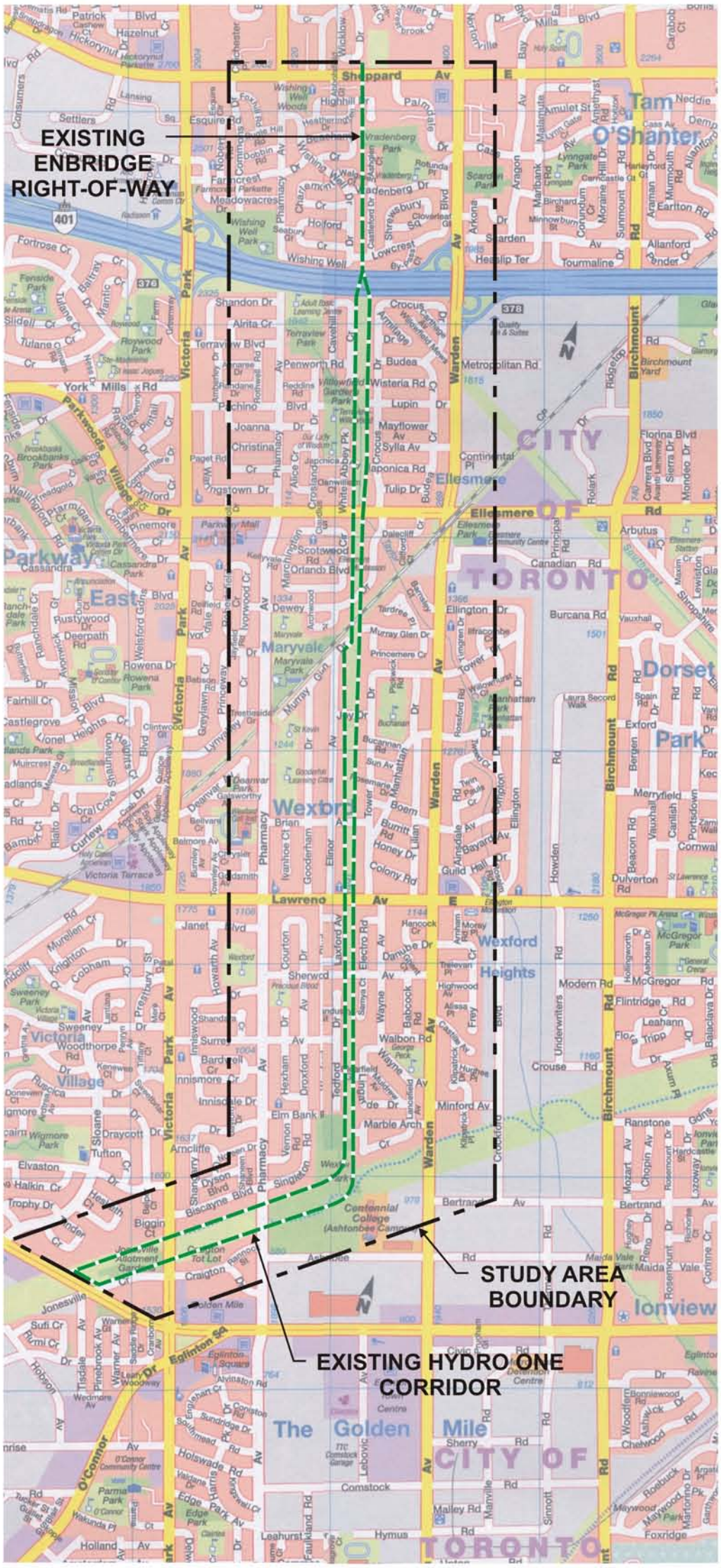
0 1 2 3 4 5 6 7 8 9 10 kilometres

ENBRIDGE

AREA 10	DWG NO. 001

DRAWING: METRO OEB

Rev: 2011-11-16
EB-2012-0451
Exhibit I.1.UGTF
Tab 4
Attachment A
Page 11 of 24
Schedule 2



1:25,000 (Approx.)

ENBRIDGE

TORONTO SYSTEM
REINFORCEMENT STUDY

STUDY AREA A

SENES Consultants	Project Number	Figure
	33485	4

Note: *The features on this map are for illustrative purposes only. Original source should be referenced for actual location and boundaries.*

Stantec

N W E S

- Study Area
- Preferred Route
- Alternate Routes

Base Map Source: Northway-Photomap Inc.

REVISION NO.	REVISION DATE	DESCRIPTION	REVISED BY:
-	-	-	-

PROJECT NAME:
ENBRIDGE NATURAL GAS PIPELINE

CLIENT NAME:
ENBRIDGE

DATE INITIATED:
OCTOBER, 2006

FILENAME:
60960211_05.cdr

FIGURE NO. A-2

PRELIMINARY PREFERRED ROUTE AND ROUTE SEGMENTS

SCALE:		PROJECT NO.:		
1:12,000		160960211		
REV. NO.	SHEET NO.	CHECKED BY:	APPROVED:	DRAWN:
0	1 OF 1	MA	DEW	CEL

Filed: 2011-11-16
EB-2011-0277
Exhibit I.1.1
Tab 4
Schedule 6
Attachment A
Page 17 of 21

APPENDIX "B"

TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2006- 0305

DATED JUNE 1, 2007

CONDITIONS OF APPROVAL

EB-2006-0305

Enbridge Gas Distribution Inc.
Toronto Portlands Reinforcement
Leave to Construct Application

Conditions of Approval

Leave to Construct

1 General Requirements

1.1 Enbridge Gas Distribution Inc. ("Enbridge") shall construct the facilities and restore the land in accordance with its application and evidence filed in EB-2006-0305, except as modified by this Order and these Conditions of Approval.

1.2 Unless otherwise ordered by the Board, authorization for Leave to Construct shall terminate December 31, 2008, unless construction has commenced prior to then.

1.3 Except as modified by this Order, Enbridge shall implement all the recommendations of the Environmental Study Reports filed in the pre-filed evidence, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee ("OPCC") review.

1.4 Enbridge shall advise the Board's designated representative of any proposed material change in construction or restoration procedures and, except in an emergency, Enbridge shall not make such change without prior approval of the Board or its designated representative. In the event of an emergency, the Board shall be informed immediately after the fact.

2 Project and Communications Requirements

2.1 The Board's designated representative for the purpose of these Conditions of Approval shall be the Manager, Facilities.

2.2 Enbridge shall designate a person as project engineer and shall provide the name of the individual to the Board's designated representative. The project engineer will be responsible for the fulfilment of the Conditions of Approval on the construction site. Enbridge shall provide a copy of the Order and Conditions of Approval to the project engineer, within seven days of the Board's Order being issued.

2.3 Enbridge shall give the Board's designated representative and the Chair of the OPCC ten days written notice in advance of the commencement of the construction.

2.4 Enbridge shall furnish the Board's designated representative with all reasonable assistance for ascertaining whether the work is being or has been performed in accordance with the Board's Order.

2.5 Enbridge shall file with the Board's designated representative notice of the date on which the installed pipelines were tested, within one month after the final test date.

2.6 Enbridge shall furnish the Board's designated representative with five copies of written confirmation of the completion of construction. A copy of the confirmation shall be provided to the Chair of the OPCC.

3 Monitoring and Reporting Requirements

3.1 Both during and after construction, Enbridge shall monitor the impacts of construction, and shall file four copies of both an interim and a final monitoring report with the Board. The interim monitoring report shall be filed within six months of the in-service date, and the final monitoring report shall be filed within fifteen months of the in-service date. Enbridge shall attach a log of all complaints that have been received to the interim and final monitoring reports. The log shall record the times of all complaints received, the substance of each complaint, the actions taken in response, and the reasons underlying such actions.

3.2 The interim monitoring report shall confirm Enbridge's adherence to Condition 1.1 and shall include a description of the impacts noted during construction and the actions taken or to be taken to prevent or mitigate the long-term effects of the impacts of construction. This report shall describe any outstanding concerns identified during construction.

3.3 The final monitoring report shall describe the condition of any rehabilitated land and the effectiveness of any mitigation measures undertaken. The results of the monitoring programs and analysis shall be included and recommendations made as appropriate. Any deficiency in compliance with any of the Conditions of Approval shall be explained.

4 Easement Agreements

4.1 Enbridge shall offer the form of agreement approved by the Board to each landowner, as may be required, along the route of the proposed work.

5 Other Approvals

5.1 Enbridge shall obtain all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project, shall provide a list thereof, and shall provide copies of all such written approvals, permits, licences, and certificates upon the Board's request.

Filed: 2006-12-07
EB-2006-0305
Exhibit E
Tab 1
Schedule 1
Page 1 of 3

ECONOMIC FEASIBILITY

METHODOLOGY

1. The overall feasibility of the project has been determined using the methodology that adheres to the parameters contained within the "Ontario Energy Board Guidelines for Assessing and Reporting on Natural System Expansion in Ontario" and as laid out in the Ontario Energy Board's EBO 188 "Report to the Board" dated January 30, 1998.

2. The economic feasibility of this project has been calculated by discounting the incremental cash flows over a 20 year customer revenue horizon. The resulting NPV represents both the economic feasibility of the project from the utility's perspective and its effect within the Rolling Project Portfolio. An NPV greater than zero indicates the project will have a positive contribution to the Rolling Project Portfolio and will be feasible from a utility cash flow perspective. Since the project NPV is less than zero, a contribution in aid of construction is required. The Customer has agreed to pay the contribution. Exhibit E, Tab 1, Schedule 2 details the NPV and the Customer contribution for the project.

KEY ASSUMPTIONS

Customer Revenue Horizon

3. The feasibility analysis for the project was based upon a 20-year customer revenue horizon. The first year revenue is calculated based on eight months as the Customer has requested a four month commissioning period.

Capital Costs

4. The total capital costs for feasibility purposes are estimated to be $41.7 million. The detailed capital cost estimates are provided at Exhibit C, Tab 2, Schedule 1. The construction period is assumed to be 7 months. We are seeking a contribution of $17.7 million. Within approximately 9 months of completion of the installation and commissioning of the distribution line and related infrastructure, the Company will establish the final contribution in aid of construction based on the actual costs incurred to complete such installation. The final contribution in aid of construction so established will be used for purposes of this agreement. This ensures that the project is still feasible.

5. Enbridge Gas Distribution has arranged for financial assurance from Portlands Energy Centre for the investment exposure. This is required to mitigate the risk associated with power plants and to protect the interests of existing ratepayers.

Contract Demand

6. The gas deliveries to the Portlands Energy Centre will be under Rate 125. The contract demand is based on twenty-four times the maximum hourly flow and is established as 2 785 885 m^3.

<u>Summary</u>

7. The feasibility for the Portlands Energy Centre reinforcement project has been prepared based on Enbridge Gas Distribution's feasibility guidelines pursuant to the Ontario Energy Board's Decision with Reasons in the Company's EB-2005-0001 Rate application.

8. The analysis contained at Exhibit E, Tab 1, Schedule 2, shows the project has a Profitability Index ("PI") of 1.0 after customer contribution in the amount of $17.7 million. The project meets the minimum project acceptance threshold PI of 1.0, and thus qualifies for approval by the Ontario Energy Board on the basis of this analysis.

Filed: 2006-12-07
EB-2006-0305
Exhibit E
Tab 1
Schedule 2
Page 1 of 6

ECONOMIC FEASIBILITY TEST

1. The following economic feasibility evidence has been completed based upon the parameters contained within the feasibility guidelines pursuant to the Ontario Energy Board's Decision with Reasons in the Company's EB-2005-0001 Rate application.

2. Discounted cash flow ("DCF") analysis is adopted to calculate net present value ("NPV") and profitability index ("PI") for the project. The economic feasibility of the project has been tested using the incremental revenues and costs associated with the project forecast over a 20-year period. This analysis incorporates all incremental capital and operating costs associated with this proposed project. A summary of the inputs and results of the feasibility are included on page 2, while pages 3 to 6 show detailed feasibility parameters and results.

SUMMARY OF INPUTS

Capital Investments

Mains	$36,278,391
Station	$1,041,757
Land	$4,422,000
Total	$41,742,148

Gas Requirements

Under Rate 125

Daily Contract Demand	2,785,885 m^3

SUMMARY OF RESULTS

Net Present Value (20 years)	$0.0
Profitability Index (20 years)	1.0
Customer Contribution	$17,746,869

Filed: 2006-12-07
EB-2006-0305
Exhibit E
Tab 1
Schedule 2
Page 3 of 6

APPENDIX 1

Portlands Energy Centre

ECONOMIC FEASIBILITY STUDY

FOR A CUSTOMER REVENUE HORIZON OF 20 YEARS

Portlands Energy Centre
Economic Feasibility - 20 Year Horizon
Parameters and Results

Line No.	Col. 1 Description	Col. 2
	FEASIBILITY PARAMETERS	
1.	Discount Rate	6.15%
2.	CCA Rate	4.00%
3.	Tax Rate	35.00%
4.	Municipal Tax rate	0.60%
5.	Capital Tax Rate	0.29%
6.	Customer Revenue Horizon (Years)	20
7.	Daily Contract Demand , m^3	2,785,885
8.	Annual Distribution Revenues (Dollars)	3,082,919
9.	Annual O&M (Dollars)	2,758
10.	Capital Investment (Dollars)	41,742,148
	Working Capital	
11.	O&M (Lead days)	(33.85)
12.	Commodity (Lag days)	3.75
	FEASIBILITY RESULTS	
13.	Net Present Value (Dollars)	0.0
14.	Profitability Index	1.000
15.	Customer Contribution in Aid of Construction (Dollars)	17,746,869

Portlands Energy Center
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Description	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
			Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
	Discount factors to project outset		0.983	0.928	0.883	0.832	0.784	0.738	0.696	0.655	0.617	0.582
	INCREMENTAL CAPITAL INVESTMENT											
1.	Investment In Mains		36,278,391	-	-	-	-	-	-	-	-	-
2.	Investment in Services		-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations		1,041,757	-	-	-	-	-	-	-	-	-
4.	Investment in Land		4,422,000	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction		(17,746,869)	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital		23,995,279	-	-	-	-	-	-	-	-	-
7.	Working Capital		-	256	-	-	-	-	-	-	-	-
8.	Total Investment		23,995,279		-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset		23,581,025	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**		**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**
	CCA TAX SHIELD											
11.	CCA Tax Shield			150,173	294,339	282,566	271,263	260,413	249,996	239,996	230,397	221,181
12.	PV Of CCA Tax Shield At Project Outset			139,379	259,931	235,078	212,602	192,275	173,892	157,266	142,230	128,631
13.	**ACCUMULATED PV OF CCA TAX SHIELD**			**139,379**	**399,310**	**634,388**	**846,991**	**1,039,266**	**1,213,158**	**1,370,424**	**1,512,654**	**1,641,285**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)											
14.	Gas Distribution Revenue			2,055,279	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919
15.	Gas Costs			-	-	-	-	-	-	-	-	-
16.	O&M Expenses			(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)
17.	Net Operating Cash (Before Taxes)			2,052,521	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161
18.	PV of Net Operating Cash (Before Taxes) At Project Outset			1,904,991	2,720,084	2,562,516	2,414,075	2,274,233	2,142,492	2,018,383	1,901,462	1,791,315
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**			**1,904,991**	**4,625,075**	**7,187,590**	**9,601,665**	**11,875,898**	**14,018,391**	**16,036,773**	**17,938,236**	**19,729,551**
	TAXES											
20.	Income Tax (Before Interest Tax Shield)			(647,021)	(1,011,772)	(1,017,494)	(1,022,783)	(1,022,979)	(1,023,166)	(1,023,346)	(1,023,519)	(1,023,685)
21.	Municipal Tax			(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)
22.	Capital Tax			(59,919)	(45,412)	(29,064)	(13,951)	(13,393)	(12,857)	(12,343)	(11,849)	(11,375)
23.	Total Taxes			(850,911)	(1,201,156)	(1,190,529)	(1,180,706)	(1,180,343)	(1,179,995)	(1,179,661)	(1,179,340)	(1,179,032)
24.	PV of Total Taxes At Project Outset			(789,750)	(1,060,738)	(990,452)	(925,378)	(871,505)	(820,779)	(773,014)	(728,037)	(685,684)
25.	**ACCUMULATED PV OF TOTAL TAXES**			**(789,750)**	**(1,850,488)**	**(2,840,940)**	**(3,766,318)**	**(4,637,823)**	**(5,458,601)**	**(6,231,615)**	**(6,959,652)**	**(7,645,336)**
	ACCUMULATED NPV AND PI											
26.	Net Present Value		(23,581,025)	(22,326,405)	(20,407,129)	(18,599,986)	(16,898,687)	(15,303,683)	(13,808,077)	(12,405,443)	(11,089,787)	(9,855,525)
27.	Profitability Index			0.053	0.135	0.211	0.283	0.351	0.414	0.474	0.530	0.582

Note a) Construction period of 7 months mid-term discounted, July 2007 is the project outset.
Note b) Year 1 Revenue from February 2008 to January 2009.
Note c) Commissioning period - February 2008 to May 2008 inclusive

Filed: 2006-12-07
EB-2006-0305
Exhibit E
Tab 1
Schedule 2
Page 5 of 6

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 4, Schedule 6, Attachment C, Page 5 of 6

Portlands Energy Center
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 12 Year 10	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
	Discount factors to project outset	0.548	0.516	0.486	0.458	0.432	0.407	0.383	0.361	0.340	0.320	0.302
	INCREMENTAL CAPITAL INVESTMENT											
1.	Investment In Mains	-	-	-	-	-	-	-	-	-	-	-
2.	Investment in Services	-	-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations	-	-	-	-	-	-	-	-	-	-	-
4.	Investment in Land	-	-	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction	-	-	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-	-
7.	Working Capital	-	-	-	-	-	-	-	-	-	-	-
8.	Total Investment	-	-	-	-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**
	CCA TAX SHIELD											
11.	CCA Tax Shield	212,333	203,840	195,686	187,859	180,345	173,131	166,206	159,557	153,175	147,048	1,476,471
12.	PV Of CCA Tax Shield At Project Outset	116,333	105,210	95,151	86,053	77,826	70,385	63,655	57,569	52,065	47,087	445,400
13.	**ACCUMULATED PV OF CCA TAX SHIELD**	**1,757,617**	**1,862,827**	**1,957,978**	**2,044,031**	**2,121,857**	**2,192,242**	**2,255,897**	**2,313,466**	**2,365,531**	**2,412,618**	**2,858,018**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)											
14.	Gas Distribution Revenue	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919
15.	Gas Costs	-	-	-	-	-	-	-	-	-	-	-
16.	O&M Expenses	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)
17.	Net Operating Cash (Before Taxes)	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161
18.	PV of Net Operating Cash (Before Taxes) At Project Outset	1,687,549	1,589,793	1,497,700	1,410,942	1,329,209	1,252,211	1,179,673	1,111,338	1,046,960	986,312	929,178
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	**21,417,100**	**23,006,892**	**24,504,592**	**25,915,534**	**27,244,743**	**28,496,954**	**29,676,627**	**30,787,965**	**31,834,925**	**32,821,238**	**33,750,415**
	TAXES											
20.	Income Tax (Before Interest Tax Shield)	(1,023,844)	(1,023,997)	(1,024,144)	(1,024,285)	(1,024,420)	(1,024,550)	(1,024,675)	(1,024,794)	(1,024,909)	(1,025,019)	(1,025,125)
21.	Municipal Tax	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)
22.	Capital Tax	(10,920)	(10,483)	(10,064)	(9,661)	(9,275)	(8,904)	(8,548)	(8,206)	(7,878)	(7,562)	(78,794)
23.	Total Taxes	(1,178,736)	(1,178,452)	(1,178,179)	(1,177,918)	(1,177,667)	(1,177,425)	(1,177,194)	(1,176,972)	(1,176,758)	(1,176,553)	(1,247,891)
24.	PV of Total Taxes At Project Outset	(645,802)	(608,246)	(572,879)	(539,573)	(508,209)	(478,671)	(450,854)	(424,657)	(399,985)	(376,750)	(376,445)
25.	**ACCUMULATED PV OF TOTAL TAXES**	**(8,291,138)**	**(8,899,383)**	**(9,472,262)**	**(10,011,836)**	**(10,520,045)**	**(10,998,716)**	**(11,449,570)**	**(11,874,228)**	**(12,274,213)**	**(12,650,963)**	**(13,027,408)**
	ACCUMULATED NPV AND PI											
26.	Net Present Value	(8,697,446)	(7,610,689)	(6,590,717)	(5,633,296)	(4,734,470)	(3,890,546)	(3,098,071)	(2,353,822)	(1,654,782)	(998,132)	**0**
27.	Profitability Index	0.631	0.677	0.721	0.761	0.799	0.835	0.869	0.900	0.930	0.958	**1.000**

Note a) Construction period of 7 months mid-term discounted, July 2007 is the pr

Note b) Year 1 Revenue from February 2008 to January 2009.

Note c) Commissioning period - February 2008 to May 2008 inclusive

...continued.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008-0065

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 pursuant to Section 90(1) of the Ontario Energy Board Act, 1998, granting leave to construct a natural gas distribution pipeline and related facilities in the City of Thorold in the Regional Municipality of Niagara.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

DECISION AND ORDER

Enbridge Gas Distribution Inc. ("Enbridge" or "EDG") has filed an application with the Board, dated June 27, 2008, under section 90(1) of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c.15, Schedule B, for orders granting leave to construct approximately 2.9 km of Nominal Pipe Size ("NPS") 12 diameter steel high pressure pipeline and a gate station (meter and pressure regulator) in the City of Thorold, in the Regional Municipality of Niagara. The pipeline and related facilities are intended to serve the requirements of natural gas demand for a gas-fired generator currently under construction.

For the reasons set out below, the Board finds that the construction of the proposed pipeline is in the public interest and grants Leave to Construct, subject to certain Conditions of Approval, which are attached to this Decision.

The Proposed Pipeline

The 2.9 km pipeline will be a dedicated line providing natural gas to a 265 MW cogeneration plant proposed by Northland Power Inc., Thorold Cogen L.P. ("Thorold Cogen facility"), in Thorold being constructed at the Abitibi Plant where both heat and electricity will be produced.

A map showing the location of the proposed pipeline and ancillary facility is attached as Appendix A. The proposed pipeline will originate at the TransCanada Pipeline ("TCPL") where it crosses Thorold Townline Road. At that location, Enbridge proposes to construct a gate station to reduce the TCPL line pressure to less than 4500 kPa (653 psi) and to measure the gas volumes to the Thorold Cogen station. Enbridge's proposed line will proceed north along the road allowance of Thorold Townline Road from the intersection with TCPL for approximately 0.6 km to Beaversdams Road. The pipeline will then proceed west along Beaversdams Road for 0.8 km to Davis Road (Highway 58) and Niagara Falls Road. The pipeline will follow Niagara Falls Road west for approximately 1.2 km to Allanburg Road where it will proceed north on Allanburg Road for 0.2 km to the route end point located at the proposed Thorold Cogen facility.

The Proceeding

The Board issued the Notice of Application on August 1, 2008, which was published and served by EGD as directed. Intervenor requests were received from Walker Community Development Corporation, Thorold Cogen L.P. and Hydro One Networks Inc. All requests for intervention were approved. No observer or letters of comment were filed. The Board proceeded by way of a written hearing. No interrogatories or submissions were filed by the intervenors

On September 4, 2008, Board Staff, through written interrogatories, requested clarification of certain aspects of the pre-filed evidence and additional information. On

September 23, 2008, EGD responded to the interrogatories, which concluded the discovery phase of the proceeding.

This is an application under section 90 of the Act, seeking a Leave to Construct Order. Section 96 of the Act provides that the Board shall make an Order granting leave if the Board finds that "the construction, expansion or reinforcement of the proposed work is in the public interest". When determining whether a project is in the public interest, the Board typically examines the need for the project, the economics of the project, the environmental impact, the impact on landowners and consultation with Aboriginal Peoples. Each of these factors will be considered in turn.

The Need for the Project

The proposed pipeline and related facilities are intended to deliver gas to the proposed Thorold Cogen facility.

The Thorold Cogen facility is a 265 MW combined heat and power ("CHP") facility that is natural-gas fired. The waste heat from the turbine will be used to produce steam, some of which will be piped over to and consumed by the Abitibi-Consolidated paper mill that is located on the same property. Thorold Cogen has entered into a 20-year agreement with the Ontario Power Authority ("OPA") to supply electricity to the province. This agreement was the result of an OPA-administered competitive Request for Proposal ("RFP") process as per an Ontario Ministry of Energy directive. The directive was in response to critical needs for new clean, efficient and reliable electricity supply in the province. Thorold Cogen was selected to develop a CHP facility through the RFP process.

EGD states, and the Board accepts, that the timely development of the facilities required to deliver natural gas to the Thorold Cogen facility is critical to achieving these reliability and efficiency objectives. Gas will be required for commissioning during the third quarter of 2009 to prepare for commercial operation in the first quarter of 2010.

The Proposed Pipeline's Design

According to EGD's evidence, the design and pipe specifications, installation and testing of the proposed pipeline adhere to the requirements of Ontario Regulation 210/01 under the *Technical Standards and Safety Act*, Oil and Gas Pipeline Systems and the CSA Z662-03 Oil and Gas Pipeline Systems code.

The Board is satisfied that the evidence establishes that the pipeline design and specifications are acceptable.

Environmental Assessment and Routing

EGD retained Stantec Consulting Limited ("Stantec") to undertake an environmental assessment, evaluate alternatives and advise on the selection of a preferred route. The environmental assessment was carried out in accordance with the Board's "Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (May 2003)" (the "Board's Environmental Guidelines"). The results of the assessment are documented in the report entitled "Environmental Report: Pipeline to serve the proposed Thorold Cogen L.P." dated April, 2008 (the "Stantec Report"), which was filed in this proceeding.

As part of the environmental assessment process, Stantec undertook consultation with government agencies and the public. Public meetings were held on May 16, 2007, June 26, 2007 and March 18, 2008 to inform the public of the project and to solicit input. The Stantec Report included details of the public consultation undertaken. No major concerns were identified.

In accordance with the Board's Environmental Guidelines, the Stantec Report was reviewed by the Ontario Pipeline Coordination Committee ("OPCC"). There are no outstanding concerns related to the OPCC review.

Stantec assessed and rated five route alternatives using routing criteria and consideration of proposed mitigation measures. The Stantec Report concluded that the preferred route selected is the shortest in length and has the least potential for encountering archaeological resources. The Report states that the mitigating

measures proposed comply with accepted industry practice and EGD's construction manual, and that the net residual environmental effects do not constitute a significant environmental effect.

EGD confirms that all permits and approvals will be secured prior to the construction of the pipeline.

The Board accepts EGD's evidence regarding the environmental assessment of the proposed pipeline, and finds that the proposed mitigation and monitoring activities are acceptable and address the environmental concerns. The Board also accepts that the proposed project is the best alternative.

Economics of the Project

The total estimated cost for the Thorold Cogen Pipeline project is $6,397,224. The economic feasibility of the project was measured in accordance with the Board's approved procedures as established in EBO 188[1]. The feasibility analysis for the project was based upon a 20-year customer revenue horizon and has been prepared based on EGD's feasibility guidelines pursuant to the Board's Decision with Reasons in EGD's EB-2006-0034 rate application. This analysis indicated that the proposed facilities have a Net Present Value ("NPV") of $0 and a Profitability Index ("PI") of 1.00. A PI at or above 1.0 indicates that the project is economic for EGD. Enbridge's Rate-125 will recover the revenue requirement through monthly demand charges.

The Board accepts EGD's evidence and finds that the project is economically feasible under the proposed feasibility analysis.

Land Issues and Form of Easement

Section 97 of the Act provides that a leave to construct will not be granted until the applicant has satisfied the Board that it has offered or will offer to each owner of land

[1] [The Consumers Gas Company Ltd, Union Gas Limited and Centra Gas Ontario Inc., Natural Gas System Expansion, Report of the Board, EBO 188, (January 30, 1998)]

affected by the approved route or location an agreement in a form approved by the Board.

EGD has indicated that the proposed pipeline is to be located entirely within existing road allowances. As such, EGD does not anticipate the need to obtain either temporary or permanent land rights. However, EGD has filed with the Board a form of easement agreement that it will offer to landowners in the event that requirement for easements change.

EGD notes that two acres of property are required for the Gate Station facilities. There are three potential locations identified for the Gate Station. Negotiations are continuing with the landowners to finalize the site for the Gate Station.

The Board approves the form of easement which has been filed by EGD.

Aboriginal Consultation Conducted by Enbridge

EGD, through the Stantec Report, advised that there were no known First Nation reserves or lands that are currently used along the proposed pipeline route for traditional or cultural purposes.

Stantec initiated consultation with the Indian and Northern Affairs Canada ("INAC") to ensure the status of lands within the Study area did not contain First Nation reserves or lands. A response from INAC's Specific Claims Branch was received on July 19, 2007, indicating that there are no land claims in the Study Area that INAC is aware of.

The Board is satisfied that EGD has conducted a proper search and that no Aboriginal groups will be adversely affected by the proposed project.

Orders Granted

For the reasons indicated, the Board finds the pipeline project proposed by EGD in this proceeding is in the public interest and grants an Order for Leave to Construct subject to the Conditions of Approval as set out in Appendix B.

THE BOARD ORDERS THAT:

1. Enbridge Gas Distribution Inc. is granted leave, pursuant to subsection 90 (1) of the Act, to construct approximately 2.9 kilometres of NPS 12 in the City of Thorold, the Regional Municipality of Niagara for the purpose of supplying natural gas to the Thorold Cogen L.P. facility, subject to the Conditions of Approval set forth in Appendix B.

2. Enbridge Gas Distribution Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto October 28, 2008

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

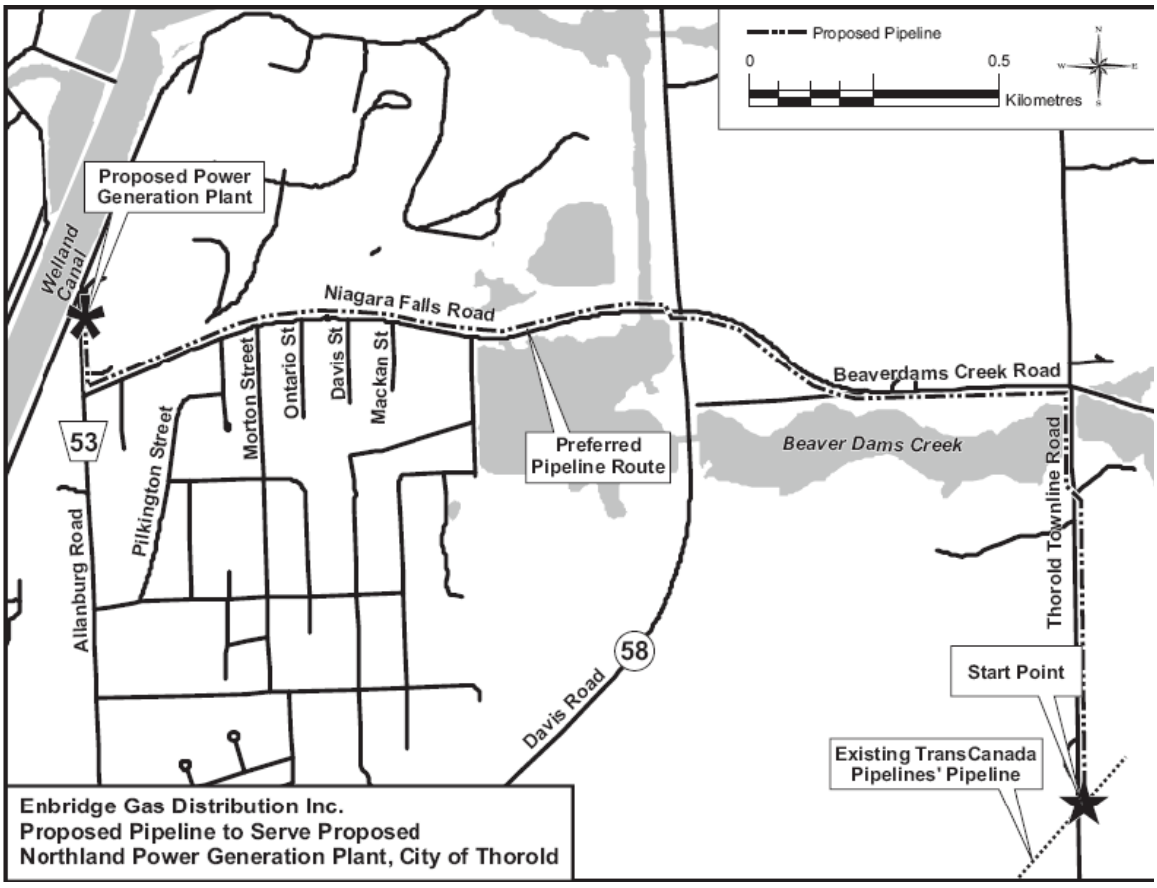
APPENDIX A

TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2008-0065

DATED October 28, 2008

MAP OF THE PIPELINE ROUTE


Proposed Pipeline
0
0.5
Kilometres
Proposed Power Generation Plant
Welland Canal
Niagara Falls Road
Morton Street
Ontario St
Davis St
Mackan St
Beaverdams Creek Road
53
Pilkington Street
Preferred Pipeline Route
Beaver Dams Creek
Thorold Townline Road
Allanburg Road
58
Davis Road
Start Point
Existing TransCanada Pipelines' Pipeline
Enbridge Gas Distribution Inc.
Proposed Pipeline to Serve Proposed
Northland Power Generation Plant, City of Thorold

APPENDIX B

TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2008-0065

DATED October 28, 2008

CONDITIONS OF APPROVAL

Conditions of Approval

Leave to Construct

1 General Requirements

1.1 Enbridge Gas Distribution Inc. ("Enbridge") shall construct the facilities and restore the land in accordance with its application and the evidence filed in EB-2008-0065, except as modified by this Order and these Conditions of Approval.

1.2 Unless otherwise ordered by the Board, authorization for Leave to Construct shall terminate December 31, 2009, unless construction has commenced prior to then.

1.3 Except as modified by this Order, Enbridge shall implement all the recommendations of the Environmental Report filed in the pre-filed evidence, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee ("OPCC") review.

1.4 Enbridge shall advise the Board's designated representative of any proposed material change in construction or restoration procedures and, except in an emergency, Enbridge shall not make such change without prior approval of the Board or its designated representative. In the event of an emergency, the Board shall be informed immediately after the fact.

2 Project and Communications Requirements

2.1 The Board's designated representative for the purpose of these Conditions of Approval shall be the Manager, Facilities Applications.

2.2 Enbridge shall designate a person as project engineer and shall provide the name of the individual to the Board's designated representative. The project engineer will be responsible for the fulfilment of the Conditions of Approval on the construction site. Enbridge shall provide a copy of the Order and Conditions of Approval to the project engineer, within seven days of the Board's Order being issued.

2.3 Enbridge shall give the Board's designated representative and the Chair of the OPCC ten days written notice in advance of the commencement of the construction.

2.4 Enbridge shall furnish the Board's designated representative with all reasonable assistance for ascertaining whether the work is being or has been performed in accordance with the Board's Order.

2.5 Enbridge shall file with the Board's designated representative notice of the date on which the installed pipelines were tested, within one month after the final test date.

2.6 Enbridge shall furnish the Board's designated representative with five copies of written confirmation of the completion of construction. A copy of the confirmation shall be provided to the Chair of the OPCC.

3 Monitoring and Reporting Requirements

3.1 Both during and after construction, Enbridge shall monitor the impacts of construction, and shall file four copies of both an interim and a final monitoring report with the Board. The interim monitoring report shall be filed within six months of the in-service date, and the final monitoring report shall be filed within fifteen months of the in-service date. Enbridge shall attach a log of all complaints that have been received to the interim and final monitoring reports. The log shall record the times of all complaints received, the substance of each complaint, the actions taken in response, and the reasons underlying such actions.

3.2 The interim monitoring report shall confirm Enbridge's adherence to Condition 1.1 and shall include a description of the impacts noted during construction and the actions taken or to be taken to prevent or mitigate the long-term effects of the impacts of construction. This report shall describe any outstanding concerns identified during construction.

3.3 The final monitoring report shall describe the condition of any rehabilitated land and the effectiveness of any mitigation measures undertaken. The results of the monitoring programs and analysis shall be included and recommendations made as appropriate. Any deficiency in compliance with any of the Conditions of Approval shall be explained.

4 Easement Agreements

4.1 Enbridge shall offer the form of agreement approved by the Board to each landowner, as may be required, along the route of the proposed work.

5 Other Approvals and Agreements

5.1 Enbridge shall obtain all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project, shall provide a list thereof, and shall provide copies of all such written approvals, permits, licences, and certificates upon the Board's request.

5.2 Enbridge shall not, without prior approval of the Board, consent to any alteration or amendment to the Gas Delivery Agreement dated and executed on August 15, 2007, where such alteration or amendment has or may have any material impact on Enbridge's ratepayers.

5.3 Enbridge shall file with the Board, a copy of Thorold Cogen L.P.'s irrevocable bank letter of credit to Enbridge for an amount not less than cost estimate of the applied-for facilities; this filing shall take place no later than 14 days after the start of construction.

ECONOMIC FEASIBILITY

METHODOLOGY

1. The economic feasibility of the project has been determined using a methodology that adheres to the "Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario" and the EBO 188 "Report of the Board" dated January 30, 1998.

2. The economic feasibility of the project has been calculated by discounting incremental cash flows over the 20-year customer revenue horizon. The resulting Net Present Value ("NPV") represents both the economic feasibility of the project from the utility's perspective and its effect within the Rolling Project Portfolio. An NPV greater than zero indicated that the project will make a positive contribution to the Rolling Project Portfolio and be feasible from a utility cash flow perspective. Exhibit E, Tab 1, Schedule 2 details the NPV for the project.

KEY ASSUMPTIONS

Customer Revenue Horizon

3. Feasibility analysis for the project was based upon a 20-year customer revenue horizon. The first year revenue is calculated based on nine months as the Customer has requested a three month commissioning period.

/u

Capital Costs

4. The project capital costs are estimated to be $6,397,224. The detailed capital cost estimates are provided at Exhibit C, Tab 2, Schedule 1. The construction period is assumed to be 5 months. As part of the requirements under the GDA, Thorold Cogen has provided financial assurances in the form of an irrevocable letter of credit. This will be in addition to the requirements under the Gas Transportation Agreement. This is required to

mitigate the risk associated with power plants and to protect the interests of existing ratepayers.

Contract Demand

5. The gas deliveries to the Thorold Cogen will be under Rate 125. For this dedicated service line, the contract demand is established by calculating the annual revenues required under Rate 125 to completely recover the capital invested in the chosen customer horizon period. Any overruns in gas consumption lead to additional revenues calculated at the unitized rate of Rate 125.

6. The 'Billing Contract Demand' is estimated to be 768,449 m^3. Within nine (9) months of completion of the installation and commissioning of the distribution line and related infrastructure which Enbridge has determined is required to be installed to service the Terminal Location, Enbridge will establish the final 'Billing Contract Demand' based on the actual costs incurred to complete such installation, and shall notify the customer of such final 'Billing Contract Demand'. The final 'Billing Contract Demand' so established will be used for purposes of this Agreement for the duration of the Term. This ensures that the project is still feasible. /u

Summary

7. The feasibility for the Thorold Cogen project has been prepared based on Enbridge's feasibility guidelines pursuant to the Ontario Energy Board's Decision with Reasons in the Company's EB-2007-0615 Application.

8. The analysis contained at Exhibit E, Tab 1, Schedule 2, shows the project has a PI of 1.0.

Filed: 2008-06-27
EB-2008-0065
Exhibit E
Tab 1
Schedule 2
Page 1 of 6

ECONOMIC FEASIBILITY TEST

1. The following economic feasibility evidence has been completed based upon the parameters contained within the feasibility guidelines pursuant to the Ontario Energy Board's Decision with Reasons in the Company's EB-2007-0615 Application.

2. Discounted cash flow ("DCF") analysis is adopted to calculate net present value ("NPV") and profitability index ("PI") for the project. The economic feasibility of the project has been tested using the incremental revenues and costs associated with the project forecast over a 20-year period. This analysis incorporates all incremental capital and operating costs associated with this proposed project. A summary of the inputs and results of the feasibility are included on page 2, while pages 3 to 6 show detailed feasibility parameters and results.

SUMMARY OF INPUTS

Capital Investments		
Mains	$3,599,872	
Station	$2,326,802	
Land	$470,550	
Total	$6,397,224	
Gas Requirements		
Under Rate 125		
Billing Contract Demand	768,449m^3	/u

SUMMARY OF RESULTS

Net Present Value (20 years)	$0.0
Profitability Index (20 years)	1.0
Customer Contribution	$0.0

APPENDIX 1

Thorold Cogen L.P.

ECONOMIC FEASIBILITY STUDY

FOR A CUSTOMER REVENUE HORIZON OF 20 YEARS

Thorold Cogen L.P.
Economic Feasibility - 20 Year Horizon
Parameters and Results

Line No.	Col. 1 Description	Col. 2	
	FEASIBILITY PARAMETERS		
1.	Discount Rate	5.98%	
2.	CCA Rate	6.00%	
3.	Tax Rate	36.12%	
4.	Municipal Tax rate	0.60%	
5.	Capital Tax Rate	0.23%	
6.	Customer Revenue Horizon (Years)	20	
7.	Billing Contract Demand , m^3	768,449	/u
8.	Annual Distribution Revenues (Dollars)	836,820	
9.	Annual O&M (Dollars)	56,000	
10.	Capital Investment (Dollars)	6,397,224	
	Working Capital		
11.	O&M (Lead days)	(26.90)	
12.	Commodity (Lag days)	4.10	
	FEASIBILITY RESULTS		
13.	Net Present Value (Dollars)	0.0	
14.	Profitability Index	1.000	
15.	Customer Contribution in Aid of Construction (Dollars)	-	

Thorold Cogen L.P.
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 2 Year 0	Col. 3 Year 1	Col. 4 Year 2	Col. 5 Year 3	Col. 6 Year 4	Col. 7 Year 5	Col. 8 Year 6	Col. 9 Year 7	Col. 10 Year 8	Col. 11 Year 9
	Discount factors to project outset	0.988	0.939	0.895	0.844	0.796	0.751	0.709	0.669	0.631	0.596
	INCREMENTAL CAPITAL INVESTMENT										
1.	Investment In Mains	3,599,872	-	-	-	-	-	-	-	-	-
2.	Investment in Services	-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations	2,326,802	-	-	-	-	-	-	-	-	-
4.	Investment in Land	470,550	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction	-	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital	6,397,224	-	-	-	-	-	-	-	-	-
7.	Working Capital	-	4,127	-	-	-	-	-	-	-	-
8.	Total Investment	6,397,224		-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset	6,316,364	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**
	CCA TAX SHIELD										
11.	CCA Tax Shield		64,221	124,590	117,114	110,087	103,482	97,273	91,437	85,951	80,794
12.	PV Of CCA Tax Shield At Project Outset		60,303	111,457	98,855	87,677	77,764	68,971	61,172	54,256	48,121
13.	**ACCUMULATED PV OF CCA TAX SHIELD**		**60,303**	**171,760**	**270,615**	**358,292**	**436,056**	**505,027**	**566,199**	**620,454**	**668,575**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)										
14.	Gas Distribution Revenue		627,615	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820
15.	Gas Costs		-	-	-	-	-	-	-	-	-
16.	O&M Expenses		(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)
17.	Net Operating Cash (Before Taxes)		571,615	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820
18.	PV of Net Operating Cash (Before Taxes) At Project Outset		536,738	698,517	659,081	621,871	586,762	553,635	522,378	492,886	465,059
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**		**536,738**	**1,235,255**	**1,894,336**	**2,516,207**	**3,102,969**	**3,656,603**	**4,178,982**	**4,671,868**	**5,136,927**
	TAXES										
20.	Income Tax (Before Interest Tax Shield)		(187,931)	(263,776)	(264,040)	(264,288)	(264,520)	(264,739)	(264,945)	(265,138)	(265,320)
21.	Municipal Tax		(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)
22.	Capital Tax		(12,935)	(12,159)	(11,429)	(10,744)	(10,099)	(9,493)	(8,923)	(8,388)	(7,885)
23.	Total Taxes		(239,249)	(314,319)	(313,853)	(313,414)	(313,003)	(312,616)	(312,252)	(311,910)	(311,588)
24.	PV of Total Taxes At Project Outset		(224,652)	(281,188)	(264,919)	(249,614)	(235,212)	(221,658)	(208,900)	(196,890)	(185,583)
25.	**ACCUMULATED PV OF TOTAL TAXES**		**(224,652)**	**(505,839)**	**(770,758)**	**(1,020,372)**	**(1,255,584)**	**(1,477,242)**	**(1,686,142)**	**(1,883,032)**	**(2,068,615)**
	ACCUMULATED NPV AND PI										
26.	Net Present Value	(6,316,364)	(5,943,975)	(5,415,189)	(4,922,172)	(4,462,238)	(4,032,924)	(3,631,976)	(3,257,326)	(2,907,075)	(2,579,478)
27.	Profitability Index		0.059	0.143	0.221	0.294	0.362	0.425	0.484	0.540	0.592

Note a) Construction period of 5 months mid-term discounted, April 2009 is the project outset.
Note b) Year 1 Revenue from September 2009 to August 2010.
Note c) Commissioning period - September 2009 to November 2009 inclusive.

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 4, Schedule 6, Attchment F, Page 5 of 6

Thorold Cogen L.P.
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 12 Year 10	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
	Discount factors to project outset	0.562	0.530	0.500	0.472	0.445	0.420	0.397	0.374	0.353	0.333	0.314
	INCREMENTAL CAPITAL INVESTMENT											
1.	Investment In Mains	-	-	-	-	-	-	-	-	-	-	-
2.	Investment in Services	-	-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations	-	-	-	-	-	-	-	-	-	-	-
4.	Investment in Land	-	-	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction	-	-	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-	-
7.	Working Capital	-	-	-	-	-	-	-	-	-	-	-
8.	Total Investment	-	-	-	-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**
	CCA TAX SHIELD											
11.	CCA Tax Shield	75,946	71,389	67,106	63,079	59,295	55,737	52,393	49,249	46,294	43,517	361,773
12.	PV Of CCA Tax Shield At Project Outset	42,680	37,854	33,574	29,778	26,411	23,424	20,776	18,427	16,343	14,495	113,703
13.	**ACCUMULATED PV OF CCA TAX SHIELD**	**711,255**	**749,109**	**782,683**	**812,461**	**838,872**	**862,296**	**883,072**	**901,499**	**917,842**	**932,337**	**1,046,040**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)											
14.	Gas Distribution Revenue	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820
15.	Gas Costs	-	-	-	-	-	-	-	-	-	-	-
16.	O&M Expenses	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)
17.	Net Operating Cash (Before Taxes)	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820
18.	PV of Net Operating Cash (Before Taxes) At Project Outset	438,803	414,029	390,654	368,599	347,789	328,154	309,627	292,146	275,652	260,090	245,406
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	**5,575,730**	**5,989,759**	**6,380,413**	**6,749,012**	**7,096,801**	**7,424,955**	**7,734,582**	**8,026,728**	**8,302,381**	**8,562,471**	**8,807,876**
	TAXES											
20.	Income Tax (Before Interest Tax Shield)	(265,491)	(265,652)	(265,803)	(265,945)	(266,078)	(266,203)	(266,321)	(266,432)	(266,536)	(266,634)	(266,726)
21.	Municipal Tax	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)
22.	Capital Tax	(7,412)	(6,967)	(6,549)	(6,156)	(5,787)	(5,439)	(5,113)	(4,806)	(4,518)	(4,247)	(37,305)
23.	Total Taxes	(311,286)	(311,002)	(310,735)	(310,484)	(310,248)	(310,026)	(309,818)	(309,622)	(309,438)	(309,264)	(342,414)
24.	PV of Total Taxes At Project Outset	(174,936)	(164,909)	(155,465)	(146,569)	(138,189)	(130,294)	(122,855)	(115,846)	(109,241)	(103,015)	(107,618)
25.	**ACCUMULATED PV OF TOTAL TAXES**	**(2,243,551)**	**(2,408,460)**	**(2,563,924)**	**(2,710,493)**	**(2,848,682)**	**(2,978,977)**	**(3,101,832)**	**(3,217,678)**	**(3,326,918)**	**(3,429,934)**	**(3,537,552)**
	ACCUMULATED NPV AND PI											
26.	Net Present Value	(2,272,931)	(1,985,956)	(1,717,192)	(1,465,384)	(1,229,374)	(1,008,090)	(800,542)	(605,815)	(423,060)	(251,490)	**(0)**
27.	Profitability Index	0.640	0.686	0.728	0.768	0.805	0.840	0.873	0.904	0.933	0.960	**1.000**

Note a) Construction period of 5 months mid-term discounted, April 2009 is the project outset.
Note b) Year 1 Revenue from September 2009 to August 2010.
Note c) Commissioning period - September 2009 to November 2009 inclusive.

...continued.

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 4, Schedule 6, Attchment F, Page 6 of 6

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2009-0187

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 pursuant to Section 90(1) of the *Ontario Energy Board Act, 1998,* granting leave to construct a natural gas pipeline in the Region of York.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Sommerville
Member

Ken Quesnelle
Member

DECISION AND ORDER

Enbridge Gas Distribution Inc. ("Enbridge") filed an application with the Ontario Energy Board (the "Board") on September 3, 2009, under section 90 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, Schedule B, (the "Act") for an order granting leave to construct approximately 16.7 kilometres of 406 millimetre (16 inch) diameter Extra High Pressure steel pipeline to deliver natural gas to the York Energy Centre LP, a proposed natural gas generating facility. The Board has assigned the application file number EB-2009-0187.

For the reasons set out below, the Board finds the construction of the proposed pipeline to be in the public interest and grants the leave to construct on the terms and conditions

(Conditions of Approval) set out in this Decision. The Board's Conditions of Approval are attached as Appendix A.

The Proposed Pipeline

The proposed pipeline route begins at Enbridge's Schomberg Gate Station located at 4955 Lloydtown-Aurora Road and proceeds east along the road allowance of Lloydtown-Aurora Road for approximately 5.5 kilometres to Jane Street. The pipeline then proceeds north along Jane Street for 3.0 kilometres to Highway 9. The pipeline follows Highway 9 eastwards for 4.2 kilometres to Dufferin Street. It then proceeds north along Dufferin Street for 3.6 kilometres and then proceeds east for approximately 0.4 kilometres to the proposed York Energy Centre, located at 18781 Dufferin Street. Construction is scheduled to start in the spring of 2010 with a planned commissioning during the second quarter of 2011 and in-service date in the last quarter of 2011.

A map showing the location of the proposed pipeline is attached as Appendix B.

The Proceeding

The Board issued a Notice of Application and Hearing dated September 22, 2009. The Board proceeded by way of a written hearing.

Intervenor status was granted to the York Region District School Board ("YRDSB") on behalf of Kettleby Public School, York Energy Centre LP ("YEC"), a customer supporting the pipeline approval and Hunter's Green Rate Payers Association, represented by Harten a Division of Harten Group ("Harten"). Harten was the only intervenor who requested and was granted cost award eligibility status and is the only intervenor who actively participated in the proceeding and opposed the approval of the application.

The Board granted Observer status to the Ontario Greenbelt Alliance and to the Global Environmental Action Group, both not-for-profit environmental organizations.

The Board also received letters of comment from Indian and Northern Affairs Canada ("INAC"), York Region Environmental Services Department ("York Region") and Save the Oak Ridges Moraine Coalition ("STORM").

On November 5, 2009 the Board issued Procedural Order No. 1 setting out a schedule for a written proceeding.

On November 27, 2009 the Board issued Procedural Order No.2 with an approved Issues List which set the scope of the proceeding.

Board Staff and Harten filed written interrogatories to Enbridge on December 11 and December 16, 2009 respectively and Enbridge responded on December 21, 2009. Harten filed intervenor evidence on January 8, 2010. Enbridge asked interrogatories on Harten's evidence on January 18, 2010 and Harten responded on January 25, 2010.

Enbridge filed its argument-in-chief on February 8, 2010. Board Staff and Harten filed their respective written submissions on February 12, 2010. Enbridge's reply argument was filed on February 22, 2010. This completed the record of the proceeding.
As part of its submissions, Harten claimed that there exists a conflict of interest among legal representatives of Enbridge in this proceeding. It asserts the conflict arises because members of the same law firm acted for the Ontario Power Authority ("OPA") in its generation procurement process, which resulted in YEC's agreement with the OPA.

Enbridge responded that, in its view, there is no conflict of interest. It argued that the fact that members from the same firm acted for different parties in the two processes does not result in a conflict of interest.

The Board agrees. The two processes referred to have very different elements and there is no inherent conflict. The OPA process was directed to the identification of an appropriate generation solution for York region. The Board's process, that is this proceeding, concerns itself with the leave to construct facilities by the local gas distribution to support the generation solution selected. These are very different regulatory processes, which are merely tangentially related.

The Public Interest Test

This is an application under section 90 of the Act seeking an order for leave to construct a natural gas pipeline. Section 96 of the Act provides that the Board shall make an Order granting leave if the Board finds that "the construction, expansion or reinforcement of the proposed work is in the public interest". When determining whether a project is in the public interest, the Board typically examines the need for the

project, the economics of the project, the impact on the ratepayers, environmental impact and the impact on land owners.

The Board set out the following four issues as defining the scope of the proceeding:

- Is there a need for the proposed pipeline?
- Are there any undue negative rate implications for Enbridge's rate payers caused by the construction and operation of the proposed pipeline?
- What are the environmental impacts associated with construction of the proposed pipeline and are they acceptable?
- Are there any outstanding landowner matters for the proposed pipeline routing and construction?

Each of these issues is addressed below.

The Need for the Project

The need for the proposed pipeline is based on the requirement to provide a dedicated gas supply to the YEC generating peaking facility. The YEC has a 20 year Gas Delivery Agreement ("GDA") with Enbridge which supports that need.

YEC has entered into a 20-year agreement with the Ontario Power Authority ("OPA") to generate and supply electricity to Ontario. This agreement was the result of an OPA-administered competitive procurement process as per a directive of the Ontario Ministry of Energy. YEC is an intervenor in this proceeding and as the customer receiving natural gas on the proposed pipeline. YEC supports the need for the project and the approval of the application.

Harten pointed that the Council of the Township of King opposes the location of the YEC within the municipality. Harten provided, in written submissions and as part of its written evidence, a history of the Township's opposition. Specifically, Harten noted that the Township passed an Interim Control By-Law #2010-05 per section 38 of the

Planning Act, R.S.O. 1990 ("Interim By-Law")[1]which allows the Township to conduct a review of land use policies with respect to power generation facilities. Harten posited that the Township's unwillingness to host the generating plant was relevant because the pipeline was "an integral component of the generator project" and therefore could not be treated separately when reviewing the leave to construct by the Board.

Enbridge replied that in its view the "…Board's jurisdiction is limited to the pipeline" and that the generating plant location approvals are outside the scope of EB-2009-1087 proceeding.

The Board noted at the outset of this proceeding, in Procedural Order No. 1, that its jurisdiction in this case is restricted to the review of matters related to the construction and operation of Enbridge's proposed pipelines. Matters related to the location, construction, operation or impacts of the generating station are not within the scope of the Board review.

Board Staff submitted that there are no outstanding issues related to the need for the pipeline.

The Board finds that Enbridge has adequately addressed the need for the pipeline.

Project Economics and Ratepayers Protection

The estimated capital cost of the pipeline is about $ 39 million. An economic evaluation of the project was conducted using the Discounted Cash Flow methodology as set out in the "OEB Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario" part of the "EBO 188 Report of the Board" dated January 1998. The Profitability Index ("PI") of the project is 1.0 over a 20 year customer horizon. This PI is achieved with the inclusion of a Contribution in Aid of Construction ("CIAC") to be paid by the YEC.

Enbridge's evidence is that its ratepayers would be protected from financial risks occurring prior to pipeline construction, upon construction and during the operation of the YEC.

[1] The Interim By-Law allows the Township of King to conduct a review of land use policies with respect to power generation facilities (EB-2009-0187 "Harten Consulting-Final Submission" February 15, 2010, page 3, paragraph 5)

Harten outlined concerns with the economics of the project and that the "…ultimate cost of course is borne by ratepayers".[2] Enbridge responded that other Enbridge ratepayers were protected and would not be subsidizing the YEC with regard to capital cost recovery. Enbridge submitted that there would be no residual depreciation after the 20-year GDA had been completed and there would be no impact on ratepayers. In addition, Enbridge replied that Board approved Rate 125 parameters were such that the revenue from the YEC would be received even if no gas is used by the generating plant.

The YEC also provided financial assurance to Enbridge in the form of an irrevocable Letter of Credit. The economic feasibility of the project is achieved by establishing the CIAC to be paid by the YEC in an estimated amount of $12.3 million, which amount will be adjusted after the actual cost of construction is determined.

