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ENBRIDGE

March 18, 2009

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.
2008 Earnings Sharing Mechanism and Other Deferral And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2009-0055

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 Thursday, March 19, 2009.

Yours truly,

Kevin Culbert

Kevin Culbert
Manager, Regulatory Accounting

Cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2008-0219 (via email)

EXHIBIT LIST

A – ADMINISTRATIVE

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

B – 2008 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 2008 Historical Year	K. Culbert
	2	1	Ontario Utility Rate Base – Comparison of 2008 Historical Year to 2007 Historical Year	K. Culbert
		2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2008 Historical Year	K. Culbert
		3	Comparison of Utility Capital Expenditures 2008 Historical Year to 2007 Historical Year	L. Au T. Ladanyi
	3	1	Utility Operating Revenue 2007 Historical Year	K. Culbert
		2	Comparison of Gas Sales and Transportation Volume by Rate Class 2008 Historical Year to 2008 Board Approved Budget	I. Chan T. Ladanyi

EXHIBIT LIST

B – 2008 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	3	3	Comparison of Gas Sales and Transportation Revenue by Rate Class 2008 Historical Year to 2008 Board Approved Budget	I. Chan T. Ladanyi
		4	Customers, Volumes and Revenues by Rate Class 2008 Actual	I. Chan T. Ladanyi
		5	Details of Other Revenue 2008 Historical Year to 2007 Historical Year	R. Lei T. Ladanyi
	4	1	Operating Cost 2008 Historical	K. Culbert
		2	Operating and Maintenance Expense by Department 2008 Historical	R. Lei T. Ladanyi
	5	1	Required Rate of Return 2008 Historical Year	K. Culbert
		2	Utility Income 2008 Historical Year	K. Culbert
		3	Cost of Capital 2008 Historical	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, 2009	K. Culbert
		2	Gas Distribution Access Rule Cost Deferral Account explanation	K. Culbert
		3	Municipal Permit Fees Deferral Account explanation	K. Culbert

EXHIBIT LIST

C – EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	4	Tax Rate and Rule Change Variance Account explanation	K.Culbert
		5	Average Use True Up Variance Account explanation	I. Chan
	2	1	Clearance of 2008 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

D – REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	Enbridge Gas Distribution Inc. 2008 Annual Report	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.

APPLICATION

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*, as amended (the "Act") for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

3. As of January 1, 2009, Enbridge began the second year of a five year Incentive Regulation plan ("IR Plan") approved by the Board in EB-2007-0615. The Settlement Agreement provides that clearance of Board-approved balances in the deferral and variance accounts will occur in conjunction with each following fiscal year's July 1st Quarterly Rate Adjustment Mechanism ("QRAM") proceeding.

4. The Settlement Agreement establishes new deferral and variance accounts that did not exist prior to the IR Plan. The new accounts are the Average Use True-Up Variance Account ("AUTUVA"), the Tax Rate and Rule Change Variance Account ("TRRCVA") and the Earnings Sharing Mechanism Deferral Account ("ESMDA"). With

respect to the last of these three accounts, the ESMDA, the Settlement Agreement specifically requires an application by Enbridge to the Board. 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.

5. 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 2008 ESMDA and the other deferral and variance accounts listed in Appendix A to this Application and for the proper conduct of this proceeding.

6. 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
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 March 18, 2009 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: Ken Culbert

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

			Col. 1	Col. 2	Col. 3	Col. 4	
			Actual at February 28, 2009		Forecast for clearance at July 1, 2009		
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	2007 DSMVA	(616.1)	(122.0)	(616.1)	(127.0)	
2.	Lost Revenue Adjustment Mechanism	2007 LRAM	(301.3)	(1.2)	(301.3)	(3.7)	
3.	Shared Savings Mechanism V/A	2007 SSMVA	8,247.5	33.7	8,247.5	101.0	
4.	Class Action Suit D/A	2009 CASDA	18,838.2	1,379.7	4,709.5	563.7	1
5.	Deferred Rebate Account	2008 DRA	2,057.3	34.0	2,057.3	50.8	
6.	Gas Distribution Access Rule Costs D/A	2008 GDARCDA	788.9	21.1	825.6	-	2
7.	Ontario Hearing Costs V/A	2008 OHCVA	2,252.1	44.0	2,252.1	62.4	
8.	Unbundled Rates Customer Migration V/A	2008 URCMVA	485.7	2.0	485.7	5.9	
9.	Open Bill Service D/A	2008 OBSDA	309.9	14.3	309.9	16.9	3
10.	Open Bill Access V/A	2008 OBAVA	476.7	1.9	476.7	5.8	3
11.	Municipal Permit Fees D/A	2008 MPFDA	717.6	-	99.6	-	2
12.	Average Use True-Up V/A	2008 AUTUVA	(2,654.1)	(10.8)	(2,654.1)	(32.5)	4
13.	Tax Rate and Rule Change V/A	2008 TRRCVA	1,830.0	7.5	1,830.0	22.4	5
14.	Earnings Sharing Mechanism D/A	2008 ESMDA	(5,750.0)	(23.5)	(5,750.0)	(70.4)	6
15.	Total non commodity related accounts		26,682.4	1,380.7	11,972.4	595.3	
	Commodity Related Accounts						
16.	Purchased Gas V/A	2008 PGVA	23,135.4	(966.4)	23,135.4	(777.4)	7
17.	Transactional Services D/A	2008 TSDA	(6,476.0)	(52.7)	(6,476.0)	(105.6)	
18.	Unaccounted for Gas V/A	2008 UAFVA	621.2	2.5	621.2	7.6	
19.	Storage and Transportation D/A	2008 S&TDA	(1,826.8)	(113.3)	(1,826.8)	(128.2)	
20.	Total commodity related accounts		15,453.8	(1,129.9)	15,453.8	(1,003.6)	
21.	Total Deferral and Variance Accounts		42,136.2	250.8	27,426.2	(408.3)	

Notes:

1. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years. The first installment was cleared in 2008, therefore the second installment is proposed for 2009. As such, 1/4 of the remaining principal, and 1/4 of the remaining interest forecast to accumulate through June 30, 2012 is proposed for clearance. The forecast interest is based on the Board's current prescribed interest rate for deferral accounts of 2.45%.
2. The forecast 2008 GDARCDA and 2008 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. Open Bill related deferral and variance accounts subject to any impact of the EB-2009-0043 Open Bill Issues proceeding.
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. The 2008 actual versus forecast year end PGVA balance. The forecast year end balance was rolled into the opening 2009 PGVA balance and used in projected rate rider clearances in 2009.

APPROVALS REQUESTED

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

    a) The Company has filed the balances at February 28, 2009, of Board approved deferral and variance accounts and is requesting approval for their clearance commencing July 1, 2009, (Exhibit C, Tab 1, Schedule 1). Clearance of the balances is proposed as a one time adjustment to customers' bills coincident with the Company's July 1, 2009 Quarterly Rate Adjustment Mechanism filing associated with any required rate adjustments with respect to changes in natural gas prices.

    b) Included within the deferral and variance account balances requested for clearance is the 2008 Earnings Sharing Mechanism Deferral Account ("ESMDA") as approved in the Company's EB-2007-0615 proceeding. Evidence in support of the Earnings Sharing calculation and EGD's Fiscal 2008 financial statements are filed within Exhibit B, Tabs 1 through 5 and Exhibit D, Tab 1.

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

    d) In order to facilitate the clearance of the deferral and variance account balances within the Company's July 1, 2009 QRAM application, a Board Decision or approval is required by approximately May 15th, 2009.

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 Fiscal 2008 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, with the intention of clearing the ESMDA at the same time as the clearance of other deferral and variance accounts, in the July 1 QRAM application.

3. The Company proposes an informal stakeholder consultative including intervenors and Board Staff, where it would present, discuss and explain the processes followed in arriving at the results and amounts within the deferral and variance accounts requested for clearance.

4. The Company's intention is that the consultative will provide stakeholders an opportunity to review the application and discuss any elements which parties require a further explanation and understanding of, with a view to reaching an outcome that results in no outstanding issues for the Board to resolve.

5. At the conclusion of the consultative, the parties would either forward a combined indication to the Board that they believe all matters have been resolved or, alternatively, they would determine the outstanding issues and address the best process to deal with them.

6. To the extent that the parties are unable to reach either of these outcomes within the consultative process, the Company proposes that an Issues / Process day would be held before the Board to determine the outstanding issues and timelines

required in order to achieve a timely Decision which would accommodate clearance of the accounts within the July 1, 2009 QRAM application.

2008 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. Included within Enbridge Gas Distribution Inc's. Fiscal 2008 year end audited financial statement results, is a utility related earnings sharing accrual of $5.75 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 mechanics as identified within the EB-2007-0615 Board Approved Settlement Agreement (Ex.N1, T.1, S.1, 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. 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) in 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 of 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.

<u>Part A)</u>

7. The level of utility income, $305.7 million (line 19) divided by the level of utility rate base, $3,779.2 million (line 24) generates a utility return on rate base of 8.089% (line 25).

8. When compared to the Company's required rate of return of 7.887% (line 26), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.202% (line 27) on total rate base.

9. As shown in lines 28 through 30, the sufficiency of 0.202% multiplied by the rate base of $3,779.2 million, produces a net over earnings or sufficiency of $7.64 million which from a pre-tax perspective, ($7.64 million divided by the reciprocal, 66.5%, of the corporate tax rate) shows an $11.50 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 $396.4 million (line 33) of utility income before income tax, less utility taxes of $90.7 million (line 38), produces the $305.7 million of utility income used in part A) above.

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) $305.7 utility income.

13. These reductions are shown at lines 34, 35 & 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 $139.1 million, line 39.

14. The $139.1 million, divided by the deemed common equity level of $1,360.5 million (line 40 or 36% of the $3,779.2 million rate base) produces a return on equity of 10.22% (line 42). When comparing the 10.22% achieved return on equity to the threshold ROE % of 9.66% (line 41), which is the Board approved formula return on equity for 2008 of 8.66% plus the approved 100 basis point dead band, there is a sufficiency in ROE of 0.56% (line 43).

15. The 0.56% multiplied by the common equity level of $1,360.5 million (line 40) produces a net over earnings or sufficiency of $7.64 million which from a pre-tax perspective, ($7.64 million divided by the reciprocal, 66.5%, of the corporate tax rate) shows an $11.50 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 regulated financial results contained within the EGD Ontario corporate trial balance.

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:
    - 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,
    - 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 & 479 decisions (Mississauga Southern Link project amounts),
- rate base disallowance from RP-2002-0133 (shared assets),
- elimination of EGD share of shared savings mechanism,
- elimination of EGD share of transactional services,
- 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, 2008

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	Actual Normalized ($millions) & (%'s)
1.	Part A) Return on Rate Base & Earnings Sharing determination		
2.	Gas Sales	(Ex.B,T5,S2,P1,Col.1,line 1)	2,353.4
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	747.3
4.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	2,137.8
5.	Gas Distribution Margin		962.9
6.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	1.8
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	38.9
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	4.3
9.	Total - TC&S, Oth. Rev. & Inc.		45.0
10.	Operations, Maintenance & Administration	(Ex.B,T5,S2,P1,Col.1,line 9)	323.4
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	236.7
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	0.7
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)	5.6
15.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 14)	44.8
16.	Total O&M, Depr., & other		611.5
17.	Utility Income before Income Tax	(line 5 + line 9 - line 16)	396.4
18.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	90.7
19.	Utility Income		305.7
20.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	5,225.4
21.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(1,955.8)
22.	Net plant		3,269.6
23.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 12)	509.6
24.	Utility Rate Base		3,779.2
25.	Indicated Return on Rate Base %	(line 19 / line 24)	8.089%
26.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	7.887%
27.	(Deficiency) / Sufficiency %		0.202%
28.	Net Earnings (Deficiency) / Sufficiency	(line 27 x line 24)	7.64
29.	Provision for Income Taxes		3.86
30.	Gross Earnings (Deficiency) / Sufficiency	(line 28 divide by 66.50%)	11.50
31.	50% Earnings sharing to ratepayers	(line 30 x 50%)	5.75
32.	Part B) Return on Equity & Earnings Sharing determination		
33.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 18)	396.4
34.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	161.4
35.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	0.2
36.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	5.0
37.	Net Income before Income Taxes		229.8
38.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	90.7
39.	Net Income Applicable to Common Equity	(line 37 - line 38)	139.1
40.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	1,360.5
41.	Approved ROE %	(EB-2007-0615 for Earnings Sharing 8.66% + 100 bp)	9.66%
42.	Achieved Rate of Return on Equity %	(line 39 divide by line 40)	10.22%
43.	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.56%
44.	Net Earnings (Deficiency) / Sufficiency	(line40 x line 43)	7.64
45.	Provision for Income Taxes		3.86
46.	Gross Earnings (Deficiency) / Sufficiency	(line 44 divide by 66.50%)	11.50
47.	50% Earnings sharing to ratepayers	(line 46 x 50%)	5.75

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 P. P. & E.	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

PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2008 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	266.5	(90.4)	176.1
2.	Distribution plant	4,692.4	(1,730.6)	2,961.8
3.	General plant	273.6	(134.6)	139.0
4.	Other plant	0.5	(0.4)	0.1
5.	Total plant in service	5,233.0	(1,956.0)	3,277.0
6.	Plant held for future use	1.7	(0.8)	0.9
7.	Sub- total	5,234.7	(1,956.8)	3,277.9
8.	Affiliate Shared Assets Value	(9.3)	1.0	(8.3)
9.	Total property, plant, and equipment	5,225.4	(1,955.8)	3,269.6

GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2008	Col. 5 Regulatory Adjustments	Col. 6 Utility Balance Dec.2008	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)	40.2	(0.2)	-	40.0	-	40.0	40.2
3.	Structures and improvements (452.00)	10.3	0.3	-	10.6	-	10.6	10.4
4.	Wells (453.00)	27.0	1.3	-	28.3	-	28.3	27.2
5.	Well equipment (454.00)	7.5	0.4	-	7.9	-	7.9	7.6
6.	Field Lines (455.00)	44.9	0.3	-	45.2	-	45.2	45.1
7.	Compressor equipment (456.00)	79.0	4.3	-	83.3	-	83.3	79.9
8.	Measuring and regulating equipment (457.00)	11.1	0.1	-	11.2	-	11.2	11.1
9.	Base pressure gas (458.00)	40.8	-	-	40.8	-	40.8	40.8
10.	Total	265.0	6.5	-	271.5	-	271.5	266.5

UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2008	Col. 6 Regulatory Adjustments	Col. 7 Utility Balance Dec.2008	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(1.9)	(0.1)	-	-	(2.0)	-	(2.0)	(1.9)
2.	Land and gas storage rights (451.00)	(17.7)	(0.9)	-	-	(18.6)	-	(18.6)	(18.1)
3.	Structures and improvements (452.00)	(3.8)	(0.3)	-	-	(4.1)	-	(4.1)	(3.9)
4.	Wells (453.00)	(14.6)	(1.3)	-	-	(15.9)	-	(15.9)	(15.2)
5.	Well equipment (454.00)	(3.7)	(0.2)	-	-	(3.9)	-	(3.9)	(3.8)
6.	Field Lines (455.00)	(17.3)	(1.1)	-	-	(18.4)	-	(18.4)	(17.8)
7.	Compressor equipment (456.00)	(24.7)	(1.9)	-	-	(26.6)	-	(26.6)	(25.7)
8.	Measuring and regulating equipment (457.00)	(3.8)	(0.4)	-	-	(4.2)	-	(4.2)	(4.0)
9.	Total	(87.5)	(6.2)	-	-	(93.7)	-	(93.7)	(90.4)

GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2008	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2008	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	9.1	11.9	-	21.0	-	21.0	9.6
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Structures and improvements (472.00)	77.5	7.8	(4.8)	80.5	(0.3)	80.2	77.2
4.	Services, house reg & meter install. (473/474)	1,814.9	85.4	(28.3)	1,872.0	-	1,872.0	1,841.6
5.	NGV station compressors (476)	2.2	-	-	2.2	-	2.2	2.2
6.	Meters (478)	329.4	24.6	(5.1)	348.9	-	348.9	330.9
7.	Sub-total	2,233.1	129.7	(38.2)	2,324.6	(0.3)	2,324.3	2,261.5
8.	Mains (475)	2,088.9	140.3	(5.0)	2,224.2	-	2,224.2	2,148.7
9.	Measuring and regulating equip. (477)	274.9	13.3	(0.2)	288.0	-	288.0	282.2
10.	Construction work-in-progress completed and in service projects	-	-	-	-	-	-	-
11.	Sub-total	2,363.8	153.6	(5.2)	2,512.2	-	2,512.2	2,430.9
12.	Total	4,596.9	283.3	(43.4)	4,836.8	(0.3)	4,836.5	4,692.4

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

DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2008	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2008	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Structures and improvements (472.00)	(6.5)	(2.2)	4.8	-	(3.9)	0.1	(3.8)	(6.5)
2.	Services, house reg & meter install. (473/474)	(719.1)	(82.4)	28.3	5.2	(768.0)	-	(768.0)	(749.8)
3.	NGV station compressors (476)	(1.1)	(0.2)	-	-	(1.3)	-	(1.3)	(1.2)
4.	Meters (478)	(88.4)	(8.2)	5.1	(0.3)	(91.8)	-	(91.8)	(90.0)
5.	Mains (475)	(712.9)	(89.4)	5.0	6.9	(790.4)	0.1	(790.3)	(755.7)
6.	Measuring and regulating equip. (477)	(120.3)	(14.4)	0.2	-	(134.5)	-	(134.5)	(127.4)
7.	Total	(1,648.3)	(196.8)	43.4	11.8	(1,789.9)	0.2	(1,789.7)	(1,730.6)

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).

GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2008	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2008	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	4.4	-	-	4.4	(0.2)	4.2	4.2
2.	Office furniture and equipment (483.00)	20.3	0.3	(0.8)	19.8	-	19.8	19.9
3.	Transportation equipment (484.00)	27.4	8.0	(1.4)	34.0	(0.1)	33.9	27.0
4.	NGV conversion kits (484.01)	6.7	0.4	-	7.1	-	7.1	6.8
5.	Heavy work equipment (485.00)	13.6	2.5	(0.1)	16.0	-	16.0	13.7
6.	Tools and work equipment (486.00)	26.9	3.6	(0.2)	30.3	-	30.3	27.4
7.	Rental equipment (487.70)	1.0	-	-	1.0	-	1.0	1.0
8.	NGV rental compressors (487.80)	8.0	-	(1.2)	6.8	-	6.8	7.3
9.	NGV cylinders (484.02 and 487.90)	1.8	0.2	-	2.0	-	2.0	1.9
10.	Communication structures & equip. (488)	2.9	0.1	-	3.0	-	3.0	2.8
11.	S.I.M. project (489.00)	47.3	-	(42.6)	4.7	-	4.7	24.2
12.	Computer equipment (490.00)	146.6	24.3	(14.2)	156.7	-	156.7	137.4
13.	Total	306.9	39.4	(60.5)	285.8	(0.3)	285.5	273.6

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

GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2008	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2008	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	(2.7)	(0.3)	-	-	(3.0)	0.1	(2.9)	(2.7)
2.	Office furniture and equipment (483.00)	(12.0)	(0.9)	0.8	-	(12.1)	-	(12.1)	(12.0)
3.	Transportation equipment (484.00)	(8.5)	(1.2)	1.4	(0.2)	(8.5)	-	(8.5)	(8.5)
4.	NGV conversion kits (484.01)	(4.2)	(0.1)	-	-	(4.3)	-	(4.3)	(4.2)
5.	Heavy work equipment (485.00)	(6.2)	(0.5)	0.1	0.1	(6.5)	-	(6.5)	(6.3)
6.	Tools and work equipment (486.00)	(11.8)	(0.7)	0.2	-	(12.3)	-	(12.3)	(12.0)
7.	Rental equipment (487.70)	(0.8)	-	-	-	(0.8)	-	(0.8)	(0.8)
8.	NGV rental compressors (487.80)	(5.0)	(0.6)	1.2	-	(4.4)	-	(4.4)	(4.7)
9.	NGV cylinders (484.02 and 487.90)	(1.3)	-	-	-	(1.3)	-	(1.3)	(1.3)
10.	Communication structures & equip. (488)	(1.6)	(0.4)	-	-	(2.0)	-	(2.0)	(1.9)
11.	S.I.M. project (489.00)	(47.3)	-	42.6	-	(4.7)	-	(4.7)	(24.2)
12.	Computer equipment (490.00)	(59.6)	(29.3)	14.2	0.5	(74.2)	-	(74.2)	(56.0)
13.	Total	(161.0)	(34.0)	60.5	0.4	(134.1)	0.1	(134.0)	(134.6)

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

GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2008	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2008	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

OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2008	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2008	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.4)	(0.1)	-	-	(0.5)	-	(0.5)	(0.4)
2.	Total	(0.4)	(0.1)	-	-	(0.5)	-	(0.5)	(0.4)

GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2007	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2008	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2008	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

PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2008 HISTORICAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.		Opening Balance Dec.2007	Additions	Retirements	Costs Net of Proceeds	Closing Balance Dec.2008	Regulatory Adjustment	Utility Balance Dec.2008	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(0.8)	-	-	-	(0.8)	-	(0.8)	(0.8)
2.	Total	(0.8)	-	-	-	(0.8)	-	(0.8)	(0.8)

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)	-	-	-
F.	TOTAL CAPITAL EXPENDITURES	319.6	322.5	(2.9)

Witnesses: L. Au
T. Ladanyi

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)	-				-
F.	TOTAL CAPITAL EXPENDITURES	280.1	9.5	28.6	1.4	319.6

Project Details:

	Col. 2	Col. 3	Col. 4	Col. 5
2.1 Incremental Accelerated 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
Sub total Additional Initiatives	9.5	28.6	1.4	39.5

Witnesses: L. Au
T. Ladanyi

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

The 2008 Actual was $319.6 million, which is $2.9 million or 0.9% less than the 2007 Actual of $322.5 million. The capital expenditure decrease was primarily related to decreased requirements in customer related expenditures. This was partially offset by increased requirements for general plant, storage plant and system improvements and upgrades. 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
T. Ladanyi

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 acceleration 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 the warehouse construction in 2008 and increased requirements for compressor upgrades as well as measurement and regulation equipment.

E. Customer Information System (CIS)

Due to the multi-year nature of this project and the separate approval process, CIS was excluded from this schedule.

Witnesses: L. Au
T. Ladanyi

UTILITY OPERATING REVENUE
2008 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	2,463.2	(109.8)	2,353.4
2.	Transportation of gas	770.6	(23.3)	747.3
3.	Transmission, compression & storage	1.8	-	1.8
4.	Other operating revenue	38.9	-	38.9
5.	Other income	4.3	-	4.3
6.	Total operating revenue	3,278.8	(133.1)	3,145.7

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2008 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	(109.8)	Gas sales
		Adjustment to gas sales revenue required to reflect normal weather.
2.	(23.3)	Transportation of gas
		Adjustment to gas transportation revenue required to reflect normal weather.

UTILITY REVENUE
2008 HISTORICAL YEAR

Line No.		Col. 1 Ontario Regulated Revenue ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Revenue ($Millions)
1.	Residential	1,529.7	-	1,529.7
2.	Commercial	759.4	-	759.4
3.	Industrial	126.9	-	126.9
4.	Wholesale	47.2	-	47.2
5.	Gas sales	2,463.2	-	2,463.2
6.	Transportation of gas	770.6	-	770.6
7.	Transmission, compression & storage	1.8	-	1.8
8.	Service charges & DPAC	12.4	-	12.4
9.	Rent from NGV rentals	0.4	0.5	0.9
10.	Late payment penalties	12.0	-	12.0
11.	Transactional services	11.1	(3.1)	8.0
12.	Open bill revenue	6.0	(0.6)	5.4
13.	Dow Moore recovery	0.2	-	0.2
14.	Affiliate asset use revenue	0.1	(0.1)	-
15.	ABC T-service (net)	5.1	(5.1)	-
16.	Other operating revenue	47.3	(8.4)	38.9
17.	Income from investments	1.7	(1.7)	-
18.	Interest during construction	5.1	(5.1)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	-	-	-
21.	Property/asset use revenue 3rd party	1.1	(1.1)	-
22.	Interest and property rental	7.9	(7.9)	-
23.	Miscellaneous	15.4	(11.1)	4.3
24.	Dividend income	65.7	(65.7)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	81.1	(76.8)	4.3
28.	Total revenue	3,371.9	(93.1)	3,278.8

EXPLANATION OF ADJUSTMENTS TO ONTARIO REGULATED REVENUE
2008 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
9.	0.5	**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 2008 TSDA, and shareholder amounts are eliminated from utility returns.	
12.	(0.6)	**Open bill revenue**	
		To eliminate shareholder portion of bill insert revenue.	(0.2)
		To eliminate the Open Bill shareholder incentive	(0.4)
			(0.6)
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.	(5.1)	**ABC T-Service (net)**	
		To eliminate the net revenue from the ABC T-Service considered to be non-utility. (RP-1999-0001)	
17.	(1.7)	**Income from investments**	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(5.1)	**Interest during construction**	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
21.	(1.1)	**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.	(11.1)	**Miscellaneous**	
		To eliminate the shareholders' incentive income recorded as a result of calculating the SSMVA amount.	
24.	(65.7)	**Dividend income**	
		To eliminate non-utility inter-company dividend income.	(3.0)
		To eliminate non-utility inter-company dividend income from the OEB approved financing transaction (EBO 179-16).	(62.7)
			(65.7)

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2008 HISTORICAL YEAR TO 2008 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2008 Actual	Col. 2 2008 Board Approved Budget	Col. 3 2008 Actual Over (Under) 2008 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 985.6	2 783.0	202.6
1.1.2	Rate 1 - T-Service	1 738.7	1 736.2	2.5
1.1	Total Rate 1	4 724.3	4 519.2	205.1
1.2.1	Rate 6 - Sales	1 815.6	1 619.0	196.6
1.2.2	Rate 6 - T-Service	2 263.9	2 147.1	116.8
1.2	Total Rate 6	4 079.5	3 766.1	313.4
1.3.1	Rate 9 - Sales	1.8	2.0	(0.2)
1.3.2	Rate 9 - T-Service	0.4	0.7	(0.3)
1.3	Total Rate 9	2.2	2.7	(0.5)
1.	Total General Service Sales & T-Service	8 806.0	8 288.0	518.0
Contract Sales				
2.1	Rate 100	98.8	87.9	10.9
2.2	Rate 110	62.3	24.0	38.3
2.3	Rate 115	8.4	46.2	(37.8)
2.4	Rate 135	5.1	3.3	1.8
2.5	Rate 145	22.4	30.8	(8.4)
2.6	Rate 170	70.9	62.1	8.8
2.7	Rate 200	183.3	150.0	33.3
2.	Total Contract Sales	451.2	404.3	46.9
Contract T-Service				
3.1	Rate 100	494.0	569.7	(75.7)
3.2	Rate 110	602.2	588.9	13.3
3.3	Rate 115	627.4	854.9	(227.5)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	52.3	50.9	1.4
3.6	Rate 145	220.6	187.4	33.2
3.7	Rate 170	618.3	667.2	(48.9)
3.8	Rate 300	35.5	31.9	3.6
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	2 650.3	2 950.9	(300.6)
4.	Total Contract Sales & T-Service	3 101.5	3 355.2	(253.7)
5.	Total	11 907.5	11 643.2	264.3

* There is no distribution volume for Rate 125 customer.

