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

Robert Bourke
Manager Regulatory Proceedings
phone: (416) 495-5616
fax: (416) 495-6072
Email: Robert.Bourke@enbridge.com

ENBRIDGE

April 16, 2010

VIA 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.
2009 Earnings Sharing Mechanism and Other Deferral
And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2010-0042**

Enclosed are two paper copies and one electronic copy on CD, of an Application and supporting evidence by Enbridge Gas Distribution Inc. for an order approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

This information has been filed through the Board's RESS system today.

Enbridge Gas Distribution will provide the Application materials on the Company's website @ www.enbridge.com/ratecase as of April 17, 2010.

Yours truly,

Robert Bourke

Robert Bourke
Manager, Regulatory Proceedings

Cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2009-0172 (via email)

EXHIBIT LIST

A – ADMINISTRATIVE

Exhibit	Tab	Schedule	Contents	Witness(es)
A	1	1	Exhibit List	R. Bourke
	2	1	Application	F. Cass
	3	1	Approvals Requested	K. Culbert
	4	1	Curriculum Vitae	R. Bourke

B – 2009 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	ESM Calculations	K. Culbert
		2	ESM Calculations and Required Rate of Return 2009 Historical Year	K. Culbert
		3	Utility Earnings – Comparison of 2009 Historical Year to 2007 Board Approved	K. Culbert
		4	Utility Earnings – Reconciliation of 2009 Utility Income to Audited EGDI Consolidated Income	K. Culbert
	2	1	Ontario Utility Rate Base – Comparison of 2009 Historical Year to 2008 Historical Year	K. Culbert
		2	Ontario Utility Rate Base – Comparison of 2008 Historical Year to 2007 Historical Year	K. Culbert
		3	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2009 Historical Year	K. Culbert

EXHIBIT LIST

B – 2009 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	2	4	Comparison of Utility Capital Expenditures 2009 Historical Year to 2008 Historical Year	L. Au D. Kelly
		5	Comparison of Utility Capital Expenditures 2008 Historical Year to 2007 Historical Year	L. Au D. Kelly
	3	1	Utility Operating Revenue 2009 Historical Year	K. Culbert
		2	Comparison of Gas Sales and Transportation Volume by Rate Class 2009 Historical Year to 2009 Board Approved Budget	I. Chan
		3	Comparison of Gas Sales and Transportation Revenue by Rate Class 2009 Historical Year to 2009 Board Approved Budget	I. Chan
		4	Customers, Volumes and Revenues by Rate Class 2009 Actual	I. Chan
		5	Details of Other Revenue 2009 Historical Year to 2008 Historical Year	R. Lei
		6	Details of Other Revenue 2008 Historical Year to 2007 Historical Year	R. Lei
	4	1	Operating Cost 2009 Historical Year	K. Culbert
		2	Operating and Maintenance Expense by Department Ending December 2009	R. Lei
	5	1	Required Rate of Return 2009 Historical Year	K. Culbert

EXHIBIT LIST

B – 2009 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	5	2	Utility Income 2009 Historical Year	K. Culbert
		3	Cost of Capital 2009 Historical Year	K. Culbert

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	1	Balances Requested for Clearance at July 1, 2010	K. Culbert
		2	Gas Distribution Access Rule Cost Deferral Account explanation	K. Culbert
		3	Municipal Permit Fees Deferral Account explanation	K. Culbert
		4	Tax Rate and Rule Change Variance Account explanation	K.Culbert
		5	Average Use True Up Variance Account explanation	I. Chan
		6	2009 OHCVA	K. Culbert
	2	1	Clearance of 2009 Deferral and Variance Account Balances	J. Collier A. Kacicnik M. Suarez-Sharma
		2	Derivation of Proposed Unit Rates	J. Collier A. Kacicnik M. Suarez-Sharma

EXHIBIT LIST

D – REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	Enbridge Gas Distribution Inc. Consolidated Financial Statements December 31, 2009	N. Kishinchandani
		2	Enbridge Gas Distribution Inc. Management's Discussion and Analysis – December 31, 2009	N. Kishinchandani

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Sched. B), as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

A P P L I C A T I O N

1. The Applicant, Enbridge Gas Distribution Inc. ("Enbridge", or the "Company") is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. Enbridge hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the *Ontario Energy Board Act, 1998* (the "Act"), as amended, for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

3. As of January 1, 2010, Enbridge began the third year of a five year Incentive Regulation plan ("IR Plan") approved by the Board in EB-2007-0615. The Board-approved Settlement Agreement in EB-2007-0615 (the "Settlement Agreement") provides that Enbridge shall maintain the deferral and variance accounts listed in Appendix B to the Settlement Agreement for the term of the IR Plan. Since that time, there have been several new deferral and variance accounts approved. The Board's Supplementary Order in EB-2008-0219 approved the establishment of Enbridge's deferral and variance accounts for 2009. The balances contained in some of those

accounts have been approved by the Board, while the balances in other accounts have not yet been reviewed by the Board.

4. The Settlement Agreement provides that clearance of Board-approved balances in Enbridge's deferral and variance accounts will occur in conjunction with each following fiscal year's July 1st Quarterly Rate Adjustment Mechanism ("QRAM") proceeding.

5. The Settlement Agreement specifically addresses the Earnings Sharing Mechanism Deferral Account ("ESMDA") and requires an application by Enbridge to the Board in respect of that account. In this regard, the Settlement Agreement states as follows:

> …Enbridge agrees to prepare an ESM calculation that pertains to each year of the Term of the IR Plan following the release of its audited financial statements for that year. Enbridge will file this calculation (and an application for disposition of any amounts recorded in the ESMDA) as soon as is reasonably possible after year-end financial results have been made public, with the intention of clearing the ESMDA no later than the time of Enbridge's July 1 QRAM. The Parties agree that stakeholders, including all Parties, should have a reasonable opportunity to review the application and calculations, including the ability to make reasonable requests for additional information with respect thereto from Enbridge, and to make submissions or provide comments thereon.

6. Clearance of Enbridge's deferral and variance accounts in conjunction with its July 1, 2010 QRAM Application would be very difficult to implement as that is the same date on which the Company must implement the provincial government's new Harmonized Sales Tax ("HST"). Enbridge requests that it be permitted to clear the

balances in its 2009 deferral and variance accounts as approved in this proceeding in conjunction with its October 1, 2010 QRAM Application.

7. Enbridge therefore applies to the Board for such final, interim or other Orders as may be necessary or appropriate for the clearance or disposition of the 2009 ESMDA and the other 2009 deferral and variance accounts listed in Appendix A to this Application.

8. Enbridge further applies to the Board pursuant to the provisions of the Act and the Board's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

9. Enbridge requests that a copy of every document filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Mr. Norm Ryckman
Director, Regulatory Affairs
Enbridge Gas Distribution Inc.

Address for personal service:	500 Consumers Road Willowdale, Ontario M2J 1P8
Mailing address:	P. O. Box 650 Scarborough, Ontario M1K 5E3
Telephone:	416-495-5499 or 1-888-659-0685
Fax:	416-495-6072
Email:	EGDRegulatoryProceedings@enbridge.com

The Applicant's counsel:

Mr. Fred D. Cass
Aird & Berlis LLP

Address for personal service and mailing address	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-865-7742
Fax:	416-863-1515
Email:	fcass@airdberlis.com

DATED April 16, 2010 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: ______________________

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

			Col. 1	Col. 2	Col. 3	Col. 4
			Actual at February 28, 2010		Forecast for clearance at October 1, 2010	
Line No.	Account Description	Account Acronym	Principal	Interest	Principal	Interest
			($000's)	($000's)	($000's)	($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2008 DSMVA	(73.3)	(56.1)	(73.3)	(56.3)
2.	Lost Revenue Adjustment Mechanism	2008 LRAM	37.3	0.1	37.3	0.2
3.	Shared Savings Mechanism V/A	2008 SSMVA	5,803.2	5.3	5,803.2	24.2
4.	Class Action Suit D/A	2009/10 CASDA	18,838.2	1,534.4	4,709.5	414.1 [1]
5.	Deferred Rebate Account	2009 DRA	2.7	(0.1)	-	-
6.	Gas Distribution Access Rule Costs D/A	2009 GDARCDA	188.7	0.8	2,838.8	- [2]
7.	Ontario Hearing Costs V/A	2009 OHCVA	531.7	0.6	474.5	2.0
8.	Open Bill Service D/A	2009/10 OBSDA	526.2	15.9	87.7	3.0 [3]
9.	Open Bill Access V/A	2009/10 OBAVA	476.7	5.9	79.5	1.2 [3]
10.	Municipal Permit Fees D/A	2009 MPFDA	916.1	-	202.2	- [2]
11.	Average Use True-Up V/A	2009 AUTUVA	5,626.9	5.2	5,626.9	23.4 [4]
12.	Tax Rate and Rule Change V/A	2009 TRRCVA	(350.0)	(0.3)	(350.0)	(1.7) [5]
13.	Earnings Sharing Mechanism D/A	2009 ESMDA	(18,750.0)	(17.2)	(19,300.0)	(77.4) [6]
14.	IFRS Transition Costs D/A	2009 IFRSTCDA	2,111.0	1.9	2,111.0	8.9
15.	Ex-Franchise Third Party Billing Services D/A	2009 EFTPBSDA	(27.9)	-	(27.9)	(0.1)
16.	Total non commodity related accounts		15,857.5	1,496.4	2,219.4	341.5
	Commodity Related Accounts					
17.	Purchased Gas V/A	2009 PGVA	(116,672.9)	(2,287.8)	(39,270.0)	(2,497.4) [7]
18.	Transactional Services D/A	2009 TSDA	(7,062.1)	(9.5)	(7,062.1)	(31.9)
19.	Unaccounted for Gas V/A	2009 UAFVA	9,596.7	8.8	9,596.7	39.6
20.	Storage and Transportation D/A	2009 S&TDA	(1,594.8)	(4.6)	(1,594.8)	(9.5)
21.	Total commodity related accounts		(115,733.1)	(2,293.1)	(38,330.2)	(2,499.2)
22.	Total Deferral and Variance Accounts		(99,875.6)	(796.7)	(36,110.8)	(2,157.7)

Notes:

1. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years (2008 - 2012). The 2008 installment was cleared in July and August 2008, and the 2009 installment will occur in April and May 2010. The Company now proposes to clear the 2010, or third installment, beginning October 1, 2010. The forecast of interest to be cleared, utilized the Board's current prescribed interest rate for deferral accounts for (Q2 2010) but will be updated with future prescribed rates as well.
2. The forecast 2009 GDARCDA and 2009 MPFDA amounts for clearance are the result of revenue requirement calculations. (Found in evidence at Ex.C, T1, S2 and Ex.C, T1, S3)
3. The forecast OBSDA and OBAVA balances are in accordance with the EB-2009-0043 approved settlement agreement.
4. The AUTUVA explanation is found in evidence at Ex.C, T1, S5.
5. The TRRCVA explanation is found in evidence at Ex.C, T1, S4.
6. The ESMDA explanation is found in evidence at Ex.B, T1, S1&2.
7. This is a projected final 2009 PGVA balance. The actual balance proposed for clearance will be determined, and updated, once the impact of the existing rate Rider "C", in place until March 31, 2010, is determined.

APPROVALS REQUESTED

1. With the filing of this application, the Company is requesting that the Board approve the clearance of deferral and variance accounts in accordance with the following:

   a) The Company has filed the balances at February 28, 2010, of Board approved deferral and variance accounts and is requesting approval for their clearance, (Exhibit C, Tab 1, Schedule 1). The Company's approved Incentive Regulation ("IR") methodology anticipates the clearance of Board Approved balances within the accounts to commence in July, 2010. While the IR agreement anticipated that each year a July clearance of deferral and variance accounts would occur, it was not possible to anticipate extenuating circumstances which could affect the timing of future clearance.

   b) Commencing July 1, 2010 EGD is required to implement the legislated Harmonized Sales Tax. In preparing for and implementing the HST, there will be considerable financial and billing system testing and analysis that EGD will encounter over the next five to six months. As a result, EGD has determined that attempting to clear deferral and variance accounts at the same time could result in potential billing complications and errors. As a result, the Company is proposing to clear these deferral and variance account balances in October, 2010. Clearance of the balances is proposed as a one time rider adjustment to customers' bills coincident with the Company's October 1, 2010 Quarterly Rate Adjustment Mechanism filing associated with any required rate adjustments with respect to changes in natural gas prices.

c) Included within the deferral and variance account balances requested for clearance is the 2009 Earnings Sharing Mechanism Deferral Account ("ESMDA"). Evidence in support of the Earnings Sharing calculation and EGD's Fiscal 2009 financial statements are filed within Exhibit B, Tabs 1 through 5 and Exhibit D, Tab 1.

d) The impacts of the clearance of the total deferral and variance account balances by rate class are provided in evidence at Exhibit B, Tab 6, Schedules 1 and 2.

e) In order to facilitate the clearance of the deferral and variance accounts in the Company's October 1, 2010 QRAM proceeding, a Board Decision granting approval is required by approximately August 1st, 2010.

2. The Board Approved Settlement Agreement in EB-2007-0615 set out a timeline for the process of the review and clearance of previously approved deferral and variance accounts. Included within the agreement was the requirement of EGD to provide the results of its annual Earnings Sharing calculations for review by the Board and stakeholders as soon as reasonably possible following the completion of EGD's audited year end results approved for public release.

3. The Company has filed the ESM calculations within this application at Exhibit B, Tab 1, Schedules 1 and 2. The Company will work with the Board and stakeholders in determining the timelines of next steps to be incorporated into a Procedural Order to be issued by the Board.

CURRICULUM VITAE OF
LINDA AU

Experience: Enbridge Gas Distribution Inc.

Capital Budget Manager
2007

Capital Budget Supervisor
1995

Revenue and Gas Cost Analyst
1991

Canada Post Corporation

Operations Planning and Budget Officer
1990

Financial Analyst
1988

Queen Elizabeth Hospital

Senior Accountant
1986

Education: Certified General Accountant
CGA Ontario 1991

Bachelor of Business Management
Ryerson 1986

Appearances: (Ontario Energy Board)
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2006-0034
RP-2005-0001

CURRICULUM VITAE OF
ROBERT ALAN BOURKE, CMA

Experience: Enbridge Gas Distribution Inc.

Manager Regulatory Proceedings
2004

Manager Budget and Administration – Operations
2003

Manager Regulatory Accounting
1998

Senior Analyst Regulatory Accounting
1995

Supervisor Revenue and Gas Cost
1992

Centra Gas (Ontario) Inc.

Supervisor, Budget Administration
1992

Thornhill Glass & Mirror Inc.

Controller
1988

The Consumer Gas Company Limited

Manager System Customer Billing
1987

Management Trainee
1986

Supervisor Income and Cash Budget
1982

Asst. Supervisor Income and Cash Budget
1980

Education: Certified Management Accountant (CMA), 1981

Memberships: The Society of Management Accountants Ontario

Appearances: (Ontario Energy Board)
EB-2009-0172
EB-2008-0219
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0001
EBRO 497
EBO 179-14/15

CURRICULUM VITAE OF
IRENE CHAN

Experience: Enbridge Gas Distribution

Manager, Margin Accounting, Business Performance and Analytics
2010

Manager, Margin Budgets and Accounting
2007

Manager, Margin Planning and Analysis
2006

Manager, Volumetric Analysis and Budgets
2003

Supervisor, Volumetric Analysis
2001

Senior Analyst, Volumes Knowledge Centre
2000

Economic Analyst, Economic Studies
1998

Queen's University

Instructor, Economics Department
1997

Research/Teaching Assistant, Economics Department
1992-1997

International Monetary Fund

Summer Intern, Research Department
1996

Consultant, Research Department
1994

Bank of Canada

Research Assistant, Research Department
1991

Education:	Certified Management Accountant, The Society of Management Accountants of Canada, 2006
	Ph.D. in Economics Queen’s University, 1998
	Master of Arts in Economics Queen’s University, 1993
	Bachelor of Arts (Honours) in Economics University of Western Ontario, 1991
Memberships:	Toronto Association for Business & Economics The Society of Management Accountants of Canada
Appearances:	(Ontario Energy Board) EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2007-0615 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2002-0133

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Design
2003

Manager, Rate Research
2000

Senior Rate Research Analyst
1996

Centra Gas Ontario Inc.

Manager, Rate Design
1995

Supervisor, Cost of Service Studies
1990

Education: Bachelor of Business Management
Ryerson Polytechnical Institute, 1988

Appearances: (Ontario Energy Board)
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
EBRO 489
EBRO 474-B, 483,484
EBRO 474-A
EBRO 474
EBRO 471

(Régie de l'énergie/Régie du gaz naturel)
R-3692-2009
R-3665-2008
R-3637-2007
R-3621-2006
R-2587-2005
R-3537-2004
R-3464-2001
R-3446-2000

CURRICULUM VITAE OF
KEVIN CULBERT

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
Current

Manager, Regulatory Accounting
2003

Senior Analyst, Regulatory Accounting
1998

Analyst, Regulatory Accounting
1991

Assistant Analyst, Regulatory Accounting
1989

Budgets – Capital Clerk, Budget Department
1987

Accounting Trainee, Financial Reporting
1984

Education: CMA (3rd level)
Seneca College 1987-89 (business/accounting)

Appearances: (Ontario Energy Board)
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0104/EB-2008-0408
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203

CURRICULUM VITAE OF
ANTON KACICNIK

Experience:	Enbridge Gas Distribution Inc.
	Manager, Rate Research & Design 2007
	Manager, Cost Allocation 2003
	Program Manager, Opportunity Development 1999
	Project Supervisor, Technology & Development 1996
	Pipeline Inspector, Construction & Maintenance 1993
Education:	Bachelor of Applied Science (Civil Engineering) University of Waterloo, 1996
Memberships:	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board) EB-2009-0172 EB-2009-0055 EB-2008-0106 EB-2008-0219 EB-2007-0615 EB-2007-0724 EB-2006-0034 EB-2005-0551 EB-2005-0001
	(RÉGIE DE L'ÉNERGIE) R-3621-2006 R-3587-2006 R-3537-2004

CURRICULUM VITAE OF
D. A. KELLY

Experience: Enbridge Gas Distribution Inc.

Manager, Capital Budgets and Accounting
2007

Manager, Operational and Capital Budgets
2005

Manager, Cost Awareness and Analysis
2001

Senior Analyst, Operation and Maintenance
2000

Supervisor, Management Reporting
1997

Supervisor, Corporate Reporting
1992

Analyst, Financial Reporting
1991

Supervisor, Non-Utility Accounting
1989

Financial Statements Accountant
1988

Internal Audit Assistant
1987

Accounting Trainee
1985

Another Company

Corporate Loans, Guaranty Trust
1983

General Accounting, Consumers Glass
1981

Education: Bachelor of Business Management
Ryerson University, 1985

Certified Management Accountant
Society of Management Accountants, 1987

Memberships: Society of Management Accountants of Ontario

Appearances: (Ontario Energy Board)
EB-2005-0001
RP-2002-0133
RP-2001-0032

CURRICULUM VITAE OF
NARIN KISHINCHANDANI

Experience: Enbridge Gas Distribution Inc.

Director, Finance & Control
2006

Chief Accountant
2005

Manager, Financial Reporting and Analysis
2003

Supervisor, Internal Reporting
2002

Senior Financial Analyst
2001

V. Dewan & Co, Chartered Accountants, Thornhill, ON

Senior Associate
1997

Mettle Financial Services Pvt. Ltd., Mumbai, India

Consultant
1995

Credit & Commerce Finance Ltd., Nairobi, Kenya

Financial Controller
1993

Across Africa Safaris Ltd., Nairobi, Kenya

Financial Controller
1991

20th Century Finance Corporation, Mumbai, India

Assistant Manager, Leasing
1990

Education:	Certified General Accountant Certified General Accountants of Ontario, 2001
	Certified Public Accountant State of Colorado (Board of Accountancy), 2000
	Chartered Accountant (India) Institute of Chartered Accountants of India, 1991
	Master of Business Administration Syracuse University, NY, 1989
	Bachelor of Business Administration United States international University, CA, 1987
	Bachelor of Commerce University of Bombay, India, 1984
Memberships:	Certified General Accountants of Ontario State of Colorado (Board of Accountancy) - Certified Public Accountant Institute of Chartered Accountants of India
Appearances:	(Ontario Energy Board) EB-2009-0172 EB-2008-0219

CURRICULUM VITAE OF
RAYMOND LEI

Experience:	Enbridge Gas Distribution Inc.
	Manager, Budgets and Business Support 2010
	Manager, Corporate Budgets and Analysis 2007
	Manager, Financial Analysis 2007
	Senior Analyst, Planning and Projects 2005
	Rogers Wireless Inc.
	Senior Analyst, Budgets and Forecast 2001
	Royal LePage Relocation Services Ltd.
	Financial Analyst 2000
	Kodak (China) Limited
	Business Analyst 1995
Education:	Certified General Accountant Certified General Accountants of Ontario, 2005
	Master of Business Administration York University, 2000
	Bachelor of Arts in Commerce and Economics Sichuan University, China
Memberships:	Certified General Accountant, Ontario
Appearances:	(Ontario Energy Board) EB-2009-0172

CURRICULUM VITAE OF
MARGARITA SUAREZ-SHARMA

Experience: Enbridge Gas Distribution Inc.

Manager, Cost Allocation
2008

Manager, DSM Reporting & Analysis
2005

Analyst, Rate Design
2004

Senior Analyst, DSM Planning and Evaluation
2002

Senior Economic Analyst, Economic & Financial Studies
1998

The Canadian Institute

Conference Producer
1997

Margaret Chase Smith Center for Public Policy

Research Assistant
1995

Education: Master of Arts in Economics
University of Maine, 1995

Bachelor of Arts in Economics
University of Maine, 1993

Appearances: (ONTARIO ENERGY BOARD)
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106

(RÉGIE DE L'ÉNERGIE)
R-3665-2008
R-3692-2009

2009 EARNINGS SHARING AMOUNT
AND DETERMINATION PROCESS

1. Included within Enbridge Gas Distribution Inc's. fiscal 2009 year end audited financial statement results, is a utility related earnings sharing accrual of $18.75 million. At the time of the accrual within the financial statements, estimates of background information supporting the accrual are sometimes required in meeting year end timing obligations. Following the close of year end processing, an analysis of the impact of weather normalization on volumes and gas in storage resulted in a revision to the earnings sharing calculation, which is now $19.3 million.

2. The amounts for utility purposes for each of the cost elements of rate base, utility income and taxes, and the capital structure components, which were used in the calculation of the earnings sharing amount, are summarized within Exhibit B, Tab 1, Schedule 2.

3. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2007-0615 Board Approved Settlement Agreement (Ex. N1, T1, S1, p. 27);
   - if in any calendar year, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated annually by the application of the Board's ROE Formula in any year of the IR Plan, then the resultant amount shall be shared equally (ie., 50/50) between Enbridge and its ratepayers;
   - for the purposes of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings;

- all revenues that would otherwise be included in revenue in a cost of service application shall be included in revenues in the calculation of the earnings calculation and only those expenses (whether operating or capital) that would be otherwise allowable as deductions from earnings in a cost of service application, shall be included in the earnings calculaton;

4. In the EB-2007-0615 Settlement Agreement the Parties acknowledge that the following shareholder incentives and other amounts are outside the ambit of the ESM:
   - amounts in respect of the application of the Shared Savings Mechanism ("SSM") and the LRAM;
   - amounts related to storage and transportation related deferral accounts; and
   - the Company's 50% share of the tax amount calculated in association with expected tax rate and rule changes as per the settlement (Ex. N1, T1, S1, p. 23).

5. As shown within the summary of return on equity and earnings sharing determination, Exhibit B, Tab 1, Schedule 2, the Company has calculated earnings for sharing purposes in two ways for confirmation purposes.

6. In part A) of the summary, a return on rate base method is shown, while in part B), a return on equity from a deemed equity embedded within rate base perspective is shown. Column 2 within the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the summary can be found. Column 3 contains results shown in units of millions of dollars or percentages.

Part A)

7. The level of utility income, $309.3 million (Line 19) divided by the level of utility rate base, $3,794.4 million (Line 24) generates a utility return on rate base of 8.151% (Line 25).

8. When compared to the Company's required rate of return of 7.470% (Line 26), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.681% (Line 27) on total rate base.

9. As shown in Lines 28 through 30, the sufficiency of 0.681% multiplied by the rate base of $3,794.4 million, produces a net over earnings or sufficiency of $25.84 million which from a pre-tax perspective, ($25.84 million divided by the reciprocal, 67.0%, of the corporate tax rate) shows an $38.57 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Part B) (Confirming the Calculated Earnings Sharing)

10. Net utility income applicable to common equity is first determined.

11. The $388.0 million (Line 33) of utility income before income tax, less utility taxes of $78.7 million (Line 38), produces the $309.3 million of utility income used in part A) above (at Line 19).

12. In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $309.3 million utility income.

13. These reductions are shown at Lines 34, 35 and 36 which along with the utility income tax reduction already mentioned and shown at Line 38, results in a net income applicable to common equity of $153.0 million, shown at Line 39.

14. The $153.0 million, divided by the deemed common equity level of $1,366.0 million (Line 40, calculated as 36% of the $3,794.4 million rate base) produces a return on equity of 11.20% (Line 42). When comparing the 11.20% achieved return on equity to the threshold ROE percentage of 9.31% (Line 41), which is the Board approved formula return on equity for 2009 of 8.31% plus the approved 100 basis point dead band, there is a sufficiency in ROE of 1.89% (Line 43).

15. The 1.89% multiplied by the common equity level of $1,366.0 million (Line 40) produces a net over earnings or sufficiency of $25.82 million which from a pre-tax perspective, ($25.82 million divided by the reciprocal, 67.0%, of the corporate tax rate) shows an $38.54 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Process Description

16. The calculation of utility earnings and any sharing requirement starts with financial results contained within the EGD Ontario corporate trial balance[1].

17. From there, in order to calculate the Ontario utility rate base, income and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the Board and the standards associated with cost of service rate related accounting processes. Examples are:

[1] EGD Ontario corporate trial balance excludes St. Lawrence Gas

- determination of rate base amounts using the average of monthly averages value concept,
- elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base, and
- elimination of corporate income taxes due to the determination of income taxes specific to utility results,

18. In addition, EGD has made the appropriate adjustments in relation to non standard rate regulated items which the Board has either decided in the past, were agreed to in the EB-2007-0615 approved settlement, or are required in order to determine an appropriate utility return on equity within the Incentive Regulation versus Cost of Service construct. Examples are:

- rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts),
- rate base disallowance from RP-2002-0133 (shared assets),
- exclusion of non-utility or unregulated activities,
- elimination of EGD share of shared savings mechanism,
- elimination of EGD share of transactional services, and
- elimination of EGD share of tax rate and rule changes.

19. As shown in the Column 2 references in the summary exhibit, supporting rate base information is found in Exhibit B, Tab 2, supporting revenue, volumes, customers and cost information is found in Exhibit B, Tabs 3 & 4, and supporting capital structure, required rate of return, utility income, and costs of capital information is found in Exhibit B, Tab 5.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2009

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	Actual Normalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales	(Ex.B,T5,S2,P1,Col.1,line 1)	2,221.6
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	627.7
4.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	1,862.6
5.	Gas Distribution Margin		986.7
6.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	1.6
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	40.9
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	7.5
9.	Total - TC&S, Oth. Rev. & Inc.		50.0
10.	Operations, Maintenance & Administration	(Ex.B,T5,S2,P1,Col.1,line 9)	336.9
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	251.0
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	6.5
13.	Debt redemption premium amortization	(Ex.B,T5,S2,P1,Col.1,line 12)	0.3
14.	Company share of IR agreement tax savings	(Ex.B,T5,S2,P1,Col.1,line 13)	9.6
15.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 14)	44.4
16.	Total O&M, Depr., & other		648.7
17.	Utility Income before Income Tax	(line 5 + line 9 - line 16)	388.0
18.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	78.7
19.	**Utility Income**		**309.3**
20.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	5,500.5
21.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(2,089.5)
22.	Net plant		3,411.0
23.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 12)	383.4
24.	**Utility Rate Base**		**3,794.4**
25.	Indicated Return on Rate Base %	(line 19 / line 24)	8.151%
26.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	7.470%
27.	(Deficiency) / Sufficiency %		0.681%
28.	Net Earnings (Deficiency) / Sufficiency	(line 27 x line 24)	25.84
29.	Provision for Income Taxes		12.73
30.	Gross Earnings (Deficiency) / Sufficiency	(line 28 divide by 67.0%)	38.57
31.	**50% Earnings sharing to ratepayers**	(line 30 x 50%)	**19.28**
32.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
33.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 18)	388.0
34.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	150.4
35.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	2.5
36.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	3.4
37.	Net Income before Income Taxes		231.7
38.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	78.7
39.	Net Income Applicable to Common Equity	(line 37 - line 38)	153.0
40.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	1,366.0
41.	Approved ROE %	(EB-2007-0615 for Earnings Sharing 8.31% + 100 bp)	9.31%
42.	Achieved Rate of Return on Equity %	(line 39 divide by line 40)	11.20%
43.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.89%
44.	Net Earnings (Deficiency) / Sufficiency	(line40 x line 43)	25.82
45.	Provision for Income Taxes		12.72
46.	Gross Earnings (Deficiency) / Sufficiency	(line 44 divide by 67.0%)	38.54
47.	**50% Earnings sharing to ratepayers**	(line 46 x 50%)	**19.27**

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS
FOR FISCAL YEAR 2009

Line No.		Col. 1 2009 Actual Normalized $Millions	Col. 2 2007 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,221.6	2,369.1		
2.	Transportation revenue	627.7	748.8		
3.	Transmission, compression & storage	1.6	1.9		
4.	Gas costs	1,862.6	2,174.6		
5.	Distribution margin	988.3	945.2	43.1	a)
6.	Other revenue	40.9	34.3	6.6	b)
7.	Other income	7.5	0.2	7.3	c)
8.	O&M	336.9	326.2	(10.7)	d)
9.	Depreciation expense	251.0	227.3	(23.7)	e)
10.	Other expense	60.8	56.4	(4.4)	f)
11.	Income taxes	78.7	85.8	7.1	g)
12.	Utility Income	309.3	284.0	25.3	
13.	LTD & STD costs	152.9	165.8	12.9	h)
14.	Preference share costs	3.4	5.0	1.7	h)
15.	Return on Equity @ 9.31%[1] in 2008, 8.39% in 2007	127.2	113.2	(14.0)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	25.9	(0.0)	25.9	
17.	Provision for taxes on Earnings Over / (Under)	12.7	(0.0)	12.7	
18.	Gross Earnings Over / (Under)	38.6	(0.0)	38.6	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,366.0			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	153.0			
21.	EGD normalized Return on Equity	11.20%			

[1] 8.31% as per Board Approved formula using October 2008 consensus forecast, plus 100 basis points as per 2008 incentive regulation Board Approved agreement.

Witness: K. Culbert

2009 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

1. The following are explanations of the Utility Normalized Earnings results as compared to the 2007 Board Approved amounts. The reference letters are in relation to those identified on page 1, Column 4, of this schedule.

   a) The distribution margin change of $43.1 million is mainly the result of the change in revenue derived from EGD's IR framework and formula where forecast cumulative 2009 IR formula revenue was an increase of $48.9 million from the base year DRR amount (beginning amount in 2008 was $753.2 million, ending amount in 2009 was $802.1 million), increases in DSM and Customer Care related Y-Factors versus 2007 Board approved levels and, partially offsetting lower required recoveries of carrying costs of gas in storage and working cash elements due to lower average gas commodity pricing within the 2009 QRAM's versus pricing embedded in 2007 approved rates. This results in a positive impact on earnings.

   b) The other revenue change of $6.6 million is due to increased late payment penalty revenue of $5.9 million, an increase in service charges of $1.4 million and a decrease in other revenue of $(0.7) million. This results in a positive impact on earnings.

   c) The other income change of $7.3 million is mainly due to revenue from the management fee for service, external 3rd party energy efficiency initiatives. This results in a positive impact on earnings.

   d) Utility O&M is $10.7 million above that of the 2007 approved level embedded in base rates used within the incentive regulation escalation formula.

e) For an explanation of the details of utility O&M please see the evidence at Exhibit B, Tab 4, Schedule 2. This results in a reduction in earnings.

f) The increase in depreciation expense of $23.7 million is due to higher levels of property, plant, and equipment associated within customer growth and system improvement activities in both 2008 and 2009, and the implementation of the new CIS system in 2009. The impact of increases in customer growth and system improvement Property Plant and Equipment in 2008 has a full year depreciation increase impact in 2009 while the increases relative to 2009 have a part year impact. The depreciation increases result in a reduction in earnings.

g) Other expenses increase of $4.4 million is the result of an increase in the recognition of EGD's $9.6 million share of the IR agreement tax savings impact within 2009 results, an increase in fixed financing costs of $5.2 million, a decrease from the elimination of the notional utility account amounts versus the 2007 approved level of $9.2 million, and decreases in municipal and capital tax of approximately $1.5 million which is primarily due to decreased capital tax rates as recognized in the IR tax savings agreement. The net result is a reduction in earnings.

h) Income tax changes are the result of the impact on taxable income of the above noted items along with differences in tax add back and tax deductible allowances per the Canada Revenue Agency and a change in the overall corporate income tax rate. This results in a positive impact on earnings.

i) The interest cost of utility long, medium and short term debt and preference share costs changed by $14.6 million relative to 2007 approved levels as a result of lower overall average cost rates. This results in a positive impact on earnings.