Enbridge also provided evidence that the revenues from the YEC are in accordance with Board approved Enbridge's Extra Large Firm Distribution Service Rate 125 which is the rate in the GDA. This rate is independent of the volume of gas YEC would consume. It protects the ratepayers during the operation of the YEC, because the revenues are based on the billing Contract Demand specified in the GDA. The Contract Demand is a maximum volume contracted that a customer has a right to receive each day. Monthly revenue consists of Monthly Customer Charge ($500.00), plus Demand Charge (fixed at 9.0093 cents per cubic metre of the Contract Demand per month), plus Direct Purchase Administration Charge ($50), plus Forecast Unaccounted for Gas Percentage (0.3%)).

Board Staff submitted that there are no outstanding issues relative to the ratepayers protection and economics as long as Enbridge adheres to the Conditions of Approval.

The Board finds Enbridge's position to be acceptable and concludes that there is no identified risk to Enbridge's ratepayers related to construction and operation of the proposed pipeline.

The financial protections established for the ratepayers are specified in the GDA. The Board has included in the Conditions of Approval a requirement for Board approval of alterations and amendments to the GDA as follows:

[2] EB-2009-0187 "Harten Consulting Evidence", January 4, 2010, page 10.

5.2 Enbridge shall not, without prior approval of the Board, consent to any alteration or amendment to the Gas Delivery Agreement dated and executed on August 28, 2009 where such alteration or amendment has or may have any material impact on Enbridge's ratepayers.

With respect to the Board's monitoring of any changes to the letter of credit related to the costs of construction and CIAC calculation, the Board has included the following as a condition of approval:

5.3 Enbridge shall file with the Board, copies of changes to the York Energy Centre LP's irrevocable bank letter of credit and Contribution in Aid of Construction payments. This filing shall take place not later than 14 days after receipt of change or payment and shall be in place until the end of construction.

The Board finds that the GDA contains all the necessary terms to protect Enbridge and its ratepayers from the financial harm should the pipeline construction be postponed or cancelled if the YEC is not built.

Environmental Assessment

The proposed route is located entirely within the road allowance. It is located in the area covered by "Oak Ridges Moraine Plan" and the "Greenbelt Plan". The routing and environmental assessment, including proposed mitigation for potential environmental impacts have been completed and filed as evidence in the Environmental Report ("ER"). The ER was prepared by Jacques Whitford Stantec Limited ("Stantec") an independent environmental consultant, retained by Enbridge. The ER and supporting evidence filed in the proceeding relating to the proposed pipeline have been produced in accordance with the *"OEB Environmental Guidelines for Hydrocarbon Pipelines and Facilities in Ontario" (2003).* The ER was reviewed by the Ontario Pipeline Coordinating Committee ("OPCC") and Enbridge confirmed that it would address any concerns raised in this review. This is addressed in Conditions of Approval-Condition 1.3.

The STORM, in a letter of comment dated October 15, 2009, stated that in their view the assessment of the different parts of the project, such as generating plant and the pipeline should be coordinated under an "umbrella assessment of the need for and potential impacts…"of the pipeline. STORM also noted that it participated in the generating plant selection process and that it continues to support the position of Concerned Citizens of King Township ("CCKT") in questioning the "…the need for the

project and the ability of the process to conform to both the Oak Ridges Moraine Conservation Plan and the Greenbelt Plan."

INAC, in a letter of comment dated September 21, 2009, stated that it would not be reviewing the project but provided sources of information to assist the applicant with "… inviting interested First Nation communities to participate…" .

York Region, Water Resources Business Unit, in a letter of comment dated October 21, 2009 did not oppose the proposed project but noted that the pipeline must conform to the requirements of the Oak Ridges Moraine Conservation Plan (2001) and the York Regional Plan.

The Board finds that Enbridge has addressed the comments of INAC, STORM and York Region appropriately. The Board also notes that comments of STORM are not directly related to the pipeline approval proceeding but rather comments on the way provincial legislation deals with approvals of all aspects of the generating plant project.

Harten submitted that the Board should not grant its approval until all permits "from third party agencies" are obtained by Enbridge. In particular, Harten addressed the approvals and permits required from: the Lake Simcoe Conservation Authority ("LSCA") and the Regional Municipality of York ("York Region").

Harten maintained that environmental studies undertaken for the proposed pipeline project are inadequate. Harten submitted that the potential impacts and mitigation of the proposed pipeline on water resources, fisheries, and wildlife were not adequately addressed. Harten also argued that the application is deficient in that it does not meet many of the legal requirements related to environmental assessment and protection including the *Environmental Assessment Act*.

Enbridge replied that the environmental assessment under the *Environmental Assessment Act* is not applicable to the pipeline project. Enbridge maintains that the ER by Stantec is prepared in accordance with the *"OEB Environmental Guidelines for Hydrocarbon Pipelines and Facilities in Ontario" (2003).* Enbridge updated the pre-filed evidence to include a hydrogeologic assessment[3]. Enbridge submitted that it has

[3] On January 29, 2010 Enbridge filed new evidence-"Hydrogeologic Investigation, Final Report" (Exhibit B, Tab 2, Schedule 5).

undertaken the environmental assessment, the archaeological assessment, hydrological assessment, and the hydrogeological assessment. Enbridge indicated that there has been no specific evidence that Enbridge has failed to meet any of the applicable requirements.

The Board is aware that other approvals will be required for Enbridge to construct the pipeline. The Board finds that Enbridge's compliance with the Conditions of Approval would ensure that issues around other permits, approvals and pipeline related environmental impacts and mitigation are fully addressed. The Board is satisfied that the environmental assessment followed the requirements of the Board's Environmental Guidelines. The Board finds that the location, mitigation and monitoring programs associated with the proposed pipeline by Enbridge are acceptable. The pipeline location, mitigation and restoration programs are consistent with the requirements of the Oak Ridges Moraine Conservation Plan (2001) and the York Regional Plan.

Regarding other approvals and permits, including applicable land use and environmental protection approvals for construction and operation of the proposed pipeline, the Board finds that condition 5.1, addresses the matter appropriately:

5.1 Enbridge shall obtain all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project, shall provide a list thereof, and shall provide copies of all such written approvals, permits, licences, and certificates upon the Board's request.

The Board finds that the evidence supports the appropriate mitigation and restoration programs required to construct the pipeline. To ensure mitigation of impacts, restoration of land and protection of endangered species, land and water resources Board imposed monitoring and reporting requirements in the Conditions of Approval.

Land Issues

The proposed route is located in the road allowances. Enbridge needs permission from the Ministry of Transportation, the Region of York and the Township of King for the location of the pipeline. Enbridge stated that the approvals by the Region of York have to be acquired from the Engineer/Road Superintendent and that this process has been started and will be completed in time for construction. Also, Enbridge stated that an Encroachment Permit to cross Hwy 400 is required from the Ministry of Transportation

and that it also needs to meet the Township of King's requirements for project construction.

The Board's condition 5.1, that requires that all other approvals be obtained by Enbridge, includes the permits to locate the pipeline within municipal road allowances.

Enbridge submits that temporary easements may be required during the construction if the road allowance is not sufficient to complete construction. For these locations Enbridge stated it would obtain temporary easement agreements in the form approved by the Board.

YRDSB expressed a concern regarding the safe construction and access in the proximity of Kettleby Public School. These concerns were addressed by Enbridge in its submission. Enbridge stated that the pipeline would be located across the road from the Kettleby Public School and that traffic management during construction would be in accordance with the requirements of the Ministry of Transportation.

Harten submitted that the operational safety risk of the proposed pipeline is higher than for other pipelines operated by Enbridge. Harten proposed that a comprehensive disaster contingency plan "…should be prepared by Enbridge and Regulators and made available for public scrutiny and comment before any leave to construct is granted."[4]

Enbridge's evidence is that the proposed pipeline is designed in accordance with requirements of Ontario Regulation 210/01, Oil and Gas Pipeline Systems, under the *Technical Standards and Safety Act, 2008* and the CSA Z662-07 Oil and Gas Pipeline Systems standard. Enbridge also noted that the Technical Standards and Safety Authority ("TSSA") reviewed the pipeline design specification and did not raise any issues regarding the safe operation of the pipeline.

The Board finds that the proposed pipeline adheres to the regulatory requirements for safe operation. Also, the TSSA, as the agency overseeing the operation of the pipelines in Ontario, has the authority to implement all of the applicable standards and regulatory requirements.

[4] EB-2009-0187 "Harten Consulting-Final Submission", February 15, 2010, page 7 paragraph 14.

Orders Granted

For the reasons set out above, the Board finds that the pipeline project being proposed by Enbridge in this proceeding is in the public interest and grants Enbridge leave to construct subject to the conditions set out in Appendix A.

THE BOARD ORDERS THAT:

1. Enbridge Gas Distribution Inc. is granted leave, pursuant to subsection 90 (1) of the Act, to construct approximately 16.7 kilometres of 406 millimetre (16 inch) diameter Extra High Pressure steel pipeline, subject to the conditions of approval set forth in Appendix A.

2. Enbridge Gas Distribution Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, April 5, 2010

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX "A"

TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2009-0187

DATED April 5, 2010

CONDITIONS OF APPROVAL

EB-2009-0187

Enbridge Gas Distribution Inc.
Leave to Construct Application

Conditions of Approval

1 General Requirements

1.1 Enbridge Gas Distribution Inc. ("Enbridge") shall construct the facilities and restore the land in accordance with its application and the evidence filed in EB-2009-0187 except as modified by this Order and these Conditions of Approval.

1.2 Unless otherwise ordered by the Board, authorization for Leave to Construct shall terminate December 31, 2010, unless construction has commenced prior to that date.

1.3 Enbridge shall implement all the recommendations of the Environmental Report filed in the pre-filed evidence, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee ("OPCC") review.

1.4 Enbridge shall advise the Board's designated representative of any proposed material change in construction or restoration procedures and, except in an emergency, Enbridge shall not make such change without prior approval of the Board or its designated representative. In the event of an emergency, the Board shall be informed immediately after the fact.

2 Project and Communications Requirements

2.1 The Board's designated representative for the purpose of these Conditions of Approval shall be the Manager, Natural Gas Applications.

2.2 Enbridge shall designate a person as project engineer and shall provide the name of the individual to the Board's designated representative. The project engineer will be responsible for the fulfillment of the Conditions of Approval on the construction site. Enbridge shall provide a copy of the Order and Conditions of Approval to the project engineer, within seven days of the Board's Order being issued.

2.3 Enbridge shall give the Board's designated representative and the Chair of the OPCC ten days written notice in advance of the commencement of the construction.

2.4 Enbridge shall furnish the Board's designated representative with all reasonable assistance for ascertaining whether the work is being or has been performed in accordance with the Board's Order.

2.5 Enbridge shall file with the Board's designated representative notice of the date on which the installed pipelines were tested, within one month after the final test date.

2.6 Enbridge shall furnish the Board's designated representative with five copies of written confirmation of the completion of construction. A copy of the confirmation shall be provided to the Chair of the OPCC.

3 Monitoring and Reporting Requirements

3.1 Both during and after construction, Enbridge shall monitor the impacts of construction, and shall file four copies of both an interim and a final monitoring report with the Board. The interim monitoring report shall be filed within six months of the in-service date, and the final monitoring report shall be filed within fifteen months of the in-service date. Enbridge shall attach a log of all complaints that have been received to the interim and final monitoring reports. The log shall record the times of all complaints received, the substance of each complaint, the actions taken in response, and the reasons underlying such actions.

3.2 The interim monitoring report shall confirm Enbridge's adherence to Condition 1.1 and shall include a description of the impacts noted during construction and the actions taken or to be taken to prevent or mitigate the long-term effects of the impacts of construction. This report shall describe any outstanding concerns identified during construction.

3.3 The final monitoring report shall describe the condition of any rehabilitated land and the effectiveness of any mitigation measures undertaken. The results of the monitoring programs and analysis shall be included and recommendations made as appropriate. Any deficiency in compliance with any of the Conditions of Approval shall be explained.

4 Easement Agreements

4.1 Enbridge shall offer the form of agreement approved by the Board to each landowner, as may be required, along the route of the proposed work.

5 Other Approvals and Agreements

5.1 Enbridge shall obtain all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project, shall provide a

list thereof, and shall provide copies of all such written approvals, permits, licences, and certificates upon the Board's request.

5.2 Enbridge shall not, without prior approval of the Board, consent to any alteration or amendment to the Gas Delivery Agreement dated and executed on August 28, 2009 where such alteration or amendment has or may have any material impact on Enbridge's ratepayers.

5.3 Enbridge shall file with the Board, copies of changes to the York Energy Centre LP's irrevocable bank letter of credit and Contribution in Aid of Construction payments. This filing shall take place not later than 14 days after receipt of change or payment and shall be in place until the end of construction.

APPENDIX "B"

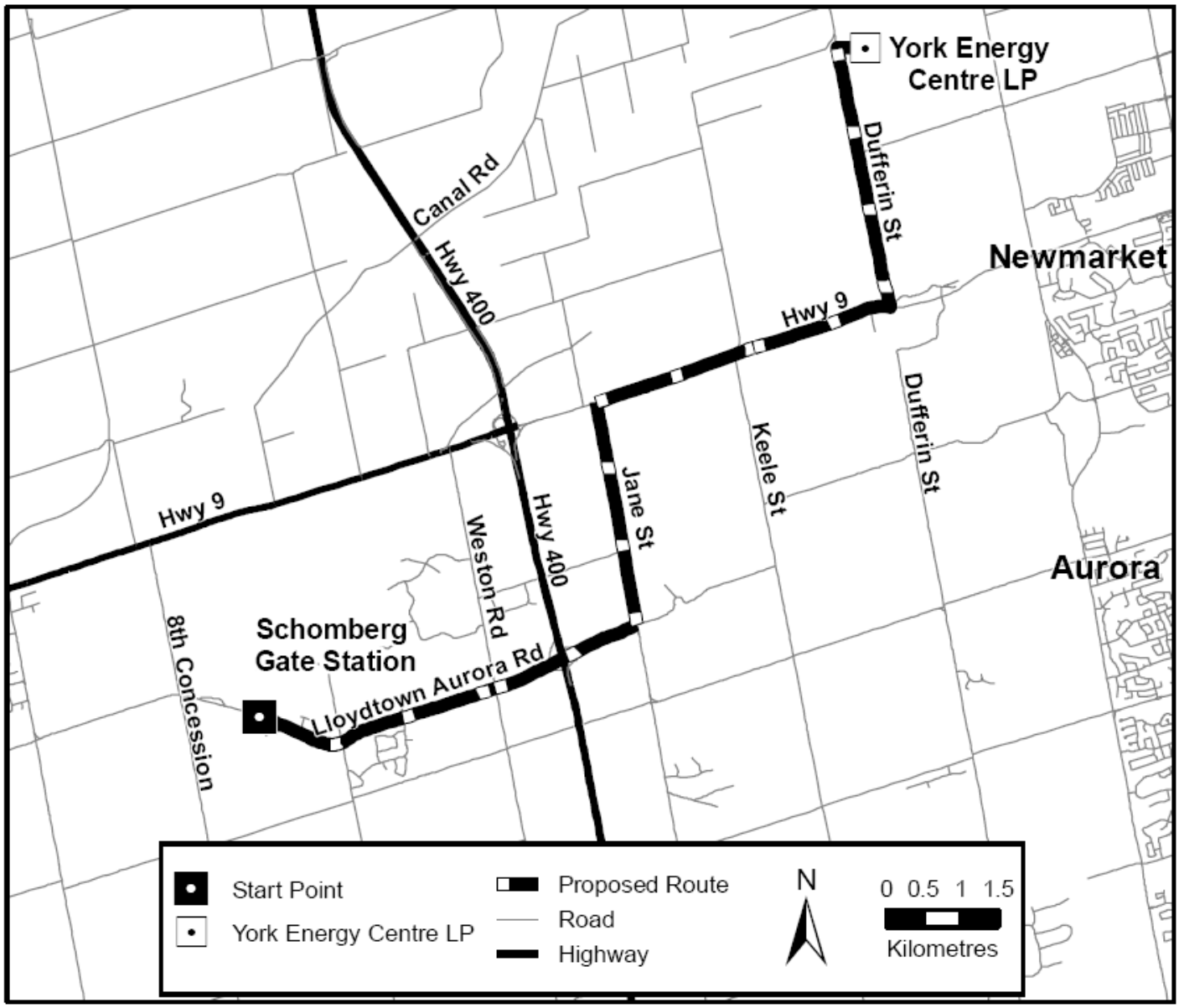
TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2009-0187

DATED April 5, 2010

MAP OF THE PIPELINE ROUTE

Enbridge Gas Distribution Inc.
York Energy Centre Pipline Project



ECONOMIC FEASIBILITY

METHODOLOGY

1. The economic feasibility of the project has been determined using a methodology that adheres to the *"Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario"* and the EBO 188 *"Report of the Board"* dated January 30, 1998.

2. The economic feasibility of the project has been calculated by discounting incremental cash flows over a 20-year customer revenue horizon. The resulting Net Present Value ("NPV") represents both the economic feasibility of the project from the utility's perspective and its effect within the Rolling Project Portfolio. An NPV greater than zero indicates the project will make a positive contribution to the Rolling Project Portfolio and will be feasible from a utility cash flow perspective. Since the project NPV is less than zero, a Contribution in Aid of Construction ("CIAC") is required. York Energy Centre LP ("YEC") has agreed to pay the contribution. The details of the NPV and YEC contribution to the project are in Exhibit E, Tab 1, Schedule 2.

KEY ASSUMPTIONS

Customer Revenue Horizon

3. Feasibility analysis for the project is based upon a 20-year customer revenue horizon. The first year revenue is calculated based on six months since the Gas Delivery Agreement has a six month commissioning period.

Capital Costs

4. The project capital costs are estimated to be $39,104,542. The detailed capital cost estimates are provided in Exhibit E, Tab 1, Schedule 2. The construction period is assumed to be 11 months. Enbidge Gas Distribution Inc. ("Enbridge") is seeking a

contribution of $12.3 million. Within approximately 15 months of completion of the installation and commissioning of the distribution line and related infrastructure, YEC will establish the final CIAC based on the actual costs incurred to complete such installation. The final CIAC so established will be used for purposes of this Agreement.

Enbridge has arranged for financial assurance from YEC for the investment exposure. This is required to mitigate the risk associated with power plants and to protect the interests of existing ratepayers.

Contract Demand

5. The gas deliveries to the YEC will be under Rate 125. The daily contract demand is based on twenty-four times the maximum hourly flow and is established as 3 264 000 m^3.

Summary

6. The feasibility for the York Energy Centre project has been prepared based on Enbridge's latest feasibility parameters.

7. The analysis contained in Exhibit E, Tab 1, Schedule 2, shows the project has a Profitability Index ("PI") of 1.0 after customer contribution in the amount of $12.3 million. The project meets the minimum project acceptance threshold PI of 1.0, and thus qualifies for approval by the Ontario Energy Board on the basis of this analysis.

Filed: 2009-09-03
EB-2009-0187
Exhibit E
Tab 1
Schedule 2
Page 1 of 6

ECONOMIC FEASIBILITY TEST

1. The following economic feasibility evidence has been completed based upon Enbridge Gas Distribution's latest feasibility parameters.

2. Discounted cash flow ("DCF") analysis is adopted to calculate net present value ("NPV") and profitability index ("PI") for the project. The economic feasibility of the project has been tested using the incremental revenues and costs associated with the project forecast over a 20-year period. This analysis incorporates all incremental capital and operating costs associated with this proposed project. A summary of the inputs and results of the feasibility are included on page 2, while pages 3 to 6 show detailed feasibility parameters and results.

SUMMARY OF INPUTS

Capital Investments	
Mains	$32,794,236
Stations	$5,506,197
Meters	$129,109
Land	$675,000
Total	$39,104,542

Gas Requirements	
Under Rate 125	
Contract Demand	3,264,000m^3

SUMMARY OF RESULTS

Net Present Value (20 years)	$0.0
Profitability Index (20 years)	1.0
Customer Contribution	$12,282,266

APPENDIX 1

York Energy Centre

ECONOMIC FEASIBILITY STUDY

FOR A CUSTOMER REVENUE HORIZON OF 20 YEARS

York Energy Centre
Economic Feasibility - 20 Year Horizon
Parameters and Results

Line No.	Col. 1 Description	Col. 2
	FEASIBILITY PARAMETERS	
1.	Discount Rate	5.75%
2.	CCA Rate	6.00%
3.	Tax Rate	33.00%
4.	Municipal Tax rate	0.62%
5.	Capital Tax Rate	0.23%
6.	Customer Revenue Horizon (Years)	20
7.	Contract Demand , m^3	3,264,000
8.	Annual Distribution Revenues (Dollars)	3,532,973
9.	Annual O&M (Dollars)	320,820
10.	Capital Investment (Dollars)	39,104,542
	Working Capital	
11.	O&M (Lead days)	(27.00)
12.	Commodity (Lag days)	4.40
13	Rate 125 (Effective July 1, 2009 - EB-2009-0145)*	
	FEASIBILITY RESULTS	
14.	Net Present Value (Dollars)	-
15.	Profitability Index	1.000
16.	Customer Contribution in Aid of Construction (Dollars)	12,282,266

* Refer to Exhibit E, Tab1, Schedule 3.

York Energy Centre

DCF Analysis

Line No.	Description	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
			Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
	Discount factors to project outset		0.975	0.911	0.874	0.826	0.781	0.739	0.699	0.661	0.625	0.591
	INCREMENTAL CAPITAL INVESTMENT											
1.	Investment In Mains		(32,794,236)	-	-	-	-	-	-	-	-	-
2.	Investment in Meters		(129,109)	-	-	-	-	-	-	-	-	-
3.	Investment in Stations		(5,506,197)	-	-	-	-	-	-	-	-	-
4.	Investment in Land		(675,000)	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction		12,282,266	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital		(26,822,276)	-	-	-	-	-	-	-	-	-
7.	Working Capital		-	23,732	-	-	-	-	-	-	-	-
8.	Total Investment		(26,822,276)		-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset		(26,122,367)	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**		**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**
	CCA TAX SHIELD											
11.	CCA Tax Shield			260,957	506,256	475,881	447,328	420,488	395,259	371,544	349,251	328,296
12.	PV Of CCA Tax Shield At Project Outset			237,749	442,301	393,166	349,489	310,664	276,152	245,475	218,205	193,965
13.	**ACCUMULATED PV OF CCA TAX SHIELD**			**237,749**	**680,050**	**1,073,216**	**1,422,705**	**1,733,369**	**2,009,521**	**2,254,996**	**2,473,201**	**2,667,165**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)											
14.	Gas Distribution Revenue			1,766,487	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973
15.	Gas Costs			-	-	-	-	-	-	-	-	-
16.	O&M Expenses			(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)
17.	Net Operating Cash (Before Taxes)			1,445,667	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153
18.	PV of Net Operating Cash (Before Taxes) At Project Outset			1,317,098	2,806,361	2,653,832	2,509,594	2,373,194	2,244,209	2,122,233	2,006,888	1,897,811
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**			**1,317,098**	**4,123,459**	**6,777,291**	**9,286,885**	**11,660,079**	**13,904,288**	**16,026,521**	**18,033,409**	**19,931,220**
	TAXES											
20.	Income Tax (Before Interest Tax Shield)			(403,254)	(987,334)	(988,405)	(989,411)	(990,357)	(991,247)	(992,083)	(992,868)	(993,607)
21.	Municipal Tax			(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)
22.	Capital Tax			(57,529)	(54,077)	(50,833)	(47,783)	(44,916)	(42,221)	(39,688)	(37,306)	(35,068)
23.	Total Taxes			(626,938)	(1,207,566)	(1,205,392)	(1,203,349)	(1,201,428)	(1,199,622)	(1,197,925)	(1,196,329)	(1,194,830)
24.	PV of Total Taxes At Project Outset			(571,182)	(1,055,014)	(995,877)	(940,153)	(887,636)	(838,130)	(791,455)	(747,442)	(705,932)
25.	**ACCUMULATED PV OF TOTAL TAXES**			**(571,182)**	**(1,626,196)**	**(2,622,073)**	**(3,562,226)**	**(4,449,862)**	**(5,287,992)**	**(6,079,447)**	**(6,826,889)**	**(7,532,821)**
	ACCUMULATED NPV AND PI											
26.	Net Present Value		(26,122,367)	(25,138,702)	(22,945,054)	(20,893,933)	(18,975,003)	(17,178,781)	(15,496,550)	(13,920,297)	(12,442,647)	(11,056,803)
27.	Profitability Index			0.038	0.122	0.200	0.274	0.342	0.407	0.467	0.524	0.577

Note a) Construction period of 11 months mid-term discounted, May 2010 is the project outset.
Note b) Year 1 Revenue from April 1st 2011 to March 31st 2012.
Note c) Commissioning period - April 2011 to September 2011 inclusive.

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 4, Schedule 6, Attachment I, Page 5 of 6

York Energy Centre

DCF Analysis

Line No.	Col. 1 Description	Col. 12 Year 10	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
	Discount factors to project outset	0.559	0.528	0.500	0.472	0.447	0.423	0.400	0.378	0.357	0.338	0.320
	INCREMENTAL CAPITAL INVESTMENT											
1.	Investment In Mains	-	-	-	-	-	-	-	-	-	-	-
2.	Investment in Meters	-	-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations	-	-	-	-	-	-	-	-	-	-	-
4.	Investment in Land	-	-	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction	-	-	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-	-
7.	Working Capital	-	-	-	-	-	-	-	-	-	-	-
8.	Total Investment	-	-	-	-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**	**(26,122,367)**
	CCA TAX SHIELD											
11.	CCA Tax Shield	308,598	290,082	272,677	256,317	240,938	226,481	212,893	200,119	188,112	176,825	1,496,225
12.	PV Of CCA Tax Shield At Project Outset	172,417	153,263	136,237	121,103	107,649	95,691	85,060	75,611	67,211	59,745	478,060
13.	**ACCUMULATED PV OF CCA TAX SHIELD**	**2,839,582**	**2,992,845**	**3,129,083**	**3,250,185**	**3,357,834**	**3,453,525**	**3,538,585**	**3,614,196**	**3,681,407**	**3,741,152**	**4,219,213**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)											
14.	Gas Distribution Revenue	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973	3,532,973
15.	Gas Costs	-	-	-	-	-	-	-	-	-	-	-
16.	O&M Expenses	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)	(320,820)
17.	Net Operating Cash (Before Taxes)	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153	3,212,153
18.	PV of Net Operating Cash (Before Taxes) At Project Outset	1,794,663	1,697,121	1,604,881	1,517,654	1,435,167	1,357,165	1,283,401	1,213,647	1,147,684	1,085,306	1,026,318
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	**21,725,883**	**23,423,004**	**25,027,885**	**26,545,538**	**27,980,706**	**29,337,870**	**30,621,271**	**31,834,918**	**32,982,602**	**34,067,908**	**35,094,227**
	TAXES											
20.	Income Tax (Before Interest Tax Shield)	(994,301)	(994,954)	(995,568)	(996,144)	(996,686)	(997,196)	(997,675)	(998,125)	(998,549)	(998,946)	(999,320)
21.	Municipal Tax	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)	(166,155)
22.	Capital Tax	(32,964)	(30,986)	(29,127)	(27,379)	(25,737)	(24,192)	(22,741)	(21,376)	(20,094)	(18,888)	(168,892)
23.	Total Taxes	(1,193,420)	(1,192,095)	(1,190,849)	(1,189,678)	(1,188,578)	(1,187,543)	(1,186,571)	(1,185,656)	(1,184,797)	(1,183,989)	(1,334,367)
24.	PV of Total Taxes At Project Outset	(666,776)	(629,836)	(594,981)	(562,090)	(531,048)	(501,748)	(474,089)	(447,976)	(423,321)	(400,040)	(426,345)
25.	**ACCUMULATED PV OF TOTAL TAXES**	**(8,199,597)**	**(8,829,433)**	**(9,424,414)**	**(9,986,505)**	**(10,517,553)**	**(11,019,301)**	**(11,493,390)**	**(11,941,366)**	**(12,364,687)**	**(12,764,727)**	**(13,191,072)**
	ACCUMULATED NPV AND PI											
26.	Net Present Value	(9,756,499)	(8,535,950)	(7,389,814)	(6,313,148)	(5,301,379)	(4,350,272)	(3,455,900)	(2,614,618)	(1,823,044)	(1,078,034)	**-**
27.	Profitability Index	0.627	0.673	0.717	0.758	0.797	0.833	0.868	0.900	0.930	0.959	**1.000**

Note a) Construction period of 11 months mid-term discounted, May 2010 is the p

Note b) Year 1 Revenue from April 1st 2011 to March 31st 2012.

Note c) Commissioning period - April 2011 to September 2011 inclusive.

...continued.

CME INTERROGATORY #7

INTERROGATORY

2012 PENSION FUNDING Z FACTOR
Reference: Exhibit B, Tab 2, Schedule 5, and Appendices

The evidence indicates that a regulation was introduced in June 2009 requiring plan sponsors to file an annual actuarial cost certificate. Please provide a copy of that regulation and the date that it went into effect if that date is other than June 23, 2009.

RESPONSE

Please see the attached regulation as released on June 23, 2009.

Witnesses: S. Kancharla
R. Lei
A. Patel

Français

ONTARIO REGULATION 239/09

made under the

PENSION BENEFITS ACT

Made: June 17, 2009
Filed: June 19, 2009
Published on e-Laws: June 23, 2009
Printed in *The Ontario Gazette*: July 4, 2009

Amending Reg. 909 of R.R.O. 1990
(General)

Note: Regulation 909 has previously been amended. For the legislative history of the Regulation, see the Table of Consolidated Regulations – Detailed Legislative History at www.e-Laws.gov.on.ca.

1. (1) The definition of "locked-in retirement account" in subsection 1 (1) of Regulation 909 of the Revised Regulations of Ontario, 1990 is revoked and the following substituted:

"locked-in retirement account" means an RRSP that meets the requirements set out in Schedule 3; ("compte de retraite avec immobilisation des fonds")

(2) Subsection 1 (2) of the Regulation is amended by adding the following definition:

"actuarial cost certificate" means an actuarial cost certificate that satisfies the requirements of section 7.1; ("certificat actuariel")

2. Subsection 4 (2) of the Regulation is amended by striking out "and" at the end of clause (c) and by adding the following clause:

(c.1) all special payments determined in accordance with section 5.6; and

3. Subsection 5 (16) of the Regulation is revoked and the following substituted:

(16) Subject to subsections (13), (14), (15), (16.1) and 5.1 (5), the prior year credit balance to be used in any report or actuarial cost certificate required under this Regulation in respect of a plan is the amount calculated using the formula,

A + B – C

in which,

"A" is the prior year credit balance stated in the last report or actuarial cost certificate filed or submitted in respect of the plan under this Regulation,

"B" is the total amount of contributions made to the plan by an employer or by a person or entity required to make contributions under the plan on behalf of an employer,

(a) after the valuation date of the last report or actuarial cost certificate filed or submitted in respect of the plan under this Regulation, and

(b) before the valuation date for the report or actuarial cost certificate being prepared, and

"C" is the total amount of contributions that, under section 4, would be required to have been made during the period described in the definition of "B" by an employer or by a person or entity required to make contributions under the plan on behalf of an employer if the contributions had been calculated without reference to any prior year credit balance.

4. The Regulation is amended by adding the following sections:

SOLVENCY FUNDING RELIEF

5.6 (1) In this section and section 5.7,

"certificate of consent" means a certificate filed with the Superintendent by the administrator of a plan that is not a jointly governed plan,

(a) that specifies,

(i) the total number of persons who were eligible members or eligible former members on the valuation date of the plan's solvency relief report and on the day the information statement under subsection 5.7 (2) was sent by the administrator, and

(ii) the number of persons described in subclause (i) who either submitted notices of objection to the election of Option 3 by the administrator or were represented by a collective bargaining agent that submitted a notice of objection on their behalf, and

(b) that confirms that the number of objections to the election that were received by the administrator represents objections from not more than one-third of the total number of persons described in subclause (a) (i); ("certificat de consentement")

"consolidated prior solvency deficiency" means, in respect of a plan, the present value as of the valuation date of the solvency relief report of all special payments, other than payments required only by reason of section 75 of the Act,

(a) that are required with respect to any solvency deficiency determined in a report under section 3, 13 or 14 that was filed before the solvency relief report is filed, and

(b) that are scheduled to be paid after the valuation date of the solvency relief report; ("déficit de solvabilité antérieur consolidé")

"eligible former member" means, with respect to a plan, a former member whose pension or pension benefit includes a defined benefit, other than,

(a) a former member who no longer has an entitlement to any payments from the plan, and

(b) a former member for whom a notice of death has been received by the administrator; ("ancien participant admissible")

"eligible member" means, with respect to a plan, a member whose pension benefit includes a defined benefit, other than,

(a) a member who no longer has an entitlement to any payments from the plan, and

(b) a member for whom a notice of death has been received by the administrator; ("participant admissible")

"excluded plan" means,

(a) a plan that does not provide defined benefits,

(b) a plan that is not registered before September 30, 2008 under the Act or the legislation of a province or territory designated under section 23 unless,

(i) the plan is deemed under section 80 of the Act to be a continuation of another plan that was registered before that day,

(ii) the plan is a successor plan described in section 81 of the Act and the original plan was registered before that day, or

(iii) the plan was formed by the merger of two or more plans and at least one of the original plans was registered before that day,

(c) a multi-employer pension plan that is a specified Ontario multi-employer pension plan under section 6.0.1,

(d) a plan that is a participating pension plan under Ontario Regulation 99/06 (Stelco Inc. Pension Plans) made under the Act,

(e) a qualifying plan, or

(f) a plan to which not all of the contributions set out in reports filed under section 3, 13 or 14 that were required to be made before the valuation date of the plan's solvency relief report have been made in accordance with the Act and the regulations; ("régime exclu")

"jointly governed plan" means a plan other than an excluded plan that is,

(a) a jointly sponsored pension plan,

(b) a multi-employer pension plan established pursuant to a collective agreement or a trust agreement,

(c) a plan whose administrator is a pension committee all of whose members are representatives of members of the plan, or

(d) a plan whose administrator is a pension committee described in clause 8 (1) (b) of the Act if at least one-half of the members of the pension committee represent members of the plan or persons receiving pensions under the plan; ("régime à gestion paritaire")

"new going concern unfunded liability" means, with respect to a plan, a going concern unfunded liability determined in the plan's solvency relief report; ("nouveau passif à long terme non capitalisé")

"new solvency deficiency" means, with respect to a plan, a solvency deficiency determined in the plan's solvency relief report; ("nouveau déficit de solvabilité")

"Option 1" means the type of solvency relief described in paragraph 1 of subsection (3); ("option 1")

"Option 2" means the type of solvency relief described in paragraph 2 of subsection (3); ("option 2")

"Option 3" means the type of solvency relief described in paragraph 3 of subsection (3); ("option 3")

"solvency relief report" means, with respect to a plan, the first report filed by the administrator under section 13 or 14 for which the valuation date is on or after September 30, 2008 and before September 30, 2011. ("rapport sur l'allègement de la capitalisation du déficit de solvabilité")

(2) This section applies despite any other provision of this Regulation.

(3) The administrator of a plan that is not an excluded plan, may, subject to this section, elect to use one or more of the following types of solvency relief:

1. If there is a new going concern unfunded liability or a new solvency deficiency, the deferral for up to 12 months of the start of the period during which special payments are required to be made to liquidate them.
2. If a solvency deficiency was determined in a report filed under section 3, 13 or 14 before the solvency relief report is filed and has not been liquidated, the establishment of a new five-year period during which the plan's consolidated prior solvency deficiency is to be liquidated.
3. If there is a new solvency deficiency, the extension of the five-year period during which the new solvency deficiency would otherwise be required to be liquidated for up to an additional five years.

(4) The following exceptions apply for the purposes of this section:

1. The administrator of a jointly sponsored pension plan may not elect Option 1.
2. The administrator of a plan that is one of the new pension plans for the purposes of Ontario Regulation 202/02 (Algoma Steel Inc. Pension Plans) made under the Act, may not elect Option 2.
3. The administrator of a plan that is not a jointly governed plan may not elect Option 3,
   i. if the administrator does not comply with section 5.7,
   ii. if the administrator receives notices of objection representing objections to the election from more than one-third of the persons who are eligible members or eligible former members described in section 5.7, or
   iii. if the administrator fails to file with the Superintendent, not more than 60 days after filing the solvency relief report, a certificate of consent.

(5) An election under this section must be in writing, may be made only once, cannot be rescinded and must be filed with the Superintendent no later than the day on which the solvency relief report is filed with the Superintendent.

(6) If the administrator of a plan makes an election under this section, the following rules apply in the circumstances described in the following paragraphs:

1. If there was a new solvency deficiency or the administrator elected Option 2 and, on a valuation date after the valuation date of the solvency relief report, the sum of the solvency assets and the solvency asset adjustment exceeds the sum of the solvency liabilities, the solvency liability adjustment and the prior year credit balance (such excess being referred to in this paragraph as the "solvency excess"), the special payments or amortization periods under subsection 5 (1) with respect to the new solvency deficiency or the special payments required to be made in respect of the consolidated prior solvency deficiency may be adjusted in accordance with the following rules:
   i. If the solvency excess is greater than or equal to the present value of the special payments under subsection 5 (1) with respect to the new solvency deficiency and the consolidated prior solvency deficiency, the special payments are reduced to zero.
   ii. If the solvency excess is less than the present value of the special payments referred to in subparagraph i, the solvency excess may be applied to reduce any of the following in order to reduce the solvency excess to zero:
      A. The special payments with respect to the new solvency deficiency over the amortization period set out in the solvency relief report.
      B. The special payments with respect to the consolidated prior solvency deficiency over the amortization period set out in the solvency relief report.
      C. The amortization period for the special payments with respect to the new solvency deficiency.
      D. The amortization period for the special payments with respect to the consolidated prior solvency deficiency.

2. If the administrator elects Option 1 and there is a new going concern unfunded liability, the beginning of the 15-year amortization period under subsection 5 (1) for the new going concern unfunded liability may be deferred to a day that is not later than 12 months after the valuation date.

3. If the administrator elects Option 1 and there is a new solvency deficiency,

   i. the beginning of the five-year amortization period under subsection 5 (1) for the new solvency deficiency may be deferred to a day that is not later than 12 months after the valuation date, and

   ii. the solvency asset adjustment under clause 1.2 (1) (d) for the new solvency deficiency must include the present value of all special payments required to be made in respect of any going concern unfunded liability that are scheduled for payment within the period that begins on the valuation date of the solvency relief report and ends at the end of the five-year amortization period chosen by the administrator in accordance with subparagraph i.

4. The period during which special payments are deferred when Option 1 is elected is deemed for the purposes of subsections 7 (3) and (4) to still be a period for which special payments are required to be made under section 5.

5. If the plan is not a jointly sponsored pension plan and the administrator elects Option 2,

   i. the consolidated prior solvency deficiency must be liquidated, with interest at the rates described in subsection 5 (2), by equal monthly instalments over a period of five years beginning on the valuation date of the solvency relief report, instead of over the remaining portion of the amortization period or periods that would otherwise apply,

   ii. the monthly instalments required to liquidate the consolidated prior solvency deficiency are deemed to be special payments under subsection 5 (1) for the purposes of liquidating a solvency deficiency,

   iii. the solvency asset adjustment under clause 1.2 (1) (d) for a new solvency deficiency must include the present value of all special payments required to liquidate the consolidated prior solvency deficiency, and

   iv. the amount by which "A" exceeds "B" may be applied to reduce the amount of any contributions to be made in accordance with the solvency relief report until the next report under section 3, 13 or 14 is filed and, for the purposes of subsection 37 (12), is deemed not to be an excess special payment, where,

      "A" is the amount of the special payments in respect of any solvency deficiency determined in a report filed previously under section 3, 13 or 14 that are made between the valuation date of the solvency relief report and the day the solvency relief report is filed, and

      "B" is the amount of the special payments required to be made in respect of the consolidated prior solvency deficiency between the valuation date of the solvency relief report and the day the solvency relief report is filed.

6. Subject to paragraph 7, if the plan is not a jointly sponsored pension plan, if the administrator elects Option 2 or 3 or both options and if, after the later of the day on which the solvency report is required to be filed and any certificate of consent is required to be filed in respect of the election, the administrator files an amendment to the plan to increase pension benefits or ancillary benefits, any increase in the going concern unfunded liability that results from the amendment must be liquidated, with interest at the going concern valuation interest rate or rates, by special payments determined under section 5 over a period of five years, beginning on the valuation date of the report under section 3 or 14 in which the increase in the going concern unfunded liability is determined.

7. Paragraph 6 does not apply with respect to an increase in a going concern unfunded liability that results from an amendment or a part of an amendment that does not take effect until after the later of,

   i. the day on which the consolidated prior solvency deficiency is liquidated, if the administrator elected Option 2 or both Options 2 and 3, and

   ii. the day on which the remaining period during which the new solvency deficiency must be liquidated is equal to five years, if the administrator elected Option 3 or both Options 2 and 3.

8. If the plan is not a jointly sponsored pension plan and the administrator elects Option 3,

   i. the period in which the new solvency deficiency must be liquidated begins on the valuation date of the solvency relief report and ends on a day not more than 10 years after that day, and

   ii. the solvency asset adjustment under clause 1.2 (1) (d) for the new solvency deficiency must include the present value of all special payments required to be made in respect of any going concern unfunded liability that are scheduled for payment during the period starting on the valuation date of the solvency relief report and ending on the same day the period referred to in subparagraph i ends.

9. If the plan is not a jointly sponsored pension plan and the administrator elects both Options 1 and 3,

i. the period in which the new solvency deficiency must be liquidated begins on a day not more than 12 months after the valuation date of the solvency relief report and ends not more than 10 years after that day, and

ii. the solvency asset adjustment under clause 1.2 (1) (d) for the new solvency deficiency must include the present value of all special payments required to be made in respect of any going concern unfunded liability that are scheduled for payment during the period starting on the valuation date of the solvency relief report and ending on the same day the period referred to in subparagraph i ends.

10. If the plan is a jointly sponsored pension plan and the administrator elects Option 3,

i. the period in which the new solvency deficiency must be liquidated begins on a day not later than 12 months after the valuation date of the solvency relief report and ends not more than 10 years after that day, and

ii. the solvency asset adjustment under clause 1.2 (1) (d) for the new solvency deficiency must include the present value of all special payments required to be made in respect of any going concern unfunded liability that are scheduled for payment during the period starting on the valuation date of the solvency relief report and ending on the same day the period referred to in subparagraph i ends.

11. Subject to paragraph 12, if the plan is a jointly sponsored pension plan, if the administrator elects Option 3 and if, after the day the solvency relief report is required to be filed, the administrator files an amendment to the plan to increase pension benefits or ancillary benefits, any increase in the going concern unfunded liability that results from the amendment must be liquidated, with interest at the going concern valuation interest rate or rates, by special payments determined under section 5 over a period of five years, beginning not later than 12 months after the valuation date of the report under section 3 or 14 in which the increase in the going concern unfunded liability is determined.

12. Paragraph 11 does not apply with respect to an increase in a going concern unfunded liability that results from an amendment or part of an amendment that does not take effect until after the day on which the remaining period during which the new solvency deficiency must be liquidated is equal to five years.

(7) An administrator who makes an election must send a notice containing the following information, not more than 60 days after the first day a special payment is required to be made in respect of the new solvency deficiency, the new going concern unfunded liability or the consolidated prior solvency deficiency, as applicable, to every person who is an eligible member or an eligible former member on the day the notice is sent and to every collective bargaining agent that represents eligible members on that day:

1. The name and provincial registration number of the plan.
2. The name of and the contact information for the administrator.
3. The valuation date of the solvency relief report.
4. A description of the option or options elected.
5. The transfer ratio of the plan as of the valuation date.
6. The estimated annual contributions that would have been required to fund the normal cost of the plan and all special payments if no election had been made and the estimated annual contributions that are required after the election.
7. An explanation of how the security of the pension benefits and ancillary benefits for eligible members and eligible former members might be affected as a result of the election.
8. If the administrator has elected Option 3 and the plan is not a jointly governed plan,

i. confirmation that the collective bargaining agent, if any, objected or chose not to object on behalf of eligible members represented by the collective bargaining agent on the valuation date of the solvency relief report, and

ii. confirmation that any objections to the election received by the administrator represented objections to the election from not more than one-third of the eligible members and eligible former members.

(8) If an administrator of a plan elects Option 3, the administrator shall send a progress report containing the following information, not more than six months after the end of each fiscal year of the plan in which a report under section 3 or 14 is filed until the new solvency deficiency has been liquidated, to every person who is an eligible member or eligible former member on the day the progress report is sent and to every collective bargaining agent that represents eligible members on that day:

1. The name and provincial registration number of the plan.
2. The name of and the contact information for the administrator.
3. The valuation date of the solvency relief report and of the most recently filed report under section 3 or 14.
4. A description of the option or options elected.
5. The transfer ratio of the plan as of the valuation date of the solvency relief report.

6. The transfer ratio of the plan as of the valuation date of the most recently filed report under section 3 or 14 in which the transfer ratio was determined.

7. The estimated annual contributions required to fund the normal cost of the plan and all special payments set out in the report referred to in paragraph 6.

8. An explanation of how the security of the pension benefits and ancillary benefits for eligible members and eligible former members might be affected as a result of the election.

(9) A progress report required under subsection (8) may be included in the written statement for the same fiscal year that is required to be sent to members under section 27 of the Act.

5.7 (1) This section applies if an administrator elects or proposes to elect Option 3 under section 5.6 in respect of a plan that is not a jointly governed plan.

(2) The administrator shall,

(a) send an information statement and a notice of objection form to every person,

(i) who is,

(A) an eligible member on the valuation date of the solvency relief report, and

(B) an eligible member or eligible former member on the day the information statement and notice of objection form are sent, and

(ii) who is not represented by a collective bargaining agent on the valuation date of the solvency relief report;

(b) send an information statement and a notice of objection form to every person who is an eligible former member on the valuation date of the solvency relief report and on the day the information statement and notice of objection form are sent;

(c) send an information statement to every person,

(i) who is,

(A) an eligible member on the valuation date of the solvency relief report, and

(B) an eligible member or eligible former member on the day the information statement is sent, and

(ii) who is represented by a collective bargaining agent on the valuation date of the solvency relief report;

(d) send an information statement and a notice of objection form to each collective bargaining agent that represented eligible members on the valuation date of the solvency relief report; and

(e) provide to the Superintendent a copy of the information statement and the notice of objection form at the time the administrator sends the statements and forms in accordance with clauses (a), (b), (c) or (d) and advise the Superintendent of when the last notice of objection form was sent.

(3) An information statement sent to a person who is an eligible member or eligible former member must be sent to the person's last known address and inform the recipient of the following:

1. The name and provincial registration number of the plan.

2. The name and status of the recipient as an eligible member or eligible former member on the valuation date of the solvency relief report.

3. The name of and the contact information for the administrator.

4. If the recipient is an eligible member on the valuation date of the solvency relief report, whether he or she was represented by a collective bargaining agent on that day.

5. That the administrator of the plan is seeking the consent of eligible members and eligible former members to extend the period of time during which the new solvency deficiency must be liquidated from five years to a period not exceeding 10 years.

6. The amount of the solvency deficiency for which the amortization period would be extended.

7. The transfer ratio of the plan as of the valuation date.

8. The estimated annual contributions that would be required to fund the normal cost of the plan and all special payments if the five-year period is not extended and the estimated annual contributions if the payment period is extended.

9. An explanation of how the security of the pension benefits and ancillary benefits for eligible members and eligible former members might be affected as a result of the election.

10. If the recipient was an eligible member on the valuation date of the solvency relief report and was represented by a collective bargaining agent on that day, a statement that the collective bargaining agent will consent or object to the extension on behalf of the eligible members represented by the collective bargaining agent on that day.

11. If the recipient was an eligible member on the valuation date of the solvency relief report and was not represented by a collective bargaining agent on that day, or was an eligible former member on that day,

    i. that the person may object to the extension by completing and submitting a notice of objection, in the form provided, and

    ii. the last day on which the administrator will accept receipt of notices of objection.

12. That if the number of notices of objection received by the administrator confirms that not more than one-third of the persons who were eligible members or eligible former members on the valuation date of the solvency relief report, and when the information statement was sent, object to the extension, the extension of the five-year period will proceed.

(4) An information statement sent to a collective bargaining agent must contain:

1. The information listed in paragraphs 1, 3, 5, 6, 7, 8, 9 and 12 of subsection (3).

2. A statement that the collective bargaining agent may object to the extension on behalf of the persons who are currently eligible members or eligible former members, were eligible members on the valuation date of the solvency relief report and were represented by the collective bargaining agent on that day, by submitting a notice of objection in the form provided.

3. The number of persons who,

    i. were eligible members on the valuation date of the solvency relief report and represented by the collective bargaining agent on the valuation date, and

    ii. were still eligible members or were eligible former members when the administrator sent the information statement to them.

4. The last day on which the administrator will accept receipt of notices of objection.

(5) A notice of objection must include the following:

1. The name and provincial registration number of the plan.

2. The name of the administrator.

3. The address to which the notice of objection form is to be sent.

4. If the notice of objection is for use by a collective bargaining agent, the number of persons represented by the collective bargaining agent in submitting the objection who were eligible members on the valuation date of the solvency relief report and were either eligible members or eligible former members when the information statement was sent to them by the administrator.

5. A statement objecting to the extension of the five-year period during which the new solvency deficiency must be liquidated to a period not exceeding 10 years.

6. The date not earlier than 45 days after the information statement is mailed by the administrator that is the final day the administrator will accept receipt of notices of objection.

(6) Nothing related to the notice of objection or the process for objecting shall enable the administrator to identify an eligible member or eligible former member who submits a notice of objection.

(7) The administrator shall retain all notices of objection it receives until the new solvency deficiency is liquidated and shall provide copies of the notices to the Superintendent upon request.

5. Section 7 of the Regulation is amended by adding the following subsections:

(3.1) Subsection (3) does not apply to plans that provide defined benefits, other than designated plans, for a fiscal year of the plan ending after June 29, 2010 and before January 1, 2013 to reduce contributions for the normal cost required to be made by an employer, by a person or entity required to make contributions on behalf of the employer, by members or by any of them for the year unless,

(a) the administrator files with the Superintendent within the first 90 days of the fiscal year an actuarial cost certificate for the fiscal year; and

(b) the amount applied to reduce the contributions for the year does not exceed the maximum amount determined under subsection (3.2).

(3.2) For the purposes of clause (3.1) (b), the maximum amount of any actuarial gain identified in the last report filed under section 3 or 14 that may be applied to reduce contributions for the normal cost for a fiscal year of the plan ending after June 29, 2010 and before January 1, 2013 is the lesser of,

(a) the amount, if any, by which the going concern assets reported in the actuarial cost certificate filed for the fiscal year exceed the sum of the estimated going concern liabilities and the prior year credit balance as reported in the certificate; and

(b) the amount, if any, by which the solvency assets reported in the certificate exceed the sum of the estimated solvency liabilities and the prior year credit balance as reported in the certificate.

6. The Regulation is amended by adding the following section:

7.1 (1) An actuarial cost certificate must be prepared by an actuary using methods and actuarial assumptions that are consistent with accepted actuarial practice and with the requirements of the Act and this Regulation, based on a valuation date of the first day of the fiscal year of the plan to which the certificate relates.

(2) An actuarial cost certificate must contain the following:

1. An estimate of the normal cost of the plan for the fiscal year of the plan commencing on the valuation date of the certificate.
2. An estimate of the total employee contributions to the plan to be made during that fiscal year.
3. The going concern assets, estimated going concern liabilities, solvency assets and estimated solvency liabilities, each determined as of the valuation date of the certificate.
4. The prior year credit balance.
5. The estimated transfer ratio, calculated using the solvency assets and estimated solvency liabilities determined in the certificate.

7. Section 14 of the Regulation is amended by adding the following subsection:

(11) Despite subsection (10), the administrator may file the first report for which the valuation date is on or after September 30, 2008 and before November 1, 2008 up to 10 months after the valuation date.

8. Section 16 of the Regulation is amended by adding the following subsection:

(5) A person preparing a report under section 3, 13 or 14 that has a valuation date after December 11, 2008 and before April 1, 2009 may calculate the solvency liability for a member, who is assumed to exercise his or her entitlement under subsection 73 (2) of the Act on the wind-up of the plan, using methods and assumptions consistent with section 3800 of the *Canadian Institute of Actuaries Standards of Practice*, effective April 1, 2009, which is available to the public from the Canadian Institute of Actuaries at Suite 800, 150 Metcalfe Street, Ottawa, Ontario K2P 1P1 or electronically on its website.

9. (1) Subsection 19 (5) of the Regulation is revoked and the following substituted:

(5) If the transfer ratio of a plan is less than one and the administrator of the plan knows or ought to know that, since the valuation date of the report most recently filed or submitted in respect of the plan under section 3, 4, 13 or 14, events have taken place that may result in the reduction of the transfer ratio by 10 per cent or more of the most recently determined transfer ratio, the administrator shall not undertake a transfer of any part of the commuted value without the prior approval of the Superintendent under subsection 42 (8) of the Act.

(2) Subsection 19 (6) of the Regulation is amended by adding "Subject to subsections (4) and (5)" at the beginning.

10. (1) Subsection 21 (1.2) of the Regulation is amended by striking out "a locked-in retirement income fund".

(2) Subsection 21 (1.3) of the Regulation is amended by striking out "a locked-in retirement income fund".

(3) Subsections 21 (2), (2.1), (2.2), (2.3), (2.4), (2.5), (2.6), (2.7), (2.8), (3) and (4) of the Regulation are revoked.

11. (1) Clause 22 (1) (c) of the Regulation is amended by striking out "or a locked-in retirement income fund".

(2) Subclause 22 (1) (f) (ii) of the Regulation is revoked and the following substituted:

(ii) in the case of a contract that is purchased with funds from a life income fund, a locked-in retirement income fund or a locked-in retirement account, the purchase is in accordance with Schedule 1, 1.1, 2 or 3 to this Regulation; and

(3) Clause 22 (1) (g) of the Regulation is revoked and the following substituted:

(g) on the death of the annuitant before payment of the annuity, the annuity shall be administered in accordance with section 48 of the Act.

(4) Subsection 22 (2) of the Regulation is revoked and the following substituted:

(2) The insurance contract must provide that, if a life income fund is being purchased as authorized by clause (1) (c), the financial institution disclose to the annuitant the difference between the commuted value of the annuity and the amount that will be transferred to the life income fund.

12. Section 22.1 of the Regulation is revoked.

13. Subsection 22.2 (2) of the Regulation is amended by striking out "a locked-in retirement income fund".

14. Sections 22.3, 22.4 and 22.5 of the Regulation are revoked.

15. (1) Subsection 2 (4) of Schedule 1 to the Regulation is amended by adding at the end "subject to the maximum set out in subsection 66 (4) of the Act".

(2) Section 2 of Schedule 1 to the Regulation is amended by adding the following subsection:

(6) It must indicate whether the commuted value of the pension benefit that was transferred into the fund was determined in a manner that differentiated on the basis of sex.

16. Section 3 of Schedule 1 to the Regulation is amended by adding the following subsection:

(3) Any transaction that contravenes subsection (1) is void.

17. (1) Subsection 6 (1) of Schedule 1 to the Regulation is revoked and the following substituted:

(1) The amount of income paid during a fiscal year out of a life income fund that is governed by this Schedule must not exceed the greater of "A" and "B" where,

"A" is the amount of the investment earnings, including any unrealized capital gains or losses, of the fund in the previous fiscal year, and

"B" is the amount calculated using the formula,

C/F

in which,

"C" is the value of the assets in the fund at the beginning of the fiscal year, and

"F" is the present value, at the beginning of the fiscal year, of an annuity of $1 payable annually in advance over the period commencing at the beginning of the fiscal year and ending on December 31 of the year in which the owner reaches 90 years of age.

(2) Subsection 6 (2) of Schedule 1 to the Regulation is amended by striking out "subsection (1)" in the portion before paragraph 1 and substituting "the definition of "B" in subsection (1)".

(3) Subsections 6 (3), (4), (5), (6) and (7) of Schedule 1 to the Regulation are revoked and the following substituted:

(3) The amount of income paid out of the fund during a fiscal year must not be less than the minimum amount prescribed for an RRIF under the *Income Tax Act* (Canada).

(4) If the minimum amount specified by subsection (3) is greater than the maximum amount determined under subsection (1), the minimum amount must be paid out of the fund during the fiscal year.

(5) This section shall not be construed to prevent or limit a payment from the fund that is permitted under section 3, 8, 9, 9.1 or 10 of this Schedule or under section 22.2 of this Regulation.

18. (1) Clauses 7 (1) (d), (e) and (f) of Schedule 1 to the Regulation are revoked.

(2) Section 7 of Schedule 1 to the Regulation is amended by adding the following subsections:

(1.3) A life annuity referred to in clause (1) (c) shall not differentiate on the basis of the sex of the beneficiary if the commuted value of the pension benefit that was transferred into the fund was determined in a manner that did not differentiate on the basis of sex.