** Less than 50,000 m³.

Witnesses: I. Chan
T. Ladanyi

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2008 HISTORICAL YEAR TO 2008 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2008 Actual	Col. 2 2008 Board Approved Budget	Col. 3 2008 Actual Over (Under) 2008 Budget (1-2)	Col. 4 2008* Adjustments		Col. 5 2008 Actual Over (Under) 2008 Budget with Adjustments (3-4)
General Service							
1.1.1	Rate 1 - Sales	2 985.6	2 783.0	202.6	144.6		58.0
1.1.2	Rate 1 - T-Service	1 738.7	1 736.2	2.5	80.5		(78.0)
1.1	Total Rate 1	4 724.3	4 519.2	205.1	225.1		(20.0)
1.2.1	Rate 6 - Sales	1 815.6	1 619.0	196.6	94.5		102.1
1.2.2	Rate 6 - T-Service	2 263.9	2 147.1	116.8	116.7		0.1
1.2	Total Rate 6	4 079.5	3 766.1	313.4	211.2		102.2
1.3.1	Rate 9 - Sales	1.8	2.0	(0.2)	0.0		(0.2)
1.3.2	Rate 9 - T-Service	0.4	0.7	(0.3)	0.0		(0.3)
1.3	Total Rate 9	2.2	2.7	(0.5)	0.0		(0.5)
1.	Total General Service Sales & T-Service	8 806.0	8 288.0	518.0	436.3		81.7
Contract Sales							
2.1	Rate 100	98.8	87.9	10.9	1.8		9.1
2.2	Rate 110	62.3	24.0	38.3	0.1		38.2
2.3	Rate 115	8.4	46.2	(37.8)	0.0	**	(37.8)
2.4	Rate 135	5.1	3.3	1.8	0.0		1.8
2.5	Rate 145	22.4	30.8	(8.4)	0.0	**	(8.4)
2.6	Rate 170	70.9	62.1	8.8	0.2		8.6
2.7	Rate 200	183.3	150.0	33.3	1.5		31.8
2.	Total Contract Sales	451.2	404.3	46.9	3.6		43.3
Contract T-Service							
3.1	Rate 100	494.0	569.7	(75.7)	5.6		(81.3)
3.2	Rate 110	602.2	588.9	13.3	1.3		12.0
3.3	Rate 115	627.4	854.9	(227.5)	0.0	**	(227.5)
3.4	Rate 125	0.0	0.0	0.0	0.0		0.0
3.5	Rate 135	52.3	50.9	1.4	0.0		1.4
3.6	Rate 145	220.6	187.4	33.2	0.1		33.1
3.7	Rate 170	618.3	667.2	(48.9)	(8.7)		(40.2)
3.8	Rate 300	35.5	31.9	3.6	0.0		3.6
3.9	Rate 315	0.0	0.0	0.0	0.0		0.0
3.	Total Contract T-Service	2 650.3	2 950.9	(300.6)	(1.7)		(298.9)
4.	Total Contract Sales & T-Service	3 101.5	3 355.2	(253.7)	1.9		(255.6)
5.	Total	11 907.5	11 643.2	264.3	438.2		(173.9)

*Note: Weather normalization adjustments have been made to the 2008 Actuals utilizing the 2008 Board Approved Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m^3.

Witnesses: I. Chan
T. Ladanyi

The principal reasons for the variances contributing to the weather normalized decrease of 173.9 10^6m^3 in the 2008 Actual over the 2008 Board Approved Budget are as follows:

1. The volumetric decrease of 20.0 10^6m^3 in Rate 1 is due to a lower average use per customer totalling 19.6 10^6m^3 and a customer shortfall of 0.4 10^6m^3;

2. The volumetric increase of 102.2 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 103.9 10^6m^3 and favourable customer variance of 2.4 10^6m^3; partially offset by a lower average use per customer totalling 4.1 10^6m^3;

3. The volumetric decrease of 0.5 10^6m^3 in Rate 9 is due to a lower average use per station totalling 0.5 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 255.6 10^6m^3 is due to decreases in the commercial sector of 189.8 10^6m^3 and the industrial sector of 107.7 10^6m^3; partially offset by increases in the apartment sector of 10.1 10^6m^3 and Rate 200 of 31.8 10^6m^3. The decrease is primarily attributable to net customer migration to General Service of 103.9 10^6m^3 as stated above, one large distributed energy customer with distribution volume of 90.7 10^6m^3 migrating from Rate 115 to Rate 125 that has no distribution volume effective July 1, 2008, as well as production decreases and plant closures in the wake of an unexpected major financial crisis and a rapidly deteriorating economy since October 2008.

Witnesses: I. Chan
T. Ladanyi

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2008 HISTORICAL YEAR AND 2008 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2008 Actual	Col. 2 2008 Board Approved Budget	Col. 3 2008 Actual Over (Under) 2008 Budget (1-2)	Col. 4 2008* Adjustments	Col. 5 2008 Actual Over (Under) 2008 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 475.7	1 339.3	136.4	(65.0)	71.4
1.1.2	Rate 1 - T-Service	343.7	329.9	13.8	(11.0)	2.8
1.1	Total Rate 1	1 819.4	1 669.2	150.2	(76.0)	74.2
1.2.1	Rate 6 - Sales	785.4	680.8	104.6	(37.5)	67.1
1.2.2	Rate 6 - T-Service	245.0	222.2	22.8	(10.9)	11.9
1.2	Total Rate 6	1 030.4	903.0	127.4	(48.4)	79.0
1.3.1	Rate 9 - Sales	0.8	0.9	(0.1)	0.0	(0.1)
1.3.2	Rate 9 - T-Service	0.1	0.1	0.0	0.0	0.0
1.3	Total Rate 9	0.9	1.0	(0.1)	0.0	(0.1)
1.	Total General Service Sales & T-Service	2 850.7	2 573.2	277.5	(124.4)	153.1
Contract Sales						
2.1	Rate 100	38.1	32.9	5.2	(0.7)	4.5
2.2	Rate 110	24.4	8.4	16.0	0.0 **	16.0
2.3	Rate 115	2.8	15.6	(12.8)	0.0 **	(12.8)
2.4	Rate 135	2.2	1.1	1.1	0.0	1.1
2.5	Rate 145	8.4	10.7	(2.3)	0.0 **	(2.3)
2.6	Rate 170	24.1	20.0	4.1	(0.1)	4.0
2.7	Rate 200	47.2	42.9	4.3	(0.6)	3.7
2.	Total Contract Sales	147.2	131.6	15.6	(1.4)	14.2
Contract T-Service						
3.1	Rate 100	46.2	47.9	(1.7)	(0.5)	(2.2)
3.2	Rate 110	42.1	34.4	7.7	(0.1)	7.6
3.3	Rate 115	36.2	41.4	(5.2)	0.0 **	(5.2)
3.4	Rate 125	4.2	3.3	0.9	0.0 ***	0.9
3.5	Rate 135	3.4	2.2	1.2	0.0	1.2
3.6	Rate 145	15.8	10.9	4.9	0.0 **	4.9
3.7	Rate 170	27.7	22.0	5.7	0.4	6.1
3.8	Rate 300	0.5	0.7	(0.2)	0.0	(0.2)
3.9	Rate 315	0.2	0.0	0.2	0.0	0.2
3.	Total Contract T-Service	176.3	162.8	13.5	(0.2)	13.3
4.	Total Contract Sales & T-Service	323.5	294.4	29.1	(1.6)	27.5
5.	Total	3 174.2	2 867.6	306.6	(126.0)	180.6

* Note: Weather normalization adjustments have been made to the 2008 Actuals utilizing the 2008 Board Approved Budget degree days in order to place the two years on a comparable basis. Please refer to Exhibit B, Tab 2, Schedule 2, Page 2, for the corresponding volumetric adjustments.

** Less than $50,000

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

Witnesses: I. Chan
T. Ladanyi

1. Gas sales and transportation of gas revenues for the 2008 Test Year Budget were developed on the basis of EB-2007-0615 rates (October 2007 QRAM).

2. The principal reasons for the variances contributing to the increase of $306.6 million in the 2008 Actual over the 2008 Budget are as follows:

3. <u>Gas Sales - Increase of $256.5 Million</u>

   The increase in gas sales revenue was due to higher actual commodity charges than budgeted, colder weather and residential customer migration from transportation service to gas sales.

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

4. <u>Transportation of Gas - Increase of $50.1 Million</u>

   The increase in T-service revenue was mainly due to colder weather and higher actual transportation charges than budgeted; partially offset by residential customer migration from transportation service to gas sales.

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

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2008 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	1 078 118	2 985.6		1 475.7
1.1.2	Rate 1 - T-Service	630 402	1 738.7		343.7
1.1	Total Rate 1	1 708 520	4 724.3		1 819.4
1.2.1	Rate 6 - Sales	104 000	1 815.6		785.4
1.2.2	Rate 6 - T-Service	51 207	2 263.9		245.0
1.2	Total Rate 6	155 207	4 079.5		1 030.4
1.3.1	Rate 9 - Sales	26	1.8		0.8
1.3.2	Rate 9 - T-Service	3	0.4		0.1
1.3	Total Rate 9	29	2.2		0.9
1.	Total General Service Sales & T-Service	1 863 756	8 806.0		2 850.7
Contract Sales					
2.1	Rate 100	129	98.8		38.1
2.2	Rate 110	34	62.3		24.4
2.3	Rate 115	1	8.4		2.8
2.4	Rate 135	3	5.1		2.2
2.5	Rate 145	11	22.4		8.4
2.6	Rate 170	5	70.9		24.1
2.7	Rate 200	1	183.3		47.2
2.	Total Contract Sales	184	451.2		147.2
Contract T-Service					
3.1	Rate 100	580	494.0		46.2
3.2	Rate 110	209	602.2		42.1
3.3	Rate 115	48	627.4		36.2
3.4	Rate 125	3	0.0	*	4.2
3.5	Rate 135	37	52.3		3.4
3.6	Rate 145	164	220.6		15.8
3.7	Rate 170	29	618.3		27.7
3.8	Rate 300	10	35.5		0.5
3.9	Rate 315	0	0.0		0.2
3.	Total Contract T-Service	1 080	2 650.3		176.3
4.	Total Contract Sales & T-Service	1 264	3 101.5		323.5
5.	Total	1 865 020	11 907.5		3 174.2

* There is no distribution volume for Rate 125 customer.

Witnesses: I. Chan
T. Ladanyi

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	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

Witnesses: T. Ladanyi
R. Lei

COST OF SERVICE
2008 HISTORICAL YEAR

Line No.		Col. 1 Utility Costs and Expenses	Col. 2 Adjustments	Col. 3 Adjusted Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	2,236.1	(98.3)	2,137.8
2.	Operation and maintenance	323.4	-	323.4
3.	Depreciation and amortization expense	236.7	-	236.7
4.	Fixed financing costs	0.7	-	0.7
5.	Debt redemption premium amortization	0.3	-	0.3
6.	Company share of IR agreement tax savings	5.6	-	5.6
7.	Municipal and other taxes	44.8	-	44.8
8.	Operating costs	2,847.6	(98.3)	2,749.3
9.	Income tax expense			90.7
10.	**Cost of service**			**2,840.0**

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2008 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	(98.3)	**Gas Costs**
		Adjustment required to gas costs to reflect normal weather.