RECONCILIATION OF AUDITED EGDI
CONSOLIDATED INCOME TO UTILITY INCOME
2009 HISTORICAL YEAR

Line no.		Col. 1 Audited Consolidated Income ($millions)	Col. 2 Utility Income ($millions)	Col. 3 Difference ($millions)	Col. 4 Reference
1.	Gas commodity and distribution revenue	2,345.9	2,221.6	(124.3)	a)
2.	Transportation of gas for customers	448.8	627.7	178.9	b)
3.		2,794.7	2,849.3	54.6	
4.	Gas commodity and distribution costs	1,769.9	1,862.6	92.7	c)
5.	Gas distribution margin	1,024.8	986.7	(38.1)	
6.	Other revenue	108.4	50.0	(58.4)	d)
7.		1,133.2	1,036.7	(96.5)	
	Expenses				
8.	Operation and maintenance	385.3	336.9	(48.4)	e)
9.	Earnings sharing	18.8	-	(18.8)	f)
10.	Depreciation	254.0	251.0	(3.0)	g)
11.	Municipal and other taxes	49.3	44.4	(4.9)	h)
12.	Company share of IR agreement tax savings	-	9.6	9.6	i)
13.		707.4	641.9	(65.5)	
14.	Income before undernoted items	425.8	394.8	(31.0)	
15.	Financing income	62.7	-	(62.7)	j)
16.	Interest and financing expenses	(189.1)	(6.8)	182.3	k)
17.	Income before income taxes	299.4	388.0	88.6	
18.	Income taxes	77.9	78.7	0.8	l)
19.	Net Income	221.5	309.3	87.8	

RECONCILIATION OF 2009
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	2,345.9	**Consolidated gas commodity and distribution revenue**
	(44.2)	Amounts related to St. Lawrence Gas
	(85.1)	Normalization adjustment
	3.1	Gazifere T-service regrouped to gas commodity and distribution revenue
	1.8	To reverse the impact of the elimination of the 2008 TRRCVA on 2009 utility results
	0.1	Rounding
	2,221.6	**Utility gas commodity and distribution revenue**
b)	448.8	**Consolidated transportation of gas for customers**
	(5.3)	Amounts related to St. Lawrence Gas
	(16.3)	Normalization adjustment
	(3.1)	Gazifere T-service regrouped to gas commodity and distribution revenue
	203.6	Ontario and Western T-Service Credits regrouped to gas costs
	627.7	**Utility transportation of gas for customers**
c)	1,769.9	**Consolidated gas commodity and distribution costs**
	(34.9)	Elimination of amounts related to St. Lawrence Gas and unregulated storage
	(76.0)	Normalization adjustment
	203.6	Ontario and Western T-Service Credits regrouped to gas costs
	1,862.6	**Utility gas commodity and distribution costs**

RECONCILIATION OF 2009
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	108.4	**Consolidated other revenue**
	(12.4)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(10.8)	Open Bill O&M expenses regrouped against program revenues
	(7.3)	ABC admin. and bad debt costs regrouped against program revenues from O&M
	(0.3)	ABC interest charges regrouped against program revenues
	5.7	Allowable interest during construction regrouped to revenues from interest and financing expenses
	0.3	NGV program revenue imputation
	(3.1)	Elimination of transactional services revenue above base amount included in rates
	(1.2)	Elimination of Open Bill revenues to reflect the shareholder incentive
	(1.4)	Elimination of affiliate and 3rd party asset use revenue considered non-utility
	(5.3)	Elimination of net ABC revenue considered non-utility
	(11.1)	Elimination of interest income from investments not included in rate base
	(5.7)	Elimination of allowable interest during construction
	(5.8)	Elimination of shareholders incentive income recorded as a result of calculating the SSMVA amount
	50.0	**Utility other revenue**
e)	385.3	**Consolidated operation and maintenance**
	(11.4)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(10.8)	Open Bill expenses regrouped against program revenues
	(7.3)	ABC admin. and bad debt costs regrouped against program revenues and eliminated
	1.0	Interest on security deposits added to utility O&M
	(0.4)	Elimination of donations
	(1.5)	Elimination of non-utility costs of supporting the ABC program
	(13.1)	Elimination of Corporate Cost Allocations above RCAM amount
	(4.9)	Elimination of CWLP CIS fees in excess of settlement agreement
	336.9	**Utility operation and maintenance**
f)	18.8	**Consolidated earnings sharing**
	(18.8)	Elimination of earnings sharing amount contained in year end financials from utility income calculation
	-	**Utility earnings sharing**
g)	254.0	**Consolidated depreciation**
	(2.7)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(0.2)	Elimination of depreciation on disallowed Mississauga Southern Link
	(0.2)	Elimination of depreciation related to shared assets
	0.1	Rounding
	251.0	**Utility depreciation**

RECONCILIATION OF 2009
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
h)	49.3	**Consolidated municipal and other taxes**
	(2.4)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(0.2)	Elimination of municipal taxes related to shared assets
	(2.3)	Adjustment to convert capital taxes to a utility "stand-alone" basis
	44.4	**Utility municipal and other taxes**
i)	-	**Consolidated IR agreement tax savings**
	9.6	Recognition of the Company's share of IR agreement tax savings on utility income, as determined in EB-2007-0615, and updated in EB-2009-0172
	9.6	**Utility IR agreement tax savings**
j)	62.7	**Consolidated financing income**
	(62.7)	Eliminate non-utility dividend income from the Board Approved financing transaction
	-	**Utility financing income**
k)	189.1	**Consolidated interest and financing expenses**
	(2.5)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(26.8)	Eliminate non-utility interest expense from the Board Approved financing transaction
	5.7	Allowable interest during construction regrouped to revenues and eliminated
	(0.3)	ABC interest charges regrouped against program revenues and eliminated
	(158.3)	Elimination of interest expense and the amortization of issue and debt discount costs which are determined through the regulated capital structure
	(0.1)	Rounding
	6.8	**Utility interest and financing expenses**
l)	77.9	**Consolidated income taxes**
	(2.3)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(75.6)	Elimination of corporate income taxes
	78.7	Addition of income taxes calculated on a utility "stand-alone" basis
	78.7	**Utility income taxes**

Witness: K. Culbert

UTILITY RATE BASE
COMPARISON OF 2009 HISTORICAL YEAR TO 2008 HISTORICAL YEAR

		Col. 1	Col. 2	Col. 3
Line No.		2009 Historical Year	2008 Historical Year	Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	5,500.5	5,225.4	275.1
2.	Accumulated depreciation	(2,089.5)	(1,955.8)	(133.7)
3.	Net property, plant, and equipment	3,411.0	3,269.6	141.4
	Allowance for Working Capital			
4.	Accounts receivable merchandise finance plan	-	-	-
5.	Accounts receivable rebillable projects	(0.1)	0.2	(0.3)
6.	Materials and supplies	26.5	28.9	(2.4)
7.	Mortgages receivable	0.7	0.8	(0.1)
8.	Customer security deposits	(53.3)	(44.8)	(8.5)
9.	Prepaid expenses	1.5	1.7	(0.2)
10.	Gas in storage	406.5	518.6	(112.1)
11.	Working cash allowance	1.6	4.2	(2.6)
12.	Total Working Capital	383.4	509.6	(126.2)
13.	Utility Rate Base	3,794.4	3,779.2	15.2

UTILITY RATE BASE
COMPARISON OF 2008 HISTORICAL YEAR TO 2007 HISTORICAL YEAR

Line No.		Col. 1 2008 Historical Year	Col. 2 2007 Historical Year	Col. 3 Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	5,225.4	4,993.6	231.8
2.	Accumulated depreciation	(1,955.8)	(1,808.1)	(147.7)
3.	Net property, plant, and equipment	3,269.6	3,185.5	84.1
	Allowance for Working Capital			
4.	Accounts receivable merchandise finance plan	-	0.1	(0.1)
5.	Accounts receivable rebillable projects	0.2	1.8	(1.6)
6.	Materials and supplies	28.9	24.5	4.4
7.	Mortgages receivable	0.8	0.8	-
8.	Customer security deposits	(44.8)	(44.8)	-
9.	Prepaid expenses	1.7	2.3	(0.6)
10.	Gas in storage	518.6	455.0	63.6
11.	Working cash allowance	4.2	0.8	3.4
12.	Total Working Capital	509.6	440.5	69.1
13.	Utility Rate Base	3,779.2	3,626.0	153.2

Witness: K. Culbert

UTILITY PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	273.1	(96.3)	176.8
2.	Distribution plant	4,921.1	(1,855.7)	3,065.4
3.	General plant	313.6	(137.3)	176.3
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	5,508.3	(2,089.8)	3,418.5
6.	Plant held for future use	1.7	(0.8)	0.9
7.	Sub- total	5,510.0	(2,090.6)	3,419.4
8.	Affiliate Shared Assets Value	(9.5)	1.1	(8.4)
9.	Total property, plant, and equipment	5,500.5	(2,089.5)	3,411.0

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2009	Col. 5 Regulatory Adjustments	Col. 6 Utility Balance Dec.2009	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	4.2	-	-	4.2	-	4.2	4.2
2.	Land and gas storage rights (450/451)	40.0	(0.2)	-	39.8	-	39.8	39.9
3.	Structures and improvements (452.00)	10.6	0.3	-	10.9	-	10.9	10.7
4.	Wells (453.00)	28.3	1.6	-	29.9	-	29.9	28.8
5.	Well equipment (454.00)	7.9	0.5	-	8.4	-	8.4	7.9
6.	Field Lines (455.00)	45.2	1.1	-	46.3	-	46.3	45.4
7.	Compressor equipment (456.00)	83.3	4.6	-	87.9	-	87.9	84.1
8.	Measuring and regulating equipment (457.00)	11.2	0.2	-	11.4	-	11.4	11.3
9.	Base pressure gas (458.00)	40.8	0.1	-	40.9	-	40.9	40.8
10.	Total	271.5	8.1	-	279.7	-	279.7	273.1

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2009	Col. 6 Regulatory Adjustments	Col. 7 Utility Balance Dec.2009	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.0)	(0.1)	-	0.1	(2.0)	-	(2.0)	(2.0)
2.	Land and gas storage rights (451.00)	(18.6)	(0.8)	-	-	(19.4)	-	(19.4)	(19.0)
3.	Structures and improvements (452.00)	(4.1)	(0.3)	-	-	(4.4)	-	(4.4)	(4.2)
4.	Wells (453.00)	(15.9)	(1.3)	-	0.7	(16.5)	-	(16.5)	(16.2)
5.	Well equipment (454.00)	(3.9)	(0.2)	-	-	(4.1)	-	(4.1)	(4.0)
6.	Field Lines (455.00)	(18.4)	(1.2)	-	-	(19.6)	-	(19.6)	(19.0)
7.	Compressor equipment (456.00)	(26.6)	(1.9)	-	-	(28.5)	-	(28.5)	(27.5)
8.	Measuring and regulating equipment (457.00)	(4.2)	(0.4)	-	-	(4.6)	-	(4.6)	(4.4)
9.	Total	(93.7)	(6.2)	-	0.8	(99.1)	-	(99.1)	(96.3)

Witness: K. Culbert

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2009	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2009	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	21.0	(9.6)	-	11.4	-	11.4	13.3
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	-	7.4	-	7.4	-	7.4	5.8
4.	Structures and improvements (472.00)	80.5	(2.4)	(0.7)	77.4	(0.3)	77.1	79.2
5.	Services, house reg & meter install. (473/474)	1,872.0	100.6	(23.1)	1,949.5	-	1,949.5	1,900.2
6.	NGV station compressors (476)	2.2	-	-	2.2	-	2.2	2.2
7.	Meters (478)	348.9	19.8	(5.1)	363.6	-	363.6	353.3
8.	Sub-total	2,324.6	115.8	(28.9)	2,411.5	(0.3)	2,411.2	2,354.0
9.	Mains (475)	2,224.2	133.6	(10.5)	2,347.3	-	2,347.3	2,274.7
10.	Measuring and regulating equip. (477)	288.0	21.2	(5.2)	304.0	-	304.0	292.4
11.	Construction work-in-progress completed and in service projects	-	-	-	-	-	-	-
12.	Sub-total	2,512.2	154.8	(15.7)	2,651.3	-	2,651.3	2,567.1
13.	Total	4,836.8	270.6	(44.6)	5,062.8	(0.3)	5,062.5	4,921.1

Note 1: The column 5 adjustment is the elimination of non-utility corporate branding costs.

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2009	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2009	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	-	(0.7)	-	-	(0.7)	-	(0.7)	(0.4)
2.	Structures and improvements (472.00)	(3.8)	(2.0)	0.7	-	(5.1)	0.1	(5.0)	(4.5)
3.	Services, house reg & meter install. (473/474)	(768.0)	(85.5)	23.1	6.5	(823.9)	-	(823.9)	(795.8)
4.	NGV station compressors (476)	(1.3)	(0.2)	-	-	(1.5)	-	(1.5)	(1.4)
5.	Meters (478)	(91.8)	(8.7)	5.1	(0.4)	(95.8)	-	(95.8)	(94.0)
6.	Mains (475)	(790.4)	(94.6)	10.5	15.9	(858.6)	0.1	(858.5)	(821.8)
7.	Measuring and regulating equip. (477)	(134.4)	(15.4)	5.2	-	(144.6)	-	(144.6)	(137.8)
8.	Total	(1,789.7)	(207.1)	44.6	22.0	(1,930.2)	0.2	(1,930.0)	(1,855.7)

Note 1: The column 6 adjustments are the removal of depreciation provisions on non-utility corporate branding costs, and on Mississauga Southern Link disallowances (EBRO 473 & 479).

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2009	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2009	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	4.4	0.3	-	4.6	(0.2)	4.4	4.3
2.	Office furniture and equipment (483.00)	19.8	1.2	(0.9)	20.1	-	20.1	20.0
3.	Transportation equipment (484.00)	34.0	8.6	(2.8)	39.8	(0.1)	39.7	34.2
4.	NGV conversion kits (484.01)	7.1	0.2	-	7.3	-	7.3	7.2
5.	Heavy work equipment (485.00)	16.0	1.9	(0.5)	17.3	-	17.3	16.5
6.	Tools and work equipment (486.00)	30.3	2.3	(0.7)	31.9	-	31.9	31.0
7.	Rental equipment (487.70)	1.0	-	-	1.0	-	1.0	1.0
8.	NGV rental compressors (487.80)	6.8	-	(0.8)	6.0	-	6.0	6.7
9.	NGV cylinders (484.02 and 487.90)	2.0	0.2	-	2.2	-	2.2	2.0
10.	Communication structures & equip. (488)	2.9	0.1	-	3.0	-	3.0	2.9
11.	S.I.M. project (489.00)	4.7	-	(4.7)	-	-	-	3.3
12.	Computer equipment (490.00)	156.7	16.7	(48.4)	124.9	-	124.9	148.8
13.	CIS (491.00)	-	127.4	-	127.4	-	127.4	35.7
14.	Total	285.7	158.9	(58.8)	385.5	(0.3)	385.2	313.6

Note 1: The column 5 adjustments are the elimination of non-utility corporate branding costs.

Witness: K. Culbert

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2009	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2009	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	(3.0)	(0.4)	-	-	(3.4)	0.1	(3.3)	(3.0)
2.	Office furniture and equipment (483.00)	(12.1)	(0.9)	0.9	-	(12.1)	-	(12.1)	(12.0)
3.	Transportation equipment (484.00)	(8.5)	(1.5)	2.8	-	(7.6)	-	(7.5)	(8.2)
4.	NGV conversion kits (484.01)	(4.3)	(0.2)	-	-	(4.4)	-	(4.4)	(4.4)
5.	Heavy work equipment (485.00)	(6.5)	(0.6)	0.5	-	(6.8)	-	(6.8)	(6.7)
6.	Tools and work equipment (486.00)	(12.3)	(0.9)	0.7	-	(12.5)	-	(12.5)	(12.4)
7.	Rental equipment (487.70)	(0.8)	-	-	-	(0.9)	-	(0.9)	(0.9)
8.	NGV rental compressors (487.80)	(4.5)	(0.5)	0.8	-	(4.2)	-	(4.2)	(4.7)
9.	NGV cylinders (484.02 and 487.90)	(1.3)	(0.1)	-	-	(1.4)	-	(1.4)	(1.4)
10.	Communication structures & equip. (488)	(2.0)	(0.1)	-	-	(2.1)	-	(2.1)	(2.0)
11.	S.I.M. project (489.00)	(4.7)	-	4.7	-	-	-	-	(3.3)
12.	Computer equipment (490.00)	(74.2)	(29.5)	48.4	-	(55.5)	-	(55.5)	(77.9)
13.	CIS (491.00)	-	(3.0)	-	-	(3.0)	-	(3.0)	(0.4)
13.	Total	(134.2)	(37.7)	58.8	-	(113.9)	0.1	(113.7)	(137.3)

Note 1: The column 6 adjustments are the elimination of non-utility corporate branding costs.

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2009	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2009	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2009	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2009	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2009	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2009	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witness: K. Culbert

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2008	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2009	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2009	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(0.8)	(0.1)	-	-	(0.9)	-	(0.9)	(0.8)
2.	Total	(0.8)	(0.1)	-	-	(0.9)	-	(0.9)	(0.8)

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2009 AND ACTUAL 2008

Item No.		Col. 1 Actuals 2009 ($Millions)	Col. 2 Actuals 2008 ($Millions)	Col. 3 2009 Over/(Under) 2008 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	48.2	60.6	(12.4)
1.1.2	Services	48.7	49.3	(0.6)
1.1.3	Meters and Regulation	11.9	9.7	2.2
1.1.4	Customer Related Distribution Plant	108.8	119.6	(10.8)
1.1.5	NGV Rental Equipment	0.2	0.3	(0.1)
1.1	TOTAL CUSTOMER RELATED CAPITAL	109.0	119.9	(10.9)
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	8.0	14.8	(6.8)
1.2.2	- Replacement	49.9	58.8	(8.9)
1.2.3	- Reinforcement	16.8	16.7	0.1
1.2.4	Total Improvement Mains	74.7	90.3	(15.6)
1.2.5	Services - Relays	37.0	30.4	6.6
1.2.6	Regulators - Refits	7.7	3.5	4.2
1.2.7	Measurement and Regulation	9.2	13.4	(4.2)
1.2.8	Meters	15.9	18.9	(3.0)
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	144.5	156.5	(12.0)
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	2.9	3.4	(0.5)
1.3.2	Office Furniture and Equipment	0.9	1.0	(0.1)
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	11.4	11.0	0.4
1.3.4	Tools and Work Equipment	2.3	3.6	(1.3)
1.3.5	Computers and Communication Equipment	24.8	18.3	6.5
1.3	TOTAL GENERAL AND OTHER PLANT	42.3	37.3	5.0
D.	Underground Storage Plant	4.6	5.9	(1.3)
E.	Customer Information System (CIS)	48.7	46.4	2.3
F.	TOTAL CAPITAL EXPENDITURES	349.1	366.0	(16.9)

Witnesses: L. Au
D. Kelly

ACTUAL 2009 CAPITAL EXPENDITURE WORKSHEET

Item No.		Col. 1 Business as Usual ($Millions)	Col. 2 Safety and Integrity Initiatives ($Millions)	Col. 3 Leave to Construct Projects ($Millions)	Col. 4 Other Additional Initiatives ($Millions)	Col. 5 Total Actual 2009 ($Millions)
A.	Customer Related					
1.1.1	Sales Mains	41.0		7.2		48.2
1.1.2	Services	48.7				48.7
1.1.3	Meters and Regulation	11.9				11.9
1.1.4	Customer Related Distribution Plant	101.6	-	7.2	-	108.8
1.1.5	NGV Rental Equipment	0.2				0.2
						-
1.1	TOTAL CUSTOMER RELATED CAPITAL	101.8	-	7.2	-	109.0
B.	System Improvements and Upgrades					
1.2.1	Mains - Relocations	8.0				8.0
1.2.2	- Replacement	43.9	6.0			49.9
1.2.3	- Reinforcement	9.2		7.6		16.8
1.2.4	Total Improvement Mains	61.1	6.0	7.6	-	74.7
1.2.5	Services - Relays	28.0	9.0			37.0
1.2.6	Regulators - Refits	7.2	0.5			7.7
1.2.7	Measurement and Regulation	8.9			0.3	9.2
1.2.8	Meters	15.9				15.9
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	121.1	15.5	7.6	0.3	144.5
C.	General and Other Plant					-
1.3.1	Land, Structures and Improvements	2.9				2.9
1.3.2	Office Furniture and Equipment	0.9				0.9
1.3.3	Transp/Heavy Work/NGV Compressor Equipme	11.4				11.4
1.3.4	Tools and Work Equipment	2.3				2.3
1.3.5	Computers and Communication Equipment	24.8				24.8
1.3	TOTAL GENERAL AND OTHER PLANT	42.3	-	-	-	42.3
D.	Underground Storage Plant	4.6				4.6
E.	Customer Information System (CIS)	-			48.7	48.7
F.	TOTAL CAPITAL EXPENDITURES	269.8	15.5	14.8	49.0	349.1
Project Details:						
2.1	Incremental Cast Iron Replacement		14.3			14.3
2.2	Kerotest Valve Replacement		0.3			0.3
2.3	S&R Regulator Replacement		0.5			0.5
2.4	Inside regulators		0.4			0.4
3.1	Portlands Energy Power Generation			1.1		1.1
3.2	Northland Thorold Power			4.0		4.0
3.3	York Energy Centre			0.4		0.4
3.4	Goreway Power Generation			0.1		0.1
3.5	Other Power Generation			0.1		0.1
3.6	Alfred and Plantagenet			1.5		1.5
3.7	Scarborough Reinforcement			5.3		5.3
3.8	Bathurst Gate Station Reinforcement			2.3		2.3
4.1	Fuel Cell Technology				0.3	0.3
4.2	Customer Information System (CIS)				48.7	48.7
Sub total Additional Initiatives			15.5	14.8	49.0	79.3

Witnesses: L. Au
D. Kelly

EXPLANATION OF MAJOR CHANGES
IN ACTUAL 2009 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2008 UTILITY CAPITAL EXPENDITURES

The 2009 actual capital expenditure was $349.1 million, which is $16.9 million or 4.6% less than the 2008 actual of $366.0 million. The capital expenditure decrease was primarily related to decreased requirements in customer related expenditures, storage plant and system improvements and upgrades. This was partially offset by increased requirements for general plant and increased spending on the Customer Information System (CIS). The major categories showing significant variances are explained below:

Item No.

1.1.4 Customer Related Distribution Plant – Decrease $10.8 Million

The decrease in customer related plant was driven by sales mains as a result of lower commercial industrial activity related to the completion of the Portlands Energy Power generation project ($10 million). A further $6.6 million of the decrease reflects the lower number of new customers added in 2009 (32,080) compared to 2008 (41,052). This was partially offset by increased expenditures for Northland Thorold Power and other power generation initiatives ($2.7M) and a higher allocation of indirect costs ($3.1M).

1.2.4 Improvement Mains – Decrease $15.6 Million

The decrease in improvement mains was primarily due to the completion of the Georgian Bay Reinforcement project in 2008 ($8.5M) and reduced allocation of indirect costs ($7.1M).

1.2.5 Service Relays – Increase $6.6 Million

The increase was primarily due the spending mix of the cast iron replacement program which is a combination of replacement mains and service relays. Relative to 2008, the service relay requirements were higher in 2009.

Witnesses: L. Au
D. Kelly

1.2.6 Regulator Refits – Increase $4.2Million

The increase was due to more refit requirements relative to 2008. This activity is mandated by the government inspection meter exchange program ($3.7M). A portion of the activity is attributable to Safety and Integrity initiatives related to regulator replacement ($0.5M).

1.2.7 Measurement and Regulation – Decrease $4.2 Million

The decrease was primarily due to reduced improvement activity ($2.8M), less spending on the Fuel Cell Turbo Expander ($1.1M) and reduced allocation of indirect costs ($0.3M) relative to 2008.

1.2.8 Meters – Decrease $3.0 Million

The decrease was primarily due to less meter replacement requirements relative to 2008.

C. General and Other Plant – Increase $5.0 Million

The actual spending in this category increased relative to 2008 actual spending due to general plant expenditures that were advanced, Computer equipment increased $6.5M and Transportation and Heavy Work Equipment increased $0.4 million. The variance was partially offset by decreased requirements in Tools and Work Equipment ($1.3M) and Land Structures and Improvements ($0.5M).

D. Underground Storage Plant – Decrease $1.3 million

The decrease in storage plant expenditures reflects a decline in structures and compression equipment and measurement and regulation equipment offset by an increase in wells.

E. Customer Information System (CIS) – Increase $2.3 million

CIS was multi-year project that commenced in 2007. CIS had its own approval process with an approved spending of approximately $120M. At the end of 2009 the life to date spend was $127.5 million. The increased costs are due to higher system integrator costs and higher interest during construction costs resulting from a delayed implementation and higher interest rates.

Witnesses: L. Au
D. Kelly

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2008 AND ACTUAL 2007

Item No.		Col. 1 Actuals 2008 ($Millions)	Col. 2 Actuals 2007 ($Millions)	Col. 3 2008 Over/(Under) 2007 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	60.6	83.9	(23.3)
1.1.2	Services	49.3	40.9	8.4
1.1.3	Meters and Regulation	9.7	11.4	(1.7)
1.1.4	Customer Related Distribution Plant	119.6	136.2	(16.6)
1.1.5	NGV Rental Equipment	0.3	0.1	0.2
1.1	TOTAL CUSTOMER RELATED CAPITAL	119.9	136.3	(16.4)
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	14.8	11.2	3.6
1.2.2	- Replacement	58.8	49.7	9.1
1.2.3	- Reinforcement	16.7	17.1	(0.4)
1.2.4	Total Improvement Mains	90.3	78.0	12.3
1.2.5	Services - Relays	30.4	35.8	(5.4)
1.2.6	Regulators - Refits	3.5	3.1	0.4
1.2.7	Measurement and Regulation	13.4	15.6	(2.2)
1.2.8	Meters	18.9	19.3	(0.4)
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	156.5	151.7	4.8
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	3.4	2.7	0.7
1.3.2	Office Furniture and Equipment	1.0	0.9	0.1
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	11.0	7.4	3.6
1.3.4	Tools and Work Equipment	3.6	1.4	2.2
1.3.5	Computers and Communication Equipment	18.3	17.5	0.8
1.3	TOTAL GENERAL AND OTHER PLANT	37.3	29.9	7.4
D.	Underground Storage Plant	5.9	4.5	1.4
E.	Customer Information System (CIS)	46.4	32.4	14.0
F.	TOTAL CAPITAL EXPENDITURES	366.0	354.9	11.1

Witnesses: L. Au
D. Kelly

ACTUAL 2008 CAPITAL EXPENDITURE WORKSHEET

Item No.		Col. 1 Business as Usual ($Millions)	Col. 2 Safety and Integrity Initiatives ($Millions)	Col. 3 Leave to Construct Projects ($Millions)	Col. 4 Other Additional Initiatives ($Millions)	Col. 5 Total Actual 2008 ($Millions)
A.	Customer Related					
1.1.1	Sales Mains	43.7		16.9		60.6
1.1.2	Services	49.3				49.3
1.1.3	Meters and Regulation	9.7				9.7
1.1.4	Customer Related Distribution Plant	102.7	-	16.9	-	119.6
1.1.5	NGV Rental Equipment	0.3				0.3
						-
1.1	TOTAL CUSTOMER RELATED CAPITAL	103.0	-	16.9	-	119.9
B.	System Improvements and Upgrades					
1.2.1	Mains - Relocations	14.8				14.8
1.2.2	- Replacement	57.0	1.8			58.8
1.2.3	- Reinforcement	5.0		11.7		16.7
1.2.4	Total Improvement Mains	76.8	1.8	11.7	-	90.3
1.2.5	Services - Relays	22.7	7.7			30.4
1.2.6	Regulators - Refits	3.5				3.5
1.2.7	Measurement and Regulation	12.0			1.4	13.4
1.2.8	Meters	18.9				18.9
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	133.9	9.5	11.7	1.4	156.5
C.	General and Other Plant					-
1.3.1	Land, Structures and Improvements	3.4				3.4
1.3.2	Office Furniture and Equipment	1.0				1.0
1.3.3	Transp/Heavy Work/NGV Compressor Equipme	11.0				11.0
1.3.4	Tools and Work Equipment	3.6				3.6
1.3.5	Computers and Communication Equipment	18.3				18.3
1.3	TOTAL GENERAL AND OTHER PLANT	37.3	-	-	-	37.3
D.	Underground Storage Plant	5.9			-	5.9
E.	Customer Information System (CIS)				46.4	46.4
F.	TOTAL CAPITAL EXPENDITURES	280.1	9.5	28.6	47.8	366.0

Project Details:

2.1 Incremental Cast Iron Replacement	6.6			6.6
2.2 Kerotest Valve Replacement	0.5			0.5
2.3 Pipeline Markers	1.3			1.3
2.4 Inside regulators	1.1			1.1
3.1 Portlands Energy Power Generation		11.1		11.1
3.2 Northland Thorold Power		1.9		1.9
3.3 Alfred and Plantagenet		3.9		3.9
3.4 Scarborough Reinforcement		3.2		3.2
3.5 Georgian Bay Reinforcement		8.5		8.5
4.1 Fuel Cell Technology			1.4	1.4
4.2 Customer Information System (CIS)			46.4	46.4
Sub total Additional Initiatives	9.5	28.6	47.8	85.9

Witnesses: L. Au
D. Kelly

EXPLANATION OF MAJOR CHANGES
IN ACTUAL 2008 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2007 UTILITY CAPITAL EXPENDITURES

The 2008 Actual was $366.0 million, which is $11.1 million or 3.1% more than the 2007 Actual of $354.9 million. The capital expenditure increase was primarily related to increased spending on the Customer Information System (CIS), increased requirements for general plant, storage plant and system improvements and upgrades. This was partially offset by decreased requirements in customer related expenditures. The major categories showing significant variances are explained below:

Item No.

1.1.4 Customer Related Distribution Plant – Decrease $16.6 Million

The decrease in customer related plant was driven by sales mains related to less commercial industrial activity related to the completion of the Goreway-Sithe project ($7.7 million) and less subdivision activity ($5.8 million) which is related to declining new construction customer additions. 2008 spending reflects lower indirect allocations due to the decreased amount of direct customer related expenditures relative to direct system improvement expenditures. As a result customer related attracted less of the indirect costs compared to 2007 ($9.2 million). This was partially offset by increased residential mains ($3.0 million) and increased services ($3.1 million) primarily due to customer mix.

1.2.4 Improvement Mains – Increase $12.3 Million

The increase in improvement mains was primarily due to reinforcement projects ($5.8 million), an increased allocation of indirect costs ($7.6 million) which was partially offset by decreased relocation activity ($1.1 million). The 2008 major reinforcement projects include Georgian Bay Reinforcement ($8.5 million) and Scarborough Reinforcement ($3.2 million).

1.2.5 Service Relays – Decrease $5.4 Million

The decrease was primarily due the spending mix of the cast iron replacement program which is a combination of replacement mains and service relays. Relative to 2007, the service relay requirements were lower in 2008.

Witnesses: L. Au
D. Kelly

1.2.6 Regulator Refits – Increase $0.4 Million

The increase was due to more refit requirements relative to 2007.

1.2.7 Measurement and Regulation – Decrease $2.2 Million

The decrease was primarily due to less station improvement requirements relative to 2007.

1.2.8 Meters – Decrease $0.4 Million

The decrease was primarily due to less meter replacement requirements relative to 2007.

C. General and Other Plant – Increase $7.4 Million

The actual spending in this category increased relative to 2007 actual spending. Land, Structures and Improvements increased ($0.7 million) primarily due to the 2007 carryover costs related to the meter shop redesign. The following categories increased due to the advancement to 2008 of planned 2009 expenditures: Transportation and Heavy Work Equipment ($3.6 million), Tools and Work Equipment ($2.2 million) and Computers and communication Equipment ($0.8 million).

D. Underground Storage Plant – Increase $1.4 million

The increase in storage plant expenditures reflects spending on structures in 2008 and increased requirements for compressor upgrades as well as measurement and regulation equipment.

E. Customer Information System (CIS) – Increase $14.0 million

CIS was multi-year project that commenced in 2007. CIS had its own approval process with an approved spending of approximately $120M. At the end of 2008 the life to date spend was $78.8 million.

Witnesses: L. Au
D. Kelly

UTILITY OPERATING REVENUE
2009 HISTORICAL YEAR

Line No.		Col. 1 Utility Revenue ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Revenue ($Millions)
1.	Gas sales	2,306.7	(85.1)	2,221.6
2.	Transportation of gas	644.0	(16.3)	627.7
3.	Transmission, compression & storage	1.6	-	1.6
4.	Other operating revenue	40.9	-	40.9
5.	Other income	7.5	-	7.5
6.	Total operating revenue	3,000.7	(101.4)	2,899.3

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2009 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(85.1)	Gas sales Adjustment to gas sales revenue required to reflect normal weather.
2.	(16.3)	Transportation of gas Adjustment to gas transportation revenue required to reflect normal weather.