(1.4) The financial institution shall not make a transfer described in subsection (1) except where,

(a) the transfer is permitted under the Act and this Regulation; and

(b) the transferee agrees to administer the amount transferred in accordance with the Act and this Regulation.

(1.5) The financial institution shall advise the transferee in writing that the amount transferred must be administered in accordance with the Act and this Regulation.

19. Schedule 1 to the Regulation is amended by adding the following section after the heading "Withdrawals from the Fund":

8. (1) On or after January 1, 2011, the owner of a life income fund that is governed by this Schedule may, upon application in accordance with this section, either withdraw from the fund or transfer from it to an RRSP or RRIF an amount representing up to 50 per cent of the total market value of the assets of the fund.

(2) For the purposes of subsection (1), the total market value of the assets of the fund is determined using the most recent statement about the fund given to the owner. The statement must be dated within one year before the owner signs the application.

(3) For the purposes of subsection (1), the owner of a fund may make a maximum of one withdrawal or transfer from the fund.

(4) Despite subsection (1), no amount may be withdrawn or transferred under this section unless an application for the withdrawal or transfer is given to the financial institution that administers the fund on or before April 30, 2012.

(5) The application must be made on a form approved by the Superintendent.

(6) The application form must be signed by the owner and accompanied by one of the following documents:

1. A declaration described in section 11 about a spouse.
2. A statement signed by the owner attesting to the fact that none of the money in the fund is derived, directly or indirectly, from a pension benefit provided in respect of any employment of the owner.

(7) If assets in the fund consist of identifiable and transferable securities, the financial institution may transfer the securities with the consent of the owner.

(8) The contract governing the fund must include the following terms and, if it does not, the contract is deemed to include them:

1. The financial institution is entitled to rely upon the information provided by the owner in an application made under this section.
2. An application that meets the requirements of this section constitutes authorization to the financial institution to make the payment or transfer from the fund in accordance with this section.
3. The financial institution is required to make the payment or transfer to which the owner is entitled under this section within 30 days after the financial institution receives the completed application form and accompanying documents.

20. The French version of paragraph 2 of subsection 9 (6) of Schedule 1 to the Regulation is amended by striking out "compte" and substituting "fonds".

21. Section 11 of Schedule 1 to the Regulation is amended by striking out "section 9, 9.1 or 10" in the portion before paragraph 1 and substituting "section 8, 9, 9.1 or 10".

22. Subsection 12 (1) of Schedule 1 to the Regulation is amended by striking out "section 9, 9.1 or 10" and substituting "section 8, 9, 9.1 or 10".

23. Subsection 12 (2) of Schedule 1 to the Regulation is amended by striking out "section 9, 9.1 or 10" and substituting "section 8, 9, 9.1 or 10".

24. Subsection 14 (5) of Schedule 1 to the Regulation is revoked and the following substituted:

(5) Notices under this section must be in writing and must be sent to the owner's address as set out in the records of the financial institution.

25. (1) Paragraph 1 of subsection 15 (2) of Schedule 1 to the Regulation is revoked and the following substituted:

1. With respect to the previous fiscal year: the sums deposited, any accumulated investment earnings, including any unrealized capital gains or losses, the payments made out of the fund, the withdrawals taken out of the fund and the fees charged against the fund.

(2) Section 15 of Schedule 1 to the Regulation is amended by adding the following subsection:

(5) The following information must be provided to the owner on or before September 30, 2010:

1. That, on or after January 1, 2011, the owner of the fund may, upon application in accordance with section 8 of this Schedule, either withdraw from the fund or transfer from it to an RRSP or RRIF an amount representing up to 50 per cent of the total market value of the assets of the fund, as determined using the most recent statement about the fund given to the owner. The statement must be dated within one year before the owner signs the application.
2. That the owner of the fund may make a maximum of one withdrawal or transfer under section 8 of this Schedule from the fund.
3. That no withdrawal or transfer may be made under section 8 of this Schedule unless an application for the withdrawal or transfer is given to the financial institution on or before April 30, 2012.

4. That, on or after January 1, 2011, the amount of income paid out of the fund during a fiscal year must not exceed the greater of "A" and "B" where,

   "A" is the amount of the investment earnings, including any unrealized capital gains or losses, of the fund in the previous fiscal year, and

   "B" is the amount calculated using the formula set out in subsection 6 (1) of this Schedule.

5. That the owner may not transfer assets from the fund to a locked-in retirement account after December 31, 2010.

6. That after December 31, 2010, if assets are transferred from the fund to a life income fund that is governed by Schedule 1.1, the owner cannot make a withdrawal or transfer described in subsection 8 (1) of Schedule 1.1.

26. (1) Subsection 2 (4) of Schedule 1.1 to the Regulation is amended by adding at the end "subject to the maximum set out in subsection 66 (4) of the Act".

(2) Section 2 of Schedule 1.1 to the Regulation is amended by adding the following subsection:

(6) It must indicate whether the commuted value of the pension benefit that was transferred into the fund was determined in a manner that differentiated on the basis of sex.

27. Section 3 of Schedule 1.1 to the Regulation is amended by adding the following subsection:

(3) Any transaction that contravenes subsection (1) is void.

28. Section 7 of Schedule 1.1 to the Regulation is amended by adding the following subsections:

(6) A life annuity referred to in subsection (1) shall not differentiate on the basis of the sex of the beneficiary if the commuted value of the pension benefit that was transferred into the fund was determined in a manner that did not differentiate on the basis of sex.

(7) The financial institution shall not make a transfer described in subsection (1) except where,

(a) the transfer is permitted under the Act and this Regulation; and

(b) the transferee agrees to administer the amount transferred in accordance with the Act and this Regulation.

(8) The financial institution shall advise the transferee in writing that the amount transferred must be administered in accordance with the Act and this Regulation.

29. (1) Subsection 8 (2) of Schedule 1.1 to the Regulation is amended by adding at the end "in relation to a transfer of assets made on or before December 31, 2009".

(2) Section 8 of Schedule 1.1 to the Regulation is amended by adding the following subsection:

(2.1) The owner of the receiving fund may, upon application in accordance with this section, either withdraw from the fund or transfer from it to an RRSP or RRIF an amount representing up to 50 per cent of the total market value of the assets transferred into the fund in relation to a transfer of assets made on or after January 1, 2010.

(3) Subsection 8 (3) of Schedule 1.1 to the Regulation is revoked and the following substituted:

(3) Despite subsections (2) and (2.1), if the assets are transferred into the receiving fund from another life income fund that is governed by this Schedule, the owner cannot make a withdrawal or transfer described in subsection (2) or (2.1) unless the transfer of assets into the receiving fund was made in accordance with the terms of an order under the *Family Law Act* or a domestic contract as defined in Part IV of that Act.

(4) Subsection 8 (3) of Schedule 1.1 to the Regulation, as remade by subsection (3), is revoked and the following substituted:

(3) Despite subsections (2) and (2.1), if the assets are transferred into the receiving fund from a life income fund or a locked-in retirement income fund, the owner cannot make a withdrawal or transfer described in subsection (2) or (2.1) unless the transfer of assets into the receiving fund was made in accordance with the terms of an order under the *Family Law Act* or a domestic contract as defined in Part IV of that Act.

(5) Subsection 8 (4) of Schedule 1.1 to the Regulation is amended by striking out "described in subsection (2)" and substituting "described in subsection (2) or (2.1)".

(6) The French version of paragraph 2 of subsection 8 (8) of Schedule 1.1 to the Regulation is amended by striking out "compte" and substituting "fonds".

(7) Subsection 8 (8) of Schedule 1.1 to the Regulation is amended by adding the following paragraph:

2.1 The total market value of the assets transferred into the fund is to be determined as of the date the assets were transferred into the fund.

30. Schedule 1.1 to the Regulation is amended by adding the following section:

8.1 (1) On or after January 1, 2010, the owner of a life income fund that is governed by this Schedule may, upon application in accordance with this section, either withdraw from the fund or transfer from it to an RRSP or RRIF an amount representing up to 25 per cent of the total market value of all assets transferred into the fund on or before December 31, 2009.

(2) For the purposes of subsection (1), the owner of a fund may make a maximum of one withdrawal or transfer from the fund.

(3) An application for the withdrawal or transfer must be given to the financial institution that administers the fund on or before December 31, 2010.

(4) The application must be made on a form approved by the Superintendent.

(5) The application form must be signed by the owner and accompanied by one of the following documents:

1. A declaration described in section 12 about a spouse.
2. A statement signed by the owner attesting to the fact that none of the money in the fund is derived, directly or indirectly, from a pension benefit provided in respect of any employment of the owner.

(6) If assets in the fund consist of identifiable and transferable securities, the financial institution may transfer the securities with the consent of the owner.

(7) The contract governing the fund must include the following terms and, if it does not, the contract is deemed to include them:

1. The financial institution is entitled to rely upon the information provided by the owner in an application made under this section.
2. An application that meets the requirements of this section constitutes authorization to the financial institution to make the payment or transfer from the fund in accordance with this section.
3. The total market value of any assets transferred into the fund is to be determined as of the date the assets were transferred into the fund.
4. The financial institution is required to make the payment or transfer to which the owner is entitled under this section within 30 days after the financial institution receives the completed application form and accompanying documents.

31. The French version of paragraph 2 of subsection 9 (6) of Schedule 1.1 to the Regulation is amended by striking out "compte" and substituting "fonds".

32. Subsection 16 (5) of Schedule 1.1 to the Regulation is revoked and the following substituted:

(5) Notices under this section must be in writing and must be sent to the owner's address as set out in the records of the financial institution.

33. (1) Paragraph 1 of subsection 17 (2) of Schedule 1.1 to the Regulation is revoked and the following substituted:

1. With respect to the previous fiscal year: the sums deposited, any accumulated investment earnings, including any unrealized capital gains or losses, the payments made out of the fund, the withdrawals taken out of the fund and the fees charged against the fund.

(2) Section 17 of Schedule 1.1 to the Regulation is amended by adding the following subsection:

(5) The following information must be provided to the owner on or before January 1, 2010:

1. That, on or after January 1, 2010, the owner of the fund may, upon application in accordance with section 8.1 of this Schedule, either withdraw from the fund or transfer from it to an RRSP or RRIF an amount representing up to 25 per cent of the total market value of all assets transferred into the fund on or before December 31, 2009.
2. That the owner of the fund may make a maximum of one withdrawal or transfer under section 8.1 of this Schedule from the fund.
3. That no withdrawal or transfer may be made under section 8.1 of this Schedule unless an application for the withdrawal or transfer is given to the financial institution on or before December 31, 2010.

34. (1) Subsection 2 (4) of Schedule 2 to the Regulation is amended by adding at the end "subject to the maximum set out in subsection 66 (4) of the Act".

(2) Section 2 of Schedule 2 to the Regulation is amended by adding the following subsection:

(6) It must indicate whether the commuted value of the pension benefit that was transferred into the fund was determined in a manner that differentiated on the basis of sex.

35. Section 3 of Schedule 2 to the Regulation is amended by adding the following subsection:

(3) Any transaction that contravenes subsection (1) is void.

36. Section 6 of Schedule 2 to the Regulation is revoked and the following substituted:

6. (1) The amount of income paid during a fiscal year out of a locked-in retirement income fund that is governed by this Schedule must not exceed the greater of "A" and "B" where,

"A" is the amount of the investment earnings, including any unrealized capital gains or losses, of the fund in the previous fiscal year, and

"B" is the amount calculated using the formula,

C/F

in which,

"C" is the value of the assets in the fund at the beginning of the fiscal year, and

"F" is the present value, at the beginning of the fiscal year, of an annuity of $1 payable annually in advance over the period commencing at the beginning of the fiscal year and ending on December 31 of the year in which the owner reaches 90 years of age.

(2) The following interest rate assumptions are to be used to determine the amount "F" in the definition of "B" in subsection (1):

1. The interest rate for each of the first 15 fiscal years of the period referred to in the definition of "F" is the greater of 6 per cent and the nominal rate of interest on long-term bonds issued by the Government of Canada for November of the year before the beginning of the fiscal year, as determined from the Canadian Socio-Economic Information Management System (CANSIM) series V122487 compiled by Statistics Canada and available on the website maintained by the Bank of Canada.

2. For the 16th and each subsequent fiscal year of the period referred to in the definition of "F", the interest rate is 6 per cent.

(3) The amount of income paid out of the fund during a fiscal year must not be less than the minimum amount prescribed for an RRIF under the *Income Tax Act* (Canada).

(4) If the minimum amount specified by subsection (3) is greater than the maximum amount determined under subsection (1), the minimum amount must be paid out of the fund during the fiscal year.

(5) This section shall not be construed to prevent or limit a payment from the fund that is permitted under section 3, 7.1, 8, 8.1 or 9 of this Schedule or under section 22.2 of this Regulation.

37. (1) Clauses 7 (1) (d), (e) and (f) of Schedule 2 to the Regulation are revoked.

(2) Section 7 of Schedule 2 to the Regulation is amended by adding the following subsections:

(4) A life annuity referred to in subsection (1) shall not differentiate on the basis of the sex of the beneficiary if the commuted value of the pension benefit that was transferred into the fund was determined in a manner that did not differentiate on the basis of sex.

(5) The financial institution shall not make a transfer described in subsection (1) except where,

(a) the transfer is permitted under the Act and this Regulation; and

(b) the transferee agrees to administer the amount transferred in accordance with the Act and this Regulation.

(6) The financial institution shall advise the transferee in writing that the amount transferred must be administered in accordance with the Act and this Regulation.

38. Schedule 2 to the Regulation is amended by adding the following section after the heading "Withdrawals from the Fund":

7.1 (1) On or after January 1, 2011, the owner of a locked-in retirement income fund may, upon application in accordance with this section, either withdraw from the fund or transfer from it to an RRSP or RRIF an amount representing up to 50 per cent of the total market value of the assets of the fund.

(2) For the purposes of subsection (1), the total market value of the assets of the fund is determined using the most recent statement about the fund given to the owner. The statement must be dated within one year before the owner signs the application.

(3) For the purposes of subsection (1), the owner of a fund may make a maximum of one withdrawal or transfer from the fund.

(4) Despite subsection (1), no amount may be withdrawn or transferred under this section unless an application for the withdrawal or transfer is given to the financial institution that administers the fund on or before April 30, 2012.

(5) The application must be made on a form approved by the Superintendent.

(6) The application form must be signed by the owner and accompanied by one of the following documents:

1. A declaration described in section 10 about a spouse.
2. A statement signed by the owner attesting to the fact that none of the money in the fund is derived, directly or indirectly, from a pension benefit provided in respect of any employment of the owner.

(7) If assets in the fund consist of identifiable and transferable securities, the financial institution may transfer the securities with the consent of the owner.

(8) The contract governing the fund must include the following terms and, if it does not, the contract is deemed to include them:

1. The financial institution is entitled to rely upon the information provided by the owner in an application made under this section.
2. An application that meets the requirements of this section constitutes authorization to the financial institution to make the payment or transfer from the fund in accordance with this section.
3. The financial institution is required to make the payment or transfer to which the owner is entitled under this section within 30 days after the financial institution receives the completed application form and accompanying documents.

39. (1) The French version of paragraph 2 of subsection 8 (6) of Schedule 2 to the Regulation is amended by striking out "compte" and substituting "fonds".

(2) Paragraph 4 of subsection 8 (6) of Schedule 2 to the Regulation is amended by striking out "document" at the end and substituting "documents".

40. Section 10 of Schedule 2 to the Regulation is amended by striking out "section 8, 8.1 or 9" in the portion before paragraph 1 and substituting "section 7.1, 8, 8.1 or 9".

41. (1) Subsection 11 (1) of Schedule 2 to the Regulation is amended by striking out "section 8, 8.1 or 9" and substituting "section 7.1, 8, 8.1 or 9".

(2) Subsection 11 (2) of Schedule 2 to the Regulation is amended by striking out "section 8, 8.1 or 9" and substituting "section 7.1, 8, 8.1 or 9".

42. The English version of subsection 12 (1) of Schedule 2 to the Regulation is amended by striking out "the owner's beneficiary" and substituting "the owner's named beneficiary".

43. Subsection 13 (5) of Schedule 2 to the Regulation is revoked and the following substituted:

(5) Notices under this section must be in writing and must be sent to the owner's address as set out in the records of the financial institution.

44. (1) Paragraph 1 of subsection 14 (2) of Schedule 2 to the Regulation is revoked and the following substituted:

1. With respect to the previous fiscal year: the sums deposited, any accumulated investment earnings, including any unrealized capital gains or losses, the payments made out of the fund, the withdrawals taken out of the fund and the fees charged against the fund.

(2) Section 14 of Schedule 2 to the Regulation is amended by adding the following subsections:

(5) The following information must be provided to the owner at the beginning of the fiscal year of the fund that ends on December 31, 2010:

1. That, on or after January 1, 2011, the owner will not be able to elect to be paid all or part of the amount carried forward under section 6 of this Schedule from a prior fiscal year.
2. That if, on or after January 1, 2011, the owner elects to be paid an amount that is less than the maximum amount determined under section 6 of this Schedule, the owner will not be able to carry forward the amount of the difference between the amount elected and the maximum amount.

(6) The following information must be provided to the owner on or before September 30, 2010:

1. That, on or after January 1, 2011, the owner of the fund may, upon application in accordance with section 7.1 of this Schedule, either withdraw from the fund or transfer from it to an RRSP or RRIF an amount representing up to 50 per cent of the total market value of the assets of the fund, as determined using the most recent statement about the fund given to the owner. The statement must be dated within one year before the owner signs the application.
2. That the owner of the fund may make a maximum of one withdrawal or transfer under section 7.1 of this Schedule from the fund.
3. That no withdrawal or transfer may be made under section 7.1 of this Schedule unless an application for the withdrawal or transfer is given to the financial institution on or before April 30, 2012.

4. That, on or after January 1, 2011, the amount of income paid out of the fund during a fiscal year must not exceed the greater of "A" and "B" where,

   "A" is the amount of the investment earnings, including any unrealized capital gains or losses, of the fund in the previous fiscal year, and

   "B" is the amount calculated using the formula set out in subsection 6 (1) of Schedule 1 to this Regulation.

5. That the owner may not transfer assets from the fund to a locked-in retirement account after December 31, 2010.

6. That after December 31, 2010, if assets are transferred from the fund to a life income fund that is governed by Schedule 1.1, the owner cannot make a withdrawal or transfer described in subsection 8 (1) of Schedule 1.1.

45. The Regulation is amended by adding the following Schedule:

SCHEDULE 3
LOCKED-IN RETIREMENT ACCOUNT REQUIREMENTS

ESTABLISHING THE ACCOUNT

1. (1) The following persons may purchase a locked-in retirement account in accordance with this section:

1. A former member who is entitled to make a transfer under clause 42 (1) (b) of the Act.

2. A spouse or former spouse of a person who was a member who is entitled to make a transfer under clause 42 (1) (b) of the Act.

3. A person who has previously transferred an amount under clause 42 (1) (b) of the Act into a locked-in retirement account.

(2) The account must be purchased using all or part of the amount transferred under clause 42 (1) (b) of the Act, or using all or part of the assets in a locked-in retirement account.

(3) For the purposes of this Schedule, a locked-in retirement account includes a contract made before June 24, 1994 to establish an RRSP for the purposes of a transfer under clause 42 (1) (b) of the Act.

2. (1) A contract establishing a locked-in retirement account must provide for the matters described in this section.

(2) It must indicate the name and address of the financial institution providing the account.

(3) It must describe the owner's powers, if any, respecting investment of the assets in the account.

(4) It must state that the owner agrees not to assign, charge, anticipate or give as security money in the account except as required by an order under the *Family Law Act* or by a domestic contract as defined in Part IV of that Act, subject to the maximum set out in subsection 66 (4) of the Act.

(5) It must describe the method for determining the value of the assets in the account.

(6) It must indicate whether the commuted value of the pension benefit that was transferred into the account was determined in a manner that differentiated on the basis of sex.

3. (1) Money in a locked-in retirement account cannot be commuted, withdrawn or surrendered in whole or in part, except as permitted by section 49 or 67 of the Act, section 22.2 of this Regulation or this Schedule.

(2) Every contract establishing a locked-in retirement account shall be deemed to include a provision setting out the restriction described in subsection (1).

(3) Any transaction that contravenes subsection (1) is void.

4. The fiscal year of a locked-in retirement account must end on December 31 and must not exceed 12 months.

TRANSFERRING ASSETS FROM THE ACCOUNT

5. (1) The owner of a locked-in retirement account may transfer any or all of the assets in it,

(a) to the pension fund of a pension plan registered under the pension benefits legislation in any Canadian jurisdiction or to a pension plan provided by a government in Canada;

(b) to another locked-in retirement account;

(c) to a life income fund that is governed by Schedule 1.1; or

(d) to purchase an immediate or deferred life annuity that meets the requirements of section 22 of this Regulation.

(2) In the contract governing the account, the financial institution must agree to make such a transfer within 30 days after the owner requests it. This does not apply with respect to the transfer of assets held as securities whose term of investment extends beyond the 30-day period.

(3) If assets in the account consist of identifiable and transferable securities, the financial institution may transfer the securities with the consent of the owner.

(4) For the purposes of the purchase of an immediate life annuity referred to in clause (1) (d), a determination as to whether the owner has a spouse is to be made on the date the annuity is purchased.

(5) Payments under a life annuity referred to in clause (1) (d) are subject to division in accordance with the terms of an order under the *Family Law Act* or a domestic contract as defined in Part IV of that Act.

(6) A life annuity referred to in clause (1) (d) shall not differentiate on the basis of the sex of the beneficiary if the commuted value of the pension benefit that was transferred into the account was determined in a manner that did not differentiate on the basis of sex.

(7) Payments under a life annuity referred to in clause (1) (d) must not begin before the earlier of,

(a) the earliest date on which the owner of the annuity would have been entitled as a former member to receive pension benefits under the Act as a result of termination of employment or termination of membership in any pension plan, from which money was transferred directly or indirectly into the locked-in retirement account; or

(b) the earliest date on which the owner of the annuity would have been entitled as a former member to receive pension benefits under any pension plan described in clause (a) as a result of termination of employment or termination of membership in the plan.

(8) The financial institution shall not make a transfer described in subsection (1) except where,

(a) the transfer is permitted under the Act and this Regulation; and

(b) the transferee agrees to administer the amount transferred in accordance with the Act and this Regulation.

(9) The financial institution shall advise the transferee in writing that the amount transferred must be administered in accordance with the Act and this Regulation.

WITHDRAWALS FROM THE ACCOUNT

6. (1) The owner of a locked-in retirement account may, upon application in accordance with this section, withdraw all the money in the account or transfer the assets to an RRSP or RRIF if, when the owner signs the application,

(a) he or she is at least 55 years of age; and

(b) the value of all assets in all life income funds, locked-in retirement income funds and locked-in retirement accounts owned by him or her is less than 40 per cent of the Year's Maximum Pensionable Earnings for that calendar year.

(2) An application for the withdrawal or transfer from the account must be given to the financial institution that administers the account.

(3) The application must be made on a form approved by the Superintendent.

(4) The application form must be signed by the owner and accompanied by one of the following documents:

1. A declaration described in section 9 about a spouse.
2. A statement signed by the owner attesting to the fact that none of the money in the account is derived, directly or indirectly, from a pension benefit provided in respect of any employment of the owner.

(5) If assets in the account consist of identifiable and transferable securities, the financial institution may transfer the securities with the consent of the owner.

(6) The contract governing the account must include the following terms and, if it does not, the contract is deemed to include them:

1. The financial institution is entitled to rely upon the information provided by the owner in an application made under this section.
2. An application that meets the requirements of this section constitutes authorization to the financial institution to make the payment or transfer from the account in accordance with this section.
3. The value of all assets in all life income funds, locked-in retirement income funds and locked-in retirement accounts owned by the owner when he or she signs the application under this section is to be determined using the most recent statement about each fund or account given to the owner. Each such statement must be dated within one year before the owner signs the application.
4. The financial institution is required to make the payment or transfer to which the owner is entitled under this section within 30 days after the financial institution receives the completed application form and accompanying documents.

7. (1) The owner of a locked-in retirement account may, upon application in accordance with this section, withdraw all the money in the account,

(a) if, when the owner signs the application, he or she is a non-resident of Canada as determined by the Canada Revenue Agency for the purposes of the *Income Tax Act* (Canada); and

(b) if the application is made at least 24 months after his or her date of departure from Canada.

(2) An application to withdraw the money from the account must be given to the financial institution that administers the account.

(3) The application must be made on a form approved by the Superintendent.

(4) The application form must be signed by the owner and accompanied by the following documents:

1. A written determination from the Canada Revenue Agency that the person is a non-resident for the purposes of the *Income Tax Act* (Canada).
2. Either a declaration described in section 9 about a spouse or a statement signed by the owner attesting to the fact that none of the money in the account is derived, directly or indirectly, from a pension benefit provided in respect of any employment of the owner.

(5) The contract governing the account must include the following terms and, if it does not, the contract is deemed to include them:

1. The financial institution is entitled to rely upon the information provided by the owner in an application made under this section.
2. An application that meets the requirements of this section constitutes authorization to the financial institution to make the payment from the account in accordance with this section.
3. The financial institution is required to make the payment to which the owner is entitled under this section within 30 days after the financial institution receives the completed application form and accompanying documents.

8. (1) The owner of a locked-in retirement account may, upon application in accordance with this section, withdraw all or part of the money in the account if, when the owner signs the application, he or she has an illness or physical disability that is likely to shorten his or her life expectancy to less than two years.

(2) An application to withdraw money from the account must be given to the financial institution that administers the account.

(3) The application must be made on a form approved by the Superintendent.

(4) The application form must be signed by the owner and be accompanied by the following documents:

1. A statement signed by a physician who is licensed to practise medicine in a jurisdiction in Canada that, in the opinion of the physician, the owner has an illness or physical disability that is likely to shorten his or her life expectancy to less than two years.
2. Either a declaration described in section 9 about a spouse or a statement signed by the owner attesting to the fact that none of the money in the account is derived, directly or indirectly, from a pension benefit provided in respect of any employment of the owner.

(5) The contract governing the account must include the following terms and, if it does not, the contract is deemed to include them:

1. The financial institution is entitled to rely upon the information provided by the owner in an application made under this section.
2. An application that meets the requirements of this section constitutes authorization to the financial institution to make the payment from the account in accordance with this section.
3. The financial institution is required to make the payment to which the owner is entitled under this section within 30 days after the financial institution receives the completed application form and accompanying documents.

9. Any of the following documents constitutes a declaration about a spouse for the purposes of a withdrawal or transfer under section 6, 7 or 8 from a locked-in retirement account:

1. A statement signed by the owner's spouse, if any, that the spouse consents to the withdrawal or transfer from the account.
2. A statement signed by the owner attesting to the fact that he or she does not have a spouse.
3. A statement signed by the owner attesting to the fact that he or she is living separate and apart from his or her spouse on the date the owner signs the application to make the withdrawal or transfer from the account.

10. (1) If the owner of a locked-in retirement account is required by section 6, 7 or 8 to give a document to a financial institution and if the document is one that must be signed by the owner or by his or her spouse, the document is a nullity if it is signed by the owner or the spouse more than 60 days before the financial institution receives it.

(2) When the financial institution receives a document required by section 6, 7 or 8, the financial institution shall give the owner of the account a receipt for the document stating the date on which it was received.

SURVIVOR'S BENEFITS

11. (1) Upon the death of the owner of a locked-in retirement account, the owner's spouse or, if there is none or if the spouse is otherwise disentitled, the owner's named beneficiary or, if there is none, the owner's estate is entitled to receive a benefit equal to the value of the assets in the account.

(2) The benefit described in subsection (1) may be transferred to an RRSP or an RRIF in accordance with the *Income Tax Act* (Canada).

(3) A spouse of the owner is not entitled to receive the value of the assets in the account unless the owner was a member or former member of a pension plan from which assets were transferred directly or indirectly to purchase the account.

(4) A spouse who is living separate and apart from the owner on the date of the owner's death is not entitled to receive the value of the assets in the account.

(5) For the purposes of subsection (1), a determination as to whether the owner has a spouse is to be made on the date of the owner's death.

(6) For the purposes of subsection (1), the value of the assets in the account includes all accumulated investment earnings, including any unrealized capital gains and losses, of the account from the date of death until the date of payment.

12. (1) A spouse of the owner of a locked-in retirement account may waive his or her entitlement to receive the survivor's benefit described in section 11 from the account by delivering to the financial institution a written waiver in a form approved by the Superintendent.

(2) A spouse who has delivered a waiver under subsection (1) may cancel it by delivering a written and signed notice of cancellation to the financial institution before the date of the death of the owner of the account.

AMENDING THE ACCOUNT

13. (1) In the contract governing a locked-in retirement account, the financial institution providing the account must agree not to amend the contract except as provided in this section.

(2) The financial institution must give the owner of the account at least 90 days notice of a proposed amendment, other than an amendment described in subsection (3).

(3) The financial institution must not amend the contract governing the account if the amendment would result in a reduction in the owner's rights under the contract unless,

(a) the financial institution is required by law to make the amendment; and

(b) the owner is entitled to transfer the assets in the account under the terms of the contract that exist before the amendment is made.

(4) When making an amendment described in subsection (3), the financial institution must notify the owner of the account of the nature of the amendment and allow the owner at least 90 days after the notice is given to transfer all or part of the assets in the account.

(5) Notices under this section must be in writing and must be sent to the owner's address as set out in the records of the financial institution.

INFORMATION TO BE PROVIDED BY THE FINANCIAL INSTITUTION

14. (1) In the contract governing a locked-in retirement account, the financial institution must agree to provide the information described in this section to the person indicated.

(2) At the beginning of each fiscal year, the following information must be provided to the owner:

1. With respect to the previous fiscal year: the sums deposited, any accumulated investment earnings, including any unrealized capital gains or losses, the payments made out of the account, the withdrawals taken out of the account and the fees charged against the account.

2. The value of the assets in the account as of the beginning of the fiscal year.

(3) If the assets in the account are transferred as described in subsection 5 (1), the owner must be given the information described in subsection (2) determined as of the date of the transfer.

(4) Upon the death of the owner, the person entitled to receive the assets in the account must be given the information described in subsection (2) determined as of the date of the owner's death.

46. (1) Subject to subsections (2) to (4), this Regulation comes into force on the day it is filed.

(2) Subsections 1 (1), 10 (3) and 11 (2) and (3), sections 12 and 14, subsection 15 (2), sections 17 and 18, subsection 26 (2), section 28, subsections 29 (4) and 34 (2) and sections 36, 37 and 45 come into force on the later of January 1, 2011 and the day this Regulation is filed.

(3) Subsection 1 (2) and sections 2 to 7 are deemed to have come into force on September 30, 2008.

(4) Section 8 is deemed to have come into force on December 11, 2008.

Français

Back to top

CME INTERROGATORY #8

INTERROGATORY

2012 PENSION FUNDING Z FACTOR
Reference: Exhibit B, Tab 2, Schedule 5, and Appendices

What is the filing deadline for the certificate that is to be prepared as of December 31, 2011?

RESPONSE

The filing deadline is March 31, 2012.

Witnesses: S. Kancharla
R. Lei
A. Patel

CME INTERROGATORY #9

INTERROGATORY

2012 PENSION FUNDING Z FACTOR
Reference: Exhibit B, Tab 2, Schedule 5, and Appendices

If the filing deadline of the certificate triggers the need for an annual contribution, then what is the latest date on which that annual contribution can be made? For example, if the certificate filing deadline is March 31, 2012, can the required contribution amount be paid in March 2013?

RESPONSE

The full contribution must be made in the year of the filing of the cost certificate. Therefore the latest date the contribution can be made is December 31, 2012.

Witnesses: S. Kancharla
R. Lei
A. Patel

CME INTERROGATORY #10

INTERROGATORY

2012 PENSION FUNDING Z FACTOR
Reference: Exhibit B, Tab 2, Schedule 5, and Appendices

Please list the differences between the Mercer Reports of September 29 and October 3, 2011, respectively, filed at Exhibit B, Tab 2, Schedule 5, Appendix B and explain why the second report was produced four (4) days after the first report.

RESPONSE

The Mercer Report on September 29, 2011 included cash funding requirements for the entire EGD RPP plan, specifically Enbridge Gas Distribution Inc., Gazifere Inc., and Enbridge Gas New Brunswick Inc. (totaling $17.7M).

The Mercer Report on October 3, 2011 was revised to include funding requirements for only Enbridge Gas Distribution Inc. in the amount of $16.6M.

Witnesses: S. Kancharla
R. Lei
A. Patel

CME INTERROGATORY #11

INTERROGATORY

2012 PENSION FUNDING Z FACTOR
Reference: Exhibit B, Tab 2, Schedule 5, and Appendices

Please identify each of the companies that participate with EGD in the pension plans described in paragraph 3 of Exhibit B, Tab 2, Schedule 5 at page 1.

RESPONSE

The EGD RPP includes: Enbridge Gas Distribution Inc., Gazifere Inc., and Enbridge Gas New Brunswick Inc.

Witnesses: S. Kancharla
R. Lei
A. Patel

CME INTERROGATORY #12

INTERROGATORY

CROSS-BORES Z FACTOR
Reference: Exhibit B, Tab 2, Schedule 6

Please describe what action EGD expects the Technical Standards and Safety Authority (the "TSSA") to take in response to its submission of an action plan to the TSSA for inspection by October 31, 2011. More particularly, what is the anticipated outcome of that inspection?

RESPONSE

The TSSA will review Enbridge's action plan and it is anticipated that the Enbridge plan will be approved by the TSSA once reviewed.

Witnesses: C. Clark
L. Lawler

CME INTERROGATORY #13

INTERROGATORY

CROSS-BORES Z FACTOR
Reference: Exhibit B, Tab 2, Schedule 6

Having regard to the evidence that the potential for a natural gas pipeline, during trenchless construction, to penetrate a sewer line is not new and that EGD has been managing the problem for several years, please provide, for each of the years 2007 to 2011, inclusive the frequency of calls EGD received from plumbers, homeowners and others who had a blocked sewer line beyond the walls of the building and describe the action EGD took in response to such calls.

RESPONSE

Please see the response to CCC Interrogatory #6 at Exhibit I, Tab 3, Schedule 6.

Enbridge removed the cross bore and repaired the sewer.

Witnesses: C. Clark
L. Lawler

CME INTERROGATORY #14

INTERROGATORY

CROSS-BORES Z FACTOR
Reference: Exhibit B, Tab 2, Schedule 6

What is involved in performing a sewer lateral locate prior to construction? Over the years, how frequently has EGD conducted sewer lateral locates prior to construction?

RESPONSE

A sewer lateral cannot be located using conventional locate technology since a sewer lateral is made of non conductive material and does not have a tracer wire installed with the pipe. There are two methods currently being used:

a) Lateral from Main consists of installing a motorized camera vehicle in the main line sewer and pushing a camera from the main line vehicle up the lateral. The camera contains a sonde which can be located using a traditional electronic locating device to determine the horizontal and vertical location of the sewer lateral.

b) Building to Main consists of installing a camera or sonde from a sewer cleanout located inside the building and pushing this device towards the main line sewer. The camera containing a sonde or sonde alone can be located using a traditional locating device to determine the horizontal and vertical location of the sewer lateral.

In 2008, Enbridge implemented revised construction procedures to address the potential of creating cross bores. As a result of this change in procedures, Enbridge has located in excess of 2800 sewer laterals per year since 2008.

Witnesses: C. Clark
L. Lawler

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 2, paragraph 7, Updated

Please confirm that the 2012 DSM operating budget of $30.9 million has been updated to $28.1 million as shown in the updated table shown on page 1.

RESPONSE

The Company's 2012 DSM Plan was filed with the Board on November 4, 2012, and was developed around the Settlement Agreement between EGD and the intervenors that resulted in a DSM portfolio for 2012 with a total budget of $30.91M. The agreed to budget avails of a provision in the 2012-2014 DSM Guidelines for Natural Gas Utilities[1] that allows up to an additional 10% of its $28.1M base budget, or $2.81M, to support low income programs.

Paragraph on page 4 of the updated Exhibit B, Tab 1, Schedule 2, erroneously states that $30.9M is included in the total revenue required outside of the incentive formula whereas at Row 20 on page 1 of the updated exhibit, it can be seen that $28.1M is now included in the total revenue required determination. EGD will file a correction to Exhibit B, Tab 1, Schedule 2.

[1] Ontario Energy Board, "*Demand Side Management Guidelines for Natural Gas Utilities, EB-2008-0346*", June 30, 2011, page 26

Witnesses: K. Culbert
A. Kacicnik
D. Small

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 4, Table 2

Please show the customer additions in 2011 based on the most recent month of actual data available relative to the same month in 2010 in the same level of detail as shown in Table 2.

RESPONSE

Please see the table below.

Col. 1	*Col. 2*	*Col. 3*
Sector	2010 YTD Actual as of 31-Oct	2011 YTD Actual as of 31-Oct
Residential		
New Construction	22,451	19,473
Replacement	4,614	5,895
Total	27,065	25,368
Apartment		
New Construction	82	17
Replacement	3	7
Total	85	24
Commercial		
New Construction	1,182	1,065
Replacement	491	613
Total	1,673	1,678
Industrial		
New Construction	4	5
Replacement	-	1
Total	4	6
Total Customer Additions	28,827	27,076

Witness: F. Ahmad

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 5, Figures 1 & 2

a) Do the 2011 estimates shown in Figures 1 & 2 include any months of actual normalized use?

b) Please update the 2011 estimates shown in Figures 1 & 2 to reflect as many months of normalized actual data as currently available.

c) For each of the 2011 estimates shown in Figures 1 & 2 please provide the most recent year-to-date normalized average use available for 2011 and for the same period in 2010.

RESPONSE

a) The normalized forecast of average use per customer is derived from average use regression models that produce forecasts on an annualized basis. The regression model's forecast includes 2010 actual billing consumption up to and including December 2010. Overall, both the 2011 Bridge Year Estimate and 2012 Budget represent the forecasts that integrate all the actual experience and the best known information at the time of developing the budget.

b) Consistent with previous filings, 2011 actual volumes will be filed as part of the 2011 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review. As stated in the EB-2007-0615 Settlement Agreement, the Company will submit the 2011 actual results following the completion of Company's audited year end results that are approved for public release.

c) Please refer to the response to part b), above.

Witness: R. Lei

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 5, Table 1

a) How many months of actual data are included in Table 1 for 2011?

b) Please provide an updated version of Table 1 that reflects as many months of actual data as are currently available for 2011.

RESPONSE

a) As stated in page 8 of Exhibit B, Tab 1, Schedule 5, the 2011 Bridge Year Estimate for contract market customers has incorporated three months of 2011 actual data. 2011 Bridge Year Estimate customer additions have incorporated four months of actual data. The average use per customer forecast is derived from annualized average use regression models. The regression model's forecast includes 2010 actual billing consumption up to and including December 2010.

b) Please refer to the response to part (b) of Board Staff Interrogatory #3 at Exhibit I, Tab 1, Schedule 3.

Witness: R. Lei

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

Ref: Exhibit B, Tab 3, Schedule 1, pages 6-8

a) Are the allocators used for the 2012 Y factors consistent with the allocators used for 2011 and previous years? If not, please explain any differences.

b) Please provide a table showing the allocations of the 2012 DRR and 2011 DRR to confirm that these allocations are very similar.

c) Did EGD consider other allocation factors for the Z factors? If so, please explain what was considered and why they were not used.

d) Is the allocation of the pension funding requirement consistent with how the cost would have been allocated in 2007 if it had existed? If not, please explain the difference.

e) Is the allocation of the cross bore costs consistent with how the cost would have been allocated in 2007 if it had existed? If not, please explain the difference.

RESPONSE

a) The Y factor allocators for Gas in Storage and CIS/Customer Care have remained consistent from previous years as indicated in Column 16 of Exhibit B, Tab 3, Schedule 10, page 6 (Item 1.1 and Item 1.4, respectively).

For 2012, the total DSM Y factor amount is separated between DSM Program Costs (Item 1.2) and DSM Low Income (Item 1.3). While DSM Program Costs continue to be directly assigned to the various rate classes based on specific programs designed for each rate class in the program year, the allocation of DSM Low Income constitutes a change in 2012.

The Company has allocated its 2012 Low Income DSM costs to all rate classes in proportion to its 2011 DRR, consistent with the new Demand Side Management Guidelines for Natural Gas Utilities issued in June 2011 (please see Exhibit B, Tab 3, Schedule 1, pages 7-8 for further explanation). In previous applications, Low Income DSM was allocated entirely to Rate 1.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

b) The proportion of the 2012 and 2011 Distribution Revenue Requirement ("DRR") to the rate classes is shown below:

	DRR Distribution (%)	
	2012	2011
Rate 1	67.8%	68.0%
Rate 6	28.8%	28.2%
Rate 9	0.0%	0.0%
Rate 100	0.0%	0.0%
Rate 110	1.0%	1.0%
Rate 115	0.4%	0.6%
Rate 125	1.0%	0.7%
Rate 135	0.1%	0.1%
Rate 145	0.3%	0.6%
Rate 170	0.3%	0.5%
Rate 200	0.3%	0.3%
Rate 300	0.0%	0.0%
Total	100.0%	100.0%

c) The Company proposes two new Z-factors for 2012: Pension Funding requirement and Crossbore/Sewer Lateral Program requirement.

As pension is part of employee benefits, the costs of which are similar in treatment to other Administrative & General ("A&G") costs embedded in all aspects of utility operation, it is the Company's view that the allocation of the pension funding requirement should represent utility operations as a whole. From that standpoint, the DRR allocation to the various rate classes is the most comprehensive representation of the distribution of costs to each rate class that is necessary to support the utility's various functions. No other method of assignment was considered for the Pension Funding requirement.

For the Crossbore/Sewer Lateral program requirement, several allocators were considered. As the potential for crossbore exists over the entire distribution network and is tied to cost characteristics of customer service lines, allocations based on customer responsibility (Total Customer Count in each rate class, Services allocator) as well as combined allocations (50% Services and 50% Low Pressure Delivery Demand) were considered.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

The Company decided to use the Services allocator as it most closely reflects the costs by rate class associated with service laterals from which the crossbore issue arises. The Services allocator reflects the level of investment in service lines by aggregating the cost of construction, installation, and materials (as influenced by length and diameter of different types of service pipe) for each rate class, adjusted for the forecast of customers in each rate class. The allocator is therefore indicative of the distribution of the investment and infrastructure that would be involved to address and resolve the crossbore issue for the various rate classes.

By comparison, an allocator based on the number of customers in each rate class would not have reflected the variations in service lateral costs by rate class and the necessary costs to rectify crossbore issues for specific rate class installations. As well, distribution capacity responsibility was not adopted as the basis for allocation because the crossbore issue deals primarily with customer service lines (or laterals).

d) Had a pension funding contribution been required in the 2007 base year, the Company would have included this amount as part of its Operating & Maintenance ("O&M") A&G costs. A&G costs are allocated to all functional O&M categories based on the proportion of each category to Total O&M. This approach is closely approximated by the use of the DRR in 2012 which spreads the pension funding contribution to all facets of the utility's operation.

e) Had crossbore costs been required in the 2007 base year, elements of the associated revenue requirement would have been included in rate base, return, taxes, O&M, and depreciation.

Because all elements of crossbore costs are the functionalization, classification, and allocation of these costs would have consistently reflected that causality. Thus, using the Board-approved cost allocation methodology which has been in place throughout the IR period and in 2007, the final allocation to the rate classes would have ultimately been approximated by using the Services allocation factor.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

Ref: Exhibit B, Tab 2, Schedule 6, page 17

Is the cross bore safety issue a risk for which EGD would take risk mitigation steps?

RESPONSE

The Z factor criterion referenced in this question was established to ensure the utility cannot claim a cost increase as a Z factor when that cost could have otherwise been avoided if the utility had acted prudently. In the case of the sewer lateral initiative, Enbridge has acted prudently and appropriately and is being responsive to the TSSA Directive.

Witnesses: C. Clark
L. Lawler

ENERGY PROBE INTERROGATORY #7

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 4, page 2

a) Where has EGD reflected the impact of the elimination of the small business surtax claw back effective July 1, 2010 on the first $500,000 of taxable income?

b) Please confirm that the reduction for the provincial small business deduction in 2012 is equal to a reduction from 11.25% to 4.5% on the first $500,000 of taxable income, or $33,750.

c) Did EGD reflect this tax reduction in the calculations for previous years? If not, why not?

RESPONSE

a)-c) EGD is not a Canadian Controlled Private Corporation ("CCPC"), thus it does not qualify for the small business deduction and is not impacted by the small business surtax claw back.

Witness: K. Culbert

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Ref: Exhibit E, Tab 3, Schedule 1

Please provide the appendix to the exhibit based on the October 2011 Consensus Forecasts.

RESPONSE

Please see EGD's response to VECC Interrogatory 13, at Exhibit I, Tab 8, Schedule 13.

Witness: S. Murray

FRPO INTERROGATORY #1

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, PG. 4,5

Preamble: EGD evidence states: "The Company and intervenors participated in a System Reliability proceeding (EB-2010-0231) and the outcome of that proceeding has been included as a part of the 2012 gas supply portfolio. As per the EB-2010-0231 Settlement Agreement the Company assigned 50,000 Gj/day of TCPL shorthaul capacity to Direct Purchase customers and has acquired 50,000 Gj/day of TCPL STFT from November to March. The Company also incorporated in its plan the acquisition of 200,000 Gj/day of TCPL STFT for three winter months which was also agreed upon as part of the settlement agreement as a substitute for traditional peaking services.

What was the total cost of System Reliability built into 2011 rates?

RESPONSE

During the System Reliability proceeding (EB-2010-0231), the Company provided intervenors with a calculation that compared the Board approved April 2010 QRAM Summary of Gas Costs (EB-2010-0048, Exhibit Q2-3, Tab1, Schedule 1) with the impact of amending that 2010 Board approved budgeted supply volumes to reflect the following changes 1) an annual assignment of 50,000 GJ's/day of TCPL shorthaul capacity and a reduction of Ontario Delivered supplies throughout the November to March period offset by western Canadian supplies and TCPL STFT for the same period, and 2) a reduction in a combination of Peaking Supplies and Ontario Discretionary supplies equivalent to 200,000 Gj's/day for three months offset by western Canadian supplies and TCPL STFT for the same period. For costing purposes the commodity and transportation unit rates underpinning the April 2010 QRAM were used. The purpose of this exercise was to provide intervenors with high level annual rate impacts assuming the April 2010 QRAM.

With respect to Fiscal 2011, the Company prepared and filed its gas supply portfolio with, among other things, the changes identified above. This represented a supply forecast that would allow the Company to meet the 2011 forecasted annual and peak day requirements in a safe and reliable fashion. The Company has replicated the

schedule referred to above for each of the 4 QRAM's in 2011 to provide a high level comparator of annual impacts of what was approved for recovery in rates and what costs may have been had the Company developed a supply portfolio without taking into consideration issues discussed previously.

As mentioned, the four attached schedules are representative of the annual cost impacts assuming the pricing inherent in each 2011 QRAM, and no attempt has been made to adjust those price forecasts for changes in the market place. For example, no adjustment was made to the 2011 Peaking Demand component due to the increase in TCPL tolls in March of 2011, because absent a RFP, prior to determining 2011 supply, it would be difficult to forecast what the cost would be and the intent was to provide a comparator based upon what was filed.

All the schedules follow the same format, therefore only a detailed description of Schedule 1 is provided.

Schedule 1 represents the annual impacts associated with the January 2011 QRAM. Columns 1 – 4 depict the Company's forecasted gas supply portfolio as filed in EB-2010-0347 (Exhibit Q1-3, Tab 1, Schedule 1).

Column 5 represents the volumetric impact of replacing 50,000 GJ's/day of western Canadian supply moved through TCPL STFT for 5 months and replacing it with Monthly Dawn volumes. Column 6 captures the dollar impact of the changes in supply taking into consideration the changes in transportation costs including the assignment of TCPL Dawn to CDA Shorthaul capacity. The total impact on the supply portfolio can be found in Column 6, Item 8. Columns 7 – 9 provide a summary of Columns 1 – 3 plus Columns 5 and 6.

Column10 represents the volumetric impact of replacing 200,000 GJ's/day of western Canadian supply moved through TCPL STFT for three months and replacing it with Monthly Dawn volumes. Column 11 captures the dollar impact of the changes in supply taking into consideration the changes in transportation costs. The total impact on the supply portfolio can be found in Column 11, Item 8. Columns 12 – 14 provide a summary of Columns 7 – 9 plus Columns 10 and 11.

Similar schedules have been provided for the April 2011, July 2011 and October 2011 QRAM's.

as per EB-2010-0347, Exhibit Q1-3, Tab 1, Schedule 1

Item #		Summary of Gas Cost to Operations Year ended December 31, 2011				Impact of 50,000 Gj's /day of STFT replacement for Dawn to CDA Supply					Impact of 200,000 Gj's /day of STFT replacement for Peaking Supplies & Dawn Supplies		Deemed Summary of Gas Cost to Operations Year ended December 31, 2011			
		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)	Col. 5 10^3m^3	Col. 6 $(000)	Col. 7 10^3m^3	Col. 8 $(000)	Col. 9 $/$10^3m^3$ (Col.2 / Col.1)	Col. 10 10^3m^3	Col. 11 $(000)	Col. 12 10^3m^3	Col. 13 $(000)	Col. 14 $/$10^3m^3$ (Col.2 / Col.1)	Col. 15 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies															
1.1	Alberta Production	-	-	-	-			-	-	-			-	-	-	-
1.2	Western - @ Empress - TCPL	1,111,440.1	151,520.2	136.328	3.617	(200,318.4)	(28,303.9)	911,121.7	123,216.2	135.236	(477,580.3)	(67,479.6)	433,541.4	55,736.7	128.561	3.411
1.3	Western - @ Nova - TCPL	691,069.2	96,918.5	140.244	3.721			691,069.2	96,918.5	140.244			691,069.2	96,918.5	140.244	3.721
1.4	Western Buy/Sell - with Fuel	1,413.9	205.5	145.328	3.856			1,413.9	205.5	145.328			1,413.9	205.5	145.328	3.856
1.5	Western - @ Alliance	963,416.6	141,529.1	146.903	3.898			963,416.6	141,529.1	146.903			963,416.6	141,529.1	146.903	3.898
1.6	Less TCPL Fuel Requirement	(61,259.4)	-					(61,259.4)	-	-			(61,259.4)	-	-	
1.	Total Western Canadian Supplies	2,706,080.4	390,173.2	144.184	3.826	(200,318.4)	(28,303.9)	2,505,762.0	361,869.3	144.415	(477,580.3)	(67,479.6)	2,028,181.8	294,389.7	145.150	3.851
2.	Peaking Supplies	52,410.0	10,924.8	208.448	5.531			52,410.0	10,924.8	208.448	47,758.0	8,189.6	100,168.0	19,114.4	190.823	5.063
3.	Ontario Production	1,460.1	286.9	196.465	5.213			1,460.1	286.9	196.465			1,460.1	286.9	196.465	5.213
	Chicago Supplies	1,846,482.9	300,299.1	162.633	4.315			1,846,482.9	300,299.1	162.633			1,846,482.9	300,299.1	162.633	4.315
	Delivered Supplies	1,463,916.2	250,068.2	170.821	4.532	200,318.4	34,351.0	1,664,234.5	284,419.2	170.901	429,822.2	73,706.7	2,094,056.8	358,125.9	171.020	4.538
6.	Total Supply Costs	6,070,349.6	951,752.2	156.787	4.160	-	6,047.1	6,070,349.6	957,799.2	157.783	-	14,416.8	6,070,349.6	972,216.1	160.158	4.249
	Transportation Costs															
7.1	TCPL - FT - Demand		103,167.4				(11,942.7)		91,224.6			(28,662.6)		62,562.1		
7.2	- FT - Commodity	1,742,663.8	4,435.4	2.545	0.068	(200,318.4)	(509.9)	1,542,345.4	3,925.6		(477,580.3)	(1,215.5)	1,064,765.1	2,710.0		-
7.3	- Parkway to CDA		2,282.6						2,282.6					2,282.6		
7.4	- STS - CDA		3,821.1						3,821.1					3,821.1		
7.5	- STS - EDA		3,407.4						3,407.4					3,407.4		
7.6	- Dawn to CDA		6,777.9				3,280.2		10,058.1					10,058.1		
7.7	- Dawn to EDA		16,308.9						16,308.9					16,308.9		
7.8	- Dawn to Iroquois		5,066.9						5,066.9					5,066.9		
7.9	Other Charges		-						-					-		
7.10	Nova Transmission		4,909.0						4,909.0					4,909.0		
7.12	Alliance Pipeline		41,042.5						41,042.5					41,042.5		
7.15	Vector Pipeline		26,177.0						26,177.0					26,177.0		
7.	Total Transportation Costs		217,396.1				(9,172.4)		208,223.7			(29,878.1)		178,345.6		
8.	Total Before PGVA Adjustment	6,070,349.6	1,169,148.3	192.600	5.110	-	(3,125.4)	6,070,349.6	1,166,022.9	192.085	-	(15,461.3)	6,070,349.6	1,150,561.6	189.538	5.029
9.	PGVA Adjustment		0.0						3,125.4					18,586.7		
10.	Total Purchases & Receipt	6,070,349.6	1,169,148.3	192.600	5.110			6,070,349.6	1,169,148.3	192.600			6,070,349.6	1,169,148.3	192.600	5.110