CALCULATION OF TAXABLE INCOME AND INCOME TAX EXPENSE
2008 HISTORICAL YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	396.4	396.4	
	Add			
2.	Depreciation and amortization	236.7	236.7	
3.	Other non-deductible items	7.4	7.4	
4.	Total Add Back	244.1	244.1	
5.	Sub-total	640.5	640.5	
	Deduct			
6.	Capital cost allowance	166.7	166.6	
7.	Items capitalized for regulatory purposes	38.2	38.2	
8.	Deduction for "grossed up" Part VI.1 tax	5.9	5.9	
9.	Amortization of share/debenture issue expense	3.0	3.0	
10.	Amortization of cumulative eligible capital	0.1	0.1	
11.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
12.	Total Deduction	214.0	213.9	
13.	Taxable income	426.5	426.6	
14.	Income tax rates	19.50%	14.00%	
15.	Provision	83.2	59.7	142.9
16.	Part VI.1 tax			2.0
17.	Investment tax credit			-
18.	Total taxes excluding interest shield			144.9
	Tax shield on interest expense			
19.	Rate base	3,779.2		
20.	Return component of debt	4.28%		
21.	Interest expense	161.7		
22.	Combined tax rate	33.500%		
23.	Income tax credit			(54.2)
24.	Total income taxes			90.7

COST OF SERVICE
2008 HISTORICAL YEAR

Line No.		Col. 1 Ontario Regulated Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	2,236.1	-	2,236.1
2.	Operation and maintenance	346.7	(23.3)	323.4
3.	Depreciation	235.9	(0.4)	235.5
4.	Amortization	1.2	-	1.2
5.	Depreciation and amortization	237.1	(0.4)	236.7
6.	Fixed financing costs	0.7	-	0.7
7.	Debt redemption premium amortization	0.3	-	0.3
8.	Company share of IR agreement tax savings	-	5.6	5.6
9.	Municipal taxes	36.7	(0.2)	36.5
10.	Capital taxes	8.5	(0.2)	8.3
11.	Municipal and other taxes	45.2	(0.4)	44.8
12.	Interest on long-term debt	159.2	(159.2)	-
13.	Amortization of preference share issue costs and debt discount and expense	2.7	(2.7)	-
14.	Interest and financing amortization	161.9	(161.9)	-
15.	Interest on short-term debt	14.8	(14.8)	-
16.	Interest due affiliates	26.9	(26.9)	-
17.	Other interest expense	41.7	(41.7)	-
18.	Total operating costs	3,069.7	(222.1)	2,847.6
19.	Current taxes	69.2	(69.2)	-
20.	Deferred taxes	20.6	(20.6)	-
21.	Income tax expense	89.8	(89.8)	-
22.	Cost of service	3,159.5	(311.9)	2,847.6

EXPLANATION OF ADJUSTMENTS TO ONTARIO REGULATED
COSTS AND EXPENSES
2008 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(23.3)	**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.	1.7
		To eliminate donations (EBRO 490).	(0.8)
		To eliminate non-utility costs and expenses relating to the support of the ABC service program.	(1.3)
		To eliminate Corporate Cost allocations above RCAM amount.	(13.1)
		To eliminate CWLP CIS fees in excess of settlement agreement.	(9.8)
			(23.3)
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.	5.6	**Company share of IR agreement tax savings**	
		To reflect the impact of the shareholder portion of agreed tax savings on utility income. (Excludes CCA related forecast rate change impacts which did not occur Ex.C. T1. S4)	
9.	(0.2)	**Municipal taxes**	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	
10.	(0.2)	**Capital taxes**	
		Adjustment to capital taxes needed to convert the capital tax calculation to a utility "stand-alone" basis.	

EXPLANATION OF ADJUSTMENTS TO ONTARIO REGULATED
COSTS AND EXPENSES
2008 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(159.2)	**Interest on long-term debt** Expense of capital.
13.	(2.7)	**Amortization of preference share issue costs and debt discount and expense** Expense of capital.
15.	(14.8)	**Interest on short-term debt** Expense of capital.
16.	(26.9)	**Interest due affiliates** To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
19.	(69.2)	**Income taxes - current** Income tax expense related to corporate earnings.
20.	(20.6)	**Income taxes - deferred** Income tax expense related to corporate earnings.

PROVINCIAL CAPITAL TAX - CALCULATED ON YEAR END BALANCES
2008 HISTORICAL YEAR

Line No.		Col. 1 Provincial Capital Tax ($Millions)
1.	Undepreciated Capital Cost - year end	2,867.9
2.	Working capital / not in service taxable work in progress	813.8
3.	Non depreciable assets - land	21.3
4.	Other unclaimed tax treatments	2.1
5.	Taxable Capital	3,705.1
6.	Less exemption	(15.0)
7.	Adjusted taxable capital	3,690.1
8.	Capital tax rate	0.225%
9.	Provincial Capital Tax	8.3

ENBRIDGE DISTRIBUTION INC.
SUMMARY OF CAPITAL COST ALLOWANCE
2008 ACTUAL

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	2,479,890,295	262,317,314	150,000	131,233,657	4.00%	(104,444,958)	2,637,912,651
2	167,305,913	0	0	0	6.00%	(10,038,355)	157,267,558
6	22,149	0	0	0	10.00%	(2,215)	19,934
8	10,157,650	1,947,479	(845,000)	551,240	20.00%	(2,141,778)	9,118,351
10	22,044,197	8,912,979	(256,667)	4,328,156	30.00%	(7,911,706)	22,788,803
12	14,902,629	29,233,154	0	14,616,577	100.00%	(29,519,206)	14,616,577
17	46,784	0	0	0	8.00%	(3,743)	43,041
38	2,569,045	264,480	(50,000)	107,240	30.00%	(802,886)	1,980,640
41	22,095,218	10,842,000	54,000	5,448,000	25.00%	(6,885,805)	26,105,414
13	1,933,656	100,000	0	50,000		(249,000)	1,784,656
3	305,957	0	0	0	5.00%	(15,298)	290,659
45	9,731,023	2,803,030	0	1,401,515	45.00%	(5,009,642)	7,524,411
Total	2,731,004,516	316,420,436	(947,667)	157,736,385		(167,024,590)	2,879,452,695

Non-utility and shared asset eliminations	341,905
Utility Federal CCA	(166,682,685)

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	2,479,883,966	262,317,314	150,000	131,233,657	4.00%	(104,444,705)	2,637,906,575
2	165,365,658	0	0	0	6.00%	(9,921,940)	155,443,719
6	22,149	0	0	0	10.00%	(2,215)	19,934
8	10,146,826	1,947,479	(845,000)	551,240	20.00%	(2,139,613)	9,109,692
10	22,044,197	8,912,979	(256,667)	4,328,156	30.00%	(7,911,706)	22,788,803
12	14,902,629	29,233,154	0	14,616,577	100.00%	(29,519,206)	14,616,577
17	46,784	0	0	0	8.00%	(3,743)	43,041
38	2,569,045	264,480	(50,000)	107,240	30.00%	(802,886)	1,980,640
41	22,095,218	10,842,000	54,000	5,448,000	25.00%	(6,885,805)	26,105,414
13	1,933,656	100,000	0	50,000		(249,000)	1,784,656
3	302,873	0	0	0	5.00%	(15,144)	287,729
45	9,731,023	2,803,030	0	1,401,515	45.00%	(5,009,642)	7,524,411
Total	2,729,044,024	316,420,436	(947,667)	157,736,385		(166,905,603)	2,877,611,190

Non-utility and shared asset eliminations	341,905	(9,648,663)
Utility Provincial CCA and UCC	(166,563,698)	2,867,962,527

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAINTENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2008

		Col. 1	Col. 2	Col. 3
Line No.	Particulars ($ 000's)	Actual 2008	Actual 2007	2008 Actual Over/(Under) 2007 Actual
1.	Finance	$ 5,843	$ 5,890	$ (47)
2.	Risk Management	1,695	2,448	(753)
3.	Customer Care Service Charges (including CIS)	84,583	87,569	(2,986)
4.	Customer Care Internal Costs	8,388	10,188	(1,800)
5.	Provision for Uncollectibles	16,660	15,205	1,455
6.	Energy Supply, Storage, Regulatory	19,471	22,562	(3,091)
7.	Legal and Corporate Services	1,147	1,069	78
8.	Operations	43,308	43,146	162
9.	Information Technology	21,247	21,637	(390)
10.	Business Development & Customer Strategy (excluding DSM)	14,656	13,828	828
11.	Human Resources (excluding benefits)	3,833	3,581	252
12.	Benefits	24,597	26,077	(1,480)
13.	Engineering	32,291	31,406	885
14.	Public and Government Affairs	5,484	5,070	414
15.	Non Departmental Expenses	29,497	23,396	6,101
16.	Corporate Allocations (including direct costs)	32,166	27,715	4,451
17.	Total	344,866	340,787	4,079
18.	Capitalization (A&G)	(21,643)	(21,238)	(405)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	323,223	319,549	3,674
20.	Demand Side Management Programs (DSM)	23,100	22,000	1,100
21.	Total Net Utility Operating and Maintenance Expense	$ 346,323	$ 341,549	$ 4,774

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.

Witnesses: T. Ladanyi
R. Lei

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2008 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
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	2,311.8	61.17	6.98	4.270	161.4
2.	Short-Term Debt	6.9	0.18	3.44	0.006	0.2
3.		2,318.7	61.35		4.276	
4.	Preference Shares	100.0	2.65	5.00	0.133	5.0
						166.6
5.	Common Equity	1,360.5	36.00	9.66	3.478	
6.		3,779.2	100.00		7.887	
7.	Rate Base (Ex. D-1-1)	($Millions)			3,779.2	
8.	Utility Income (Ex. D-4-2)	($Millions)			305.7	
9.	Indicated Rate of Return				8.089	
10.	Sufficiency in Rate of Return				0.202	
11.	Net Sufficiency	($Millions)			7.64	
12.	Gross Sufficiency	($Millions)			11.50	
13.	Revenue at Existing Rates	($Millions)			3,102.7	
14.	Revenue Requirement	($Millions)			3,091.2	
15.	Gross Revenue Sufficiency	($Millions)			11.5	
	Common Equity					
16.	Allowed Rate of Return				9.660	
17.	Earnings on Common Equity				10.22	
18.	Sufficiency in Common Equity Return				0.56	

UTILITY INCOME
2008 HISTORICAL YEAR

Line No.		Col. 1 Utility Income ($Millions)
1.	Gas sales	2,353.4
2.	Transportation of gas	747.3
3.	Transmission, compression and storage revenue	1.8
4.	Other operating revenue	38.9
5.	Interest and property rental	-
6.	Other income	4.3
7.	Total operating revenue (Ex. B-3-1-pg.1)	3,145.7
8.	Gas costs	2,137.8
9.	Operation and maintenance	323.4
10.	Depreciation and amortization expense	236.7
11.	Fixed financing costs	0.7
12.	Debt redemption premium amortization	0.3
13.	Company share of IR agreement tax savings	5.6
14.	Municipal and other taxes	44.8
15.	Interest and financing amortization expense	-
16.	Other interest expense	-
17.	Cost of service (Ex. B-4-1-pg.1)	2,749.3
18.	Utility income before income taxes	396.4
19.	Income tax expense (Ex. B-4-1-pg.3)	90.7
20.	Utility income	305.7

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2008 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	2,333.8		163.0
2.	Unamortized Finance Costs	(22.0)		-
3.	(Profit)/Loss on Redemption	-		-
4.		2,311.8		163.0
5.	Calculated Cost Rate		6.98%	
	Short-Term Debt			
6.	Calculated Cost Rate		3.44%	
	Preference Shares			
7.	Preference Share Summary	100.0		5.0
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		5.0
11.	Calculated Cost Rate		5.00%	
	Common Equity			
12.	Board Approved Formula ROE		8.66%	
13.	100 Basis Point Allowance Before Earnings Sharing		1.00%	
14.	Total Allowed ROE for ESM Purposes		9.66%	

DEFERRAL & VARIANCE ACCOUNTS FOR CLEARANCE REQUESTED
JULY 1, 2009

1. The deferral and variance accounts for which EGD is requesting clearance of commencing July 1, 2009 are shown at page 2 of this schedule. The balances requested for clearance total approximately $27 million, which is the combination of principal and interest amounts shown in Columns 3 and 4.

2. As shown within the footnotes or evidence referenced in the footnotes on page 2, EGD has provided some 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.

3. For example, the DSM related accounts and amounts were approved within the EB-2008-0271 Decision, the DRA amount is the carried-forward amount that was not cleared to ratepayers from prior years accounts as a result of an inability to locate customers during clearance, the OHCVA is the variance of total actual Board, intervenor, consulting, legal & other proceeding related costs versus the level embedded in base rates of $5.84 million, and the URCMVA is the revenue consequence of actual customer migration versus forecast for the approved unbundled rates 125 and 300.