UTILITY REVENUE
2009 HISTORICAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Revenue	Col. 2 Adjustment	Col. 3 Utility Revenue
		($Millions)	($Millions)	($Millions)
1.	Residential	1,441.7	1.8	1,443.5
2.	Commercial	717.1	-	717.1
3.	Industrial	102.0	-	102.0
4.	Wholesale	44.1	-	44.1
5.	Gas sales	2,304.9	1.8	2,306.7
6.	Transportation of gas	644.0	-	644.0
7.	Transmission, compression & storage	1.6	-	1.6
8.	Service charges & DPAC	12.7	-	12.7
9.	Rent from NGV rentals	0.3	0.3	0.6
10.	Late payment penalties	14.0	-	14.0
11.	Transactional services	11.1	(3.1)	8.0
12.	Open bill revenue	6.6	(1.2)	5.4
13.	Dow Moore recovery	0.2	-	0.2
14.	Affiliate asset use revenue	0.1	(0.1)	-
15.	ABC T-service (net)	5.3	(5.3)	-
16.	Other operating revenue	50.3	(9.4)	40.9
17.	Income from investments	11.1	(11.1)	-
18.	Interest during construction	5.7	(5.7)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	-	-	-
21.	Property/asset use revenue 3rd party	1.3	(1.3)	-
22.	Interest and property rental	18.1	(18.1)	-
23.	Miscellaneous	21.5	(14.0)	7.5
24.	Dividend income	63.6	(63.6)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	85.1	(77.6)	7.5
28.	Total revenue	3,104.0	(103.3)	3,000.7

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2009 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	1.8	Residential Gas Sales	
		To reverse the impact of the elimination of the 2008 TRRCVA on 2009 utility results, previously reflected in the 2008 ESM approved amount.	
9.	0.3	Rent from NGV rentals	
		NGV revenue imputation to equate the program's overall return to the required regulated return.	
11.	(3.1)	Transactional services	
		To eliminate transactional services revenues above the base amount included in approved rates. Ratepayer amounts above the base have been transferred to the 2009 TSDA, and shareholder amounts are eliminated from utility returns.	
12.	(1.2)	Open bill revenue	
		To eliminate the Open Bill shareholder incentive	(1.2)
			(1.2)
14.	(0.1)	Affiliate asset use revenue	
		To reflect the elimination of asset use revenue in conjunction with the removal of affiliate use asset values from rate base and all related cost of service elements. (RP-2002-0133)	
15.	(5.3)	ABC T-Service (net)	
		To eliminate the net revenue from ABC T-Service considered to be non-utility. (RP-1999-0001)	
17.	(11.1)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(5.7)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
21.	(1.3)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(14.0)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(8.2)
		To eliminate the shareholders' incentive income recorded as a result of calculating the SSMVA amount.	(5.8)
			(14.0)
24.	(63.6)	Dividend income	
		To eliminate non-utility inter-company dividend income.	(0.9)
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	(62.7)
			(63.6)

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2009 ACTUAL AND 2009 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2009 Actual	Col. 2 2009 Board Approved Budget	Col. 3 2009 Actual Over (Under) 2009 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 119.7	2 896.6	223.1
1.1.2	Rate 1 - T-Service	1 625.8	1 705.0	(79.2)
1.1	Total Rate 1	4 745.5	4 601.6	143.9
1.2.1	Rate 6 - Sales	1 932.4	1 819.2	113.2
1.2.2	Rate 6 - T-Service	2 450.0	2 659.8	(209.8)
1.2	Total Rate 6	4 382.4	4 479.0	(96.6)
1.3.1	Rate 9 - Sales	1.1	2.1	(1.0)
1.3.2	Rate 9 - T-Service	0.2	0.5	(0.3)
1.3	Total Rate 9	1.3	2.6	(1.3)
1.	Total General Service Sales & T-Service	9 129.2	9 083.2	46.0
Contract Sales				
2.1	Rate 100	17.4	0.0	17.4
2.2	Rate 110	59.8	71.5	(11.7)
2.3	Rate 115	4.4	4.4	0.0
2.4	Rate 135	0.6	3.3	(2.7)
2.5	Rate 145	25.7	22.5	3.2
2.6	Rate 170	77.0	56.3	20.7
2.7	Rate 200	179.3	151.3	28.0
2.	Total Contract Sales	364.2	309.3	54.9
Contract T-Service				
3.1	Rate 100	82.9	0.0	82.9
3.2	Rate 110	517.8	619.5	(101.7)
3.3	Rate 115	460.1	532.1	(72.0)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	51.3	54.8	(3.5)
3.6	Rate 145	222.6	203.6	19.0
3.7	Rate 170	467.4	545.6	(78.2)
3.8	Rate 300	39.3	51.7	(12.4)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 841.4	2 007.3	(165.9)
4.	Total Contract Sales & T-Service	2 205.6	2 316.6	(111.0)
5.	Total	11 334.8	11 399.8	(65.0)

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2009 ACTUAL AND 2009 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2009 Actual	Col. 2 2009 Board Approved Budget	Col. 3 2009 Actual Over (Under) 2009 Budget (1-2)	Col. 4 2009* Adjustments	Col. 5 2009 Actual Over (Under) 2009 Budget with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 119.7	2 896.6	223.1	141.0	82.1
1.1.2	Rate 1 - T-Service	1 625.8	1 705.0	(79.2)	70.6	(149.8)
1.1	Total Rate 1	4 745.5	4 601.6	143.9	211.6	(67.7)
1.2.1	Rate 6 - Sales	1 932.4	1 819.2	113.2	39.3	73.9
1.2.2	Rate 6 - T-Service	2 450.0	2 659.8	(209.8)	44.6	(254.4)
1.2	Total Rate 6	4 382.4	4 479.0	(96.6)	83.9	(180.5)
1.3.1	Rate 9 - Sales	1.1	2.1	(1.0)	0.0	(1.0)
1.3.2	Rate 9 - T-Service	0.2	0.5	(0.3)	0.0	(0.3)
1.3	Total Rate 9	1.3	2.6	(1.3)	0.0	(1.3)
1.	Total General Service Sales & T-Service	9 129.2	9 083.2	46.0	295.5	(249.5)
Contract Sales						
2.1	Rate 100	17.4	0.0	17.4	0.3	17.1
2.2	Rate 110	59.8	71.5	(11.7)	0.1	(11.8)
2.3	Rate 115	4.4	4.4	0.0	0.0 **	0.0
2.4	Rate 135	0.6	3.3	(2.7)	0.0	(2.7)
2.5	Rate 145	25.7	22.5	3.2	0.2	3.0
2.6	Rate 170	77.0	56.3	20.7	0.1	20.6
2.7	Rate 200	179.3	151.3	28.0	1.0	27.0
2.	Total Contract Sales	364.2	309.3	54.9	1.7	53.2
Contract T-Service						
3.1	Rate 100	82.9	0.0	82.9	1.2	81.7
3.2	Rate 110	517.8	619.5	(101.7)	1.5	(103.2)
3.3	Rate 115	460.1	532.1	(72.0)	0.1	(72.1)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	51.3	54.8	(3.5)	0.0	(3.5)
3.6	Rate 145	222.6	203.6	19.0	3.7	15.3
3.7	Rate 170	467.4	545.6	(78.2)	6.0	(84.2)
3.8	Rate 300	39.3	51.7	(12.4)	0.0	(12.4)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 841.4	2 007.3	(165.9)	12.5	(178.4)
4.	Total Contract Sales & T-Service	2 205.6	2 316.6	(111.0)	14.2	(125.2)
5.	Total	11 334.8	11 399.8	(65.0)	309.7	(374.7)

*Note: Weather normalization adjustments have been made to the 2009 Actual utilizing the 2009 Board Approved Budget Degree Days in order to place the two years on a comparable basis.

** Less than 50,000 m^3

The principal reasons for the variances contributing to the weather normalized decrease of 374.7 10^6m^3 in the 2009 Actual over the 2009 Board Approved Budget are as follows:

1. The volumetric decrease of 67.7 10^6m^3 in Rate 1 was due to a lower average use per customer totalling 36.0 10^6m^3 and an unfavourable customer variance of 31.7 10^6m^3;

2. The volumetric decrease of 180.5 10^6m^3 in Rate 6 was due to net customer migration to Contract Sales and T-Service of 74.5 10^6m^3, unfavourable customer variance of 99.3 10^6m^3 and a lower average use per customer totalling 6.7 10^6m^3;

3. The volumetric decrease of 1.3 10^6m^3 in Rate 9 was due to a lower average use per station totalling 1.2 10^6m^3 and the loss of two stations of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 125.2 10^6m^3 was due to decreases in the commercial sector of 167.4 10^6m^3 and the industrial sector of 43.5 10^6m^3; partially offset by an increase in the apartment sector of 58.7 10^6m^3 and Rate 200 of 27.0 10^6m^3. The decrease was primarily attributable to production decreases and plant closures in the wake a of an unexpected major financial crisis and a rapidly deteriorating economy since October 2008.

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2009 HISTORICAL YEAR AND 2009 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2009 Actual		Col. 2 2009 Board Approved Budget	Col. 3 2009 Actual Over (Under) 2009 Budget (1-2)	Col. 4 2009* Adjustments		Col. 5 2009 Actual Over (Under) 2009 Budget with Adjustments (3+4)
General Service								
1.1.1	Rate 1 - Sales	1 488.6		1 581.2	(92.6)	(58.2)		(150.8)
1.1.2	Rate 1 - T-Service	318.3		355.9	(37.6)	(9.7)		(47.3)
1.1	Total Rate 1	1 806.9		1 937.1	(130.2)	(67.9)		(198.1)
1.2.1	Rate 6 - Sales	766.4		880.1	(113.7)	(3.3)		(117.0)
1.2.2	Rate 6 - T-Service	245.7		303.5	(57.8)	(2.1)		(59.9)
1.2	Total Rate 6	1 012.1		1 183.6	(171.5)	(5.4)		(176.9)
1.3.1	Rate 9 - Sales	0.4		1.1	(0.7)	0.0		(0.7)
1.3.2	Rate 9 - T-Service	0.0	**	0.1	(0.1)	0.0		(0.1)
1.3	Total Rate 9	0.4		1.2	(0.8)	0.0		(0.8)
1.	Total General Service Sales & T-Service	2 819.4		3 121.9	(302.5)	(73.3)		(375.8)
Contract Sales								
2.1	Rate 100	7.6		0.0	7.6	(0.1)		7.5
2.2	Rate 110	15.9		29.1	(13.2)	0.0	**	(13.2)
2.3	Rate 115	1.2		1.8	(0.6)	0.0	**	(0.6)
2.4	Rate 135	0.1		1.3	(1.2)	0.0		(1.2)
2.5	Rate 145	8.1		9.2	(1.1)	(0.1)		(1.2)
2.6	Rate 170	19.4		21.6	(2.2)	0.0	**	(2.2)
2.7	Rate 200	44.1		51.7	(7.6)	(0.5)		(8.1)
2.	Total Contract Sales	96.4		114.7	(18.3)	(0.7)		(19.0)
Contract T-Service								
3.1	Rate 100	8.4		0.0	8.4	(0.1)		8.3
3.2	Rate 110	32.6		44.0	(11.4)	(0.1)		(11.5)
3.3	Rate 115	21.3		32.8	(11.5)	0.0	**	(11.5)
3.4	Rate 125	6.9		6.6	0.3	0.0	***	0.3
3.5	Rate 135	2.2		3.1	(0.9)	0.0		(0.9)
3.6	Rate 145	13.4		15.0	(1.6)	(0.2)		(1.8)
3.7	Rate 170	13.5		26.1	(12.6)	(0.3)		(12.9)
3.8	Rate 300	0.5		0.5	0.0	0.0		0.0
3.9	Rate 315	0.4		0.0	0.4	0.0		0.4
3.	Total Contract T-Service	99.2		128.1	(28.9)	(0.7)		(29.6)
4.	Total Contract Sales & T-Service	195.6		242.8	(47.2)	(1.4)		(48.6)
5.	Total	3 015.0		3 364.7	(349.7)	(74.7)		(424.4)

* Note: Weather normalization adjustments have been made to the 2009 Actuals utilizing the 2009 Board Approved Budget degree days in order to place the two years on a comparable basis. Please refer to Exhibit B, Tab 3, Schedule 2, Page 2, for the corresponding volumetric adjustments.

** Less than $50,000

*** There is no distribution volume for Rate 125 customers

1. Gas sales and transportation of gas revenues for the 2009 Test Year Budget were developed on the basis of EB-2008-0219 rates.

2. The principal reasons for the variances contributing to the decrease of $349.7 million in the 2009 Actual over the 2009 Budget are as follows:

3. Gas Sales - Decrease of $225.3 Million

The decrease in gas sales revenue was primarily due to lower actual commodity charges than budgeted; partially offset by general service customer migration from transportation service to gas sales.

Details on volumes are at Exhibit B, Tab 3, Schedule 2, pages 1 to 3.

4. Transportation of Gas - Decrease of $124.4 Million

The decrease in T-service revenue was mainly due to the elimination of the Ontario T-service credit in the actual revenue effective September 1, 2009, general service customer migration from transportation service to gas sales and lower actual transportation charges than budgeted.

Please refer to EB-2009-0309, Exhibit Q4-2, Tab 4, Schedule 1, pages 4 to 5, for a more detailed explanation of the elimination of the Ontario T-service credit.

Details on volumes are at Exhibit B, Tab 3, Schedule 2, pages 1 to 3.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2009 ACTUAL

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)	
General Service					
1.1.1	Rate 1 - Sales	1 140 498	3 119.7	1 488.6	
1.1.2	Rate 1 - T-Service	591 689	1 625.8	318.3	
1.1	Total Rate 1	1 732 187	4 745.5	1 806.9	
1.2.1	Rate 6 - Sales	108 014	1 932.4	766.4	
1.2.2	Rate 6 - T-Service	46 722	2 450.0	245.7	
1.2	Total Rate 6	154 736	4 382.4	1 012.1	
1.3.1	Rate 9 - Sales	24	1.1	0.4	
1.3.2	Rate 9 - T-Service	2	0.2	0.0	**
1.3	Total Rate 9	26	1.3	0.4	
1.	Total General Service Sales & T-Service	1 886 949	9 129.2	2 819.4	
Contract Sales					
2.1	Rate 100	25	17.4	7.6	
2.2	Rate 110	35	59.8	15.9	
2.3	Rate 115	1	4.4	1.2	
2.4	Rate 135	2	0.6	0.1	
2.5	Rate 145	12	25.7	8.1	
2.6	Rate 170	5	77.0	19.4	
2.7	Rate 200	1	179.3	44.1	
2.	Total Contract Sales	81	364.2	96.4	
Contract T-Service					
3.1	Rate 100	88	82.9	8.4	
3.2	Rate 110	205	517.8	32.6	
3.3	Rate 115	37	460.1	21.3	
3.4	Rate 125	3	0.0 *	6.9	
3.5	Rate 135	31	51.3	2.2	
3.6	Rate 145	173	222.6	13.4	
3.7	Rate 170	28	467.4	13.5	
3.8	Rate 300	10	39.3	0.5	
3.9	Rate 315	0	0.0	0.4	
3.	Total Contract T-Service	575	1 841.4	99.2	
4.	Total Contract Sales & T-Service	656	2 205.6	195.6	
5.	Total	1 887 605	11 334.8	3 015.0	

* There is no distribution volume for Rate 125 customers.

** Less than $50,000.

Witness: I. Chan

DETAILS OF OTHER REVENUE
2009 ACTUAL AND 2008 ACTUAL

Item No.		Col. 1 2009 Actual (Calendar Year) ($Millions)	Col. 2 2008 Actual (Calendar Year) ($Millions)	Col. 3 2009 Actual Over/(Under) 2008 Actual ($Millions)
1.1	Service Charges & DPAC	12.7	12.4	0.3
1.2	Rental Revenue - NGV Program	0.6	0.9	(0.3)
1.3	Late Payment Penalties	14.0	12.0	2.0
1.4	Dow Moore Recovery	0.2	0.2	-
1.5	Transactional Services (net)	8.0	8.0	-
1.6	Miscellaneous	7.5	4.3	3.2
1.7	Open Bill Revenue	5.4	5.4	-
1.0	Total Other Revenue	48.4	43.2	5.2

Witness: R. Lei

DETAILS OF OTHER REVENUE
2008 ACTUAL AND 2007 ACTUAL

Item No.		Col. 1 2008 Actual (Calendar Year) ($Millions)	Col. 2 2007 Actual (Calendar Year) ($Millions)	Col. 3 2008 Actual Over/(Under) 2007 Actual ($Millions)
1.1	Service Charges & DPAC	12.4	12.3	0.1
1.2	Rental Revenue - NGV Program	0.9	1.1	(0.2)
1.3	Late Payment Penalties	12.0	11.1	0.9
1.4	Dow Moore Recovery	0.2	0.2	-
1.5	NGV Merchandising Revenue(net)	-	0.1	(0.1)
1.6	Transactional Services (net)	8.0	8.0	-
1.7	Miscellaneous	4.3	1.4	2.9
1.8	Open Bill Revenue	5.4	5.4	-
1.0	Total Other Revenue	43.2	39.6	3.6

Witness: R. Lei

COST OF SERVICE
2009 HISTORICAL YEAR

Line No.		Col. 1 Utility Costs and Expenses ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Adjusted Utility Costs and Expenses ($Millions)
1.	Gas costs	1,938.6	(76.0)	1,862.6
2.	Operation and maintenance	336.9	-	336.9
3.	Depreciation and amortization expense	251.0	-	251.0
4.	Fixed financing costs	6.5	-	6.5
5.	Debt redemption premium amortization	0.3	-	0.3
6.	Company share of IR agreement tax savings	9.6	-	9.6
7.	Municipal and other taxes	44.4	-	44.4
8.	Operating costs	2,587.3	(76.0)	2,511.3
9.	Income tax expense			78.7
10.	Cost of service			2,590.0

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2009 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(76.0)	Gas Costs Adjustment required to gas costs to reflect normal weather.

CALCULATION OF TAXABLE INCOME AND INCOME TAX EXPENSE
2009 HISTORICAL YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	388.0	388.0	
	Add			
2.	Depreciation and amortization	251.0	251.0	
3.	Other non-deductible items	2.0	2.0	
4.	Total Add Back	253.0	253.0	
5.	Sub-total	641.0	641.0	
	Deduct			
6.	Capital cost allowance	209.2	209.2	
7.	Items capitalized for regulatory purposes	38.0	38.0	
8.	Deduction for "grossed up" Part VI.1 tax	4.0	4.0	
9.	Amortization of share/debenture issue expense	2.1	2.1	
10.	Amortization of cumulative eligible capital	0.4	0.4	
11.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
12.	Total Deduction	253.8	253.8	
13.	Taxable income	387.2	387.2	
14.	Income tax rates	19.00%	14.00%	
15.	Provision	73.6	54.2	127.8
16.	Part VI.1 tax			1.3
17.	Investment tax credit			-
18.	Total taxes excluding interest shield			129.1
	Tax shield on interest expense			
19.	Rate base	3,794.4		
20.	Return component of debt	4.03%		
21.	Interest expense	152.9		
22.	Combined tax rate	33.000%		
23.	Income tax credit			(50.4)
24.	Total income taxes			78.7

COST OF SERVICE
2009 HISTORICAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses	Col. 2 Adjustment	Col. 3 Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	1,938.6	-	1,938.6
2.	Operation and maintenance	374.6	(37.7)	336.9
3.	Depreciation	251.0	(0.4)	250.6
4.	Amortization	0.4	-	0.4
5.	Depreciation and amortization	251.4	(0.4)	251.0
6.	Fixed financing costs	6.5	-	6.5
7.	Debt redemption premium amortization	0.3	-	0.3
8.	Company share of IR agreement tax savings	-	9.6	9.6
9.	Municipal and other taxes	36.7	(0.2)	36.5
10.	Capital taxes	10.2	(2.3)	7.9
11.	Municipal and other taxes	46.9	(2.5)	44.4
12.	Interest on long-term debt	151.0	(151.0)	-
13.	Amortization of preference share issue costs and debt discount and expense	2.2	(2.2)	-
14.	Interest and financing amortization	153.2	(153.2)	-
15.	Interest on short-term debt	6.6	(6.6)	-
16.	Interest due affiliates	26.8	(26.8)	-
17.	Other interest expense	33.4	(33.4)	-
18.	Total operating costs	2,804.9	(217.6)	2,587.3
19.	Current taxes	50.9	(50.9)	-
20.	Deferred taxes	26.6	(26.6)	-
21.	Income tax expense	77.5	(77.5)	-
22.	Cost of service	2,882.4	(295.1)	2,587.3

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2009 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(37.7)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	1.0
		To eliminate donations (EBRO 490).	(0.4)
		To eliminate non-utility costs and expenses relating to the support of the ABC service program.	(1.5)
		To eliminate Corporate Cost allocations above RCAM amount.	(13.1)
		To eliminate CWLP CIS fees in excess of settlement agreement.	(4.9)
		To eliminate 2009 ESM amount in corporate financials.	(18.8)
			(37.7)
3.	(0.4)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.2)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.2)
			(0.4)
8.	9.6	Company share of IR agreement tax savings	
		To reflect the impact of the shareholder portion of agreed tax savings on utility income.	
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	
10.	(2.3)	Capital taxes	
		Adjustment to capital taxes needed to convert the capital tax calculation to a utility "stand-alone" basis.	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2009 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(151.0)	Interest on long-term debt Expense of capital.
13.	(2.2)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
15.	(6.6)	Interest on short-term debt Expense of capital.
16.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
19.	(50.9)	Income taxes - current Income tax expense related to corporate earnings.
20.	(26.6)	Income taxes - deferred Income tax expense related to corporate earnings.

PROVINCIAL CAPITAL TAX - CALCULATED ON YEAR END BALANCES
2009 HISTORICAL YEAR

Line No.		Col. 1 Provincial Capital Tax ($Millions)
1.	Undepreciated Capital Cost - year end	3,068.0
2.	Working capital / not in service taxable work in progress	453.3
3.	Non depreciable assets - land	11.8
4.	Other unclaimed tax treatments	6.7
5.	Taxable Capital	3,539.8
6.	Less exemption	(15.0)
7.	Adjusted taxable capital	3,524.8
8.	Capital tax rate	0.225%
9.	Provincial Capital Tax	7.9

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2009 HISTORICAL YEAR

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2008	UCC Carry Forward
1	2,192,911,569	0	150,000	75,000	4.00%	(87,719,463)	2,105,342,106
51	417,743,424	263,519,530	0	131,759,765	6.00%	(32,970,191)	648,292,763
2	156,941,562	0	0	0	6.00%	(9,416,494)	147,525,068
6	20,809	0	0	0	10.00%	(2,081)	18,728
8	8,724,195	2,102,210	(845,000)	628,605	20.00%	(1,870,560)	8,110,845
10	25,335,000	9,392,472	(256,667)	4,567,903	30.00%	(8,970,871)	25,499,934
12	12,672,508	21,418,160	0	10,709,080	100.00%	(23,381,588)	10,709,080
12	0	120,172,660	0	60,086,330	50.00%	(30,043,165)	90,129,495
17	45,204	0	0	0	8.00%	(3,616)	41,588
38	4,011,635	1,750,000	(50,000)	850,000	30.00%	(1,458,491)	4,253,145
41	22,125,570	12,376,568	54,000	6,215,284	25.00%	(7,085,214)	27,470,925
13	1,132,698	3,100,000	0	1,550,000		(249,000)	3,983,698
3	290,629	0	0	0	5.00%	(14,532)	276,098
45	5,352,063	0	0	0	45.00%	(2,408,428)	2,943,635
50	3,466,711	2,660,187	0	1,330,094	55.00%	(2,638,243)	3,488,656
52	0	1,330,094	0	0	100.00%	(1,330,094)	0
Total	2,850,773,577	437,821,881	(947,667)	217,772,060		(209,562,029)	3,078,085,762

Non-utility and shared asset eliminations	344,170	
Utility Federal CCA	(209,217,859)	

Capital Cost Allowance - Ontario

Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2008	UCC Carry Forward
1	2,192,905,569	0	150,000	75,000	4.00%	(87,719,223)	2,105,336,346
51	417,743,424	263,519,530	0	131,759,765	6.00%	(32,970,191)	648,292,763
2	156,941,562	0	0	0	6.00%	(9,416,494)	147,525,068
6	20,809	0	0	0	10.00%	(2,081)	18,728
8	8,724,195	2,102,210	(845,000)	628,605	20.00%	(1,870,560)	8,110,845
10	25,335,000	9,392,472	(256,667)	4,567,903	30.00%	(8,970,871)	25,499,934
12	12,672,508	21,418,160	0	10,709,080	100.00%	(23,381,588)	10,709,080
12	0	120,172,660	0	60,086,330	50.00%	(30,043,165)	90,129,495
17	45,204	0	0	0	8.00%	(3,616)	41,588
38	4,011,635	1,750,000	(50,000)	850,000	30.00%	(1,458,491)	4,253,145
41	22,125,570	12,376,568	54,000	6,215,284	25.00%	(7,085,214)	27,470,925
13	1,132,698	3,100,000	0	1,550,000		(249,000)	3,983,698
3	287,729	0	0	0	5.00%	(14,386)	273,343
45	5,352,063	0	0	0	45.00%	(2,408,428)	2,943,635
50	3,466,711	2,660,187	0	1,330,094	55.00%	(2,638,243)	3,488,656
52	0	1,330,094	0	0	100.00%	(1,330,094)	-
Total	2,850,764,677	437,821,881	(947,667)	217,772,060		(209,561,644)	3,078,077,247

Non-utility and shared asset eliminations	344,170	(10,115,838)
Utility Provincial CCA and UCC	(209,217,474)	3,067,961,409

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAINTENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2009

Line No.	Particulars ($ 000's)	Col. 1 Actual 2009	Col. 2 Actual 2008	Col. 3 2009 Actual Over/(Under) 2008 Actual	Col. 4 Board Approved 2007 Utility O&M
1.	Finance	$ 5,981	$ 5,843	$ 138	$ 8,380
2.	Risk Management	2,865	1,695	1,170	1,986
3.	Customer Care Service Charges (including CIS)	82,042	84,583	(2,541)	83,493
4.	Customer Care Internal Costs	7,868	9,679	(1,812)	7,302
5.	Provision for Uncollectibles	17,855	16,660	1,195	15,105
6.	Energy Supply, Storage, Regulatory	19,016	19,471	(455)	21,904
7.	Legal and Corporate Services	1,170	1,147	23	1,207
8.	Operations	44,199	43,308	891	44,728
9.	Information Technology	22,695	21,247	1,448	21,790
10.	Business Development & Customer Strategy (excluding DSM)	14,255	13,364	891	19,118
11.	Human Resources (excluding benefits)	14,568	13,272	1,296	13,059
12.	Benefits	26,241	24,597	1,644	21,405
13.	Engineering	24,949	22,851	2,098	20,982
14.	Public and Government Affairs	5,764	5,484	280	5,760
15.	Non Departmental Expenses	30,899	29,497	1,403	17,305
16.	Corporate Allocations (including direct costs)	34,266	32,166	2,100	18,100
17.	Total	354,633	344,866	9,768	321,624
18.	Capitalization (A&G)	(23,902)	(21,643)	(2,259)	(17,424)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	330,731	323,223	7,508	304,200
20.	Demand Side Management Programs (DSM)	24,255	23,100	1,155	22,000
21.	Total Net Utility Operating and Maintenance Expense	$ 354,986	$ 346,323	$ 8,663	$ 326,200
22.	Regulatory Adjustments				
23.	To eliminate Corporate Cost Allocations above RCAM	(13,100)	(13,066)	(34)	
24.	To eliminate CIS fees above Customer Care settlement agreement	(4,900)	(9,811)	4,911	
25.	Total Adjustments	(18,000)	(22,877)	4,877	
26.	Utility O&M	$ 336,986	$ 323,446	$ 13,540	

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.
2) 2008 Actual and 2007 OEB approved O&M costs by department have been recasted to reflect the 2009 structure

EXPLANATION OF MAJOR CHANGES
ACTUAL 2009 O&M EXPENSES COMPARED TO ACTUAL 2008 O&M EXPENSES

The 2009 Actual Utility O&M was $337 million, which was $13.5 million higher than the 2008 Actual Utility O&M of $323.4 million. The increase was primarily driven by higher employee related costs, new CIS costs, provision for uncollectibles, and corporate cost allocations. The increased O&M costs were partially offset by higher A&G capitalization.

Line No:

2. Risk Management increased $1.2 million due to a $1.0 million insurance deductible payment related to an incident in 2009.

3. Customer Care Service Charges decreased $2.5 million due to lower old CIS fees, with new CIS hosting and support costs now residing in Information Technology.

4. Customer Care Internal Costs decreased $1.8 million due to lower Customer Care licenses and employee costs.

5. Provision for Uncollectibles increased $1.2 million due to higher write-offs of receivables as a result of the economic downturn.

9. Information Technology increased $1.4 million due to maintenance, lease, and support costs for the new CIS.

11. Human Resources (excluding Benefits) increased $1.3 million due to higher severance, labour arbitration, and facilities maintenance costs.

12. Benefits increased $1.6 million due to higher health and dental premiums, increased employee relocations, and costs of switching benefit carriers.

13. Engineering costs increased $2.1 million mainly from required increased pipeline inspections as well as incremental costs required for a new Technical Training department.

15. Non Departmental Expenses increased $1.4 million in relation to an increased variable compensation related expense.

16. Corporate Allocations increased $2.1 million largely due to higher stock based compensation.

18. A&G Capitalization increased $2.3 million due to higher employee related costs.

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2009 HISTORICAL YEAR

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component	Col. 5 (col 1x col 3) Interest & pref share Expense
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	2,180.4	57.46	6.90	3.965	150.4
2.	Short-Term Debt	148.0	3.90	1.66	0.065	2.5
3.		2,328.4	61.36		4.030	
4.	Preference Shares	100.0	2.64	3.35	0.088	3.4
						156.3
5.	Common Equity	1,366.0	36.00	9.31	3.352	
6.		3,794.4	100.00		7.470	
7.	Rate Base (Ex. B-2-1)	($Millions)			3,794.40	
8.	Utility Income (Ex. B-5-2)	($Millions)			309.30	
9.	Indicated Rate of Return				8.151	
10.	Sufficiency in Rate of Return				0.681	
11.	Net Sufficiency	($Millions)			25.84	
12.	Gross Sufficiency	($Millions)			38.57	
13.	Revenue at Existing Rates	($Millions)			2,850.90	
14.	Revenue Requirement	($Millions)			2,812.33	
15.	Gross Revenue Sufficiency	($Millions)			38.57	
	Common Equity					
16.	Allowed Rate of Return				9.310	
17.	Earnings on Common Equity				11.20	
18.	Sufficiency in Common Equity Return				1.89	

Witness: K. Culbert

UTILITY INCOME
2009 HISTORICAL YEAR

Line No.		Col. 1 Utility Income ($Millions)
1.	Gas sales	2,221.6
2.	Transportation of gas	627.7
3.	Transmission, compression and storage revenue	1.6
4.	Other operating revenue	40.9
5.	Interest and property rental	-
6.	Other income	7.5
7.	Total operating revenue (Ex. B-3-1-pg.1)	2,899.3
8.	Gas costs	1,862.6
9.	Operation and maintenance	336.9
10.	Depreciation and amortization expense	251.0
11.	Fixed financing costs	6.5
12.	Debt redemption premium amortization	0.3
13.	Company share of IR agreement tax savings	9.6
14.	Municipal and other taxes	44.4
15.	Interest and financing amortization expense	-
16.	Other interest expense	-
17.	Cost of service (Ex. B-4-1-pg.1)	2,511.3
18.	Utility income before income taxes	388.0
19.	Income tax expense (Ex. B-4-1-pg.3)	78.7
20.	Utility income	309.3

Witness: K. Culbert

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2009 HISTORICAL YEAR

Line No.		Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	2,200.8		151.9
2.	Unamortized Finance Costs	(20.4)		-
3.	(Profit)/Loss on Redemption	-		-
4.		2,180.4		151.9
5.	Calculated Cost Rate		6.90%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.66%	
	Preference Shares			
7.	Preference Share Summary	100.0		3.4
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		3.4
11.	Calculated Cost Rate		3.35%	
	Common Equity			
12.	Board Approved Formula ROE		8.31%	
13.	100 Basis Point Allowance Before Earnings Sharing		1.00%	
14.	Total Allowed ROE for ESM Purposes		9.31%	

DEFERRAL & VARIANCE ACCOUNTS FOR
CLEARANCE REQUESTED OCTOBER 1, 2010

1. The deferral and variance accounts EGD is requesting clearance of at October 1, 2010 are shown on page 2 of this schedule. The balances requested for clearance total approximately $(38.3) million, which is the combination of principal and interest amounts shown in Columns 3 and 4.

2. As explained in evidence at Exhibit B, Tab 1, Schedule 1, the requested clearance commencing in October rather than in July of 2010, is the result of additional efforts required by the Company this year in relation to the July 1, 2010 implementation of the provincial government's Harmonized Sales Tax ("HST"). Clearance of the deferral and variance accounts in October will help in minimizing complications which could arise when attempting to analyze, test, and implement billing changes in July in association with the clearance of deferral / variance accounts and the required HST changes.

3. As shown within the footnotes or evidence referenced in the footnotes on page 2, EGD has provided additional explanation information for selected accounts. The remaining accounts have either been approved in another proceeding, or have a previously established process which has been followed in determining account balances.

4. The interest calculated on the principal balances reflects the use of the Board's January 1, 2010 prescribed interest rates for deferral and variance accounts. The eventual amounts of interest to be cleared will be calculated using any updated Board quarterly prescribed interest rates throughout 2010.

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at February 28, 2010 Principal ($000's)	Col. 2 Actual at February 28, 2010 Interest ($000's)	Col. 3 Forecast for clearance at October 1, 2010 Principal ($000's)	Col. 4 Forecast for clearance at October 1, 2010 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2008 DSMVA	(73.3)	(56.1)	(73.3)	(56.3)
2.	Lost Revenue Adjustment Mechanism	2008 LRAM	37.3	0.1	37.3	0.2
3.	Shared Savings Mechanism V/A	2008 SSMVA	5,803.2	5.3	5,803.2	24.2
4.	Class Action Suit D/A	2009/10 CASDA	18,838.2	1,534.4	4,709.5	414.1 [1]
5.	Deferred Rebate Account	2009 DRA	2.7	(0.1)	-	-
6.	Gas Distribution Access Rule Costs D/A	2009 GDARCDA	188.7	0.8	2,838.8	- [2]
7.	Ontario Hearing Costs V/A	2009 OHCVA	531.7	0.6	474.5	2.0
8.	Open Bill Service D/A	2009/10 OBSDA	526.2	15.9	87.7	3.0 [3]
9.	Open Bill Access V/A	2009/10 OBAVA	476.7	5.9	79.5	1.2 [3]
10.	Municipal Permit Fees D/A	2009 MPFDA	916.1	-	202.2	- [2]
11.	Average Use True-Up V/A	2009 AUTUVA	5,626.9	5.2	5,626.9	23.4 [4]
12.	Tax Rate and Rule Change V/A	2009 TRRCVA	(350.0)	(0.3)	(350.0)	(1.7) [5]
13.	Earnings Sharing Mechanism D/A	2009 ESMDA	(18,750.0)	(17.2)	(19,300.0)	(77.4) [6]
14.	IFRS Transition Costs D/A	2009 IFRSTCDA	2,111.0	1.9	2,111.0	8.9
15.	Ex-Franchise Third Party Billing Services D/A	2009 EFTPBSDA	(27.9)	-	(27.9)	(0.1)
16.	Total non commodity related accounts		15,857.5	1,496.4	2,219.4	341.5
	Commodity Related Accounts					
17.	Purchased Gas V/A	2009 PGVA	(116,672.9)	(2,287.8)	(39,270.0)	(2,497.4) [7]
18.	Transactional Services D/A	2009 TSDA	(7,062.1)	(9.5)	(7,062.1)	(31.9)
19.	Unaccounted for Gas V/A	2009 UAFVA	9,596.7	8.8	9,596.7	39.6
20.	Storage and Transportation D/A	2009 S&TDA	(1,594.8)	(4.6)	(1,594.8)	(9.5)
21.	Total commodity related accounts		(115,733.1)	(2,293.1)	(38,330.2)	(2,499.2)
22.	Total Deferral and Variance Accounts		(99,875.6)	(796.7)	(36,110.8)	(2,157.7)

Notes:

1. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years (2008 - 2012). The 2008 installment was cleared in July and August 2008, and the 2009 installment will occur in April and May 2010. The Company now proposes to clear the 2010, or third installment, beginning October 1, 2010. The forecast of interest to be cleared, utilized the Board's current prescribed interest rate for deferral accounts for (Q2 2010) but will be updated with future prescribed rates as well.
2. The forecast 2009 GDARCDA and 2009 MPFDA amounts for clearance are the result of revenue requirement calculations. (Found in evidence at Ex.C, T1, S2 and Ex.C, T1, S3)
3. The forecast OBSDA and OBAVA balances are in accordance with the EB-2009-0043 approved settlement agreement.
4. The AUTUVA explanation is found in evidence at Ex.C, T1, S5.
5. The TRRCVA explanation is found in evidence at Ex.C, T1, S4.
6. The ESMDA explanation is found in evidence at Ex.B, T1, S1&2.
7. This is a projected final 2009 PGVA balance. The actual balance proposed for clearance will be determined, and updated, once the impact of the existing rate Rider "C", in place until March 31, 2010, is determined.

Witness: K. Culbert

GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNT

1. Within the EB-2008-0219 Supplementary Order, the Board approved a 2009 Gas Distribution Access Rule Costs Deferral Account ("GDARCDA") for the costs associated with the Company maintaining compliance with the Board's Gas Distribution Access Rule directives.

2. EGD recorded all of the costs incurred in 2009 relative to this deferral account, both capital and operating expense costs.

3. In the EB-2007-0615 Final Rate Order and EB-2009-0055 Decision, the Board approved clearance of the 2007 and 2008 GDAR compliance costs through revenue requirement calculations to customers as one time rate rider adjustments. The result is that the Company's distribution rates do not contain the ongoing impacts of GDAR compliance spending, and therefore, associated rate rider adjustments need to be established and cleared annually. As a result, the cumulative 2010 revenue requirement impact of the 2007, 2008, and 2009 Board Approved deferral account costs requires clearance through a rate rider adjustment. The Company is once again not seeking to recover the total amount of cash expended, as is the case for the majority of deferral accounts, but is proposing to recover on a one time basis the 2010 annual revenue requirement, determined through a revenue requirement / cost of service type of calculation, for the 2007 through 2009 cumulative expenditures. This revenue requirement treatment is consistent with the EB-2007-0615 and EB-2009-0055 Board Decisions. In its EB-2006-0034 decision, the Board accepted the disposition of the 2005 and 2006 GDAR deferral accounts whereby the Company capitalized the related amounts into rate base and effected the recovery of those accounts in a cost of service revenue requirement manner.