Filed: 2011-11-16
EB-2011-0277
Exhibit I
Tab 6
Schedule 1
Attachment A
Page 1 of 4

as per EB-2011-0051, Exhibit Q2-3, Tab 1, Schedule 1

Item #		Summary of Gas Cost to Operation: Year ended March 31, 2012				Impact of 50,000 Gj's /day of STFT replacement for Dawn to CDA Supply					Impact of 200,000 Gj's /day of STFT replacement for Peaking Supplies & Dawn Supplies		Deemed Summary of Gas Cost to Operation Year ended March 31, 2012			
		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)	Col. 5 10^3m^3	Col. 6 $(000)	Col. 7 10^3m^3	Col. 8 $(000)	Col. 9 $/$10^3m^3$ (Col.2 / Col.1)	Col. 10 10^3m^3	Col. 11 $(000)	Col. 12 10^3m^3	Col. 13 $(000)	Col. 14 $/$10^3m^3$ (Col.2 / Col.1)	Col. 15 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies															
1.1	Alberta Production	-	-	-	-			-	-	-			-	-	-	-
1.2	Western - @ Empress - TCPL	1,111,440.1	151,981.6	136.743	3.628	(200,318.4)	(27,416.2)	911,121.7	124,565.4	136.717	(477,580.3)	(65,363.2)	433,541.4	59,202.2	136.555	3.623
1.3	Western - @ Nova - TCPL	691,069.2	98,063.1	141.901	3.765			691,069.2	98,063.1	141.901			691,069.2	98,063.1	141.901	3.765
1.4	Western Buy/Sell - with Fuel	1,413.9	198.2	140.214	3.720			1,413.9	198.2	140.214			1,413.9	198.2	140.214	3.720
1.5	Western - @ Alliance	963,416.6	136,625.9	141.814	3.763			963,416.6	136,625.9	141.814			963,416.6	136,625.9	141.814	3.763
1.6	Less TCPL Fuel Requirement	(61,259.4)	-					(61,259.4)	-	-			(61,259.4)	-	-	
1.	Total Western Canadian Supplies	2,706,080.4	386,868.9	142.963	3.793	(200,318.4)	(27,416.2)	2,505,762.0	359,452.7	143.450	(477,580.3)	(65,363.2)	2,028,181.8	294,089.5	145.002	3.847
2.	Peaking Supplies	52,410.0	11,692.5	223.097	5.919			52,410.0	11,692.5	223.097	47,758.0	8,174.4	100,168.0	19,866.9	198.336	5.262
3.	Ontario Production	1,460.1	313.2	214.490	5.691			1,460.1	313.2	214.490			1,460.1	313.2	214.490	5.691
	Chicago Supplies	1,846,482.9	298,447.5	161.630	4.288			1,846,482.9	298,447.5	161.630			1,846,482.9	298,447.5	161.630	4.288
	Delivered Supplies	1,463,916.2	241,678.4	165.090	4.380	200,318.4	34,287.0	1,664,234.5	275,965.4	165.821	429,822.2	73,569.4	2,094,056.8	349,534.9	166.918	4.429
6.	Total Supply Costs	6,070,349.6	939,000.5	154.686	4.104	-	6,870.8	6,070,349.6	945,871.3	155.818	-	16,380.7	6,070,349.6	962,252.0	158.517	4.206
	Transportation Costs															
7.1	TCPL - FT - Demand		137,888.7				(15,962.1)		121,926.6			(38,309.1)		83,617.6		
7.2	- FT - Commodity	1,742,663.8	9,443.0	5.419	0.144	(200,318.4)	(1,085.5)	1,542,345.4	8,357.5		(477,580.3)	(2,587.9)	1,064,765.1	5,769.6		-
7.3	- Parkway to CDA		3,238.4						3,238.4					3,238.4		
7.4	- STS - CDA		5,793.8						5,793.8					5,793.8		
7.5	- STS - EDA		4,687.0						4,687.0					4,687.0		
7.6	- Dawn to CDA		9,471.0				4,495.9		13,966.9					13,966.9		
7.7	- Dawn to EDA		22,582.0						22,582.0					22,582.0		
7.8	- Dawn to Iroquois		6,886.7						6,886.7					6,886.7		
7.9	Other Charges		-						-					-		
7.10	Nova Transmission		4,909.0						4,909.0					4,909.0		
7.12	Alliance Pipeline		40,652.6						40,652.6					40,652.6		
7.15	Vector Pipeline		25,590.4						25,590.4					25,590.4		
7.	Total Transportation Costs		271,142.7				(12,551.6)		258,591.1			(40,896.9)		217,694.1		
8.	Total Before PGVA Adjustment	6,070,349.6	1,210,143.2	199.353	5.289	-	(5,680.9)	6,070,349.6	1,204,462.4	198.417	-	(24,516.2)	6,070,349.6	1,179,946.1	194.379	5.157
9.	PGVA Adjustment		0.0						5,680.9					30,197.1		
10.	Total Purchases & Receipt	6,070,349.6	1,210,143.2	199.353	5.289			6,070,349.6	1,210,143.2	199.353			6,070,349.6	1,210,143.2	199.353	5.289

as per EB-2011-0129, Exhibit Q3-3, Tab 1, Schedule 1

Item #		Summary of Gas Cost to Operations Year ended June 30, 2012				Impact of 50,000 Gj's /day of STFT replacement for Dawn to CDA Supply					Impact of 200,000 Gj's /day of STFT replacement for Peaking Supplies & Dawn Supplies		Deemed Summary of Gas Cost to Operations Year ended June 30, 2012			
		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)	Col. 5 10^3m^3	Col. 6 $(000)	Col. 7 10^3m^3	Col. 8 $(000)	Col. 9 $/$10^3m^3$ (Col.2 / Col.1)	Col. 10 10^3m^3	Col. 11 $(000)	Col. 12 10^3m^3	Col. 13 $(000)	Col. 14 $/$10^3m^3$ (Col.2 / Col.1)	Col. 15 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies															
1.1	Alberta Production	-	-	-	-			-	-	-			-	-	-	-
1.2	Western - @ Empress - TCPL	1,111,440.1	159,479.1	143.489	3.807	(200,318.4)	(29,295.4)	911,121.7	130,183.7	142.883	(477,580.3)	(69,843.3)	433,541.4	60,340.4	139.180	3.693
1.3	Western - @ Nova - TCPL	691,069.2	103,655.7	149.993	3.980			691,069.2	103,655.7	149.993			691,069.2	103,655.7	149.993	3.980
1.4	Western Buy/Sell - with Fuel	1,413.9	214.9	151.975	4.032			1,413.9	214.9	151.975			1,413.9	214.9	151.975	4.032
1.5	Western - @ Alliance	963,416.6	147,991.3	153.611	4.076			963,416.6	147,991.3	153.611			963,416.6	147,991.3	153.611	4.076
1.6	Less TCPL Fuel Requirement	(61,259.4)	-					(61,259.4)	-	-			(61,259.4)	-	-	
1.	Total Western Canadian Supplies	2,706,080.4	411,341.0	152.006	4.033	(200,318.4)	(29,295.4)	2,505,762.0	382,045.6	152.467	(477,580.3)	(69,843.3)	2,028,181.8	312,202.2	153.932	4.084
2.	Peaking Supplies	52,410.0	11,607.7	221.478	5.876			52,410.0	11,607.7	221.478	47,758.0	8,399.9	100,168.0	20,007.6	199.740	5.300
3.	Ontario Production	1,460.1	328.7	225.152	5.974			1,460.1	328.7	225.152			1,460.1	328.7	225.152	5.974
	Chicago Supplies	1,846,482.9	311,704.3	168.810	4.479			1,846,482.9	311,704.3	168.810			1,846,482.9	311,704.3	168.810	4.479
	Delivered Supplies	1,463,916.2	251,433.9	171.754	4.557	200,318.4	35,233.0	1,664,234.5	286,666.8	172.251	429,822.2	75,599.2	2,094,056.8	362,266.1	172.997	4.590
6.	Total Supply Costs	6,070,349.6	986,415.6	162.497	4.311	-	5,937.6	6,070,349.6	992,353.1	163.475	-	14,155.8	6,070,349.6	1,006,508.9	165.807	4.399
	Transportation Costs															
7.1	TCPL - FT - Demand		137,888.7				(15,962.1)		121,926.6			(38,309.1)		83,617.6		
7.2	- FT - Commodity	1,742,663.8	9,443.0	5.419	0.144	(200,318.4)	(1,085.5)	1,542,345.4	8,357.5		(477,580.3)	(2,587.9)	1,064,765.1	5,769.6		-
7.3	- Parkway to CDA		3,238.4						3,238.4					3,238.4		
7.4	- STS - CDA		5,793.8						5,793.8					5,793.8		
7.5	- STS - EDA		4,687.0						4,687.0					4,687.0		
7.6	- Dawn to CDA		9,471.0				4,495.9		13,966.9					13,966.9		
7.7	- Dawn to EDA		22,582.0						22,582.0					22,582.0		
7.8	- Dawn to Iroquois		6,886.7						6,886.7					6,886.7		
7.9	Other Charges		-						-					-		
7.10	Nova Transmission		4,909.0						4,909.0					4,909.0		
7.12	Alliance Pipeline		40,363.5						40,363.5					40,363.5		
7.15	Vector Pipeline		25,155.5						25,155.5					25,155.5		
7.	Total Transportation Costs		270,418.6				(12,551.6)		257,867.0			(40,896.9)		216,970.1		
8.	Total Before PGVA Adjustment	6,070,349.6	1,256,834.2	207.045	5.493	-	(6,614.1)	6,070,349.6	1,250,220.1	205.955	-	(26,741.1)	6,070,349.6	1,223,479.0	201.550	5.348
9.	PGVA Adjustment		0.0						6,614.1					33,355.2		
10.	Total Purchases & Receipt	6,070,349.6	1,256,834.2	207.045	5.493			6,070,349.6	1,256,834.2	207.045			6,070,349.6	1,256,834.2	207.045	5.493

Filed: 2011-11-16
EB-2011-0277
Exhibit I
Tab 6
Schedule 1
Attachment A
Page 3 of 4

as per EB-2011-0296, Exhibit Q4-3, Tab 1, Schedule 1

Item #		Summary of Gas Cost to Operations Year ended September 30, 2012				Impact of 50,000 Gj's /day of STFT replacement for Dawn to CDA Supply					Impact of 200,000 Gj's /day of STFT replacement for Peaking Supplies & Dawn Supplies		Deemed Summary of Gas Cost to Operations Year ended September 30, 2012			
		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)	Col. 5 10^3m^3	Col. 6 $(000)	Col. 7 10^3m^3	Col. 8 $(000)	Col. 9 $/$10^3m^3$ (Col.2 / Col.1)	Col. 10 10^3m^3	Col. 11 $(000)	Col. 12 10^3m^3	Col. 13 $(000)	Col. 14 $/$10^3m^3$ (Col.2 / Col.1)	Col. 15 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies															
1.1	Alberta Production	-	-	-	-			-	-	-			-	-	-	-
1.2	Western - @ Empress - TCPL	1,111,440.1	144,748.3	130.235	3.455	(200,318.4)	(26,843.9)	911,121.7	117,904.5	129.406	(477,580.3)	(63,998.6)	433,541.4	53,905.9	124.339	3.299
1.3	Western - @ Nova - TCPL	691,069.2	95,318.8	137.930	3.660			691,069.2	95,318.8	137.930			691,069.2	95,318.8	137.930	3.660
1.4	Western Buy/Sell - with Fuel	1,413.9	200.1	141.536	3.755			1,413.9	200.1	141.536			1,413.9	200.1	141.536	3.755
1.5	Western - @ Alliance	963,416.6	137,745.8	142.976	3.793			963,416.6	137,745.8	142.976			963,416.6	137,745.8	142.976	3.793
1.6	Less TCPL Fuel Requirement	(61,259.4)	-					(61,259.4)	-	-			(61,259.4)	-	-	
1.	Total Western Canadian Supplies	2,706,080.4	378,013.1	139.690	3.706	(200,318.4)	(26,843.9)	2,505,762.0	351,169.3	140.145	(477,580.3)	(63,998.6)	2,028,181.8	287,170.7	141.590	3.757
2.	Peaking Supplies	52,410.0	10,752.0	205.151	5.443			52,410.0	10,752.0	205.151	47,758.0	7,920.8	100,168.0	18,672.8	186.415	4.946
3.	Ontario Production	1,460.1	313.3	214.563	5.693			1,460.1	313.3	214.563			1,460.1	313.3	214.563	5.693
	Chicago Supplies	1,846,482.9	292,110.6	158.198	4.197			1,846,482.9	292,110.6	158.198			1,846,482.9	292,110.6	158.198	4.197
	Delivered Supplies	1,463,916.2	242,442.9	165.613	4.394	200,318.4	33,223.4	1,664,234.5	275,666.4	165.642	429,822.2	71,287.4	2,094,056.8	346,953.7	165.685	4.396
6.	Total Supply Costs	6,070,349.6	923,631.9	152.155	4.037	-	6,379.6	6,070,349.6	930,011.4	153.206	-	15,209.6	6,070,349.6	945,221.0	155.711	4.131
	Transportation Costs															
7.1	TCPL - FT - Demand		137,888.7				(15,962.1)		121,926.6			(38,309.1)		83,617.6		
7.2	- FT - Commodity	1,742,663.8	9,443.0	5.419	0.144	(200,318.4)	(1,085.5)	1,542,345.4	8,357.5		(477,580.3)	(2,587.9)	1,064,765.1	5,769.6		-
7.3	- Parkway to CDA		3,238.4						3,238.4					3,238.4		
7.4	- STS - CDA		5,793.8						5,793.8					5,793.8		
7.5	- STS - EDA		4,687.0						4,687.0					4,687.0		
7.6	- Dawn to CDA		9,471.0				4,495.9		13,966.9					13,966.9		
7.7	- Dawn to EDA		22,582.0						22,582.0					22,582.0		
7.8	- Dawn to Iroquois		6,886.7						6,886.7					6,886.7		
7.9	Other Charges		-						-					-		
7.10	Nova Transmission		4,909.0						4,909.0					4,909.0		
7.12	Alliance Pipeline		40,546.8						40,546.8					40,546.8		
7.15	Vector Pipeline		25,431.2						25,431.2					25,431.2		
7.	Total Transportation Costs		270,877.6				(12,551.6)		258,325.9			(40,896.9)		217,429.0		
8.	Total Before PGVA Adjustment	6,070,349.6	1,194,509.4	196.778	5.221	-	(6,172.1)	6,070,349.6	1,188,337.4	195.761	-	(25,687.3)	6,070,349.6	1,162,650.1	191.529	5.082
9.	PGVA Adjustment		0.0						6,172.1					31,859.4		
10.	Total Purchases & Receipt	6,070,349.6	1,194,509.4	196.778	5.221			6,070,349.6	1,194,509.4	196.778			6,070,349.6	1,194,509.4	196.778	5.221

Filed: 2011-11-16
EB-2011-0277
Exhibit I
Tab 6
Schedule 1
Attachment A
Page 4 of 4

FRPO INTERROGATORY #2

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, PG. 4,5

Preamble: EGD evidence states: "The Company and intervenors participated in a System Reliability proceeding (EB-2010-0231) and the outcome of that proceeding has been included as a part of the 2012 gas supply portfolio. As per the EB-2010-0231 Settlement Agreement the Company assigned 50,000 Gj/day of TCPL shorthaul capacity to Direct Purchase customers and has acquired 50,000 Gj/day of TCPL STFT from November to March. The Company also incorporated in its plan the acquisition of 200,000 Gj/day of TCPL STFT for three winter months which was also agreed upon as part of the settlement agreement as a substitute for traditional peaking services.

What were the actual costs of System Reliability in 2011?

RESPONSE

In response to FRPO Interrogatory #1 at Exhibit I, Tab 6, Schedule 1, the Company provided a series of schedules to illustrate, at a high level, the approximate annual impacts of the outcome of the System Reliability proceeding based upon budgeted information under a number of specific scenarios.

To attempt to recreate similar schedules for the 2011 actuals would not be meaningful. While the actual costs of the supplies purchased in 2011 can be identified it would be inappropriate to compare those costs versus an assumed acquisition cost of Peaking Supplies and Ontario Delivered Supplies. For example, the Company filled the TCPL STFT capacity throughout the year using a combination of Monthly and Daily Empress and Nova supplies. As for alternative supplies the Company would have to make a number of assumptions such as, would EGD have acquired an equal level of Dawn Supplies under comparable Monthly and Daily quantities and associated prices and second for costing of Peaking Services the Company would be required to assume what Demand Charge would have been paid for the incremental peaking supply and then to make assumptions as to what days that supply would have been called upon to determine an estimated commodity price for the supply.

Ultimately, comparing actual costs incurred of a supply portfolio that was approved by Board against a hypothetical supply at a number of "what if" pricing assumptions would not be beneficial.

Witness: D. Small

FRPO INTERROGATORY #3

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, PG. 4,5

Preamble: EGD evidence states: "The Company and intervenors participated in a System Reliability proceeding (EB-2010-0231) and the outcome of that proceeding has been included as a part of the 2012 gas supply portfolio. As per the EB-2010-0231 Settlement Agreement the Company assigned 50,000 Gj/day of TCPL shorthaul capacity to Direct Purchase customers and has acquired 50,000 Gj/day of TCPL STFT from November to March. The Company also incorporated in its plan the acquisition of 200,000 Gj/day of TCPL STFT for three winter months which was also agreed upon as part of the settlement agreement as a substitute for traditional peaking services.

How is the variance between the forecast and actual for these costs treated (i.e., to what account would the variance accrue and would variances be cleared)?

RESPONSE

Any variances between actual gas acquisition costs and forecasted gas acquisition cost are captured in the PGVA and are cleared in accordance with the Board approved methodology.

Witness: D. Small

FRPO INTERROGATORY #4

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, PG. 4,5

Preamble: EGD evidence states: "The Company and intervenors participated in a System Reliability proceeding (EB-2010-0231) and the outcome of that proceeding has been included as a part of the 2012 gas supply portfolio. As per the EB-2010-0231 Settlement Agreement the Company assigned 50,000 Gj/day of TCPL shorthaul capacity to Direct Purchase customers and has acquired 50,000 Gj/day of TCPL STFT from November to March. The Company also incorporated in its plan the acquisition of 200,000 Gj/day of TCPL STFT for three winter months which was also agreed upon as part of the settlement agreement as a substitute for traditional peaking services.

What is the forecast for 2012 System Reliability costs?

RESPONSE

The attached schedule was prepared in a similar fashion and using the same assumptions as the schedules attached to FRPO Interrogatory #1 at Exhibit I, Tab 6, Schedule 1. The pricing information is based upon the October 2011 QRAM.

Witness: D. Small

as per EB-2011-0277, Exhibit B, Tab 4, Schedule 2, page1

Item #		Summary of Gas Cost to Operation: Year ended December 31, 2012				Impact of 50,000 Gj's /day of STFT replacement for Dawn to CDA					Impact of 200,000 Gj's /day of STFT replacement for Peaking Supplies		Deemed Summary of Gas Cost to Operation Year ended December 31, 2012			
		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)	Col. 5	Col. 6	Col. 7 10^3m^3	Col. 8 $(000)	Col. 9 $/$10^3m^3$ (Col.2 / Col.1)	Col. 10 10^3m^3	Col. 11 $(000)	Col. 12 10^3m^3	Col. 13 $(000)	Col. 14 $/$10^3m^3$ (Col.2 / Col.1)	Col. 15 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies															
1.1	Alberta Production	-	-	-	-			-	-	-			-	-	-	-
1.2	Western - @ Empress - TCPL	1,597,128.1	214,603.4	134.368	3.565	(200,318.4)	(27,775.8)	1,396,809.7	186,827.6	133.753	(477,580.3)	(66,220.5)	919,229.5	120,607.1	131.205	3.481
1.3	Western - @ Nova - TCPL	943,063.3	133,838.3	141.919	3.765			943,063.3	133,838.3	141.919			943,063.3	133,838.3	141.919	3.765
1.4	Western Buy/Sell - with Fuel	1,854.8	267.4	144.146	3.825			1,854.8	267.4	144.146			1,854.8	267.4	144.146	3.825
1.5	Western - @ Alliance	957,382.1	141,515.2	147.815	3.922			957,382.1	141,515.2	147.815			957,382.1	141,515.2	147.815	3.922
1.6	Less TCPL Fuel Requirement	(59,603.3)	-					(59,603.3)	-	-			(59,603.3)	-	-	
1.	Total Western Canadian Supplies	3,439,824.9	490,224.4	142.514	3.781	(200,318.4)	(27,775.8)	3,239,506.5	462,448.6	142.753	(477,580.3)	(66,220.5)	2,761,926.2	396,228.1	143.461	3.806
2.	Peaking Supplies	37,242.5	10,064.5	270.242	7.170			37,242.5	10,064.5	270.242	47,758.0	8,222.2	85,000.5	18,286.7	215.136	5.708
3.	Ontario Production	730.0	160.0	219.169	5.815			730.0	160.0	219.169			730.0	160.0	219.169	5.815
	Chicago Supplies	1,837,120.7	300,419.2	163.527	4.339			1,837,120.7	300,419.2	163.527			1,837,120.7	300,419.2	163.527	4.339
	Delivered Supplies	1,488,789.8	252,144.0	169.362	4.494	200,318.4	34,263.2	1,689,108.2	286,407.2	169.561	429,822.2	73,518.3	2,118,930.4	359,925.5	169.862	4.507
6.	Total Supply Costs	6,803,707.9	1,053,012.1	154.770	4.106	-	6,487.3	6,803,707.9	1,059,499.4	155.724	-	15,520.0	6,803,707.9	1,075,019.4	158.005	4.192
	Transportation Costs															
7.1	TCPL - FT - Demand		197,326.2				(15,962.1)		181,364.1			(38,309.1)		143,055.0		
7.2	- FT - Commodity	3,459,902.6	13,451.6	3.888	0.103	(200,318.4)	(1,085.5)	3,259,584.2	12,366.1		(477,580.3)	(2,587.9)	2,782,004.0	9,778.3		-
7.3	- Parkway to CDA		3,238.4						3,238.4					3,238.4		
7.4	- STS - CDA		5,793.8						5,793.8					5,793.8		
7.5	- STS - EDA		4,687.0						4,687.0					4,687.0		
7.6	- Dawn to CDA		9,471.0				4,495.9		13,966.9					13,966.9		
7.7	- Dawn to EDA		22,582.0						22,582.0					22,582.0		
7.8	- Dawn to Iroquois		7,063.3						7,063.3					7,063.3		
7.9	Other Charges		(2,541.6)						(2,541.6)					(2,541.6)		
7.10	Nova Transmission		7,039.6						7,039.6					7,039.6		
7.12	Alliance Pipeline		42,485.0						42,485.0					42,485.0		
7.15	Vector Pipeline		25,272.4						25,272.4					25,272.4		
7.	Total Transportation Costs		335,868.7				(12,551.6)		323,317.0			(40,896.9)		282,420.1		
8.	Total Before PGVA Adjustment	6,803,707.9	1,388,880.7	204.136	5.416	-	(6,064.3)	6,803,707.9	1,382,816.4	203.245	-	(25,376.9)	6,803,707.9	1,357,439.5	199.515	5.294
9.	PGVA Adjustment		(65,066.0)						(58,998.6)					(33,621.7)		
10.	Total Purchases & Receipt	6,803,707.9	1,323,814.7	194.573	5.162			6,803,707.9	1,323,817.9	194.573			6,803,707.9	1,323,817.9	194.573	5.162

Filed: 2011-11-16
EB-2011-0277
Exhibit I
Tab 6
Schedule 4
Attachment A
Page 1 of 1

FRPO INTERROGATORY #5

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: EB-2010-0146 Ex. 1, Tab 4, Schedule 12

Preamble: In response to FRPO's IR 12 in the 2011 proceeding, EGD stated in the second paragraph: "...The 2011 gas supply revenues reflect the 2011 forecast of Gas Costs to Operations (at the October 1, 2010 QRAM reference price) in the amount of $1,416.30 million (Exhibit B, Tab 1, Schedule 2, page 1, Row 25, Col. 1) including changes to the Company's 2011 gas supply portfolio relative to the 2010 gas supply portfolio as well as storage and storage associated transportation costs. Changes to these elements are not captured through the Company's QRAM rate changes.

Please describe the nature of the "storage and associated storage associated transportation costs".

RESPONSE

The reference to "storage and storage associated transportation costs" pertains to the forecasted costs payable by the Company for third party storage contracts, Union transmission cost, costs attributable to storage injection and withdrawal fuel requirements, and Union Transmission fuel requirements.

Any variances associated with third party storage contracts due to $US exchange and Union transmission costs due to Union toll changes are captured in the S&TDA. Any variances relating to storage and transmission fuel costs are the risk of the Company.

Witness: D. Small

FRPO INTERROGATORY #6

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: EB-2010-0146 Ex. 1, Tab 4, Schedule 12

Preamble: In response to FRPO's IR 12 in the 2011 proceeding, EGD stated in the second paragraph: "...The 2011 gas supply revenues reflect the 2011 forecast of Gas Costs to Operations (at the October 1, 2010 QRAM reference price) in the amount of $1,416.30 million (Exhibit B, Tab 1, Schedule 2, page 1, Row 25, Col. 1) including changes to the Company's 2011 gas supply portfolio relative to the 2010 gas supply portfolio as well as storage and storage associated transportation costs. Changes to these elements are not captured through the Company's QRAM rate changes.

With respect to System Reliability, how are these costs incurred, tracked and recovered?

RESPONSE

The $1,416.3 million, referred to above, represents the gas cost forecast the Company applied for in EB-2010-0146 and was subsequently approved by the Board. The gas cost forecast included outcomes of the System Reliability Consultative. The approval and recovery in rates of these elements/outcomes can be found in the Board's decision in EB-2010-0231(System Reliability).

The PGVA Reference Price comprises of commodity, transportation and load balancing costs. These elements of the gas costs forecast are updated as part of the QRAM process throughout the year. Variances in actual purchase costs versus forecasted purchase costs are recorded in the PGVA for disposition.

Please note that the storage and storage associated transportation costs are not part of the PGVA reference price (please see response to FRPO #5 at Exhibit I, Tab 6, Schedule 5). Note that the storage and associated transportation costs are not impacted by the System Reliability Decision.

Witness: D. Small

FRPO INTERROGATORY #7

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, page 5, para. 11

What actions did EGD take with customers who had their CDS nominations cut? What were the cost consequences of the cut and how were they costs accounted for and recovered?

RESPONSE

To the extent that a customer continued to consume gas when asked to curtail and had their CDS supplies been cut, then that customer would have been billed Unauthorized Overrun Gas Supply charges and dependent upon the volumes consumed, may have had their seasonal credits clawed back. Unauthorized Overrun charges are credited to the PGVA account for subsequent disposition in accordance with the Board approved Cost Allocation and Rate Design Methodology. Any seasonal credits that were clawed back from customers were also credited to the PGVA.

If the CDS supplies were cut after the final nomination window the Company would have taken more gas from TCPL and be subject to LBA penalties. The Company is obligated to eliminate its cumulative LBA imbalances in a timely fashion or be subject to additional penalties. The Company would eliminate any LBA balance by acquiring additional supplies and the cost impacts of those supplies versus budgeted costs would be captured in the PGVA for future disposition.

Witness: D. Small

FRPO INTERROGATORY #8

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, page 5, para. 11

Preamble: EGD states: In addition, the Company did not receive deliveries as a result of one of the peaking suppliers having their supplies cut. This has led the Company to lower the amount of traditional peaking supplies that it will plan to acquire in 2012. To compensate for this reduction the Company has included an additional 75,000 Gj/day of TCPL STFT for three winter months.
The Company has also taken an assignment of 26,956 Gj/day of TCPL-FT Empress to Iroquois capacity.

Peaking Supplies

a. How were the EGD peaking supplies contracted (e.g., Demand contract)?
b. What were the operational effects of EGD not receiving the peaking supplies?
c. What were the cost consequences of the failure to deliver and how were they handled?

RESPONSE

a) Peaking Supply contracts have a fixed demand cost component payable whether or not gas supplies are nominated under that contract as well as a commodity component tied to a gas supply index payable for every unit physically received under that contract.

b) If Peaking Supplies, or any other supply for that matter, does not show up as nominated then EGD will attempt to procure alternative supplies. If the Company is unable to acquire alternative supplies then operationally the Company would take excess gas from TCPL and be subject to LBA penalties (see response to FRPO Interrogatory #7 at Exhibit I, Tab 6, Schedule 7).

c) To offset any cost consequences identified above the Company sought damages from the peaking supplier in question as per the terms of the Peaking contract. The monies received from the Peaking Supplier as damages were booked to the PGVA account for subsequent disposition.

Witness: D. Small

FRPO INTERROGATORY #9

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, page 5, para. 11

Preamble: EGD states: In addition, the Company did not receive deliveries as a result of one of the peaking suppliers having their supplies cut. This has led the Company to lower the amount of traditional peaking supplies that it will plan to acquire in 2012. To compensate for this reduction the Company has included an additional 75,000 Gj/day of TCPL STFT for three winter months.
The Company has also taken an assignment of 26,956 Gj/day of TCPL-FT Empress to Iroquois capacity.

Additional STFT

a. What are the cost implications of the additional 75,000 GJ's of STFT?
b. Please provide the incremental STFT cost along with the estimated reduction in contracted peaking service?
c. How does EGD intend to recover the incremental cost?

RESPONSE

This question and others posed by FRPO refer back to System Reliability and the cost impacts of changes in supply alternatives. The System Reliability Consultative dealt with 4 main issues: 1) to address the fact that a significant amount of the Company's supply – Direct Purchase supply - was not underpinned by firm contracts (this was an issue that the Board directed the Company and Intervenors to come to a resolution on), 2) to address FT Turnback issues to ensure like for like service, 3) a number of concerns the Company had around the value of interruptible customers and penalties associated with non-compliance, and 4) an issue brought forward by the Company during the consultative in which the Company expressed a concern that Peaking Services that the Company had traditionally relied upon to meet peak day demand were not necessarily underpinned by firm transportation. This formed the basis for the Company proposing the acquisition of 200,000 Gj's/day of STFT in lieu of traditional peaking services.

The outcomes agreed upon by members of the consultative were the assignment of EGD contracted TCPL Shorthaul capacity to Direct Purchase customers to address firm

transportation concerns, changes to the Company's Rate Handbook to address FT Turnback issues and strengthen the rules around curtailment and finally to grant the Company prior approval to an element of its' budgeted gas supply portfolio for 2011. The Company felt that the System Reliability Hearing was the opportune time to discuss this issue.

Typically for a forecast period the Company would evaluate the optimum supply portfolio to meet its forecasted annual and peak day requirements. These decisions are not based entirely upon price but also take into consideration reliability of the service and where that supply will be delivered. The Company then would seek approval of that supply portfolio and associated costs from the Board through the rate application for that test year.

For Fiscal 2012, as in any other year, the Company has developed a forecasted supply portfolio that it feels will meet the forecasted annual and peak day demand for 2012 and the Company is seeking approval of that forecast. One element of that forecasted supply portfolio is a forecasted need for 75,000 Gj's/day of STFT capacity which, when compared to the 2011 forecasted supply portfolio, would appear to be incremental. However, a strict comparison between one year to the next can not necessarily always be made because the Company needs to be able to adapt to circumstances such as changes in degree days, customer additions and changes in the gas supply market place. Based upon circumstances that occurred during the winter of 2011 (ie. failure of direct purchase deliveries, CDS deliveries, peaking service deliveries and the impact of Direct Purchase migration) and in the interest of providing safe and reliable service to its' customers the Company believes the prudent decision is to reduce its' reliance upon traditional peaking service and contract for 75,000 Gj's/day of TCPL STFT for the November to March period. This will provide the Company additional capability to meet its seasonal and peak day requirements.

Identifying the cost impacts of this particular supply alone would not provide value unless it was intended to be compared against an alternative source. The Company, as stated above, had concerns about the reliability of certain supplies and given that all of the Company's firm commitments on TCPL were met the Company believes that contracting for STFT is currently the only option available and that there is no comparable source of supply in the market place today.

FRPO INTERROGATORY #10

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, page 5, para. 11

Preamble: EGD states: In addition, the Company did not receive deliveries as a result of one of the peaking suppliers having their supplies cut. This has led the Company to lower the amount of traditional peaking supplies that it will plan to acquire in 2012. To compensate for this reduction the Company has included an additional 75,000 Gj/day of TCPL STFT for three winter months.
The Company has also taken an assignment of 26,956 Gj/day of TCPL-FT Empress to Iroquois capacity.

FT Empress-Iroquois

a. What is the term of the contract EGD accepted?
b. How does EGD propose that the April to October demand charges of this contract be handled?

RESPONSE

a)-b) Migration of Direct Purchase customers back to System Gas increased the Company's transportation requirements for 2012. In order to meet increased annual demand the Company has entered into a one year assignment of TCPL-FT Empress to Iroquois capacity from a third party effective November 1, 2011. The Company chose to take advantage of this assignment because it was able to acquire the capacity at a discount.

Transportation costs are recovered through the Company's transportation charge in accordance with the Board approved Cost Allocation and Rate Design Methodology.

Witness: D. Small

FRPO INTERROGATORY #11

INTERROGATORY

GAS COSTS, TRANSPORTATION AND STORAGE

REF: Ex. B, Tab 4, Schedule 1, page 5, para. 11

Preamble: EGD states: In addition, the Company did not receive deliveries as a result of one of the peaking suppliers having their supplies cut. This has led the Company to lower the amount of traditional peaking supplies that it will plan to acquire in 2012. To compensate for this reduction the Company has included an additional 75,000 Gj/day of TCPL STFT for three winter months.
The Company has also taken an assignment of 26,956 Gj/day of TCPL-FT Empress to Iroquois capacity.

Approvals

a. Please file the Settlement Agreement for System Reliability from EB-2010-0231.
b. Respectfully, does EGD believe that the System Reliability Agreement allows EGD to make discretionary changes each year to the composition of the measures it takes for System Reliability?
c. What specific approval(s) is EGD seeking for System Reliability in this proceeding?

RESPONSE

a) Please see the attached System Reliability Settlement Agreement (EB-2010-0231).

b)-c) EGD, as the system operator, is responsible for ensuring that the demand of its customers is met in a safe and reliable manner and as such, EGD must develop a supply portfolio that will achieve that objective.

Please see EGD's response to FRPO Interrogatory #9, at Exhibit I, Tab 6, Schedule 9.

Witness: D. Small

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2010-0231

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving a system reliability Settlement Agreement.

BEFORE: Marika Hare
Presiding Member

Paula Conboy
Member

DECISION AND ORDER

Enbridge Gas Distribution Inc. ("Enbridge") filed an application on July 15, 2010 (the "Application") with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Sched. B, as amended, for an order or orders of the Board approving a system reliability Settlement Agreement (the "Settlement Agreement") and approving changes to rates in order to give effect to the provisions of the Settlement Agreement. The Application included the Settlement Agreement, supporting evidence and minutes of meetings of stakeholder consultations. The Board assigned File Number EB-2010-0231 to this application.

Background

In Enbridge's 2009 rates proceeding, EB-2008-0219, Enbridge raised a system reliability matter for the Board's consideration. System reliability in this context refers to Enbridge's assuredness that the required gas deliveries will materialize on peak days. The trend in recent years was towards a lower proportion of shippers' gas deliveries arriving via firm transportation arrangements. This trend gave rise to Enbridge's concern about the reliability of the system. The issue went to hearing, and in the Board's Phase 2 Decision and Order released on July 14, 2009, Enbridge was directed to file an application with the intention of having a long term resolution for system reliability in place for the 2010/2011 winter season. The Board also stated

its expectation that the application would include evidence of a stakeholder consultation on the issue of system reliability. Enbridge initiated a consultation process and held a number of meetings commencing in August 2009 and concluding in early summer 2010.

At the conclusion of the consultation process, the parties reached a full settlement on a resolution to the system reliability matter. A broad group of stakeholders representing a wide spectrum of interests in the Ontario gas industry participated in the consultation and signed on to the Settlement Agreement. None of the stakeholders opposed the Settlement Agreement.

The Settlement Agreement

The Settlement Agreement sets out the terms of a long term resolution of the system reliability issue. It is based on the following elements:

- Assignment of 50,000 GJ/day of short haul transportation capacity and replacement of that capacity with Short Term Firm Transportation ("STFT");
- Replacement of peaking supplies. Enbridge will reduce the amount of peaking supplies in its gas supply portfolio by 200,000 GJ/day and will replace those supplies with STFT;
- Changes to the terms of service for large volume customers in order to enhance the effectiveness and reliability of gas supply planning;
- Revisions to the curtailment rules and practices in order to increase the effectiveness and reliability of curtailment; and,
- Turnback provisions will be changed to place restrictions and administrative requirements for the turnback of firm transportation capacity.

The specific details of the elements above are included in the Settlement Agreement, attached as Appendix "A" to this Decision and Order.

Process

The Board issued the Notice of Application on July 26, 2010 and Procedural Order No. 1 on August 6, 2010.

In Procedural Order No.1 the Board set out a process for parties to ask questions and make submissions on the Application. Board staff asked three interrogatories. The Canadian Manufacturers & Exporters made a submission on August 18, 2010 in which it urged the Board to approve the Settlement Agreement. Enbridge replied on August 20, 2010 and requested that the Board move quickly to approve the Settlement Agreement. There were no other submissions.

Board staff interrogatories asked Enbridge to confirm the ratepayer bill impacts that were shown in the Settlement Agreement. Board staff also asked Enbridge to confirm that the gas cost

increases will be built into the forecast gas acquisition costs and that variances will be captured within the Purchased Gas Variance Account. Enbridge confirmed both of these questions but noted that the cost impacts may change based on prevailing market conditions in the gas markets and the prevailing transportation tolls. A third question dealt with whether in Enbridge's view the changes will achieve the desired level of system reliability. Enbridge replied that it would but it may need to make further adjustments if there are material changes in demand, supply or the availability of transport to its franchise area.

The Board notes that Enbridge, in its Application, has requested that the Settlement Agreement be approved prior to September 1, 2010 in order to allow for its implementation for the upcoming 2010/2011 winter season. Appendix "B" to the Settlement Agreement lists the changes required to the rate handbook to give effect to some of the elements of the Settlement Agreement. Enbridge proposed in its August 20, 2010 letter that the rate handbook changes be implemented as part of its October 1, 2010 Quarterly Rate Adjustment Mechanism ("QRAM") filing.

Decision

The Board has reviewed the Settlement Agreement and considered the rationale underlying the Settlement Agreement and has found it to be adequate. The Board also finds that the quality and detail of the supporting evidence is sufficient to allow the Board to make findings on all of the matters of concern. The Board accepts the Settlement Agreement in its entirety and finds that it is in the public interest. Lastly, the Board commends Enbridge on the thoroughness of its consultative process which led to unanimous acceptance of the actions to improve system reliability. Enbridge should proceed to implement the provisions of the Settlement Agreement as soon as possible for the upcoming 2010/2011 winter season.

THE BOARD ORDERS THAT:

1. The October 1, 2010 QRAM filing shall include the rate handbook changes as contemplated in Appendix "B" to the Settlement Agreement.

DATED at Toronto, August 26, 2010
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX "A"

SETTLEMENT AGREEMENT

System Reliability

EB-2010-0231

Corrected: July 19, 2010
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Page 1 of 16
Plus Appendices /c

SETTLEMENT AGREEMENT

ENBRIDGE GAS DISTRIBUTION INC.

SYSTEM RELIABILITY

JULY 15, 2010

TABLE OF CONTENTS

Page

I. BACKGROUND AND CONTEXT

II. SETTLEMENT PREAMBLE

III. TERMS OF SETTLEMENT

IV. MATERIAL CHANGE IN CIRCUMSTANCES

V. AGREEMENT OF THE PARTIES

I. BACKGROUND AND CONTEXT

In its EB-2008-0219 Phase 2 Decision and Order issued on July 14, 2009, the Ontario Energy Board (the "Board") addressed a "system reliability issue"[1] raised by Enbridge Gas Distribution Inc. ("Enbridge"). The Decision set out an interim resolution of the issue that would be in place for the upcoming winter of 2009/2010 and that would remain in place until a long term resolution has been approved by the Board.

In the Decision, the Board went on to state its view that a long term resolution of the system reliability issue is needed. The Board directed Enbridge to bring forward an application with the intention of having the long term resolution implemented for the winter of 2010/2011. The Board also stated its expectation that, for the hearing of the long term resolution, evidence of stakeholder consultation would be brought forward. In order to fulfill the Board's expectation, Enbridge initiated a consultation process with stakeholders to consider a long term solution to the system reliability issue.

The initial meeting of the consultative was held on August 13, 2009. The consensus of the participants in this consultative meeting was that a smaller group (the "Working Group") should be created to continue discussions about a long term resolution of the system reliability issue and that the Working Group should report back to the broader group of participants (the "Consultative Group"). At a second meeting of the consultative on October 16, 2009, the following were chosen as members of the Working Group:

Canadian Manufacturers & Exporters (CME)
Industrial Gas Users Association (IGUA)
Union Gas Limited (Union)
TransCanada PipeLines Limited (TCPL)
Shell Energy North America (Canada) Inc.
Aegent Energy Advisors Inc. (Aegent)
Consumers Council of Canada/Vulnerable Energy Consumers Coalition (CCC/VECC)
Direct Energy Marketing Limited (Direct)
Enbridge.

[1] In this Background and Context section of the Settlement Agreement, the words "system reliability issue" are quoted from the EB-2008-0219 Phase 2 Decision and Order.

The Working Group met on November 20, 2009, January 21, 2010, February 25, 2010, April 8, 2010 and April 30, 2010 to discuss the system reliability issue. Discussions on the issue advanced to the point where the members of the Working Group agreed that it would be of value to hold a settlement meeting to consider whether the Working Group could agree on a long term resolution. A further consultative meeting of the Working Group was held during the morning of May 17, 2010. The settlement meeting of the Working Group began in the afternoon of May 17th and continued on May 18th.

By the conclusion of the settlement meeting on May 18th, the Working Group had agreed on the components of a proposal for a long term resolution to the system reliability issue (referred to in the following provisions of this agreement as the "Long Term Resolution") to be presented to the Consultative Group. The Working Group reported back to the Consultative Group with regard to this proposal on June 15, 2010 and a further meeting of the Consultative Group took place on June 23, 2010. In addition to the members of the Working Group, the participants in the Consultative Group are as follows:

Access Gas Services Inc. (Access)
Association of Power Producers of Ontario (APPrO)
Building Owners and Managers Association of Greater Toronto (BOMA)
BP Canada (BP)
E2 Energy Inc. (E2)
ECNG Energy L.P. (ECNG)
Energy Probe Research Foundation (Energy Probe)
Federation of Rental-Housing Providers of Ontario (FRPO)[2]
Jason F. Stacey
Just Energy Ontario L.P. (Just Energy)
Ontario Association of Physical Plant Administrators (OAPPA)
Superior Energy Management Gas L.P. (Superior)

[2] By letter dated May 27, 2010, the Board granted late intervention status to FRPO.

II. SETTLEMENT PREAMBLE

As a result of the consultative process, the Consultative Group has reached agreement on all aspects of the Long Term Resolution of the system reliability issue. Board Staff has attended meetings during the consultative process, but it is not a party to this Settlement Agreement. Certain members of the Consultative Group are of the view that Enbridge has been unable to establish to their satisfaction that it does, in fact, have a system reliability problem by reason of the level of firm upstream transportation arrangements to its franchise areas. Nevertheless, these parties recognize that the Board has acknowledged Enbridge's system reliability concern, and accept that the Long Term Resolution addresses Enbridge's concerns, and should address any concerns of the Board, in a manner that is minimally intrusive of the market and that minimizes ratepayer costs.

The facts supporting this Settlement Agreement are found in the record of information exchanged and discussed at, or in conjunction with, the meetings of the Consultative Group and of the Working Group. The parties are of the view not only that this record supports the Settlement Agreement but also that the quality and detail of the record, together with the corresponding rationale set out in Appendix A to this agreement, will allow the Board to accept the Long Term Resolution.

The parties to the settlement all agree that this Settlement Agreement is a package: the individual aspects of this agreement are inextricably linked to one another and none of the parts of this settlement are severable. As such, there is no agreement among the parties to settle any aspect of the issues addressed in this Settlement Agreement in isolation from the balance of the issues addressed herein. The parties agree, therefore, that in the event that the Board does not accept this Settlement Agreement in its entirety, then there is no agreement. If the Board does not accept the Settlement Agreement, Enbridge will file an application seeking approval of a proposal for a long term resolution of the system reliability issue and the parties to this Settlement Agreement will be at liberty to take such positions as they see fit in respect of that application. More specifically, the efforts of the parties to reach a settlement of the system reliability issue will not in any way prejudice the positions that they may take in the event that the Settlement Agreement is rejected by the Board.

Further, the agreement by the parties on the Long Term Resolution in this case will not in any way prejudice the positions that they may take in future proceedings, particularly if issues relating to Enbridge's system reliability are reconsidered.

While the consultative process under which this settlement was reached was not formally initiated by the Board under Rule 31 of the *Ontario Energy Board Rules of Practice and Procedure*, the parties agree that it is appropriate that Rules 31.09, 31.10 and 32 apply to the settlement process and this Settlement Agreement.

Enbridge is not seeking recovery of any administrative, system, and internal process change costs that may be over and above what is provided for in the existing IR framework unless expressly set out in this Agreement.

III. TERMS OF SETTLEMENT

The Long Term Resolution of the system reliability issue agreed to by the Consultative Group consists of the following terms.

1. Assignment of Short Haul Capacity

Enbridge has contracted with TCPL for short haul firm transportation capacity from Dawn, Ontario to TCPL's Enbridge Central Delivery Area ("CDA"). Subject to the Annual Review described below, Enbridge will assign[3] 50,000 GJ/day of this short haul firm transportation capacity to agents for mass market customers[4] that meet the definition of "Agent" below and Enbridge will replace the assigned capacity with an equivalent volume of TCPL Short Term Firm Transportation ("STFT") capacity from Empress, Alberta that it will secure annually, or if economic, equivalent firm transportation.[5] The cost consequences of this component of the Long Term Resolution will be recovered from sales and Western-T service customers allocated by volume, pursuant to the Board-approved cost allocation and rate design methodology.

---

[3] Each such assignment of short haul firm transportation capacity will be a "temporary assignment", as that term is used by TCPL.

[4] Mass market customers are those in the general service rate classes, which currently are Rate 1, Rate 6 and Rate 9.

[5] Should Enbridge contract for any such equivalent firm transportation as part of the Long Term Resolution, it will include a note in its QRAM filing to that effect.

The customer bill impacts of this component of the Long Term Resolution are set out at page 11 of Appendix A.

For the purpose of the temporary assignment of short haul firm transportation capacity, an agent is defined to be an agent for mass market customers that has signed a Master Services Agreement with Enbridge and that more particularly meets all of the following criteria:

(i) the agent has created a pool of non-affiliated customers, such that the agent does not own a controlling interest (50% or more) of all of the entities served at the gas delivery locations included within the pool;
(ii) the agent has on file for presentment executed Agency Appointment Letters for all customers included in the pool; and
(iii) the agent has a total mass market Ontario T-service ("OTS") Mean Daily Volume ("MDV") delivery obligation of 1,500 GJ/day or more.

An agent within the meaning of this definition will be referred to as an "Agent' in the following provisions of this Settlement Agreement.

The temporary assignment of short haul firm transportation capacity to an Agent by Enbridge will be mandatory and will be made on the following terms:

(i) each assignment will be for a one year period (the "Assignment Year") and will commence on November 1st, starting with November 1, 2010;
(ii) the amount of transportation capacity assigned to each Agent for each Assignment Year will be determined using an allocation methodology (the "Allocation Methodology") on a date in the immediately preceding year (the "Allocation Date") that accommodates the procurement of STFT by Enbridge when first offered by TCPL for the winter season of the Assignment Year;
(iii) the steps in the Allocation Methodology are as follows:

(a) for each Agent, calculate the total of all mass market account MDV's within the Agent's OTS pools (excluding any large volume account MDVs);

(b) calculate the total of all mass market OTS MDV's (excluding any large volume account MDVs) for all Agents ("Total Mass Market OTS Volumes"); and

(c) for each Agent, divide the total derived from step (a) by the Total Mass Market OTS Volumes derived from step (b) and multiply this amount by 50,000 GJ/day, or such other amount as is determined under the Annual Review described below, to arrive at the amount of short haul firm transportation capacity that will be assigned to the Agent.

(iv) prior to the end of the term of each group of one-year assignments, the transportation capacity to be assigned to each Agent for the next Assignment Year will be determined on the Allocation Date using the Allocation Methodology; and

(v) the total amount of short haul firm transportation capacity to be assigned to Agents by Enbridge will be reviewed annually as of the Allocation Date (the "Annual Review") and the capacity to be assigned for each Assignment Year will be determined in the following manner:

(a) the total amount of short haul firm transportation capacity to be assigned to Agents for the Assignment Year beginning November 1, 2010 is 50,000 GJ/day;

(b) as of each subsequent Allocation Date, the ratio of 50,000 GJ/day to Total Mass Market OTS Volumes will be determined;

(c) if the ratio calculated under (b), above, is such that 50,000 GJ/day represents no more than 40% of Total Mass Market OTS Volumes, then the total amount of short haul firm transportation capacity to be allocated to Agents for the following Assignment Year will be 50,000 GJ/day;

(d) if the ratio calculated under (b) above, is such that 50,000 GJ/day represents more than 40% of Total Mass Market OTS Volumes, then the total amount of short haul firm transportation capacity to be allocated to Agents for the following Assignment Year will be adjusted (that is, decreased below 50,000 GJ/day) to a level that represents 40% of Total Mass Market OTS Volumes; and

(e) in no event will there be an adjustment resulting from the Annual Review under this provision of the Settlement Agreement that increases the total capacity of short haul firm transportation to be assigned above 50,000 GJ/day.

The 50,000 GJ/day of STFT capacity contracted for annually by Enbridge will be for the months of November, December, January, February and March and this STFT service, or the equivalent firm transportation capacity referred to above, will be acquired throughout the term of the Long Term Resolution, unless otherwise agreed to by the parties or ordered by the Board.

2. Replacement of Peaking Supplies

As part of its gas supply portfolio, Enbridge contracts for peaking supplies that are utilized in peak and near-peak conditions. Peaking supplies are pre-contracted arrangements for delivered supply to Enbridge's franchise area that it can call upon, typically on at least ten days during the winter season.

Enbridge will reduce the amount of peaking supplies held under contract as part of its gas supply portfolio by 200,000 GJ/day and it will replace these peaking supplies with an equivalent volume (200,000 GJ/day) of TCPL STFT service from Empress that it will secure annually, or, if economic, equivalent firm transportation.[6] The 200,000 GJ/day of STFT service contracted for annually by Enbridge will be for a period of three months (not limited to calendar months) over the winter throughout the term of the Long Term Resolution, unless otherwise agreed to by the parties or ordered by the Board. The STFT service will be utilized in lieu of an equivalent amount of peaking supplies in peak

[6] Should Enbridge contract for any such equivalent firm transportation as part of the Long Term Resolution, it will include a note in its QRAM filing to that effect.

and near-peak conditions. In addition, STFT service will be used to displace other winter purchases, when it is economic and operationally appropriate to do so. The cost consequences of this component of the Long Term Resolution will be recovered from all customers using the deliverability allocator (that is, rate class demand in excess of its average winter demand) under the Board approved cost allocation and rate design methodology and the benefits associated with displacement of other winter purchases will be allocated by volume to sales and Western-T service customers. The customer bill impacts of this component of the Long Term Resolution are set out at page 14 of Appendix A.

3. Terms of Service for Large Volume Customers

The terms of service for Large Volume customers will be changed in order to enhance the effectiveness and reliability of gas supply planning. These changes will require revisions to Enbridge's Rate Handbook, as set out in Appendix B to this Settlement Agreement. The changes to the terms of service are as follows:

(i) Currently, the Rate Handbook is silent with regard to the notice that must be given by large volume customers to Enbridge in order to suspend deliveries.[1] The Rate Handbook will be revised to state that a large volume customer must deliver its MDV to Enbridge, but that the customer may suspend delivery, fully or partially, of its MDV without authorization from Enbridge, provided that the customer gives notice to Enbridge of the suspension, and of the customer's intent to decrease consumption in tandem with the suspension, at least two full business days before the suspension will commence. Notices of suspension must be given in accordance with Enbridge's Business Transaction Rules.

(ii) Failure to provide proper notice will result in Unauthorized Supply Overrun Gas calculated as the difference between Daily Delivered Volume and the Mean Daily Volume.

(iii) Currently, the contracts for service to large volume customers contain provisions regarding Enbridge's rights in the event of non-compliance by a customer, but these provisions require additional clarity, particularly with respect to Enbridge's right to suspend gas distribution services. The provisions of these contracts will be revised to state that Enbridge may suspend service to a customer taking Unauthorized Supply Overrun Gas or to a customer that has failed to deliver its MDV to Enbridge and that has not given notice that meets the requirements set out in paragraph 3(i), above. Enbridge will amend the wording of its Large Volume Distribution Contract to put into effect this element of the Settlement Agreement, including changes to Part 4.1, Unauthorized Overrun Gas, and Part 6.2, Suspension of Company's Obligations.

[1] Such suspension is distinct from requests by customers to suspend deliveries for purposes of balancing their banked gas account(s) ("BGA"). These BGA balancing suspensions are pre-authorized by Enbridge through EnTRAC. Enbridge is changing its EnTRAC Business Transaction Rules for pre-authorized suspension and make-up requests to reduce the minimum notice period from five business days to two business days. Two business days is the minimum notice that the Company can accommodate based on current operational and system constraints.

4. Curtailment

Enbridge relies on curtailment of interruptible customers in order to meet peak demands on its system. As part of the Long Term Resolution, steps will be taken to increase the effectiveness and reliability of curtailment, which in turn will increase the effectiveness and reliability of Enbridge's gas supply planning. These steps will require revisions to Enbridge's Rate Handbook, as set out in Appendix B to this Settlement Agreement. The steps to increase the effectiveness of curtailment are as follows:

(i) Enbridge's Rate Handbook provides, in respect of interruptible service under Rate 145, that service shall be subject to curtailment upon the Company issuing a notice not less than 72 hours prior to the time at which curtailment is to commence, and that the customer may, by contract, agree to a shorter notice period. The curtailment credit rates are based on a 16 hour notice period and a 72 hour notice period. Curtailment of service that requires a notice period of 72 hours is no longer an effective part of Enbridge's gas supply planning. Interruptible service on 72 hours notice under Rate 145 will therefore be eliminated. This will require changes to the Rate Handbook that include changing the reference to 72 hours notice under "Character of Service" to 16 hours and removing the curtailment credit for interruptible service with a 72 hour notice period.

(ii) The provisions of the Rate Handbook currently provide that a customer that has taken Unauthorized Supply Overrun Gas is deemed to have purchased such volume of gas at 150% of the average price on each day on which an overrun occurred for the calendar month as published by the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively. The current provisions of the Rate Handbook also state that the third instance of an interruptible customer taking Unauthorized Overrun Gas may result in the customer forfeiting the right to be served under the interruptible rate schedule. The effectiveness of curtailment will be improved by establishing more appropriate penalties that will apply in the event that a customer fails to comply with a curtailment notice. The wording of the Rate Handbook will be changed to state that, when a customer takes Unauthorized Supply Overrun Gas, the customer shall purchase gas at 150% of the highest price on each day on which an overrun occurred (rather than 150% of the average price). The

wording will also be changed to state that, when a customer takes a material volume of Unauthorized Supply Overrun Gas during a period of ordered curtailment, the customer will forfeit its curtailment credits for the respective winter season of December through March inclusive. Finally, the wording which now states that the third instance in a contract year when a customer takes Unauthorized Overrun Gas may result in the customer forfeiting the right to be served under an interruptible rate will be changed to say that any instance when a customer takes a material volume of Unauthorized Supply Overrun Gas during a period of ordered curtailment may result in the customer forfeiting the right to receive interruptible service.

(iii) The Rate Handbook does not currently contain an explicit requirement that customers receiving service under an interruptible rate have a demonstrable ability to curtail their consumption. The effectiveness of curtailment will be improved by ensuring that customers who receive service under an interruptible rate do indeed have the ability to curtail upon receipt of the prescribed notice from Enbridge, rather than relying solely on Curtailment Delivered Supply.[2] This will be accomplished by changes to the wording in the Rate Handbook for Rates 145 and 170 to state that service under these Rates is available only to customers who have a demonstrated capability to cease or reduce operations, or to utilize a backup fuel, in order to curtail their consumption of natural gas in accordance with a curtailment notice.

Enbridge will report on curtailment compliance in its application filed with the Board for 2013 rates.

5. Turnback

Rider A, Transportation Service Rider, in the Rate Handbook contains provisions with respect to TCPL Firm Transportation (FT) capacity turnback. These provisions are applicable to Ontario T-Service customers who have been or will be assigned TCPL capacity by Enbridge. Rider A states that Enbridge will accommodate TCPL capacity turnback to the extent that it is allowed to turnback FT capacity to TCPL and in a manner that minimizes stranded and other transitional costs. Rider A also states that

[2] Curtailment Delivered Supply ("CDS") refers to additional supply that a customer plans to deliver to the Enbridge franchise area in order to be able to continue consuming in the face of a request for curtailment

Enbridge is committed to maintaining the integrity of its distribution system and the sanctity of all contracts. Rider A currently is silent with respect to turnback for Western-T Service customers, but in the past Enbridge has accommodated a level of turnback for these customers.

These provisions will be changed to place restrictions on the turnback of FT capacity, in view of Enbridge's concern about firm transportation arrangements to its franchise areas and because FT capacity turnback affects Enbridge's operational ability to meet winter demand using TCPL's Storage and Transportation Service (STS), as such STS entitlement is available based on contracted long haul FT capacity. The turnback changes will require revisions to Enbridge's Rate Handbook, as set out in Appendix B to this Settlement Agreement. The changes to the turnback provisions of Rider A are as follows:

(i) The "Applicability" provision will be changed to include both Ontario T-service customers and Western T-service customers;

(ii) Paragraphs 1, 3 to 7 inclusive and 9 of the "Terms and Conditions of Service" will be removed and replaced with the new paragraph 1 that follows below. The remaining paragraphs of the Terms and Conditions of Service will be re-numbered accordingly. The new paragraph 1 of the Terms and Conditions of Service is:

1. The Company will accommodate TCPL FT capacity turnback requests from customers, but only if it can do so in accordance with the following considerations:

i. The TCPL FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to the TCPL FT capacity;

ii The amount of TCPL turnback capacity that Enbridge otherwise may accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs arising from any turnback request that reduces flexibility to meet winter demand using TCPL STS; and

iii Enbridge will act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.

The new paragraph 2 is "Request for TCPL Turnback must be made in writing to the attention of Enbridge's Direct Purchase Group". This paragraph has been restated to reflect the new administrative process resulting from the Turnback changes listed above in Section V.

These new provisions of Rider A will not apply to any existing turnback arrangements or pending turnback requests that have been accepted by Enbridge prior to the final adoption of the new turnback wording in the Rate Handbook.

IV. MATERIAL CHANGE IN CIRCUMSTANCES

In the event of a change in circumstances that affects security of supply to Enbridge's franchise area and/or the Long Term Resolution in any material way ("Material Change"), Enbridge will review the implications of the change and, within a reasonable period of time after the change has become known, will report to the parties to this Settlement Agreement regarding the implications of the change on system reliability and/or the Long Term Resolution. For this purpose, a Material Change will include, but not be limited to, the following:

~ construction of new facilities that increase the availability of short haul firm transportation service to Enbridge's franchise area

~ a material change in the availability of TCPL discretionary services

~ the conclusion from any future Board process that addresses matters relevant to Enbridge's system reliability.

While Enbridge will be responsible to monitor market or regulatory developments for a Material Change, nothing in this agreement precludes any party from bringing its concerns regarding a Material Change to the Board for consideration of any impact on the Long Term Resolution.

V. AGREEMENT OF THE PARTIES

TCPL and Union do not oppose, but take no position on, the settlement set out in this Settlement Agreement. VECC does not oppose, but takes no position on, part 1 of the Terms of Settlement (Assignment of Short Haul Capacity), and the resulting cost consequences; VECC agrees with the remainder of the settlement. FRPO does not oppose, but takes no position on, part 2 of the Terms of Settlement (Replacement of Peaking Services); FRPO agrees with the remainder of the settlement. All other members of the Working Group or the Consultative Group agree with the settlement set out in this Settlement Agreement.

DATED at Toronto, Ontario July 15, 2010.