Witness: K. Culbert

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

			Col. 1	Col. 2	Col. 3	Col. 4	
			Actual at February 28, 2009		Forecast for clearance at July 1, 2009		
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	2007 DSMVA	(616.1)	(122.0)	(616.1)	(127.0)	
2.	Lost Revenue Adjustment Mechanism	2007 LRAM	(301.3)	(1.2)	(301.3)	(3.7)	
3.	Shared Savings Mechanism V/A	2007 SSMVA	8,247.5	33.7	8,247.5	101.0	
4.	Class Action Suit D/A	2009 CASDA	18,838.2	1,379.7	4,709.5	563.7	1
5.	Deferred Rebate Account	2008 DRA	2,057.3	34.0	2,057.3	50.8	
6.	Gas Distribution Access Rule Costs D/A	2008 GDARCDA	788.9	21.1	825.6	-	2
7.	Ontario Hearing Costs V/A	2008 OHCVA	2,252.1	44.0	2,252.1	62.4	
8.	Unbundled Rates Customer Migration V/A	2008 URCMVA	485.7	2.0	485.7	5.9	
9.	Open Bill Service D/A	2008 OBSDA	309.9	14.3	309.9	16.9	3
10.	Open Bill Access V/A	2008 OBAVA	476.7	1.9	476.7	5.8	3
11.	Municipal Permit Fees D/A	2008 MPFDA	717.6	-	99.6	-	2
12.	Average Use True-Up V/A	2008 AUTUVA	(2,654.1)	(10.8)	(2,654.1)	(32.5)	4
13.	Tax Rate and Rule Change V/A	2008 TRRCVA	1,830.0	7.5	1,830.0	22.4	5
14.	Earnings Sharing Mechanism D/A	2008 ESMDA	(5,750.0)	(23.5)	(5,750.0)	(70.4)	6
15.	Total non commodity related accounts		26,682.4	1,380.7	11,972.4	595.3	
	Commodity Related Accounts						
16.	Purchased Gas V/A	2008 PGVA	23,135.4	(966.4)	23,135.4	(777.4)	7
17.	Transactional Services D/A	2008 TSDA	(6,476.0)	(52.7)	(6,476.0)	(105.6)	
18.	Unaccounted for Gas V/A	2008 UAFVA	621.2	2.5	621.2	7.6	
19.	Storage and Transportation D/A	2008 S&TDA	(1,826.8)	(113.3)	(1,826.8)	(128.2)	
20.	Total commodity related accounts		15,453.8	(1,129.9)	15,453.8	(1,003.6)	
21.	Total Deferral and Variance Accounts		42,136.2	250.8	27,426.2	(408.3)	

Notes:

1. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years. The first installment was cleared in 2008, therefore the second installment is proposed for 2009. As such, 1/4 of the remaining principal, and 1/4 of the remaining interest forecast to accumulate through June 30, 2012 is proposed for clearance. The forecast interest is based on the Board's current prescribed interest rate for deferral accounts of 2.45%.
2. The forecast 2008 GDARCDA and 2008 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. Open Bill related deferral and variance accounts subject to any impact of the EB-2009-0043 Open Bill Issues proceeding.
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. The 2008 actual versus forecast year end PGVA balance. The forecast year end balance was rolled into the opening 2009 PGVA balance and used in projected rate rider clearances in 2009.

GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNT

1. Within the EB-2007-0615 Decision with Reasons, the Board approved a 2008 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 2008 relative to this deferral account, the majority of which were capital expenditure related with minor amounts of operating type costs.

3. In the EB-2007-0615 Final Rate Order, the Board approved clearance of the 2007 GDAR compliance costs through a revenue requirement calculation, which was cleared to customers as a one time rate rider adjustment in 2008. The result is that the Company’s distribution rates do not contain the ongoing impact of the 2007 GDAR compliance spending and that associated rate rider adjustments need to be established and cleared annually. As a result, the cumulative 2009 revenue requirement impact of the 2007 and 2008 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 2009 annual revenue requirement, determined through a revenue requirement / cost of service type of calculation, for the 2008 and 2007 cumulative expenditures. This revenue requirement treatment is consistent with the EB-2007-0615 Board Decision. In its EB-2006-0034 decision, the Board accepted the disposition of the 2005 & 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 Approved GDARCDA revenue requirement determination.

5. The Company is proposing to recover $0.8 million as a one time billing adjustment in July 2009 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 2009 annual revenue requirement associated with the combined 2007 and 2008 GDAR deferral account costs is shown in pages 2 through 6 of this schedule.

ONTARIO UTILITY CAPITAL STRUCTURE
2007 & 2008 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)	(107.3)	(1,407.8)	(1,558.3)	(1,583.9)
8.	Rate base	6,273.7	5,545.8	4,178.7	2,579.1	979.5
9.	Indicated rate of return	(1.17)%	(1.93)%	(33.69)%	(60.42)%	(161.70)%
10.	(Def.) / suff. in rate of return	(8.75)%	(9.51)%	(41.27)%	(68.00)%	(169.28)%
11.	Net (def.) / suff.	(548.9)	(527.4)	(1,724.5)	(1,753.8)	(1,658.1)
12.	Gross (def.) / suff.	(859.3)	(825.6)	(2,699.6)	(2,745.5)	(2,595.6)

ONTARIO UTILITY RATE BASE
2007 & 2008 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Property, plant, and equipment					
1.	Cost or redetermined value	7,004.5	7,776.3	8,000.7	8,000.7	8,000.7
2.	Accumulated depreciation	(730.8)	(2,230.5)	(3,822.0)	(5,421.6)	(7,021.2)
3.		6,273.7	5,545.8	4,178.7	2,579.1	979.5
	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	5,545.8	4,178.7	2,579.1	979.5

ONTARIO UTILITY INCOME
2007 & 2008 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	-	-	-
9.	Depreciation and amortization	1,461.6	1,560.6	1,599.6	1,599.6	1,599.6
10.	Municipal and other taxes	10.4	1.0	-	-	-
11.	Total costs and expenses	1,512.4	1,686.4	1,599.6	1,599.6	1,599.6
12.	Utility income before inc. taxes	(1,512.4)	(1,686.4)	(1,599.6)	(1,599.6)	(1,599.6)
	Income taxes					
13.	Excluding interest shield	(1,338.3)	(1,490.4)	(124.9)	-	-
14.	Tax shield on interest expense	(100.4)	(88.7)	(66.9)	(41.3)	(15.7)
15.	Total income taxes	(1,438.7)	(1,579.1)	(191.8)	(41.3)	(15.7)
16.	Ontario utility net income	(73.7)	(107.3)	(1,407.8)	(1,558.3)	(1,583.9)

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

($ 000's)

Line No.		2008	2009	2010	2011	2012
1.	Utility income before income taxes	(1,512.4)	(1,686.4)	(1,599.6)	(1,599.6)	(1,599.6)
	Add Backs					
2.	Depreciation and amortization	1,461.6	1,560.6	1,599.6	1,599.6	1,599.6
3.	Large corporation tax	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-
6.	Total added back	1,461.6	1,560.6	1,599.6	1,599.6	1,599.6
7.	Sub total - pre-tax income plus add backs	(50.8)	(125.8)	-	-	-
	Deductions					
8.	Capital cost allowance - Federal	3,654.5	4,000.4	345.8	-	-
9.	Capital cost allowance - Provincial	3,654.5	4,000.4	345.8	-	-
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	3,654.5	4,000.4	345.8	-	-
17.	Total Deductions - Provincial	3,654.5	4,000.4	345.8	-	-
18.	Taxable income - Federal	(3,705.3)	(4,126.2)	(345.8)	-	-
19.	Taxable income - Provincial	(3,705.3)	(4,126.2)	(345.8)	-	-
20.	Income tax provision - Federal	(819.6)	(912.7)	(76.5)	-	-
21.	Income tax provision - Provincial	(518.7)	(577.7)	(48.4)	-	-
22.	Income tax provision - combined	(1,338.3)	(1,490.4)	(124.9)	-	-
23.	Part V1.1 tax	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(1,338.3)	(1,490.4)	(124.9)	-	-
	Tax shield on interest expense					
26.	Rate base as adjusted	6,273.7	5,545.8	4,178.7	2,579.1	979.5
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	277.9	245.7	185.1	114.3	43.4
29.	Combined tax rate	36.120%	36.120%	36.120%	36.120%	36.120%
30.	Income tax credit	(100.4)	(88.7)	(66.9)	(41.3)	(15.7)
31.	Total income taxes	(1,438.7)	(1,579.1)	(191.8)	(41.3)	(15.7)

ONTARIO UTILITY REVENUE REQUIREMENT
2007 & 2008 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Cost of capital					
1.	Rate base	6,273.7	5,545.8	4,178.7	2,579.1	979.5
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	475.5	420.4	316.7	195.5	74.2
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	40.4	124.8	-	-	-
6.	Depreciation and amortization	1,461.6	1,560.6	1,599.6	1,599.6	1,599.6
7.	Municipal and other taxes	10.4	1.0	-	-	-
8.	Cost of service	1,512.4	1,686.4	1,599.6	1,599.6	1,599.6
	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)	(1,490.4)	(124.9)	-	-
13.	Tax shield provided by interest expense	(100.4)	(88.7)	(66.9)	(41.3)	(15.7)
14.	Income taxes on earnings	(1,438.7)	(1,579.1)	(191.8)	(41.3)	(15.7)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	(859.3)	(825.6)	(2,699.6)	(2,745.5)	(2,595.6)
16.	Net (def.) / suff.	(548.9)	(527.4)	(1,724.5)	(1,753.8)	(1,658.1)
17.	Taxes on (def.) / suff.	310.4	298.2	975.1	991.7	937.5
18.	Revenue requirement	859.6	825.9	2,699.6	2,745.5	2,595.6
	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)	(825.6)	(2,699.6)	(2,745.5)	(2,595.6)

MUNICIPAL PERMIT FEES DEFERRAL ACCOUNT

1. Within the EB-2007-0615 Decision with Reasons, the Board approved the 2008 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 2008 deferral account are capital expenditure related. As a result, the Company is proposing to recover on a one time basis the 2009 annual revenue requirement, determined through a revenue requirement / cost of service type of calculation, associated with the 2008 expenditures. This treatment is similar to that proposed for the 2008 GDARCDA, and that which was approved in relation to the clearance of prior GDARCDA amounts in the EB-2007-0615 and EB-2006-0034 proceedings. The treatment/clearance of the MPFDA in the same manner as the GDAR costs deferral accounts is appropriate as the costs for each are predominantly capital expenditure related.

3. 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 2008-2012 Incentive Regulation approved rates mechanism.

Witness: K. Culbert

4. The Company is proposing to recover $0.1 million as a one time billing adjustment in July 2009 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 2009 annual revenue requirement associated with the 2008 MPFDA is shown in pages 2 through 6 of this schedule.

5. The revenue requirement impact of $0.1 million is only the 2009 financial impact, within the 2008-2012 incentive regulation term, associated with the 2008 municipal permit fees of $0.7 million. Additional municipal permit fees incurred by the Company in the years 2009-2012, of a level similar to those incurred in 2008 will increase the annual cumulative revenue requirement impact each year by approximately $0.1 million. However, if the level of municipal permit fees increases materially in 2009 through 2012, there would be a corresponding increase in the cumulative annual revenue requirement.

6. The Company is requesting the continuation, tracking and clearance of the municipal permit fees deferral account throughout the five year incentive term.

ONTARIO UTILITY CAPITAL STRUCTURE
2008 MPFDA IMPACT

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	(3.5)	(11.2)	(12.1)	(12.9)	(13.7)
8.	Rate base	204.3	691.3	660.1	628.9	597.7
9.	Indicated rate of return	(1.71)%	(1.62)%	(1.83)%	(2.05)%	(2.29)%
10.	(Def.) / suff. in rate of return	(9.29)%	(9.20)%	(9.41)%	(9.63)%	(9.87)%
11.	Net (def.) / suff.	(19.0)	(63.6)	(62.1)	(60.6)	(59.0)
12.	Gross (def.) / suff. (Note: 1)	(29.7)	(99.6)	(97.2)	(94.9)	(92.4)

Note: 1 Includes only 2008 permit fees of $0.7 million. Permit fees in 2009 and beyond would increase the annual revenue requirements.