4. Within this revenue requirement calculation, the typical items recovered in a cost of service revenue requirement such as depreciation, total return on rate base including interest, equity and taxes, and other operating costs are being requested for recovery. The Company has used the 2007 Board Approved capital structure as a base within the revenue requirement calculation as it is the underlying capital structure within base rates which are used in EGD's 2008-2012 Incentive Regulation approved rates mechanism. This is consistent with the 2007 and 2008 Approved GDARCDA revenue requirement determinations.

5. The Company is proposing to recover $2.8 million as a one time billing adjustment in October, 2010 as shown within the proposed one time clearance balances at Exhibit C, Tab 1, Schedule 1, page 2, Columns 3 and 4. The determination of the 2010 annual revenue requirement associated with the combined 2007, 2008, and 2009 GDAR deferral account costs is shown in pages 3 through 7 of this schedule.

ONTARIO UTILITY CAPITAL STRUCTURE
2007, 2008 & 2009 GDARCDA IMPACTS

2007 Approved Capital Structure

Line No.		Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component
		%	%	%
1.	Long-term debt	59.65	7.31	4.36
2.	Short-term debt	1.68	4.12	0.07
3.		61.33		4.43
4.	Preference shares	2.67	5.00	0.13
5.	Common equity	36.00	8.39	3.02
6.		100.00		7.58

	($ 000's)	2008	2009	2010	2011	2012
7.	Ontario Utility Income	(73.7)	(78.5)	(1,491.0)	(1,569.3)	(1,595.1)
8.	Rate base	6,273.7	5,455.9	4,251.9	2,640.3	1,028.7
9.	Indicated rate of return	(1.17)%	(1.44)%	(35.07)%	(59.44)%	(155.06)%
10.	(Def.) / suff. in rate of return	(8.75)%	(9.02)%	(42.65)%	(67.02)%	(162.64)%
11.	Net (def.) / suff.	(548.9)	(492.1)	(1,813.4)	(1,769.5)	(1,673.1)
12.	Gross (def.) / suff.	(859.3)	(770.4)	(2,838.8)	(2,770.0)	(2,619.1)

ONTARIO UTILITY RATE BASE
2007, 2008 & 2009 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Property, plant, and equipment					
1.	Cost or redetermined value	7,004.5	7,676.4	8,060.5	8,060.5	8,060.5
2.	Accumulated depreciation	(730.8)	(2,220.5)	(3,808.6)	(5,420.2)	(7,031.8)
3.		6,273.7	5,455.9	4,251.9	2,640.3	1,028.7
	Allowance for working capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-
12.		-	-	-	-	-
13.	Ontario utility rate base	6,273.7	5,455.9	4,251.9	2,640.3	1,028.7

ONTARIO UTILITY INCOME
2007, 2008 & 2009 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Revenue					
1.	Gas sales	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-
4.	Other operating revenue	-	-	-	-	-
5.	Other income	-	-	-	-	-
6.	Total revenue	-	-	-	-	-
	Costs and expenses					
7.	Gas costs	-	-	-	-	-
8.	Operation and Maintenance	40.4	124.8	130.2	-	-
9.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6	1,611.6
10.	Municipal and other taxes	10.4	1.1	-	-	-
11.	Total costs and expenses	1,512.4	1,667.1	1,741.8	1,611.6	1,611.6
12.	Utility income before inc. taxes	(1,512.4)	(1,667.1)	(1,741.8)	(1,611.6)	(1,611.6)
	Income taxes					
13.	Excluding interest shield	(1,338.3)	(1,501.3)	(182.7)	-	-
14.	Tax shield on interest expense	(100.4)	(87.3)	(68.1)	(42.3)	(16.5)
15.	Total income taxes	(1,438.7)	(1,588.6)	(250.8)	(42.3)	(16.5)
16.	Ontario utility net income	(73.7)	(78.5)	(1,491.0)	(1,569.3)	(1,595.1)

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2007, 2008 & 2009 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
1.	Utility income before income taxes	(1,512.4)	(1,667.1)	(1,741.8)	(1,611.6)	(1,611.6)
	Add Backs					
2.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6	1,611.6
3.	Large corporation tax	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-
6.	Total added back	1,461.6	1,541.2	1,611.6	1,611.6	1,611.6
7.	Sub total - pre-tax income plus add backs	(50.8)	(125.9)	(130.2)	-	-
	Deductions					
8.	Capital cost allowance - Federal	3,654.5	4,030.3	375.7	-	-
9.	Capital cost allowance - Provincial	3,654.5	4,030.3	375.7	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-
16.	Total Deductions - Federal	3,654.5	4,030.3	375.7	-	-
17.	Total Deductions - Provincial	3,654.5	4,030.3	375.7	-	-
18.	Taxable income - Federal	(3,705.3)	(4,156.2)	(505.9)	-	-
19.	Taxable income - Provincial	(3,705.3)	(4,156.2)	(505.9)	-	-
20.	Income tax provision - Federal	(819.6)	(919.4)	(111.9)	-	-
21.	Income tax provision - Provincial	(518.7)	(581.9)	(70.8)	-	-
22.	Income tax provision - combined	(1,338.3)	(1,501.3)	(182.7)	-	-
23.	Part V1.1 tax	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(1,338.3)	(1,501.3)	(182.7)	-	-
	Tax shield on interest expense					
26.	Rate base as adjusted	6,273.7	5,455.9	4,251.9	2,640.3	1,028.7
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	277.9	241.7	188.4	117.0	45.6
29.	Combined tax rate	36.120%	36.120%	36.120%	36.120%	36.120%
30.	Income tax credit	(100.4)	(87.3)	(68.1)	(42.3)	(16.5)
31.	Total income taxes	(1,438.7)	(1,588.6)	(250.8)	(42.3)	(16.5)

ONTARIO UTILITY REVENUE REQUIREMENT
2007, 2008 & 2009 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Cost of capital					
1.	Rate base	6,273.7	5,455.9	4,251.9	2,640.3	1,028.7
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	475.5	413.6	322.3	200.1	78.0
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	40.4	124.8	130.2	-	-
6.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6	1,611.6
7.	Municipal and other taxes	10.4	1.1	-	-	-
8.	Cost of service	1,512.4	1,667.1	1,741.8	1,611.6	1,611.6
	Misc. & Non-Op. Rev					
9.	Other operating revenue	-	-	-	-	-
10.	Other income	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-
	Income taxes on earnings					
12.	Excluding tax shield	(1,338.3)	(1,501.3)	(182.7)	-	-
13.	Tax shield provided by interest expense	(100.4)	(87.3)	(68.1)	(42.3)	(16.5)
14.	Income taxes on earnings	(1,438.7)	(1,588.6)	(250.8)	(42.3)	(16.5)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	(859.3)	(770.4)	(2,838.8)	(2,770.0)	(2,619.1)
16.	Net (def.) / suff.	(548.9)	(492.1)	(1,813.4)	(1,769.5)	(1,673.1)
17.	Taxes on (def.) / suff.	310.4	278.3	1,025.4	1,000.5	946.0
18.	Revenue requirement	859.6	770.4	2,838.7	2,769.9	2,619.1
	Revenue at existing Rates					
19.	Gas sales	0.0	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.3	0.3	0.0	0.0	0.0
23.	Revenue at existing rates	0.3	0.3	0.0	0.0	0.0
24.	Gross revenue (def.) / suff.	(859.3)	(770.1)	(2,838.7)	(2,769.9)	(2,619.1)

Witness: K. Culbert

MUNICIPAL PERMIT FEES DEFERRAL ACCOUNT

1. Within the EB-2008-0219 Supplementary Order, the Board approved the 2009 Municipal Permit Fees Deferral Account ("MPFDA") for fees imposed by Municipal governments for activities, such as road cuts, incurred in association with the Company's construction and maintenance operations. These are new charges, not included in base 2007 rates, resulting from changes to Ontario regulations made under the Municipal Act, 2001.

2. All amounts in relation to the 2009 deferral account are capital expenditure related, as were amounts related to the Board's approval of the 2008 account.

3. In the EB-2009-0055 Decision, the Board approved clearance of the 2008 MPFDA costs through a revenue requirement calculation, to be cleared to customers as a one time rate rider adjustment. As a result, the Company's distribution rates do not contain the ongoing impact of the 2008 MPFDA spending. Therefore associated rate rider adjustments need to be established and cleared annually. As a result, the cumulative 2010 revenue requirement impact of the 2008 and 2009 Board Approved deferral account costs requires clearance through a rate rider adjustment. The Company is not seeking to recover the total amount of cash expended, as is the case for the majority of deferral accounts, but is proposing to recover on a one time basis the 2010 annual revenue requirement, determined through a revenue requirement / cost of service type of calculation, for the 2008 and 2009 cumulative expenditures. This revenue requirement treatment is consistent with the EB-2009-0055 Board Decision regarding the clearance of the 2008 MPFDA, and multiple decisions regarding the clearance of GDARCDA amounts. The treatment/clearance of MPFDA costs in the same manner as GDARCDA costs is appropriate as the costs for each are predominantly capital expenditure related.

4. The revenue requirement calculation includes the typical items recovered in a cost of service calculation such as depreciation, total return on rate base including interest, equity and taxes, and other operating costs. The Company has used the 2007 Board Approved capital structure within the revenue requirement calculation, the same as that used within the GDAR deferral account treatment, as it is the underlying capital structure within base rates which are used in EGD's 2008 through 2012 Incentive Regulation approved rates mechanism.

5. The Company is proposing to recover $0.2 million as a one time billing adjustment in October, 2010 as shown within the proposed one time clearance balances within Exhibit C, Tab 1, Schedule 1, page 2, Columns 3 and 4. The determination of the 2010 annual revenue requirement associated with the 2008 and 2009 MPFDA is shown in pages 3 through 7 of this schedule.

ONTARIO UTILITY CAPITAL STRUCTURE
2008 & 2009 MPFDA IMPACTS

2007 Approved Capital Structure

Line No.		Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component
		%	%	%
1.	Long-term debt	59.65	7.31	4.36
2.	Short-term debt	1.68	4.12	0.07
3.		61.33		4.43
4.	Preference shares	2.67	5.00	0.13
5.	Common equity	36.00	8.39	3.02
6.		100.00		7.58

	($ 000's)	2008	2009	2010	2011	2012
7.	Ontario Utility Income	(1.6)	(12.9)	(22.9)	(29.0)	(34.3)
8.	Rate base	204.3	1,038.8	1,538.4	1,466.4	1,394.4
9.	Indicated rate of return	(0.78)%	(1.24)%	(1.49)%	(1.98)%	(2.46)%
10.	(Def.) / suff. in rate of return	(8.36)%	(8.82)%	(9.07)%	(9.56)%	(10.04)%
11.	Net (def.) / suff.	(17.1)	(91.6)	(139.5)	(140.2)	(140.0)
12.	Gross (def.) / suff. (Note: 1)	(25.7)	(136.7)	(202.2)	(195.4)	(189.8)

Note: 1 Includes 2008 permit fees of $0.7 million and 2009 permit fees of $0.9 million. Permit fees in 2010 and beyond will increase the prospective annual revenue requirements.

ONTARIO UTILITY RATE BASE
2008 & 2009 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Property, plant, and equipment					
1.	Cost or redetermined value	207.0	1,070.6	1,633.7	1,633.7	1,633.7
2.	Accumulated depreciation	(2.7)	(31.8)	(95.3)	(167.3)	(239.3)
3.		204.3	1,038.8	1,538.4	1,466.4	1,394.4
	Allowance for working capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-
12.		-	-	-	-	-
13.	Ontario utility rate base	204.3	1,038.8	1,538.4	1,466.4	1,394.4

ONTARIO UTILITY INCOME
2008 & 2009 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Revenue					
1.	Gas sales	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-
4.	Other operating revenue	-	-	-	-	-
5.	Other income	-	-	-	-	-
6.	Total revenue	-	-	-	-	-
	Costs and expenses					
7.	Gas costs	-	-	-	-	-
8.	Operation and Maintenance	-	-	-	-	-
9.	Depreciation and amortization	10.7	48.6	72.0	72.0	72.0
10.	Municipal and other taxes	1.6	3.5	1.1	-	-
11.	Total costs and expenses	12.3	52.1	73.1	72.0	72.0
12.	Utility income before inc. taxes	(12.3)	(52.1)	(73.1)	(72.0)	(72.0)
	Income taxes					
13.	Excluding interest shield	(7.7)	(24.0)	(29.1)	(24.6)	(21.5)
14.	Tax shield on interest expense	(3.0)	(15.2)	(21.1)	(18.4)	(16.2)
15.	Total income taxes	(10.7)	(39.2)	(50.2)	(43.0)	(37.7)
16.	Ontario utility net income	(1.6)	(12.9)	(22.9)	(29.0)	(34.3)

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2008 & 2009 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
1.	Utility income before income taxes	(12.3)	(52.1)	(73.1)	(72.0)	(72.0)
	Add Backs					
2.	Depreciation and amortization	10.7	48.6	72.0	72.0	72.0
3.	Large corporation tax	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-
6.	Total added back	10.7	48.6	72.0	72.0	72.0
7.	Sub total - pre-tax income plus add backs	(1.6)	(3.5)	(1.1)	-	-
	Deductions					
8.	Capital cost allowance - Federal	21.5	69.3	92.6	87.0	81.8
9.	Capital cost allowance - Provincial	21.5	69.3	92.6	87.0	81.8
10.	Items capitalized for regulatory purposes	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-
16.	Total Deductions - Federal	21.5	69.3	92.6	87.0	81.8
17.	Total Deductions - Provincial	21.5	69.3	92.6	87.0	81.8
18.	Taxable income - Federal	(23.1)	(72.8)	(93.7)	(87.0)	(81.8)
19.	Taxable income - Provincial	(23.1)	(72.8)	(93.7)	(87.0)	(81.8)
20.	Income tax provision - Federal	(4.5)	(13.8)	(16.9)	(14.4)	(12.3)
21.	Income tax provision - Provincial	(3.2)	(10.2)	(12.2)	(10.2)	(9.2)
22.	Income tax provision - combined	(7.7)	(24.0)	(29.1)	(24.6)	(21.5)
23.	Part V1.1 tax	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(7.7)	(24.0)	(29.1)	(24.6)	(21.5)
	Tax shield on interest expense					
26.	Rate base as adjusted	204.3	1,038.8	1,538.4	1,466.4	1,394.4
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	9.1	46.0	68.2	65.0	61.8
29.	Combined tax rate	33.500%	33.000%	31.000%	28.250%	26.250%
30.	Income tax credit	(3.0)	(15.2)	(21.1)	(18.4)	(16.2)
31.	Total income taxes	(10.7)	(39.2)	(50.2)	(43.0)	(37.7)

ONTARIO UTILITY REVENUE REQUIREMENT
2008 & 2009 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Cost of capital					
1.	Rate base	204.3	1,038.8	1,538.4	1,466.4	1,394.4
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	15.5	78.7	116.6	111.2	105.7
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	-	-	-	-	-
6.	Depreciation and amortization	10.7	48.6	72.0	72.0	72.0
7.	Municipal and other taxes	1.6	3.5	1.1	-	-
8.	Cost of service	12.3	52.1	73.1	72.0	72.0
	Misc. & Non-Op. Rev					
9.	Other operating revenue	-	-	-	-	-
10.	Other income	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-
	Income taxes on earnings					
12.	Excluding tax shield	(7.7)	(24.0)	(29.1)	(24.6)	(21.5)
13.	Tax shield provided by interest expense	(3.0)	(15.2)	(21.1)	(18.4)	(16.2)
14.	Income taxes on earnings	(10.7)	(39.2)	(50.2)	(43.0)	(37.7)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	(25.7)	(136.7)	(202.2)	(195.4)	(189.8)
16.	Net (def.) / suff.	(17.1)	(91.6)	(139.5)	(140.2)	(140.0)
17.	Taxes on (def.) / suff.	8.6	45.1	62.7	55.2	49.8
18.	Revenue requirement	25.7	136.7	202.2	195.4	189.8
	Revenue at existing Rates					
19.	Gas sales	0.0	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.0	0.0	0.0	0.0	0.0
23.	Revenue at existing rates	0.0	0.0	0.0	0.0	0.0
24.	Gross revenue (def.) / suff.	(25.7)	(136.7)	(202.2)	(195.4)	(189.8)

TAX RATE AND RULE CHANGE VARIANCE ACCOUNT

1. Within the EB-2008-0219 Supplementary Order, the Board approved a 2009 Tax Rate and Rule Change Variance Account (“TRRCVA”) to record the ratepayer portion of any variance relating to changes in tax rates and rules which differ from those assumed and embedded in rates. In the event that actual tax rates and rules do not equate to those expected within the tax savings sharing mechanism embedded in the 2009 approved distribution revenue formula, the Company is required to calculate the appropriate amounts which are to be shared equally, based upon 2007 Board Approved base level benchmarks, and record the resulting variance in this account to be cleared to ratepayers.

2. Included within EGD’s 2009 approved distribution revenue was a cumulative annual reduction of $9.25 million to distribution revenue and ratepayer rates ($7.44 million reduction to 2008 rates, EB-2007-0615, Final Rate Order, Appendix A, page 1, Column 1, Line 10, plus an incremental $1.8 million reduction to 2009 rates, EB-2008-0219, Final Rate Order, Appendix A, page 1, Column 1, Line 9), which represented a 50% share of the 2009 cumulative annual anticipated tax reductions of $18.51 million associated with certain expected tax rate and rule changes. Details of the approved forecast tax reductions to be incorporated into rates, for EGD’s entire IR term, were included within the EB-2007-0615, Final Rate Order, Schedule 1, page 1, of Appendix A, which is reproduced at page 4 of this exhibit.

3. The $18.51 million was calculated based on changes to corporate income tax rates, provincial capital tax rates, and capital cost allowance rates that were anticipated at the time of the agreement and forecase to occur in the future. However, as indicated in Exhibit C, Tab 1, Schedule 4, in the EB-2009-0172 proceeding, additional changes have occurred which resulted in a required updating of the tax sharing agreement amounts. The revised approved tax sharing schedule, updated

on page 4 of Exhibit C, Tab 1, Schedule 4 from the EB-2009-0172 proceeding, is reproduced at page 3 of this exhibit. With regard to the impacts on 2009, the original tax savings agreement took account of purchases of certain computer equipment previously considered within CCA class 45 at 45% changing to class 50 at 55%. A new class, 52, has since been passed into law and allows for a 100% write off (with no half year rule), of such purchases between January 28, 2009 and February 1, 2011.

4. The result of this change impacted the amount of tax savings that were anticipated in 2009 and beyond. The updated tax sharing schedule included at page 3 of this exhibit incorporates the impact of the new CCA class 52.

5. The updated cumulative annual shared tax savings amounts resulting from this change, and other prospective changes, are shown at Line 50, Columns 2 through 5 on page 3 of this exhibit. The original agreed upon cumulative annual shared amounts are shown at Line 51 on page 3, and at Line 45 on page 4, which is reproduced from of the EB-2007-0615 Rate Order Schedule 1.

6. The impact for 2009 is that the original forecast tax savings, in the amount of $9.25 million (Line 51, Col. 2, p. 3), now becomes $9.60 million (Line 50, Col. 2, p. 3). The increase of $0.35 million (Line 52, Col. 2, p. 3), which due to timing, could not be incorporated into 2009 rates, has been credited to the 2009 Tax Rate and Rule Change Variance Account ("TRRCVA"). The Company is requesting clearance of the account along with the other deferral and variance accounts shown in Exhibit C, Tab 1, Schedule 1, page 2, to be cleared to ratepayers commencing October 1, 2010.

Schedule 1

Summary - Sharing of Tax Change Savings (Updated for new CCA Class 52)

New CCA Class 52 in effect for new purchases within, February through December 2009, 2010, and January of 2011

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		2008	**2009**	**2010**	**2011**	**2012**	
	Tax Related Amounts Forecast from CCA Rate Changes **($ Millions)**						
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45/50) - Opening UCC Balance	1.54	2.24	1.14	0.51	1.64	
6.	New purchases (2007 Board Approved additions) -**with update for new Class 52**	2.13	2.13	2.13	2.13	2.13	
7.	**Re-grouping of amounts eligible for Class 52 (included at line 11)**	-	(1.95)	(2.13)	(0.18)	-	
8.	Capital Cost Allowance (CCA) at 55% -2007 Federal Budget tax rule CCA rate	1.43	1.28	0.63	0.82	1.49	
9.	Closing Undepreciated Capital Cost (UCC)	2.24	1.14	0.51	1.64	2.28	
10.	Computer Equipment (**New Class 52**) - Opening UCC Balance	-	-	-	-	-	
11.	New purchases (2007 Board Approved additions) -**with update for new Class 52**	-	1.95	2.13	0.18	-	
12.	Capital Cost Allowance (CCA) at 100% -2007 Federal Budget tax rule CCA rate	-	1.95	2.13	0.18	-	
13.	Closing Undepreciated Capital Cost (UCC)	-	-	-	-	-	
14.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.76	687.71	898.86	1101.57	
15.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
16.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
17.	Closing Undepreciated Capital Cost (UCC)	467.76	687.71	898.86	1101.57	1296.16	
18.	Distribution Assets (Class 51) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
19.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
20.	Capital Cost Allowance (CCA) at 6% -2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
21.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
22.	CCA Difference	7.27	12.82	15.85	17.29	20.67	
23.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	32.00%	30.50%	29.00%	
24.	Tax Impact	2.44	4.23	5.07	5.27	6.00	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.46	7.59	8.44	33.47
26.	Incremental Amount	3.65	2.66	1.14	0.13	0.86	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.57**	**$0.07**	**$0.43**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
28.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
29.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
30.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
31.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
32.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
33.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	32.00%	30.50%	29.00%	
34.	Tax Rate Variance	2.62%	3.12%	4.12%	5.62%	7.12%	
35.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	9.57	13.06	16.55	
36.	Grossed-up Tax Savings	9.16	10.82	14.07	18.79	23.31	76.15
37.	Incremental Amount	9.16	1.66	3.25	4.72	4.52	
38.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$1.63**	**$2.36**	**$2.25**	
	Tax Related Amounts Forecast from Capital Tax Rate Changes						
39.	2007 Taxable Capital as Filed (EB-2006-0034, D3,T1,S1,P6,L7)	3,571.0	3,571.0	3,571.0	3,571.0	3,571.0	
40.	2007 Decision and Settlement Agreement Adjustments to Taxable Capital	(118.8)	(118.8)	(118.8)	(118.8)	(118.8)	
41.	2007 Board Approved Taxable Capital	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
42.	2007 Board Approved Capital Tax Rate (EB-2006-0034, D3,T1,S1,P6,L8)	0.285%	0.285%	0.285%	0.285%	0.285%	
43.	Anticipated Capital Tax Rates During the IR Term	0.225%	0.225%	0.150%	0.000%	0.000%	
44.	Capital Tax Rate Variance	0.060%	0.060%	0.135%	0.285%	0.285%	
45.	Annual Capital Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	2.07	2.07	4.66	9.84	9.84	28.48
46.	Incremental Amount	2.07	0.00	2.59	5.18	0.00	
47.	**50% of the Amount to Reduce Rates**	**$1.03**	**$0.00**	**$1.29**	**$2.59**	**$0.00**	
48.	**Cumulative Total Forecast Tax Related Amount (lines 25+36+45)**	**14.88**	**19.20**	**26.19**	**36.22**	**41.59**	138.10
49.	**Total Incremental Ratepayer Amounts into rates (lines 26+37+46)**	**$7.44**	**$2.16**	**$3.49**	**$5.02**	**$2.68**	
50.	**Total Updated Annual Ratepayer & Company Shareholder Tax Savings (50% of row 48)**	**$7.44**	**$9.60**	**$13.09**	**$18.11**	**$20.79**	$69.03
51.	***Total Original Agreement Annual Ratepayer Tax Savings***	***$7.44***	***$9.25***	***$12.91***	***$18.34***	***$20.91***	*$68.85*
52.	Amount to be credited to 2009 TRRCVA for return to ratpayers ($9.60M - $9.25M) (col.2, line 50 - 51)		$0.35				
53.	Ratepayer share of 2010 incremental tax amounts ($13.09 - $9.25) (col.3, line 50 - col.2, line 51)			3.84			
54.	Ratepayer share of 2011 incremental tax amounts ($18.11M - $13.09M) (col.4, line 50 - col.3, line 50)				$5.02		
55.	Ratepayer share of 2012 incremental tax amounts ($20.79M - $18.11M) (col.5, line 50 - col.4, line 50)					$2.68	

Witness: K. Culbert

Originally
EB-2007-0615
Draft Rate Order
Schedule 1

Schedule 1

Summary - Sharing of Tax Change Forecast Amounts

Line No.	Tax Related Amounts Forecast from CCA Rate Changes ($ Millions)	Col. 1 2008	Col. 2 2009	Col. 3 2010	Col. 4 2011	Col. 5 2012	Col. 6
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45) - Opening UCC Balance	1.54	2.24	2.55	2.69	2.76	
6.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
7.	Capital Cost Allowance (CCA) at 55% - 2007 Federal Budget tax rule CCA rate	1.43	1.82	1.99	2.07	2.10	
8.	Closing Undepreciated Capital Cost (UCC)	2.24	2.55	2.69	2.76	2.78	
9.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.77	687.72	898.87	1101.58	
10.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
11.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
12.	Closing Undepreciated Capital Cost (UCC)	467.77	687.72	898.87	1101.58	1296.17	
13.	Distribution Assets (Class 1) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
14.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
15.	Capital Cost Allowance (CCA) at 6% - 2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
16.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
17.	CCA Difference	7.27	11.41	15.08	18.36	21.29	
18.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	32.00%	30.50%	29.00%	
19.	Tax Impact	2.44	3.76	4.83	5.60	6.17	
20.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.66	5.62	7.10	8.06	8.69	33.13
21.	Incremental Amount	3.66	1.95	1.48	0.96	0.64	
22.	**50% of the Amount to Reduce Rates**	**$1.83**	**$0.98**	**$0.74**	**$0.48**	**$0.32**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
23.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
24.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
25.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
26.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
27.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
28.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	32.00%	30.50%	29.00%	
29.	Tax Rate Variance	2.62%	3.12%	4.12%	5.62%	7.12%	
30.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	9.57	13.06	16.55	
31.	Grossed-up Tax Savings	9.16	10.82	14.07	18.79	23.31	76.15
32.	Incremental Amount	9.16	1.66	3.25	4.72	4.52	
33.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$1.63**	**$2.36**	**$2.25**	
	Tax Related Amounts Forecast from Capital Tax Rate Changes						
34.	2007 Taxable Capital as Filed (EB-2006-0034, D3,T1,S1,P6,L7)	3,571.0	3,571.0	3,571.0	3,571.0	3,571.0	
35.	2007 Decision and Settlement Agreement Adjustments to Taxable Capital	(118.8)	(118.8)	(118.8)	(118.8)	(118.8)	
36.	2007 Board Approved Taxable Capital	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
37.	2007 Board Approved Capital Tax Rate (EB-2006-0034, D3,T1,S1,P6,L8)	0.285%	0.285%	0.285%	0.285%	0.285%	
38.	Anticipated Capital Tax Rates During the IR Term	0.225%	0.225%	0.150%	0.000%	0.000%	
39.	Capital Tax Rate Variance	0.060%	0.060%	0.135%	0.285%	0.285%	
40.	Annual Capital Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	2.07	2.07	4.66	9.84	9.84	28.48
41.	Incremental Amount	2.07	0.00	2.59	5.18	0.00	
42.	**50% of the Amount to Reduce Rates**	**$1.03**	**$0.00**	**$1.29**	**$2.59**	**$0.00**	
43.	**Cumulative Total Forecast Tax Related Amount (lines 20+31+40)**	**14.89**	**18.51**	**25.83**	**36.69**	**41.84**	**137.76**
44.	**Total Incremental Ratepayer Amounts into rates (lines 21+32+41)**	**$7.44**	**$1.81**	**$3.66**	**$5.43**	**$2.57**	
45.	**Total Annual Ratepayer Tax Savings (50% of row 43)**	**$7.44**	**$9.25**	**$12.91**	**$18.34**	**$20.91**	**$68.85**
46.	**50% Ratepayer and Company Shareholder ESM Amount During the IR Term**	**$68.85**					

Witness: K. Culbert

2009 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2009 Average Use True-up Variance Account ("AUTUVA") amount.

2. Table 1 of Appendix A details the calculations that result in the amount of $5.63 million that will be debited to rate payers. This is primarily due to the unexpected and rapidly deteriorating economic conditions experienced since October 2008 after the 2009 Budget was developed (Summer 2008). This was also discussed in detail within the variance explanation between the 2009 Bridge Year Estimate and the 2009 Board Approved Budget which was a component of the 2010 volume budget evidence filed in EB-2009-0172 at Exhibit B, Tab 1, Schedule 5.

3. Other than the unexpected impact of a slowing economy, the remaining shortfall in general service average uses was not unanticipated although it was difficult to segregate from the ongoing actual conservation and energy efficiency trend. As indicated in the 2009 volume budget evidence filed at EB-2008-0219, Exhibit B, Tab 1, Schedule 5, pages 10, 11 and 19, both Rate 1 and Rate 6 average use budget numbers reflect a tendency to be on the high side due to difficulties encountered in identifying and applying the estimated energy savings resulting from the new 2006 Building Code and other green energy technology.

4. Besides the impact of technology on usages, other incremental conservation initiatives originated by customers themselves or promoted by government

programs in 2009 would also further reduce residential usages below budgeted volumes. For instance, factors causing residential usage to fall short of budgeted levels include the following:

- the energy conservation impact of the federal Home Renovation Tax Credit announced in January 2009 would not be incorporated into 2009 budget that was developed in Summer 2008 based upon historical actual trend; and
- a culture of conservation further promoted by the Ontario Ministry of Energy and Infrastructure in 2009 with the passage of the Green Energy Act[1] and doubling its investment in its Home Energy Savings program[2].

5. In addition to the impact of the slowing economy, technology and behaviour on usages, unexpected net rate switching losses from a general service rate class to contract rate (or transfer losses) of 74.5 10^6m^3 (or $2.8 million) also contributed to the shortfall in Rate 6 usage between actual and budget. Tables 2 and 3 in the Appendix illustrate that timing of migration (i.e., migrated later than expected) as well as the impact of some customers that still stayed in a contract rate class even though they would realize a financial benefit (i.e., cost savings as mentioned at EB-2008-0219, Exhibit B, Tab 1, Schedule 5, pp. 16 and 17) by migrating to Rate 6 were factors contributing to these unexpected net rate switching losses.

6. Last year, unanticipated rate switching from the contract market to general service Rate 6 resulted in net transfer gain of $4.16 million (103.9 10^6m^3) that was more

[1] "Ontario's bold new plan for a green economy: McGuinty Government To Boost Renewable Energy, Economic Growth And Create A Culture of Conservation." February 23, 2009. <http://www.newswire.ca/en/releases/archive/February2009/23/c2932.html>
[2] "Ontario Helps Homeowners Save On Energy Costs." Ministry of Energy and Infrastructure. May 22, 2009. <http://ogov.newswire.ca/ontario/GPOE/2009/05/22/c6706.html?lmatch=&lang=_e.html>

than the offset of the shortfall in both of 2008 actual residential and Rate 6 usage variances of 19.3 10^6m^3 ($1.48 million) and 0.6 10^6m^3, respectively. Consequently, this resulted in a net total of $2.65 million credited to ratepayers based upon a partial (three-months only) impact of the unexpected global financial crisis that occurred in 2008 and was reflected in last year's average usages. On the other hand, the full year impact of this slowing economy was realized in the 2009 actual usage variances.

7. Further rate class detail and explanations are provided at Exhibit B, Tab 2, Schedules 2 to 4.

8. As filed in response to VECC's Interrogatory at EB-2008-0219, Exhibit I, Tab 7, Schedule 8, part(d), the numerical calculation of Table 1 was previously illustrated and explained. In accordance with the settlement agreement filed at EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 15 and 16 and EB-2007-0615, Decision and Rate Order, Appendix C, page 25, the purpose of the AUTUVA is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6, and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use excludes the volumetric impact of Demand Side Management programs in that year. The revenue impact is calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism ("LRAM"), extended by the average use volume variance per customer and the number of customers.

9. As was the case in previous rate case proceedings, the audited actual volume savings of DSM activities will not be available until later in the 2010 year. The 2009 Board Approved Budget DSM volumes still represent an accurate estimate of 2009 actual DSM volumes.

10. Tables 4 and 5 of Appendix A illustrate the corresponding actual weather normalized volumes and actual customers for both Rate 1 and Rate 6 that underpin Table 1's calculation. Further rate class detail and explanations are provided at Exhibit B, Tab 3, Schedule 2.

TABLE 1

2009 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Exhibit Reference:	EB-2008-0219, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 21	Tables 4-5 on pages 4-5		EB-2008-0219, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 1		EB-2008-0219, Exhibit B, Tab 1, Schedule 5, Tables 3-6				Unit Rate of the Revenue Impact, exclusive of gas costs	Collect dollars from rate payers, Credit Operating Revenue, Debit AUTUVA
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
			=Col. 2-1		=Col. 3*4			=Col. 7-6	=Col. 5-8		=Col. 9*10
Rate Class	2009 Budget Annual Use (m^3)	2009 Normalized Actual	Normalized Usage Variance (m^3)	Budget Customer Meters	Normalized Volumetric Variance (10^6m^3)	2009 DSM Budget (10^6m^3)	2009 DSM Actual (10^6m^3)	DSM Volumetric Variance (10^6m^3)	Normalized Volumetric Variance Excluding DSM (10^6m^3)	Unit Rate ($/$m^3$)	AUTUVA: Revenue Impact, Exclusive of Gas Costs ($ millions)
1	2,637	2,616	(21)	1,747,095	(36.0)	(15.1)	(15.1)	0.0	(36.0)	0.0705	(2.53)
6	28,165	27,654	(511)	158,767	(81.2)	(20.4)	(20.4)	0.0	(81.2)	0.0381	(3.09)
Total					(117.1)	(35.5)	(35.5)	0.0	(117.1)		(5.63)

TABLE 2
CUSTOMER MIGRATION FROM CONTRACT RATE CLASS TO RATE 6
BETWEEN 2009 ACTUAL AND 2009 BOARD APPROVED BUDGET

1. Customers migrated to Rate 6 due to rate design changes

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	6	Apartment	2.8
	1	Chemical and Chemical Products	1.1
	2	Food, Beverage, Drug & Tobacco	0.9
	1	Government Services	0.6
	2	Health, Social & Other Services	2.1
	1	Non-Metallic Mineral Products	2.4
	1	Primary Metal & Machinery	1.1
	1	Rubber Products	0.6
	2	Transportation Equipment	12.0
Total	17		23.6

2. Production cuts or plants consolidation due to unfavourable business environment

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	1	Chemical and Chemical Products	0.3
	3	Food, Beverage, Drug & Tobacco	0.9
	1	Government Services	3.3
	1	Non-Metallic Mineral Products	0.6
	8	Primary Metal & Machinery	5.5
	2	Pulp & Paper	24.7
	7	Transportation Equipment	4.1
Total	23		39.4
Grand Total	**40**		**63.0**

*The number here only counts the billing account number which is different from meter count. This count does not reflect the timing of the migration.