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 21 of 72

ENBRIDGE

EGD Presentation to Stakeholders on System Reliability Issue

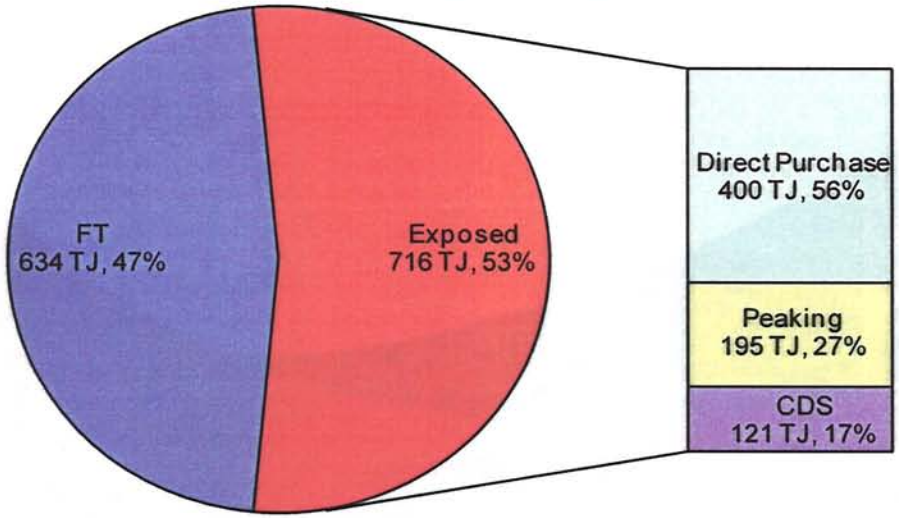
June 15, 2010

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

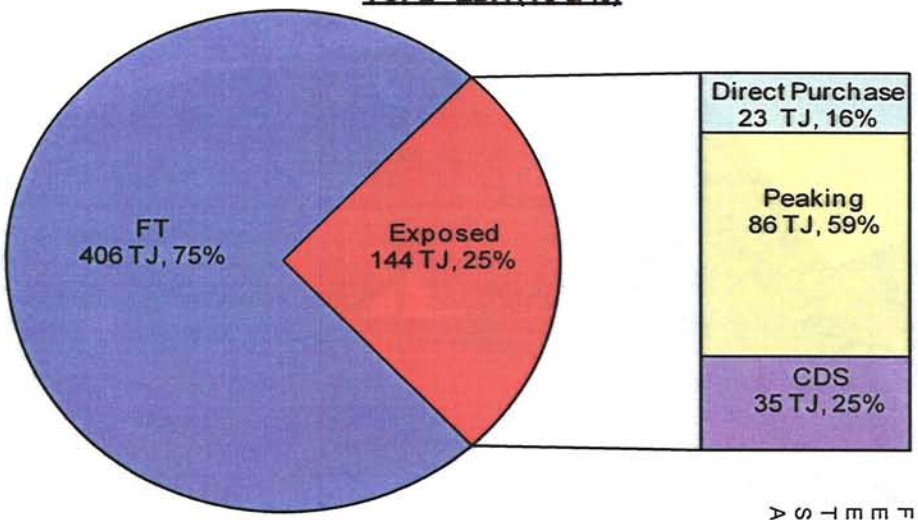
System Reliability Issue as identified by Enbridge

- Extensive use of TCPL's discretionary (non-FT) services to meet firm service commitments to end use customers creates a system reliability concern on peak day
- Use of discretionary transport exceeds 50% and 20% of TCPL deliveries in the CDA and EDA respectively on peak day
- With the exception of pre-contracted STFT, other discretionary services are less reliable in respect of terms of service under extreme weather and pipeline outage situations
- Upstream pipeline outages are often correlated with extreme weather events particularly in low utilization situations
- A supply shortfall in the franchise could result in loss of service to end use customers

TCPL - CDA (TJ & %)



TCPL - EDA (TJ & %)



ENBRIDGE

Working Committee: System Reliability – June 15, 2010

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 22 of 72

Description of TCPL Discretionary Services

- Not all discretionary services are of the same quality
- Pre-contracted STFT is closest in quality to FT

	Pros	Cons
STFT	High priority High availability if pre-contracted	Lower availability in event of extreme weather or outages if not pre-contracted Not renewable
Upstream Diversion	High priority	Requires deal with FT holder
Downstream Diversion		Low priority
IT		Lowest priority

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 23 of 72

Recent Outages and Potential Impact on EGD Customers

- In 2009 TCPL had two outages
  - In Jan 2009, TCPL had a capacity reduction of 600 TJ due to loss of compression. Supply shortfall at the timely window was confirmed at subsequent intra day windows
  - In Sept 2009, TCPL had a capacity reduction of ~1770 TJ due to line break. Given the prevailing demand conditions, there was no impact on supply

- Assuming no discretionary services were successfully acquired to serve EGD's franchise, the table below shows the maximum potential supply shortfall of these events on peak day
  - A residential customer consumes 1 GJ on peak day. The supply shortfall below could result in an equivalent number of residential customers losing service
  - An outage to 100,000 residential customers could take up to 2 weeks to restore

Upstream Pipeline Capacity Outage Scenario (GJ)	600,000 Jan 2009	1,770,000 Sep 2009
EGD potential GJ shortfall/equivalent residential customer impact	176,000	860,000

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 24 of 72

How can EGD's System Reliability Concerns be Addressed in the Longer Term? (In Response to the Board's Direction)

- Firm Transport
  - Ensure that a significant proportion of peak day requirements are met through FT and pre-contracted winter period STFT
- Load Shedding
  - Ensure that Large Volume customers who fail to deliver cease consumption
  - Verify that interruptible customers are truly able to cease consumption or switch to an alternate fuel rather than rely solely on curtailment delivered supplies
- Changes to Turnback Policy
  - Turnback capacity must be replaced with alternative contracted firm transportation of equivalent quality to TCPL FT capacity
  - EGD may reduce FT Turnback volume if it reduces flexibility to meet winter demand using TCPL's Storage Transportation Service (STS)

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 25 of 72

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 26 of 72

System Reliability Working Committee
Presentation to Stakeholders

June 15, 2010

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

AGENDA

1. Description of EGD Proposal
2. Description of Components, Rationale and Customer Impacts of EGD Proposal
3. Proposal Matrix – Impact on System Reliability, Ratepayer Costs and Implementation
4. Impact of the Proposal on System Reliability
5. Conclusion

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 27 of 72

EGD – Original Proposal

EGD Objectives

- Address system reliability at reasonable cost
- Minimize impact on competitive market
- Establish longer term resolution

EGD Proposal to Working Committee

✓ Mass Market retailers receive a temporary assignment of 50,000 GJ/d of short haul capacity to CDA. EGD replaces assignment with STFT for five months for sales customers

✓ EGD replaces 200,000 GJ/d of peaking supplies with STFT for three months

X *Acquire 80,000 GJ/d of STFT for Three Months to Provide a Reserve Margin*

✓ Rate Handbook & Contract Changes to LV Firm Service

✓ Increase Effectiveness of Curtailment

✓ Changes to Turnback Policy

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 28 of 72

1. Assignment of Shorthaul Component

- EGD will provide a temporary assignment (Nov 1) to mass market retailers of 50,000 GJ/d of short haul capacity from Dawn to CDA
- EGD will replace the assignment with STFT (Nov to March) from Empress, AB to EGD CDA or, if economic, equivalent firm transportation
- Assignment criteria
  - Mandatory for agents with General Service Ontario T MDV delivery obligations of 1500 GJ/d or more
  - ~30% of MDV obligation based on current profile
  - Capped at 50,000 Gj/d
  - Reviewed prior to Nov 1 each year to reflect customer migration
    - *Assignment remains at 50,000 GJ/d, or*
    - *Assignment adjusted downward such that assigned short haul capacity represents no more than 40% of total mass market OTS volumes*

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 29 of 72

1. Shorthaul Component and Rationale

Underlying Rationale

- Increase in firm transport utilization by mass market direct purchase customers
- Increased access to competitive Dawn supplies for mass market direct purchase customers under the proposal would better match the currently diversified portfolio for Sales and Western T customers
- Increased security of supply for all customers

Customer Impact

- Incremental gas costs of $5.4M based on current tolls and basis differentials
- Sales and Western T customers incur an increase in their transportation costs but benefit from increased security of supply for all customers
- Ontario T mass market retailers/customers receive access to lower cost firm transport assuming currently prevailing tolls and basis differentials

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 30 of 72

1. Shorthaul Component - Customer Impact*

TYPICAL CUSTOMER VOLUME PROFILES	Annual Volume	Unit Rate ($/m3)	Annual Bill Impact $	Burner Tip Annual Bill	Impact
GENERAL SERVICE	m^3	Sales & Western T		$	%
RATE 1 RESIDENTIAL					
Htg. & Wtr.Htg.	3,064	0.0009	3	1,201	0.2%
RATE 6 COMMERCIAL					
Heating & Other Uses	22,606	0.0009	20	7,671	0.3%
Medium Customer	169,563	0.0009	149	50,234	0.3%
CONTRACT SERVICE					
RATE 100					
Commercial - small size	339,188	0.0009	298	103,577	0.3%
RATE 145					
Commercial - small size	339,188	0.0009	313	94,289	0.3%
RATE 110					
Industrial - small size, 50% LF	598,568	0.0010	602	166,913	0.4%
RATE 115					
Industrial - avg. size	4,299,152	0.0010	4,435	1,120,056	0.4%
RATE 135					
Industrial - Seasonal Firm	598,567	0.0010	625	151,625	0.4%
RATE 170					
Industrial - avg. size, 50% LF	9,976,121	0.0010	9,746	2,421,577	0.4%

- Assumes EB-2010-0048 rates
- Assumes current TCPL tolls, analysis reflects current basis spreads between AECO, Chicago and Dawn. Impacts are subject to change based on market conditions at the time of implementation

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 31 of 72

2. Firming of Peaking Supply Component

- EGD replaces 200,000 GJ/d of peaking supplies with STFT for three winter months from Empress, or equivalent firm transportation, if economic
  - Represents ~75% of design day peaking requirements for 2009 & 2010
- Utilized in lieu of equivalent amount of peaking supplies in peak and near-peak conditions
- When economic, STFT will be used to displace other winter purchases

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 32 of 72

2. Peaking Rationale and Customer Impact

Underlying Rationale

- EGD has determined that its delivered peaking supplies have been less than firm in extreme weather/system outage situations
- Increase system reliability by reducing reliance on peaking supplies delivered through lower priority discretionary services

Customer Impact

- Incremental gas costs of $17.8M based on current tolls and basis differentials
- Cost impact of firming up peaking supplies borne mostly by heat sensitive sales and direct purchase customers
- Benefits associated with displacement of other winter purchases allocated by volume to sales and Western-T service customers
- Costs and benefits will be allocated to customers using the Board approved cost allocation and rate design methodology

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 33 of 72

2. Peaking Supply Component Customer Impact*

TYPICAL CUSTOMER VOLUME PROFILES	Annual Volume	Unit Rate $/m³		Annual Bill Impact $		Burner Tip %	
GENERAL SERVICE	m³	Sales & Western T	Ontario T	Sales & Western T	Ontario T	Sales & Western T	Ontario T
RATE 1 RESIDENTIAL							
Htg. & Wtr.Htg.	3,064	0.0017	0.0029	5	9	0.4%	0.7%
RATE 6 COMMERCIAL							
Heating & Other Uses	22,606	0.0015	0.0026	34	60	0.4%	0.8%
Medium Customer	169,563	0.0015	0.0026	256	447	0.5%	0.9%
CONTRACT SERVICE							
RATE 100							
Commercial - small size	339,188	0.0015	0.0026	511	894	0.5%	0.9%
RATE 145							
Commercial - small size	339,188	(0.0011)	0.0000	(382)	0	-0.4%	0.0%
RATE 110							
Industrial - small size, 50% LF	598,568	(0.0008)	0.0003	(484)	191	-0.3%	0.1%
RATE 115							
Industrial - avg. size	4,299,152	(0.0010)	0.0001	(4,307)	541	-0.4%	0.0%
RATE 135							
Industrial - Seasonal Firm	598,567	(0.0011)	0.0000	(675)	0	-0.4%	0.0%
RATE 170							
Industrial - avg. size, 50% LF	9,976,121	(0.0011)	0.0000	(11,249)	0	-0.5%	0.0%

- Assumes EB-2010-0048 rates
- Assumes current TCPL tolls, analysis reflects current basis spreads between AECO, Chicago and Dawn. Impacts are subject to change based on market conditions at the time of implementation.

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 34 of 72

3. Reserve Margin Component (not included in Settlement)

- Acquire 80,000 GJ/d of STFT for three months to provide a Reserve Margin
- Reserve margin would have been used for coverage in different scenarios, such as
  - one DD over current design day of 39.5 DD
  - higher than average wind conditions on current design day
  - failure to deliver (>300,000 GJ/d of direct shipper gas uses discretionary services)
- Total costs of $11.5 million based on current tolls and basis differentials
- Costs would have been allocated to all customers to match benefits to all customers through increased security of supply
- EGD agreed to withdraw this component for purposes of settlement

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 35 of 72

3. Reserve Margin - Customer Impact*

TYPICAL CUSTOMER VOLUME PROFILES	Annual Volume	Unit Rate $/m³	Annual Bill Impact $	Burner Tip %
GENERAL SERVICE	m³	All Customers	All Customers	All Customers
RATE 1 RESIDENTIAL				
Htg. & Wtr.Htg.	3,064	0.0010	3	0.3%
RATE 6 COMMERCIAL				
Heating & Other Uses	22,606	0.0010	24	0.3%
Medium Customer	169,563	0.0010	177	0.4%
CONTRACT SERVICE				
RATE 100				
Commercial - small size	339,188	0.0010	354	0.3%
RATE 145				
Commercial - small size	339,188	0.0010	354	0.4%
RATE 110				
Industrial - small size, 50% LF	598,568	0.0010	624	0.4%
RATE 115				
Industrial - avg. size	4,299,152	0.0010	4,485	0.4%
RATE 135				
Industrial - Seasonal Firm	598,567	0.0010	624	0.4%
RATE 170				
Industrial - avg. size, 50% LF	9,976,121	0.0010	10,407	0.4%

- Assumes EB-2010-0048 rates
- Assumes current TCPL tolls, analysis reflects current basis spreads between AECO, Chicago and Dawn. Impacts are subject to change based on market conditions at the time of implementation.

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 36 of 72

4. LV Component and Rationale

- Rate Handbook Changes
  - Large Volume customers obligated to deliver Mean Daily Volume
  - Large Volume customers have to provide 2 business days notice of suspension of deliveries
    - *Shortfall in delivered volume without adequate notice will be treated as Unauthorized Supply Overrun Volume*
    - *Consumption of Unauthorized Supply Overrun Volume could result in cessation of service*

- Contract Changes
  - EGD will ensure contractual ability to suspend service to large volume customers in an Unauthorized Supply Overrun situation

<u>Underlying Rationale</u>

- Provides EGD with the contractual ability to shed load, targeted to customers who fail to deliver
  - Provides Gas Control timely information in forecasting demand and planning supply
  - Requires large volume customers to accept the consequences of their gas supply and transportation contracting practices

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 37 of 72

5. Curtailment Component and Rationale

- Customer must demonstrate ability to curtail or use backup fuel rather than relying solely on Curtailment Delivered Supply (CDS)

- Changes to remedies should a customer fail to deliver/curtail during curtailment and takes Unauthorized Supply Overrun Gas
  - Customer pays 150% of highest price on each day applied to unauthorized volume
  - Customer forfeits curtailment credits for the respective winter season (December to March inclusive)
  - Customer taking a material volume of Unauthorized Supply Overrun Gas may forfeit the right to receive service under an interruptible rate

- Elimination of 72 hour curtailment notice service under Rate 145
  - No impact on credits for other interruptible customers

<u>Underlying Rationale</u>

- Provides Gas Control more effective ability to rely on curtailment under peak conditions
  - Strengthen obligations to deliver/curtail under this service
  - Curtailment of customers with 72 hours notice no longer provides benefit under peak day conditions

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 38 of 72

6. Turnback Component

- Applicability of turnback policy in the Rate Handbook will include Ontario T and Western T service
- Provisions of Rider A* that have become effective on a date will not apply retroactively to turnback requests that have been accepted
- EGD will accommodate turnback of TCPL long haul capacity, only if it can do so in accordance with the following circumstances
  - Turnback is replaced with alternative contracted firm capacity (primary or assigned) of equivalent quality to TCPL FT
  - Turnback volume may be reduced to address the impact of stranded costs, other transitional or incremental gas costs arising from reduced flexibility to meet winter demand using TCPL's STS service
  - EGD maintains the integrity and reliability of the gas distribution system while respecting the sanctity of contracts

<u>Background</u>

- EGD has offered turnback of TCPL FT capacity over the last decade**
- The direct purchase community has subscribed to turnback in large quantities
- Ontario T assignments as of November 2010 equal ~30,000 GJ
- Western T assignments as of November 1, 2010 equal ~141,000 GJ
  - 91% of Western-T capacity is held on behalf of mass market customers

* Rider A Transportation Service Rider EGD Rate Handbook
**Except in April 2009

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 39 of 72

6. Turnback Rationale

- A change to current Turnback Policy is required to support the long term resolution
- Further turnback of TCPL FT long haul capacity will impact EGD's operational ability to meet winter demand using TCPL's STS
- EGD will accommodate requests if FT turnback capacity is replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to TCPL FT capacity (Note: dependent upon operational considerations stated in bullet #2 above)

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 40 of 72

4. Combined Shorthaul & Peaking Supply Components - Customer Impact

TYPICAL CUSTOMER VOLUME PROFILES	Annual Volume	Unit Rate $/m³		Annual Bill Impact $		Burner Tip %	
GENERAL SERVICE	m³	Sales & Western T	Ontario T	Sales & Western T	Ontario T	Sales & Western T	Ontario T
RATE 1 RESIDENTIAL							
Htg. & Wtr.Htg.	3,064	0.0026	0.0029	8	9	0.7%	0.7%
RATE 6 COMMERCIAL							
Heating & Other Uses	22,606	0.0024	0.0026	54	60	0.7%	0.8%
Medium Customer	169,563	0.0024	0.0026	405	447	0.8%	0.9%
CONTRACT SERVICE							
RATE 100							
Commercial - small size	339,188	0.0024	0.0026	809	894	0.8%	0.9%
RATE 145							
Commercial - small size	339,188	(0.0002)	0.0000	(69)	0	-0.1%	0.0%
RATE 110							
Industrial - small size, 50% LF	598,568	0.0002	0.0003	118	191	0.1%	0.1%
RATE 115							
Industrial - avg. size	4,299,152	0.0000	0.0001	129	541	0.0%	0.0%
RATE 135							
Industrial - Seasonal Firm	598,567	(0.0001)	0.0000	(50)	0	0.0%	0.0%
RATE 170							
Industrial - avg. size, 50% LF	9,976,121	(0.0002)	0.0000	(1,503)	0	-0.1%	0.0%

- Assumes EB-2010-0048 rates
- Assumes current TCPL tolls, analysis reflects current basis spreads between AECO, Chicago and Dawn. Impacts are subject to change based on market conditions at the time of implementation.

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 41 of 72

Proposal Matrix

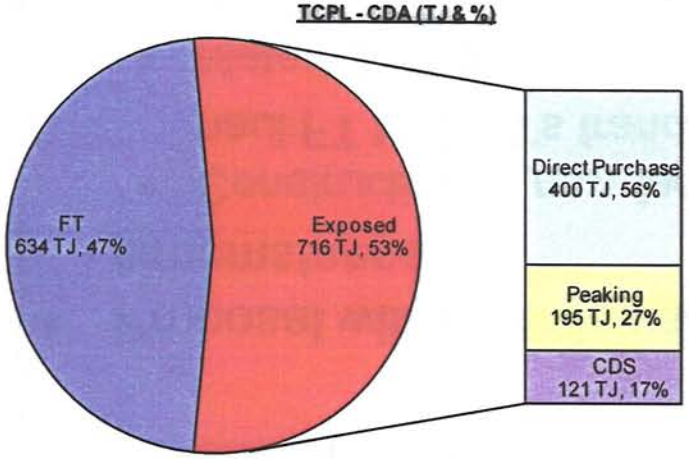
Impact of Proposal	System Reliability		Ratepayer Costs	Implementation
Component	**Firm Transport**	**Load Shedding**	**Ratepayer Costs**	**Implementation**
1. Dawn-CDA Short Haul FT Capacity - Assign 50,000 GJ/d SH FT to Mass Market - EGD contracts STFT 5 months	Positive		Borne by sales and western T customers. Mass market direct purchase customers benefit	Nov 1, 2010
2. Peaking replacement (partial) - Replace 200,000 of peaking with STFT for 3 Mths	Positive		Borne by heat sensitive sales and direct purchase customers. Partial offset for sales and western T customers	Nov 1, 2010
3. Contract changes to LV Firm Service		Positive	Tightening of contract terms	Jan 1, 2011 or earlier
4. Increase Curtailment Effectiveness		Positive	Tightening of contract terms	Jan 1, 2011 or earlier
5. Turnback Policy Changes	Positive		Tightening of contract terms	April 2011

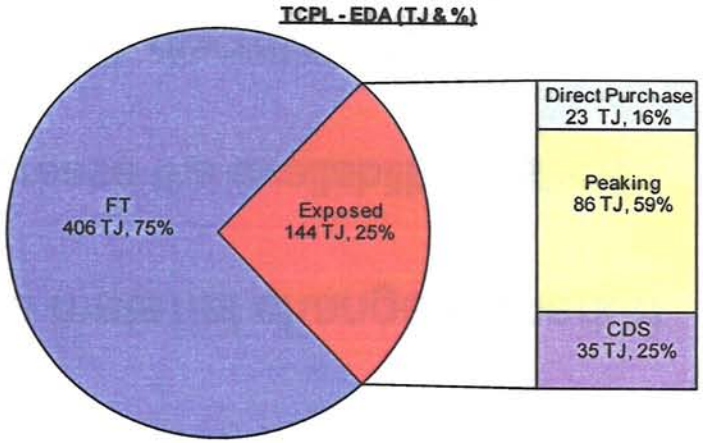
Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

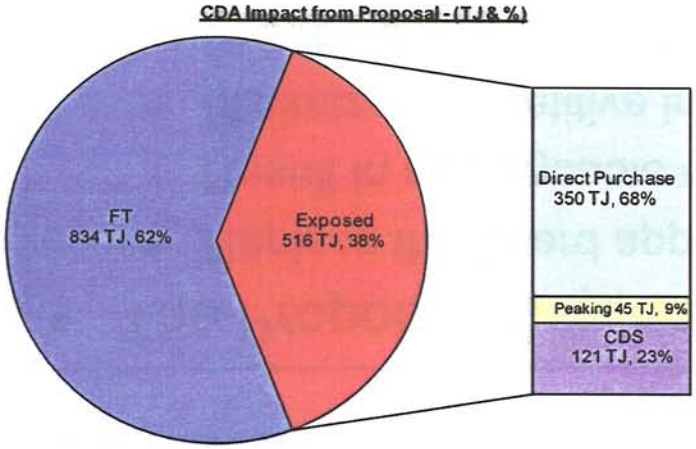
Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 42 of 72

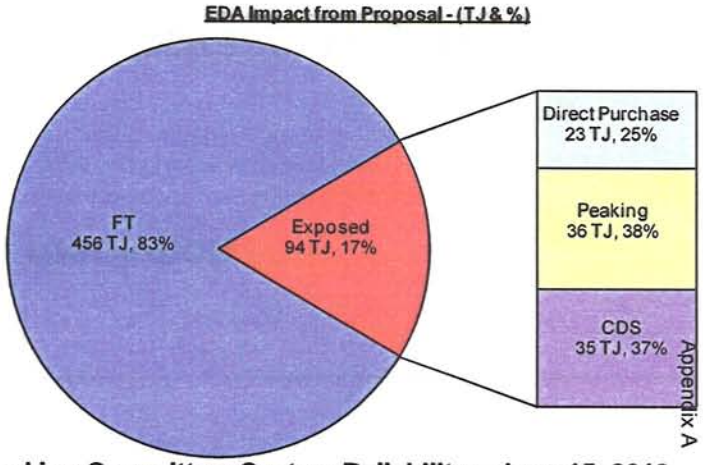
Impact of the Proposal on System Reliability

- The long term resolution will significantly reduce reliance on "less assured" forms of discretionary services in the current market environment









Note : Winter season STFT is treated as Firm. Exposure quantities does not reflect benefits from changes to large volume firm and interruptible rates/contracts

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 43 of 72

Conclusion

- The Proposal, if approved, will
  - Replace the Board approved interim resolution
  - Result in manageable cost impacts
  - Minimize competitive impacts
  - Provide a long term resolution in current upstream market environment

- Proposal will be reviewed if there is a material change in market circumstances
  - Construction of new facilities that increase the availability of short haul FT to EGD's franchise area
  - Material change in the availability of TCPL discretionary services
  - Conclusions from future Board process that addresses matters relevant to Enbridge's system reliability

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 44 of 72

Discussion, Q&A, and follow up ...

- The afternoon of June 15 is scheduled for an extended discussion and Q&A session of the proposed settlement
- Any questions that remain unanswered at the end of day can be submitted by June 18 (?) for a response to be provided by June 22 (?)
- A follow-up session with the Broader Group can be provided for, if required, on June 23 (?)
- At the completion of these proposed steps, parties will be canvassed to indicate whether or not they are in support of the settlement agreement

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 45 of 72

Next Steps - Process

- Enbridge will apply to the Board for approval of a settlement that results from the consultative process
- Enbridge will propose that the Board give such notice as the Board deems appropriate and that the process for approval be expedited in light of the agreement reached by the consultative
- Enbridge's filing in support of the request for approval will include a description of the consultative process, to which will be attached
  - Meeting minutes and presentations; and
  - Where appropriate, material exchanged as part of the consultative process that sheds light on the discussions and presentations at the meetings

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 6, Schedule 11, Attachment A, Page 46 of 72

RATE HANDBOOK

Filed: 2010-03-11
EB-2010-0048
Exhibit Q2-3
Tab 4
Schedule 7
Page 1 of 61

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

PART I:	GLOSSARY OF TERMS	Page 1
PART II:	RATES AND SERVICES AVAILABLE	Page 4
PART III:	TERMS AND CONDITIONS - APPLICABLE TO ALL SERVICES	Page 5
PART IV:	TERMS AND CONDITIONS - DIRECT PURCHASE ARRANGEMENTS	Page 7
PART V:	RATE SCHEDULES	Page 10

Issued: 2010-04-01
Replaces: 2010-01-01

ENBRIDGE

Part I

GLOSSARY OF TERMS

In this Handbook of Rates and Distribution Services, each term set out below shall have the meaning set out opposite it:

Annual Turnover Volume ("ATV"): The sum of the contracted volumes injected into and withdrawn from storage by an applicant within a contract year.

Annual Volume Deficiency: The difference between the Minimum Annual Volume and the volume actually taken in a contract year, if such volume is less than the Minimum Annual Volume.

Applicant: The party who makes application to the Company for one or more of the services of the Company and such term includes any party receiving one or more of the services of the Company.

Authorized Volume: In regards to Sales Service Agreements, the Contract Demand.

In regards to Bundled Transportation Service arrangements, the Contract Demand (CD) less the amount by which the Applicant's Mean Daily Volume (MDV) exceeds the Daily Delivered Volume (Delivery) and less the volume by which the Applicant has been ordered to curtail or discontinue the use of gas (Curtailment Volume) or otherwise represented as:

CD – (MDV – Delivery) – Curtailment Volume

Back-stopping: A service whereby alternative supplies of gas may be available in the event that an Applicant's supply of gas is not available for delivery to the Company.

Banked Gas Account: A record of the amount of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of volume of gas taken by the Applicant at the Terminal Location (debits)

Billing Contract Demand: Applicable only to new customers who take Dedicated Service under Rate 125. The Company and the Applicant shall determine a Billing Contract Demand which would result in annual revenues over the term of the contract that would enable the Company to recover the invested capital, return on capital, and O&M costs of the Dedicated Service in accordance with its system expansion policies.

Billing Month: A period of approximately thirty (30) days following which the Company renders a bill to an applicant. The billing month is determined by the Company's monthly Reading and Billing Schedule. With respect to rate 135 LVDC's, there are eight summer months and four winter months.

Board: Ontario Energy Board. (OEB)

Bundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Company utilizing Load balancing resources.

Buy/Sell Arrangement: An arrangement, the terms of which are provided for in one or more agreements to which one or more of an end user of gas (being a party that buys from the Company gas delivered to a Terminal Location), an affiliate of an end user and a marketer, broker or agent of an end user is a party and the Company is a party, and pursuant to which the Company agrees to buy from the end user or its affiliate a supply of gas and to sell to the end user gas delivered to a Terminal Location served from the gas distribution network. The Company will not enter into any new buy/sell agreement after April 1, 1999.

Buy/Sell Price: The Price per cubic meter which the Company would pay for gas purchased pursuant to a Buy/Sell Arrangement in which the purchase takes place in Ontario.

Commodity Charge: A charge per unit volume of gas actually taken by the Applicant, as distinguished from a demand charge which is based on the maximum daily volume an Applicant has the right to take.

Company: Enbridge Gas Distribution Inc.

Contract Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule for each Terminal Location which is the maximum volume of gas the Company is required to deliver on a daily basis under a Large Volume Distribution Contract.

Cubic Metre ("m³"): That volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre. "10^3m^3" means 1,000 cubic metres.

Curtailment: An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Curtailment Credit: A credit available to interruptible customers to recognize the benefits they provide to the system during the winter months.

Curtailment Delivered Supply (CDS): An additional volume of gas, in excess of the Applicant's Mean Daily Volume and determined by mutual agreement between the Applicant and the Company, which is Nominated and delivered by or on behalf of the Applicant to a point of interconnection with the Company's distribution system on a day of Curtailment.

Customer Charge: A monthly fixed charge that reflects being connected to the gas distribution system.

Daily Consumption VS Gas Quantity: The volume of natural gas taken on a day at a Terminal Location as measured by daily metering equipment or, where the Company does not own and maintain daily metering equipment at a Terminal Location, the volume of gas taken within a billing period divided by the number of days in the billing period.

Daily Delivered Volume: The volume of gas accepted by the Company as having been delivered by an Applicant to the Company on a day.

Dedicated Service: An Unbundled Service provided through a gas distribution pipeline that is initially constructed to serve a single customer, and for which the volume of gas is measured through a billing meter that is directly connected to a third party transporter or other third party facility, when service commences.

Delivery Charge: A component of the Rate Schedule through which the Company recovers its operating costs.

Demand Charge: A fixed monthly charge which is applied to the Contract Demand specified in a Service Contract.

Demand Overrun: The amount of gas taken at a Terminal Location exceeding the Contract Demand.

Direct Purchase: Natural gas supply purchase arrangements transacted directly between the Applicant and one or more parties, including the Company.

Disconnect and Reconnect Charges: The charges levied by the Company for disconnecting or reconnecting an Applicant from or to the Company's distribution system.

Diversion: Delivery of gas on a day to a delivery point different from the normal delivery point specified in a Service Contract.

Firm Service: A service for a continuous delivery of gas without curtailment, except under extraordinary circumstances.

Firm Transportation ("FT"): Firm Transportation service offered by upstream pipelines to move gas from a receipt point to a delivery point, as defined by the pipeline.

Force Majeure: Any cause not reasonably within the control of the Company and which the Company cannot prevent or overcome with reasonable due diligence, including:

(a) physical events such as an act of God, landslide, earthquake, storm or storm warning such as a hurricane which results in evacuation of an affected area, flood, washout, explosion, breakage or accident to machinery or equipment or lines of pipe used to transport gas, the necessity for making repairs to or alterations of such machinery or equipment or lines of pipe or inability to obtain materials, supplies (including a supply of services) or permits required by the Company to provide service;

(b) interruption and/or curtailment of firm transportation by a gas transporter for the Company;

(c) acts of others such as strike, lockout or other industrial disturbance, civil disturbance, blockade, act of a public enemy, terrorism, riot, sabotage, insurrections or war, as well as physical damage resulting from the negligence of others;

(d) in relation to Load Balancing, failure or malfunction of any storage equipment or facilities of the Company; and

(e) governmental actions, such as necessity for compliance with any applicable laws.

Gas: Natural Gas.

Gas Delivery Agreement: A written agreement pursuant to which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Gas Distribution Network: The physical facilities owned by the Company and utilized to contain, move and measure natural gas.

Gas Sale Contract: A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Gas Supply Charge: A charge for the gas commodity purchased by the applicant.

Gas Supply Load Balancing Charge: A charge in the Rate Schedules where the Company recovers the cost of ensuring gas supply matches consumption on a daily basis.

General Service Rates: The Rate Schedules applicable to those Bundled Services for which a specific contract between the Company and the Applicant is not generally required. The General Service Rates include Rates 1, 6, and 9 of the Company.

Gigajoule ("GJ"): See Joule.

Hourly Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule which is the maximum volume of gas the Company is required to deliver to an Applicant on a hourly basis under a Service Contract.

Imperial Conversion Factors:

Volume:		
1,000 cubic feet (cf)	=	1 Mcf
	=	28.32784 cubic metres (m^3)
1 billion cubic feet (cf)	=	28.32784 $10^6 m^3$
Pressure:		
1 pound force per square inch (p.s.i.)	=	6.894757 kilopascals (kPa)
1 inch Water Column (in W.C.) (60°F)		
	=	0.249 kPa (15.5°C)
1 standard atmosphere	=	101.325 kPa
Energy:		
1 million British thermal units	=	1 MMBtu
	=	1.055056 gigajoules (GJ)
948,213.3 Btu	=	1 GJ
Monetary Value:		
$1 per Mcf	=	$0.03530096 per m^3
$1 per MMBtu	=	$0.9482133 per GJ

Interruptible Service: Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.

Intra-Alberta Service: Firm transportation service on the Nova pipeline system under which volumes are delivered to an Intra-Alberta point of acceptance.

Joule ("J"): The amount of work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force. One megajoule ("MJ") means 1,000,000 joules; one gigajoule ("GJ") means 1,000,000,000 joules.

Large Volume Distribution Contract: (LVDC): A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Large Volume Distribution Contract Rates: The Rate Schedules applicable for annual consumption exceeding 340,000 cubic metres of gas per year and for which a specific contract between the Company and the Applicant is required.

Load-Balancing: The balancing of the gas supply to meet demand. Storage and other peak supply sources, curtailment of interruptible services, and diversions from one delivery point to another may be used by the Company.

Make-up Volume: A volume of gas nominated and delivered, pursuant to mutually agreed arrangements, by an Applicant to the Company for the purpose of reducing or eliminating a net debit balance in the Applicant's Banked Gas Account.

Mean Daily Volume (MDV): The volume of gas which an Applicant who delivers gas to the Company, under a T-Service arrangement, agrees to deliver to the Company each day in the term of the arrangement.

Metric Conversion Factors:

Volume:

1 cubic metre (m^3)	=	35.30096 cubic feet (cf)
1,000 cubic metres	=	10^3m^3
	=	35,300.96 cf
	=	35.30096 Mcf
28.32784 m^3	=	1 Mcf

Pressure:

1 kilopascal (kPa)	=	1,000 pascals
	=	0.145 pounds per square inch (p.s.i.)
101.325 kPa	=	one standard atmosphere

Energy:

1 megajoule (MJ)	=	1,000,000 joules
	=	948.2133 British thermal units (Btu)
1 gigajoule (GJ)	=	948,213.3 Btu
1.055056 GJ	=	1 MMBtu

Monetary Value:

\$1 per 10^3m^3	=	\$0.02832784 per Mcf
\$1 per gigajoule	=	\$1.055056 per MMBtu

Minimum Annual Volume: The minimum annual volume as stated in the customer's contract, also Section E.

Natural Gas: Natural and/or residue gas comprised primarily of methane.

Nominated Volume: The volume of gas which an Applicant has advised the Company it will deliver to the Company in a day.

Nominate, Nomination: The procedure of advising the Company of the volume which the Applicant expects to deliver to the Company in a day.

Ontario Energy Board: An agency of the Ontario Government which, amongst other things, approves the Company's Rate Schedules (Part V of this HANDBOOK) and the matters described in Parts III and IV of this HANDBOOK.

Point of Acceptance: The point at which the Company accepts delivery of a supply of natural gas for transportation to, or purchase from, the Applicant.

Rate Schedule: A numbered rate of the Company as fixed or approved by the OEB. that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Seasonal Credit: A credit applicable to Rate 135 customers to recognize the benefits they provide to the storage operations during the winter period.

Service Contract: An agreement between the Company and the Applicant which describes the responsibilities of each party in respect to the arrangements for the Company to provide Sales Service or Transportation Service to one or more Terminal Locations.

System Sales Service: A service of the Company in which the Company acquires and sells to the Applicant the Applicant's natural gas requirements.

T-Service: Transportation Service.

Terminal Location: The building or other facility of the Applicant at or in which natural gas will be used by the Applicant.

Transportation Service: A service in which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Unbundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Applicant contracting for separate services (upstream transportation, load balancing/storage, transportation on the Company's distribution system) of which only Transportation Service is mandatory with the Company.

Western Canada Buy Price: The price per cubic metre which the Company would pay for gas pursuant to a Buy/Sell Agreement in which the purchase takes place in Western Canada.

PART II

RATES AND SERVICES AVAILABLE

The provisions of this PART II are intended to provide a general description of services offered by the Company and certain matters relating thereto. Such provisions are not definitive or comprehensive as to their subject matter and may be changed by the Company at any time without notice.

SECTION A - INTRODUCTION

1. In Franchise Services

Enbridge Gas Distribution provides in franchise services for the transportation of natural gas from the point of its delivery to Enbridge Gas Distribution to the Terminal Location at which the gas will be used. The natural gas to be transported may be owned by the Applicant for service or by the Company. In the latter case, it will be sold to the customer at the outlet of the meter located at the Terminal Location.

Applicants may elect to have the Company provide all-inclusively the services which are mutually agreed to be required or they may select (from the 300 series of rates, and Rate 125) only the amounts of those services which they consider they need.

The all-inclusive services are provided pursuant to Rates 1, 6 and 9, ("the General Service Rates") and Rates 100, 110, 115, 135, 145, and 170 ("the Large Volume Service Rates"). Individual services are available under Rates 125, 300, 315, and 316 ("the Unbundled Service Rates").

Service to residential locations is provided pursuant to Rate 1.

Service which may be interrupted at the option of the Company is available, at rates lower than would apply for equivalent service under a firm rate schedule, pursuant to Rates 145, 170. Under all other rate schedules, service is provided upon demand by the Applicant, i.e., on a firm service basis.

2. Ex-Franchise Services

Enbridge Gas Distribution provides ex-franchise services for the transportation of natural gas through its distribution system to a point of interconnection with the distribution system of other distributors of natural gas. Such service is provided pursuant to Rate 200 and provides for the bundled transportation of gas owned by the Company, owned by customers of that distributor, or owned by that distributor.

For the purposes of interpreting the terms and conditions contained in this Handbook of Rates and Distribution Services the ex - franchise distributor shall be considered to be the applicant for the transportation of its customer owned gas and shall assume all the obligations of transportation as if it owned the gas.

Nominations for transportation service must specify whether the volume to be transported is to displace firm or interruptible demand or general service.

In addition, the Company provides Compression, Storage, and Transmission services on its Tecumseh system under Rates 325, 330 and 331.

SECTION B - DIRECT PURCHASE ARRANGEMENTS

Applicants who purchase their natural gas requirements directly from someone other than the Company or who are brokers or agents for an end user, may arrange to transport gas on the Company's distribution network in conjunction with a Western Buy/Sell Arrangement or pursuant to an Ontario Delivery Transportation Service Arrangement, whether Bundled or Unbundled, or a Western Bundled Transportation Service Arrangement.

B. Western Canada

Buy/Sell in a Western Canada Buy/Sell Arrangement the Applicant delivers gas to a point in Western Canada which connects with the transmission pipeline of TransCanada PipeLines Limited. At that point, the Company purchases the gas from the Applicant at a price specified in Rider 'B' of the rate schedules less the costs for transmission of the gas from the point of purchase to a point in Ontario at which the Company's gas distribution network connects with a transmission pipeline system. The Company will not be entering into any new Western Canada buy/sell arrangements after April 1, 1999.

C. Ontario Delivery T-Service Arrangements

In an Ontario Delivery T-Service Arrangement the Applicant delivers gas, to a contractually agreed-upon point of acceptance in Ontario.

Delivery from the point of direct interconnection with the Company's gas distribution network to a Terminal Location served from the Company's gas distribution network may be obtained by the Applicant either under the Bundled Service Rate Schedules or under the Unbundled Service Rate Schedules.

(i) Bundled T-Service

Bundled T-Service is so called because all of the services required by the Applicant (delivery and load balancing) are provided for the prices specified in the applicable Rate Schedule. In a Bundled T-Service arrangement the Applicant contracts to deliver each day to the Company a Mean Daily Volume of gas. Fluctuations in the demand for gas at the Terminal Location are balanced by the Company.

(ii) Unbundled T-Service

The Unbundled Service Rates allow an Applicant to contract for only such kinds of service as the Applicant chooses. The potential advantage to an Applicant is that the chosen amounts of service may be less than the amounts required by an average customer represented in the applicable Rate Schedule, in which case the Applicant may be able to reduce the costs otherwise payable under Bundled T-Service.

D. Western Delivery T-Service Arrangement

In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas. Delivery from that point to the Terminal Location is carried out by the Company using its contracted capacity on the TransCanada PipeLines Limited. system and its gas distribution network. Unbundled T-Service in Ontario is not available with the Western Delivery Option.

An Applicant desiring to receive Transportation Service or to establish a Buy/Sell Agreement must first enter into the applicable written agreements with the Company.

PART III

TERMS AND CONDITIONS APPLICABLE TO ALL SERVICES

The provisions of this PART III are applicable to, and only to, Sales Service and Transportation Service.

SECTION A - AVAILABILITY

Unless otherwise stated in a Rate Schedule, the Company's rates and services are available throughout the entire franchised area serviced by the Company. Transportation service and/or sales service will be provided subject to the Company having the capacity in its gas distribution network to provide the service requested. When the Company is requested to supply the natural gas to be delivered, service shall be available subject to the Company having available to it a supply of gas adequate to meet the requirement without jeopardizing the supply to its existing customers.

Service shall be made available after acceptance by the Company of an application for service to a Terminal Location at which the natural gas will be used.

SECTION B - ENERGY CONTENT

The price of natural gas sold at a Terminal Location is based on the assumption that each cubic metre of such natural gas contains a certain number of megajoules of energy which number is specified in the Rate Schedules. Variations in cost resulting from the energy content of the gas actually delivered to the Company by its supplier(s) differing from the assumed energy content will be recorded and used to adjust future bills. Such adjustments shall be made in accordance with practices approved from time to time by the Ontario Energy Board.

SECTION C - SUBSTITUTION PROVISION

The Company may deliver gas from any standby equipment provided that the gas so delivered shall be reasonably equivalent to the natural gas normally delivered.

SECTION D - BILLS

Bills will be mailed or delivered monthly or at such other time period as set out in the Service Contract. Gas consumption to which the Company's rates apply will be determined by the Company either by meter reading or by the Company's estimate of consumption where meter reading has not occurred. The rates and charges applicable to a billing month shall be those applicable to the calendar month which includes the last day of the billing month.

SECTION E - MINIMUM BILLS

The minimum bill per month applicable to service under any particular Rate Schedule shall be the Customer Charge plus any applicable Contract Demand Charges for Delivery, Gas Supply Load Balancing, and Gas Supply and any applicable Direct Purchase Administration Charge, all as provided for in the applicable Rate Schedule.

In addition, for service under each of the Large Volume Distribution Contact Rates, if in a contract year a volume of gas equal to or greater than the product of the Contract Demand multiplied by a contractually specified multiple of the Contract Demand ("Minimum Annual Volume") is not taken at the Terminal Location the Applicant shall pay, in addition to the minimum monthly bills, the amount obtained when the difference between the Minimum Annual Volume and the volume taken in the contract year (such difference being the Annual Volume Deficiency) is multiplied by the applicable Minimum Bill Charge(s) as provided for in the applicable Rate Schedule. Notwithstanding the foregoing, the Minimum Annual Volume shall be the greater of the Minimum Annual Volume as determined above and 340,000 m^3.

If gas deliveries to the Terminal Location have been ordered to be curtailed or discontinued in a contract year at the request of the Company and have been curtailed or discontinued as ordered, the Minimum Annual Volume shall be reduced for each day of curtailment or discontinuance by the excess of the Contract Demand over the volume delivered to the Terminal Location on such day.

SECTION F - PAYMENT CONDITIONS

Enbridge Gas Distribution charges are due when the bill is received, which is considered to be three days after the date the bill is rendered, or within such other time period as set out in the Service Contract. A late payment charge of 1.5% per month (19.56% effectively per annum) of all of the unpaid Enbridge Gas Distribution charges, including all applicable federal and provincial taxes, is applied to the account on the seventeenth (17th) day following the date the bill is due.

SECTION G - TERM OF ARRANGEMENT

When gas service is provided and there is no written agreement in effect relating to the provision of such service, the term for which such service is to continue shall be one year. The term shall automatically be extended for a further year immediately following the expiry of any initial one year term or one year extension unless reasonable notice to terminate service is given to the Company, in a manner acceptable to the Company, prior to the expiry of the term. An Applicant receiving such service who temporarily discontinues service in the initial one year term or any one year extension and does not pay all the minimum bills for the period of such temporary discontinuance of service shall, upon the continuance of service, be liable to pay an amount equal to the unpaid minimum bills for such period. When a written agreement is in effect relating to the provision of gas service, the term for which such service is to continue shall be as provided for in the agreement.

SECTION H - RESALE PROHIBITION

Gas taken at a Terminal Location shall not be resold other than in accordance with all applicable laws and regulations and orders of any governmental authority or OEB having jurisdiction.

SECTION I - MEASUREMENT

The Company will install, operate and maintain at a Terminal Location such measurement equipment of suitable capacity and design as is required to measure the volume of gas delivered. Any special conditions for measurement are contained in the General Terms and Conditions which form part of each Large Volume Distribution Contract.

SECTION J - RATES IN CONTRACTS

Notwithstanding any rates for service specified in any Service Contract, the rates and charges provided for in an applicable Rate Schedule shall apply for service rendered on and after the effective date stated in such Rate Schedule until such Rate Schedule ceases to be applicable.

SECTION K - ADVICE RE: CURTAILMENT

The Company, if requested, will advise Applicants taking interruptible service of its estimate of service curtailment for the forthcoming winter. Such estimate will be provided as guidance to the Applicant in arranging for alternate fuel supply requirements. Abnormal weather and/or other unforeseen events may cause greater or lesser curtailment of service than expected.

SECTION L - DAILY DELIVERED VOLUMES

For purposes including that of calculating daily overrun gas volumes, the Company will recognize as having been delivered to it on a given day the sum of:

a) the volume of gas delivered under Intra-Alberta transportation arrangements, if any, plus;

b) the volume of gas delivered under FT transportation arrangements, if any, plus;

SECTION M - AUTHORIZED OVERRUN GAS

If an Applicant requests permission to exceed the Authorized Volume for a day, and such authorization is granted, such gas shall constitute Authorized Overrun Gas. Such gas shall either be sold by the Company to the Applicant pursuant to the provisions of Rate 320 applicable on such day, or, at the Company's sole discretion, under the Rate Schedule the customer is purchasing prior to such request. If the Applicant is supplying their own gas requirements and if the Applicant request and at the Company's sole discretion, such Overrun Gas will be debited to the Applicant's Baked gas Account.

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

If an Applicant for Transportation Service pursuant to the General Service Rates on any day delivers to the Company a Daily Delivered Volume which is less than the Mean Daily Volume, the volume of gas by which the Mean Daily Volume applicable to such day exceeds the Daily Delivered Volume delivered by the Applicant to the Company on such day shall constitute Unauthorized Supply Overrun Gas and shall be deemed to have been taken and purchased on such day. The rate applicable to such volume shall be 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under the Large Volume Distribution Contract Rates is:

(a) the volume of gas by which the Daily Gas Quantity under the Service Contract on such day exceeds the Authorized Volume for such day, if any

plus

(b) if the day is in the months of December to March inclusive for an Applicant taking service on Rate 135 under Option a) or if the day is in the month of December under Option b), or if the day is a day on or in respect of which the Applicant has been requested

in accordance with the Service Contract to curtail or discontinue the use of gas and the Service Contract is in whole or in part for interruptible Transportation Service, the volume of gas, if any, by which

(i) the Mean Daily Volume set out in the Service Contract and is applicable to such day exceeds

(ii) the Daily Delivered Volume delivered by the Applicant to the Company on such day, which excess volume of gas shall be deemed to have been taken and purchased by the Applicant on such day.

The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

An Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate must provide two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean Daily Volume for a specified time period. Failure to provide proper notice will result in Unauthorized Supply Overrun Gas calculated as the difference between Daily Delivered Volume and the Mean Daily Volume.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under Rate 125 or Rate 300 shall be determined from the provisions of the applicable Rate Schedule. The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

SECTION O – COMPANY RESPONSIBILTY AND LIABILITY

This Section O applies only to gas distribution service under Rates 1, 6 and 9, and does not replace or supercede the terms in any applicable Service Contract.
The Company shall make reasonable efforts to maintain, but does not guarantee, continuity of gas service to its customers. The Company may, in its sole discretion, terminate or interrupt gas service to customers;

to maintain safety and reliability on, or to facilitate construction, installation, maintenance, repair, replacement or inspection of the Company's facilities; or

for any reason related to dangerous or hazardous circumstances, emergencies or Force Majeure.

The Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether direct, indirect, special or consequential in nature, (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising from or connected with any failure, defect, fluctuation or interruption in the provision of gas service by the Company to its customers.

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

Any Applicant, at the time of applying for service, may elect, in and for the term of any Service Contract, to deliver its own natural gas requirements to the Company and the Company shall deliver gas to a Terminal Location as required by the Applicant, subject to the terms and conditions contained in the applicable Rate Schedule and in the Service Contract. For Buy/Sell Arrangements and Bundled T-Service the deliveries by the Applicant to the Company shall be at the Applicant's estimated mean daily rate of consumption.

Backstopping of an Applicant's natural gas supply for Transportation Service arrangements will be available pursuant to Rate 320 subject to the Company's ability to do so using reasonable commercial efforts. Gas Purchase Agreements in respect to Buy/Sell Arrangements shall specify terms and conditions available to the Company to alleviate certain consequences of the Applicant's failure to deliver the required volume of gas.

The following Terms and Conditions shall apply to, and only to, Transportation Service and/or Gas Purchase Agreements.

SECTION A - NOMINATIONS

An Applicant delivering gas to the Company pursuant to a contract is responsible for advising the Company, by means of a contractually specified Nomination procedure, of the daily volume of gas to be delivered to the Company by or on behalf of the Applicant.

An initial daily volume must be Nominated by a contractually specified time before the first day on which gas is to be delivered to the Company. Any Nomination, once accepted by the Company, shall be considered as a standing nomination applicable to each subsequent day in a contract term unless specifically varied by written notice to the Company.

A contract may specify certain contractual provisions that are applicable in the event that an Applicant either fails to advise of a revised daily nomination or fails to deliver the daily volume so nominated.

A Nominated Volume in excess of the Applicant's Maximum Daily Volume as specified in the Service Contract will not be accepted except as specifically provided for in any contract.

SECTION B - OBLIGATION TO DELIVER

During any period of curtailment or discontinuance of Bundled interruptible Transportation Service as ordered by the Company, any Applicant supplying its own gas requirements must, on such day, deliver to the Company the Mean Daily Volume of gas specified in any Service Contract.

Each Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate is obligated to deliver the Mean Daily Volume of gas as specified in any Service Contract, unless the Applicant provides two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean daily Volume for a specified time period.

An Applicant taking service on Rate 135 under Option a) must deliver to the Company the Mean Daily Volume of gas specified in the Service Contract in the months of December to March, inclusive.

An Applicant taking service on Rate 135 under Option b) must deliver to the Company the Modified Mean Daily Volume of gas specified in the Service Contract in the month of December.

Applicants taking service on General Service rates pursuant to a Direct Purchase Agreement must, on each day in the term of such agreement, deliver to the Company the Mean Daily Volume of gas specified in such agreement.

SECTION C - DIVERSION RIGHTS

Subject to compliance with the Terms and Conditions of all Required Orders, an Applicant who has entered into a Transportation Service Agreement or Agreements which provide(s) for deliveries to the Company for more than one Terminal Location shall have the right, on such terms and only on such terms as are specified in the applicable Transportation Service Agreement, to divert deliveries from one or more contractually specified Terminal Locations to other contractually specified Terminal Locations.

SECTION D - BANKED GAS ACCOUNT (BGA)

For T-Service Applicants, the Company shall keep a record ("Banked Gas Account") of the volume of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of the volume of gas taken by the Applicant at the Terminal Location (debits). (Any volume of gas sold by the Company to the Applicant in respect to the Terminal Location shall not be debited to the Banked Gas Account). The Company shall periodically report to the Applicant the net balance in the Applicant's Banked Gas Account.

SECTION E - DISPOSITION OF BANKED GAS ACCOUNT (BGA) BALANCES

A. The following Terms and Conditions shall apply to Bundled T-Service:

(a) At the end of each contract year, disposition of any net debit balance in the Banked Gas Account (BGA) shall be made as follows:

The Applicant, by written notice to the Company within thirty (30) days of the end of the contract year, may elect to return to the Company, in kind, during the one hundred and eighty (180) days following the end of the contract year, that portion of any debit balance in the Banked Gas Account as at the end of the contract year not exceeding a volume of twenty times the Applicant's Mean Daily Volume by the Applicant delivering to the Company on days agreed upon by the Company and the Applicant a volume of gas greater than the Mean Daily Volume, if any, applicable to such day under a Service Contract. Any volume of gas returned to the Company as aforesaid shall not be credited to the Banked Gas Account in the subsequent contract year. Any debit balance in the Banked Gas Account as at the end of the contract year which is not both elected to be returned, and actually returned, to the Company as aforesaid shall be deemed to have been sold to the Applicant and the Applicant shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be:

(1) for *Bundled Western T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

(2) for *Bundled Ontario T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus the Company's average transportation cost to its franchise area over the contract year.

(b) A credit balance in the Banked Gas Account as at the end of the contract year must be eliminated in one or more of the following manners, namely:

(i) Subject to clause (ii), if the Applicant continues to take service from the Company under a contract pursuant to which the Applicant delivers gas to the Company and the Applicant so elects (by written notice to the Company within thirty (30) days of the end of the contract year), that portion of such balance which the Applicant stipulates in such written notice and which does not exceed twenty times the Applicant's Mean Daily Volume may be carried forward as a credit to the Banked Gas Account for the next succeeding contract year. Any volume duly elected to be carried forward under this clause shall, and may only, be reduced within the period of one hundred and

Deleted: Unless otherwise authorized by the Company in writing, each Applicant taking service pursuant to an OTS-ABC Gas Delivery Agreement shall meet its obligation to deliver gas to the Company by underpinning a minimum percentage and volume of their gas deliveries with firm transport (which in this section is both Firm Transportation and Short Term Firm Transportation) for the winter period commencing January 1 and ending March 31 (the "winter period"). ¶

Deleted: The minimum amounts to be underpinned by firm transport shall be expressed in both volumetric and percentage terms. For the percentage amount, each Applicant shall calculate the annual percentage of gas deliveries to the Company for each of the immediate past three winter periods which were underpinned by firm transport, and taking the average of these three years' percentages, add ten percentage[(1)] points to the average to establish the minimal amount of gas deliveries that must be underpinned by firm transport for the winter period (e.g., if the average of the past three years is 50% then the addition of ten points will yield 60%[(2)]). ¶

¶

No later than November 1 of each year and beginning November 1, 2009, each Applicant shall provide written confirmation to the Company of their gas delivery plans for the winter period, including the amounts to be underpinned by firm transport (expressed in both volumetric and percentage terms) as calculated above.¶

Deleted: (1) If a direct shipper had no deliveries for a given year, then the calculation should exclude that year; if a direct shipper has less than three winter periods, the calculation will be the average of the periods in which deliveries occurred. ¶

(2) The amount shall not exceed 100%. ¶

eighty (180) days ("Adjustment Period") immediately following the contract year, by the Applicant delivering to the Company, on days in the Adjustment Period agreed upon by the Company and the Applicant ("Adjustment Days"), a volume of gas less than the Mean Daily Volume applicable to such day under a Service Contract. Subject to the foregoing, the credit balance in the Banked Gas Account shall be deemed to be reduced on each Adjustment Day by the volume ("Daily Reduction Volume") by which the Mean Daily Volume applicable to such day exceeds the greater of the volume of gas delivered by the Applicant on such day and the Nominated Volume for such day which was accepted by the Company.

(ii) Any portion of a credit balance in the Banked Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to the Company within thirty (30) days of the end of the contract year) to sell under this clause, shall be deemed to have been tendered for sale to the Company and the Company shall purchase such portion at:

(1) for *Bundled Western T*-Service, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the Company's average transportation cost to its franchise area over the contract year.