ONTARIO UTILITY RATE BASE
2008 MPFDA IMPACT

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Property, plant, and equipment					
1.	Cost or redetermined value	207.0	717.6	717.6	717.6	717.6
2.	Accumulated depreciation	(2.7)	(26.3)	(57.5)	(88.7)	(119.9)
3.		204.3	691.3	660.1	628.9	597.7
	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	204.3	691.3	660.1	628.9	597.7

ONTARIO UTILITY INCOME
2008 MPFDA IMPACT

($ 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	31.2	31.2	31.2	31.2
10.	Municipal and other taxes	2.0	1.9	1.8	1.8	1.7
11.	Total costs and expenses	12.7	33.1	33.0	33.0	32.9
12.	Utility income before inc. taxes	(12.7)	(33.1)	(33.0)	(33.0)	(32.9)
	Income taxes					
13.	Excluding interest shield	(5.9)	(10.8)	(10.4)	(10.0)	(9.6)
14.	Tax shield on interest expense	(3.3)	(11.1)	(10.5)	(10.1)	(9.6)
15.	Total income taxes	(9.2)	(21.9)	(20.9)	(20.1)	(19.2)
16.	Ontario utility net income	(3.5)	(11.2)	(12.1)	(12.9)	(13.7)

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2008 MPFDA IMPACT

($ 000's)

Line No.		2008	2009	2010	2011	2012
1.	Utility income before income taxes	(12.7)	(33.1)	(33.0)	(33.0)	(32.9)
	Add Backs					
2.	Depreciation and amortization	10.7	31.2	31.2	31.2	31.2
3.	Large corporation tax	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-
6.	Total added back	10.7	31.2	31.2	31.2	31.2
7.	Sub total - pre-tax income plus add backs	(2.0)	(1.9)	(1.8)	(1.8)	(1.7)
	Deductions					
8.	Capital cost allowance - Federal	14.4	28.1	27.0	25.9	24.9
9.	Capital cost allowance - Provincial	14.4	28.1	27.0	25.9	24.9
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	14.4	28.1	27.0	25.9	24.9
17.	Total Deductions - Provincial	14.4	28.1	27.0	25.9	24.9
18.	Taxable income - Federal	(16.4)	(30.0)	(28.8)	(27.7)	(26.6)
19.	Taxable income - Provincial	(16.4)	(30.0)	(28.8)	(27.7)	(26.6)
20.	Income tax provision - Federal	(3.6)	(6.6)	(6.4)	(6.1)	(5.9)
21.	Income tax provision - Provincial	(2.3)	(4.2)	(4.0)	(3.9)	(3.7)
22.	Income tax provision - combined	(5.9)	(10.8)	(10.4)	(10.0)	(9.6)
23.	Part V1.1 tax	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(5.9)	(10.8)	(10.4)	(10.0)	(9.6)
	Tax shield on interest expense					
26.	Rate base as adjusted	204.3	691.3	660.1	628.9	597.7
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	9.1	30.6	29.2	27.9	26.5
29.	Combined tax rate	36.120%	36.120%	36.120%	36.120%	36.120%
30.	Income tax credit	(3.3)	(11.1)	(10.5)	(10.1)	(9.6)
31.	Total income taxes	(9.2)	(21.9)	(20.9)	(20.1)	(19.2)

ONTARIO UTILITY REVENUE REQUIREMENT
2008 MPFDA IMPACT

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Cost of capital					
1.	Rate base	204.3	691.3	660.1	628.9	597.7
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	15.5	52.4	50.0	47.7	45.3
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	-	-	-	-	-
6.	Depreciation and amortization	10.7	31.2	31.2	31.2	31.2
7.	Municipal and other taxes	2.0	1.9	1.8	1.8	1.7
8.	Cost of service	12.7	33.1	33.0	33.0	32.9
	Misc. & Non-Op. Rev					
9.	Other operating revenue	-	-	-	-	-
10.	Other income	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-
	Income taxes on earnings					
12.	Excluding tax shield	(5.9)	(10.8)	(10.4)	(10.0)	(9.6)
13.	Tax shield provided by interest expense	(3.3)	(11.1)	(10.5)	(10.1)	(9.6)
14.	Income taxes on earnings	(9.2)	(21.9)	(20.9)	(20.1)	(19.2)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	(29.7)	(99.6)	(97.2)	(94.9)	(92.4)
16.	Net (def.) / suff.	(19.0)	(63.6)	(62.1)	(60.6)	(59.0)
17.	Taxes on (def.) / suff.	10.7	36.0	35.1	34.3	33.4
18.	Revenue requirement	29.7	99.6	97.2	94.9	92.4
	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.	(29.7)	(99.6)	(97.2)	(94.9)	(92.4)

TAX RATE AND RULE CHANGE VARIANCE ACCOUNT

1. Within the EB-2007-0615 Decision with Reasons, the Board approved a 2008 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 proposed and embedded in rates. In the event that actual tax rates and rules did not equate to those expected within the tax savings sharing mechanism embedded in the 2008 approved distribution revenue formula, the Company was to calculate the appropriate amounts which should 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 2008 approved distribution revenue, (Final Rate Order, EB-2007-0615, Appendix A, page 1, Column 1, Line 10) was a reduction of $7.44 million to distribution revenue and ratepayer rates which represented a 50% share of anticipated tax reduction amounts of $14.89 million associated with certain expected tax rate and rule changes.

3. The $14.89 million included within it, a forecast amount of $3.66 million of tax reductions relating to anticipated capital cost allowance ("CCA") tax rate changes being passed into law in 2008 (page 2, Column 1, Lines 43 & 21). The anticipated CCA rate changes were not passed into law in 2008 and as a result, the anticipated tax reductions of $3.66 million and a 50% ratepayer share of $1.83 million (page 2, Column 1, Line 22), used in determining the 2008 Board Approved rates did not materialize. A copy of the approved tax rate and rule change forecast reductions is filed at page 2 of this schedule.

4. As a result, the Company has recorded $1.83 million, the ratepayer portion of the variance relating to the change in tax rates different from those embedded in rates, in the Tax Rate and Rule Change Variance account in accordance with the provisions of the account and the 2008 Board Approved agreement. 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 recovered from ratepayers commencing July 1, 2009.

SUMMARY - SHARING OF TAX CHANGE FORECAST AMOUNTS
(FROM EB-2007-0615, FINAL RATE ORDER, APPENDIX A - SCHEDULE 1)

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					

2008 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2008 Average Use True-up Variance Account ("AUTUVA") amount.

2. Table 1 of Appendix A presents the amount of $2.65 million that will be credited to ratepayers primarily due to the unanticipated rate switching from contract customers to general service Rate 6 (or net transfer losses) between the circumstances experienced in our 2008 actual and the assumptions inherent in the 2008 Board Approved Budget as referred to in the 2009 Volume Budget Evidence at EB-2008-0219, Exhibit B, Tab 3, Schedule 2, partially offset by minor decline in residential usage variance. After removing this favourable rate switching impact of 103.9 10^6m^3 as stated at Exhibit B, Tab 3, Schedule 2, page 3, there was a short fall in Rate 6 usage. This is not unexpected given the rapidly deteriorating economic conditions that began to take deep root in the early fall of 2008. Further rate class detail and explanations are provided at Exhibit B, Tab 3, Schedules 2 to 4.

3. The numerical presentation and calculation of Table 1 follows the established and previously reviewed methodology exhibited in response to a VECC Interrogatory (ref. EB-2008-0219, Exhibit I, Tab 7, Schedule 8, part(d)). In accordance with the settlement agreement as filed at EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 15 to 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 Board Approved 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 will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be 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.

4. Consistent with previous rate case proceedings, the audited actual of DSM volumes will not be available until later in the year of 2009. Therefore, 2008 Board Approved Budget DSM volumes still represent the proper and accurate estimate of 2008 actual.

5. Tables 2 and 3 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 2, Schedules 2 to 4.

Witnesses: I. Chan
T. Ladanyi

TABLE 1

2008 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Exhibit Reference:	EB-2007-0615, Exhibit C, Tab 2, Schedule 1, Appendix A, Page 20	Tables 2-3 on pages 2-3		EB-2007-0615, Exhibit C, Tab 2, Schedule 1, Appendix A, Page 1		EB-2007-0615, Exhibit C, Tab 2, Schedule 1, Tables 2-5				Unit Rate of the Revenue Impact, exclusive of gas costs	Refund dollars to rate payers, Debit Operating Revenue, Credit 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	2008 Budget Annual Use (m^3)	2008 Normalized Actual	Normalized Usage Variance (m^3)	Budget Customer Meters	Normalized Volumetric Variance (10^6m^3)	2008 DSM Budget (10^6m^3)	2008 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	2,647	2,636	(11)	1,707,652	(19.3)	(18.0)	(18.0)	0.0	(19.3)	0.0769	(1.48)
6	24,204	24,869	665	155,266	103.3	(14.3)	(14.3)	0.0	103.3	0.0400	4.13
Total					84.0	(32.3)	(32.3)	0.0	84.0		2.65

TABLE 2
GENERAL SERVICE RATE 1
2008 ACTUAL - NORMALIZED VOLUME, CUSTOMERS, AVERAGE USE

Item.		Col. 1 Jan	Col. 2 Feb	Col. 3 Mar	Col. 4 Apr	Col. 5 May	Col. 6 Jun	Col. 7 Jul	Col. 8 Aug	Col. 9 Sep	Col. 10 Oct	Col. 11 Nov	Col. 12 Dec	Col. 13 Total	Exhibit Reference
1.1	Normalized Volumes (10^6m^3)	804.8	755.8	647.6	444.8	253.6	145.8	127.3	115.0	104.9	171.2	353.1	575.2	4,499.1	Exhibit B, Tab 2, Schedule 2, Page 2, Item 1.1, Col. 1 and Col. 4
1.2	Customer Meters	1,696,273	1,700,261	1,703,379	1,705,962	1,707,943	1,707,091	1,706,577	1,707,023	1,709,269	1,713,355	1,719,442	1,725,664	1,708,520	Exhibit B, Tab 2, Schedule 4, Page 1, Item 1.1
1.3	Average Use per Customer (m^3)	474	445	380	261	148	85	75	67	61	100	205	333	2,636	

TABLE 3
GENERAL SERVICE RATE 6
2008 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 ($10^6 m^3$)	655.2	621.6	546.3	405.9	221.0	134.1	84.5	91.7	91.0	153.4	329.7	533.8	3,868.2	Exhibit B, Tab 2, Schedule 2, Page 2, Item 1.2, Col. 1 and Col. 4
1.2	Customer Meters	154,921	155,519	156,037	156,248	156,133	155,589	154,735	154,087	153,713	153,844	155,216	156,440	155,207	Exhibit B, Tab 2, Schedule 4, Page 1, Item 1.2
1.3	Average Use per Customer (m^3)	4,229	3,997	3,501	2,598	1,415	862	546	595	592	997	2,124	3,412	24,869	

Clearance of 2008 Deferral and Variance Account Balances

1. The Company is proposing to clear 2008 deferral and variance account balances to customers in two equal installments during the July and August 2009 billing cycles.

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 2008 consumption volume for the period January 1, 2008 to December 31, 2008 and will be recovered or remitted equally in July and August.

3. The proposed unit rates for clearance of 2008 deferral and variance accounts are derived as follows under Exhibit C, Tab 2, Schedule 2:
   - page 2 determines the balance (principal and interest) to be cleared for each Board-approved 2008 deferral and variance account;
   - page 3 allocates account balances to the rate classes based on cost drivers for each type of account;
   - page 4 summarizes the allocation of account balances 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 2008 consumption volumes for each rate class and each type of service.

4. The table on page 6 shows the bill adjustments in July and August 2009 for typical customers resulting from the clearance of the 2008 deferral and account balances.

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

5. The Company is proposing to clear the 2008 account balances in two equal installments since the total balance and bill adjustments are similar to the amounts which resulted from the clearance of 2007 deferral and variance accounts. In that proceeding the Board directed the Company to clear the balance over two months in equal installments.

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

UNIT RATE AND TYPE OF SERVICE: EQUAL CLEARING IN JULY AND AUGUST 2009

		COL.1	COL. 2	COL. 3
		TOTAL (¢/m³)	July Unit Rate (¢/m³)	Aug Unit Rate (¢/m³)
Bundled Services:				
RATE 1	- SYSTEM SALES	0.3145	0.1573	0.1573
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1093	0.0546	0.0546
	- WESTERN T-SERVICE	0.4871	0.2435	0.2435
RATE 6	- SYSTEM SALES	(0.1128)	(0.0564)	(0.0564)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.1591)	(0.0796)	(0.0796)
	- WESTERN T-SERVICE	0.2187	0.1094	0.1094
RATE 9	- SYSTEM SALES	(0.2022)	(0.1011)	(0.1011)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.3517	0.1758	0.1758
RATE 100	- SYSTEM SALES	1.2050	0.6025	0.6025
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.7824	0.3912	0.3912
	- WESTERN T-SERVICE	1.1603	0.5801	0.5801
RATE 110	- SYSTEM SALES	0.1732	0.0866	0.0866
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.4295	0.2148	0.2148
	- WESTERN T-SERVICE	0.8073	0.4037	0.4037
RATE 115	- SYSTEM SALES	1.2359	0.6180	0.6180
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0045)	(0.0023)	(0.0023)
	- WESTERN T-SERVICE	0.3733	0.1866	0.1866
RATE 135	- SYSTEM SALES	(0.5004)	(0.2502)	(0.2502)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0135	0.0068	0.0068
	- WESTERN T-SERVICE	0.3913	0.1957	0.1957
RATE 145	- SYSTEM SALES	0.4868	0.2434	0.2434
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.1569)	(0.0784)	(0.0784)
	- WESTERN T-SERVICE	0.2209	0.1105	0.1105
RATE 170	- SYSTEM SALES	(0.4063)	(0.2032)	(0.2032)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.3660)	(0.1830)	(0.1830)
	- WESTERN T-SERVICE	0.0119	0.0059	0.0059
RATE 200	- SYSTEM SALES	0.2415	0.1207	0.1207
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0472)	(0.0236)	(0.0236)
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000
Unbundled Services:				
RATE 125	- All	(0.1274)	(0.0637)	(0.0637)
RATE 300	- All	(1.3173)	(0.6587)	(0.6587)

Determination of Balances to be Cleared from the 2008 Deferral and Variance Accounts