TABLE 3
CUSTOMER MIGRATION FROM RATE 6 TO CONTRACT RATE CLASS
BETWEEN 2009 ACTUAL AND 2009 BOARD APPROVED BUDGET

1. Customers were already migrated to Rate 6 in 2009 (Timing)

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(1)	All Other Industrial	(0.6)
	(89)	Apartment	(29.2)
	(1)	Asphalt	(0.7)
	(6)	Business & Financial Service Industries	(4.0)
	(1)	Chemical and Chemical Products	(0.6)
	(1)	Construction Industries	(0.0)
	(2)	Education Services	(1.3)
	(10)	Food, Beverage, Drug & Tobacco	(5.1)
	(10)	Government Services	(8.6)
	(1)	Greenhouses/Agriculture	(0.1)
	(9)	Hotels	(3.4)
	(2)	Non-Metallic Mineral Products	(0.6)
	(1)	Plastic Products	(0.4)
	(11)	Primary Metal & Machinery	(3.7)
	(7)	Pulp & Paper	(2.0)
	(1)	Recreational & Household Industries	(0.2)
	(1)	Rubber Products	(0.2)
	(1)	Textile Products	(0.6)
	(2)	Transportation and Storage and Utilities	(0.6)
	(7)	Transportation Equipment	(4.6)
	(5)	Wholesale & Retail Trade	(2.1)
	(1)	Wood & Furniture Industries	(0.7)
Total	(170)		(69.0)

2. Customers will be migrated to Rate 6 in 2010

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(1)	All Other Industrial	(2.7)
	(4)	Apartment	(2.1)
	(1)	Asphalt	(0.9)
	(1)	Business & Financial Service Industries	(0.6)
	(4)	Chemical and Chemical Products	(4.0)
	(2)	Food, Beverage, Drug & Tobacco	(3.9)
	(1)	Health, Social & Other Services	(1.0)
	(2)	Hotels	(2.3)
	(1)	Primary Metal & Machinery	(0.4)
	(1)	Pulp & Paper	(3.0)
	(1)	Rubber Products	(0.7)
	(1)	Wholesale & Retail Trade	(0.7)
	(1)	Wood & Furniture Industries	(2.2)
Total	(21)		(24.7)

Customers who did not migrate to Rate 6, even though it would have been beneficial to do so.

3. Customers stayed at contract even though they were benefical to migate to rate 6

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(40)	Apartment	(22.4)
	(1)	Education Services	(1.2)
	(1)	Electronics/High Tech	(0.6)
	(1)	Food, Beverage, Drug & Tobacco	(1.3)
	(1)	Government Services	(0.3)
	(2)	Greenhouses/Agriculture	(1.8)
	(1)	Hotels	(1.1)
	(2)	Primary Metal & Machinery	(2.5)
	(1)	Pulp & Paper	(0.3)
	(2)	Rubber Products	(2.1)
	(1)	Textile Products	(0.3)
	(2)	Transportation Equipment	(1.7)
	(1)	Wood & Furniture Industries	(0.6)
Total	(56)		(36.3)

4. Customers stayed at contract due to change of ownership or others

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(1)	All Other Industrial	(0.1)
	(3)	Apartment	(1.6)
	(2)	Asphalt	(0.9)
	(1)	Food, Beverage, Drug & Tobacco	(0.4)
	(1)	Government Services	(2.2)
	(1)	Health, Social & Other Services	(0.6)
	(1)	Other Utility Industries (Cogen)	(1.7)
Total	(10)		(7.5)
Grand Total	**(257)**		**(137.5)**

*The number here only counts the billing account number which is different from meter count. This count does not reflect the timing of the migration.

TABLE 4
GENERAL SERVICE RATE 1
2009 ACTUAL - NORMALIZED VOLUME, CUSTOMERS, 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	Exhibit Reference
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1.1	Normalized Volumes ($10^6 m^3$)	783.8	752.1	650.6	465.0	260.2	158.4	125.7	126.7	121.1	179.9	338.7	571.6	4,533.8	Exhibit B, Tab 3, Schedule 2
1.2	Customer Meters	1,732,249	1,735,493	1,737,672	1,739,610	1,739,878	1,739,355	1,737,856	1,737,104	1,727,462	1,715,474	1,714,182	1,729,905	1,732,187	Exhibit B, Tab 3, Schedule 4, Col. 1 Item 1.1
1.3	Average Use per Customer (m^3)	452	433	374	267	150	91	72	73	70	105	198	330	2,616	

TABLE 5
GENERAL SERVICE RATE 6
2009 ACTUAL - NORMALIZED VOLUME, CUSTOMERS, 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	Exhibit Reference
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1.1	Normalized Volumes (10^6m^3)	716.6	706.3	616.2	442.4	294.4	155.4	111.9	110.0	107.4	191.9	314.0	532.1	4,298.6	Exhibit B, Tab 3, Schedule 2
1.2	Customer Meters	157,282	157,752	157,980	157,830	157,484	157,091	155,946	154,966	151,802	148,934	148,782	150,983	154,736	Exhibit B, Tab 3, Schedule 4, Col. 1 Item 1.2
1.3	Average Use per Customer (m^3)	4,556	4,477	3,900	2,803	1,869	989	718	710	708	1,288	2,110	3,524	27,654	

2009
ENBRIDGE GAS DISTRIBUTION
ONTARIO HEARING COSTS
VARIANCE ACCOUNT

Line No.	Test Year Proceeding Costs	Col. 1 Baseline Regulatory Cost Budget ($000's)	Col. 2 2009 Regulatory Costs Incurred ($000's)	Col. 3 Variance ($000's)
1.	Legal	840.0	551.0	
2.	Intervenor	1,155.0	361.3	
3.	Ontario Energy Board	4,040.0	3,960.3	
4.	Consultants	500.0	275.5	
5.	Transcripts, newspaper notices, printing, other	420.0	182.5	
6.	Sub-total	6,955.0	5,330.6	
7.	Other proceedings	1,887.5	1,043.6	
8.	2009 Agreed to OHCVA threshold reduction	(3,000.0)	-	
9.	Actual versus OHCVA threshold variance	5,842.5	6,374.2	531.7

Line No.	Breakdown of Other Proceedings (Line 7 above)	
10.	EB-2009-0084 OEB Cost of Capital Consultative	611.4
11.	EB-2008-0408 OEB IFRS Consultative	181.1
12.	CIS & Open Bill Consultatives	128.6
13.	DSM Clearance Application & Consultative	69.9
14.	Consultation on Energy Issues / Low Income Consumers	45.0
15.	Gas Storage Allocation / other Consultative	7.6
		1,043.6

Witness: K. Culbert

CLEARANCE OF 2009 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The Company is proposing to clear 2009 deferral and variance account balances to customers during the October 2010 billing cycle.

2. The unit rates for each type of service are shown at Exhibit C, Tab 2, Schedule 2, page 1. These unit rates will be applied to each customer's actual 2009 consumption volume for the period January 1, 2009 to December 31, 2009 and will be recovered or remitted in October of 2010.

3. The proposed unit rates for clearance of 2009 deferral and variance accounts are derived as follows under Exhibit C, Tab 2, Schedule 2:
   - Page 2 indicates the balance (principal and interest) to be cleared for each Board-approved 2009 deferral and variance account;
   - Page 3 allocates the account balance to the rate classes based on the cost drivers for each type of account;
   - Page 4 summarizes the allocation by rate class and type of service; and
   - Page 5 derives the unit rates for the clearance / disposition by rate class and type of service. The unit rates are derived using actual 2009 consumption volumes for each rate class and each type of service.

4. The table on page 6 shows the bill adjustments in October 2010 for typical customers resulting from the clearance of the 2009 deferral and account balances. These bill adjustments will be shown as a separate line item on customers' October 2010 bills.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

5. Two new deferral accounts have been approved by the Board for inclusion in 2009. They are the International Financial Reporting Standards Transition Costs Deferral Account (IFRSTCDA) and the Ex-Franchise Third Party Billing Services Deferral Account (EFTPBSDA). The proposed classification and allocation of these accounts by rate class can be found at Exhibit C, Tab 2, Schedule 2 page 3.

UNIT RATE AND TYPE OF SERVICE: CLEARING IN OCTOBER 2010

		COL.1 TOTAL (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	(0.7560)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0031)
	- WESTERN T-SERVICE	0.1186
RATE 6	- SYSTEM SALES	(0.9854)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0211
	- WESTERN T-SERVICE	0.1423
RATE 9	- SYSTEM SALES	(1.4680)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(1.2880)
	- WESTERN T-SERVICE	(1.1663)
RATE 100	- SYSTEM SALES	(5.9740)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.7679
	- WESTERN T-SERVICE	0.8896
RATE 110	- SYSTEM SALES	(0.4631)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1125
	- WESTERN T-SERVICE	0.2342
RATE 115	- SYSTEM SALES	(0.5350)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1786
	- WESTERN T-SERVICE	0.3003
RATE 135	- SYSTEM SALES	(1.1580)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0573
	- WESTERN T-SERVICE	0.1790
RATE 145	- SYSTEM SALES	(0.7948)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1721
	- WESTERN T-SERVICE	0.2938
RATE 170	- SYSTEM SALES	(0.6509)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1288
	- WESTERN T-SERVICE	0.2509
RATE 200	- SYSTEM SALES	(0.8233)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0224
	- WESTERN T-SERVICE	0.0000
Unbundled Services:		
RATE 125	- All	(1.8637)
RATE 300	- All	(9.2208)

Determination of Balances to be Cleared from the 2009 Deferral and Variance Accounts

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL For CLEARING ($000)
	PGVA - COMMODITY COMPONENT			
1.1	COMMODITY	(642,635.08)	(40,868.8)	(683,503.9)
1.2	RIDER C 2009	476,475.9	30,301.8	506,777.7
1.3	INVENTORY ADJUSTMENT	116,444.8	7,405.4	123,850.1
	Subtotal PGVA Commodity	(49,714.4)	(3,161.6)	(52,876.0)
	PGVA - LOAD BALANCING COMPONENT			
1.4	SEASONAL PEAKING	(3,914.2)	(248.9)	(4,163.1)
1.5	SEASONAL DISCRETIONARY	2,022.9	128.6	2,151.6
	Subtotal PGVA Load Balancing	(1,891.3)	(120.3)	(2,011.6)
1.6	**PGVA TRANSPORTATION COMPONENT**	12,731.4	809.7	13,541.1
1.7	**PGVA CURTAILMENT PENALTY COMPONENT**	(395.7)	(25.2)	(420.9)
1.	**TOTAL PGVA ***	(39,270.0)	(2,497.4)	(41,767.4)
2.	**TRANSACTIONAL SERVICES D/A**	(7,062.1)	(31.9)	(7,094.0)
3.	**UNACCOUNTED FOR GAS V/A**	9,596.7	39.6	9,636.3
4.	**STORAGE AND TRANSPORTATION D/A**	(1,594.8)	(9.5)	(1,604.3)
5.	**DEFERRED REBATE ACCOUNT**	0.0	0.0	0.0
6.	**DEMAND SIDE MANAGEMENT 2008**	(73.3)	(56.3)	(129.6)
7.	**LOST REVENUE ADJ MECHANISM 2008**	37.3	0.2	37.5
8.	**SHARED SAVINGS MECHANISM 2008**	5,803.2	24.2	5,827.4
9.	**CLASS ACTION SUIT D/A**	4,709.5	414.1	5,123.6
10.	**ONTARIO HEARING COSTS V/A**	474.5	2.0	476.5
11.	**GAS DISTRIBUTION ACCESS RULE D/A**	2,838.8	0.0	2,838.8
12.	**AVERAGE USE TRUE-UP V/A**	5,626.9	23.4	5,650.3
13.	**IFRS TRANSITION COSTS D/A**	2,111.0	8.9	2,119.9
14.	**MUNICIPAL PERMIT FEES D/A**	202.2	0.0	202.2
15.	**OPEN BILL SERVICE D/A**	87.7	3.0	90.7
16.	**OPEN BILL ACCESS V/A**	79.5	1.2	80.7
17.	**EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A**	(27.9)	(0.1)	(28.0)
18.	**TAX RATE & RULE CHANGE V/A**	(350.0)	(1.7)	(351.7)
19.	**EARNINGS SHARING MECHANISM**	(19,300.0)	(77.4)	(19,377.4)
20.	**TOTAL**	(36,110.8)	(2,157.7)	(38,268.5)

* Note: "Total PGVA" is a projected final balance for the 2009 PGVA. The actual balance proposed for clearance will be determined, and updated, once the impact of the 2009 Rider C, which was in place until March 31, 2010, is determined. Note that the Company has implemented the 12-month rolling Rider C methodology as approved by the Board in EB-2008-0106 effective January 1, 2010. Consequently, 2009 is the last year-end true-up of the PGVA.

Classification and Allocation of Deferral and Variance Account Balances

ITEM NO.		COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DISTRIBUTION REV REQ (DRR) ($000)	COL. 8 DIRECT ($000)	COL. 9 NUMBER OF CUSTOMERS ($000)	COL. 10 RATE BASE ($000)	COL. 11 INVENTORY (SALES SERVICE) ($000)
	CLASSIFICATION											
	PGVA - COMMODITY COMPONENT											
1.1	COMMODITY	(683,503.9)		(683,503.9)								
1.2	RIDER C 2009	506,777.7							506,777.7			
1.3	INVENTORY ADJUSTMENT	123,850.1										123,850.1
	Subtotal PGVA Commodity	(52,876.0)	0.0	(683,503.9)	0.0	0.0	0.0	0.0	506,777.7	0.0	0.0	123,850.1
	PGVA - LOAD BALANCING COMPONENT											
1.4	SEASONAL PEAKING	(4,163.1)					(4,163.1)					
1.5	SEASONAL DISCRETIONARY	2,151.6				2,151.6						
	Subtotal PGVA Load Balancing	(2,011.6)	0.0	0.0	0.0	2,151.6	(4,163.1)	0.0	0.0	0.0	0.0	0.0
1.6	PGVA TRANSPORTATION COMPONENT	13,541.1	13,541.1									
1.7	PGVA CURTAILMENT PENALTY COMPONENT	(420.9)					(210.5)		(210.5)			
1.	**TOTAL PGVA ***	(41,767.4)	13,541.1	(683,503.9)	0.0	2,151.6	(4,373.6)	0.0	506,567.3	0.0	0.0	123,850.1
2.	**TRANSACTIONAL SERVICES D/A**	(7,094.0)	(2,911.7)			(2,154.9)	(2,027.4)					
3.	**UNACCOUNTED FOR GAS V/A**	9,636.3			9,636.3							
4.	**STORAGE AND TRANSPORTATION D/A**	(1,604.3)				(826.6)	(777.7)					
5.	**DEFERRED REBATE ACCOUNT**	0.0			0.0							
6.	**DEMAND SIDE MANAGEMENT 2008**	(129.6)							(129.6)			
7.	**LOST REVENUE ADJ MECHANISM 2008**	37.5							37.5			
8.	**SHARED SAVINGS MECHANISM 2008**	5,827.4							5,827.4			
9.	**CLASS ACTION SUIT D/A**	5,123.6								5,123.6		
10.	**ONTARIO HEARING COSTS V/A**	476.5									476.5	
11.	**GAS DISTRIBUTION ACCESS RULE D/A**	2,838.8								2,838.8		
12.	**AVERAGE USE TRUE-UP V/A**	5,650.3							5,650.3			
13.	**IFRS TRANSITION COSTS D/A**	2,119.9						2,119.9				
14.	**MUNICIPAL PERMIT FEES D/A**	202.2									202.2	
15.	**OPEN BILL SERVICE D/A**	90.7								90.7		
16.	**OPEN BILL ACCESS V/A**	80.7								80.7		
17.	**EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A**	(28.0)								(28.0)		
18.	**TAX RATE & RULE CHANGE V/A**	(351.7)									(351.7)	
19.	**EARNINGS SHARING MECHANISM**	(19,377.4)						(19,377.4)				
20.	**TOTAL**	(38,268.5)	10,629.3	(683,503.9)	9,636.3	(829.9)	(7,178.7)	(17,257.5)	517,952.9	8,105.8	327.0	123,850.1
	ALLOCATION											
1.1	RATE 1	(21,979.6)	5,451.9	(397,229.0)	4,048.4	(398.5)	(3,722.2)	(11,591.7)	300,596.3	7,438.5	219.2	73,207.3
1.2	RATE 6	(16,418.5)	4,467.0	(246,048.9)	3,738.7	(366.0)	(3,252.1)	(4,830.3)	182,971.4	664.5	93.9	46,143.5
1.3	RATE 9	(18.1)	1.5	(135.1)	1.1	0.0	(0.0)	(17.9)	131.3	0.1	0.4	0.6
1.4	RATE 100	(332.6)	91.2	(2,214.6)	85.5	(8.6)	(76.2)	(113.1)	1,481.4	0.5	2.2	419.1
1.5	RATE 110	423.8	191.0	(7,613.4)	492.8	(12.9)	(51.2)	(225.8)	7,378.2	1.0	3.6	260.5
1.6	RATE 115	814.3	21.3	(555.4)	396.2	(2.5)	(12.8)	(119.7)	1,062.4	0.2	1.6	22.9
1.7	RATE 125	(113.5)	0.0	0.0	0.0	0.0	0.0	(115.4)	0.0	0.0	1.8	0.0
1.8	RATE 135	52.6	30.3	(71.4)	44.3	0.0	0.0	(14.4)	63.5	0.1	0.2	0.0
1.9	RATE 145	252.1	104.8	(3,275.2)	211.9	(12.6)	0.0	(97.8)	2,971.2	0.8	1.5	347.6
1.10	RATE 170	119.4	112.1	(9,805.1)	464.5	(17.9)	0.0	(83.7)	8,953.8	0.1	1.5	494.2
1.11	RATE 200	(1,059.5)	158.3	(16,555.7)	153.0	(10.9)	(64.2)	(38.7)	12,343.4	0.0	0.9	2,954.5
1.12	RATE 300	(8.7)	0.0	0.0	0.0	0.0	0.0	(8.9)	0.0	0.0	0.2	0
1.		(38,268.5)	10,629.3	(683,503.9)	9,636.3	(829.9)	(7,178.7)	(17,257.5)	517,952.8	8,105.8	327.0	123,850.1

* Note: "Total PGVA" is a projected final balance for the 2009 PGVA. The actual balance proposed for clearance will be determined, and updated, once the impact of the 2009 Rider C, which was in place until March 31, 2010, is determined.
Note that the Company has implemented the 12-month rolling Rider C methodology as approved by the Board in EB-2008-0106 effective January 1, 2010. Consequently, 2009 is the last year-end true-up of the PGVA.

ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	INVENTORY (SALES SERVICE)
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:												
RATE 1	- SYSTEM SALES	(23,584.0)	3,797.5	(397,229.0)	2,661.4	(262.0)	(2,447.0)	(7,620.4)	299,273.9	4,890.0	144.1	73,207.3
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(8.2)	0.0	0.0	227.5	(22.4)	(209.2)	(651.3)	216.9	418.0	12.3	0.0
	- WBT	1,612.5	1,654.5	0.0	1,159.5	(114.1)	(1,066.1)	(3,320.0)	1,105.5	2,130.5	62.8	0.0
RATE 6	- SYSTEM SALES	(19,041.4)	2,352.2	(246,048.9)	1,648.5	(163.7)	(1,454.4)	(2,160.1)	180,306.5	293.0	42.0	46,143.5
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	150.3	0.0	0.0	608.0	(58.7)	(522.0)	(775.3)	775.2	108.1	15.1	0.0
	- WBT	2,472.6	2,114.8	0.0	1,482.1	(143.6)	(1,275.7)	(1,894.9)	1,889.7	263.4	36.8	0.0
RATE 9	- SYSTEM SALES	(15.6)	1.3	(135.1)	0.9	0.0	(0.0)	(15.0)	131.3	0.1	0.3	0.6
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(0.7)	0.0	0.0	0.0	0.0	(0.0)	(0.8)	0.0	0.0	0.0	0.0
	- WBT	(1.8)	0.2	0.0	0.1	0.0	(0.0)	(2.2)	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	(1,039.1)	21.2	(2,214.6)	14.8	(1.5)	(13.2)	(19.6)	754.3	0.1	0.4	419.1
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	194.9	0.0	0.0	21.6	(2.2)	(19.3)	(28.6)	222.6	0.1	0.6	0.0
	- WBT	511.6	70.0	0.0	49.1	(4.9)	(43.7)	(64.9)	504.4	0.3	1.3	0.0
RATE 110	- SYSTEM SALES	(276.9)	72.8	(7,613.4)	51.0	(1.3)	(5.3)	(23.4)	6,981.8	0.1	0.4	260.5
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	473.2	0.0	0.0	358.9	(9.4)	(37.3)	(164.4)	322.0	0.7	2.6	0.0
	- WBT	227.5	118.2	0.0	82.9	(2.2)	(8.6)	(38.0)	74.3	0.2	0.6	0.0
RATE 115	- SYSTEM SALES	(23.3)	5.3	(555.4)	3.7	(0.0)	(0.1)	(1.1)	501.3	0.0	0.0	22.9
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	798.1	0.0	0.0	381.3	(2.4)	(12.3)	(115.2)	545.0	0.2	1.6	0.0
	- WBT	39.5	16.0	0.0	11.2	(0.1)	(0.4)	(3.4)	16.1	0.0	0.0	0.0
RATE 135	- SYSTEM SALES	(6.5)	0.7	(71.4)	0.5	0.0	0.0	(0.2)	63.9	0.0	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	15.4	0.0	0.0	23.0	0.0	0.0	(7.5)	(0.2)	0.1	0.1	0.0
	- WBT	43.6	29.7	0.0	20.8	0.0	0.0	(6.8)	(0.2)	0.1	0.1	0.0
RATE 145	- SYSTEM SALES	(204.4)	31.3	(3,275.2)	21.9	(1.3)	0.0	(10.1)	2,681.1	0.1	0.2	347.6
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	279.3	0.0	0.0	138.5	(8.3)	0.0	(63.9)	211.5	0.5	1.0	0.0
	- WBT	177.3	73.5	0.0	51.5	(3.1)	0.0	(23.8)	78.6	0.2	0.4	0.0
RATE 170	- SYSTEM SALES	(501.2)	93.7	(9,805.1)	65.7	(2.5)	0.0	(11.8)	8,664.4	0.0	0.2	494.2
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	582.8	0.0	0.0	385.9	(14.9)	0.0	(69.6)	280.1	0.1	1.2	0.0
	- WBT	37.8	18.4	0.0	12.9	(0.5)	0.0	(2.3)	9.3	0.1	0.0	0.0
RATE 200	- SYSTEM SALES	(1,070.5)	158.3	(16,555.7)	110.9	(7.9)	(46.6)	(28.1)	12,343.4	0.0	0.7	2,954.5
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	11.0	0.0	0.0	42.1	(3.0)	(17.7)	(10.6)	0.0	0.0	0.3	0.0
	- WBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:												
RATE 125		(113.5)	0.0	0.0	0.0	0.0	0.0	(115.4)	0.0	0.0	1.8	0.0
RATE 300		(8.7)	0.0	0.0	0.0	0.0	0.0	(8.9)	0.0	0.0	0.2	0.0
		(38,268.5)	10,629.3	(683,503.9)	9,636.3	(829.9)	(7,178.7)	(17,257.5)	517,952.8	8,105.8	327.0	123,850.1

UNIT RATE AND TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	INVENTORY (SALES SERVICE)
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)
Bundled Services:												
RATE 1	- SYSTEM SALES	(0.7560)	0.1217	(12.7329)	0.0853	(0.0084)	(0.0784)	(0.2443)	9.5930	0.1567	0.0046	2.3466
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0031)	0.0000	0.0000	0.0853	(0.0084)	(0.0784)	(0.2443)	0.0813	0.1567	0.0046	0.0000
	- WESTERN T-SERVICE	0.1186	0.1217	0.0000	0.0853	(0.0084)	(0.0784)	(0.2443)	0.0813	0.1567	0.0046	0.0000
RATE 6	- SYSTEM SALES	(0.9854)	0.1217	(12.7329)	0.0853	(0.0085)	(0.0753)	(0.1118)	9.3308	0.0152	0.0022	2.3879
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0211	0.0000	0.0000	0.0853	(0.0082)	(0.0732)	(0.1088)	0.1088	0.0152	0.0021	0.0000
	- WESTERN T-SERVICE	0.1423	0.1217	0.0000	0.0853	(0.0083)	(0.0734)	(0.1091)	0.1088	0.0152	0.0021	0.0000
RATE 9	- SYSTEM SALES	(1.4680)	0.1217	(12.7329)	0.0853	0.0000	(0.0012)	(1.4114)	12.3779	0.0086	0.0306	0.0533
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(1.2880)	0.0000	0.0000	0.0853	0.0000	(0.0012)	(1.4114)	0.0000	0.0086	0.0306	0.0000
	- WESTERN T-SERVICE	(1.1663)	0.1217	0.0000	0.0853	0.0000	(0.0012)	(1.4114)	0.0000	0.0086	0.0306	0.0000
RATE 100	- SYSTEM SALES	(5.9740)	0.1217	(12.7329)	0.0853	(0.0085)	(0.0759)	(0.1128)	4.3369	0.0005	0.0022	2.4096
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.7679	0.0000	0.0000	0.0853	(0.0085)	(0.0759)	(0.1128)	0.8772	0.0005	0.0022	0.0000
	- WESTERN T-SERVICE	0.8896	0.1217	0.0000	0.0853	(0.0085)	(0.0759)	(0.1128)	0.8772	0.0005	0.0022	0.0000
RATE 110	- SYSTEM SALES	(0.4631)	0.1217	(12.7329)	0.0853	(0.0022)	(0.0089)	(0.0391)	11.6766	0.0002	0.0006	0.4356
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1125	0.0000	0.0000	0.0853	(0.0022)	(0.0089)	(0.0391)	0.0765	0.0002	0.0006	0.0000
	- WESTERN T-SERVICE	0.2342	0.1217	0.0000	0.0853	(0.0022)	(0.0089)	(0.0391)	0.0765	0.0002	0.0006	0.0000
RATE 115	- SYSTEM SALES	(0.5350)	0.1217	(12.7329)	0.0853	(0.0005)	(0.0028)	(0.0258)	11.4944	0.0000	0.0003	0.5252
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1786	0.0000	0.0000	0.0853	(0.0005)	(0.0028)	(0.0258)	0.1219	0.0000	0.0003	0.0000
	- WESTERN T-SERVICE	0.3003	0.1217	0.0000	0.0853	(0.0005)	(0.0028)	(0.0258)	0.1219	0.0000	0.0003	0.0000
RATE 135	- SYSTEM SALES	(1.1580)	0.1217	(12.7329)	0.0853	0.0000	0.0000	(0.0278)	11.3951	0.0003	0.0003	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0573	0.0000	0.0000	0.0853	0.0000	0.0000	(0.0278)	(0.0008)	0.0003	0.0003	0.0000
	- WESTERN T-SERVICE	0.1790	0.1217	0.0000	0.0853	0.0000	0.0000	(0.0278)	(0.0008)	0.0003	0.0003	0.0000
RATE 145	- SYSTEM SALES	(0.7948)	0.1217	(12.7329)	0.0853	(0.0051)	0.0000	(0.0394)	10.4232	0.0003	0.0006	1.3515
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1721	0.0000	0.0000	0.0853	(0.0051)	0.0000	(0.0394)	0.1303	0.0003	0.0006	0.0000
	- WESTERN T-SERVICE	0.2938	0.1217	0.0000	0.0853	(0.0051)	0.0000	(0.0394)	0.1303	0.0003	0.0006	0.0000
RATE 170	- SYSTEM SALES	(0.6509)	0.1217	(12.7329)	0.0853	(0.0033)	0.0000	(0.0154)	11.2516	0.0000	0.0003	0.6418
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1288	0.0000	0.0000	0.0853	(0.0033)	0.0000	(0.0154)	0.0619	0.0000	0.0003	0.0000
	- WESTERN T-SERVICE	0.2509	0.1217	0.0000	0.0853	(0.0033)	0.0000	(0.0154)	0.0619	0.0003	0.0003	0.0000
RATE 200	- SYSTEM SALES	(0.8233)	0.1217	(12.7329)	0.0853	(0.0061)	(0.0358)	(0.0216)	9.4932	0.0000	0.0005	2.2723
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0224	0.0000	0.0000	0.0853	(0.0061)	(0.0358)	(0.0216)	0.0000	0.0000	0.0005	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services:												
RATE 125	- All	(1.8637)	0.0000	0.0000	0.0000	0.0000	0.0000	(1.8936)	0.0000	0.0000	0.0299	0.0000
RATE 300	- All	(9.2208)	0.0000	0.0000	0.0000	0.0000	0.0000	(9.4320)	0.0000	0.0000	0.2112	0.0000

Note: (1) Unit Rates derived based on 2009 actual volumes

Enbridge Gas Distribution Inc.
2009 Deferral and Variance Account Clearing
Bill Adjustment in October 2010 for Typical Customers

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Unit Rates			Bill Adjustment		
	GENERAL SERVICE	Annual Volume m^3	Sales cents/m^3	Ontario TS cents/m^3	Western TS cents/m^3	Sales Customers $	Ontario TS Customers $	Western TS Customers $
1.1	**RATE 1 RESIDENTIAL**							
1.2	Heating & Water Heating	3,064	(0.7560)	(0.0031)	0.1186	(23)	(0)	4
2.1	**RATE 6 COMMERCIAL**							
2.2	General Use	43,285	(0.9854)	0.0211	0.1423	(427)	9	62
	CONTRACT SERVICE							
3.1	**RATE 100**							
3.2	Industrial - small size	339,188	(5.9740)	0.7679	0.8896	(20,263)	2,605	3,018
4.1	**RATE 110**							
4.2	Industrial - small size, 50% LF	598,568	(0.4631)	0.1125	0.2342	(2,772)	673	1,402
4.3	Industrial - avg. size, 75% LF	9,976,120	(0.4631)	0.1125	0.2342	(46,198)	11,220	23,364
5.1	**RATE 115**							
5.2	Industrial - small size, 80% LF	4,471,609	(0.5350)	0.1786	0.3003	(23,924)	7,984	13,428
6.1	**RATE 135**							
6.2	Industrial - Seasonal Firm	598,567	(1.1580)	0.0573	0.1790	(6,932)	343	1,071
7.1	**RATE 145**							
	Commercial - small size	598,568	(0.7948)	0.1721	0.2938	(4,757)	1,030	1,759
8.1	**RATE 170**							
8.2	Industrial - avg. size, 75% LF	9,976,120	(0.6509)	0.1288	0.2509	(64,933)	12,854	25,029

Notes:
Col. 6 = Col. 2 x Col. 3
Col. 7 = Col. 2 x Col. 4
Col. 8 = Col. 2 x Col. 5

ENBRIDGE GAS DISTRIBUTION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2009

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)	(Signed)
Janet Holder President	**William G. Ross** Vice President, Finance & Information Technology

February 18, 2010

PRICEWATERHOUSECOOPERS

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February 18, 2010

Auditors' Report

To the Shareholders of
Enbridge Gas Distribution Inc.