(2) for *Bundled Ontario T-Service*, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

Any volume of gas deemed to have been so tendered for sale shall be deemed to have been eliminated from the credit balance of the Banked Gas Account.

During the Adjustment Period the Company shall use reasonable efforts to accept the Applicant's reduced gas deliveries. Any credit balance in the Banked Gas Account not eliminated as aforesaid in the Adjustment Period shall be forfeited to, and be the property of, the Company, and such volume of gas shall be debited to the Banked Gas Account as at the end of the Adjustment Period.

Subject to its ability to do so, the Company will attempt to accommodate arrangements which would permit adjustments to Banked Gas Account balances at times and in a manner which are mutually agreed upon by the Applicant and the Company.

B. The following Terms and Conditions shall apply to Unbundled Service:

The Terms and Conditions for disposition of Cumulative Imbalance Account balances shall be as specified in the applicable Service Contracts.

RATE NUMBER: 100	FIRM CONTRACT SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified annual volume of natural gas of not less than 340,000 cubic metres to be delivered at a specified maximum daily rate.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$121.52**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.1674 ¢/m³**
For the next 28,000 m³ per month	**3.8084 ¢/m³**
For all over 42,000 m³ per month	**3.2494 ¢/m³**
Gas Supply Load Balancing Charge	**0.4858 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0876 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **100**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

10.2535 ¢/m³

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: 110	LARGE VOLUME LOAD FACTOR SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 183 times a specified maximum daily volume of not less than 1,865 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$585.00**
Delivery Charge	
Per cubic metre of Contract Demand	**22.9100 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.6267 ¢/m³**
For all over 1,000,000 m³ per month	**0.4767 ¢/m³**
Gas Supply Load Balancing Charge	**0.1346 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0244 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **110**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.3615 ¢/m³

In determining the Annual Volume Deficiency, the minimum bill multiplier shall not be less than 183.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: 115	LARGE VOLUME LOAD FACTOR SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 292 times a specified maximum daily volume of not less than 1,165 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$620.86**
Delivery Charge	
Per cubic metre of Contract Demand	**24.3600 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.3616 ¢/m³**
For all over 1,000,000 m³ per month	**0.2616 ¢/m³**
Gas Supply Load Balancing Charge	**0.0452 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0244 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **115**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.0070 ¢/m³

In determining the Annual Volume Deficiency the minimum bill multiplier shall not be less than 292.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: 135	SEASONAL FIRM SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 340,000 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure. A maximum of five percent of the contracted annual volume may be taken by the Applicant in a single month during the months of December to March inclusively.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month	
	December to March	April to November
Monthly Customer Charge	**$114.82**	**$114.82**
Delivery Charge		
For the first 14,000 m³ per month	**6.7929 ¢/m³**	**2.0929 ¢/m³**
For the next 28,000 m³ per month	**5.5929 ¢/m³**	**1.3929 ¢/m³**
For all over 42,000 m³ per month	**5.1929 ¢/m³**	**1.1929 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0869 ¢/m³**	**21.0869 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

The applicant has the option of delivering either Option a) a Mean Daily Volume ("MDV") based on 12 months, or Option b) a Modified Mean Daily Volume ("MMDV") based on nine months of deliveries. Authorized Volumes for the months of January, February and March would be zero under option b).

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in t Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Failure to deliver a volume of gas equal to the Mean Daily Volume under Option a) set out in the Service Contract during the months of December to March inclusive may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

Failure to deliver a volume of gas equal to the Modified Mean Daily Volume under Option b) set out in the Service Contract during the month of December may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

RATE NUMBER: **135**

SEASONAL CREDIT:

Rate per cubic metre of Mean Daily Volume from December to March	$	0.77 /m³
Rate per cubic metre of Modified Mean Daily Volume for December	$	0.77 /m³

SEASONAL OVERRUN CHARGE:

During the months of December through March inclusively, any volume of gas taken in a single month in excess of five percent of the annual contract volume (Seasonal Overrun Monthly Volume) will be subject to Seasonal Overrun Charges in place of both the Delivery and Gas Supply Load Balancing Charges. The Seasonal Overrun Charge applicable for the months of December and March shall be calculated as 2.0 times the sum of the Gas Supply Load Balancing Charge, Transportation Charge and the maximum Delivery Charge. The Seasonal Overrun Charge applicable for the months of January and February shall be calculated as 5.0 times the sum of the Load Balancing Charge, Transportation Charge and the maximum Delivery Charge.

Seasonal Overrun Charges:

December and March	**22.8956 ¢/m³**
January and February	**57.2390 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **8.2598 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: 145	INTERRUPTIBLE SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source.
Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than ~~72~~ 16 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$122.73**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.8750 ¢/m³**
For the next 28,000 m³ per month	**1.5160 ¢/m³**
For all over 42,000 m³ per month	**0.9570 ¢/m³**
Gas Supply Load Balancing Charge	**0.3639 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.2033 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.50**	**/m³**
~~Rate for 72 hours of notice per cubic metre of Mean Daily Volume from December to March~~	~~$~~	~~0.11~~	~~/m³~~

RATE NUMBER: **145**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail ~~The third instance of such failure~~ in any contract year may result in the Applic forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**7.8391 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: 170	LARGE INTERRUPTIBLE SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company.
The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source.
The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$278.27**
Delivery Charge	
Per cubic metre of Contract Demand	**4.0900 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5583 ¢/m³**
For all over 1,000,000 m³ per month	**0.3583 ¢/m³**
Gas Supply Load Balancing Charge	**0.2040 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0244 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

RATE NUMBER: **170**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail ~~The third instance of such failure~~ in any contract year may result in the Applic forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.3625 ¢/m³

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: 200	WHOLESALE SERVICE

APPLICABILITY:

To any Distributor who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of an annual supply of natural gas to customers outside of the Company's franchise area.

CHARACTER OF SERVICE:

Service shall be continuous (firm), except for events as specified in the Service Contract including force majeure, up to the contracted firm daily demand and subject to curtailment or discontinuance, of demand in excess of the firm contract demand, upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge The monthly customer charge shall be negotiated with the applicant and shall not exceed:	**$2,000.00**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**14.7000 ¢/m³**
Per cubic metre of gas delivered	**1.1667 ¢/m³**
Gas Supply Load Balancing Charge	**0.5236 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0244 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**21.0020 ¢/m³**

The rates quoted above shall be subject to the Gas Inventory Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable to volumes of natural gas purchased from the Company. The volumes purchased shall be the volumes delivered at the Point of Delivery less any volumes, which the Company does not own and are received at the Point of Acceptance for delivery to the Applicant at the Point of Delivery.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

RATE NUMBER: **200**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

The third instance of such failure in any contract year may result in the Applicant orfeiting the right to be served under this Rate Schedule. In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **6.2905 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January1, 2010.

RIDER: A	TRANSPORTATION SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Transportation Agreement with the Company under any rate other than Rates 125 and 300.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00 per month
Account Charge	$0.21 per month per account

AVERAGE COST OF TRANSPORTATION:

The average cost of transportation effective January 1, 2010:

Point of Acceptance	Firm Transportation (FT)
CDA, EDA	4.6549 ¢/m³

TCPL FT CAPACITY TURNBACK:

APPLICABILITY:

To Ontario T-Service and Western T-Service customers who have been or will be assigned TCPL capacity by the Company.

TERMS AND CONDITIONS OF SERVICE:

~~1. The Company will accommodate TCPL FT capacity turnback from customers to the extent that the Company is allowed to turnback FT capacity to TCPL.~~

~~2. The Company will accommodate all TCPL FT capacity turnback requests in a manner that minimizes stranded and other transitional costs. The Company is committed to maintaining the integrity of its distribution system and the sanctity of all contracts.~~

1. The Company will accommodate TCPL FT capacity turnback requests from customers, but only if it can do so in accordance with the following considerations:
   i. The FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to the TCPL FT capacity;
   ii. The amount of turnback capacity that Enbridge otherwise may accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs resulting from the loss of STS capacity arising from any turnback request; and
   iii. Enbridge must act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.

~~3. The Company may amend any contracts to accommodate a customer's request to turnback capacity.~~

~~4. Notice of TCPL FT turnback capacity will be accepted on Enbridge's Election for Enbridge Firm Transportation Assignment form or other authorized written notice.~~

2. Requests for TCPL FT turnback must be made in writing to the attention of Enbridge's Direct Purchase group.

~~5. The daily contractual right to receive natural gas would still be subject to the delivery, on a firm basis, of the full Mean Daily Volume into the Company's Central Delivery Area (CDA) and/or Eastern Delivery Area (EDA). The delivery area must match the area in which consumption will occur.~~

RIDER: **A**

~~6.~~ ~~The proportion of TCPL FT capacity that an eligible customer may request to be turned back each year ("percentage turnback") shall not exceed the proportion of the TCPL capacity that Enbridge is entitled to turn-back that year. This percentage turnback will be applied to calculate the customer's turnback capacity limit based on the renewal volume of the direct purchase agreement.~~

~~7.~~ ~~If the Company is unable to accommodate all or a portion of an eligible customer's request to turnback TCPL FT capacity in the month requested by the customer, the Company will indicate the month(s) when such customer request can be fully satisfied and the costs, if any, associated with accommodating this request. The customer may then advise the Company as to whether or not they wish to proceed with the TCPL FT capacity turnback request.~~

~~8.~~ 3. All TCPL FT capacity turnback requests will be treated on an equitable basis.

~~9.~~ ~~Customers may withdraw their original election given they provide notice to the Company a minimum of one week prior to the deadline specified in the TransCanada tariff for FT contract extension.~~

~~10.~~ 4. The percentage turnback of TCPL FT capacity will be applied at the Direct Purchase Agreement level.

~~11.~~ 5. Written notice to turnback capacity must be received by the Company the earlier of:

(a) Sixty days prior to the expiry date of the current contract.

or

(b) A minimum of one week prior to the deadline specified in TransCanada tariff for FT contract extension.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after April 1, 2010. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

FRPO INTERROGATORY #12

INTERROGATORY

REF: Ex. B, Tab 2, Schedule 6

Cross Bore

a. Please provide the number of investigation for sewer lateral blockage that resulted in gas investigation in 2011
b. Please provide the actual cost in 2011 for:
    i. Investigations
    ii. Required repairs
    iii. Incidents

RESPONSE

(a) Enbridge has received and completed 3884 sewer safety inspections up to the end of October 2011.

(b) Actual costs YTD October are as follows:
    I. $1,6M
    II. $52,000
    III. $0

Witnesses: C. Clark
L. Lawler

FRPO INTERROGATORY #13

INTERROGATORY

REF: Ex. B, Tab 3, Schedule 1,2

Preamble: The Customer Charge is increasing to $70/month for 2012 for Rate 6

Based upon your last cost allocation study, what percentage of the annual fixed costs per customer does the annualized customer charge cover?

RESPONSE

The Rate 6 Customer Charge of $70/month will cover, on average, approximately 35% of the annual fixed delivery cost.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

JUST ENERGY INTERROGATORY #1

INTERROGATORY

Please provide a breakdown of the annual level of direct purchase and system supply customers in terms of volume and numbers for the past three years with estimates for the next year.

REPONSE

The following Table 1 illustrates the breakdown of annual volume of system supply and direct purchase customers; Table 2 on page 2, illustrates the breakdown of annual average number of customers for system supply and direct purchase customers.

Table 1
Summary of System Supply and Direct Purchase Volumes
(Volumes in $10^6 m^3$)

	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year Estimate	2012 Budget
System Supply	5 254.2	5 417.4	5 386.3	6 359.5	6 613.0
Direct Purchase	6 653.3	5 917.4	5 554.3	5 099.5	4 687.1
Total	11 907.5	11 334.8	10 940.6	11 459.0	11 300.1

Witnesses: I. Chan
D. Small

Table 2
Summary of Average Number of Customer Meters

	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year Estimate	2012 Budget
System Supply	1 182 328	1 248 617	1 373 282	1 518 107	1 595 595
Direct Purchase	682 692	638 988	553 012	439 626	389 139
Total	1 865 020	1 887 605	1 926 294	1 957 733	1 984 734

Witnesses: I. Chan
D. Small

VECC INTERROGATORY #1

INTERROGATORY

Reference: Exhibit B Tab 1 Schedule 4 Page 6

a) Provide 2011 YTD Customer additions and compare to Board Approved Forecast.

b) Provide a 5 year history of Customer additions including comparison of actuals to Board-approved and showing both 2011 and 2012 forecasts.

RESPONSE

a) As of October 31, 2011, the customer additions YTD actual is 27,076, and the Board Approved Forecast for the full year is 36,237.

b) Please see Table 1- New Customer Additions Actual vs. Board Approved provided on the following page.

Table 1 - New Customer Additions Actual vs. Board-Approved

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
Sector	2005 Actual	2005 Board Approved Budget	2006 Actual	2006 Board Approved Budget	2007 Actual	2007 Board Approved Budget	2008 Actual	2008 Board Approved Budget	2009 Actual	2009 Board Approved Budget	2010 Actual	2010 Board Approved Budget	2011 Forecast	2012 Forecast
Residential														
New Construction	39,115	40,481	34,677	37,822	32,900	35,098	30,300	33,897	23,110	31,739	28,214	22,616	27,303	29,450
Replacement	8,191	7,780	8,566	8,132	7,008	8,518	7,742	7,092	6,385	6,548	6,147	7,174	6,309	5,948
Total	47,306	48,261	43,243	45,954	39,908	43,616	38,042	40,989	29,495	38,287	34,361	29,790	33,612	35,398
Apartment														
New Construction					5		22	43	66	41	89	19	30	49
Replacement					5		6	17	2	7	9	7	8	10
Total					10		28	60	68	48	98	26	38	59
Commercial														
New Construction	2,383	1,927	2,761	1,882	1,943	1,641	2,019	2,381	1,899	1,955	1,571	1,665	1,762	1,678
Replacement	995	892	1,582	1,147	1,050	948	957	1,086	621	941	868	888	821	788
Total	3,378	2,819	4,343	3,029	2,993	2,589	2,976	3,467	2,520	2,896	2,439	2,553	2,583	2,466
Industrial														
New Construction	11	12	26	18	6	16	5	13	5	8	4	7	3	3
Replacement	2	12	10	10	3	7	1	5	1	2	0	3	1	1
Total	13	24	36	28	9	23	6	18	6	10	4	10	4	4
Total Customer Additions	50,697	51,104	47,622	49,011	42,920	46,228	41,052	44,534	32,089	41,241	36,902	32,379	36,237	37,927

VECC INTERROGATORY #2

INTERROGATORY

VECC Question 2

Reference**:** Exhibit B Tab 1 Schedule 5 Page 1

a) Provide a 5 year history of gas volume forecasts actual and Board approved.

b) Comment on changes including customer migration and drivers affecting trends for 2012 and beyond.

RESPONSE

a) Table 1 on page 2 provides the requested information for historical volumes and the number of customers.

b) Consistent with previous rate cases, the general service average use forecast incorporated economic assumptions that are filed at Exhibit B, Tab 1, Schedule 7. Annual econometric models are employed to develop and quantify the impact of various driver variables on average use per customer. The models are maintained continuously by incorporating updated driver variables and historical data, to ensure that they produce accurate forecasts of general service average use.

As shown in Figure 3 of Exhibit B, Tab 1, Schedule 5, customer migration between general service and contract market customers has decelerated in 2012. Most of the Rate 100 and 145 customers that were impacted by the rate design changes have now migrated to and stayed in general service. This migration has driven up average use per customer in Rate 6. It is expected that rate switching between general service customers and contract market will be stabilized in 2012 and beyond.

Witness: R. Lei

c) **Table 1 - Summary of Gas Sales and Transportation Volumes and Customers**

(Volumes in 10^6m^3)

	2006		2007		2008		2009		2010		2011	
	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Estimate
General Service	7,932.8	7,490.5	7,642.2	8,314.8	8,288.0	8,806.0	9,083.2	9,129.2	9,083.5	8,757.0	9,283.4	9,419.8
Contract	4,387.9	3,996.4	4,134.3	3,758.5	3,355.2	3,101.5	2,316.6	2,205.6	2,008.6	2,183.6	2,022.9	2,039.2
Total Volumes	12,320.7	11,486.9	11,776.5	12,073.3	11,643.2	11,907.5	11,399.8	11,334.8	11,092.1	10,940.6	11,306.3	11,459.0
No. Customers (avg.)	1,792,615	1,782,813	1,823,258	1,824,789	1,864,047	1,865,020	1,906,437	1,887,605	1,931,528	1,926,294	1,965,538	1,957,733

Witness: R. Lei

VECC INTERROGATORY #3

INTERROGATORY

VECC Question 3

References: Exhibit B Tab 1 Schedule 5 Page 4 and Figure 1:
Exhibit B Tab 1 Schedule 5 Appendix A Page 15

a) Breakdown Residential normalized average use into the three regions (chart) and show how the results translate into the franchise total shown in Figure 1.

b) Update Figure 1 forecast 2011 to show 9 and 3 (or latest available) forecast. Adjust 2012 forecast based on 2011 YTD as needed.

c) Modify update explanatory notes as needed.

RESPONSE

a) Table 1 on page 2 illustrates the regional breakdown of residential normalized average Use. Table 2 on page 3 shows how 2012 residential normalized average use of 2,510 m^3 is derived.

b) Consistent with previous filings, 2011 actual volumes will be filed as part of the 2011 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review. As stated in the EB-2007-0615 Settlement Agreement, the Company will submit the 2011 actual results following the completion of Company's audited year end results that are approved for public release. Both the 2011 Bridge Year Estimate and the 2012 Budget represent the forecasts that integrate all the actual experience and the best known information at the time of developing the budget.

c) Please refer to the response to (b).

Witness: R. Lei

TABLE 1
RESIDENTIAL 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
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Bridge Year Estimate	2012 Budget
Central		3,078	2,978	2,946	2,927	2,885	2,817	2,791	2,780	2,754	2,698	2,672	2,618	2,597
	Change		(100)	(32)	(19)	(41)	(69)	(25)	(11)	(26)	(56)	(26)	(54)	(21)
	% Change		-3.26%	-1.08%	-0.65%	-1.42%	-2.38%	-0.91%	-0.39%	-0.94%	-2.03%	-0.95%	-2.03%	-0.80%
Eastern		2,739	2,555	2,579	2,584	2,545	2,481	2,431	2,445	2,394	2,388	2,305	2,293	2,270
	Change		(184)	24	5	(39)	(64)	(50)	14	(51)	(6)	(83)	(12)	(23)
	% Change		-6.71%	0.96%	0.18%	-1.52%	-2.51%	-2.03%	0.58%	-2.07%	-0.24%	-3.48%	-0.52%	-1.01%
Niagara		2,667	2,575	2,574	2,542	2,470	2,395	2,341	2,358	2,333	2,247	2,185	2,183	2,153
	Change		(93)	(1)	(32)	(72)	(75)	(54)	17	(26)	(86)	(62)	(2)	(30)
	% Change		-3.48%	-0.04%	-1.23%	-2.84%	-3.03%	-2.25%	0.74%	-1.08%	-3.68%	-2.74%	-0.08%	-1.37%

* All historical average uses are on a calendar-year basis and have been normalized to the respective regions of 2012 Budget degree days.

TABLE 2
2012 BUDGET MONTHLY RESIDENTIAL VOLUMES AND UNLOCKS

	Regional Average Use (m^3)			Unlocks				Volume (m^3)				Total Average Use (m^3)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7 (Col. 4 + Col. 5 + Col. 6)	Col. 8 (Col. 1 * Col. 4)	Col. 9 (Col. 2 * Col. 5)	Col. 10 (Col. 3 * Col. 6)	Col. 11 (Col. 8 + Col. 9 + Col. 10)	Col. 12 (Col. 11/Col. 7)
	Central	Eastern	Niagara	Central	Eastern	Niagara	Total	Central	Eastern	Niagara	Total	Total
Jan	459	419	387	1,389,082	278,882	148,592	1,816,556	637,114,283	116,722,547	57,526,127	811,362,957	447
Feb	424	393	363	1,391,919	279,127	149,413	1,820,459	590,358,325	109,683,075	54,269,225	754,310,626	414
Mar	369	326	317	1,394,936	279,729	150,176	1,824,841	515,125,553	91,254,322	47,536,651	653,916,525	358
Apr	263	227	233	1,395,461	279,537	150,627	1,825,625	366,471,784	63,406,264	35,030,369	464,908,416	255
May	171	147	150	1,394,956	279,062	150,889	1,824,907	238,080,499	40,957,326	22,686,045	301,723,870	165
Jun	82	67	62	1,395,263	278,680	151,296	1,825,239	114,497,993	18,786,822	9,383,840	142,668,655	78
Jul	55	43	36	1,397,256	279,087	151,807	1,828,150	77,078,659	12,069,704	5,460,013	94,608,376	52
Aug	59	46	41	1,397,370	278,712	152,199	1,828,281	82,819,338	12,854,604	6,221,100	101,895,042	56
Sep	65	49	47	1,394,887	277,549	152,377	1,824,813	90,869,511	13,600,097	7,144,598	111,614,206	61
Oct	98	83	76	1,397,580	277,729	153,312	1,828,621	137,131,849	23,012,512	11,701,514	171,845,875	94
Nov	195	164	154	1,401,854	278,061	154,516	1,834,431	273,084,261	45,599,268	23,730,953	342,414,481	187
Dec	357	306	288	1,405,641	278,358	155,621	1,839,620	502,038,348	85,216,425	44,814,316	632,069,089	344
Total	2,597	2,270	2,153	1,396,351	278,709	151,735	1,826,795	3,624,670,401	633,162,965	325,504,751	4,583,338,118	2,510

VECC INTERROGATORY #4

INTERROGATORY

References: Exhibit B Tab 1 Schedule 5 Page 6 and Figure 2
Exhibit B Tab 1 Schedule 5 Appendix A Page 15

a) Update Figure 2 forecast 2011 to show a 9 and 3 forecast. Adjust 2012 forecast based on 2011 YTD as needed.

RESPONSE

a) Please refer to the response to part b) of Board Staff Interrogatory #3 at Exhibit I, Tab 1, Schedule 3.

Witness: R. Lei

VECC INTERROGATORY #5

INTERROGATORY

VECC Question 5

Reference**:** Exhibit B Tab 1 Schedule 5 Page 11/12 Tables 3 and 4

a) Provide a Version of Table 3 that includes
   - **i.** 2010 Actual and Forecast
   - **ii.** 2011 Forecast based on 9 and 3
   - **iii.** Updated 2012 forecast based on above

b) Update Table 4 to reflect 2011- 9 and 3 (or latest available).

c) Update explanatory notes as needed.

RESPONSE

a) i. Table 1 on page 2 provides a Version of Table 3 that includes the 2010 Actual and the 2011 Estimate. The table quantifies the volumetric impact of the average use driver variables on the residential sector's average use forecast and customer growth respectively.

ii -iii. As mentioned in the response to Board Staff Interrogatory #3 at Exhibit I, Tab 1, Schedule 3, 2011 actual volumes will be filed as part of the 2011 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review. Both the 2011 Bridge Year Estimate and the 2012 Budget represent the forecasts that integrate all the actual experience and the best known information at the time of developing the budget.

b)-c) Please refer to the response to a).

Table 1

Factors Influencing the Changes in Residential Gas Consumption

Between 2011 Bridge Year Estimate and 2010 Actual (10^6m^3)

Factors	Total Volume (10^6m^3)
Customer Growth	69.0
DSM Initiatives	(7.3)
New Homes - historical trend (a)	(75.3)
Gas Prices	1.6
Other Conservation (b)	(21.0)
Gas Appliances (c)	4.6
Total	(28.3)

(a) Measured by vintage variable, reflecting the historical impacts of improved building envelopes for new homes along with more efficient new space heating furnaces and water heaters on average uses based upon both historical building code, the new 2006 Building Code for new homes effective December 31, 2006. Further changes to this 2006 Building Code effective December 31, 2008, require near-full-height basement insulation effective December 31, 2009.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces and more energy efficient gas-fired storage water heaters for existing homes, and conservation initiatives originated by customers themselves or promoted by government programs, such as programmable thermostats, low-flow showerheads, and home renovations, other historical impact not reflected in the mentioned driver variables, etc.

(c) Measured by employment variable to reflect the demand for gas appliances or gas technologies.

VECC INTERROGATORY #6

INTERROGATORY

Reference: Exhibit B Tab 2 Schedule 1 Page 2 Table 1

a) Confirm that the York Central Power Plant Pipeline is completed on time and budget per Table 1 and the assets will be in rate base for all of 2012.

b) If not adjust Exhibit B Tab 2 Schedule 1 Appendix A.

RESPONSE

a) – b) The pipeline in-service date is now anticipated on December 1, 2011. As such, the pipeline assets ($26.8M) will be in rate base for all of 2012. Total costs of the project are forecast as $29.9M, which includes some restoration work that will be done in 2012. The amount capitalized and closed into rate base, which supports the associated Y factor amount will remain at $26.8M. The difference between the total project costs and $26.8M will be covered by a customer contribution in aid of construction. The one month in-service delay for the project results in an immaterial increase in the 2012 Y factor amount, which remains at $6.6M.

Witnesses: K. Culbert
A. Kacicnik
S. Murray
J. Sim

VECC INTERROGATORY #7

INTERROGATORY

VECC Question 7

Reference**:** Exhibit B Tab 1 Schedule 2 Page 7 para. 22 -Updated Evidence

a) Provide a schedule that presents the breakdown of the 2012 DSM budget.

b) Provide the DSM Program maximum potential 2012 spend, including identifying the DSMVA and incentives components.

RESPONSE

a) – b) Please see the table provided below.

Program Type	Program Base Budget	Program Budget with 10% increase for Low Income	% of Total	Maximum Incentive Available	Maximum DSMVA Available	Total Maximum Potential
Low Income	$4,215,000	$7,025,000	22.73%	$2,375,000	$1,053,750	$10,453,750
Market Transformation	$4,833,600	$4,833,600	15.64%	$1,634,135	$725,040	$7,192,775
Resource Acquisition	$19,051,400	$19,051,400	61.64%	$6,440,865	$2,857,710	$28,349,975
Total	$28,100,000	$30,910,000	100%	$10,450,000	$4,636,500	$45,996,500

Witness: A. Mandyam

VECC INTERROGATORY #8

INTERROGATORY

Reference: Exhibit B Tab 2 Schedule 5 Pages 4 -8 Plus Appendix A

a) Provide a table similar to Appendix A which shows for the years 2003 through 2011 YTD, the percentage growth in Plan assets and liabilities year over year.
b) Provide the averages over the period and provide a projection for 2012 based on the 2003-2011 YTD growth rates.
c) Provide the funding requirement for 2012 based on average 5 year growth rates.
d) Will the investment strategy remain substantially the same in 2012? If not discuss the changes.
e) Provide a projection of the end 2012 Plan position using higher/lower discount rates of 5.75% ± 1.00%.

RESPONSE

a) Historical growth in plan assets and liabilities is not indicative of future growth in plan assets and liabilities as there are multiple economic, demographic, and actuarial factors that play a part in the plan position. Therefore, using an average historical growth rate to project a plan position for 2012 is not a meaningful analysis. Further, the plan position for 2012 has no bearing on funding requirements to be made in 2012 as the funding requirements to be made in 2012 are based on the plan position as of December 31, 2011.

b) See response above.

c) The funding requirement of $16.6M will not change as long as the plan is in a deficit position. The funding requirements triggered are the minimum requirements which are equal to the service costs and the service cost is not dependant on the size of the deficit.

The service cost has been calculated using membership data from the 2010 Valuation. Therefore the funding requirements could change from the estimated $16.6M when the cost certificate is prepared using current membership data but will not change due to the size of the deficit.

d) The investment objectives of the plan will remain the same in 2012, however, there will be a number of measured changes to the asset mix in 2011/2012.

Witnesses: S. Kancharla
R. Lei
A. Patel

The primary objectives of the DB Pension Funds are:

- Ensuring that pension benefits are secured over time.
- Maintaining the affordability of the DB Plans by maximizing the long-term investment return on assets within acceptable risk parameters such that the growth of the Plans' assets exceeds the growth of the Plans' liabilities over time.
- Maintaining a high level of diversification across and within asset classes to minimize investment risk, funded surplus volatility and contribution volatility, and to increase overall risk adjusted returns.

The following changes to the asset mix policy of the Plan were approved by the Human Resources and Compensation Committee ("HRCC") at their May 10, 2011 meeting.

Increase Allocation to Infrastructure - Building on the existing 5% exposure, with favorable experience to date, an additional 4% investment in Infrastructure was approved. Infrastructure is an attractive fit for the Plan as it is a good match for pension liabilities with stable returns and inflation protection. Additionally, infrastructure provides strong risk adjusted returns that are largely uncorrelated to public markets, increasing the diversification benefits.

Allocate Assets to Real Estate – A 6.5% investment in Real Estate was approved. This asset class provides strong diversification benefits, inflation protection, and is common among pension plans because it is a good match for pension liabilities. Due to low correlations to public equity and fixed income, Real Estate is expected to reduce portfolio risk within the Plan.

Allocate Assets to Stand Alone Emerging Markets - A 7% allocation to stand alone Emerging Markets public equities was approved to obtain enhanced access to the rapidly developing regions which now represent 15% of the global equity markets.

e) The plan position for 2012 has no bearing on funding requirements in 2012 as the funding requirements in 2012 are based on the plan position as of December 31, 2011. For sensitivities on the 2011 plan liabilities and service cost based on the discount rate less 1%, refer to page 12 of the Mercer Report.

Witnesses: S. Kancharla
R. Lei
A. Patel

VECC INTERROGATORY #9

INTERROGATORY

Reference: Exhibit B Tab 2 Schedule 6 paras 29 and 30

a) Provide a consolidated table that shows both 2011 and 2012 estimated costs in the same categories as the referenced Table.

b) Provide a consolidated Table that shows 2011 costs and 2012 costs and activity levels in the format of the referenced Table.

c) Provide the volume and cost of routine and emergency locates for the past 5 years.

RESPONSE

a)-b)

Components of Action Plan	Expenditure Type	Expenditure Amount	
		2011	2012
New procedures for addressing blocked sewer Lines	Capital	$1336	$1,521
	O&M	$2,214,805	$2,662,687
Public education/awareness and response campaign	Capital	0	0
	O&M	$300,000	$300,000
New construction procedures when trenchless technologies are to be utilized	Capital	$1,415,105	$1,844,697
	O&M	0	0
Legacy investigations (to seek to identify existing cross bores)	Capital	$8,000	$16,000
	O&M	$293,222	$668,920
Records management, research and development	Capital	$8,000	$228,900
	O&M	$6,615	$50,100
Totals	Capital	$1,424,441	$2,091,118
	O&M	$2,814,642	$3,681,707
		$4,239,083	$5,772,825

Witnesses: C. Clark
L. Lawler

c)

Year	Routine Locate Volume	Emergency Locate Volume
2007	0	0
2008	2849	0
2009	3236	198
2010	4093	1495
2011 YTD	5763	3884

Witnesses: C. Clark
L. Lawler

VECC INTERROGATORY #10

INTERROGATORY

Reference: Exhibit B, Tab 3, Schedule 1, pages 6-8

a) Describe the rate class allocators that will be used for the 2012 Y factors--DSM and Cross Bore O&M and Capital.

b) Discuss why these allocators are appropriate based on cost causality and other factors.

c) What other allocators were considered and why were these not used?

RESPONSE

a) This response assumes that VECC is interested in the rate class allocators used for the newly-proposed Z-factors, as well as for the Low Income DSM Y factor.

The 2012 DSM Low Income Y factor is allocated to all rate classes in proportion to its 2011 DRR, as consistent with the new DSM guidelines for natural gas utilities (also please see EGD's response to Energy Probe Interrogatory 5 at Exhibit I, Tab 5, Schedule 5, page 1, part a) for further detail).

The 2012 Crossbore/Sewer Lateral program requirement Z factor is allocated using the Services allocation factor (please see EGD's response to Energy Probe Interrogatory 5 at Exhibit I, Tab 5, Schedule 5, page 3 for further detail).

The 2012 Pension Funding requirement Z factor is allocated on 2012 DRR (before Z factors).

b) - c) Please see response to Energy Probe Interrogatory #5 at Exhibit I, Tab 5, Schedule 5, part c), d), and e).

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

VECC INTERROGATORY #11

INTERROGATORY

Reference: Exhibit E Tab 1, Schedule 1 Page 55- Settlement Agreement

a) Provide a schedule that compares the 2012 allocation to Rate Classes to that shown at page 55 of the EB-2007-0615 Settlement Agreement.

b) Comment on the differences for the Rate 1 and Rate 6 classes.

RESPONSE

a) Although the interrogatory specifies that the 2012 allocation to rate classes be compared to page 55 of the EB-2007-0615 Settlement Agreement, page 55 refers to the 2010 test year. We assume that VECC intends to compare the 2012 allocation to the 2012 test year as shown at page 57 of the Settlement Agreement. This response reflects that interpretation.

A similar schedule to Exhibit E, Tab 1, Schedule 1, page 57 was provided as part of this Application (EB-2011-0277) at Exhibit B, Tab 3, Schedule 10, page 7. The exhibits are reproduced on pages 3 and 4 of this response for ease of comparison.

b) The rate class assignments of DRR before Y & Z factors for 2012 (Table 2, item 1.0) have remained consistent with the estimates for 2012 from EB-2007-0615 as contained in the Settlement Agreement and reproduced in Table 1, item 1.5.

The rate class assignments of Total DRR with Y factors for 2012 (Table 2, item 1.7) have also remained consistent with the estimates for 2012 from the Settlement Agreement (Table 1, item 1.0) as the relative amounts and allocations of the Y factors are comparable. With the inclusion of proposed Z factors for 2012 (Table 2, item 2.1), total DRR remains in line with the 2012 estimates.

The 2012 Rate 1 assignment with Y factors is lower than the estimate. The inclusion of Z factors increases the 2012 assignment to Rate 1 by $4 million above estimates from the Settlement Agreement.

The 2012 Rate 6 assignment is higher than the estimate, reflecting customer migration from contract rates to Rate 6, as well as the inclusion of proposed Z factors.

Witnesses: R. Bourke
J. Collier
A. Kacicnik

It should be noted that the Company's revenue cap per customer IR Model allows forecasts of volumes, customer numbers, etc. and subsequently, allocators to be updated annually. This ensures that the assignment of revenue requirement by rate class and consequently rate impacts, remains responsive to factors such as customer growth, volumetric gains or losses, and customer migration between various rates and service offerings.

Witnesses: R. Bourke
J. Collier
A. Kacicnik

Table 1
Settlement Agreement (page 57)

2012

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	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
1.0	Total DRR	1,029.1	688.8	268.1	1.3	28.2	11.4	8.6	6.5	0.7	5.0	5.4	2.4	0.4	0.2	1.6
	Y Factor: Other															
1.1	2012 Gas in Storage & Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2012	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2012	89.2	82.0	7.1	-	-	-	-	-	-	-	-	0.0	-	-	
	Y Factor: Capital Investment															
1.4	2012 Leave to Construct	2.9	1.3	1.1	0.0	0.1	0.1	0.1	0.2	0.0	-	-	0.0	-	-	
	Total Y-Factor	159.5	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	0.0
1.5	Total DRR minus Y-Factor	869.6	573.4	236.4	1.3	23.2	10.1	7.0	6.3	0.7	3.9	2.9	1.8	0.4	0.2	1.6

Witnesses: R. Bourke
J. Collier
A. Kacicnik

2012 Distribution Revenue Requirement with Y- and Z- Factor Detail
December 31, 2012
(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300 Firm	Col. 14 RATE 300 Int	Col. 15 DIRECT PURCHASE	Col. 16
1.0	DRR before Y- & Z- Factors	838.6	559.4	248.0	0.3	0.0	7.8	3.7	9.3	0.9	2.4	2.0	2.2	0.3	0.2	2.2	
	Y Factor: Other																
1.1	2012 Gas in Storage and Working Cash Carrying Cost	30.6	14.1	14.7	(0.0)	-	0.3	0.2	0.0	0.0	0.3	0.6	0.4	0.0	-	-	
1.2	2012 DSM Program Costs*	23.8	7.4	13.3	-	-	1.2	0.3	0.0	0.1	0.7	0.7	0.0	0.0	-	-	
1.3	2012 DSM Low Income*	4.3	2.9	1.2	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	
1.4	2012 CIS/ Customer Care	99.2	91.3	7.9	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	
	Y Factor: Capital Investment																
1.5	2012 Leave to Construct	6.6	3.0	2.7	0.0	-	0.1	0.1	0.6	0.0	0.0	0.0	0.1	0.0	-	-	
1.6	**Total Y-Factor**	164.5	118.7	39.8	0.0	-	1.7	0.6	0.6	0.1	1.1	1.3	0.5	0.0	0.0	-	
1.7	**DRR with Y-Factors**	1,003.1	678.2	287.8	0.3	0.0	9.5	4.3	9.9	1.0	3.4	3.3	2.7	0.3	0.2	2.2	
	Z Factor: Proposed																allocated in proportion
1.8	2012 Pension Funding requirement	16.6	11.2	4.8	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	-	to Line 1.7
1.9	2012 Crossbore/Sewer Lateral Program requirement	3.8	3.4	0.4	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	
2.0	Total Z-Factor (Proposed)	20.4	14.7	5.1	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	-	
2.1	**Total 2012 DRR with All Y-& Z-Factors**	1,023.5	692.8	292.9	0.3	0.0	9.7	4.4	10.0	1.0	3.5	3.4	2.8	0.3	0.2	2.2	
	* Note:																
	2012 Total DSM Y-factor amount (1.2 + 1.3)	28.1	10.4	14.5	0.0	0.0	1.3	0.3	0.0	0.1	0.7	0.8	0.0	0.0	0.0	0.0	

VECC INTERROGATORY #12

INTERROGATORY

Reference: Exhibit E Tab 1, Schedule 1 Page 58- Settlement Agreement

a) Provide an update and comparison to the Schedule shown at Page 58, including actual and forecast rate impacts and actual and forecast base DRRs 2008-2012.

b) Provide an update/comparison of Bill impacts2008-2012 in the schedule on Page 59 of the settlement Agreement.

c) Provide a table showing the 5 year history of Rate 1 Customer charges in absolute terms and as a percentage of Distribution charges for average and low volume customers.

RESPONSE

a) Please see Table 1 on page 3.

b) Please see Table 2 on page 4.

c) Please see the following table:

	Typical Customer (3,064m^3/year)				Typical Customer (1,081m^3/year)		
Year	Customer Charge	Distribution Total	Customer Charge as % of Total		Customer Charge	Distribution Total	Customer Charge as % of Total
2008	168.00	424.54	39.57%		168.00	264.71	63.47%
2009	192.00	429.49	44.70%		192.00	281.50	68.21%
2010	216.00	428.07	50.46%		216.00	295.93	72.99%
2011	228.00	427.62	53.32%		228.00	303.22	75.19%
2012	240.00	443.44	54.12%		240.00	316.65	75.79%

A low volume customer consumes approximately 1,081 m^3 per year and generally uses natural gas for water heating and one other life style application such as a natural gas fireplace or natural gas range. This type of customer represents approximately 1% of the residential customers on Enbridge's system. The typical residential customer uses natural gas for space and water heating and consumes approximately 3,064m^3 per year. Approximately 90% of Enbridge customers use natural gas for space and water heating.

Witnesses: R. Bourke
J. Collier
A. Kacicnik

TABLE 1

ESTIMATED 2008-2012 RATE IMPACTS

Rate Class	ADR 2008 [1] T-Service Rate Impact		ADR 2009 [2] T-Service Rate Impact		ADR 2010 [3] T-Service Rate Impact		ADR 2011 [4] T-Service Rate Impact		ADR 2012 [5] T-Service Rate Impact	
	Estimate	Approved [6]	Estimate	Approved [7]	Estimate	Approved [8]	Estimate	Approved [9]	Estimate	Proposed [10]
1	0.1%	0.3%	2.1%	0.5%	1.6%	0.2%	1.5%	-0.8%	1.7%	2.1%
6	0.0%	0.1%	1.8%	0.4%	1.3%	0.0%	1.2%	-1.5%	1.4%	0.9%
9	0.1%	0.1%	0.8%	0.0%	1.1%	0.2%	1.2%	-0.4%	1.6%	0.6%
100	0.1%	0.1%	1.3%	-0.3%	1.0%	0.2%	0.9%	-2.2%	0.9%	-1.4%
110	0.1%	0.1%	1.1%	-0.3%	1.0%	0.2%	0.9%	-3.6%	0.9%	-0.9%
115	0.1%	0.1%	1.1%	-0.4%	0.8%	0.2%	0.8%	-4.3%	0.8%	-1.7%
135	0.6%	0.6%	0.9%	-0.1%	0.9%	0.2%	0.9%	-4.7%	0.9%	-0.6%
145	0.2%	0.2%	1.0%	0.0%	0.9%	0.2%	0.8%	-3.6%	0.8%	-2.4%
170	0.4%	0.4%	1.0%	-0.4%	0.9%	0.3%	0.9%	-5.5%	0.9%	-2.0%
200	0.4%	0.4%	1.0%	0.0%	0.9%	0.1%	0.8%	-3.2%	1.0%	-0.2%
	ADR 2008 Distribution Rate Impact		ADR 2009 Distribution Rate Impact		ADR 2010 Distribution Rate Impact		ADR 2011 Distribution Rate Impact		ADR 2012 Distribution Rate Impact	
125	0.0%	0.0%	0.7%	0.1%	0.7%	0.3%	0.7%	0.5%	0.7%	1.2%
300	0.1%	0.1%	0.9%	0.1%	0.9%	0.3%	0.9%	0.5%	0.9%	1.2%

Notes:

1. - 2008 Distribution Revenue Requirement of $935 M (Estimate), 2008 Distribution Revenue Requirement of $938 M (Approved)
2. - 2009 Distribution Revenue Requirement of $963 M (Estimate), 2009 Distribution Revenue Requirement of $974 M (Approved)
3. - 2010 Distribution Revenue Requirement of $986 M (Estimate), 2010 Distribution Revenue Requirement of $981 M (Approved)
4. - 2011 Distribution Revenue Requirement of $1,006 M (Estimate) , 2011 Distribution Revenue Requirement of $989 M (Approved)
5. - 2012 Distribution Revenue Requirement of $1,029 M (Estimate), 2012 Distribution Revenue Requirement of $1,025 M (Proposed)
6. - From EB-2007-0615, Exhibit C, Tab 6, Schedule 8
7. - From EB-2008-0219, Exhibit B, Tab 3, Schedule 1, Page 4
8. - From EB-2009-0172, Exhibit B, Tab 4, Schedule 1, Page 3
9. - From EB-2010-0142, Draft Final Rate Order
10. - From EB-2011-0277, Exhibit B, Tab 3, Schedule 1, Page 3

TABLE 2

Typical Customer Estimated T-Service Bill Impacts from 2008 to 2012
As Per Settlement Proposal

	October 1, 2007 T-Service Bill (1) Annual Bill ($)	Estimated 2008 T-Service Bill Annual Bill ($)	Approved 2008 T-Service Bill Annual Bill ($)	Estimated 2008 T-Service Bill Annual $ change	Approved 2008 T-Service Bill Annual $ change	Estimated 2009 T-Service Bill Annual $ change	Approved 2009 T-Service Bill Annual $ change	Estimated 2010 T-Service Bill Annual $ change	Approved 2010 T-Service Bill Annual $ change	Estimated 2011 T-Service Bill Annual $ change	Approved 2011 T-Service Bill Annual $ change	Estimated 2012 T-Service Bill Annual $ change	Proposed 2012 T-Service Bill Annual $ change
Rate 1													
Rate 1 T-Service Bill Impact	409.37	416.18	416.66	6.81	7.29	8.68	8.07	6.93	6.73	6.45	(0.22)	7.58	11.72
Note: (1) based on annual consumption of 1,955 m3													
Rate 1 T-Service Bill Impact	558.77	559.89	556.36	1.12	(2.41)	11.67	(0.94)	9.32	(2.95)	8.67	(7.09)	10.19	11.64
Note: (1) based on annual consumption of 3,064 m3													
Rate 1 T-Service Bill Impact	772.67	755.35	756.56	(17.32)	(16.11)	15.75	(13.66)	12.57	(16.72)	11.70	(16.90)	13.75	11.39
Note: (1) based on annual consumption of 4,691 m3													
Rate 6													
Rate 6 T-Service Bill Impact	2,879.90	2,882.78	2,844.04	2.88	(35.86)	51.73	26.51	39.42	6.94	36.71	(40.32)	42.53	48.34
Note: (1) based on annual consumption of 22,606 m3													
Rate 6 T-Service Bill Impact	5,023.61	4,710.21	4,716.59	(313.40)	(307.02)	84.52	(5.71)	64.40	(37.88)	59.99	(126.25)	69.50	34.88
Note: (1) based on annual consumption of 43,285 m3													
Rate 115													
Rate 115 T-Service Bill Impact	3,356,187.92	3,359,795.82	3,358,151.13	3,607.90	1,963.21	36,957.75	(19,803.81)	25,690.51	6,906.39	25,723.00	(193,091.37)	25,969.18	(82,520.06)
Note: (1) based on annual consumption of 69,832,850 m3 at 80% Load Factor													

VECC INTERROGATORY #13

INTERROGATORY

Reference: Exhibit E Tab 3 Schedule 1 Page 1

a) Provide the ROE Update for 2012 referenced in Paragraph 3.

RESPONSE

a) Provided below is the ROE Update for 2012 as referenced in Exhibit E, Tab 3, Schedule 1, page 1.

1. The formula to update the Board's 1997 "Draft Guidelines on a Formula-Based Return on Equity for Regulated Utilities" is as follows:

$$ROE_t = 10.65\% + 0.75 \times (LCBF_t - 7.25\%);$$

Where $LCBF_t$ is the Long Canada Bond Forecast at time, t

2. The updated calculation for the 2012 ROE is as follows:

Consensus Long Canada Bond[1] (3-month forecast)	2.30%	
Consensus Long Canada Bond[1] (12-month forecast)	2.60%	
Average		2.45%
30-day historical bond yields[2] (30-years)		2.80%
30-day historical bond yields[2] (10-years)		2.17%
Difference	0.63%	

Therefore, $LCBF_t = 2.45\% + 0.63\% = 3.08\%$

3. Plugging in the updated $LCBF_t$ term yields the following:

$$2012\ ROE = 10.65\% + 0.75 \times (3.08\% - 7.25\%)$$
$$2012\ ROE = 7.52\%$$

[1] Consensus Economics Inc. Survey date October 10, 2011 (data for Sept. 13 – Oct. 10, 2011); pg. 17
[2] Canadian Bonds table found in Financial Post section of National Post, for dates Sept 13 – Oct 10, 2011

Witness: S. Murray

4. ROE of 7.52% will be used for the calculation of earnings sharing, if any, for 2012.

VECC INTERROGATORY #14

INTERROGATORY

Reference: Exhibit B Tab 3 Schedule 2 Rate Handbook page 6

a) Provide information on EGDI Late payment policy including Days for Payment, Applicable Interest Rate(s).

b) Provide information on policies regarding Security Deposits.

c) Have there been any changes as a result of the recent GDAR proceeding? If so specify these.

d) Have these changes affect the forecast of LPP revenue for 2012? If so show the Impact relative to 2010/2011.

e) Compare/discuss EGD and Union policies and provisions.

f) When will EGD implement Low Income-specific policies and provisions related to Late Payment and Security Deposits.

RESPONSE

a) The Ontario Energy Board ("Board") issued amendments to the Gas Distribution Access Rule ("GDAR") on October 14, 2011. As per section 8.2.1 of GDAR, the Company published its Conditions of Service which describes Enbridge's operating practices and policies with respect to gas distribution services and customer service. The Conditions of Service as published on the Company's website at www.enbridgegas.com/ConditionsofService are presented in Appendix A. At page 10 in the Conditions of Service, the Company presents its Late Payment Policy. As per Section F, Part III of the Rate Handbook, bills are due when they are received which is deemed to be three days after the bill is rendered. Customers are then provided a period of 17 days after the bill is due to make a payment before a Late Payment Charge is applied to their account. A charge of 1.5% per month, compounded monthly on all of the unpaid charges, including all applicable federal and provincial taxes, will be applied to the account.

Witnesses: T. Ferguson
S. McGill

b) At page 9 in the Conditions of Service attached in Appendix A, the Company presents its policies regarding Security Deposits. Security deposits are collected to secure payment for future charges in the event of a customer not paying their bill. All new residential customers are subject to a security deposit, unless they meet one of the waiver criteria outlined below. New residential customers are charged a security deposit in the amount of $250.00.

Enbridge will waive a residential security deposit requirement if the customer meets any of the following criteria:

- If the customer has moved and their previous account is in good standing;
- If the customer chooses to sign up for our Pre-Authorized Payment Plan; or
- If you the customer can provide a reference letter from another utility in Canada dated within the past 60 days.

If a customer has paid a security deposit, it will be refunded once the customer has demonstrated good payment history for a period of 24 months.

c) In September 2010, the Board initiated a Consultation on Customer Service Standards for Natural Gas Distributors. On January 20, 2011, the Board requested that Natural Gas Distributors provide input to the process by reviewing the customer service rules for electricity distributors and documenting their current policies and practices in the areas addressed by those rules, and suggest new or modified policies that are appropriate for gas distributors. The Company's response is attached in Appendix B. With respect to Late Payment Penalties, the Company suggested making a system change to allow for three additional days before Late Payment charges would be applicable. This change requires changes to the Company's CIS System and as per the Notice of Amendment for Residential Customer Service Amendments to the Gas Distribution Access Rule, the coming into force date for these changes is April 1, 2012. The Company will have changes implemented by the coming into force date.

With respect to Security Deposits, the Company suggested making three changes. First, the Company will allow payment arrangements for paying first time security deposits, second, the Company is making system changes to allow for refunding of security deposits after 12 months rather than 24 months and finally, the Company will consider the security deposit when issuing a disconnection notice or disconnecting a customer for non-payment. This means that arrears net of security deposit will be used to trigger a disconnection notice or disconnection. These changes require business process changes and changes to the Company's CIS

System. As per the Notice of Amendment for Residential Customer Service Amendments to the Gas Distribution Access Rule, the coming into force date for these changes is April 1, 2012. The Company will have these changes implemented by the coming into force date.

d) The forecast of LPP revenue for 2012 was reduced by $350k as a result of the change to allow for three additional days before Late Payment charges would be applicable. This impact is estimated based on a half year impact. At the time the 2012 Budget was determined, it was assumed that this change would be implemented in July 2012. Now that the in-force date for these changes has been decided by the Board to be April 1, 2012, the actual impact will likely be slightly higher.

e) Policies related to Late Payment Penalties and Security Deposits are similar for Enbridge and Union Gas. With respect to late payment penalties, Union Gas provides customers a period of 16 days before late payment penalties are applied. Like Enbridge, a charge of 1.5% per month, compounded monthly on all of the unpaid charges is, applied.

With respect to Security Deposits, Union Gas charges residential customers a security deposit equal to the two highest months of gas usage based on the prior 12 months usage history or $250 if there is insufficient history on the account. Union Gas also provides waiver criteria for customers who sign-up for both their Equal Billing Plan and Automatic Payment Plan or if a customer can provide a reference letter with a good rating from another natural gas or hydro utility dated within the last 60 days. Union Gas will also refund a security deposit after the customer has exhibited 12 months of good payment history.

f) In a letter dated June 29, 2011, the Board initiated a similar approach to the Customer Service Standards for Low-Income Customer Service Standards. The Board requested that Natural Gas Distributors provide input to the process by reviewing the low-income related customer service rules for electricity distributors and documenting their current policies and practices in the areas addressed by those rules, and suggest new or modified policies that are appropriate for gas distributors. The Company's response is attached in Appendix C. With respect to Late Payment Penalties, there were no further changes proposed for Low-Income customers other than the changes proposed in (c) above. Enbridge has a practice of working with customers based on their individual circumstances and waiving security deposits does not promote the correct behaviour where customers call the Company to advise of payment difficulties and make suitable arrangements.

Witnesses: T. Ferguson
S. McGill

With respect to Security Deposits, there were also no further changes proposed for Low-Income customers other than the changes proposed in (c) above. The purpose of a security deposit is to ensure that monthly bills are paid on time and to cover any outstanding arrears at the time the customer ceases to be a residential gas service customer. If the Company were to forego its right to charge security deposits for any reason, the risk to bad debt would be borne by all customers and security deposits are charged to protect and minimize impacts to rates for all customers.

The Board has yet to issue a Notice of Amendment to the Gas Distribution Access Rule for Low-Income related Customer Service Rules.

Witnesses: T. Ferguson
S. McGill

ENBRIDGE GAS DISTRIBUTION INC.

CONDITIONS OF SERVICE

SEPTEMBER 30, 2011

Contents

Preface 3
1. Enbridge Franchise Area and Gas Distribution Services 4
2. Gas Distribution Services 5
   2.1. Gas Supply and Delivery 5
   2.2. Gas supply and/or delivery under more than one rate schedule 5
   2.3. Interruptions in Gas Distribution and/or Supply 5
   2.4. Force Majeure 5
3. Rate Schedule 5
   3.1. Changes in Rate Schedules 5
4. Initiation of Service 6
   4.1. Main Extensions 6
   4.2. Service Installations 6
   4.3. Location of Meter and Service Regulators 6
   4.4. Alterations 7
   4.5. Customer Responsibilities regarding Building Piping Appliances & Equipment 7
   4.6. Inspections of New Installations 7
5. Maintenance of Service 8
   5.1. Turning Off and Turning on Gas Supply 8
   5.2. Meter Exchange and Testing 8
6. Customer Service 9
   6.1. Setting up an Enbridge Account 9
   6.2. Meter Reading 9
   6.3. Security Deposits 9
   6.4. Bill Issuance and Payment 10
   6.5. Correction of Billing Errors 13
   6.6. Discontinuance of Gas Supply or Delivery 13
   6.7. Arrears Management Programs 14
   6.8. Allocation of Payments between gas and non-gas charges 14
   6.9. Management of Customer Accounts 15
   6.10. Our Customer Service Process 15

Appendix A – Definition of Terms 16

Preface

As Canada's largest natural gas distribution company, Enbridge Gas Distribution ("Enbridge") has been providing natural gas services in a safe and reliable manner for more than 160 years, and currently provides service to approximately 1.9 million homes and businesses.

These Conditions of Service describe in summary form Enbridge's operating practices and policies, and are provided as part of our commitment to providing our customers with safe and reliable gas services.

We reserve the right to modify the contents of the Conditions of Service at any time. These Conditions of Service are meant as guidelines and do not supersede any terms and conditions agreed to in our contracts for gas supply with you.

1. Enbridge Franchise Area and Gas Distribution Services

The following is a list of cities and towns that Enbridge provides distributions services to.

Eastern Region

Admaston
Alfred & Plantagenet
Arnprior
Beckwith
Brockville
Carleton Place
Casselman
Champlain
Clarence-Rockland
Deep River
Drummond-North Elmsley
Elizabethtown-Kitley
Hawkesbury
Horton
Laurentian Hills
Laurentian Valley
Leeds and Grenville
McNab-Braeside
Merrickville-Wolford
Mississippi Mills
Montague
North Glengarry
North Grenville
North Stormont
Ottawa
Pembroke
Perth
Petawawa
Renfrew
Rideau Lakes
Russell
Smiths Falls
South Glengarry
Tay Valley
The Nation
Whitewater Region

Central Region

Adjala
Ajax
Amaranth
Asphodel-Norwood
Athens
Aurora
Barrie
Bradford-West Gwillimbury
Brampton
Brighton
Brock
Caledon
Cavan Monaghan
Clarington
Clearview
Collingwood
Douro-Dummer
Dufferin
Durham
East Garafraxa
East Gwillimbury
East Luther Grand Valley
Erin
Essa
Georgina
Grey Highlands
Havelock Belmont Methuen
Innisfil
Kawartha Lakes
King
Markham
Melancthon
Midland
Mississauga
Mono
Mulmur
New Tecumseh
Newmarket
Orangeville
Oshawa
Otonabee S- Monaghan
Penetanguishene
Peterborough
Pickering
Richmond Hill
Scugog
Severn
Shelburne
Smith-Ennismore-Lakefield
Southgate
Springwater
Tay
Tiny
Toronto
Trent Hills
Uxbridge
Vaughan
Wasaga Beach
Wellington
Whitby
Whitchurch

Niagara Region

Fort Erie
Grimsby
Lincoln
Niagara Falls
Niagara-on-the-Lake
Pelham
Port Colburne
St. Catharines
Thorold
Wainfleet
Welland
West Lincoln

2. Gas Distribution Services

2.1. Gas Supply and Delivery

Gas will be delivered and/or supplied to our customers within our franchise area subject to these Conditions of Service and to the provisions of Enbridge's rate schedules, under the following circumstances:

- there is sufficient supply of gas;
- there is sufficient capacity in Enbridge's distribution system; and,
- the supplying and/or delivering of gas is economically feasible.

2.2. Gas supply and/or delivery under more than one rate schedule

Gas may be supplied and/or delivered under more than one rate:

- Provided the customer meets all the applicability requirements of each rate schedule as approved by the Ontario Energy Board. Gas supplied and/or delivered under each rate schedule will normally be metered separately but may be taken through one meter provided:
    - Enbridge and the customer agree in writing upon a formula for determining the supply and/or delivery service that the customer will purchase under each rate schedule.