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST TO 2009-07-31 ($000)	COL. 3 TOTAL For CLEARING ($000)
	PGVA:			
1.1	COMMODITY	(31,433.30)	(4,750.9)	(36,184.2)
1.2	SEASONAL PEAKING-LOAD BALANCING	3,111.1	81.5	3,192.6
1.3	SEASONAL DISCRETIONARY-LOAD BALANCING	(3,498.0)	(371.4)	(3,869.4)
1.4	TRANSPORTATION TOLLS	34,618.8	1,105.0	35,723.8
1.5	CURTAILMENT REVENUE	(824.8)	(15.3)	(840.1)
1.6	RIDER C 2008 DIRECT ALLOCATION	(17,868.0)	3,051.9	(14,816.1)
1.7	INVENTORY ADJUSTMENT	39,029.6	121.7	39,151.4
1.	**TOTAL PGVA**	23,135.4	(777.4)	22,357.9
2.	**TRANSACTIONAL SERVICES D/A**	(6,476.0)	(105.6)	(6,581.6)
3.	**UNACCOUNTED FOR GAS V/A**	621.2	7.6	628.8
4.	**STORAGE AND TRANSPORTATION D/A**	(1,826.8)	(128.2)	(1,955.0)
5.	**DEFERRED REBATE ACCOUNT**	2,057.3	50.8	2,108.1
6.	**DEMAND SIDE MANAGEMENT 2007**	(616.1)	(127.0)	(743.1)
7.	**LOST REVENUE ADJ MECHANISM 2007**	(301.3)	(3.7)	(305.0)
8.	**SHARED SAVINGS MECHANISM 2007**	8,247.5	101.0	8,348.5
9.	**CLASS ACTION SUIT D/A**	4,709.5	563.7	5,273.2
10.	**ONTARIO HEARING COSTS V/A**	2,252.1	62.4	2,314.5
11.	**GAS DISTRIBUTION ACCESS RULE D/A**	825.6	0.0	825.6
12.	**AVERAGE USE TRUE-UP V/A**	(2,654.1)	(32.5)	(2,686.6)
13.	**MUNICIPAL PERMIT FEES D/A**	99.6	0.0	99.6
14.	**UNBUNDLED RATE CUSTOMER MIGRATION D/A**	485.7	5.9	491.6
15.	**OPEN BILL SERVICE D/A**	309.9	16.9	326.8
16.	**OPEN BILL ACCESS V/A**	476.7	5.8	482.5
17.	**TAX RATE & RULE CHANGE V/A**	1,830.0	22.4	1,852.4
18.	**EARNINGS SHARING MECHANISM**	(5,750.0)	(70.4)	(5,820.4)
19.	**TOTAL**	27,426.2	(408.3)	27,017.8

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:											
1.1	COMMODITY	(36,184.2)		(36,184.2)								
1.2	SEASONAL PEAKING-LOAD BALANCING	3,192.6					3,192.6					
1.3	SEASONAL DISCRETIONARY-LOAD BALANCING	(3,869.4)				(3,869.4)						
1.4	TRANSPORTATION TOLLS	35,723.8	35,723.8									
1.5	CURTAILMENT REVENUE	(840.1)					(420.0)		(420.0)			
1.6	RIDER C 2008 DIRECT ALLOCATION	(14,816.1)							(14,816.1)			
1.7	INVENTORY ADJUSTMENT	39,151.4										39,151.4
1.		22,357.9	35,723.8	(36,184.2)	0.0	(3,869.4)	2,772.6	0.0	(15,236.1)	0.0	0.0	39,151.4
2.	**TRANSACTIONAL SERVICES D/A**	(6,581.6)				(3,289.2)	(3,292.4)					
3.	**UNACCOUNTED FOR GAS V/A**	628.8			628.8							
4.	**STORAGE AND TRANSPORTATION D/A**	(1,955.0)				(977.0)	(978.0)					
5.	**DEFERRED REBATE ACCOUNT**	2,108.1			2,108.1							
6.	**DEMAND SIDE MANAGEMENT 2007**	(743.1)							(743.1)			
7.	**LOST REVENUE ADJ MECHANISM 2007**	(305.0)							(305.0)			
8.	**SHARED SAVINGS MECHANISM 2007**	8,348.5							8,348.5			
9.	**CLASS ACTION SUIT D/A**	5,273.2								5,273.2		
10.	**ONTARIO HEARING COSTS V/A**	2,314.5									2,314.5	
11.	**GAS DISTRIBUTION ACCESS RULE D/A**	825.6								825.6		
12.	**AVERAGE USE TRUE-UP V/A**	(2,686.6)							(2,686.6)			
13.	**MUNICIPAL PERMIT FEES D/A**	99.6									99.6	
14.	**UNBUNDLED RATE CUSTOMER MIGRATION D/A**	491.6							491.6			
15.	**OPEN BILL SERVICE D/A**	326.8								326.8		
16.	**OPEN BILL ACCESS V/A**	482.5								482.5		
17.	**TAX RATE & RULE CHANGE V/A**	1,852.4									1,852.4	
18.	**EARNINGS SHARING MECHANISM**	(5,820.4)						(5,820.4)				
19.	**TOTAL**	27,017.8	35,723.8	(36,184.2)	2,736.9	(8,135.6)	(1,497.8)	(5,820.4)	(10,130.7)	6,908.1	4,266.5	39,151.4
	ALLOCATION											
1.1	RATE 1	17,856.9	17,847.2	(20,806.7)	1,065.2	(3,804.1)	(723.8)	(3,917.4)	(3,905.9)	6,329.0	2,858.6	22,914.8
1.2	RATE 6	1,746.0	14,254.7	(12,652.8)	887.7	(3,282.6)	(590.3)	(1,520.8)	(11,355.5)	575.5	1,150.7	14,279.5
1.3	RATE 9	(2.3)	8.0	(12.2)	0.6	0.0	(0.1)	(7.6)	2.3	0.1	6.4	0.2
1.4	RATE 100	6,233.9	1,551.3	(688.5)	155.0	(430.8)	(76.3)	(158.5)	5,213.3	1.8	104.1	562.5
1.5	RATE 110	3,166.9	707.9	(433.9)	144.5	(125.7)	(34.1)	(64.8)	2,883.5	0.8	44.2	44.5
1.6	RATE 115	147.6	104.2	(58.4)	212.4	(60.2)	(40.9)	(48.9)	(28.3)	0.2	29.8	37.7
1.7	RATE 125	(7.7)	0.0	0.0	0.0	0.0	0.0	(21.6)	0.0	0.0	13.9	0.0
1.8	RATE 135	63.0	100.5	(35.3)	12.8	0.0	(0.1)	(4.3)	(13.0)	0.1	2.3	0.0
1.9	RATE 145	2.4	324.1	(155.9)	51.4	(115.8)	(8.9)	(28.5)	(290.0)	0.5	19.3	206.2
1.10	RATE 170	(2,451.9)	366.9	(494.0)	171.9	(213.8)	(5.2)	(31.4)	(2,440.9)	0.1	23.0	171.5
1.11	RATE 200	264.1	459.0	(846.6)	35.4	(102.6)	(18.0)	(13.3)	(196.2)	0.0	12.0	934.5
1.12	RATE 300	(1.2)	0.0	0.0	0.0	0.0	0.0	(3.2)	0.0	0.0	2.0	0.0
1.		27,017.8	35,723.8	(36,184.2)	2,736.9	(8,135.6)	(1,497.8)	(5,820.4)	(10,130.7)	6,908.1	4,266.5	39,151.4

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	9,389.9	11,280.1	(20,806.7)	673.2	(2,404.1)	(457.4)	(2,475.7)	(5,140.6)	3,999.7	1,806.5	22,914.8
	- 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	0.6			0.1	(0.4)	(0.1)	(0.5)	0.4	0.7	0.3	
	- WBT	8,466.4	6,567.0		391.9	(1,399.6)	(266.3)	(1,441.3)	1,234.3	2,328.5	1,051.7	
RATE 6	- SYSTEM SALES	(2,047.1)	6,859.6	(12,652.8)	395.1	(1,460.9)	(262.7)	(676.8)	(9,296.1)	256.1	512.1	14,279.5
	- 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	(487.8)			66.7	(246.7)	(44.4)	(114.3)	(278.9)	43.2	86.5	
	- WBT	4,280.9	7,395.2		425.9	(1,575.0)	(283.2)	(729.7)	(1,780.5)	276.1	552.1	
RATE 9	- SYSTEM SALES	(3.5)	6.6	(12.2)	0.5	0.0	(0.1)	(6.3)	2.3	0.1	5.3	0.2
	- 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	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	- WBT	1.3	1.4		0.1	0.0	(0.0)	(1.3)	0.0	0.0	1.1	
RATE 100	- SYSTEM SALES	1,190.5	373.3	(688.5)	25.8	(71.8)	(12.7)	(26.4)	1,010.7	0.3	17.4	562.5
	- 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	1,425.6			47.6	(132.4)	(23.5)	(48.7)	1,550.0	0.5	32.0	
	- WBT	3,617.9	1,178.1		81.5	(226.6)	(40.2)	(83.4)	2,652.7	0.9	54.8	
RATE 110	- SYSTEM SALES	107.8	235.2	(433.9)	13.5	(11.8)	(3.2)	(6.1)	265.3	0.1	4.1	44.5
	- 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	2,049.1			103.7	(90.2)	(24.5)	(46.6)	2,074.3	0.6	31.8	
	- WBT	1,009.9	472.6		27.2	(23.7)	(6.4)	(12.2)	543.9	0.2	8.3	
RATE 115	- SYSTEM SALES	103.5	31.7	(58.4)	2.8	(0.8)	(0.5)	(0.6)	91.4	0.0	0.4	37.7
	- 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	(27.6)			203.2	(57.6)	(39.1)	(46.8)	(116.0)	0.2	28.5	
	- WBT	71.7	72.6		6.4	(1.8)	(1.2)	(1.5)	(3.7)	0.0	0.9	
RATE 135	- SYSTEM SALES	(25.4)	19.2	(35.3)	1.1	0.0	(0.0)	(0.4)	(10.2)	0.0	0.2	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	4.2			6.9	0.0	(0.0)	(2.3)	(1.7)	0.1	1.3	
	- WBT	84.3	81.3		4.8	0.0	(0.0)	(1.6)	(1.2)	0.0	0.9	
RATE 145	- SYSTEM SALES	108.9	84.5	(155.9)	4.7	(10.7)	(0.8)	(2.6)	(18.4)	0.0	1.8	206.2
	- 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	(246.6)			33.3	(74.9)	(5.7)	(18.4)	(193.6)	0.3	12.5	
	- WBT	140.1	239.6		13.4	(30.2)	(2.3)	(7.4)	(78.1)	0.1	5.0	
RATE 170	- SYSTEM SALES	(288.0)	267.8	(494.0)	17.7	(22.0)	(0.5)	(3.2)	(227.7)	0.0	2.4	171.5
	- 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	(2,167.0)			147.7	(183.7)	(4.5)	(27.0)	(2,119.4)	0.1	19.8	
	- WBT	3.1	99.1		6.5	(8.1)	(0.2)	(1.2)	(93.9)	0.0	0.9	
RATE 200	- SYSTEM SALES	293.3	459.0	(846.6)	23.4	(68.0)	(11.9)	(8.8)	(196.2)	0.0	8.0	934.5
	- 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	(29.2)			11.9	(34.6)	(6.1)	(4.5)	0.0	0.0	4.1	
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Unbundled Services:												
RATE 125		(7.7)	0.0	0.0	0.0	0.0	0.0	(21.6)	0.0	0.0	13.9	0.0
RATE 300		(1.2)	0.0	0.0	0.0	0.0	0.0	(3.2)	0.0	0.0	2.0	0.0
		27,017.8	35,723.8	(36,184.2)	2,736.9	(8,135.6)	(1,497.8)	(5,820.4)	(10,130.7)	6,908.1	4,266.5	39,151.4