We have audited the consolidated statements of financial position of **Enbridge Gas Distribution Inc.** as at December 31, 2009 and 2008 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars) Year ended December 31,	**2009**	2008
Gas Commodity and Distribution Revenue	**2,345.9**	2,506.2
Transportation of Gas for Customers	**448.8**	504.8
	2,794.7	3,011.0
Gas Commodity and Distribution Costs excluding depreciation *(Note 16)*	**(1,769.9)**	(2,000.4)
Gas Distribution Margin	**1,024.8**	1,010.6
Other Revenue	**108.4**	93.9
	1,133.2	1,104.5
Expenses		
Operating and administrative *(Note 16)*	**385.3**	373.5
Depreciation and amortization	**254.0**	239.0
Municipal and other taxes	**49.3**	47.3
Earnings sharing *(Note 3)*	**18.8**	5.8
	707.4	665.6
	425.8	438.9
Affiliate Financing Income *(Note 16)*	**62.7**	62.7
Interest Expense *(Notes 7 and 16)*	**(189.1)**	(200.8)
	299.4	300.8
Income Taxes *(Note 13)*		
Current	**(51.1)**	(68.2)
Future	**(26.8)**	(21.2)
	(77.9)	(89.4)
Earnings	**221.5**	211.4
Preferred Share Dividends	**(3.3)**	(4.9)
Earnings Applicable to the Common Shareholder	**218.2**	206.5

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars)

Year ended December 31,	**2009**	2008
Earnings	**221.5**	211.4
Other Comprehensive Income/(Loss)		
Change in unrealized gain on cash flow hedges, net of tax	**0.7**	-
Reclassification to earnings of realized cash flow hedges, net of tax	**1.5**	-
Change in foreign currency translation adjustment	**(2.8)**	4.1
Other Comprehensive Income/(Loss)	**(0.6)**	4.1
Comprehensive Income	**220.9**	215.5

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(millions of Canadian dollars) Year ended December 31,	**2009**	2008
Preferred Shares *(Note 8)*	**100.0**	100.0
Common Shares *(Note 8)*	**1,070.7**	1,070.7
Contributed Surplus	**202.5**	202.5
Retained Earnings		
Balance at beginning of year	**566.6**	518.3
Earnings applicable to the common shareholder	**218.2**	206.5
Common share dividends	**(188.0)**	(158.2)
Balance at End of Year	**596.8**	566.6
Accumulated Other Comprehensive Loss		
Balance at beginning of year	**(2.1)**	(6.2)
Other comprehensive (loss)/income	**(0.6)**	4.1
Balance at End of Year	**(2.7)**	(2.1)
Total Shareholders' Equity	**1,967.3**	1,937.7

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars) Year ended December 31,	**2009**	2008
Operating Activities		
Earnings	**221.5**	211.4
Depreciation and amortization	**254.0**	239.0
Future income taxes	**26.8**	21.2
Other	**1.7**	6.8
Changes in operating assets and liabilities *(Note 15)*	**467.3**	(115.4)
Settlement recoverable *(Notes 3 and 5)*	**-**	4.7
	971.3	367.7
Investing Activities		
Additions to property, plant and equipment	**(309.3)**	(346.7)
Additions to intangible assets	**(61.0)**	(64.5)
Change in construction payable	**(11.0)**	(4.1)
Other	**(2.5)**	9.5
	(383.8)	(405.8)
Financing Activities		
Net change in short-term borrowings	**(366.8)**	328.9
Issue of short-term note payable to affiliate company *(Note 16)*	**5.5**	5.3
Repayment of short-term note payable to affiliate company *(Note 16)*	**(5.8)**	(3.6)
Debenture and term note issues	**-**	200.0
Debenture and term note repayments	**(102.5)**	(270.0)
Preferred share dividends	**(4.1)**	(4.9)
Common share dividends	**(180.6)**	(158.2)
Other	**(1.4)**	0.8
	(655.7)	98.3
Increase/(Decrease) in Cash and Cash Equivalents	**(68.2)**	60.2
Cash and Cash Equivalents at Beginning of Year	**55.4**	(4.8)
Cash and Cash Equivalents at End of Year	**(12.8)**	55.4
Cash and Cash Equivalents[1]	**-**	100.0
Bank Overdraft	**(12.8)**	(44.6)
	(12.8)	55.4
Supplementary Cash Flow Information		
Income taxes paid *(Note 13)*	**112.7**	43.1
Interest paid *(Note 7)*	**187.3**	206.0

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

[1] Cash and cash equivalents consists of $nil (2008 - $nil) of cash and $nil (2008 - $100.0 million) of short-term investments.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(millions of Canadian dollars)

December 31,	**2009**	2008
Assets		
Current Assets		
Cash and cash equivalents	**-**	100.0
Accounts receivable *(Note 16)*	**769.1**	980.3
Gas inventories	**395.7**	656.3
Other current assets	**32.5**	7.5
Future income taxes *(Note 13)*	**-**	15.3
	1,197.3	1,759.4
Property, Plant and Equipment, net *(Notes 2 and 4)*	**4,289.8**	3,514.3
Investment in Affiliate Company *(Note 16)*	**825.0**	825.0
Deferred Amounts and Other Assets *(Notes 2 and 5)*	**486.9**	40.0
Intangible Assets *(Notes 2 and 6)*	**178.8**	146.4
Liabilities and Shareholders' Equity		
Current Liabilities		
Bank overdraft	**12.8**	44.6
Short-term borrowings *(Note 7)*	**514.5**	881.6
Accounts payable *(Note 16)*	**725.6**	677.1
Other current liabilities	**55.8**	88.1
Current maturities of long-term debt *(Note 7)*	**150.0**	100.0
Future income taxes *(Note 13)*	**4.6**	-
	1,463.3	1,791.4
Long-Term Debt *(Note 7)*	**2,015.4**	2,167.1
Other Long-Term Liabilities *(Note 2)*	**972.3**	10.9
Future Income Taxes *(Notes 2 and 13)*	**184.5**	3.0
Loans from Affiliate Company *(Notes 7 and 16)*	**375.0**	375.0
	5,010.5	4,347.4
Shareholders' Equity		
Share capital		
Preferred shares *(Note 8)*	**100.0**	100.0
Common shares *(Note 8)*	**1,070.7**	1,070.7
Contributed surplus	**202.5**	202.5
Retained earnings	**596.8**	566.6
Accumulated other comprehensive loss	**(2.7)**	(2.1)
	1,967.3	1,937.7
Commitments and Contingencies *(Notes 16 and 17)*		
	6,977.8	6,285.1

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

Approved by the Board of Directors:

(Signed)

J. Richard Bird
Director

(Signed)

Stephen J. J. Letwin
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. In addition, the Company 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 (Canadian 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: carrying values of regulatory assets and liabilities (Note 3); depreciation rates of property, plant and equipment (Note 4); amortization rates of intangible assets (Note 6); valuation of share based compensation (Note 9); allowance for doubtful accounts (Note 10); fair values of financial instruments (Notes 10 and 11); income taxes (Note 13); post-employment benefits (Note 14) and commitments and contingencies (Note 17). 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). Long-term investments are assessed for impairment if the Company identifies an event indicative of possible impairment.

REGULATION

The utility operations of the Company and St. Lawrence are regulated by the Ontario Energy Board (OEB) and the New York State Public Service Commission (NYSPSC), respectively (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 these 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 degree day deficiency values experienced. Degree day deficiency 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.

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 16).

Loans and Receivables
Loans and receivables, which include Accounts Receivable, are initially recognized at fair value and are subsequently measured at amortized cost, 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, Other Current Liabilities, Long-Term Debt and Loans from Affiliate Company.

Held to Maturity
The Company has not classified any financial assets or liabilities as held to maturity.

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 it 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 natural gas prices and 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. Any hedge ineffectiveness is recorded in current period earnings.

The majority of St. Lawrence's cash flow hedges 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 hedges 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 at that date is deferred in OCI and 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, Debt Redemption and Refinancing
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.

Unless directed otherwise by the Regulators, any gains or losses on the redemption or refinancing of debt, together with related unamortized debt issue costs, are taken into earnings in the period of redemption.

INCOME TAXES
The regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences.

With the revision of the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *Income Taxes* (Note 2), 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 substantively enacted tax rate that is expected to apply when the temporary differences reverse. A corresponding 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 cumulative 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 three months or less when purchased.

GAS INVENTORIES

Gas inventories is primarily comprised of natural gas in storage. Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply 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, 2009, $163.9 million of natural gas was held on behalf of transportation service customers (December 31, 2008 - $175.9 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 rates authorized by the Regulators.

For normal retirements of utility assets, the cost of such assets net of any proceeds is charged to accumulated depreciation. Upon retirement or sale of major items of utility property, any gain or loss is included in earnings.

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 as well as 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 (Note 2).

DEPRECIATION AND AMORTIZATION

Depreciation

Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets 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 (Note 2).

Amortization

Amortization of intangible assets is provided on a straight-line basis over the estimated useful lives of the assets 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 when they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is 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

Pension Plans

The Company provides non-contributory defined benefit pensions and/or defined contribution pensions to the majority of its employees. Contributions to the plans are expensed as paid, consistent with the recovery of such costs in rates. Under the defined benefit plan, retirement benefits are based on employees' years of service and remuneration. Under the defined contribution plan, contributions by the Company are generally based on the employee's years of service and remuneration.

Post-employment Benefits Other Than Pensions

Post-employment benefits other than pensions (OPEB) include group health care and life insurance coverage for qualifying retired employees and their dependants. The cost of these benefits is expensed as paid, consistent with the recovery of such costs in rates.

With the removal of the CICA Handbook Section 1100 exemption for rate regulated entities (Note 2), 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.
- For the purpose of calculating the expected return on plan assets, those assets are valued at fair value.
- The excess of the net actuarial gain or loss over 10% of the greater of the 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 plan 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 plan 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.

A regulatory liability and asset in respect of the Company's pension asset and OPEB liability, respectively, have been recorded to the extent the Company is able to collect or refund the amounts in the future through rates (Note 2).

COMPARATIVE AMOUNTS

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

2. CHANGES IN ACCOUNTING POLICIES

ACCOUNTING FOR THE EFFECTS OF RATE REGULATION

Effective January 1, 2009, the Company adopted revisions to the CICA Handbook Section 1100, *Generally Accepted Accounting Principles* and Section 3465, *Income Taxes*. In accordance with the transitional provisions in these revised standards, the revisions to Section 1100 were adopted prospectively and accordingly, prior periods were not restated, while the revisions to Section 3465 were applied retrospectively without restatement of prior periods. The adoption of the revised standards did not impact the Company's earnings or cash flows.

Generally Accepted Accounting Principles

The revised standard no longer provides an exemption for rate-regulated entities to measure assets and liabilities on a basis other than in accordance with primary sources of Canadian GAAP. As a result, for the Company's pension plans and OPEB, the Company recognized post-employment benefit assets and liabilities for the amount of benefits expected to be included in future rates and recovered from, or paid to, customers. In addition, the Company reclassified certain reserves for future removal and site restoration.

Pension Plans and OPEB

On adoption of the revised standard at January 1, 2009, the Company recognized a net pension asset of $199.5 million and a net OPEB liability of $63.6 million, with an offsetting long-term net pension regulatory liability and long-term net OPEB regulatory asset, respectively, to the extent that the amounts are to be collected or refunded in future rates. At December 31, 2009, the Company had a net pension asset of $201.9 million and a net OPEB liability of $69.5 million, with an offsetting long-term net pension regulatory liability and a long-term net OPEB regulatory asset, respectively, to the extent that the amounts are to be collected or refunded in future rates.

Future Removal and Site Restoration Reserves

At January 1, 2009, on adoption of the revised standard, the Company reclassified amounts collected for future removal and site restoration of $640.0 million, which were previously netted against Property, Plant and Equipment, to a long-term regulatory liability. At December 31, 2009, this long-term regulatory liability was $691.6 million.

Income Taxes

The revised standard removes the exemption for rate-regulated entities to recognize future income taxes to the extent they were expected to be included in regulator-approved future rates and recovered from or refunded to future customers. As a result, on January 1, 2009, the Company recognized a future income tax liability of $212.2 million on regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset. A regulatory asset has been recognized as the associated future income tax liability is expected to be recoverable in future rates. At December 31, 2009, the Company had a future income tax liability of $174.0 million related to regulatory assets with an offsetting long-term regulatory asset.

INTANGIBLE ASSETS

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064, *Goodwill and Intangible Assets,* which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. As a result of adopting this standard, the Company reclassified certain software costs from Property, Plant and Equipment to Intangible Assets. This standard has been applied retrospectively and affects presentation only.

As a result of adopting this standard, on January 1, 2009, the Company reclassified $146.4 million of net CIS and software costs from Property, Plant and Equipment to Intangible Assets. At December 31, 2009, the Company had $178.8 million of net CIS and software costs recorded in Intangible Assets.

FINANCIAL INSTRUMENTS - DISCLOSURES

Effective December 31, 2009, the Company adopted the amendments to CICA Handbook Section 3862, *Financial Instruments – Disclosures*, which requires the inclusion of additional disclosure about fair value measurements of financial instruments and enhances liquidity risk disclosure requirements. The additional disclosures required under this standard have been included in Note 11, Fair Value of Financial Instruments.

FUTURE ACCOUNTING POLICY CHANGES

Business Combinations

The CICA issued Handbook Section 1582, *Business Combinations*, which replaces Section 1581. This new standard aligns accounting for business combinations under Canadian GAAP with International Financial Reporting Standards (IFRS). The standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination to be expensed in the period in which they are incurred. The adoption of this standard will impact the accounting treatment of future business combinations. The revised standard is effective for business combinations occurring on or after January 1, 2011; however, earlier application is permitted.

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 financial statements. The revised standards are effective January 1, 2011. Should the Company early adopt Section 1582, it would also be required to adopt Sections 1601 and 1602 at the same time.

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 an Incentive Regulation (IR) methodology. This IR methodology adjusts revenues every year, and consequently rates, 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, 2009 (2008 – 8.39%) based on a 36% (2008 – 36%) deemed common equity component of capital for regulatory purposes.

To align the interests of customers with the Company's 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 annual allowed utility return on equity (NROE) by certain prescribed thresholds, earnings are shared with customers. The 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 after-tax rate of return on its rate base was 7.4% for the year ended December 31, 2009 (2008 – 7.8%). Its after-tax rate of return on common equity was 8.89% for the year ended December 31, 2009 (2008 – 9.6%) based on a 51.5% (2008 – 51.5%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 9.6% (2008 – 9.6%) are shared with customers on the basis disclosed in the following table. The calculation of such earnings is cumulative over the three-year period commencing January 1, 2007 and ending December 31, 2009, and resulted in no sharing impact as at December 31, 2009.

If St. Lawrence earns a return on equity above prescribed levels, the excess earnings are to be shared with customers as indicated in the table below:

ROE Range	Sharing Basis
9.6% to 10.6%	Share with customers on a 50/50 basis
Greater than 10.6% to 12.6%	Share: 65% - customers; 35% - St. Lawrence
Greater than 12.6%	Defer for the benefit of customers for later disposition by the NYSPSC

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 would not recognize certain 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. Long-term regulatory liabilities are recorded in Other Long-Term Liabilities and current regulatory liabilities are recorded in Accounts Payable and Other Current Liabilities.

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:

(millions of Canadian dollars) December 31,	2009	2008	Consolidated Statements of Financial Position Location**	Estimated Recovery/ Settlement Period (years)	Earnings Impact[1] 2009	Earnings Impact[1] 2008
Regulatory Assets/(Liabilities)						
Enbridge Gas Distribution						
Class action lawsuit settlement [2]	**20.4**	20.1	AR/DA	3	**0.2**	(1.2)
Ontario hearing costs [3]	**5.6**	5.3	AR/DA	2	**0.2**	(1.8)
Purchased gas variance [4]	**(226.7)**	(75.2)	AP	1	**-**	-
Unaccounted for gas variance [5]	**10.2**	0.6	AR	1	**6.4**	(3.6)
Transactional services deferral [6]	**(13.6)**	(6.5)	AP	1	-	-
Pension plans [7]	**(205.1)**	-	OLTL	*	**(6.2)**	-
OPEB [8]	**62.4**	-	DA	*	**4.0**	-
Future removal and site restoration reserves [9]	**(691.6)**	-	OLTL	*	**-**	-
Future income taxes [10]	**174.0**	-	DA	*	**(0.7)**	-
Demand Side Management variance[11]	**(0.9)**	(0.9)	AP	2-4	-	(0.8)
Shared Savings Mechanism [12]	**14.1**	8.2	AR	*	-	-
Union Gas regulatory deferral [13]	**(3.5)**	(1.9)	AP	1	**(1.1)**	(3.5)
Deferred rebate deferral [14]	**2.1**	2.1	AR	1	-	-
Gas distribution access rule deferral[15]	**1.0**	0.8	AR	*	**0.1**	(4.3)
EnergyLink deferral [16]	-	-	N/A	N/A	-	(3.1)
Customer care procurement costs [17]	**2.9**	3.9	DA	3	**(0.7)**	(0.7)
CIS procurement and selection costs [18]	**3.1**	4.1	DA	3	**(0.7)**	2.7
Earnings sharing deferral [19]	**(24.4)**	(5.8)	AP	1	-	-
Tax rate and rule change variance [20]	**(0.3)**	1.8	(AP)/AR	*	**(1.4)**	1.2
Average use true-up variance [21]	**2.9**	(2.7)	AR/(AP)	*	**3.7**	(1.8)
IFRS transition cost deferral[22]	**2.1**	-	AR	*	**1.4**	-
Other regulatory assets and liabilities	**2.8**	2.9	***	*	-	(1.2)
	(862.5)	(43.2)			**5.2**	(18.1)
St. Lawrence						
Pension and OPEB variances [23]	**(1.9)**	2.7	(OLTL)/DA	1	**(3.1)**	-
Gas adjustment clause [24]	**0.4**	(2.6)	AR/(AP)	1	**2.0**	(2.0)
Kamine/Natural Dam deferred revenue [25]	**(0.6)**	(1.2)	OCL	2	**0.4**	0.2
Other regulatory assets and liabilities	**0.7**	1.3	***	*	**(0.4)**	0.8
	(1.4)	0.2			**(1.1)**	(1.0)
	(863.9)	(43.0)			**4.1**	(19.1)

* Refer to the footnote for details.
** AR – Accounts Receivable
AP – Accounts Payable
OCL – Other Current Liabilities
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. Class action lawsuit settlement 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.

3. Ontario 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.

4. 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.

5. 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 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.

6. 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.

7. The pension plans' balance represents the regulatory offset to the pension asset recognized in the current year resulting from the adoption of a revised accounting standard in 2009 (Note 2). 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.

8. The OPEB balance represents the regulatory offset to the OPEB liability recognized in the current year resulting from the adoption of a revised accounting standard in 2009 (Note 2). 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.

9. The future removal and site restoration reserves balance results from the adoption of a revised accounting standard in 2009 (Note 2). With the approval of the OEB, Enbridge Gas Distribution collects amounts from customers 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 future income taxes balance represents the regulatory offset to future income tax liabilities recognized in the current year resulting from adoption of a revised accounting standard in 2009 (Note 2). 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.

11. Demand Side Management (DSM) variance relates to costs incurred by Enbridge Gas Distribution to promote energy efficient use of natural gas in excess of the estimated amount. Enbridge Gas Distribution has historically been granted OEB approval to recover the variance through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. In the absence of rate regulation, these excess costs would be charged to earnings as incurred.

12. Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its DSM (i.e. 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. In the absence of rate regulation, the amount would be included in earnings in the year of approval.

13. Union Gas regulatory deferral represents the incremental amount paid to or received from Union Gas Limited on account of its approved rates for natural gas transportation being at a variance from Union Gas Limited's forecast rates. Enbridge Gas Distribution has historically been required by the OEB to refund or collect the amount outstanding to or from customers in the following year. In the absence of rate regulation, the variance would be included in earnings in the year incurred.

14. Deferred rebate deferral represents an accumulation of amounts required by the OEB to be recovered from or refunded to customers, but remains pending due to the inability to locate certain customers. This amount will be cleared to customers in the subsequent year. There would be no change in the treatment of this item in the absence of rate regulation.

15. Gas distribution access rule (GDAR) deferral represents amounts that are expended for the GDAR implementation, mandated by the OEB, which includes costs relating to consulting services for system design and development. The amount will be recovered from customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, these costs would be charged to earnings as incurred.

16. EnergyLink deferral represents costs incurred by Enbridge Gas Distribution on establishment of the EnergyLink program. A subsequent decision of the OEB required discontinuation of the program. However, the OEB approved complete recovery in 2008 of amounts already incurred. In the absence of rate regulation, these costs would have been charged to earnings as incurred.

17. Customer care procurement costs represent costs incurred by Enbridge Gas Distribution relating to procurement of a new customer care service provider. As part of its customer care settlement agreement, which was approved by the OEB, Enbridge Gas Distribution will recover these amounts through rates over five years. In the absence of rate regulation, the amounts would be charged to earnings as incurred.

18. CIS procurement and selection costs represent costs incurred by Enbridge Gas Distribution relating to procurement of a new CIS. As part of its CIS settlement agreement, which was approved by the OEB, Enbridge Gas Distribution will recover these amounts through rates over five years. In the absence of rate regulation, the amounts would be charged to earnings as incurred.

19. 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 return on equity (ROE) in excess of 100 basis points above the notional allowed utility return on equity (NROE). 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.

20. Tax rate and rule change variance represents the rate impact to be recovered from or returned to customers relating to changes with respect to corporate income tax rates, provincial capital tax rates, capital cost allowance rates and rules that are different from those proposed and embedded in current and future rates. The amount will be recovered from or returned to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the amounts would be charged to earnings as incurred.

21. Average use true-up variance represents the net revenue impact to be recovered from or returned 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 returned 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.

22. IFRS transition cost deferral represents costs incurred by EGD for the transition to IFRS. The OEB has approved an accounting order which permits EGD to accumulate costs relating to the transition to IFRS. OEB approval will be sought for recovery of these amounts from customers, which will then determine the timing of the recovery of the amount through rates. In the absence of rate regulation, the amounts would be charged to earnings as incurred.

23. Pension and OPEB variances represent deferred amounts relating to the differences between the actual and estimated costs (used in the rate case) for these items. These amounts are recorded and deferred until the next rate case for application for recovery. In the absence of rate regulation, these variances would be included in earnings in the year incurred.

24. Gas Adjustment Clause is the difference between the actual and estimated cost of natural gas purchased by St. Lawrence. The estimated cost of natural gas is approved by the NYSPSC and is reflected in rates. St. Lawrence has historically been granted NYSPSC approval for recovery or refund of this variance within a year. In the absence of rate regulation, the actual cost of natural gas would be included in cost of sales as incurred.

25. Kamine / Natural Dam deferred revenue relates to the deferred portion of a settlement from Kamine / Natural Dam in 1998 to extinguish its obligations to St. Lawrence under an agreement. The deferred revenue balance will be fully amortized into earnings by 2011. In the absence of rate regulation, earnings would not include the impact of this amortization.

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 into the rate base on an ongoing basis. The Company is authorized to charge depreciation on such capitalized costs in future years. In the absence of accounting for the effects of rate regulation, some of these operating costs may be charged to earnings in the year incurred.

The Company entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2009, costs relating to this consulting contract of $111.8 million (2008 - $93.7 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 current earnings.

Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include 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, 2009, $127.4 million of such costs were capitalized to Intangible Assets in accordance with regulatory treatment. At December 31, 2008, $78.7 million was included in work-in-progress. In the absence of rate regulation, a portion of these costs 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, 2009 is $40.6 million (2008 - $36.8 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 form part of gas inventory as incurred and be charged to gas cost based on consumption throughout the year.

Depreciation

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

4. PROPERTY, PLANT AND EQUIPMENT

(millions of Canadian dollars) **December 31, 2009**	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Gas mains	**4.2%**	**2,372.5**	**439.1**	**1,933.4**
Gas services	**4.4%**	**1,960.5**	**593.3**	**1,367.2**
Regulating and metering equipment	**3.7%**	**676.6**	**215.7**	**460.9**
Storage	**2.8%**	**228.1**	**73.4**	**154.7**
Computer technology	**19.5%**	**27.3**	**3.4**	**23.9**
Land and right-of-way	**3.3%**	**68.2**	**27.7**	**40.5**
Under construction	**-**	**71.4**	**-**	**71.4**
Other	**3.4%**	**246.8**	**79.2**	**167.6**
		5,651.4	**1,431.8**	**4,219.6**
Unregulated storage	**4.1%**	**48.5**	**1.2**	**47.3**
Construction materials inventory	**-**	**22.9**	**-**	**22.9**
		5,722.8	**1,433.0**	**4,289.8**

(millions of Canadian dollars) December 31, 2008	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Gas mains	4.2%	2,251.3	800.3	1,451.0
Gas services	4.5%	1,884.2	772.6	1,111.6
Regulating and metering equipment	3.7%	647.0	230.9	416.1
Storage	2.8%	261.2	70.4	190.8
Computer technology	18.8%	25.9	7.2	18.7
Land and right-of-way	3.3%	68.3	24.5	43.8
Under construction	-	108.1	-	108.1
Other	3.7%	203.0	77.7	125.3
		5,449.0	1,983.6	3,465.4
Unregulated storage	1.8%	22.3	0.1	22.2
Construction materials inventory	-	26.7	-	26.7
		5,498.0	1,983.7	3,514.3

5. DEFERRED AMOUNTS AND OTHER ASSETS

(millions of Canadian dollars) December 31,	**2009**	2008
Pension asset (Note 2)	**205.1**	-
Regulatory asset related to:		
- Future income taxes (Note 2)	**174.0**	-
- OPEB (Note 2)	**62.4**	-
Settlement recoverable	**14.1**	14.1
Long-term portion of derivative assets (Note 11)	**3.6**	-
CIS procurement and selection costs	**3.1**	4.1
Customer care procurement costs	**2.9**	3.9
Deferred rate hearing costs	**2.8**	3.0
Other	**18.9**	14.9
	486.9	40.0

The settlement recoverable relates to the settlement of a class action lawsuit regarding late payment penalties.

6. INTANGIBLE ASSETS

(millions of Canadian dollars) **December 31, 2009**	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Software	**20.5%**	**106.5**	**52.1**	**54.4**
CIS	**10.5%**	**127.4**	**3.0**	**124.4**
		233.9	**55.1**	**178.8**

(millions of Canadian dollars) December 31, 2008	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Software	20.0%	139.6	71.9	67.7
CIS	-	78.7	-	78.7
		218.3	71.9	146.4

Intangible assets include $8.8 million of work-in-progress for the year ended December 31, 2009 (2008 - $81.9 million). The 2008 work-in-progress balance includes $78.7 million for CIS.

Total amortization expense for intangible assets was $26.7 million for the year ended December 31, 2009 (2008 - $23.6 million).

7. DEBT

(millions of Canadian dollars) December 31,	Weighted Average Interest Rate	Maturity	**2009**	2008
Debentures	11.04%	2010-2024	**385.0**	485.0
Medium-term notes	5.8%	2014-2036	**1,795.0**	1,795.0
Commercial paper and credit facility draws, net			**507.7**	874.5
Other			**11.5**	15.7
Deferred debt issue costs			**(19.3)**	(21.5)
Total Debt			**2,679.9**	3,148.7
Current Maturities			**(150.0)**	(100.0)
Short-Term Borrowings	0.26%		**(514.5)**	(881.6)
Long-Term Debt			**2,015.4**	2,167.1
Loans from Affiliate Company			**375.0**	375.0

Debenture and term note maturities for the years ending December 31, 2010 through 2014 are $150.0 million, $150.0 million, $nil, $nil, and $400.0 million, respectively. The Company’s debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2010 through 2014 are $146.1 million, $120.0 million, $111.9 million, $111.9 million and $106.4 million, respectively.

INTEREST EXPENSE

(millions of Canadian dollars)

Year ended December 31,	**2009**	2008
Debentures and medium-term notes	**150.9**	161.8
Loans from affiliate company	**26.8**	26.8
Commercial paper and credit facility draws	**3.5**	12.8
Other interest and finance costs	**13.6**	4.5
Capitalized	**(5.7)**	(5.1)
	189.1	200.8

In 2009, total interest paid to third parties was $160.5 million (2008 - $179.2 million) and total interest paid to affiliated companies was $26.8 million (2008 - $26.8 million).

CREDIT FACILITIES

At December 31, 2009, the Company had $800.0 million (2008 - $1.0 billion) of committed credit facilities, of which $505.0 million (2008 - $874.5 million) was drawn or allocated to backstop commercial paper. At December 31, 2009, the Company had $5.2 million (2008 - $6.1 million) of uncommitted lines of credit, against which $2.7 million was borrowed (2008 - $2.5 million). Credit facilities carried a weighted average standby fee of 0.07% per annum from January to July 2009 and 0.6% per annum from August to December 2009 on the unused portion and draws bear interest at market rates.

In the third quarter of 2009, the Company elected to reduce its committed credit facilities and commercial paper program limit by $200.0 million. The Company currently has an $800.0 million commercial paper program limit that is backstopped by committed lines of credit of $800.0 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.

8. 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

(millions of Canadian dollars; number of common shares in millions)

December 31,	**2009**		2008	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	**140.7**	**1,070.7**	140.7	1,070.7
Common shares issued	**-**	**-**	-	-
Balance at end of year	**140.7**	**1,070.7**	140.7	1,070.7

PREFERRED SHARES

(millions of Canadian dollars, number of preferred shares in millions) December 31, 2009 and 2008	Authorized	Issued and Outstanding	Amount
Group 1	**0.2**	**Nil**	**-**
Group 2, Series A - C, Cumulative Redeemable Retractable	**6.0**	**Nil**	**-**
Group 2, Series D, Cumulative Redeemable Convertible	**4.0**	**Nil**	**-**
Group 3, Series A - C, Cumulative Redeemable Retractable	**6.0**	**Nil**	**-**
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	**4.0**	**4.0**	**100.0**
Group 4	**10.0**	**Nil**	**-**
Group 5	**10.0**	**Nil**	**-**
			100.0

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 3, Series D preferred shareholders opted not to convert these shares into Group 2, Series D preferred shares effective July 1, 2009.

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.

9. 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, 2009, 244,350 stock options (2008 – 220,600 options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $39.61 in 2009 (2008 - $40.42) and a grant date fair value of $6.73 (2008 - $6.20).

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for 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 2007, 2008 and 2009 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, 2009, 6,900 PSUs (2008 – 6,700) 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, 2009, Enbridge Inc. granted 61,800 RSUs (2008 – 52,000) 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, 2009, the direct charge totaled $5.0 million (2008 – $4.2 million) and the allocation totaled $4.3 million (2008 – $3.4 million). These costs are included in operating and administrative expenses.

10. 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 commodity 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. Floating to fixed interest rate swaps and options may be used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.82%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2020. A total of $200.0 million of future fixed rate term debt issuances have been hedged at an average government bond rate of 4.0%.

A 1% increase across the interest rate yield curve would have caused a $nil increase (2008 - $nil) in earnings and a $15.4 million increase (2008 - $nil) in OCI at December 31, 2009 due to the revaluation of interest rate derivatives. If interest rates had been 1% higher during the 12 months ended December 31, 2009, there would have been a $3.6 million decrease (2008 - $5.9 million) in earnings due to increased interest expense related to the Company's floating rate debt, partially offset by an increase in earnings due to increased realized fair value gains on settled interest rate hedges of $1.1 million (2008 - $nil).

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.

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 adherence to 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, 2009		December 31, 2008	
	Maturity	Notional principal or Quantity Outstanding	Maturity	Notional principal or Quantity Outstanding
Natural gas *($10^6 m^3$)*	**2010**	**12**	2009	43
Interest rate contracts *(millions of Canadian dollars)*	**2010-2012**	**513.0**	2009	8.6

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

The Company estimates that $2.5 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 forecast transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 36 months at December 31, 2009.

Additional information regarding the Company's derivative instruments is in Note 11, Fair Value of Financial Instruments.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments (Note 17), as they become due. In order to manage this risk, the Company forecasts cash requirements over the near and long term 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 longer 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 7) 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 and expects to be in compliance throughout 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. The Company expects to generate sufficient cash from operations and commercial paper issuances and draws under its committed credit facilities to fund liabilities as they become due, finance planned investing activities and pay dividends throughout the year. Additional liquidity, if necessary, is expected to be available through access to the capital markets.

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 7 and 16).

For the years ending December 31, 2010 through 2014, and thereafter, the Company has estimated that the following undiscounted cash flows will arise from its derivative instruments based on valuation at the balance sheet date.

(millions of Canadian dollars)	2010	2011	2012	2013	2014	Thereafter
Cash inflows	1.8	2.0	1.6	-	-	-
Cash outflows	(2.8)	-	-	-	-	-
Net cash flows	(1.0)	2.0	1.6	-	-	-

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 11, Fair Value of Financial Instruments.

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

(millions of Canadian dollars)

Year ended December 31,	**2009**	2008
Balance at beginning of year	**(50.3)**	(47.0)
Additional allowance	**(29.0)**	(26.4)
Amounts used and reversed	**22.2**	23.1
Balance at end of year	**(57.1)**	(50.3)

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 enters into risk management transactions only 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, 2009, the Company has a maximum exposure to credit risk of $2.3 million related to its derivative counterparties.

11. 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, 2009							
(millions of Canadian dollars)	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
Assets								
Accounts receivable[2]	**-**	**-**	**701.7**	**-**	**1.8**	**65.6**	**769.1**	703.5
Investment in affiliate company[3]	**-**	**825.0**	**-**	**-**	**-**	**-**	**825.0**	N/A
Deferred amounts and other assets	**-**	**-**	**-**	**-**	**3.6**	**483.3**	**486.9**	3.6
Liabilities								
Bank overdraft	**12.8**	**-**	**-**	**-**	**-**	**-**	**12.8**	12.8
Short-term borrowings	**-**	**-**	**-**	**514.5**	**-**	**-**	**514.5**	514.5
Accounts payable[2]	**-**	**-**	**-**	**429.9**	**2.8**	**292.9**	**725.6**	432.7
Other current liabilities	**-**	**-**	**-**	**55.8**	**-**	**-**	**55.8**	55.8
Long-term debt	**-**	**-**	**-**	**2,165.4**	**-**	**-**	**2,165.4**	2,444.5
Loans from affiliate company[4]	**-**	**-**	**-**	**375.0**	**-**	**-**	**375.0**	N/A

	December 31, 2008							
(millions of Canadian dollars)	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
Assets								
Cash and cash equivalents	100.0	-	-	-	-	-	100.0	100.0
Accounts receivable[2]	-	-	955.5	-	-	24.8	980.3	955.5
Investment in affiliate company[3]	-	825.0	-	-	-	-	825.0	N/A
Liabilities								
Bank overdraft	44.6	-	-	-	-	-	44.6	44.6
Short-term borrowings	-	-	-	881.6	-	-	881.6	881.6
Accounts payable[2]	-	-	-	583.0	0.8	93.3	677.1	583.8
Other current liabilities	-	-	-	88.1	-	-	88.1	88.1
Long-term debt	-	-	-	2,267.1	-	-	2,267.1	2,253.0
Loans from affiliate company[4]	-	-	-	375.0	-	-	375.0	N/A

1 Fair value does not include non-financial instruments and equity instruments held at cost that do not trade on an actively quoted market.

2 Accounts receivable as at December 31, 2009 excludes $65.6 million of regulatory assets that do not meet the definition of a financial instrument (2008 - $24.8 million). Accounts payable as at December 31, 2009 excludes $292.9 million of regulatory liabilities that do not meet the definition of a financial instrument (2008 - $93.3 million).

3 The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliated company under common control. The investment, classified as an available-for-sale instrument, provides a weighted average dividend yield of 7.60%. 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. The Company currently has no plans to dispose of this investment. 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.

4 The Company has loans outstanding to IPL System Inc., an affiliated company under common control, in the amounts of $200.0 million and $175.0 million. The loans bear interest at 6.85% and 7.50%, respectively, and mature 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. These loans were created between affiliated companies to meet the financing demands of the Company, as such, there is no external market for the instruments. Currently, the Company has no plans to settle the instruments prior to their maturity. As these financial liabilities originated in related party transactions and have no quoted market prices in an active market, they are carried at cost and fair values have not been determined.

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 that would have been 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 assets and liabilities 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 an asset or liability 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 valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivative instruments 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 instrument. Instruments valued using Level 2 inputs include non-exchange traded derivatives such as interest rate swaps and commodity swaps for which observable inputs can be obtained.

Level 3

Level 3 includes valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the instruments' fair value. Generally, Level 3 valuations 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 contracts 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, 2009			
(millions of Canadian dollars)	Level 1	Level 2	Level 3	Total
Financial assets:				
Current derivative assets	**-**	**1.8**	**-**	**1.8**
Long-term derivative assets	**-**	**3.6**	**-**	**3.6**
Financial liabilities:				
Current derivative liabilities	**-**	**(2.8)**	**-**	**(2.8)**
Long-term derivative liabilities	**-**	**-**	**-**	**-**
Total net derivative asset	**-**	**2.6**	**-**	**2.6**

	December 31, 2008			
(millions of Canadian dollars)	Level 1	Level 2	Level 3	Total
Financial assets:				
Current derivative assets	-	-	-	-
Long-term derivative assets	-	-	-	-
Financial liabilities:				
Current derivative liabilities	-	(0.8)	-	(0.8)
Long-term derivative liabilities	-	-	-	-
Total net derivative liability	-	(0.8)	-	(0.8)

12. 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:

(millions of Canadian dollars)

December 31,	**2009**	2008
Bank overdraft	**12.8**	44.6
Short-term borrowings	**514.5**	881.6
Long-term debt (includes current portion)	**2,184.7**	2,288.6
Loans from affiliate company	**375.0**	375.0
Shareholders' equity	**1,970.0**	1,939.8
Cash and cash equivalents	**-**	(100.0)
	5,057.0	5,429.6

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 shareholders. 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 shareholders, 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, 2009, the Company was in compliance with these covenants.

13. INCOME TAXES

INCOME TAX RATE RECONCILIATION

(millions of Canadian dollars) Year ended December 31,	**2009**	2008
Earnings before income taxes	**299.4**	300.8
Combined statutory income tax rate	**33.0%**	33.5%
Income taxes at statutory rate	**98.8**	100.8
Increase/(decrease) resulting from:		
Non-taxable dividend income from affiliated companies	**(20.7)**	(21.0)
Future income taxes related to regulated operations	**-**	10.8
Other	**(0.2)**	(1.2)
Income Taxes	**77.9**	89.4
Effective income tax rate	**26.0%**	29.7%

The future income taxes recorded in current liabilities of $4.6 million (2008 – current asset of $15.3 million) arise primarily from temporary differences relating to regulatory deferral accounts.