2.3. Interruptions in Gas Distribution and/or Supply

Customers may be required to curtail or discontinue the use of gas if the supply of gas is jeopardized by any of the following:

- in the event of actual or threatened shortage of gas due to circumstances beyond the control of Enbridge; or,
- when curtailment or restriction is ordered by any government or agency having jurisdiction.

Enbridge shall not be liable for any loss of production, nor for any damages whatsoever due to curtailment or discontinuance, nor because of the length of advance notice given to customers regarding curtailment or discontinuance.

2.4. Force Majeure

Customers of Enbridge shall not have any claim against Enbridge for damages sustained as a result of the interruption or cessation of gas deliveries caused by force majeure which include:

- acts of God, the elements;
- labour disputes, strikes, lockouts;
- fires, accidents;
- the breakage or repair of pipelines or machinery;
- depletion or shortage of gas supply;
- order of any legislative body or duly constituted authority; or,
- any other cause or contingencies beyond the control of Enbridge.

3. Rate Schedule

3.1. Changes in Rate Schedules

In the event the Ontario Energy Board amends the rate schedules of Enbridge, the amended price or amended terms and conditions shall apply to services provided under the rate schedules after the effective date established by the Ontario Energy Board.

4. Initiation of Service

4.1. Main Extensions

Enbridge will extend its gas main within its franchise area to serve new customers when it is feasible to do so. Enbridge will look at the following when determining feasibility:

- the number of potential new customers within the next five years;
- the amount of natural gas to be used; and,
- the cost of extending the gas main.

If the cost of the extension is not economically feasible, the applicant/s will be required to pay a contribution in aid of construction. Enbridge will determine the contribution amount and communication will be provided to the applicant/s in writing.

4.2. Service Installations

Enbridge reserves the right to designate the location at which the service will enter a building. The normal point of entry will be through the wall nearest to the gas supply. Where no additional cost is involved, the service may be installed to accommodate requirements of the applicant for service.

For residential service, Enbridge will usually install a service at no charge to the applicant, provided the service installed is 20 metres in length measured from the property line to a point of delivery up to 2 metres beyond the front building wall. For residential and non residential service, the cost of the service in excess of the cost of a normal residential service of 20 metres in length, and any length exceeding 2 metres beyond the front building wall, may be charged to the applicant.

Where an applicant for gas service requests an installation on property that is not owned by the customer such as road allowance, municipal or neighboring property, land rights (in the form of an easement) from the property owner will be required for the installation and maintenance of all necessary gas lines and equipment.

Enbridge will try to restore property to the approximate condition in which it was found before starting our operations. This includes property that is excavated or may be disrupted during laying, constructing, repairing or removing our facilities.

4.3. Location of Meter and Service Regulators

Enbridge shall supply each customer with a meter of a size and type that will adequately measure the gas supplied. Enbridge shall:

4.3.1. Make every effort to install meters and service regulators so as to be at all times accessible for inspection, reading, testing, maintaining and exchanging.

4.3.2. Not install meters in locations prohibited by law. The following locations are specifically prohibited:

- under combustible stairways;
- unventilated areas;
- inaccessible areas; or,
- within 90 cm (3 feet) of a source of ignition.

4.3.3. Install all meters outside the building to which gas is supplied except in rare circumstances where it is not practical.

4.3.4. Provide protection where outside meters and regulators are installed in locations that do not afford reasonable protection from damage.

Anyone who is not an authorized agent of Enbridge shall not be permitted to connect or disconnect our meters or regulators, nor shall any piping be connected to or disconnected from Enbridge's facilities except by representatives of Enbridge.

Customers are responsible, subject to the provisions of paragraph 4.3.4, for protecting all metering and regulating equipment necessary for the supply of gas and for keeping it accessible at all times.

4.4. Alterations

Alterations or service relocation requests will be dealt with as follows:

- The cost of work done to relocate existing equipment solely for the convenience of the customer will be charged to the customer.
- The undepreciated cost of any equipment abandoned as a result of relocation for the customer's convenience, or replacing equipment to increase their capacity to accommodate a customer's increased requirements, may be charged to the customer.

4.5. Customer Responsibilities regarding Building Piping Appliances & Equipment

As an applicant for service, a customer shall:

- at their own expense install, all piping, controls, safety devices, and other attachments necessary from the meter to the equipment or appliances served;
- ensure the building piping, appliances, and equipment are installed in accordance with regulations made under the authority of statutes passed by the Province of Ontario establishing the requirements for the installations of such facilities; and,
- be responsible for maintaining all building piping, appliances and equipment in a good and safe condition. Such maintenance will be at the customer's own expense.

If there is a leakage or escape of gas on a customer's premise, the customer is required to notify Enbridge immediately by calling our Emergency number at 1-866-763-5427.

Enbridge shall not be liable to the customer for any damages. The customer shall indemnify Enbridge from and against all loss, costs, damages, injury, or expense associated with any injury or damage to persons or property arising, either directly or indirectly, from or incidental to the escape of gas or products of combustion of gas from building piping, venting systems or appliances on the customer's side of the point of delivery.

For the purpose of inspecting or repairing or of altering or disconnecting any service pipe within or outside the building, the customer shall ensure that free access is permitted to Enbridge at all reasonable times, and upon reasonable notice given and request made, to all parts of every building or other premises to which gas is supplied.

4.6. Inspections of New Installations

All inspections shall conform to the Technical Standards and Safety Act and regulations made under the Act. All new installations of supply piping, gas appliances and installations will be inspected prior

to gas being introduced to a building in accordance with the requirements of the Technical Standards and Safety Act and the regulations made under the Act. If the inspection reveals that repairs or adjustments are required, the customer will be advised and repairs or adjustments will need to be corrected prior to the gas being turned on.

5. Maintenance of Service

5.1. Turning Off and Turning on Gas Supply

In an emergency, the gas supply to appliances may be turned off in the interest of safety. Only a qualified person holding an appropriate certificate from the Regulatory Authority having jurisdiction may turn on the supply of gas to appliances which have been turned off.

Except in the case of a notification of a hazard, the turning on and off of the gas supply for purposes of installing, servicing, removing or repairing gas appliances may only be done by a person certified to perform this work by the Regulatory Authority having jurisdiction.

5.2. Meter Exchange and Testing

5.2.1. Meter Exchange

Under Government of Canada regulations (Section 12 of the Electricity and Gas Inspection Act), Enbridge is required to periodically exchange gas meters for government inspection.

To complete the meter exchange, we will shut off the gas supply to your existing meter, replace it with a new meter and then relight and inspect all of your natural gas equipment.
There is no charge for this service. If we are required to exchange your meter we will contact you via letter or telephone. Please call the number provided at the time of contact to make an appointment. The inspector who comes to your property will carry valid Enbridge photo ID and you may ask to see it before providing access.

5.2.2. Meter Testing

Should a meter fail to register the amount of gas used, consumption shall be estimated by Enbridge and supply and/or delivery charges shall be paid for by the customer in accordance with such estimate.

Should a customer dispute the accuracy of a meter, an application for a Government Inspection of the meter in accordance with the Electricity and Gas Inspection Act may be made. If, after the test, the meter is found to register with an error greater than that permitted by regulations, such error shall be held to have existed for a period of three months or from the date on which the meter was last sealed if the said sealing took place within three calendar months of the request. In the event of the meter being more than three months past due for re-verification, Enbridge or the customer, as the case may be, is entitled to the amount represented by the full error of the meter from the date on which it should have been re-verified. All costs involved in effecting this test shall be borne by the party against whom the decision is given.

In the event of an erroneous connection or incorrect use of an apparatus, the error shall be deemed to have existed from the time of connection.

In the event it can be, through records, determined when an error occurred, the bill will be retroactive to that time.

6. Customer Service

For the purposes of this section, “customer” means a residential customer (referred to as “you” in this section).

In accordance with Enbridge’s submission to Ontario Energy Board regarding Gas Distribution Access Rule customer service standards for natural gas distributors, Enbridge will be revising its policies and practices and amending its Conditions of Service by September 30, 2012.

6.1. Setting up an Enbridge Account

Whether you are a first time customer to Enbridge or moving from an existing Enbridge account, you should notify us before taking possession of a new home. On our website you will find information on how to submit a “First Time Customer” form or a Move request or you can call the Enbridge Call Centre at 1-877-362-7434.

As an Enbridge customer you will be expected to comply with the Conditions of Service and will be obliged to pay for all gas supplied and/or delivered to your premises. These Conditions of Service will remain in effect until Enbridge has accepted and completed your request for termination or until we have processed your move request.

6.2. Meter Reading

Enbridge reads your meter every other month and will estimate your consumption based on your historical gas usage in between readings. If Enbridge’s representative is unable to read the meter, a bill will be issued based on an estimated reading. If Enbridge has been unable to read a meter during normal working hours, arrangements will be made to obtain a reading at the customer’s convenience. You can also submit your own meter reading using the Submit Meter Reading Form on our website or alternatively, you can call the Enbridge Call Centre at 1-800-268-5442.

6.3. Security Deposits

Security deposits are collected to secure payment for future charges in the event of a customer not paying their bill. To protect against losses, Enbridge reserves the right to request a security deposit from its customers as a condition of supplying gas service. A security deposit may be required if you are a first time Enbridge customer, or if you have not been able to maintain a good payment history.

All new residential customers are subject to a security deposit, unless they meet one of the waiver criteria outlined below. If you are required to pay a security deposit an amount of $250.00 will be charged on your next gas bill. Payment of the security deposit is required by the Late Payment Effective Date on the bill.

Enbridge will waive your security deposit requirement if you meet any of the following criteria:

- If you have moved and your previous account is in good standing;
- If you choose to sign up for our Pre-Authorized Payment Plan; or
- If you can provide a reference letter from another utility in Canada dated within the past 60 days.

Enbridge will review all security deposits on a monthly basis from the date the deposit is fully paid. If you have paid a security deposit, it will be refunded once you have demonstrated good payment history for a period of 24 months. Your security deposit will be returned with interest as a credit on your next gas bill. If you choose to have the amount refunded, you can call the Enbridge Call Centre at 1-877-362-7434 and a refund cheque will be issued.

Good payment history is maintained unless you have experienced any of the following:

- Receipt of a disconnection notice from Enbridge;
- A payment you provided to Enbridge has been returned for insufficient funds; or
- Your gas has been turned off due to non-payment.

Interest earned on your security deposit will be paid upon return of all or any part of the security deposit or at the time you close your account, whichever comes first. Simple interest will be earned on all security deposits except those held for a total of six months or less. The interest rate applicable to security deposits in any year will be established quarterly and will be based upon the Ontario Energy Board prescribed interest rates. Interest is calculated retroactively to the date the security deposit was received.

Security deposits are not to be considered as prepayments for future charges.

6.4. Bill Issuance and Payment

6.4.1. Your Monthly Bill

Enbridge charges you the following charges on a monthly basis:

- **Monthly Customer Charge**
  Enbridge has a minimum charge per gas meter to help recover a portion of the fixed costs that the company incurs to keep the system ready for customer use at all times. These fixed costs (such as 24-hour emergency service, meter reading, pipeline maintenance and customer support services) do not vary with the amount of gas used.

- **Transportation to Enbridge**
  This charge is for the cost of transporting natural gas to distribution facilities in Ontario, including tolls.

- **Delivery to You**
  Once natural gas is received by Enbridge, these are the costs to safely and reliably deliver natural gas to our customers.

- **Gas Supply Charge**
  The charge for natural gas itself varies with the amount of gas used by each of our customers. You can choose to have your gas supplied by Enbridge Gas Distribution or an independent marketer. The rates that Enbridge charges for gas used are regulated by the Ontario Energy Board.

There are other charges that may appear on your bill from time to time based on events that occur with your account. These include:

- **New Account Charge**
  If you open a new account with Enbridge, the first bill will include a one time service charge of $25.00, to help cover the costs of setting up the account, taking a meter reading and related work.

- **Late Payment Effective Date/Late Payment Charge**
  Enbridge charges are due when the bill is received, which is considered to be three days after the date the bill is rendered. Customers are provided a period of 17 days to make a payment before a Late Payment Charge is applied to their account.

  When payment in full of the Enbridge invoice is not received on or before the “Late Payment Effective Date” on the bill, a late payment charge will be incurred on the next

bill. A charge of 1.5% per month (19.56% effectively per annum) on all of the unpaid charges, including all applicable federal and provincial taxes, will be applied to the account.

Late payment charges are not applied to security deposits amounts owing.

- **Adjustments**
  Your bill may show adjustments to charges from time to time when there is a correction made on your account.

For more information on the charges that appear on your bill, visit the Understanding Your Bill section on our website.

6.4.2. Charges from Other Companies

The Enbridge Billing Service allows other energy companies to include their charges on the Enbridge bill. If you have purchased a product or service from a participating company, the charges would appear in the section called “Charges From Other Companies” on your Enbridge bill.

This service helps make paying bills more convenient for you. You receive one bill and make one monthly payment to Enbridge Gas Distribution. This service also helps to keep rates low by sharing costs with other billers.

6.4.3. Billing from a licensed energy marketer

If you buy your natural gas supply from a licensed energy broker, your gas supply charges, along with the name of the licensed energy broker will appear in the 'Charges For Gas' section of your Enbridge bill.

6.4.4. Billing Options

- **Paperless Billing**

Enbridge offers customers an environmentally friendly and secure bill delivery option in the form of a paperless bill. You can view and store up to 24 months of bills electronically through this service.

- **Budget Billing Plan**

The Enbridge Budget Billing Plan (BBP) provides all residential gas heating customers the convenience of paying equal amounts throughout the year and avoiding higher bills in winter months. Using your prior year’s gas usage, Enbridge forecasts the amount of gas you will use and applies the current gas price to determine your monthly BBP installment.
The BBP season runs from September to July each year. In July, Budget Billing Plans are reviewed and reconciled and customers are billed or credited a BBP Final Adjustment that represents the difference between the charges for gas actually used from the time you join the plan and the monthly BBP installments billed to date. In the month of August, you are billed for the actual gas used in the month. The new plan then starts again in September.

Should a credit balance result after the annual reconciliation, the amount will be credited to your account and will appear on your July bill. If you choose to have the amount refunded, you can call the Enbridge Call Centre at 1-877-362-7434 and a refund cheque will be issued.

Should a chargeable balance result after the annual reconciliation, the amount will be charged to your account and will appear on your July bill. In the event that the BBP Final Adjustment charge is higher than expected, you may choose to call the Enbridge Call Centre at 1-877-362-7434 and one of our Customer Service Representatives will work with you to determine suitable payment arrangements.

At a minimum, one mid-season BBP review will occur usually at the beginning of the next calendar year. The mid-season review will recalculate your monthly BBP installment to ensure accuracy as weather, usage and rate changes could affect the actual charges for gas you use. After the mid-season review, the new monthly installment amount will be billed on your next bill and a bill message will explain that there was a review of your monthly BBP installment. **Customers are encouraged to monitor their BBP details (actual gas charges billed to date versus BBP installments billed to date) and may request a review at any time.**

A number of factors can create a variance in the plan. Significant changes in weather, gas prices, change in gas marketers, or gas use in the home, such as installing a new natural gas appliance, can create a difference between actual gas costs and installment amounts.

First time gas customers are automatically assigned to the BBP unless they request otherwise.

6.4.5.Payment Options

- **Pre-Authorized Payment**

Enbridge also offers a Pre-Authorized Payment Plan. Signing up for the Pre-Authorized Payment Plan will allow your amount due to be automatically withdrawn from your bank account on the day before the Late Payment Effective Date.

- **Other payment options include:**

  - Online or in person at a financial institution

  - Telephone Banking

  - Credit Card
    For a Credit Card Convenience fee of $2.85 for every $150 charge paid to our Credit Card Service Provider, you may use a valid credit card to make a payment.

  - Western Union
    For customers with overdue amounts that are at or nearing disconnection for non-payment, you may choose to make a payment for a fee through Western Union.

  - Standard Mail
    You can send a cheque or money order (no cash please), along with the bottom tear-off portion of your bill, to:

    Enbridge
    P.O. Box 644
    Toronto, ON M1K 5H1

    Please make your cheque payable to "Enbridge" and write your account number on the front.

- Pay in Person
  You may also drop your payment off at one of our payment drop boxes located in the following locations 24 hours a day:
  (Please note: for your security, we cannot accept cash at these offices.)

  VPC Office
  500 Consumers Road
  North York, Ontario

  Ottawa Office
  400 Coventry Road
  Ottawa, Ontario

  Thorold Office
  3401 Schmon Parkway
  Thorold, Ontario

6.5. Correction of Billing Errors

Retroactive billing ensures that all gas consumption and other Enbridge charges, not billed previously, are billed correctly to the customer. Retroactive billing can be the result of either a customer error or a company error. When a customer has been billed incorrectly, retroactive billing is required.

Where billing errors, either through company or customer error, have resulted in overbilling, the customer will be credited with the amount erroneously billed for a period not exceeding six years.

Where billing errors have resulted in underbilling, the customer shall be charged with the amount erroneously not billed for a period not exceeding:

- two (2) years, in the case of a company error affecting a residential customer.
- six (6) years, in the case of a residential customer error

If you have been underbilled, Enbridge will work with you to determine a suitable payment arrangement.

6.6. Discontinuance of Gas Supply or Delivery

6.6.1. Customer Initiated Discontinuance

A customer will continue to be bound by these Conditions of Service and will be obliged to pay for all gas supplied and/or delivered to the premises along with any other monthly charges applicable including late payment penalties until Enbridge has terminated the supply of gas following the acceptance of a request for termination from the customer.

6.6.2. Emergency or Safety related Discontinuance

Enbridge may discontinue gas supply and/or delivery to any customer for any of the following reasons:

- for use of gas for any purpose other than that described in the service application, gas supply contract, or rate schedule;
- in case Enbridge, is refused access for any lawful purposes to the premises to which gas is supplied and/or delivered;

- when Enbridge property on a customer's premises is in any manner tampered with, damaged, or destroyed;
- when Enbridge has reason to believe that an unsafe condition exists on the premises or may develop from a continuation of gas supply and/or delivery;
- when a gas installation contravenes the provisions of the Technical Standards and Safety Act, associated regulations, or any other applicable enactment; or
- when there is evidence of gas theft.

Discontinuance of gas supply and/or delivery for any of the reasons set out in paragraph 6.6.2 shall result in a disconnection charge payable by the Customer.

6.6.3. Discontinuance of Service for Non-payment

Enbridge charges are due when the bill is received, which is considered to be three days after the date the bill is rendered. If, for any reason, you are unable to make full payment you are encouraged to contact Enbridge to make suitable payment arrangements. Customers can call the Enbridge Call Centre at 1-877-362-7434.

If the bill is not paid in full and you have not contacted Enbridge to make payment arrangements, under the Public Utilities Act, Enbridge has the right to discontinue gas service. Prior to discontinuance of gas service Enbridge will provide a minimum 48 hours notice in writing along with a call to advise when the disconnection will occur.

If you are seeking payment assistance through a registered charity, government agency, social service agency or a third party, you must provide consent to Enbridge to provide details of your account to these third parties. Enbridge will place any disconnection or collections actions on hold and will work with the third party to obtain payment to avoid disconnection of your gas service.

If your meter has been turned off for non-payment, when payment in full is received by Enbridge including any disconnection charges and security deposit, Enbridge will reconnect your gas meter within 48 hours.

6.7. Arrears Management Programs

Enbridge has different arrears management programs available to customers who are unable to pay their entire bill. Enbridge works with customers depending on their individual circumstances to come up with a mutually agreeable payment arrangement. Customers requiring assistance are encouraged to call the Enbridge Call Centre at 1-877-362-7434 to discuss options.

In the event that you are having difficulty paying your bill, emergency financial assistance is also available. The Ontario Energy Board has initiated the Low Income Energy Assistance Program which operates similar to our Winter Warmth Program and provides financial assistance to families in need. You can choose to apply for financial assistance through various community agencies. Disconnection of gas service is always a last resort.

6.8. Allocation of Payments between gas and non-gas charges

Payments are applied to your gas bill charges based upon the oldest billed amounts being paid first. In the event that payment is insufficient to cover all charges invoiced in a month, payments will be allocated to non-gas charges first, unless otherwise notified of a dispute. Any charges that remain outstanding past the late payment effective date will incur a late payment charge as mentioned in the Bill issuance and Payment section.

6.9. Management of Customer Accounts

Enbridge is committed to providing excellent service and to ensuring that relationships with customers are conducted with integrity and in a responsible, fair, honest and ethical manner. Consistent with these objectives Enbridge maintains high standards of confidentiality with respect to the personal information in its possession. Any personal information related to a customer's account will only be shared with the party named on the account or any third party designated by the customer. To provide consent for another person or a third party to discuss your account details with Enbridge, you must contact our Enbridge Call Centre at 1-877-362-7434 to advise us of your permission to discuss your account with these parties.

In a landlord tenant situation Enbridge will follow directions recorded on the account when gas service was initially established.

6.10. Our Customer Service Process

Step 1: Call the Enbridge Call Centre at 1-877-362-7434
Enbridge customer service representatives (CSRs) are trained to help answer your questions.

Step 2: Ask to Speak to a Supervisor
If you feel that your questions are not being fully addressed by the CSR, please ask to speak to a supervisor. They'll try to work with you to resolve your issue.

Step 3: Contact the Enbridge Customer Ombud
If you've spoken to a CSR and a supervisor and are not completely satisfied with the solution provided, the supervisor will offer to elevate your concern to the Enbridge Customer Ombud's office.

For complete information regarding our dispute resolution process, please visit the Enbridge website: https://www.enbridgegas.com/contact-us/

APPENDIX A

DEFINITION OF TERMS

British thermal unit – means the amount of heat required to raise the temperature of one pound of distilled water from 60° Fahrenheit to 61° Fahrenheit.

Building piping – includes pipe, whether indoors, outdoors, exposed or buried, which brings gas from the "point of delivery" to each point of utilization including plugged or capped gas valves.

Cubic metre - A standard cubic metre of gas is the volume of gas contained in a one cubic metre at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa"). 10^3m^3 equals 1,000 cubic metres.

Curtailment - An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Customer – means any person, persons, company or corporation responsible for purchasing gas through Enbridge's meter.

Gas – natural gas or its equivalent containing not less than the heating value specified from time to time in Enbridge's rate schedules.

Gas appliance – means any device approved by the appropriate governmental authority which uses gas as a fuel or as a raw material.

Joule - A measurement of heat.

Late payment effective date – means the date late payment charges will be added to your bill if full payment has not been received.

Late payment charge – means a charge which is imposed when full payment of the gas bill is not made by the "late payment effective date".

Meter – means a device approved by the appropriate governmental authority and installed to measure the volume of gas delivered to the customer.

Month or monthly – means, for the purposes of calculating customers' accounts, a period of approximately 30 days.

Point of delivery – means that point at which gas leaves Enbridge's metering and regulating facilities and is delivered to you or, if there are no such facilities, Enbridge's shut-off valve.

Property line – means that line which delineates the boundary between one property and the next immediately adjacent property whether it is public or private.

Rate schedule – means one of a set of schedules filed by Enbridge with and approved by the Ontario Energy Board that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Service – means the pipe or tubing and associated fittings which transmits gas from the pipeline to the meter inlet connection. Where unmetered gas is provided, the service shall be deemed to terminate at the shut-off valve located closest to the building entry, immediately inside the building wall. Where gas pressure regulation is necessary, the service regulator shall form part of the service.

Standard conditions – Temperature of 60°F and 15°C for Imperial and S.I. respectively. Pressure of 14.73 pounds per square inch absolute (psia) and 101.325 kilopascals absolute (kPa) for Imperial and SI respectively. Water vapour content less than 7 pounds per million cubic feet and 100 milligrams per cubic metre for Imperial and SI respectively.

500 Consumers Road
North York, Ontario
M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Shari Lynn Spratt
Supervisor Regulatory Proceedings
Telephone: (416) 495-5499
Fax: (416) 495-6072
Email: EGDRegulatoryProceedings@enbridge.com

February 17, 2011

VIA RESS, E-MAIL & COURIER

Ms. Kristen Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Ontario Energy Board File No. EB-2010-0280
Customer Service Amendments to the Gas Distribution Access Rule
Submission of Enbridge Gas Distribution Inc. ("Enbridge")

On January 20, 2011 the Ontario Energy Board ("Board") issued a letter seeking input in assessing the need for developing customer service standards for natural gas distributors.

As per the Board's instructions attached please find Enbridge's submission. This submission is being filed through the Board's Regulatory Electronic Submission System.

Please contact the undersigned if you have any questions.

Yours truly,

Shari Lynn Spratt
Supervisor Regulatory Proceedings

Attachment

cc: Mr. David Stevens, Aird & Berlis (via email)
All EB-2010-0280 Interested parties (via email)

EB-2010-0280
Consultation on Customer Service Standards for Natural Gas Distributors

SUBMISSIONS OF
ENBRIDGE GAS DISTRIBUTION INC.

February 17, 2011

SUBMISSIONS OF ENBRIDGE GAS DISTRIBUTION INC. IN RESPONSE TO THE FIRST PHASE OF THE CONSULTATION ON CUSTOMER SERVICE STANDARDS FOR NATURAL GAS DISTRIBUTORS

1. Enbridge Gas Distribution Inc. ("Enbridge", or the "Company") is Ontario's largest gas distributor, serving over 1.9 million customers in Ontario. Enbridge has a very long history (over 150 years) serving customers in its franchise areas. Over the years, Enbridge has developed responsive, efficient and effective customer service policies and practices. Enbridge's current customer service policies function effectively and fairly, to the benefit of the Company, its customers and its ratepayers. Among other things, these practices ensure that Enbridge's customers have the benefit of reliable gas distribution services, and ensure that customers are not unduly burdened by costs caused by the small proportion of customers who fail to pay their bills on time or at all.

A. Overview

2. In its January 20, 2011 letter, the Ontario Energy Board (the "OEB" or the "Board") set out a consultation process that it intends to conduct prior to proposing any amendments to the Gas Distribution Access Rule ("GDAR") in respect of customer service rules. As the first step in this process, the Board has invited gas utilities to provide information about their current customer service practices and policies, and about how they compare with the final customer service rules for electricity distributors issued on July 2, 2010 in the EB-2007-0722 proceeding (the "Electricity Customer Service Rules"). The Board has also asked gas distributors to suggest any new or modified policies that are appropriate. Finally, the Board asked two specific questions about whether it is appropriate to issue prescriptive customer service rules that would apply to all gas distributors.

3. Enbridge understands the focus of the Board's attention in this matter to be on residential customers (Rate 1 for Enbridge). Accordingly, Enbridge's submissions are confined to customer service policies in place for that class of customers, and do not address customer service policies for larger volume and commercial customers. Enbridge further understands that the Board may pursue a related initiative to consider customer service policy issues specifically related to low-income consumers. Enbridge will participate in any such process when it happens and is open to considering whether

different customer service policies are appropriate for low-income customers. For the purposes of these submissions, Enbridge is not separately addressing any particular issues related to low-income customers.

4. Enbridge's submissions in response to the Board's January 20, 2011 letter are highlighted below and explained in more detail in the sections that follow.

5. In response to the Board's first question, Enbridge submits that there is no need or benefit to adopting a prescriptive approach which would impose a requirement for gas distributors to create customer service policies that align with the Electricity Customer Service Rules. Enbridge states this in light of the lack of complaints received about the Company's current customer service policies and practices and in recognition of the disparity between the costs and the anticipated benefits of a prescriptive approach that would apply the Electricity Customer Service Rules to gas distributors.

6. Instead, as contemplated in the Board's second question, Enbridge urges the Board to adopt a distributor-specific approach that will allow Enbridge to manage its own customer service policies. Such an approach will allow Enbridge to continue to tailor its customer service approaches to the circumstances of its own customers. It will also allow for the costs of moving to new customer service rules to be minimized.

7. In the event that the Board wishes to formally ensure the development and publication of gas distributors' customer service policies, Enbridge submits that any changes to be made to GDAR can be simple and broad. As contemplated in the second question in the Board's letter, such changes can simply require each rate regulated gas distributor to maintain, publish and adhere to customer service standards in certain areas (presumably the same areas included in the chart attached to the Board's letter).

8. Overall, Enbridge believes that its current customer service policies function effectively in the interest of customers and the Company. As set out in detail in these submissions, Enbridge's current customer service policies are already consistent with the spirit and intent of the Board's Electricity Customer Service Rules, providing protection and certainty for customers while allowing Enbridge to maintain appropriate flexibility to account for operational and financial considerations.

9. Nonetheless, the Board's process in this consultation is a good prompt that ongoing consideration and evaluation of customer service policies and approaches is important. Through this process, Enbridge has carefully considered its current customer service policies in light of the Board's policy objectives that underlie the Electricity Customer Service Rules. As a result, Enbridge has determined that it could make certain refinements to some of its policies. The chart attached as Appendix A to these submissions sets out Enbridge's current customer service policies, and notes the areas in which Enbridge can make some changes in order to address certain of the policies that underlie the Electricity Customer Service Rules.

10. Enbridge believes that many of the Electricity Customer Service rules are unnecessary for Enbridge as it already has in place its own customer service policies that meet the intent of the vast majority of the Electricity Customer Service Rules. Moreover, Enbridge questions whether some of the Electricity Customer Service Rules are too limiting, as compared to Enbridge's current approach. For example, the Electricity Customer Service Rules related to arrears management are overly prescriptive, and risk greatly increasing Enbridge's bad debt exposure. Enbridge's current approach, which invites any customer to discuss and establish an appropriate payment arrangement for arrears, is currently functioning well with at least 150,000 such arrangements established in 2010. As another example, the Electricity Customer Service Rules related to security deposits are too restrictive, and take away the protection that ought to be provided by a security deposit. Again, this risks increasing bad debt exposure, which will be expensive for all ratepayers.

11. On a go-forward basis, Enbridge is prepared to publish its customer service policies on its website, and provide a copy of the policies to all new customers. This will promote transparency and certainty for Enbridge's customers.

12. Enbridge's complaint process already refers customers to the Board where the Company is not able to resolve customer service complaints to the customer's satisfaction. Enbridge plans to continue that approach.

13. Enbridge's intended approach, which will maintain and publish its current customer service policies, with several possible refinements, and which will maintain the Board's

role as the ultimate recipient of any customer complaints, meets the Board's objectives set out in the January 20, 2011 letter. This approach provides for customer service standards that are fair, transparent and consistent.

14. Finally, given that there will be significant costs associated with the amendment of current customer service policies (which costs will be quite substantial if the Electricity Customer Service Rules are mandated), a mechanism must be established to allow for such costs to be recovered from ratepayers. Enbridge proposes that, at least until the time of its next cost of service rate proceeding, it be authorized to create a deferral account to track and collect such costs for later disposition.

B. OEB-regulated new customer service rules are not required

15. The Board's January 20, 2011 letter asks Enbridge to answer two questions:

    (a) Should the Board develop rules which prescribe specific customer service standards to be applied to all rate-regulated gas distributors? If so, should these standards be analogous to the electricity code provisions for customer service standards? What are the potential advantages and disadvantages of this prescriptive approach?

    (b) Should the Board develop rules which require each rate regulated gas distributor to develop, publish, and adhere to customer service standards for certain prescribed areas of customer service? If so, should the rules include the requirement that gas distributors develop complaint processes which include recourse to the Board in the event disputes are not resolved to the satisfaction of the parties? What are the potential advantages and disadvantages of this less prescriptive approach?

16. Enbridge's overall response is that there is no current need for a suite of new prescriptive rules governing how a distribution utility is to deal with its customers. Ontario's gas distribution utilities have lengthy experience and expertise in serving their customers, generally without complaint or issue. Through their close relationships with their own customers, gas distributors are able to identify repeating and new issues, and

use that information to shape, in a very responsive manner, the way that they work with their customers.

17. An example of Enbridge's responsive practices relates to its winter disconnection policies. It is Enbridge's practice not to initiate disconnections during the winter heating season (after the end of November until March). Beyond this, though, before the start of the heating season, Enbridge visits each customer who is then disconnected, to educate customers about payment options available, including the Winter Warmth Fund. This visit is followed up with a letter and two phone calls, urging the customer to investigate payment options to allow reconnection to proceed.

18. Ordinarily, one would expect that prescriptive new customer service rules for gas distributors would only be necessary as a response to widespread customer complaints or market issues. The fact is, though, that there have not been a significant number of complaints or issues raised by Enbridge's customers (or, as far as Enbridge is aware, by customers of Union Gas). This can be seen in several ways.

19. Enbridge's own experience and records do not indicate any such concerns being raised by customers with any increasing, or concerning, frequency. Over the past three years, there has been an average of less than 50 customer service complaints per year to the OEB from Enbridge customers.[1] That is an extremely low number when considered in the context of Enbridge providing service and monthly accounts to more than 1.9 million customers (i.e. ~23 million bills per year).

20. Similarly, the Board's public records (as set out in the April to June 2010 Consumer Snapshot[2]) indicate that less than 20% of the consumer complaints received relate to utility practices, and that many (perhaps most) of those relate to electricity distributors.[3] In terms of absolute numbers, the Board's records indicate that it receives less than

[1] Enbridge's records (from its Ombuds Office) track calls from the OEB related to customer complaints - the number of complaints has ranged from 32 to 60 over the past three years.

[2] http://www.oeb.gov.on.ca/OEB/_Documents/For%20Consumers/ConsumerSnapshot_2010_Apr-Jun.pdf ; see also the OEB's records from the last several years at: http://www.oeb.gov.on.ca/OEB/Industry/Media+Room/Publications/Consumer+Reports/Overall+Consumer+Enquiries+and+Issues

[3] As seen by the fact that the "top ten" issues raised in respect of utilities include several electricity-only issues such as smart meters, debt retirement charge and Provincial Benefit.

1,000 customer complaints per year in respect of all utility issues (again, most of these may relate to electricity distributors).

21. Additionally, the Board itself has recognized that, at least in respect of security deposits, there are no substantial customer concerns in respect of Enbridge's current policies. This is seen in EB-2008-0313 proceeding, where the Board decided not to proceed with changes to security deposit rules for gas distributors based, in part, on its determination that "the security deposit policies of the two largest natural gas distributors do not appear to be the subject of widespread concern at this time".[4]

22. To the extent that the proposal to develop and implement new customer service rules for gas distributors that mirror the Electricity Customer Service Rules is influenced by a desire to align the policies of electricity and gas distributors, Enbridge submits that such alignment is unnecessary. Concerns that the Board might have about standardizing the customer service practices of the more than 80 electricity distributors are not applicable in the context of gas distribution, where there are only two significant regulated market participants. To date, the Board has not found it necessary to comprehensively prescribe the customer service policies employed by Ontario's main gas distributors, and there has been no change in circumstances to justify why such a step is needed now.

23. One aspect of the creation and implementation of new customer service rules that must not be overlooked is the associated cost. Assuming that new customer service rules for Enbridge would be substantially similar to the Electricity Customer Service Rules, these costs will arise in three main ways: up-front implementation costs (system and process changes), increased administration and annual operating costs and increased bad debt and working capital costs.

24. Enbridge estimates that in adopting the Electricity Customer Service Rules, the Company would incur up-front implementation costs to address such items as system changes (including testing), updates to training and process documentation and the actual training of staff that would be administering these new rules. Enbridge estimates these costs (which would be one-time costs) would be in the range of $2.5 to $5 million.

[4] http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/140042/view/Notice_Termination_GDAR_20090717.PDF

25. The costs of additional staff time to administer the various new account management and security deposit processes for all customers would be substantial. The administration costs primarily stem from handle times in the call centre for educating customers on the rules and working through payment arrangements over an extended period of time in addition to responding to customer inquiries around confusion on the practical application of the rules for security deposits. Enbridge estimates that these costs would be in the range of $2.5 to $3.5 million per year. In the event that the Board requires that all customers be provided the opportunity to pay their accounts using a credit card (such that the credit card fees had to absorbed by the Company), then this could add over $15M in additional annual costs.

26. Beyond the additional operating (system and staffing) costs that would result from new customer service rules in the form of the Electricity Customer Service Rules, it is highly likely that bad debt and working capital costs will increase beyond what is currently approved. Allowing customers more time and greater flexibility in paying outstanding accounts, and denying distributors the ability to meaningfully use security deposits to reduce exposure to bad debt, will increase costs/losses to distributors. Enbridge's preliminary estimate is that implementation of the Electricity Customer Service Rules would increase its bad debt and working capital costs, and reduce late payment penalty revenue, by an amount in the range of $9.5 to $14.5 million per year.

27. The additional costs associated with any new customer service rules will ultimately be absorbed by Enbridge's ratepayers. Thus, while the implementation of the Electricity Customer Service Rules could potentially benefit a small subset of customers who could receive more generous payment terms and treatment of overdue accounts and security deposits, that benefit would essentially be funded by other prompt-paying customers (currently over 90% of Enbridge's customers pay their accounts in a timely fashion). As set out above, Enbridge estimates that these costs would be in the range of $2.5 to $5 million for one-time costs and $12 to $18 million for additional annual costs (not including the over $15 million in further additional annual costs that will be added if Enbridge is required to provide a no-cost credit card payment option to customers).

28. Another issue to consider is the time required to implement new customer service rules that align with the Electricity Customer Service Rules. Enbridge's preliminary estimate in

this regard is that it would need at least eighteen months lead time to fully implement new customer service rules of that type.

29. In light of the apparent costs associated with the Electricity Customer Service Rules, and in light of the fact that the need for these rules is not easily apparent, Enbridge encourages the Board to refrain from the prescriptive approach contemplated in the first question in the January 20, 2011 letter.

30. To the extent that the Board deems it necessary to develop rules to mandate customer service policies for gas distributors, then Enbridge firmly believes that such rules should be broadly drafted and minimally prescriptive, as contemplated in the second question in the Board's letter. This will allow each gas distributor to develop and maintain its own rules that are responsive to the particular circumstances of its own customers, service area and business.

31. The imposition of prescriptive rules that govern all utilities in these practices takes away or severely limits flexibility that allows utilities to tailor their specific customer requirements and approach to meet the changing circumstances and needs of their customers.

32. This points to a potential concern about the unintended consequences of the approach taken in the Electricity Customer Service Rules, which have the effect of mandating particular customer service rules for every utility to apply to every customer. If gas distribution utilities find that their flexibility to tailor different approaches to customers is taken away or reduced, or if gas distribution utilities find that the new rules are increasing the bad debt costs that must be borne by their ratepayers, then it is possible that some of their current practices that benefit customers may be discontinued.

33. For example, Enbridge currently works with customers to set up suitable payment arrangements based on that customer's needs. In some cases this may mean multiple payment arrangements in a 24 month period. In addition, Enbridge's customers are generally not asking for 5 and 10 month payment arrangements – indeed, in some cases a long payment arrangement term is not to the customer's benefit as it sets an artificial budget and can lead to the customer further over-extending themselves. Enbridge believes that its flexibility to continue a variety of payment arrangement approaches

(which was used in over 150,000 instances over the past year) will be reduced if the Electricity Customer Service Rules are extended to apply to gas distributors.

34. As another example, Enbridge's current policy with respect to new accounts allows Enbridge to initiate new accounts for premises where the previous account-holder moves out, even if the new occupant has not provided a written request for service. This seldom results in any disputes or concerns – where there is an issue, Enbridge addresses it on a case-specific basis. If, however, Enbridge is required to get written confirmation of a new occupant's account request before setting up a new account, then this could add substantial inconvenience and expense. That is because, in the absence of a written request from a new occupant, Enbridge would have to disconnect at the time that the prior occupant terminates. In the context of the more than 200,000 annual moves related to premises served by Enbridge, such a requirement would add significantly to the number of disconnections and reconnections being performed, adding to costs to be borne by customers for little or no benefit.

35. The Board's January 20, 2011 letter indicates that the objective of this consultation is "to ensure appropriate customer service standards that are fair, transparent, and consistent across all gas distributors and are enforceable by the Board".

36. Enbridge submits that its current customer service standards (policies) are fair and appropriate. The relative lack of complaints made by Enbridge's customers demonstrates that its policies are seen to be fair and properly administered. That said, Enbridge has determined that it could make certain refinements to some of its policies. The chart attached as Appendix A to these submissions sets out Enbridge's current customer service policies, and notes the areas in which Enbridge can make some changes in order to address certain of the policies that underlie the Electricity Customer Service Rules.

37. Enbridge has undertaken a preliminary examination of the time and costs associated with implementing these refinements to its customer service policies. The associated one-time costs related to items such as Customer Information System changes and new training are estimated at $1.5 to $2.0 million and the ongoing (annual) costs for items such as additional staffing and increased bad debt/working capital costs (and decreased

late payment penalty revenue) are estimated at $1.0 to $1.5 million per year. The Company estimates that the lead-time required to implement system changes and training to accommodate these refinements is approximately one year from the time that work starts on this initiative.

38. Enbridge is proceeding on the understanding that it will be able to recover all of these additional costs from ratepayers. For those utilities that are not in cost of service (like Enbridge), there is currently no straightforward means to recover such costs. To facilitate cost recovery, Enbridge proposes that, at least until the time of its next cost of service rate proceeding, it be authorized to create a deferral account to track and collect such costs, for later disposition.

39. Enbridge is prepared to publish its customer service policies (updated as suggested in the chart that follows) on the Company's website, and provide a paper copy to each new customer, as part of the customer welcome packages. This will promote transparency and certainty for Enbridge's customers in respect of its customer service policies and practices.

40. Enbridge intends to maintain its current customer service complaint process, a description of which is available to all customers on its website (a copy of this document is attached at Appendix B).[5] That process encourages Enbridge's customers to try to resolve complaints with an Enbridge customer service representative, but also contains an escalation process through which unresolved issues are referred first to Enbridge's ombudsperson and then, if no resolution results, to the OEB. In that manner, the Board will be the ultimate recipient of customer service complaints involving Enbridge's customers.

41. In the result, if Enbridge's intended approach is endorsed, then the Board's objective of fair and transparent customer service standards will be achieved. Consistent with the Board's objectives (set out in its January 20, 2011 letter), Enbridge's intended approach will ensure protection and certainty for customers while allowing Enbridge an appropriate measure of flexibility to allow it to account for operational and financial considerations.

[5] https://portal-plumprod.cgc.enbridge.com/portal/server.pt?open=512&objID=733&PageID=0&cached=true&mode=2&userID=2

42. While Enbridge's intended approach would not require the Board to make any amendments to GDAR, the Company recognizes that the Board may wish to add to that Rule. If that is the case, Enbridge submits that any changes to be made to GDAR can be simple and broad. As contemplated in the second question in the Board's January 20, 2011 letter, such changes can simply require each rate regulated gas distributor to maintain, publish and adhere to customer service standards in certain areas (presumably the same areas included in the chart attached to the Board's letter).

C. Enbridge's current customer service policies and practices

43. In its January 20, 2011 letter, the Board invited gas distributors to fill in a chart setting out the gas distributor's current customer service policies and practices in each of the areas that are part of the Electricity Customer Service Rules. Gas distributors were also invited to set out any changes that they would be prepared to make to their current customer service policies and practices to align with the approach set out in the Electricity Customer Service Rules. The chart set out as Appendix A to these submissions contains Enbridge's response.

44. As set out in detail in the chart at Appendix A, Enbridge's current customer service policies generally address and are consistent with the policy considerations that underlie the Electricity Customer Service Rules. Where Enbridge's customer service policies are different from the Electricity Customer Service Rules, there are good reasons for that difference. In a number of cases, though, as seen in the third column of the chart, Enbridge could make certain refinements to its customer service policies, to further align with the Board's policy objectives that underlie the Electricity Customer Service Rules.

45. While the details of Enbridge's current policies, and potential changes to those policies, are set out in the chart, the following is an overview of how Enbridge's current policies are consistent with the spirit and intention of the Electricity Customer Service Rules in each of the nine areas highlighted by the Board.

(a) *Under the heading "Bill Issuance and Payment", the Board states that "Mandatory rules for determining when a bill is overdue for payment will benefit customers and distributors alike by providing both clarity and uniformity of practice. Customers should not be exposed to late payment charges or disconnection by reason of delays in the processing of payment."*

Enbridge's current policies and practices ensure that customers are treated fairly and are not exposed to penalties because of payment processing delays. Enbridge could make modest changes to its approach, to extend the time before late payment charges apply so that a due date does not take effect on a non-business day and to accommodate additional time for payments by mail.

(b) *Under the heading "Allocation of Payment between Gas & Non-gas Charges", the Board states that Customers should not be exposed to late payment charges or disconnection by reason of partial payments being allocated in whole or in part to non-gas charges.*

Enbridge treats all charges on its bills consistently, so that payments are applied first to the oldest non-current charges, and then to current charges. Late payment charges are applied to all overdue amounts. Enbridge sees no reason why a non-gas charge should not attract late payment penalties. Any overdue amounts represent an extension of credit that is unpaid, and it is appropriate to charge penalties to cover carrying costs for this, and to encourage timely payments. As made clear in the Open Bill proceeding, the same bad debt rates apply to third party charges as to utility charges. It should be noted, though, that there is a clear process directing that when a customer disputes any third party charges, then a hold is placed on the account, and the dispute is referred back to the third party for resolution. Finally, disconnection of gas service is always a last resort for Enbridge and the Company is prepared to work with customer to avoid disconnection of service.

(c) *Under the heading "Correction of Billing Errors", the Board states that "Customers should not sustain undue impacts through no fault of their own. A distributor should not benefit from billing errors at the expense of the customer. Practice should be consistent, not discretionary."*

Enbridge's current policies and practices ensure that customers are not unduly impacted by billing errors. On a go-forward basis, Enbridge could make refinements to its current approach to bring it into greater alignment with the Electricity Customer Service Rules to ensure that over- or under-billing adjustments relate to a two-year period.

(d) *Under the heading "Equal Payment & Equal Billing Plans", the Board notes that these tools are "Of benefit to customers (easier to budget) and distributors (customers more likely to pay; consistent cash flow). Customers can co-ordinate due dates with receipt of income. Review and reconciliation procedures protect customers from significant over- or under-billing."*

Enbridge's "Budget Billing Plan", which is available to all gas heating customers, is currently used by approximately 53% of its customers and allows those customers to smooth their monthly payments. Enbridge administers the Budget Billing Plan in a manner that seeks to minimize over and under billing and commits to performing a review at least once per year along with the annual reconciliation. On a go-forward basis, Enbridge could the Budget Billing Plan to customers in arrears who have entered into a payment arrangement. Additionally, Enbridge could conduct a semi-annual review to adjust the monthly payments if consumption or approved changes have materially changed.

(e) *Under the heading "Disconnection Notices", the Board notes that "Customers should receive adequate notice of disconnection and the options available to avoid disconnection."*

Enbridge's disconnection processes ensure that customers receive proper advance notice. Current practices ensure that disconnection notices are sent to customers in a timely fashion, and a last call is made to a customer 48 hours before disconnection. Going forward, Enbridge could make some changes to its

disconnection notices to more explicitly set out options available to customers to avoid disconnection.

(f) *Under the heading "Disconnection Procedures", the Board notes that "Additional notice of disconnection and information on payment options may help customers avoid disconnection". The Board also has a hearing titled "Suspending disconnection action", under which it notes that "Customers and distributors can avoid disconnection if payment is imminent."*

Enbridge's disconnection processes require that customers be provided with final notice, which includes information about payment options, before disconnection is completed. Where Enbridge receives notice that a customer is arranging for payment from a third party (including social agencies), then disconnection actions are suspended. On a go-forward basis, Enbridge could its policy to stipulate that this suspension of disconnection will be in place for 21 days.

(g) *Under the heading "Security Deposits", the Board notes that Security deposits: (i) must be applied to gas charges before a disconnection notice can be issued; (ii) may be paid or repaid in instalments; and (iii) must be waived/refunded with good payment history.*

Enbridge's security deposit policy is broadly consistent with these requirements, with one exception. Enbridge does not apply the security deposit to gas charges before initiating disconnection actions. On a go-forward basis, Enbridge could make changes to its current policies to ensure that Enbridge will take into account the amount of any security deposit being held before issuing a disconnection notice. In other words, no disconnection notice would be issued if the amount of arrears is less than or equal to the amount of the security deposit.

(h) *Under the heading "Arrears Management Programs", the Board notes that "These programs provide terms by which customers and distributors may avoid disconnection and mitigates accumulation of very large arrears."*

Enbridge offers all customers in arrears the opportunity to discuss and establish a payment arrangement in order to avoid disconnection and clear up arrears.

These payment arrangements are set based on a customer's particular circumstances, and vary from case to case. Enbridge requires and uses a flexible approach to tailor varied solutions that work in different situations. This approach is very effective – Enbridge established over 150,000 payment arrangements with customers in 2010. On a go-forward basis, Enbridge could refine this process to ensure that customers receive 10 days written notice if a payment arrangement is to be cancelled.

(i) *Under the heading "Management of Customer Accounts" the Board notes that this will "Support constructive third party involvement and protects customers and distributors from fraud and misunderstandings".*

Enbridge's current account management approach, where accounts are created upon receipt of a request from a customer or its agent, does not appear to cause any issues in terms of "fraud and misunderstandings". However, in order to enhance clarity of account ownership in landlord/tenant situations, on a go-forward basis Enbridge could create clearer forms of agreement to stipulate that landlords are responsible for accounts in the event that a tenant moves away and no new tenant enrols with Enbridge.

D. Next Steps

46. The Board's January 20, 2011 letter indicates that once the Board has received the requested information from gas distributors, and responding submissions from other stakeholders, then it will assess the next steps in the development of customer service rules for gas distributors.

47. In the event that the Board determines that it is necessary and appropriate to make amendments to GDAR, or to create other rules in respect of Enbridge's customer service policies, then Enbridge requests that it be provided with a meaningful opportunity to provide submissions about the content of any such proposed rules.

48. Among other things, Enbridge believes that it will be important to provide information about the costs and timing associated with any proposed rules, so that their full impact can be assessed and an implementation timetable and cost recovery approach can be

determined before the rules are finalized. In order to best facilitate a complete exchange of information, it may be appropriate to convene a stakeholder conference with all interested parties, as well as Board members and OEB Staff, so that all perspectives can be presented and exchanged efficiently and transparently.

49. Enbridge would be pleased to answer any questions about these submissions and other matters related to this consultation process.

Attachment A:

Existing and Proposed Customer Service Policies and Practices of Natural Gas Distributors

Completed by: *Tanya Ferguson*
Enbridge Gas Distribution
Customer Care
Manager, Customer Care Operations
(416) 495-5765
Tanya.ferguson@enbridge.com

Date: **February 17, 2011**

1. **Bill Issuance and Payment:** Mandatory rules for determining when a bill is overdue for payment will benefit customers and distributors alike by providing both clarity and uniformity of practice. Customers should not be exposed to late payment charges or disconnection by reason of delays in the processing of payment.

Customer Service Rules for Electricity Distributors[1]	**Existing policies and practices**	**Proposed modified policies and practices**
The minimum payment period (before a late payment penalty can be applied) will be at least 16 days from the date the bill was issued to the customer. The date on which the bill was issued is determined to be three days after it was printed if sent by mail or on the date on which an email was sent over the internet. A bill payment is deemed to be received from the customer: three days before it is received by the distributor if sent by mail; on the date when the payment is acknowledged by a bank, or when the credit card payment is accepted by the	Enbridge's current policies and practices meet the intent of this rule. Invoices are sent to customers on the same day as they are printed, on the "Invoice Date". The payment period is 20 days from the "Invoice Date". Enbridge has already accommodated the three days for bills sent by mail in the payment period. Paper bills are printed and mailed and ebills are sent and posted to the internet on the same day. With respect to electronic and credit card payments, Enbridge is in compliance. Electronic payments are applied to the account as of the date that the payment is acknowledged by the customer's financial institution. Payments received by credit card	Enbridge is proposing to maintain its current policies and practices but would consider a potential enhancement to them with a system change. This change would allow for 3 additional days before LPP is calculated, however the LPP Effective dates shown on the bill will not change. This will accommodate payments received by mail being deemed 3 days earlier and will ensure that payments received after 5pm will not attract LPP. This will also accommodate due dates that fall on a weekend and allow an additional 3 days before LPP is calculated. Such a change will require updates to the Customer Information System, updates to training and process documentation and will reduce LPP Revenue.

[1] Amendments to the Distribution System Code (DSC), the Retail Settlement Code (RSC) and the Standard Supply Service Code (SSSC) coming into force January 1, 2011.

financial institution. Any payment made after 5:00 p.m. is still effective on the day the payment is made. If a due date is a non-business day, it is extended to the next business day.	are applied once the charge has been accepted by the financial institution. Payments received by mail are applied to the account as of the date received. Please see "Proposed modified policies and practices". Payments received after 5pm are effective the following day. Please see "Proposed modified policies and practices". If a due date is a non-business day, it is not extended to the next business day. Please see "Proposed modified policies and practices".	

2. **Allocation of Payment between Gas & Non-gas Charges:** Customers should not be exposed to late payment charges or disconnection by reason of partial payments being allocated in whole or in part to non-gas charges.

Customer Service Rules for Electricity Distributors	**Existing policies and practices**	**Proposed modified policies and practices**
If a bill includes charges other than electricity charges, any payment must first go directly to the electricity charges and then, if funds are remaining, to the other charges. If payment is sufficient to cover electricity charges, the distributor shall not issue late payment charges, a disconnection notice or disconnect the electricity supply. This applies to joint billing agreements when they are renewed, or after two years, whichever comes sooner.	Enbridge's current policies and practices largely meet the intent of this rule. Disconnection is always a last resort for the Utility. Payments received are allocated to the oldest arrears first, regardless of the type of charge, unless otherwise notified of a dispute by the customer. Enbridge will work with customers if there is a dispute about a charge. If a customer notifies that they are disputing a charge, Enbridge will put a hold on the accounts so that no LPP would be calculated and Enbridge will block that charge from being cleared by any subsequent payments on the account. In the event that the payment is insufficient to cover the current month's charges, the partial payment is first allocated to non-gas charges and then to gas charges. Any overdue balances attract Late Payment Penalties, however, a disconnection notice and disconnection is not triggered unless the gas arrears reach a threshold amount.	Enbridge is proposing to maintain its current policies and practices. The Company does not see any reason why non-gas charges should not attract LPP if there is no dispute outstanding on the charge. That unpaid amount represents an extension of credit to the customer and therefore should attract LPP.

3. **Correction of Billing Errors:** Customers should not sustain undue impacts through no fault of their own. A distributor should not benefit from billing errors at the expense of the customer. Practice should be consistent, not discretionary.

Customer Service Rules for Electricity Distributors	**Existing policies and practices**	**Proposed modified policies and practices**
Over or under-billing adjustments are permitted over a period of up to two years for all classes of customers. Note that the Limitations Act, 2002 provides a standard two-year limitation period for all actions in debt (subject to any considerations of discoverability).	Enbridge's current policies and practices largely meet the intent of this rule. Enbridge's current policy is such that over or under-billing adjustments on residential accounts are permitted for up to two years if the error is a result of actions by the Company and up to six years if the error is a result of actions by the customer. Please see "Proposed modified policies and practices".	Enbridge is proposing to maintain its current policies and practices but would consider a potential enhancement to them with a change to its policies for processing over or under-billing adjustments. Billing Adjustments will only be permitted over a period of up to two years for residential customers, except in the case of theft or illegal acts of a customer, in which case Enbridge will bill as far back as the information available will allow. Such a change will require updates to training and process documentation and will have an impact on bad debt. In addition, Enbridge would consider a potential system change to include a bill message on bills issued for accounts that are in a credit balance advising the customer that they may call to receive a refund cheque.
If a customer has been over-billed by an amount equal to or greater than the customer's average bill, the customer has the option of receiving a cheque or a credit on their next bill. If a customer has been over-billed and the amount is less than the customer's average bill, the customer will receive a credit on their next bill. If the customer has outstanding arrears, the distributor may apply the over-billed amount to the arrears first, and may credit or repay the balance to the customer.	Enbridge's current policies and practices meet the intent of this rule. If a customer has been over-billed by any amount, a credit is applied to the account. If the customer chooses to have the amount refunded, they can call Enbridge's call centre and a refund cheque will be issued to them. Please see "Proposed modified policies and practices".	
If a customer is under-billed and is not responsible for the error, the customer is allowed to pay the under-billed amount in equal installments over the same amount of time as they were under-billed for up to a maximum of two years. (e.g., if a customer has been under-billed for five	Enbridge's current policies and practices meet the intent of this rule. If a customer is under-billed for any reason, the charge is applied to the account. If the customer chooses to pay the under-billed amount in installments, Enbridge will work with the customer to determine a suitable payment	

months, they will have five months to pay the under-billed amount). When a customer is responsible for the under-billing error, the distributor may require payment of the full amount on the next bill or on a separate bill. These rules do not apply when a distributor has under-billed or over-billed a customer but issues a corrected bill within 16 days of the date the incorrect bill was issued.	arrangement based on that customer's circumstances. Enbridge will allow for a payment arrangement of up to the amount of time the customer was under-billed. Amendments to the Retail Settlement Code sections 7.7.8 and 7.7.9 refer to the payment of interest on over-billing and billing of interest on situations where Enbridge has under-billed customers. Enbridge currently does not charge interest to customers in these circumstances, nor does it pay interest as a practice. Amendment to the Retail Settlement Code section 7.7.10 refers to requirements to advise customers of meter errors and their rights under the Electricity and Gas Inspection Act (Canada). Enbridge currently only advises the customers of these rights if asked by the customer in dispute of a billing adjustment. Please see "Proposed modified policies and practices".	In addition, Enbridge would consider a potential system change to include correspondence or a bill insert in circumstances where a meter error was detected.

4. **Equal Payment & Equal Billing Plans:** Of benefit to customers (easier to budget) and distributors (customers more likely to pay; consistent cash flow). Customers can co-ordinate due dates with receipt of income. Review and reconciliation procedures protect customers from significant over- or under-billing.

Customer Service Rules for Electricity Distributors	**Existing policies and practices**	**Proposed modified policies and practices**
Distributors are required to offer all residential customers receiving standard supply service the option to join an equal monthly payment plan.	Enbridge's current policies and practices meet the intent of this rule. Enbridge offers customers the Budget Billing Plan ("BBP"), which is a program that helps spread annual gas costs evenly throughout the year. This plan is not currently offered to non-heating customers, given that their consumption is relatively flat all year long.	Enbridge is proposing to maintain its current policies and practices but would consider a potential enhancement to them with a change to its policies related to allowing customers in arrears to join the Company's Budget Billing Plan. Enbridge customers who are in arrears and have entered into a payment arrangement will be permitted to join Budget Billing Plan. Such a change will require updates to the Customer Information System and updates to training and process documentation.
Only customers that are in arrears and have not entered into an arrears payment agreement may be refused an equal monthly payment option.	Enbridge's current policies and practices meet the intent of this rule. Customers in arrears are not currently eligible to join the Budget Billing Plan. Please see "Proposed modified policies and practices".	
Customers can join equal monthly payment plans any time of the year.	Enbridge's current policies and practices meet the intent of this rule. Customers can join the BBP anytime of the year up to the end of February. If a customer chooses to join the plan after February, their plan will be deferred until September, the start of the next year's plan. After the month of February, consumption drops significantly and the benefits of joining the BBP at that time also drop significantly. New customers are automatically signed up to the Budget Billing Plan. When a new customer calls into the call centre, they are avised that Enbridge has a Budget Billing plan and asked if they would like to join the plan.	

Distributors may require customers who join an equal monthly payment plan to also join an automatic payment withdrawal plan if the billing cycle is less frequent than monthly. Residential equal payment customers who participate in automatic payment arrangements must be given a choice of at least two dates within a month for automatic payments to be withdrawn. Distributors may continue to issue bills on a monthly, bi-monthly or quarterly basis.	Enbridge's current policies and practices meet the intent of this rule. Enbridge's billing cycles are monthly and customers on BBP are not required to sign up for automatic withdrawal. Customers who are on BBP and have signed up for Pre-authorized payment, are not given a choice of withdrawal dates. Customers are BBP are treated the same as customers not on BBP in this area and payments are withdrawn on the LPP Effective date. Having customers choose between 2 dates would add customer confusion as such a change would result in a customer potentially receiving their next bill before the first bill was due.	
Utilities will review customer's monthly billing plans quarterly or semi-annually and adjust the monthly equalized payment if electricity consumption or approved charges have changed materially.	Enbridge's current policies and practices meet the intent of this rule. A review of customers' billing plans is conducted at least once per year, outside of the annual reconciliation. Enbridge is committing to ensuring that a review is conducted at least once per year. If necessary, BBP installment amounts are adjusted. Throughout the year, as customers monitor their BBP progress, they can request review as well. Installments at the start of the plan year and in the mid year review are based on the forecast of consumption, which is based on the consumption at the premise in the preceding 12 months, adjusted for prices in the current year.	
Utilities are required to reconcile all of their equal monthly payment plans once during the calendar year but not on the 12th month anniversary of a customer joining the plan. If a customer is in the first year of a plan, they may be reconciled earlier.	Enbridge's current policies and practices meet the intent of this rule. The BBP season at Enbridge is from September to July each year. In July, customers' Budget Billing Plans are reviewed and customers are billed or credited a BBP reconciliation adjustment that represents the difference between the charges for gas actually used from the time	

	they joined the plan and the monthly BBP installments billed to date. In the month of August, customers on BBP are billed for the gas used in the month.	In addition, as stated above, Enbridge would consider a potential system change to include a bill message on bills issued for accounts that are in a credit balance advising the customer that they may call to receive a refund cheque.
If the annual reconciliation shows that the customer is owed an amount equal to or exceeding the customer's average monthly billing, the amount will be credited to the customer's account. The customer will be notified of this credit and will have 10 days to request a refund cheque instead of the credit on their bill. If the annual reconciliation shows that the amount owed to the customer is less than the average billing amount, the amount will be credited to the customer's account.	Enbridge's current policies and practices meet the intent of this rule. If the annual reconciliation shows that the customer is owed funds (of any amount), a credit is applied to the account. If the customer chooses to have the amount refunded, they can call Enbridge's call centre and a refund cheque will be issued to them. Please see "Proposed modified policies and practices".	
If the annual reconciliation shows that the customer owes an amount equal to or exceeding the customer's average monthly billing, the distributor shall recover the balance over the first 11 months of the following year's equal monthly payment plan. If the annual reconciliation shows that the amount the customer owes is less than the customer's average monthly billing, the distributor may collect the full amount by a charge on the bill in the 12th month of the equal monthly payment plan.	Enbridge's current policies and practices meet the intent of this rule. If the annual reconciliation shows that funds are owed by the customer (of any amount), the charge is applied to the account. If the customer chooses to pay the reconciliation amount in installments, Enbridge will work with the customer to determine a suitable payment arrangement based on that customer's circumstances. Enbridge believes that recovering the reconciliation amount in the following year's Budget Billing Plan is not in the best interest of the customer longer term and creates an artificial budget for the customer and promotes potentially overextending themselves even further.	

5. **Disconnection Notices:** Customers should receive adequate notice of disconnection and the options available to avoid disconnection.

Customer Service Rules for Electricity Distributors	**Existing policies and practices**	**Proposed modified policies and practices**
All customers must receive 10 days notice before being disconnected for non-payment.	Enbridge's current policies and practices meet the intent of this rule. A disconnection notice is issued at least 10 days prior to disconnecting a customer for non-payment. The disconnection notice is effective for 30 days and if the service has not been disconnected, a new disconnection notice is issued.	Enbridge is proposing to maintain its current policies and practices but would consider a potential enhancement to them with a system change to the information provided on a disconnection notice. The disconnection notice will be updated to include the earliest and latest date disconnection may occur, that Enbridge will work with the customer to arrange a suitable payment arrangement based on the customer's circumstances (please refer to Enbridge comments under "Arrears Management") and advise the customer that a disconnection may take place at any time whether or not the customer is home at the time. Such a change will require updates to the Customer Information System and updates to training and process documentation.
Residents who have provided documentation from a physician that disconnection will pose a significant health risk, must receive 60 days notice before being disconnected for non-payment.	Enbridge's current policies and practices meet the intent of this rule. Enbridge currently has no way to track that a customer has a significant health risk, however, if a customer calls into the call centre and explains their situation, a Field Investigator is sent to the premise to investigate the situation. If there is a significant health risk, disconnection of the premise will be suspended. This rule would be much more significant in electricity supply.	
When a disconnection notice is issued in a building with multiple units, and a master meter, a copy of the notice must be posted in a conspicuous place in the building.	Enbridge's current policies and practices meet the intent of this rule. Disconnection notices for multi-unit buildings are posted in a conspicuous place in the building.	
Disconnection notices sent to residential customers must contain prescribed information, such as the earliest and latest date disconnection may occur, the forms of payment a customer may use, that a Board-prescribed arrears management program is available, and that a disconnection may take place whether or not the customer is home at the time.	Enbridge's current policies and practices largely meet the intent of this rule. The disconnection notice includes the date that the notice is issued, the overdue amount to be paid, the forms of payment available at this late stage of collections and the phone number to call to report a payment and avoid disconnection. Please see "Proposed modified policies and practices".	

5a. **Disconnection Procedures:** Additional notice of disconnection and information on payment options may help customers avoid disconnection.

Customer Service Rules for Electricity Distributors	**Existing policies and practices**	**Proposed modified policies and practices**
Distributors must make a reasonable effort to contact the customer one final time, in person or by telephone, prior to disconnecting service at least 48 hours before the scheduled disconnection date. There is certain prescribed information that a distributor must provide, such as advising of the potential availability of an arrears program.	Enbridge's current policies and practices meet the intent of this rule. A "last call before redlock" is performed approximately 48 hours prior to a customer being disconnected for non-payment. The customer is informed that the disconnection has been scheduled, and about payment options available to avoid disconnection, a phone number to report a payment and avoid disconnection and the hours of operation. Please see "Proposed modified policies and practices".	Enbridge is proposing to maintain its current policies and practices but would consider a potential enhancement to them with a system change to the information provided in a "last call before redlock". The last call before redlock will be updated to state that Enbridge will work with the customer to arrange a suitable payment arrangement based on the customer's circumstances. Such a change will require updates to the Customer Information System and updates to training and process documentation.
If a distributor has been unable to contact a customer 48 hours before a planned disconnection, they should generally make a reasonable attempt to communicate with the customer at the door (subject to consideration of the safety and security of utility field staff).	Enbridge's current policies and practices are different from this rule. Currently out of the consideration for the safety or field staff, there is no additional attempt to communicate with the customer at the door. Enbridge believes that this poses a significant risk to the safety of its employees and contractors	In addition, Enbridge would consider potential change to its business processes to leave a door hanger or card at the door of the customer advising the customer that they have been disconnected and that they may pay by credit card. Such a change will require updates to training and process documentation.
Distributors must, at a minimum, have the facilities and staff available during regular business hours so residential customers can pay overdue amounts by credit card. When a distributor visits a customer's property to disconnect service, customers must be allowed to pay overdue amounts by credit card (and any other form of payment the distributor wishes to accept). *Distributors should reconnect a property*	Enbridge's current policies and practices meet the intent of this rule. A credit card payment option is available for customers in arrears and/or avoiding disconnection, for a fee. The fee is charged by and paid to Enbridge's credit card payment processer. Enbridge does not retain any part of this fee. The credit card option is available 24x7 through Enbridge's IVR system and through Enbridge's website. It is important to note that if the credit card payment option was provided to customers as a standard option,	

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 8, Schedule 14, Attachment B, Page 27 of 37
EB-2010-0280
Enbridge Submission
Appendix A

within two business days of payment in full or entering into an arrears management agreement 85% of the time. (This metric already exists in the GDAR 7.3.7.1)	the cost to the ratepayers would be significant at approximately 2% of the amount of the payments processed, which could be in excess of $15 million depending on the number of customers that would choose this option. Given the availability of the credit card payment option and the fact that for a customer in arrears and pending disconnection, there are 7 opportunities with Enbridge touch points to arrange a payment, Enbridge believes that offering credit card payments at the door is not necessary.	

5b. **Suspending disconnection action:** Customers and distributors can avoid disconnection if payment is imminent.

Customer Service Rules for Electricity Distributors	**Existing policies and practices**	**Proposed modified policies and practices**
If, during the disconnection notice period, a registered charity, government agency or social service agency advises a distributor they are assessing whether a residential customer is eligible for bill payment assistance, the distributor must suspend disconnection action for a period of 21 days after receiving notification from the agency.	Enbridge's current policies and practices meet the intent of this rule. Disconnection action is suspended if there is notification from a social assistance agency of assessment of a customer's eligibility for payment assistance. Enbridge works with the customer on their individual circumstances; however, there is no set time period for the suspension. Please see "Proposed modified policies and practices".	Enbridge is proposing to maintain its current policies and practices and would consider a potential enhancement to them with a business process change such that when Enbridge is notified by a registered charity, government agency, social service agency or a third party that an assessment or arrangement for payment is in process, disconnection action will be suspended for a period of 21 days. Such a change will require updates to training and process documentation.
If, during the disconnection notice period, a third party, who had previously been designated by the customer to receive any disconnection notices, advises a distributor they are attempting to arrange assistance to help the customer pay their bill, the distributor must suspend disconnection action for a period of 21 days.	Enbridge's current policies and practices meet the intent of this rule. Third party notification is performed through consent, where the customer calls to allow Enbridge to discuss their account with a third party, due to Privacy Legislation. If there is notification from a third party advising that they are attempting to arrange for assistance for the customer, then Enbridge will work with the customer based on their individual circumstances. Any suspension of disconnection is not for a set time period. Please see "Proposed modified policies and	

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 8, Schedule 14, Attachment B, Page 28 of 37
EB-2010-0280
Enbridge Submission
Appendix A

A distributor must act on the disconnection notice within 11 days of its issuance or the lifting of a suspension. If disconnection does not occur within 11 days from the date of the notice or the lifting of the suspension, the distributor must issue a new disconnection notice and start the process once again.	practices". Enbridge's current policies and practices meet the intent of this rule. If the time period of the suspension elapses and the 48 hour notice is still effective, disconnection will occur immediately, otherwise a new 48 hour notice will be issued.	

6. **Security Deposits:** Security deposits: (i) must be applied to gas charges before a disconnection notice can be issued; (ii) may be paid or repaid in installments; and (iii) must be waived/refunded with good payment history.

Customer Service Rules for Electricity Distributors	Existing policies and practices	Proposed modified policies and practices
Residential customers can pay a required deposit, an increase in a security deposit or a replacement of a deposit applied against arrears, in equal installments over at least six months.	Enbridge's current policies and practices largely meet the intent of this rule. The purpose of a security deposit is to ensure that monthly bills are paid on time and to cover any outstanding arrears at the time the customer ceases to be a residential gas service customer. Security deposits may be required of new customers or customers who have had their gas service disconnected for non-payment. Security deposits are billed on the first monthly invoice and are due by the Late Payment Effective Date. Enbridge will work with the customer to determine a suitable payment arrangement based on that customer's circumstances. Security deposits may be waived if, (1) the Customer provides a letter of reference; (2) the Customer enrolls in Enbridge's Pre-Authorized payment plan; or (3) the Customer has a previous residential account with good payment history. Please see "Proposed modified policies and practices".	Enbridge is proposing to maintain its current policies and practices and would consider a potential enhancement to them with a business process change to allow for a payment arrangement for the payment of a security deposit over a period of up to six months in the case of a new customer. No change is being proposed for customers that are required to pay a security deposit after having their service disconnected for non-payment. Such a change will require updates to training and process documentation. In addition, Enbridge would consider a potential system change to have the CIS review customers' security deposits after 12 months from the month it is fully paid to determine if the deposit should be refunded. Such changes will require updates to the system and updates to training and process documentation.
There must be a review of the security deposit during the year after the first anniversary of the first installment payment.	Enbridge's current policies and practices largely meet the intent of this rule. After two years with a good payment history, the security deposit on file will be refunded with interest in the form of a credit to their bill after the second anniversary of the security deposit being paid. Please see "Proposed modified policies and practices".	In addition, Enbridge would consider a potential system change to have the CIS calculate the arrears, net of the security deposit and compare that to a threshold amount prior to issuing a disconnection notice or disconnection. Enbridge feels this meets the intent of this rule. For clarity, disconnection notices and disconnections would only be issued if the net amount owing, less the security deposit is over the threshold amount. Such changes will require updates to the system and updates to training and
A residential customer's average monthly consumption over a 12-month,	Enbridge's current policies and practices are different from this rule. Security deposits for	

consecutive period in the last two years, must always be used to calculate the maximum amount a distributor can collect for a security deposit. Security deposits must be applied against any arrears and be insufficient to cover any amounts owing before a disconnection notice can be issued to a residential customer. When a security deposit has been applied against any arrears, the customer may have to repay the security deposit, and be allowed to repay in equal installments over at least six months.	residential customers are administered as a flat rate of $250, regardless of the historical consumption. In its Legacy CIS system, the Company had always administered a flat rate Security Deposit Policy. When the new CIS was implemented in 2009, a variable Security Deposit was implemented which was calculated based on the customer's average monthly consumption. This change resulted in significant customer complaints and as a result, Enbridge implemented a system change to apply flat rate security deposits again. Based on experience, a variable security deposit approach will not be accepted by Enbridge's customers. Enbridge's current policies and practices are different from this rule. Security deposits are not prepayments for gas charges. Enbridge believes that applying security deposits against amounts owing before a disconnection notices is issued is not to the benefit for the customer. This will create a situation where customers use their security deposit as a prepayment of gas charges and a form of revolving credit, which is not the purpose of the deposit. Operationally, this will also cause customer confusion as the Company submits a subsequent request for a security deposit once it is applied. Customers would in practice receive a bill that had the security deposit credited and then a subsequent request for the same deposit back. Security deposits are only applied to an account in situations where the account is in good standing for a period of 24 months or the account has been disconnected for non-payment. Please see "Proposed modified policies and practices".	process documentation.

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 8, Schedule 14, Attachment B, Page 31 of 37
EB-2010-0280
Enbridge Submission
Appendix A

7. **Arrears Management Programs:** These programs provide terms by which customers and distributors may avoid disconnection and mitigates accumulation of very large arrears.

Customer Service Rules for Electricity Distributors	Existing policies and practices	Proposed modified policies and practices
Utilities must make arrears management programs available to any residential customer unable to pay their electricity charges. In the case of distributors who also collect water, sewer and other charges, these amendments apply only to the electricity charges.	Enbridge's current policies and practices meet the intent of this rule. Enbridge makes arrears management programs available to customers. Disconnection of gas service is always a last resort for Enbridge. The Company will work with customers to determine a suitable payment arrangement based on the customer's individual circumstances. Payment arrangements are offered to all customers in arrears, depending on payment arrangement history.	Enbridge is proposing to maintain its current policies and practices but would consider a potential enhancement to them with a system change to issue a cancellation notice in writing to customers who miss a payment on a payment arrangement advising them that the cancellation of the payment arrangement will take place 10 days later. Such changes will require updates to the system and updates to training and process documentation.
Any security deposit must be applied to the amounts owing before entering into an arrears payment agreement.	Enbridge's current policies and practices are different from this rule. As identified above, the purpose of a security deposit is to ensure that monthly bills are paid on time and to cover any outstanding arrears at the time the customer ceases to be a residential gas service customer. Enbridge believes that applying security deposits against amounts owing before a disconnection notices is issued is not to the benefit for the customer. This will create a situation where customers use their security deposit as a prepayment of gas service and a form of revolving credit, which is not the purpose of the deposit. Operationally, this will also cause customer confusion as the Company submits a subsequent request for a security deposit once it is applied. Customers would in practice receive a bill that had the security deposit applied and then a subsequent request for the same deposit back.	

Customers may be required to make a down payment of up to 15% of the arrears plus any accumulated late payment charges (not including other service charges such as reconnection charges) when entering into an arrears management agreement. If a customer owes less than twice their average monthly bill after applying the security deposit and down payment, the minimum length of time to pay the remaining amount is five months. If a customer owes more than twice their average monthly bill after applying the security deposit and down payment, the minimum length of time to pay the remaining amount is 10 months.	Enbridge's current policies and practices meet the intent of this rule. Down payment requirements and length of payment arrangements are arranged based on the individual circumstances of each customer. Enbridge's current policies and practices meet the intent of this rule. If a customer is in arrears for any amount, Enbridge will work with the customer to determine a suitable payment arrangement based on that customer's circumstances and will also allow for multiple payment arrangements in a year. Enbridge believes that imposing timelines for payment arrangements is not in the best interest of the customer over the longer term and creates an artificial budget for the customer and promotes potentially overextending themselves even further. In addition, given that Enbridge will offer payment arrangements more frequently then this rule stipulates, the Company is more flexible now when working with customers and such a rule could limit the Company's ability to work with customers based on their circumstances.	
Distributors can cancel the agreement if a customer defaults on the arrears payment or current bill payment more than once. Customers must be given 10 days written notice before an agreement can be cancelled, and the agreement must be reinstated if the customer pays in full before the cancellation date.	Enbridge's current policies and practices largely meet the intent of rule. Payment arrangements are currently collected on a timeline that has the payment arrangement cancelled 10 days after the first missed payment. Enbridge currently issues a friendly reminder call to customers 1 day after a payment is missed, then a subsequent call 5 days later with the payment arrangement being cancelled on the 10th day.	

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 8, Schedule 14, Attachment B, Page 33 of 37
EB-2010-0280
Enbridge Submission
Appendix A

8. **Management of Customer Accounts**: Support constructive third party involvement and protects customers and distributors from fraud and misunderstandings.

Customer Service Rules for Electricity Distributors	Existing policies and practices	Proposed modified policies and practices
If a distributor opens a new account based on a request from a third party, a letter must be sent to the new user within 15 days of the opening of the account. The account will not be set up if the new user has not approved the opening of the account within 15 days of the letter. However, a solicitor or person with Power of Attorney can agree on behalf of the new customer to the opening of the account. Distributors can only recover charges from a person who has agreed in writing to become a customer. When a tenant customer moves out of a rental unit, distributors cannot seek to recover future charges from any other person, including the landlord, unless that person has agreed in writing to assume responsibility for the account. A distributor and a landlord may enter into an agreement where the landlord agrees to automatically assume responsibility for paying for continued service after the closure of a tenants account.	Enbridge's current policies and practices are different from this rule. New accounts are opened via lawyers' letters from either parties' lawyer (in the event of a move) or by customer's request. If a customer moving out or their lawyer has notified the Company of a pending move, and the moving in party has not contacted the Company, an account in the name of "Owner Occupant" is created and bills are issued to the address. Attempts are made to validate the customer's information at the premise through the use of door hangers or correspondence. Locking the premise would be a last resort. Obtaining written confirmation from the customer would add significant time and complication to the process of moving customers in and out of premises. This change would also result in an increase in backdated transactions and add significant risk to the Company for customers not communicating proactively. Enbridge's current policies and practices largely meet the intent of this rule. When a tenant moves out of a rental unit, the Company attempts to recover those charges from that customer, not any subsequent customer. If there is no move-in party, then Enbridge will attempt to recover future charges at the property from the landlord to avoid disconnection of the property. Arrangements are in place with some landlords where the account will go in the	Enbridge is proposing to maintain its current policies and practices but would consider a potential change to the handling of landlord properties. The Company is proposing to enter into landlord agreements to have the landlord assume responsibility for the charges at their property after a tenant has moved out or in the event that a new tenant has not contacted the Company with their personal information. Clear accountability will reduce complaints over the responsibility for the account. Such changes will require updates to the system and updates to training and process documentation.

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 8, Schedule 14, Attachment B, Page 34 of 37
EB-2010-0280
Enbridge Submission
Appendix A

	name of the landlord and charges billed to the landlord if there is not tenant to avoid disconnection.	
Comments or Suggestions		

EB-2010-0280
Enbridge Submission
Appendix B

Related Links

Helping you get the assistance you need is important to us. Watch our video.

Customer Assistance

If you have a problem or concern, contact us and we'll do our best to resolve it quickly and conveniently.

STEP 1: Give Us a Call

Our Customer Service Representatives (CSRs) are trained to help with your concerns and questions.

In most cases, they'll have the answers you need.

Contact us directly by:

Telephone

Reason	Number
You smell gas or have an emergency.	1-866-SMEL-GAS (1-866-763-5427)
You have questions about your billing information, or you have concerns about an inspection or a gas meter.	1-877-Enbridge (1-877-362-7434)

Mail

If you'd prefer to write to us, please include a written summary of your problem and your full name, address and telephone number.

If you send more than one letter, please include your contact information on each one.

Our address is:

Customer Resolution
500 Consumers Road
North York, ON
M2J 1P2

STEP 2: Ask to Speak to a Supervisor

If you feel that your problem has not been appropriately resolved by one of our CSRs, please ask to speak to a manager or supervisor.

The CSR will arrange for a manager or supervisor to contact you within 48 hours to discuss your situation.

The supervisor or manager will work with you to resolve your issue.

STEP 3: Contact our Customer Ombud

If after speaking with a CSR and a supervisor, you feel that your inquiry has not been appropriately addressed, you may contact the office of the Ombud to speak to a member of our team. The office of the Ombud will contact you to confirm receipt of your information—in most cases within 48 hours—and will review your issue as soon as possible.

You may contact a member of the Ombud team directly via telephone or email at:

Mail	**Debbie Boukydis, Customer Ombud** P.O. Box 650 Scarborough, Ontario M1K 5E3
Email	ombud@enbridge.com
Telephone	416-495-6155
Toll Free	1-866-817-6836
Fax	416-495-5021

Claim Inquiries: Any claims issues that may be subject to a claim inquiries that have not already been sent to the Enbridge Claims Department will be forwarded to the Enbridge Claims Department. A member of the Enbridge Claims Department will contact you directly to review your issue as soon as possible. Once the Enbridge Claims Department has reviewed the issue and made a decision, you still have the option to have it reviewed by the office of the Ombud.

STEP 4: Contact the Ontario Energy Board

If you've followed the above steps and your problem has not been resolved, please contact the Ontario Energy Board (OEB).

To contact the OEB, go to www.oeb.gov.on.ca.

© 2011 Enbridge Gas Distribution Inc. All Rights Reserved.

500 Consumers Road
North York, Ontario
M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Bonnie Jean Adams
Regulatory Coordinator
Telephone: (416) 495-5499
Fax: (416) 495-6072
Email: EGDRegulatoryProceedings@enbridge.com

July 22, 2011

VIA RESS, E-MAIL & COURIER

Ms. Kristen Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Ontario Energy Board File No. EB-2010-0280
Customer Service Amendments to the Gas Distribution Access Rule
Submission of Enbridge Gas Distribution Inc. ("Enbridge")

By email and web posting the Ontario Energy Board issued a letter dated June 29, 2011 regarding low-income related customer service standards and requested gas distributors to provide information and respond to two sets of questions, Attachment A to the letter.

As per the Board's request, attached please find Enbridge's responses and submission. Enbridge's submission is being filed through the Board's Regulatory Electronic Submission System.

Please contact the undersigned if you have any questions.

Yours truly,

for

Bonnie Jean Adams
Regulatory Coordinator

Attachment

cc: Mr. David Stevens, Aird & Berlis (via email)
All EB-2010-0280 Interested parties (via email)

EB-2010-0280
Low-Income Related Customer Service Standards

SUBMISSIONS OF
ENBRIDGE GAS DISTRIBUTION INC.

July 22, 2011

SUBMISSIONS OF ENBRIDGE GAS DISTRIBUTION INC. ("ENBRIDGE") IN RESPONSE TO OEB LETTER RE. LOW-INCOME RELATED CUSTOMER SERVICE STANDARDS

1. In its June 29, 2011 letter, the Ontario Energy Board (the "OEB" or the "Board") sought stakeholder input in respect of possible low-income related customer service standards for rate-regulated gas distributors. As the first step in this process, the Board has invited gas utilities to provide information about their current customer service practices and policies for low-income customers, and about how they compare with the final low-income customer service rules for electricity distributors which come into force on October 1, 2011 (the "Electricity Low-Income Customer Service Rules"). The Board has also asked gas distributors to suggest any new or modified policies that are appropriate. Finally, the Board asked two specific questions about whether it is appropriate to issue prescriptive customer service rules for low-income customers that would apply to all gas distributors.

A. OVERVIEW

2. As set out in detail below, Enbridge submits that no specific or additional regulation or prescription of its customer service policies for low-income customers is necessary. The approach endorsed by the OEB in its June 29, 2011 Notice of Proposal to Amend the Gas Distribution Access Rule ("GDAR") which requires gas distributors to publish and adhere to customer service policies for all customers that address a variety of subject areas is sufficient to ensure that all gas distributor customers are treated fairly and appropriately.

3. Enbridge's current customer service policies and practices function effectively in the interest of customers and the Company. Enbridge's current customer service policies provide protection and certainty for customers while allowing Enbridge to maintain appropriate flexibility to account for operational and financial considerations. The responsiveness and effectiveness of Enbridge's customer service policies will be enhanced when the "refinements" to Enbridge's customer service policies that were endorsed by the Board in its June 29th Notice are adopted. In the result, the customer service needs of all of Enbridge's customers have been and will continue to be met in a responsive manner.

4. Enbridge does not distinguish between customers based on income level when addressing arrears management issues. The Company does not support creating and implementing different customer service policies and practices for low-income customers. Enbridge's current and pending customer service practices and policies are sufficiently broad to allow the Company to accommodate customers facing payment difficulties, including low-income customers. As explained in its February 17, 2011 submissions, Enbridge's customer service practices and policies are premised on flexibility, to allow changes to be made over time, and to allow different approaches for different customers. As set out in Attachment "A" to these submissions, Enbridge's interpretation and application of its practices and policies allows for appropriate approaches to meet the needs and circumstances of customers facing payment difficulties, including low-income customers. For example, with the implementation of the customer service refinements, Enbridge will permit even customers in arrears to join its Budget Billing Plan and Enbridge works closely with customers to avoid disconnections and will suspend disconnection actions for a period of 21 days for customers who are seeking assistance from LEAP, social agencies and third parties.

5. It is significant to note that the Company's dealings with low-income customers do not appear to be a significant topic of complaint or concern by customers or the Board. As explained in previous submissions, over the past three years there have been fewer than 50 customer service complaints per year (on average) by Enbridge customers to the OEB. That is an extremely low number when considered in the context of Enbridge providing service and monthly bills to more than 1.9 million customers (i.e. ~23 million bills per year). Of course, many or most of these complaints will not have involved low-income customer issues. Given the lack of expressed concerns, Enbridge submits that there is no need here to align the policies of electricity and gas distributors for low-income customers.

6. Enbridge is concerned that the Board's adoption of a more prescriptive approach that would specify and mandate particular rules for low-income customers, as set out in the Electricity Low-Income Customer Service Rules, would not only add costs and reduce flexibility, but might also lead to further unintended consequences. While these, by their very nature, cannot be accurately foreseen, the point is that Enbridge's current practices have been tried and tested over time and, as a result, have evolved and developed in a

way that takes account of and ameliorates any impacts. Enbridge believes that the introduction of prescriptive rules will not allow the same leeway to accommodate unintended consequences.

7. As noted in other submissions, Enbridge remains concerned that the overall impact of prescriptive new customer service rules, whether for all customers or for a sub-group of customers, will be to increase operating, bad debt and working capital costs. The costs arising from specific customer service rules for low-income customers would be recoverable from all ratepayers (or all residential class ratepayers). Of course, this raises concerns around cross-subsidization between ratepayers. Enbridge therefore urges the Board to specifically consider these additional costs, and address why it is appropriate for all ratepayers (the majority of whom would not benefit from new customer service rules for low-income customers) to bear the costs.

8. In summary and in response to the Board's two questions, Enbridge submits that:

   (a) Its current customer service policies and practices, along with the pending "refinements" to those policies, ensure appropriate levels of service for low-income customers (and are reasonably consistent with Union Gas); and

   (b) Accordingly, there is no need for additional rules (in the form of changes to GDAR or otherwise) to prescribe the customer service policies applicable to its low-income customers, or to require that separate low-income customer service polices be developed and implemented.

B. ENBRIDGE'S CURRENT APPROACH

9. The Board's June 29, 2011 letter asks gas distributors to provide information (in chart form) about their current customer service practices and policies for low-income customers, and to compare those approaches to the Electricity Low-Income Customer Service Rules. Enbridge's response is set out at Attachment "A" to these submissions. As seen in Attachment "A" to these submissions, in most areas Enbridge's practices and policies are consistent with the intent of the Electricity Low-Income Customer Service Rules. Where there are divergences between Enbridge's approach and the Electricity Low-Income Customer Service Rules, there are good reasons for such differences.

10. For many years, Enbridge has been aware of and responsive to the particular circumstances faced by low-income customers. For example, without any OEB directive Enbridge has already been a leader in identifying and addressing issues faced by low-income customers. Enbridge and the United Way created the Winter Warmth Fund in 2004 to provide emergency assistance to low-income customers. The Winter Warmth Fund has continued, expanded and grown since that time. The approach used for the Winter Warmth Fund has now been adopted, in large part, by the Board as the Low Income Energy Assistance Plan (LEAP) initiative, which provides financial assistance to qualifying customers on a year-round basis.

11. As seen in the chart at Attachment "A", and in the following sub-paragraphs, Enbridge's current customer service practices and policies address the issues faced by low-income customers and other customers facing payment difficulties in many ways. For example:

    (a) Enbridge's approach to disconnections ensures that customers in arrears are not disconnected during the winter heating season. Beyond this, though, before the start of the heating season, Enbridge visits each customer who is then disconnected, to educate customers about payment options available, including the Winter Warmth Fund. This visit is followed up with a letter and two phone calls, urging the customer to investigate payment options to allow reconnection to proceed.

    (b) Enbridge offers (and encourages) all customers the option to participate in a Budget Billing Plan, which is a program that helps spread annual gas costs evenly throughout the year. The Board has recognized the importance of this type of approach to assist low-income customers in managing their energy costs throughout the year. As part of the "refinements" to be implemented to its customer service policies, Enbridge will allow customers in arrears who have entered into payment arrangements to enrol in the Budget Billing Plan. This will assist all customers (including low-income customers) experiencing payment difficulties to manage their future costs.

    (c) Enbridge has developed a flexible approach to arrears management. Enbridge offers all customers in arrears the opportunity to discuss and establish a payment

arrangement in order to avoid disconnection and clear up arrears, based on that customer's needs. Enbridge's approach is less rigid than what is set out in the Electricity Low-Income Customer Service Rules. In some cases Enbridge's customers will establish multiple payment arrangements in a 12 month period. In addition, Enbridge's customers are generally not asking for 5 and 10 month (or longer) payment arrangements – indeed, in some cases a long payment arrangement term is not to the customer's benefit as it sets an artificial budget and can lead to the customer further over-extending themselves. Enbridge believes that its flexibility to continue a variety of payment arrangement approaches (which is very effective and was used in over 150,000 instances over the past year) will be reduced if the Electricity Low-Income Customer Service Rules are implemented for gas utilities. In contrast to the Electricity Low-Income Customer Service Rules, Enbridge does not propose to waive service and late payment fees for low-income customers who enter into payment arrangements. The Company believes that it is appropriate for all customers whose actions result in the Company incurring costs related to collections, disconnection and non-payment, be accountable for the payment of those charges. Most of these costs could be avoided by prompt action on the part of the customer, for example, calling the Company at the time they know that payment will be difficult. This would avoid additional collections and potentially disconnection costs from being incurred. The Company believes that the posting of Customer Service Policies on its website will encourage customers to call and notify the Company of payment issues.

(d) Enbridge's disconnection policy ensures multiple contacts with customers before any actual disconnection. Through those contacts, which are by phone, bill message or separate notice, Enbridge ensures that customers are provided with information about the arrears amount and payment options. As part of the pending changes to its policies, Enbridge will ensure that when it is notified by a registered charity, government agency, social service agency or third party that an assessment or arrangement for payment is in process, then disconnection actions will be suspended for 21 days. Further, and also as part of the pending changes to its policies, Enbridge will take into account the amount of any security

deposit being held before issuing a Disconnection Notice. In other words, no Disconnection Notice would be issued if the amount of arrears is less than or equal to the amount of the security deposit.

(e) As part of the refinements to its customer service policies, Enbridge will be reviewing customer security deposits after one year, to determine whether some or all amounts should be credited/refunded to the customer. This will benefit all customers, including low-income customers. All customers also benefit from Enbridge's current policy of waiving security deposits in a variety of circumstances, including when they provide a letter of reference from another utility, or enroll in Enbridge's Pre-Authorized payment plan, or have had a previous residential account with good payment history. In contrast to the Electricity Low-Income Customer Service Rules, Enbridge does not propose to waive security deposits for low-income customers, although Enbridge's refined policy will be to allow security deposits to be paid over a number of months. The purpose of a security deposit is to ensure that monthly bills are paid on time and to cover any outstanding arrears at the time the customer ceases to be a residential gas service customer. If the Company were to not charge security deposits for any reason, the risk to bad debt would be borne by all customers. Security deposits are charged to protect and minimize impacts to rates for all customers.

(f) Finally, Enbridge proposes to make two additional modest changes to its customer service practices and policies for all customers, with the intent that such changes may be of particular benefit to low-income customers. First, Enbridge will add information about the LEAP program to Disconnection Notices. Second, Enbridge will enhance the messaging provided to its customers through the various stages in the disconnection process (from the initial notice of arrears up to the actual disconnection work order) to ensure that the customer is made aware of the ability to make a payment arrangement. Enbridge will also enhance its messaging to ensure that customers are made aware of possible assistance from LEAP and/or social service agencies. These changes would be made along with the other "refinements" to Enbridge's policies being implemented in response to the Board's June 29th Notice.

12. As explained in Enbridge's February 17th submissions, and as seen above and in Attachment "A" to these submissions, the Company's customer service practices and policies are appropriate and responsive, and create flexibility to allow Enbridge to create solutions that are considerate of particular customers' circumstances. That means that Enbridge can be and is mindful of the circumstances faced by low-income customers and other customers facing payment difficulties when working with those customers.

13. Accordingly, there is no need for a prescriptive approach to specify customer service policies that Enbridge must adopt for its low-income customers. A prescriptive approach could take away from the flexibility currently available, and would likely add costs to be borne by all ratepayers. Moreover, such an approach would require Enbridge to identify and track which of its customers should be classified as "low-income", which could be a new requirement that would be expensive and difficult to assess, monitor, update and enforce.

14. Enbridge notes that while the process established by the Board's June 29th letter anticipates that stakeholders will provide comments on the gas distributors' submissions, no allowance has been made for responses by gas distributors to the stakeholder submissions. Enbridge requests that it be provided an opportunity to respond to issues and proposals advanced by stakeholders.

15. In addition, should the Board conclude, notwithstanding Enbridge's comments, that further low-income customer service practices and policies may be appropriate, then Enbridge urges the Board create a process to examine current experience before making any determination about what new rules are needed. To be able to best understand how Enbridge's current approaches are working, it may be appropriate to convene a stakeholder conference with all interested parties, as well as Board members and OEB Staff, so that all perspectives can be presented and exchanged.

16. Finally, Enbridge notes that there will be costs associated with any additional customer service policies that are prescribed or mandated for low-income customers. These costs are appropriately recovered from ratepayers, and Enbridge would expect to record such costs in an appropriate deferral or variance account for later disposition.

C. RESPONSE TO BOARD'S QUESTIONS

17. The Board's June 29th letter asked stakeholders to answer two questions.

    (a) *Are current low-income customer service standards, along with the proposed modifications and enhancements, sufficient to ensure reasonable consistency across the province and appropriate levels of service for low-income customers such that a less prescriptive approach to Board oversight is warranted?*

    (b) *If so, should the Board adopt the same approach as that proposed for customer service standards in general (i.e., require each rate-regulated gas distributor to develop, publish, and adhere to low-income related customer service standards for certain prescribed areas of customer service, including a complaint process with recourse to the Board)?*

18. Enbridge's customer service policies and practices provide protection and certainty for all customers while allowing Enbridge to maintain appropriate flexibility to account for operational and financial considerations. As set out in Attachment "A", Enbridge's policies (with the "refinements" to be implemented in response to the Board's June 29th Notice) provide for appropriate levels of service to all of Enbridge's customers, including low-income customers. These policies are consistent for all of Enbridge's customers, and are reasonably similar to the corresponding policies of Union Gas (as can be seen from Union's February 17, 2011 submissions), meaning that virtually all gas consumers in Ontario benefit from relatively uniform policies and practices.

19. In the result, and in response to the Board's first question, there is no need for a prescriptive approach to specify customer service policies that Enbridge must adopt for its low-income customers.

20. Indeed, and in response to the Board's second question, no additional Board oversight of Enbridge's customer service policies and practices is warranted. Enbridge's updated and refined customer service practices and policies will ensure that Enbridge's low-income customers have the benefit of fair and flexible customer service policies which continue to allow Enbridge to appropriately address the issues faced by low-income customers and other customers facing payment difficulties. As noted by the Board in its June 29th Notice, the new section 8 of the GDAR ensures that Enbridge's customer service practices and policies will be transparent and enforceable by the OEB. All customers will also have access to a dispute resolution process which includes recourse

to the OEB where necessary. Accordingly, there is no need for any further requirement for Enbridge to create and/or maintain discrete low-income customer service policies and practices.

Attachment A:

Proposed Customer Service Policies and Practices for Eligible Low-Income Natural Gas Customers

Completed by: *Tanya Ferguson*
Enbridge Gas Distribution
Customer Care
Manager, Customer Care Operations
(416) 495-5765
Tanya.ferguson@enbridge.com

Date: **July 22, 2011**

1. **Definition of Eligible Low-Income Customer:** A definition of eligible low-income customers is required in order to implement low-income customer service standards and rules.

New Low-Income Code Provisions for Electricity Distributors[1]	**Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers**
Eligible low-income customers are residential electricity customers who have a pre-tax household income at or below Statistics Canada's most recent pre-tax Low Income Cut-Off plus 15%, taking into account family and community size and are qualified by a Social Service or Government Agency. Customers must be qualified by a Social Service or Government Agency that: i) partners with their local electricity distributor to assess eligibility for Emergency Financial Assistance; or ii) assesses eligibility for other energy financial assistance or for other low-income financial assistance programs, and partners with their local distributor to qualify customers for eligibility. If customers have qualified for Emergency Financial	*Enbridge's current policies and practices meet the intent of this rule. The Company is proposing no additional changes to policies and practices for low-income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers. For LEAP Emergency Financial Assistance Program purposes, this eligibility guideline for determination of low income is used.* *In the Company's daily correspondence with its customers, it does not currently track or request information to assess a customer's eligibility for low income status. Enbridge's current policies and practices are to work with our customers based on individual circumstances and determine appropriate actions. We will direct customers having financial difficulties to agencies responsible for providing Winter Warmth and Leap funding. The Company's practice is to negotiate and work with*

[1] The Board has approved and issued customer service rules for eligible low-income electricity customers. They will come into effect October 1, 2011. These will supplement the customer service rules applicable to all residential customers which were released on July 2, 2010.

Assistance under the Low-income Energy Assistance Program (LEAP), they will automatically qualify for all of the low-income customer service rules under the codes. After qualifying as an eligible low-income electricity customer, their low-income status will remain in effect for purposes of the codes for 2 years from the date they qualified. Eligible low-income customers must contact their distributor before a special low-income customer code rule will be made available to them.	*customers based on their individual situation and determine an appropriate payment arrangement, or payment extension as needed.*

2. **Security Deposits:** Existing security deposits must be returned if requested by an eligible low-income customer after paying any arrears. Eligible low-income customers may request a waiver if their distributor requests a new security deposit.

New Low-Income Code Provisions for Electricity Distributors	**Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers**
If an eligible low-income consumer has previously paid their distributor a security deposit, they may ask for it to be returned, after paying any outstanding arrears. Distributors shall advise all residential customers of this right annually. Any remaining security deposit returned to the customer will be credited to their account if the amount due is less than their average monthly bill. If the amount is equal to or greater than their average monthly bill, they could request a refund by cheque. An eligible low-income customer may request a waiver if their distributor requests a new security deposit. Distributors are to advise customers of this right when issuing a bill for a security deposit.	*Enbridge's current policies and practices are different from this rule. The Company is proposing no additional changes to policies and practices for low income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers.* *The purpose of a security deposit is to ensure that monthly bills are paid on time and to cover any outstanding arrears at the time the customer ceases to be a residential gas service customer. If the Company were to forego its right to charge security deposits for any reason, the risk to bad debt would be borne by all customers and security deposits are charged to protect and minimize impacts to rates for all customers.* *Security deposits may be required of new customers or customers who have had their gas service disconnected for non-payment. Security deposits are billed on the first monthly invoice and are due by the Late Payment Effective Date. Enbridge will work with the customers based on individual circumstances and has already agreed to a business process change in its Customer Service Policies to allow for a payment arrangement for the payment of a security deposit over a period of up to six months in the case of a new customer.* *Enbridge also already offers a number of ways to have security deposits waived:* *(1) the Customer provides a letter of reference;* *(2) the Customer enrolls in Enbridge's Pre-Authorized payment plan; or* *(3) the Customer has a previous residential account with good payment history.*

	In addition, Enbridge has already agreed to amend its Customer Service Polices to have its CIS review customers' security deposits after 12 months from the month it is fully paid to determine if the deposit should be refunded, rather than 24 months as it is today. Such a change will result in customers having their security refunded for good payment history sooner than in the past.

3. **Correction of Billing Errors:** Eligible low-income customers may pay under-billing adjustments over an extended period of time depending on the under-billed amount.

New Low-Income Code Provisions for Electricity Distributors	**Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers**
When a billing error has occurred and an eligible low-income customer owes their electricity distributor for an underpayment, they may elect to pay over: i) a period equal to the duration of the billing error (up to a maximum of 2 years); or ii) a period of 10 months where the under-billed amount is less than twice the customer's average monthly bill and over a period of 20 months where the under-billed amount equals or exceeds twice the customer's average monthly bill. Distributors shall advise customers of these options.	*Enbridge's current policies and practices meet the intent of this rule. The Company is proposing no additional changes to policies and practices for low income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers. If a customer is under-billed for any reason, the charge is applied to the account. If the customer chooses to pay the under-billed amount in installments, Enbridge will work with the customer to determine a suitable payment arrangement based on that customer's circumstances. Enbridge will allow for a payment arrangement of up to the amount of time the customer was under-billed.* *In addition, Enbridge has already agreed to amend its policies for processing over or under-billing adjustments. Billing Adjustments will only be permitted over a period of up to two years for residential customers, except in the case of theft or illegal acts of a customer, in which case Enbridge will bill as far back as the information available will allow. Such a change will result in a limit to the amounts that can be back-billed.*

4. **Equal Payment and Equal Billing Plans:** Distributors must offer to eligible low-income customers equal billing plans that do not require automatic payment withdrawals.

New Low-Income Code Provisions for Electricity Distributors	**Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers**
If the eligible low-income customer's electricity distributor bills monthly, they may request an equalized monthly billing plan	*Enbridge's current policies and practices meet the intent of this rule. The Company is proposing no additional changes to*

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 8, Schedule 14, Attachment C, Page 16 of 24

without enrolling in an automatic withdrawal payment plan. If their electricity distributor bills bi-monthly, they must be offered either a monthly or bi-monthly equal billing option.	*policies and practices for low income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers. Enbridge already offers customers the Budget Billing Plan ("BBP"), which is a program that helps spread annual gas costs evenly throughout the year. Enbridge does not require any of its customers joining its BBP to also sign up for an automatic withdrawal payment plan.* *In addition, Enbridge has already agreed to amend its Customer Service Policies to allow customers in arrears to join the Company's BBP. Enbridge customers who are in arrears and have entered into a payment arrangement will be permitted to join the BBP.*

5. Disconnection for Non-payment

5a) Disconnection Period: A distributor must extend the disconnection notice period if the distributor is notified that a customer is being assessed for emergency financial assistance.

New Low-Income Code Provisions for Electricity Distributors	**Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers**
Eligible low-income customers must be granted a disconnection suspension for 21 days after their electricity distributor is notified by a Social Service or Government Agency that they are being assessed for Emergency Financial Assistance.	*Enbridge's current policies and practices meet the intent of this rule. The Company is proposing no additional changes to policies and practices for low income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers.* *Disconnection action is suspended if there is notification from a social assistance agency of assessment of a customer's eligibility for payment assistance. Enbridge works with the customer on their individual circumstances; however, Enbridge has already agreed to amend its Customer Service Policies such that when Enbridge is notified by a registered charity, government agency, social service agency or a third party that an assessment or arrangement for payment is in process, disconnection action will be suspended for a period of 21 days.*

5b) Assistance Information before Disconnection: Disconnection Notices must inform customers that Emergency Financial Assistance and special arrears agreements may be available to eligible low-income customers.

New Low-Income Code Provisions for Electricity Distributors	**Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers**
Information provided in the written Disconnection Notice, and in the telephone call 48 hours before disconnection, must include references to the special arrears payment agreement available for eligible low-income customers. The Disconnection Notice,	*Enbridge's current policies and practices largely meet the intent of this rule. The Company is proposing a minor edit to the Disconnection Notice for all customers. The Disconnection Notice currently includes the date that the notice is issued, the*

and telephone call 48 hours before disconnection, must also inform customers that Emergency Financial Assistance may be available for eligible low-income customers, and that more information is available from their electricity distributor.	*overdue amount to be paid, the forms of payment available at this late stage of collections and the phone number to call to report a payment and avoid disconnection.* *In addition, Enbridge has already agreed to a system change to the information provided on a Disconnection Notice. The Disconnection Notice will be updated to include the earliest and latest date disconnection may occur, that Enbridge will work with the customer to arrange a suitable payment arrangement based on the customer's circumstances and to advise the customer that a disconnection may take place at any time whether or not the customer is home at the time.* *Enbridge is also proposing to include information on Emergency Financial Assistance that may be available for eligible low-income customers in its Disconnection Notice and call before redlock.*

6. Arrears Management Programs

6a) Down-Payment: A low-income arrears payment agreement is subject to a reduced down payment requirement.

New Low-Income Code Provisions for Electricity Distributors	Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers
A down payment of up to 10% of the electricity charges accumulated plus any accumulated late payment charges (not including other service charges such as reconnection charges) may be requested the first time an eligible low-income customer enters into a low-income customer arrears agreement or after having successfully completed a previous such agreement.	*Enbridge's current policies and practices meet the intent of this rule. The Company is proposing no additional changes to policies and practices for low-income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers. Down payment requirements and length of payment arrangements are arranged based on the individual circumstances of each customer.*

6b) Repayment Time Periods: Eligible low-income customers are provided with extended periods of time to pay arrears depending on the amount owned.

New Low-Income Code Provisions for Electricity Distributors	Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers
The time periods to repay arrears are extended to: • 8 months if the amount owed is less than or equal to 2 times the customer's average monthly bill; • 12 months if the amount owed is more than 2 and less than or equal to 5 times the customer's average monthly bill; or • 16 months if the amount owed is more than 5 times the customer's average monthly bill.	*Enbridge's current policies and practices meet the intent of this rule. The Company is proposing no additional changes to policies and practices for low-income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers. If a customer is in arrears for any amount, Enbridge will work with the customer to determine a suitable payment arrangement based on that customer's circumstances and will also allow for multiple payment arrangements in a year. Enbridge believes that imposing timelines for payment arrangements is not in the best interest of the customer over the longer term and creates an artificial budget for the customer and promotes potentially*

	overextending themselves even further. In addition, given that Enbridge will offer payment arrangements more frequently then this rule stipulates, the Company is more flexible now when working with customers and such a rule could limit the Company's ability to work with customers based on their circumstances.

6c) Service charges and late payment charges: Distributors are required to waive any non-payment related service charges and to not apply any additional late payment charges when an eligible low-income customer enters into an arrears agreement.

New Low-Income Code Provisions for Electricity Distributors	Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers
Where an eligible low-income customer enters into an arrears payment agreement with a distributor for the first time or subsequent to having successfully completed a previous arrears payment agreement as an eligible low-income customer, the distributor must waive any service charges specifically related to collection, disconnection, non-payment or load control devices. No further late payment charges may be imposed on an eligible low-income customer after the customer has entered into an arrears payment agreement in respect of the amount that is the subject of that agreement. However, the distributor is not required to waive any late payment charges that accrue to the date of the arrears agreement.	*Enbridge's current policies and practices are different from this rule. The Company is proposing changes to collections messaging for all customers to communicate our policy of working with customers in all stages of arrears.* *Enbridge works with customers to develop suitable payment arrangements for them based on their individual circumstances. The Company believes that it is appropriate for all customers, whose actions result in the Company incurring costs related to collections, disconnection and non-payment, be accountable for the payment of those charges. Most of these costs could be avoided by prompt action on the part of the customer, for example, calling the Company at the time they know that payment will be difficult. This would avoid additional collections and potentially disconnection costs from being incurred. The Company believes that the posting of Customer Service Policies on its website will facilitate and encourage customers to call and notify the Company of payment issues.* *Enbridge is proposing to change messaging provided to customers in arrears throughout the collections process to encourage them to call the Company so that we can work with them to educate them on services, funding available and negotiate payment arrangements. There are currently 7 touchpoints with the customer before a disconnection work order is initiated. These include outbound calls, messages on the bill and notices. . Updates to the communications will be implemented for all customers.*

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 8, Schedule 14, Attachment C, Page 22 of 24

6d) Payment Defaults: Eligible low-income customers must be allowed two payment defaults before a distributor may cancel an arrears agreement.

New Low-Income Code Provisions for Electricity Distributors	Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers
Eligible low-income customers must be allowed two payment defaults before a low-income arrears agreement can be cancelled. The defaults must occur over at least 2 months.	*Enbridge's current policies and practices largely meet the intent of this rule. The Company is proposing no additional changes to policies and practices for low-income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers.* *Payment arrangements can be over days or over months. Enbridge has already agreed to a system change to issue a cancellation notice in writing to customers who miss a payment in a payment arrangement advising them that the cancellation of the payment arrangement will take place 10 days later. Such change will result in the customer being notified and allowing them sufficient time to contact the Company and amend their payment arrangement as needed. Again, we will work with the customer based on their individual circumstances.*

6e) Second or Further Arrears Payment Agreement: Eligible low-income customers are allowed to request a new arrears payment agreement after they have successfully completed a payment agreement. Depending upon the circumstances, the second arrears agreement may be a standard one or enhanced one.

New Low-Income Code Provisions for Electricity Distributors	Gas Distributors' Current and Proposed Modified Policies and Practices for Eligible Low-Income Customers
If an eligible low-income customer successfully completes an arrears payment agreement, the customer can request a new agreement anytime needed thereafter. However, if a new agreement is requested within 12 months of the end of the prior successfully completed agreement, the distributor can offer the new agreement on the same terms as those provided to other residential customers even if the customer is an	*Enbridge's current policies and practices meet the intent of this rule. The Company is proposing no additional changes to policies and practices for low-income customers and we believe that the Customer Service Policies and modifications already agreed to will be sufficient to protect all customers. If a customer is in arrears for any amount, Enbridge will work with the customer to determine a suitable payment arrangement*

Filed: 2011-11-16, EB-2011-0277, Exhibit I, Tab 8, Schedule 14, Attachment C, Page 23 of 24

eligible low-income customer.	*based on that customer's circumstances and will also allow for multiple payment arrangements in a year. Enbridge already offers payment arrangements more frequently than this rule stipulates, and such a rule could limit the Company's ability to work with customers based on their circumstances.*

VECC INTERROGATORY #15

INTERROGATORY

References: Exhibit B, Tab 5, Schedule 1, pages 1 and 2.
Exhibit C Tab 1 Schedule 1 Page 5

a) Provide full details (breakdown) of revenues and expenses related to the 2011 TSDA Balance - ($3,620,800) plus interest ($41,500).

b) Compare to 2010 TSDA and

c) 5 year TSD history 2008-2011.

RESPONSE

a) – c) Please see the following table.

2007	Storage Optimization $(000's)	Pipeline Optimization $(000's)	Total Revenue $(000's)
Net Revenue	10,302.0	9,902.1	20,204.1
Rate Payer - %	90.00%	75.00%	
Rate Payer - $(000's)	9,271.8	7,426.6	16,698.4
Amount Included in Rates			(8,000.0)
Amount Transferred to TSDA			8,698.4

2008	Storage Optimization $(000's)	Pipeline Optimization $(000's)	Total Revenue $(000's)
Net Revenue	8,589.1	8,994.4	17,583.5
Rate Payer - %	90.00%	75.00%	
Rate Payer - $(000's)	7,730.2	6,745.8	14,475.0
Amount Included in Rates			(8,000.0)
Amount Transferred to TSDA			6,476.0

Witnesses: K. Culbert
A. Kacicnik
D. Small

2009	Storage Optimization $(000's)	Pipeline Optimization $(000's)	Total Revenue $(000's)
Net Revenue	9,850.1	8,262.7	18,112.8
Rate Payer - %	90.00%	75.00%	
Rate Payer - $(000's)	8,865.1	6,197.0	15,062.1
Amount Included in Rates			(8,000.0)
Amount Transferred to TSDA			7,062.1

2010	Storage Optimization $(000's)	Pipeline Optimization $(000's)	Total Revenue $(000's)
Net Revenue	8.960.6	9,599.9	18,560.5
Rate Payer - %	90.00%	75.00%	
Rate Payer - $(000's)	8,064.5	7,199.9	15,264.5
Amount Included in Rates			(8,000.0)
Amount Transferred to TSDA			7,264.5

2011 - Estimate	Storage Optimization $(000's)	Pipeline Optimization $(000's)	Total Revenue $(000's)
Net Revenue	2,249.8	12,794.7	15,044.5
Rate Payer - %	90.00%	75.00%	
Rate Payer - $(000's)	2,024.8	9,596.0	11,620.8
Amount Included in Rates			(8,000.0)
Amount Transferred to TSDA			3,620.8

Witnesses: K. Culbert
A. Kacicnik
D. Small

N – Settlement Agreement

Draft Rate Order

Decision and Order