On January 1, 2009, the Company recognized a future income tax liability of $212.2 million on regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset. A regulatory asset has been recognized as the associated future income tax liability is expected to be recoverable in future rates. At December 31, 2009, the Company had a future income tax liability of $174.0 million related to regulatory assets with an offsetting long-term regulatory asset (Note 2).

14. POST-EMPLOYMENT BENEFITS

PENSION PLANS

The Company provides funded defined benefit pension and/or defined contribution pension to the majority of its employees. The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2009.

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, 2006	December 31, 2009

The defined benefit pension plan 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

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	
(millions of Canadian dollars)	**2009**	2008	**2009**	2008
Change in Accrued Benefit Obligation				
Benefit obligation at beginning of year	**578.9**	639.8	**83.2**	99.5
Service cost	**12.9**	14.6	**1.2**	1.5
Interest cost	**38.6**	35.9	**5.4**	5.6
Net transfer out	**0.4**	(4.8)	**-**	-
Adjustment due to change in measurement date	**-**	-	**-**	0.2
Actuarial gain	**(11.5)**	(78.9)	**(5.8)**	(20.3)
Benefits paid	**(31.4)**	(27.7)	**(3.5)**	(3.3)
Benefit obligation at end of year	**587.9**	578.9	**80.5**	83.2
Change in Plan Assets				
Fair value of plan assets at beginning of year	**700.4**	831.7	**-**	-
Transfer to the defined contribution component	**(1.2)**	(1.3)	**-**	-
Actual return/(loss) on plan assets	**26.0**	(96.2)	**-**	-
Employer's contributions	**0.8**	0.6	**3.5**	3.3
Benefits paid	**(31.4)**	(27.7)	**(3.5)**	(3.3)
Net transfer out	**0.5**	(6.7)	**-**	-
Fair value of plan assets at end of year	**695.1**	700.4	**-**	-
Funded Status				
Benefit obligation	**(587.9)**	(578.9)	**(80.5)**	(83.2)
Fair value of plan assets	**695.1**	700.4	**-**	-
Overfunded/(Underfunded) status at end of year	**107.2**	121.5	**(80.5)**	(83.2)
Contribution after measurement date	**0.3**	0.1	**0.8**	0.8
Unamortized prior service cost/(credit)	**4.9**	6.1	**-**	(0.6)
Unamortized transitional obligation/(asset)	**(94.2)**	(119.4)	**18.7**	21.8
Unamortized net actuarial loss/(gain)	**183.7**	191.2	**(8.5)**	(2.4)
Net amount recognized on an accrual basis at end of year	**201.9**	199.5	**(69.5)**	(63.6)
Presented as follows:				
Deferred Amounts and Other Assets (Note 5)	**205.1**	- [1]	**-**	- [1]
Other Long-Term Liabilities	**(3.2)**	- [1]	**(69.5)**	- [1]
Net amount recognized in the Consolidated Statement of Financial Position at end of year[1]	**201.9**	- [1]	**(69.5)**	- [1]

1. Prior to January 1, 2009, the Company recognized pension benefit and OPEB costs on the cash basis. As a result, these amounts were not recognized in the Consolidated Statements of Financial Position (Note 2).

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,	**2009**	2008	**2009**	2008
Discount rate	**6.60%**	6.70%	**6.60%**	6.70%
Average rate of salary increases	**5.00%**	5.00%	**3.50%**	5.00%

Net Benefit Costs Recognized

(millions of Canadian dollars)	Pension Benefits		OPEB	
Year ended December 31,	**2009**	2008	**2009**	2008
Benefits earned during the year	**12.9**	14.6	**1.2**	1.5
Interest cost on projected benefit obligations	**38.6**	35.9	**5.4**	5.6
Actual loss/(return) on plan assets	**(26.0)**	96.2	**-**	-
Actuarial gain	**(11.5)**	(78.9)	**(5.7)**	(20.3)
Difference between actual and expected return on plan assets	**(22.1)**	(154.6)	**-**	-
Amortization of prior service costs/(credits)	**1.2**	1.3	**(0.1)**	(0.1)
Amortization of transitional obligation/(asset)	**(25.2)**	(25.1)	**3.1**	3.1
Amortization of actuarial loss	**24.6**	83.8	**6.0**	21.3
Net defined benefit costs on an accrual basis	**(7.5)**	(26.8)	**9.9**	11.1
Defined contribution benefit costs	**1.2**	1.3	**-**	-
Costs (credits) on an accrual basis	**(6.3)**	(25.5)	**9.9**	11.1

Costs related to the period on an accrual basis are presented above. However, no earnings impact resulted due to the continuity of the existing regulatory mechanism in place under which plan contributions and actual OPEB benefit costs are expensed as paid, consistent with the recovery of such costs in rates (Note 2). Such costs totaled $1.3 million for pension benefits and $3.5 million for OPEB for the year ended December 31, 2009 (2008 - $0.9 million and $3.3 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,	**2009**	2008	**2009**	2008
Discount rate	**6.70%**	5.60%	**6.70%**	5.60%
Average rate of return on pension plan assets	**7.25%**	7.25%	**-**	-
Average rate of salary increases	**5.00%**	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	9.38%	4.50%	2030
Other Medical and Dental	4.50%	4.50%	2030

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $9.6 million in the accumulated post-employment benefit obligations and an increase of $0.9 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $7.9 million in the accumulated post-employment benefit obligations and a decrease of $0.7 million in benefit and interest costs.

PLAN ASSETS

Major Categories of Plan Assets

	Pension Benefits			OPEB		
(millions of Canadian dollars)	**2009**		2008	**2009**		2008
As at December 31,	Allocation	Amount	Allocation	Allocation	Amount	Allocation
Equity securities	**55%**	**386.1**	49%	**-**	**-**	**-**
Fixed income securities	**41%**	**283.0**	46%	**-**	**-**	-
Other	**4%**	**26.0**	5%	**-**	**-**	-
Total Assets	**100%**	**695.1**	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 fund by setting a long-term asset mix policy 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%

Expected Rate of Return on Plan Assets

	Pension Benefits		OPEB	
Year ended December 31,	**2009**	2008	**2009**	2008
Equity securities	**8.75%**	8.75%	**-**	-
Fixed income securities	**5.00%**	5.00%	**-**	-

PLAN CONTRIBUTIONS BY THE COMPANY

(millions of Canadian dollars)	Pension Benefits		OPEB	
Year ended December 31,	**2009**	2008	**2009**	2008
Total contributions	**0.8**	0.6	**3.5**	3.3
Contributions expected to be paid in 2010	**1.0**		**3.5**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

(millions of Canadian dollars)						
Year ended December 31,	2010	2011	2012	2013	2014	2015-2019
Expected future benefit payments	35.9	37.5	39.1	41.4	42.8	244.3

15. CHANGES IN OPERATING ASSETS AND LIABILITIES

(millions of Canadian dollars)		
Year ended December 31,	**2009**	2008
Accounts receivable	**211.2**	(66.6)
Gas inventories	**260.6**	(62.7)
Other current assets	**(25.0)**	2.6
Accounts payable	**59.5**	(15.2)
Other current liabilities (excluding impact of dividends payable)	**(39.0)**	26.5
	467.3	(115.4)

16. RELATED PARTY TRANSACTIONS

(millions of Canadian dollars) Year ended December 31,	**2009**	2008
Enbridge Inc.		
Purchase of treasury and other management services	**29.8**	27.4
Enbridge Commercial Services Inc.		
Purchase of information services	**2.0**	3.4
Alliance Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**23.6**	23.6
Alliance Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**17.7**	17.1
Vector Pipeline Limited Partnership		
Purchase of gas transportation services	**28.6**	27.0
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**44.1**	47.2
IPL System Inc.		
Dividend income	**62.7**	62.7
Interest expense	**26.8**	26.8

The Company had related party balances as follows:

(millions of Canadian dollars) December 31,	**2009**	2008
Note payable to affiliate company		
Enbridge (U.S.) Inc.	**6.8**	7.1
Note receivable from affiliate company		
Enbridge (U.S.) Inc.	**3.7**	-
Investment in affiliate company		
IPL System Inc.	**825.0**	825.0
Dividend receivable	**5.3**	5.3
Loans from affiliate company		
IPL System Inc.	**375.0**	375.0
Interest payable	**2.3**	2.3
Accounts receivables (payables)		
Enbridge Inc.	**(2.4)**	(1.9)
Gazifère Inc.	**4.3**	9.3

Financing Transactions
The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand. The note receivable from Enbridge (U.S.) Inc. bears interest at 1.75% and is payable on demand.

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, 2009, the Company's total investment of $825.0 million (2008 - $825.0 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2009, the borrowing from IPL System Inc. stood at $375.0 million ($200.0 million at 6.85% and $175.0 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, 2009, interest paid amounted to $26.8 million (2008 - $26.8 million).

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.

Information Services
The Company purchases access to its Enterprise Financial 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.

Gas Transportation Services
The Company has contracted for natural gas transportation services from Alliance Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (U.S.) and Vector Pipeline Limited Partnership, related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2010 - $63.9 million, 2011 to 2012 - $126.4 million, 2013 to 2014 - $121.2 million and thereafter - $48.9 million.

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.

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.

17. COMMITMENTS AND CONTINGENCIES

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

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Consulting contract [1]	33.2	9.4	13.6	10.2	-
Customer care service contracts [2]	128.3	56.4	71.9	-	-
CIS contracts [3]	11.1	4.1	7.0	-	-
Total Contractual Obligations	172.6	69.9	92.5	10.2	-

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.
2. In 2007, the Company entered into new 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 entered into 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 $79.0 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 $70.0 million and punitive damages in the amount of $5.0 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 $50.0 million in damages and $5.0 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.

Oral examinations for discovery were substantially completed during the summer of 2005. A mandatory mediation originally scheduled for November 2005 was postponed. In February 2007, the parties agreed to a revised timetable for the next steps in the action pursuant to which the plaintiff was required to set the action down for trial by January 31, 2008. While the plaintiff did set the action down for trial by the prescribed date, required steps in the discovery process have not yet been completed by the plaintiff. As a result, on February 12, 2008, the Court established a new timetable for the completion of the discovery process. 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, 2007, 2008 and 2009 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 has also applied to the OEB for the establishment of a 2010 deferral account in its 2010 rate adjustment application.

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. The Court's decision has been reserved and the Company expects it to be released in early 2010. The Company does not believe any fines that may be levied will have a material financial impact on the Company.

The Company has also been named as a defendant in a number of civil actions related to the explosion. All significant civil actions have been settled without any material financial impact on the Company. A Coroner's Inquest in connection with the explosion is also possible.

Goods & Services Tax (GST) Overpayment

In December 2007, the Company discovered that it had remitted excess GST to the Canada Revenue Agency (CRA). In respect of certain months within the 2003 to 2005 calendar year periods, the amount of such overpayment was approximately $40 million and was included in accounts receivable. In April 2009, the Company received the requested refund of GST overpayments, including interest, from the CRA.

Settlement of Class Action Lawsuit Regarding Late Payment Penalties

In September 2007, the Company applied to the OEB for recovery in rates of all amounts paid, including the $22 million settlement, as a result of the class action lawsuit regarding late payment penalties. In February 2008, the OEB approved the Company's application. The OEB's decision allows the Company to recover all amounts paid in connection with the settlement from customers, including the Company's legal expenses, over a five-year period commencing in 2008 (Notes 3 and 5).

In May 2008, the representative plaintiff in the class action made a petition to the Lieutenant Governor in Council of Ontario (LGiC) in which he asked the LGiC to require the OEB to reconsider its decision of February 4, 2008. On December 1, 2008, the LGiC issued an Order in Council confirming that the OEB's decision of February 4, 2008 will stand. There is no possible appeal or review of the LGiC's decision.

OTHER 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%, 10.80% and 11.95% debentures

CIBC 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, CIBC Mellon Trust Company is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium-Term Notes
Canadian Imperial Bank of Commerce
BCE Place
161 Bay Street, 5th Floor
Toronto, Ontario, M5J 2S8

TRUSTEE

Medium-Term Notes
CIBC Mellon Trust Company
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 4, 2009), which is incorporated herein by reference.

ENBRIDGE GAS DISTRIBUTION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2009

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 18, 2010 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) for the year ended December 31, 2009, which are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). All financial measures presented in this MD&A are expressed in Canadian dollars. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

OVERVIEW

The Company is a rate-regulated natural gas distribution utility and has been in operation for more than 160 years. The Company serves approximately 1.9 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, the Company 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.

PERFORMANCE OVERVIEW

(millions of Canadian dollars, except per share amounts)

Year ended December 31,	**2009**	2008	2007
Earnings Applicable to the Common Shareholder	**218.2**	206.5	185.0
Earnings Excluding the Effect of Weather[1]	**201.2**	183.4	170.8
Cash Flow Data			
Cash provided by operating activities	**971.3**	367.7	528.7
Cash used by investing activities	**(383.8)**	(405.8)	(368.6)
Cash (used)/provided by financing activities	**(655.7)**	98.3	(150.3)
Dividends			
Common share dividends declared	**188.0**	158.2	88.4
Dividends declared per common share	**1.34**	1.12	0.64
Preferred share dividends declared	**3.3**	4.9	4.9
Dividends declared per preferred share	**0.84**	1.23	1.23
Total Revenues	**2,903.1**	3,104.9	2,953.9
Total Assets	**6,977.8**	6,285.1	5,921.1
Total Long-Term Liabilities	**3,547.2**	2,556.0	2,442.3

(1) Earnings excluding the effect of weather is a non-GAAP measure that does not have any standardized meaning prescribed by Canadian GAAP. For more information on this non-GAAP measure see page 4.

EARNINGS APPLICABLE TO THE COMMON SHAREHOLDER

Earnings applicable to the common shareholder were $218.2 million for the year ended December 31, 2009 compared with $206.5 million for the year ended December 31, 2008. The increase of $11.7 million primarily resulted from customer growth, higher other revenue, lower interest expense and lower income taxes. This was partially offset by higher depreciation and amortization, higher earnings sharing with customers under the current Incentive Regulation (IR) term and higher operating and administrative costs.

Earnings applicable to the common shareholder were $206.5 million for the year ended December 31, 2008 compared with $185.0 million for the year ended December 31, 2007. The increase of $21.5 million was primarily due to colder weather, customer growth, higher other revenue and lower interest expense, partially offset by higher depreciation and amortization.

EARNINGS EXCLUDING THE EFFECT OF WEATHER

(millions of Canadian dollars)

Year ended December 31,	**2009**	2008	2007
Earnings Applicable to the Common Shareholder	**218.2**	206.5	185.0
Colder than normal weather	**17.0**	23.1	14.2
Earnings Excluding the Effect of Weather	**201.2**	183.4	170.8

The effect of weather is measured by degree day deficiency and is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 degree days for that day. Degree day deficiency is a key measure used by the Company to isolate the impact of weather, a factor beyond the control of management. This enables a meaningful analysis of the operational performance of the Company over different periods.

Normal weather is the weather forecast by the Company in the Greater Toronto Area, using the forecasting methodology approved by the Ontario Energy Board (OEB). Normal weather is a measure that is unique to the Company and does not have any standardized meaning. In addition, due to differing franchise areas, it is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other entities. Moreover, normal weather may not be comparable from year to year given that the forecasting models are updated annually to reflect the most recent weather trend.

Earnings excluding the effect of weather were $201.2 million for the year ended December 31, 2009 compared with $183.4 million for the year ended December 31, 2008. Earnings increased primarily due to customer growth, higher other revenue, lower interest expense and lower income taxes. This was partially offset by higher depreciation and amortization, higher earnings sharing with customers under the current IR term and higher operating and administrative costs.

Earnings excluding the effect of weather were $183.4 million for the year ended December 31, 2008 compared with $170.8 million for the year ended December 31, 2007. Earnings increased primarily due to customer growth, higher other revenue and lower interest expense, partially offset by higher depreciation and amortization.

REVENUES

Revenues for the year ended December 31, 2009 were $2,903.1 million compared with $3,104.9 million for the year ended December 31, 2008. The decrease in revenues was primarily a result of lower natural gas prices and warmer weather compared to the prior year, partially offset by customer growth.

Revenues for the year ended December 31, 2008 were $3,104.9 million compared with $2,953.9 million for the year ended December 31, 2007. The increase in revenues was primarily due to colder weather, higher natural gas prices and customer growth.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholder and potential investors with information about the Company and its subsidiaries, including management's assessment of the Company's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'' and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to expected capital expenditures.

Although the Company believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and *uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.*

The Company's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates and commodity prices and supply and demand for natural gas, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Company's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Company assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to the Company or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURE

This MD&A contains references to earnings excluding the effect of weather, which represents earnings applicable to the common shareholder adjusted for weather. Management believes that the presentation of this measure provides useful information to investors and the shareholder as it provides increased transparency and predictive value. Management uses this measure to set targets and assess performance of the Company. Earnings excluding the effect of weather is not a measure that has a standardized meaning prescribed by Canadian GAAP and is not considered a Canadian GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers.

STRATEGY

The Company's vision is to become North America's leading energy distribution and services company. To achieve its vision, the Company has outlined the following strategic objectives:

- achieve top decile safety performance;
- deliver shareholder value;
- maintain and enhance customer and stakeholder relationships;
- maintain a healthy and productive work environment; and
- enhance governance, integrity and transparency in all business processes.

The Company's strategic initiatives are designed to protect and enhance its core business with a continued focus on optimizing performance during the IR term. The Company will target new growth opportunities, which complement its core business, by pursuing newly evolving business models and technologies to support green energy initiatives. In addition, the Company will continue to grow its natural gas storage assets.

SIGNIFICANT EVENTS

New Customer Information System (CIS) Implemented
In September 2009, the Company successfully implemented its new CIS, which replaced the Company's legacy system. The Company expects to fully recover in rates the total cost of the project in accordance with an agreement with customer groups that was approved by the OEB in 2007.

Green Energy Initiatives
In September 2009, Ontario's Minister of Energy and Infrastructure issued a Directive that permits the Company to own and operate stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities up to 10 megawatts in capacity. The Company will also be permitted to own and operate district and distributed energy systems, including facilities that produce power and thermal energy from a single source. Finally, the Minister's Directive permits the Company to own and operate assets that would assist the Government of Ontario in achieving its goals in energy conservation, including assets related to solar-thermal water and ground source heat pumps.

In the absence of the Minister's Directive, the Company's Undertakings to the Lieutenant Governor in Council would not have permitted the Company to engage in the foregoing activities directly. The Company plans to increase its role in this area and is looking to expand its efforts to explore and pursue alternative and/or renewable energy technologies subject to OEB approval, where appropriate.

While the Directive permits the Company to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates. As a result of this decision, the Company will seek clarification of the OEB's broader policies with respect to such investments and activities in 2010.

Unregulated Storage Services
The deregulation of new natural gas storage in Ontario, coupled with the growing need for high-deliverability storage services by gas-fired power generators and other users, has created unregulated storage growth opportunities for the Company. As of December 31, 2009, the Company had expanded its storage capacity by 6% (0.2 billion cubic metres or 5.5 billion cubic feet (bcf)) and sold unregulated storage services into the storage market. A second expansion, amounting to an additional 2 bcf of capacity, is planned to be in service in 2010.

Goods & Services Tax (GST) Overpayment
In December 2007, the Company discovered that it had remitted excess GST to the Canada Revenue Agency (CRA). In respect of certain months within the 2003 to 2005 calendar year periods, the amount of such overpayment was approximately $40 million and was included in accounts receivable. In April 2009, the Company received the requested refund of GST overpayments, including interest, from the CRA.

RESULTS OF OPERATIONS

(millions of Canadian dollars)

Year ended December 31,	**2009**	2008	2007
Gas distribution margin	**1,024.8**	1,010.6	984.7
Other revenue	**108.4**	93.9	81.4
Operating and administrative expenses	**(385.3)**	(373.5)	(367.0)
Depreciation and amortization	**(254.0)**	(239.0)	(228.0)
Municipal and other taxes	**(49.3)**	(47.3)	(55.1)
Earnings sharing	**(18.8)**	(5.8)	-
Affiliate financing income	**62.7**	62.7	62.7
Interest expense	**(189.1)**	(200.8)	(210.3)
Income taxes	**(77.9)**	(89.4)	(78.5)
Earnings	**221.5**	211.4	189.9
Earnings applicable to the common shareholder	**218.2**	206.5	185.0

Gas Distribution Margin

Gas distribution margin for the year ended December 31, 2009 increased by $14.2 million compared with the year ended December 31, 2008. The increase in gas distribution margin was primarily due to customer growth, favorable changes in customer mix and higher distribution charges as a result of the application of the IR formula approved by the OEB, partially offset by warmer weather compared to the prior year.

Weather, measured in degree days, was 3,767 degree days for the year ended December 31, 2009 compared with 3,802 degree days for the year ended December 31, 2008. The degree days reported in 2009 were 253 degree days colder compared with forecast degree days. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2009 would have been lower by approximately $25.3 million (2008 – $34.8 million).

Gas distribution margin for the year ended December 31, 2008 increased by $25.9 million compared with the year ended December 31, 2007. The increase primarily resulted from colder weather and customer growth.

Weather, measured in degree days, was 3,802 degree days for the year ended December 31, 2008 compared with 3,659 degree days for the year ended December 31, 2007. The degree days reported in 2008 were 259 degree days colder compared with forecast degree days. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2008 would have been lower by approximately $34.8 million (2007 – $22.3 million).

Degree days were colder in 2009 and 2008 by a similar magnitude; however, there was a less significant weather normalization impact on 2009 earnings when compared to 2008 earnings. This is primarily due to a lower per unit volumetric charge with a corresponding increase in fixed charges in 2009 when compared to 2008. While the increase in monthly fixed charges does not materially impact earnings over 12 consecutive months, it shifts a portion of earnings from the winter months to the summer months. The progressive substitution of lower per unit volumetric charges with corresponding increases in fixed charges enables the Company to diminish the volatility in earnings for a given level of weather variability. In addition, there were differences in the pattern of distribution of degree days during the year and their relative effectiveness. Degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Other Revenue

Other revenue for the year ended December 31, 2009 increased by $14.5 million compared with the year ended December 31, 2008. The increase was primarily due to interest income related to the recovery of the GST overpayment and revenue from the unregulated storage business, which was not fully operational in the prior year. This was partially offset by lower Shared Savings Mechanism (SSM) revenue, which results from exceeding targets on delivery of energy efficiency programs for promotion of energy efficient use of natural gas to customers.

Other revenue for the year ended December 31, 2008 increased by $12.5 million compared with the year ended December 31, 2007. The increase primarily resulted from higher revenue from the sale of oil, recovered as a byproduct from the Company's natural gas storage operations, due to higher oil prices. Also contributing to the increase was new revenue relating to the management of fee-for-service energy efficiency initiatives for external parties and higher SSM revenue.

Operating and Administrative

Operating and administrative costs for the year ended December 31, 2009 increased by $11.8 million compared with the year ended December 31, 2008. The increase was primarily due to higher employee related costs, higher customer support related costs and higher Demand Side Management (DSM) costs incurred in connection with the promotion of energy efficient use of natural gas by customers.

Operating and administrative costs for the year ended December 31, 2008 increased by $6.5 million compared with the year ended December 31, 2007. The increase was primarily due to a provision for one-time charges to better align certain operating practices with the Company's strategy under IR, higher employee related costs, costs relating to the management of fee-for-service energy efficiency initiatives for external parties and higher DSM costs, partially offset by lower rate hearing costs and lower customer support related costs.

Depreciation and Amortization

Depreciation and amortization charge for the year ended December 31, 2009 increased by $15.0 million compared with the year ended December 31, 2008. The increase was primarily due to an increase in the overall asset base resulting from customer growth, spending on distribution system improvements and new information systems.

Depreciation and amortization charge for the year ended December 31, 2008 increased by $11.0 million compared with the year ended December 31, 2007. The increase was due to higher property, plant and equipment primarily as a result of customer growth and system improvements.

Municipal and Other Taxes

Municipal and other taxes for the year ended December 31, 2009 increased by $2.0 million compared with the year ended December 31, 2008. The increase was primarily due to tax related true-ups.

Municipal and other taxes for the year ended December 31, 2008 decreased by $7.8 million compared with the year ended December 31, 2007. The decrease was primarily due to the prior year expense including amounts relating to the GST overpayment. See CONTINGENCIES AND COMMITMENTS.

Earnings Sharing

Earnings sharing represents the estimated customer portion of normalized earnings in excess of 100 basis points above the OEB prescribed return on equity threshold, relating to the current fiscal year. The earnings sharing mechanism results in the return of revenue of $18.8 million to customers for the year ended December 31, 2009 (2008 - $5.8 million), subject to OEB approval in 2010. See RATE REGULATION for a more detailed discussion of the earnings sharing mechanism that forms part of the IR methodology, which was implemented effective January 1, 2008.

Interest Expense

Interest expense for the year ended December 31, 2009 decreased by $11.7 million compared with the year ended December 31, 2008. The decrease was primarily due to lower short-term borrowings and lower short-term interest rates. The lower requirement for borrowings was a result of lower working capital requirements due to lower natural gas prices. Partially offsetting the decrease in interest expense were higher credit facility fees.

Interest expense for the year ended December 31, 2008 decreased by $9.5 million compared with the year ended December 31, 2007. The decrease was primarily due to lower short-term interest rates and lower weighted average short-term borrowings as a result of the timing of capital outlays.

Income Taxes

(millions of Canadian dollars)

Year ended December 31,	**2009**	2008	2007
Earnings before income taxes	**299.4**	300.8	268.4
Income taxes	**77.9**	89.4	78.5
Effective tax rate (%)	**26.0**	29.7	29.2

The effective tax rate for the year ended December 31, 2009 was lower compared with the year ended December 31, 2008. The decrease was primarily due to temporary differences relating to the CIS asset and a 0.5% reduction in the federal income tax rate.

The effective tax rate for the year ended December 31, 2008 was higher compared with the year ended December 31, 2007. The increase was primarily due to greater temporary differences relating to rate-regulated property, plant and equipment, compared to the prior year, partially offset by a reduction in the statutory income tax rate for 2008.

RATE REGULATION

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

Incentive Regulation
In 2008, the OEB approved the Company's application to move to a five year IR methodology for the years 2008 through 2012. Under IR, the Company's distribution revenue requirement and associated rates are based on a formulaic approach, using prior year cumulative data with 2007 as the starting point.

The objectives of the IR plan are as follows:
- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates.

2010 Rate Adjustment Application
In September 2009, the Company filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula, to increase funding of its pension plans, and to seek approval for specific changes to the Rate Handbook. The OEB issued a first procedural order in October 2009, in which the OEB indicated that it would consider its jurisdiction with regard to inclusion of green energy related projects within the regulated operations of the Company. The OEB issued a decision in December 2009 which effectively prevents the inclusion of such activities in rate-making for the purposes of setting 2010 rates. As a result of this decision, the Company will seek clarification of the OEB's broader policies with respect to such investments and activities in 2010.

Cost of Capital
In March 2009, the OEB convened a consultative process directed at examining the appropriateness of the cost of capital parameter values for the 2009 rate year for Ontario's electric local distribution companies. In June 2009, the OEB released its decision indicating no change to the 2009 cost of capital parameter values; however, it decided to increase and expand the scope of the consultative process to review the cost of capital policy in general. After reviewing the positions of various stakeholders, the OEB issued a report in December 2009 making several changes to the cost of capital for Ontario's regulated utilities.

The new policy guidelines established a new base level return on equity of 9.75% for all of Ontario's utilities for the 2010 rate year. The treatment of deemed capital structure was left unchanged. A new annual adjustment formula was also established which will change annually with changes in the interest rates on long-term Canada bonds and Canadian A-Rated utility bonds.

The Company anticipates that the new ROE policy guidelines will be applied to the determination of the annual earnings sharing mechanism for 2010 and for the remainder of the IR term. The Company also anticipates applying the new ROE policy guidelines to the determination of rates after the conclusion of the IR term, for the rate year beginning 2013.

2009 Rate Adjustment Application
In September 2008, the Company filed an application with the OEB to adjust rates for 2009 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. A settlement agreement containing all applied for aspects of the formulaic component of the IR rate setting process was approved by the OEB in December 2008.

The Company received a fiscal 2009 final rate order from the OEB in February 2009 approving the implementation of a rate change effective April 1, 2009, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2009.

2008 Rates

In 2007, the Company filed a rate application requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the Settlement Agreement (the Settlement) with customer representatives.

The key terms of the Settlement are summarized as follows:

Revenue Per Customer Cap – The Settlement provides an incentive for the Company to continue growing its customer base and provides the opportunity annually to adjust distribution volumes for rate-setting to protect the Company from exposure to declining average use of natural gas by residential and small commercial customers.

Revenue Escalation – Distribution revenues were adjusted by 60% of the rate of inflation[♦] in 2008, by 55% in 2009, and will be adjusted by 55% in 2010, 50% in 2011 and 45% in 2012. In addition to the annual inflation adjustment, revenues will also grow by the annual increase in the number of customers. Based on an assumed inflation rate of 2%, the combined inflation and growth factors are forecast to result in an overall revenue escalation averaging approximately 3% per year through the term of the plan.

Earnings Sharing – 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 shareholder retains the first 100 basis points of ROE above the NROE (up to 9.66% in 2008), while earnings represented by the ROE in excess of 100 basis points above the NROE are shared equally with customers.

Adjustments – There are several cost and deferral accounts that fall outside of the revenue escalation formula, including the amount of capital invested in new power generation laterals. The Company is also allowed to apply for recovery of expenses above a defined threshold to the extent any such expenses meet certain criteria set out in the IR plan.

Off Ramps – An OEB review will be triggered if the Company's ROE on a normalized basis varies more than 300 basis points (either negatively or positively) relative to the NROE. The review, if triggered, would determine the reasons for the variance in earnings and in such circumstances could result in adjustments to the Settlement or a return to Cost of Service (COS) regulation. The review would not have an impact on earnings for prior years. The Settlement does not preclude the Company from applying to the OEB for an increase in the embedded ROE.

The Company received a fiscal 2008 final rate order from the OEB in May 2008, approving the implementation of a change in rates effective July 1, 2008, which enabled the Company to recover the approved revenues retroactively to January 1, 2008 and to refund or collect from customers specified deferral and variance accounts commencing July 1, 2008. The final rate order also approved a change in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, with no material annual earnings impact. The fixed charge portion will increase progressively over the IR term.

Impact of Rate Regulation

The Company follows Canadian GAAP, which may differ in their application to the Company's regulated operations, as compared to non-regulated businesses. These differences occur when the Regulators render their decisions on the Company's rate applications, and generally involve the timing of revenue

[♦] The inflation index is defined as the year-over-year change in the annualized average of four quarters of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand.

and expense recognition to ensure that the actions of the Regulators, which create assets and liabilities, have been reflected in the consolidated financial statements.

Accounting Guideline 19 (AcG-19), *Disclosures by Entities Subject to Rate Regulation*, requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the Company's consolidated financial statements. Detailed disclosure on rate regulation is included in Note 3 to the 2009 Annual Consolidated Financial Statements.

The Company has several instances where the difference between the amount approved by the Regulators for inclusion in regulated rates and the Company's actual experience is deferred until the Regulators approve the refund to or recovery from customers.

The difference between the total natural gas distributed by the Company and the amount of natural gas billed or billable to customers for their recorded consumption, unaccounted for natural gas variance, is an example. To the extent the difference varies from the approved amount built into rates, the variance is deferred until the subsequent year, and upon refund or recovery, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved estimate of this variance and the related revenue, rather than the actual variance and related revenue.

There are other areas where the determination of the amounts to be recovered in current rates is different from the determination that would be reported by a non-regulated business, and the Company records those items on the same basis as they are recovered in rates. Income taxes and employee future benefits are the most significant such examples.

The recognition or omission of these items is based on an expectation of the future actions of the Regulators. For example, the regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences.

With the revision of the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *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 substantively enacted tax rate that is expected to apply when the temporary differences reverse. A corresponding regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates. See CHANGE IN ACCOUNTING POLICIES for more details.

As another example, contributions to the Company's pension plans are expensed as paid, consistent with recovery of such costs in rates. With the removal of the CICA Handbook Section 1100 exemption for rate-regulated entities, the Company has recorded a pension asset and an other post-employment benefit liability in accordance with Canadian GAAP, as determined by the most recent actuarial valuations updated to December 31, 2009. A corresponding regulatory liability and asset have been recorded reflecting the Company's ability to collect or refund the amounts in the future through rates. See CHANGE IN ACCOUNTING POLICIES for more details.

To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position, or that would have been recorded on the consolidated statement of financial position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations, the issuance of commercial paper and credit facility draws, and the issuance of long-term debt to fund liabilities as they become due, finance capital expenditures and pay dividends. At December 31, 2009, the Company had $800.0 million (2008 - $1.0 billion) of committed credit facilities, of which $505.0 million was drawn or allocated to backstop commercial paper. At December 31, 2009, the Company had $5.2 million (2008 - $6.1 million) of uncommitted lines of credit, against which $2.7 million was borrowed. The net available liquidity is expected to be sufficient to finance all currently approved capital projects and to provide flexibility for new investment opportunities.

In the third quarter of 2009, the Company elected to reduce its committed credit facilities and commercial paper program limit by $200.0 million. The Company currently has an $800.0 million commercial paper program limit that is backstopped by committed lines of credit of $800.0 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.

The following table provides details of the Company's credit facilities at December 31, 2009.

(millions of Canadian dollars)	Expiry Dates	Total Facilities	Credit Facility Draws[1]	Available
Enbridge Gas Distribution Inc.	2011	800.0	505.0	295.0
St. Lawrence Gas Company, Inc.	2010	5.2	2.7	2.5
		805.2	507.7	297.5

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

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. At December 31, 2009, this ratio was 2.74 (2008 – 2.78). 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.

Changes in natural gas prices impact accounts receivable, gas inventories and accounts payable, which may result in the working capital being negative on a temporary basis.

(millions of Canadian dollars) December 31,	**2009**	2008
Cash and cash equivalents	**-**	100.0
Accounts receivable	**769.1**	980.3
Gas inventories	**395.7**	656.3
Other current assets	**32.5**	7.5
Bank overdraft	**(12.8)**	(44.6)
Short-term borrowings	**(514.5)**	(881.6)
Accounts payable	**(725.6)**	(677.1)
Other current liabilities	**(55.8)**	(88.1)
Working capital	**(111.4)**	52.7

OPERATING ACTIVITIES

Cash provided by operating activities increased to $971.3 million for the year ended December 31, 2009 from $367.7 million for the year ended December 31, 2008 and $528.7 million for the year ended December 31, 2007.

The increase was primarily due to a net inflow in 2009 from changes in working capital, compared to a net outflow in 2008, resulting from significant decreases in accounts receivable and gas inventories compared to increases in the prior year. These impacts are primarily the result of a significant decrease in the price of natural gas in the current year compared to an increase in the prior year. The net outflow in 2008 from changes in working capital, compared to a net inflow in 2007, was also due to higher working capital in 2008 as a result of fluctuations in the market price of natural gas.

INVESTING ACTIVITIES

In 2009, cash used for investing activities was $383.8 million compared with $405.8 million in 2008, a decrease of $22.0 million. The decrease was primarily due to higher comparative spending in 2008 for unregulated storage facilities and lower customer-related capital expenditures in the current year.

Cash used for investing activities for the year ended December 31, 2008 was $405.8 million compared with $368.6 million in 2007. The increase of $37.2 million was a result of increased capital expenditures primarily in growth projects such as the unregulated storage project. In addition, there was a significant increase in capital accruals in 2007, compared to a decrease in 2008, due to the timing of capital expenditures.

Capital Expenditures

(millions of Canadian dollars)

Year ended December 31,	**2009**	2008	2007
System expansion	**107.1**	120.3	135.6
System improvements and upgrades	**143.7**	154.3	153.6
Computers and communication equipment	**73.5**	64.6	50.0
Unregulated storage	**11.8**	28.2	8.3
Other	**34.2**	43.8	37.7
Total capital expenditures	**370.3**	411.2	385.2

The Company's existing distribution network consists of approximately 35,000 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required. The Company also requires capital for ongoing core maintenance and capital improvements. The Company expects to spend approximately $391 million in 2010 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $376 million. The 2010 capital projects include the cast iron replacement program, power generation customer additions, green energy initiatives and unregulated storage projects. The Company expects to finance these expenditures through cash from operating activities and available liquidity.

FINANCING ACTIVITIES

In 2009, the Company used $655.7 million for financing activities compared with cash generated of $98.3 million and cash used of $150.3 million in 2008 and 2007, respectively. The cash used in 2009 compared with cash generated in 2008 was primarily a result of net repayments of short-term borrowings, compared to net issuances of short-term borrowings and debentures in the prior year. Increased cash from operating activities and decreased cash required for investing activities have reduced financing requirements in 2009. Cash generated in 2008 compared with cash used in 2007 was primarily the result of increased short-term borrowings in 2008 due to the impact of higher natural gas prices on accounts receivable and gas inventories. This was partially offset by an increase in dividends paid and net repayment of long-term borrowings.

In 2009, the Company did not issue any long-term notes. The Company had total note maturities of $102.5 million. Financing activities in 2008 included the issuance of $200.0 million of term notes to offset term note maturities of $270.0 million.

Short-term borrowings are used primarily to finance working capital, including gas inventories.

Preferred Shares

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 3, Series D preferred shareholders opted not to convert these shares into Group 2, Series D preferred shares effective July 1, 2009.

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.

Outstanding Share Data[1]

	Number
Preferred Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4,000,000
Common shares	140,732,747

[1] Outstanding share data information is provided as at February 18, 2010.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2008 and December 31, 2009.

Consolidated statements of financial position category	**Increase/ (Decrease)** *(millions of Canadian dollars)*	**Explanation**
Cash and cash equivalents	(100.0)	Primarily due to a short-term investment held over year-end in the prior year as a result of the timing of cash requirements.
Accounts receivable	(211.2)	Primarily due to significantly lower natural gas prices and lower sales volumes as a result of warmer weather in December 2009.
Gas inventories	(260.6)	Primarily due to significantly lower natural gas prices and lower volumes in storage.
Property, plant and equipment, net♦	775.5	Primarily due to the reclassification of reserves for future removal and site restoration (originally included in accumulated depreciation and netted against property, plant and equipment) to other long-term liabilities and due to capital additions, partially offset by depreciation.
Deferred amounts and other assets♦	446.9	Primarily due to recording of the previously unrecorded pension asset and the regulatory recoverables for the post-employment benefits other than pensions (OPEB) liability and the future income tax liability on regulated assets.

♦ See CHANGE IN ACCOUNTING POLICIES

Short-term borrowings	(367.1)	Primarily due to repayments of short-term borrowings using cash and cash equivalents generated from operations.
Long-term debt (including current portion)	(101.7)	Primarily due to a $100.0 million repayment of debentures during the first quarter.
Other long-term liabilities ♦	961.4	Primarily due to the reclassification of reserves for future removal and site restoration from property, plant and equipment. Also due to recording the previously unrecorded OPEB liability and the regulatory offset to the pension asset.
Future income taxes – liability (non-current) ♦	181.5	Primarily due to recording the previously unrecorded future income tax liability on regulated assets.

♦ See CHANGE IN ACCOUNTING POLICIES

OFF-BALANCE SHEET ARRANGEMENTS

Gas Held on Behalf of Transportation Service Customers
Transportation service customers source their natural gas supplies independently or through a broker and their estimated consumption is delivered into the Company's system evenly throughout the year. However, the consumption pattern varies from the even natural gas delivery pattern. Depending on the consumption / replenishment cycle, the Company typically has natural gas loaned to or borrowed from customers. Specific defined parameters are in place and are monitored carefully to ensure that the volume of natural gas loaned does not exceed certain threshold levels. Customer accounts beyond these defined threshold levels incur penalties. All loaned volumes are trued up annually. The Company also has strict credit policies in place to mitigate this risk. See CREDIT RISK.

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, 2009, $163.9 million of natural gas was held on behalf of transportation service customers (2008 - $175.9 million), a decrease of $12.0 million compared to the prior year. These transactions have no impact on the Company's consolidated earnings, cash flows or financial position.

CONTINGENCIES AND COMMITMENTS

The Company is occasionally named as a party in various claims and legal proceedings which arise during the normal course of its business. The Company reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. Although there can be no assurance that any particular claim will be resolved in the Company's favour, the Company does not believe that the outcome of any claims or potential claims of which it is currently aware will have a material adverse effect on the Company, taken as a whole.

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 totalling approximately $79.0 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 $70.0 million and punitive damages in the amount of $5.0 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 $50.0 million in damages and $5.0 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.

Oral examinations for discovery were substantially completed during the summer of 2005. A mandatory mediation originally scheduled for November 2005 was postponed. In February 2007, the parties agreed to a revised timetable for the next steps in the action pursuant to which the plaintiff was required to set the action down for trial by January 31, 2008. While the plaintiff did set the action down for trial by the prescribed date, required steps in the discovery process have not yet been completed by the plaintiff. As a result, on February 12, 2008, the Court established a new timetable for the completion of the discovery process. 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, 2007, 2008 and 2009 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 has also applied to the OEB for the establishment of a 2010 deferral account in its 2010 rate adjustment application.

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. The Court's decision has been reserved and the Company expects it to be released in early 2010. The Company does not believe any fines that may be levied will have a material financial impact on the Company.

The Company has also been named as a defendant in a number of civil actions related to the explosion. All significant civil actions have been settled without any material financial impact on the Company. A Coroner's Inquest in connection with the explosion is also possible.

GST Overpayment
In December 2007, the Company discovered that it had remitted excess GST to the CRA. In respect of certain months within the 2003 to 2005 calendar year periods, the amount of such overpayment was approximately $40 million and was included in accounts receivable. In April 2009, the Company received the requested refund of GST overpayments, including interest, from the CRA.

CONTRACTUAL OBLIGATIONS
Payments due for contractual obligations over the next five years and thereafter are as follows:

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt [1]	2,184.7	150.0	150.0	400.0	1,484.7
Loans from affiliate company [1]	375.0	-	-	-	375.0
Consulting contract [2]	33.2	9.4	13.6	10.2	-
Customer care service contracts	128.3	56.4	71.9	-	-
CIS contracts	11.1	4.1	7.0	-	-
Gas transportation contracts	861.8	323.6	281.5	164.8	91.9
Pension obligations [3]	4.5	4.5	-	-	-
Total Contractual Obligations	3,598.6	548.0	524.0	575.0	1,951.6

1. Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.
2. Primarily consulting fees relating to services provided with respect to work and asset management initiatives. The majority of these expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2009, $111.8 million (2008 - $93.7 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.
3. Assumes only required payments will be made into the pension plans in 2010. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2009. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.

QUARTERLY FINANCIAL INFORMATION[1]

(millions of Canadian dollars)

2009	**Q1**	**Q2**	**Q3**	**Q4**	**Total**
Revenues	**1,353.9**	**468.3**	**308.5**	**772.4**	**2,903.1**
Earnings/(loss) applicable to the common shareholder	**115.6**	**32.0**	**(1.3)**	**71.9**	**218.2**

(millions of Canadian dollars)

2008	Q1	Q2	Q3	Q4	Total
Revenues	1,194.4	465.9	376.0	1,068.6	3,104.9
Earnings/(loss) applicable to the common shareholder	114.0	22.5	(3.9)	73.9	206.5

1. Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.

Revenues include amounts billed to customers for natural gas, which varies with fluctuations in natural gas prices. Higher natural gas prices would increase revenues, but would not similarly impact earnings, given that the cost of natural gas flows through to customers.

In addition, the Company operates in a seasonal industry. Earnings for interim periods in isolation are not indicative of results for the fiscal year since volumes delivered during the peak winter months are significantly higher.

Earnings for a given quarter in two successive years may vary significantly primarily due to potentially varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather. As a result, a meaningful comparison can only be achieved after adjusting earnings for the impact of weather.

Further, as a result of continued changes in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, a portion of revenues and earnings will shift from the colder winter quarters progressively to the warmer summer quarters, with no material impact on full year revenue and earnings. This change will also impact the comparability of a given quarter from year to year.

FOURTH QUARTER 2009 HIGHLIGHTS

Earnings applicable to the common shareholder were $71.9 million for the three months ended December 31, 2009 compared with $73.9 million for the same period in 2008. The decrease of $2.0 million was primarily due to lower volumes distributed as a result of warmer weather, partially offset by additional tax differences relating to property, plant and equipment. Earnings applicable to the common shareholder for the three months ended December 31, 2009, excluding the effect of weather, were higher than the prior year due to additional tax differences relating to property, plant and equipment, partially offset by lower gas distribution margin.

RELATED PARTY TRANSACTIONS

The Company had transactions with related parties during the year. Amounts are invoiced on a monthly basis and are usually due and paid on a quarterly basis.

Enbridge Inc., the ultimate parent company, provided treasury and other management services and charges the Company amounts designed to recover the costs of providing such services. Charges incurred for the year ended December 31, 2009 were $29.8 million (2008 - $27.4 million) with an outstanding payable balance of $2.4 million at December 31, 2009 (2008 - $1.9 million).

Enbridge (U.S.) Inc., an affiliated company under common control, advanced the Company $6.8 million (2008 - $7.1 million) at the LIBOR rate plus 0.55%, and is payable on demand. The note receivable from Enbridge (U.S.) Inc. of $3.7 million (2008 - $nil) bears interest at 1.75% and is payable on demand.

IPL System Inc. The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliated company under common control. At December 31, 2009, the investment of $825.0 million resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2009, dividends received amounted to $62.7 million (2008 - $62.7 million) with an outstanding receivable balance of $5.3 million at December 31, 2009 (2008 - $5.3 million).

IPL System Inc. advanced the Company $375.0 million ($200.0 million at 6.85% and $175.0 million at 7.50%) 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, 2009, interest paid amounted to $26.8 million (2008 - $26.8 million) with an outstanding payable balance of $2.3 million at December 31, 2009 (2008 - $2.3 million).

Alliance Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2009 were $23.6 million (2008 - $23.6 million) with an outstanding payable of $nil at December 31, 2009 (2008 - $nil).

Alliance Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2009 were $17.7 million (2008 - $17.1 million) with an outstanding payable of $nil at December 31, 2009 (2008 - $nil).

Vector Pipeline Limited Partnership, a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2009 were $28.6 million (2008 - $27.0 million) with an outstanding payable of $nil at December 31, 2009 (2008 - $nil).

Gazifère Inc., an affiliated company under common control, purchases wholesale services from the Company. These services are pursuant to a contract negotiated between the two companies and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie. Total revenues for the year ended December 31, 2009 were $44.1 million (2008 - $47.2 million) with an outstanding receivable of $4.3 million at December 31, 2009 (2008 - $9.3 million).

Enbridge Commercial Services Inc., an affiliated company under common control, provides information services to the Company. Total charges for the year ended December 31, 2009 were $2.0 million (2008 - $3.4 million) with an outstanding payable of $0.2 million at December 31, 2009 (2008 - $0.2 million).

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company has formal risk management policies, procedures and systems designed to mitigate the risks described below.

REGULATORY RISK

The formula currently approved by the OEB for determination of the ROE, which is embedded and escalated within rates over the IR period, is based on the OEB's risk assessment of the Company for the 2007 fiscal year.

The OEB issued a report in December 2009 making several changes to the cost of capital for Ontario's regulated utilities. The new policy guidelines established a new base level return on equity of 9.75% for all of Ontario's utilities for the 2010 rate year. The treatment of deemed capital structure was left unchanged.

A new annual adjustment formula was also established which will change annually with changes in the interest rates on long-term Canada bonds and Canadian A-Rated utility bonds.

The Company anticipates that the new ROE policy guidelines will be applied to the determination of the annual earnings sharing mechanism for 2010 and for the remainder of the IR term. The Company also anticipates applying the new ROE policy guidelines to the determination of rates after the conclusion of the IR term, for the rate year beginning 2013.

The Settlement allows certain Y and Z factors (which represent specific categories of expense from a COS view and uncontrollable external factors, respectively) in the IR formula, which will permit the Company to recover, with OEB approval, certain costs that are beyond management control, but are necessary for the maintenance of its services. The Settlement also includes a mechanism to reassess the IR plan and return to COS if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the Settlement mitigate the Company's risk to factors beyond management's control.

The Company does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased, including risk management costs for St. Lawrence, and the price approved by the Regulators. This difference is deferred as a receivable from or payable to customers until the Regulators approve its refund or collection. The Company monitors the balance and its potential impact on customers and will request interim rate relief that will allow the Company to recover or refund the natural gas cost differential.

The Company, excluding St. Lawrence, has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB.

VOLUME RISKS

Since customers are billed on both a fixed charge and on a volumetric basis, the Company's ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and the growth of customers. Over the life of the current IR agreement, the portion of fixed charges will increase thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of the Company's customer base uses natural gas for space heating. Weather, measured in terms of degree day deficiency, normally directly impacts earnings of the Company as noted below. Degree day is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

Factor	Incremental change	Approximate incremental impact
Weather	18 degree days	1 billion cubic feet
Volume	1 billion cubic feet	$1.3 million (after-tax)

An unusual pattern of distribution of degree days during the year and their relative effectiveness may impact the above sensitivity. Degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 81% (2008 - 79%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where the Company attains its total forecast distribution volume, the Company may not earn the ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for general service customers is mitigated by the average use true-up variance account that was established under the IR Settlement Agreement. This variance account enables recovery from or repayment to customers amounts representing variances in the actual and forecast average use by general service customers. The Company remains at risk of distribution volume for large volume contract commercial and industrial customers.

MARKET PRICE RISK

The Company's earnings, cash flows and other comprehensive income are subject to movements in interest rates, foreign exchange rates and natural gas commodity prices (collectively, market price risk).

The following section summarizes the primary types of market price risks to which the Company is exposed and outlines the financial derivative hedging programs implemented.

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 obligations. Floating to fixed interest rate swaps and options may be used to hedge against the effect of future period interest rate movements. The Company has implemented a hedging program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.82%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates on future fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2020. A total of $200.0 million of future fixed rate term debt issuances have been hedged at an average government bond rate of 4.0%.

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.

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. Historically, the Company has managed the exposure to natural gas price risk by entering into fixed price natural gas contracts; however, in adhering to the directive of the OEB, the Company no longer manages the natural gas price risk exposure on behalf of customers other than for St. Lawrence customers. Fluctuations in natural gas prices are borne by the customers.

CREDIT RISK

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.

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 enters into risk management transactions only 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.

FINANCING RISK
The Company's financing risk relates to the price volatility and availability of debt to finance capital expenditures and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian debt market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian public capital markets by maintaining a current shelf prospectus with the securities regulators.

LIQUIDITY RISK
Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments. To manage this risk, the Company forecasts the cash requirements over the near and long term 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 longer 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.

MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES
For the years ending December 31, 2010 through 2014, and thereafter, the Company has estimated that the following undiscounted cash flows will arise from its derivative instruments based on valuation at the balance sheet date.

(millions of Canadian dollars)	2010	2011	2012	2013	2014	Thereafter
Cash inflows	1.8	2.0	1.6	-	-	-
Cash outflows	(2.8)	-	-	-	-	-
Net cash flows	(1.0)	2.0	1.6	-	-	-

GENERAL BUSINESS RISKS

Distribution Operating Risk
The Company's distribution network is exposed to operational risks such as accidental damage to mains and service lines, corrosion leaks in mains and service lines, breaks in cast iron pipes, malfunction of compression and decompression equipment and other issues that can lead to outages. Leaks in the distribution system are an inherent risk of operations. A comprehensive surveillance, maintenance and repair program as well as the phased replacement of cast iron pipes significantly reduces the exposure.

Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the distribution network. The occurrence or continuance of any of these events could increase the cost of operating the Company's distribution network or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks.

Environmental, Health and Safety Risk
The Company's operations are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and distribution network must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities and the distribution network are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. The Company could be targeted by environmental groups attempting to draw attention to greenhouse gas emissions.

The Company is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to the shareholder, customers and employees. The Company has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

Climate Change Legislation
The Canadian Federal Government has indicated that Canada will target a 20% reduction of greenhouse gas (GHG) emissions by 2020, based on 2006 emission levels. It has also signaled that 90% of Canada's electricity will be provided by non-emitting sources, such as hydro, nuclear, clean-coal, solar and wind, by 2020. Details of Canada's GHG management plan will not be released until there is clarity in the United States about its intention to regulate GHG emissions. Canadian regulations will likely be compatible to those of the United States in order for Canadian businesses to remain competitive and avoid the potential for punitive trade sanctions. It is uncertain how climate legislation could affect the industry. The Company continues to monitor this activity.

Workforce
The potential lack of qualified and properly trained technical, professional and operational staff and leaders would increase the risk that the Company will not be able to implement its corporate strategy. This risk may be compounded by the increasing rates of retirement due to workforce demographics, turnover due to competition in certain markets and growing demand for staff to support business growth. The Company continues to monitor company-wide workforce planning. The Company offers competitive compensation programs, training, leadership development and succession planning. Further, the supply of human resources is balanced between hiring full-time employees and expanding the contractor workforce.

Approximately 36% of the Company's workforce is represented by the Communications, Energy and Paperworkers Union, Local 975 (CEPU) or the International Brotherhood of Electrical Workers (IBEW), Local 97. In the first quarter of 2009, two-year collective agreements were signed with both CEPU and IBEW, expiring in December 2010 and February 2011, respectively.

FINANCIAL INSTRUMENTS

	December 31, 2009							
(millions of Canadian dollars)	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
Assets								
Accounts receivable[2]	**-**	**-**	**701.7**	**-**	**1.8**	**65.6**	**769.1**	**703.5**
Investment in affiliate company[3]	**-**	**825.0**	**-**	**-**	**-**	**-**	**825.0**	**N/A**
Deferred amounts and other assets	**-**	**-**	**-**	**-**	**3.6**	**483.3**	**486.9**	**3.6**
Liabilities								
Bank overdraft	**12.8**	**-**	**-**	**-**	**-**	**-**	**12.8**	**12.8**
Short-term borrowings	**-**	**-**	**-**	**514.5**	**-**	**-**	**514.5**	**514.5**
Accounts payable[2]	**-**	**-**	**-**	**429.9**	**2.8**	**292.9**	**725.6**	**432.7**
Other current liabilities	**-**	**-**	**-**	**55.8**	**-**	**-**	**55.8**	**55.8**
Long-term debt	**-**	**-**	**-**	**2,165.4**	**-**	**-**	**2,165.4**	**2,444.5**
Loans from affiliate company[4]	**-**	**-**	**-**	**375.0**	**-**	**-**	**375.0**	**N/A**

	December 31, 2008							
(millions of Canadian dollars)	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
Assets								
Cash and cash equivalents	100.0	-	-	-	-	-	100.0	100.0
Accounts receivable[2]	-	-	955.5	-	-	24.8	980.3	955.5
Investment in affiliate company[3]	-	825.0	-	-	-	-	825.0	N/A
Liabilities								
Bank overdraft	44.6	-	-	-	-	-	44.6	44.6
Short-term borrowings	-	-	-	881.6	-	-	881.6	881.6
Accounts payable[2]	-	-	-	583.0	0.8	93.3	677.1	583.8
Other current liabilities	-	-	-	88.1	-	-	88.1	88.1
Long-term debt	-	-	-	2,267.1	-	-	2,267.1	2,253.0
Loans from affiliate company[4]	-	-	-	375.0	-	-	375.0	N/A

1 Fair value does not include non-financial instruments and equity instruments held at cost that do not trade on an actively quoted market.

2 Accounts receivable as at December 31, 2009 excludes $65.6 million of regulatory assets that do not meet the definition of a financial instrument (2008 - $24.8 million). Accounts payable as at December 31, 2009 excludes $292.9 million of regulatory liabilities that do not meet the definition of a financial instrument (2008 - $93.3 million). Accounts receivable is measured at amortized cost net of impairment. Accounts payable is measured at amortized cost.

3 The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliated company under common control. The investment, classified as an available-for-sale instrument, provides a weighted average dividend yield of 7.60%. 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. The Company currently has no plans to dispose of this investment. 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.

4 The Company has loans outstanding to IPL System Inc., an affiliated company under common control, in the amounts of $200.0 million and $175.0 million. The loans bear interest at 6.85% and 7.50%, respectively, and mature 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. These loans were created between affiliated companies to meet the financing demands of the Company, as such, there is no external market for the instruments. Currently, the Company has no plans to settle the instruments prior to their maturity. As these financial liabilities originated in related party transactions and have no quoted market prices in an active market, they are carried at cost and fair values have not been determined.

Fair Value of Financial Instruments

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 prices 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 that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents, bank overdraft and short-term borrowings approximates their carrying value due to their short-term maturities. 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.

Derivative Instruments

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments. The Company does not have any credit-risk related contingent features associated with its derivative instruments.

	December 31, 2009		December 31, 2008	
	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
Natural gas *($10^6 m^3$)*	**2010**	**12**	2009	43
Interest rate contracts *(millions of Canadian dollars)*	**2010-2012**	**513.0**	2009	8.6

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 10 and 11 of the 2009 Annual Consolidated Financial Statements.

CRITICAL ACCOUNTING ESTIMATES

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 degree day deficiency values experienced.

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2009 of $4,289.8 million (2008 - $3,514.3 million), or 61.5% of total assets (2008 – 55.9%), is provided on a straight-line basis over the estimated useful lives of the assets 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.

These depreciation rates are reviewed through periodic depreciation studies conducted by an external consulting firm that makes an objective assessment of the useful lives of the Company's property, plant and equipment. The depreciation rates used by the Company are subject to approval by the OEB for rate setting purposes, which may not always reflect the recommendations of the latest depreciation study. The last such study was completed in 2006. The external consulting firm also provides an estimate of the net cumulative amount collected from customers for future site removal and restoration of property, plant and equipment.

REGULATORY ASSETS AND LIABILITIES

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 operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the Regulators. 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. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2009, the Company's regulatory assets totaled $306.1 million (2008 - $54.9 million) and regulatory liabilities totaled $1,170.0 million (2008 - $97.9 million). To the extent that the Regulators' actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees as well as OPEB to eligible retirees.

Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. However, there is significant measurement uncertainty incorporated into the actuarial valuation process. For example, there is no assurance that the pension plan will be able to earn the assumed rate of return.

Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. However, no earnings impact would result due to the continuity of the existing regulatory mechanism in place under which plan contributions and actual OPEB benefit costs are expensed as paid, consistent with the recovery of such costs in rates.

The Company's plan remains in a surplus position thus precluding any contribution requirements by the Company. The difference between the actual and expected return on plan assets was a shortfall of $22.1 million for the year ended December 31, 2009 (2008 – a shortfall of $154.6 million) as disclosed in Note 14 to the 2009 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension plans, funding in 2010 will be $4.5 million.

(millions of Canadian dollars)

Impact of a 0.5% Change in Key Assumptions	**Pension Benefits**		**OPEB**	
	Obligation	**Expense**	**Obligation**	**Expense**
Decrease in discount rate	35.1	4.2	5.3	0.1
Decrease in expected return on assets	n/a	3.4	n/a	-
Decrease in rate of salary increase	(5.5)	(1.9)	-	-

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 17 of the 2009 Annual Consolidated Financial Statements.

REGULATORY GOVERNANCE

Undertakings

The Company, and its parent Enbridge Inc., have entered into Undertakings with the Lieutenant Governor in Council for Ontario that commit Enbridge Inc. and the Company to certain obligations relating to the maintenance of common equity, as well as restrictions on diversification to the effect that the Company must not carry on, except through an affiliate or affiliates, any business activity other than the distribution, storage or transmission of natural gas without the OEB’s prior approval. In compliance with these undertakings, the Company has obtained OEB approval to carry on the Natural Gas Vehicle Program, Agent Billing and Collection Program and Gas Sales and Oil Production activity.

In August 2006, the Government of Ontario approved changes to the Undertakings that allow the Company to provide services related to the promotion of electricity conservation, natural gas conservation and the efficient use of electricity, electricity load management, and the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. In addition, the Company is allowed to engage in activities and provide services related to the local distribution of steam, hot and cold water in an initiative with Markham District Energy Inc., and pursuit of a pilot project for the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

In September 2009, as discussed under GREEN ENERGY INITIATIVIES, Ontario's Minister of Energy and Infrastructure issued a Directive that permits the Company to own and operate stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities up to 10 megawatts in capacity. The Company will also be permitted to own and operate district and distributed energy systems, including facilities that produce power and thermal energy from a single source. Finally, the Minister's Directive permits the Company to own and operate assets that would assist the Government of Ontario in achieving its goals in energy conservation, including assets related to solar-thermal water and ground source heat pumps.

In the absence of the Minister's Directive, the Company's Undertakings to the Lieutenant Governor in Council would not have permitted the Company to engage in the foregoing activities directly. The Company plans to increase its role in this area and is looking to expand its efforts to explore and pursue alternative and/or renewable energy technologies subject to OEB approval, where appropriate.

While the Directive permits the Company to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates. As a result of this decision, the Company will seek clarification of the OEB’s broader policies with respect to such investments and activities in 2010.

Affiliate Relationships Code

The Company is subject to the provisions of the OEB’s Affiliate Relationships Code for Gas Utilities (the Code). The Code sets out the standards and conditions that govern the interaction between natural gas distributors, transmitters and storage companies in Ontario and their respective affiliated companies and is intended to:

- minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities;
- protect the confidentiality of consumer information collected in the course of providing utility services; and
- ensure there is no preferential access to regulated utility services.

The Code specifically sets out standards of conduct including the degree of separation, sharing of services and resources, terms under which service agreements must be prepared and transfer pricing guidelines.

CHANGE IN ACCOUNTING POLICIES

ACCOUNTING FOR THE EFFECTS OF RATE REGULATION

Effective January 1, 2009, the Company adopted revisions to the CICA Handbook Section 1100, *Generally Accepted Accounting Principles* and Section 3465, *Income Taxes*. In accordance with the transitional provisions in these revised standards, the revisions to Section 1100 were adopted prospectively and accordingly, prior periods were not restated, while the revisions to Section 3465 were applied retrospectively without restatement of prior periods. The adoption of the revised standards did not impact the Company's earnings or cash flows.

Generally Accepted Accounting Principles

The revised standard no longer provides an exemption for rate-regulated entities to measure assets and liabilities on a basis other than in accordance with primary sources of Canadian GAAP. As a result, for the Company's pension plans and OPEB, the Company recognized post-employment benefit assets and liabilities for the amount of benefits expected to be included in future rates and recovered from, or paid to, customers. In addition, the Company reclassified certain reserves for future removal and site restoration.

Pension Plans and OPEB

On adoption of the revised standard at January 1, 2009, the Company recognized a net pension asset of $199.5 million and a net OPEB liability of $63.6 million, with an offsetting long-term net pension regulatory liability and long-term net OPEB regulatory asset, respectively, to the extent that the amounts are to be refunded or collected in future rates. At December 31, 2009, the Company had a net pension asset of $201.9 million and a net OPEB liability of $69.5 million, with an offsetting long-term net pension regulatory liability and a long-term net OPEB regulatory asset, respectively, to the extent that the amounts are to be refunded or collected in future rates.

Future Removal and Site Restoration Reserves

At January 1, 2009, on adoption of the revised standard, the Company reclassified amounts collected for future removal and site restoration of $640.0 million, which were previously netted against Property, Plant and Equipment, to a long-term regulatory liability. At December 31, 2009, this long-term regulatory liability was $691.6 million.

Income Taxes

The revised standard removes the exemption for rate-regulated entities recognizing future income taxes to the extent they were expected to be included in regulator-approved future rates and recovered from or refunded to future customers. As a result, on January 1, 2009, the Company recognized a future income tax liability of $212.2 million on regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset. A regulatory asset has been recognized as the associated future income tax liability is expected to be recoverable in future rates. At December 31, 2009, the Company had a future income tax liability of $174.0 million related to regulatory assets with an offsetting long-term regulatory asset.

INTANGIBLE ASSETS

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. As a result of adopting this standard, the Company reclassified certain software costs from Property, Plant and Equipment to Intangible Assets. This standard has been applied retrospectively and affects presentation only.

As a result of adopting this standard, on January 1, 2009, the Company reclassified $146.4 million of net CIS and software costs from Property, Plant and Equipment to Intangible Assets. At December 31, 2009, the Company had $178.8 million of net CIS and software costs recorded in Intangible Assets.

FINANCIAL INSTRUMENTS - DISCLOSURES

Effective December 31, 2009, the Company adopted the amendments to CICA Handbook Section 3862, *Financial Instruments – Disclosures*, which requires the inclusion of additional disclosure about fair value measurements of financial instruments and enhances liquidity risk disclosure requirements. The additional disclosures required under this standard have been included in Note 11 to the 2009 Annual Consolidated Financial Statements.

FUTURE ACCOUNTING POLICIES

Business Combinations

The CICA issued Handbook Section 1582, Business Combinations, which replaces Section 1581. This new standard aligns accounting for business combinations under Canadian GAAP with International Financial Reporting Standards. The standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination to be expensed in the period in which they are incurred. The adoption of this standard will impact the accounting treatment of future business combinations. The revised standard is effective for business combinations occurring on or after January 1, 2011; however, earlier application is permitted.

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 financial statements. The revised standards are effective January 1, 2011. Should the Company early adopt Section 1582, it would also be required to adopt Sections 1601 and 1602 at the same time.

International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board (AcSB) confirmed in February 2008 that publicly accountable entities will be required to adopt IFRS for interim and annual financial statements beginning on January 1, 2011, including comparative financial statements for 2010.

The Company's preparations for IFRS conversion include preparing, together with Enbridge Inc., IFRS compliant accounting policies, drafting model IFRS financial disclosures, identifying accounting differences, developing and implementing systems solutions and process changes that support the preparation of 2010 comparative data as well as a sustainable conversion to IFRS in 2011.

The Audit, Finance & Risk Committee of the Company's Board of Directors receives regular reports on the advancement of the conversion to IFRS.

Accounting and Reporting

To date, detailed IFRS compliant accounting policies and model financial statement disclosures are complete. The Company's IFRS compliant accounting policies differ in some regards from the Company's current accounting policies. The most significant differences are expected to impact the following areas:

- property, plant and equipment
- decommissioning liabilities (asset retirement obligations)
- impairments

The Company is carefully monitoring the International Accounting Standards Board's (IASB) project on Rate Regulated Activities. The IASB's exposure draft on Rate Regulated Activities, published in July 2009, would allow the Company to continue to apply rate-regulated accounting with some changes. It is not possible to determine with certainty the extent of the changes to the Company's accounting for rate regulated activities until the final standard, expected to be published by the end of the second quarter of 2010, is available.

The Company has selected IFRS 1 elective exemptions which are practical and provide the most relevant presentation on conversion to IFRS. The primary result of the exemptions selected is to apply certain IFRS differences prospectively, minimizing adjustments to the IFRS opening balance sheet. The IASB's exposure draft on Rate Regulated Activities includes an IFRS 1 exemption which would allow the Company to use the carrying amount of rate regulated property, plant and equipment, as calculated under Canadian GAAP, as the deemed cost for IFRS on the date of adoption. This would reduce changes to property, plant and equipment on adoption and, if it's available, the Company expects to use this exemption.

Information Systems and Business Processes

In January 2010, the Company implemented changes to information systems and processes which ensure that data needed for IFRS reporting of 2010 financial information for comparative purposes is gathered. The Company has also developed processes to derive the 2010 opening balance sheet under IFRS and is building processes and systems solutions to create 2010 IFRS compliant quarterly financial information for comparative purposes.

During the first quarter of 2010, the Company will determine the systems solution which will be implemented in 2011 to support and sustain IFRS changes after conversion. Process changes needed to sustain IFRS conversion starting in 2011 have been identified and during 2010, process design and training is expected to be completed. Related impacts to internal controls over financial reporting and disclosure controls and procedures are expected to be identified during 2010.

Training and Communication

The Company has a comprehensive plan to train internal personnel who will be impacted by the conversion to IFRS. Training started during 2009 and is expected to continue throughout 2010. The Company has also commenced preparation of an external communication plan which will depend on the nature and magnitude of changes to the financial statements expected under IFRS.

Business Activities

The Company has reviewed the effect of IFRS conversion on its debt covenants, compensation agreements and hedging activities and does not expect the conversion to IFRS to significantly impact these activities or requirements.

The expected timing of key activities identified above may change prior to the IFRS conversion date due to changes in regulation, economic conditions or other factors and the issuance of new accounting standards or amendments to existing accounting standards, including and in addition to those noted above.

ENBRIDGE GAS DISTRIBUTION INC.
HIGHLIGHTS

Year ended December 31,	**2009**	2008
Financial *(millions of Canadian dollars)*		
Gas commodity and distribution revenue	**2,345.9**	2,506.2
Transportation of gas for customers	**448.8**	504.8
Other revenue	**108.4**	93.9
Total revenue	**2,903.1**	3,104.9
Gas commodity and distribution costs	**(1,769.9)**	(2,000.4)
Net revenue	**1,133.2**	1,104.5
Earnings	**221.5**	211.4
Earnings applicable to the common shareholder	**218.2**	206.5
Return on equity[1] (%)	**11.8**	11.4
Operating		
Volumetric Statistics *(millions of cubic metres)*		
Gas commodity sales	**5,513**	5,346
Transportation of gas for customers	**6,035**	6,906
Total distribution volume	**11,548**	12,252
Number of active customers[2] *(thousands)*	**1,937**	1,898
Degree day deficiency[3]		
Actual	**3,767**	3,802
Forecast based on normal weather	**3,514**	3,543

1. Return on equity data relates to the consolidated entity.
2. Active customers is the number of natural gas consuming customers at the end of the year.
3. Degree day deficiency is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 degree days for that day. The figures given are those accumulated in the Greater Toronto Area.