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	0.3145	0.3778	(0.6969)	0.0225	(0.0805)	(0.0153)	(0.0829)	(0.1722)	0.1340	0.0605	0.7675
	- 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	0.1093			0.0225	(0.0805)	(0.0153)	(0.0829)	0.0710	0.1340	0.0605	0.0000
	- WESTERN T-SERVICE	0.4871	0.3778		0.0225	(0.0805)	(0.0153)	(0.0829)	0.0710	0.1340	0.0605	0.0000
RATE 6	- SYSTEM SALES	(0.1128)	0.3778	(0.6969)	0.0218	(0.0805)	(0.0145)	(0.0373)	(0.5120)	0.0141	0.0282	0.7865
	- 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	(0.1591)			0.0218	(0.0805)	(0.0145)	(0.0373)	(0.0910)	0.0141	0.0282	0.0000
	- WESTERN T-SERVICE	0.2187	0.3778		0.0218	(0.0805)	(0.0145)	(0.0373)	(0.0910)	0.0141	0.0282	0.0000
RATE 9	- SYSTEM SALES	(0.2022)	0.3778	(0.6969)	0.0302	0.0000	(0.0054)	(0.3578)	0.1332	0.0045	0.3025	0.0098
	- 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	0.0000			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.3517	0.3778		0.0302	0.0000	(0.0054)	(0.3578)	0.0000	0.0045	0.3025	0.0000
RATE 100	- SYSTEM SALES	1.2050	0.3778	(0.6969)	0.0261	(0.0727)	(0.0129)	(0.0267)	1.0230	0.0003	0.0176	0.5694
	- 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	0.7824			0.0261	(0.0727)	(0.0129)	(0.0267)	0.8507	0.0003	0.0176	0.0000
	- WESTERN T-SERVICE	1.1603	0.3778		0.0261	(0.0727)	(0.0129)	(0.0267)	0.8507	0.0003	0.0176	0.0000
RATE 110	- SYSTEM SALES	0.1732	0.3778	(0.6969)	0.0217	(0.0189)	(0.0051)	(0.0098)	0.4260	0.0001	0.0067	0.0715
	- 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	0.4295			0.0217	(0.0189)	(0.0051)	(0.0098)	0.4348	0.0001	0.0067	0.0000
	- WESTERN T-SERVICE	0.8073	0.3778		0.0217	(0.0189)	(0.0051)	(0.0098)	0.4348	0.0001	0.0067	0.0000
RATE 115	- SYSTEM SALES	1.2359	0.3778	(0.6969)	0.0334	(0.0095)	(0.0064)	(0.0077)	1.0908	0.0000	0.0047	0.4497
	- 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	(0.0045)			0.0334	(0.0095)	(0.0064)	(0.0077)	(0.0191)	0.0000	0.0047	0.0000
	- WESTERN T-SERVICE	0.3733	0.3778		0.0334	(0.0095)	(0.0064)	(0.0077)	(0.0191)	0.0000	0.0047	0.0000
RATE 135	- SYSTEM SALES	(0.5004)	0.3778	(0.6969)	0.0223	0.0000	(0.0001)	(0.0074)	(0.2003)	0.0002	0.0041	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	0.0135			0.0223	0.0000	(0.0001)	(0.0074)	(0.0055)	0.0002	0.0041	0.0000
	- WESTERN T-SERVICE	0.3913	0.3778		0.0223	0.0000	(0.0001)	(0.0074)	(0.0055)	0.0002	0.0041	0.0000
RATE 145	- SYSTEM SALES	0.4868	0.3778	(0.6969)	0.0212	(0.0476)	(0.0036)	(0.0117)	(0.0820)	0.0002	0.0079	0.9216
	- 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	(0.1569)			0.0212	(0.0476)	(0.0036)	(0.0117)	(0.1231)	0.0002	0.0079	0.0000
	- WESTERN T-SERVICE	0.2209	0.3778		0.0212	(0.0476)	(0.0036)	(0.0117)	(0.1231)	0.0002	0.0079	0.0000
RATE 170	- SYSTEM SALES	(0.4063)	0.3778	(0.6969)	0.0249	(0.0310)	(0.0008)	(0.0046)	(0.3212)	0.0000	0.0033	0.2420
	- 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	(0.3660)			0.0249	(0.0310)	(0.0008)	(0.0046)	(0.3579)	0.0000	0.0033	0.0000
	- WESTERN T-SERVICE	0.0119	0.3778		0.0249	(0.0310)	(0.0008)	(0.0046)	(0.3579)	0.0001	0.0033	0.0000
RATE 200	- SYSTEM SALES	0.2415	0.3778	(0.6969)	0.0193	(0.0560)	(0.0098)	(0.0073)	(0.1615)	0.0000	0.0066	0.7693
	- 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	(0.0472)			0.0193	(0.0560)	(0.0098)	(0.0073)	0.0000	0.0000	0.0066	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
Unbundled Services:												
RATE 125	- All	(0.1274)	0.0000	0.0000	0.0000	0.0000	0.0000	(0.3588)	0.0000	0.0000	0.2314	0.0000
RATE 300	- All	(1.3173)	0.0000	0.0000	0.0000	0.0000	0.0000	(3.5487)	0.0000	0.0000	2.2313	0.0000

Note: (1) Unit Rates derived based on 2008 actual volumes

Enbridge Gas Distribution Inc.
2008 Deferral and Variance Account Clearing
Bill Adjustment in July and August 2009 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 m³	Sales cents/m³	Ontario TS cents/m³	Western TS cents/m³	Sales Customers $	Ontario TS Customers $	Western TS Customers $
1.1	RATE 1 RESIDENTIAL							
1.2	Heating & Water Heating	3,064	0.1573	0.0546	0.2435	5	2	7
2.1	RATE 6 COMMERCIAL							
2.2	General Use	43,285	(0.0564)	(0.0796)	0.1094	(24)	(34)	47
	CONTRACT SERVICE							
3.1	RATE 100							
3.2	Industrial - small size	339,188	0.6025	0.3912	0.5801	2,044	1,327	1,968
4.1	RATE 145							
4.2	Commercial - average size	598,568	0.2434	(0.0784)	0.1105	1,457	(469)	661
5.1	RATE 110							
5.2	Industrial - small size, 50% LF	598,568	0.0866	0.2148	0.4037	518	1,285	2,416
5.3	Industrial - avg. size, 75% LF	9,976,120	0.0866	0.2148	0.4037	8,637	21,424	40,270
6.1	RATE 115							
6.2	Industrial - small size, 80% LF	4,471,609	0.6180	(0.0023)	0.1866	27,633	(101)	8,346
7.1	RATE 135							
7.2	Industrial - Seasonal Firm	598,567	(0.2502)	0.0068	0.1957	(1,498)	40	1,171
8.1	RATE 170							
8.2	Industrial - avg. size, 75% LF	9,976,120	(0.2032)	(0.1830)	0.0059	(20,268)	(18,255)	594

Notes:
Calculation of Bill Adjustment:
Sales- Col. 2 x Col. 3
Ontario TS - Col. 2 x Col. 4
Western TS - Col. 2 x Col. 5

ENBRIDGE GAS DISTRIBUTION INC.

Financial and Operating Highlights

(expressed in millions of dollars except ratios and number of securities) Year ended December 31,		**2008**		2007
Financial[1]				
Gas commodity and distribution revenue	**$**	**2,506.2**	$	2,372.3
Transportation of gas for customers		**504.8**		500.2
Other revenue		**93.9**		81.4
Total revenue		**3,104.9**		2,953.9
Gas commodity and distribution costs excluding amortization		**2,000.4**		1,887.8
Net revenue		**1,104.5**		1,066.1
Earnings		**211.4**		189.9
Earnings applicable to common shares	**$**	**206.5**	$	185.0
Earnings coverage ratio[2]		**2.4x**		2.2x
Net tangible asset coverage ratio of long-term debt		**1.7x**		1.7x
Outstanding equity securities[3]				
Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible Preference Shares		**4,000,000**		4,000,000
Common Shares		**140,732,747**		140,732,747
Operating				
Volumetric statistics *(millions of cubic metres)*				
Gas commodity sales		**5,346**		5,094
Transportation of gas for customers		**6,906**		7,358
Total distribution volume		**12,252**		12,452
New customer additions[4]		**41,297**		43,160
Number of active customers[4]		**1,898,229**		1,860,857
Degree day deficiency[5]				
Actual		**3,802**		3,659
Forecast based on normal weather		**3,543**		3,617

1. *The financial information presented has been prepared in accordance with Canadian generally accepted accounting principles and is reported in Canadian dollars.*
2. *This ratio is calculated in accordance with applicable Canadian securities legislation.*
3. *As of February 11, 2009. All dividends paid by the Company are, pursuant to proposed Section 89(14) of the Income Tax Act, designated as eligible dividends. An eligible dividend paid to a Canadian resident is entitled to the enhanced dividend tax credit.*
4. *New customer additions relate to new service lines installed during the year. Active customers relate to the count of natural gas consuming customers at the end of the year.*
5. *Degree day deficiency is a measure of coldness that is indicative of volumetric requirements of natural gas utilized for heating purposes in the Company's franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius equals 18 degree days. The figures given are those accumulated in the Greater Toronto Area.*

ENBRIDGE GAS DISTRIBUTION INC.
Management's Discussion & Analysis
For the year ended December 31, 2008
Dated February 11, 2009

OVERVIEW

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, 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. Amounts are stated in Canadian dollars and are presented in accordance with Canadian generally accepted accounting principles (GAAP), unless otherwise noted.

HIGHLIGHTS

(millions of dollars, except per share amounts and statistical data as noted)	**Year ended December 31, 2008**	Year ended December 31, 2007	Year ended December 31, 2006
Total revenue	**$3,104.9**	$2,953.9	$3,016.1
Earnings applicable to common shares	**206.5**	185.0	122.3
Total assets	**6,285.1**	5,921.1	5,849.3
Total long-term liabilities	**2,556.0**	2,442.3	2,636.4
Return on equity*	**11.4%**	10.9%	7.6%
Dividends declared per common share	**1.12**	0.64	1.04
Dividends declared per preference share	**1.23**	1.23	1.23
Degree day deficiency**	**3,802**	3,659	3,355
Total distribution volume (*million cubic metres*)	**12,252**	12,452	11,550
New customer additions***	**41,297**	43,160	47,622
Number of active customers***	**1,898,229**	1,860,857	1,819,765

* *Return on equity data relates to the consolidated entity.*

** *Degree day deficiency is a measure of coldness that is indicative of volumetric requirements of natural gas utilized for heating purposes in the Company's franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius equals 18 degree days. The figures given are those accumulated in the Greater Toronto Area.*

*** *New customer additions relate to new service lines installed during the year. Active customers relate to the count of natural gas consuming customers at the end of the year.*

Earnings applicable to common shares were $206.5 million for the year ended December 31, 2008, compared with $185.0 million for the year ended December 31, 2007, an increase of $21.5 million.

Significant Variances Affecting Earnings (After-tax Amounts)

(millions of dollars)	**Year ended December 31, 2008**	Year ended December 31, 2007	Year ended December 31, 2006
Colder (warmer) than normal weather	**$23.1**	$14.2	$(36.9)

The effect of weather is measured by degree day deficiency and is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius equals 18 degree days. This 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 trend.

Significant Operating Items Impacting Earnings

Earnings applicable to common shares in 2008 compared with 2007, excluding the effect of weather, were higher primarily due to customer growth, higher other revenue and lower borrowing costs, partially offset by higher amortization. Total revenue for the year ended December 31, 2008 increased by $151.0 million compared with the year ended December 31, 2007. The increase was primarily due to higher natural gas commodity prices and customer growth.

Earnings applicable to common shares in 2007 compared with 2006, excluding the effect of weather, were higher primarily due to customer growth, higher rates from an increased rate base, and a higher deemed equity component of the rate base for regulatory purposes, partially offset by higher amortization and interest expense. Total revenue for the year ended December 31, 2007 decreased by $62.2 million compared with the year ended December 31, 2006. The decrease was primarily due to lower natural gas commodity prices, partially offset by additional revenue generated through increased volumes distributed as a result of colder weather, and customer growth.

Non-GAAP Measure

This Management's Discussion and Analysis (MD&A) contains references to earnings excluding the effect of weather, which represents earnings applicable to common shares adjusted for weather. Management believes that the presentation of this measure provides useful information to investors and shareholders 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 GAAP and is not considered a GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers.

SIGNIFICANT EVENTS

Year Ended December 31, 2008

Rate Regulation – Incentive Regulation (IR)

The Company received a fiscal 2008 final rate order from the OEB on May 15, 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. The final rate order also allowed the Company to refund or collect from customers specified deferral and variance accounts commencing July 1, 2008.

In 2007, the Company filed an IR application for the 2008 to 2012 period. All elements of the Company's IR plan, including the previously unsettled issue related to customer additions during the IR period, were approved by the OEB in the first quarter of 2008.

A copy of the OEB's 2008 rate decision is available at www.oeb.gov.on.ca. Refer to the "Rate Regulation" section later in this document for a more detailed discussion.

Goods and 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. The Company expects that it will recover the overpayment from the CRA during 2009.

Progress on New Customer Information System (CIS) Implementation

The Company continues to be on track for implementing its new CIS, which will replace the legacy system, by July 2009, within the OEB approved budget of $119.0 million. The project is currently in the testing phase.

Natural Gas Electricity Interface Review (NGEIR)

In November 2006, the OEB released its initial decision in the NGEIR proceeding and approved the provision of a number of new services to meet the needs of gas-fired power generators. As well, the OEB concluded that it would cease regulating prices for any new storage services offered by the Company in order to stimulate the development of these services by utilities and other providers. Certain stakeholders in the NGEIR proceeding had filed motions with the OEB seeking review and rehearing of the NGEIR decision. In its final decision issued July 30, 2007, the OEB decided not to vary its original NGEIR decision.

In addition to the OEB process, certain stakeholders made a petition to the Lieutenant Governor in Council of Ontario (LGiC). On April 9, 2008, the LGiC confirmed the decision of the OEB and dismissed the petition.

The Company provides storage services to wholesale storage market participants. In 2008, the Company provided approximately 3 million gigajoules of high deliverability storage capacity to these customers. Management continues to monitor the storage market and expects to develop new storage capacity when it is economically feasible.

<u>Year Ended December 31, 2007</u>

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. The Company expects that it will recover the overpayment from the CRA.

Regulatory Decision

The OEB released its final decision relating to the Company's 2007 Cost of Service rate application on July 5, 2007. The final 2007 rates approved by the OEB resulted in an overall increase in rates of approximately 3.5% over 2006 for the average residential customer.

Significant highlights of the decision were:

- Approval of a proposed 20-year trend method to calculate normal weather for the Company's main franchise area, the Greater Toronto Area.
- Approval of a 1% increase in the equity component of the deemed capital structure to 36% from 35%.
- For operations regulated by the OEB, the Company was directed to cease its natural gas commodity risk management program, which utilized price swaps, calls and collars to manage the volatility in the price of natural gas for its customers.

The decision enabled the Company to continue to fulfill its commitment to distribute natural gas safely and reliably. It also established a reasonable starting point from which the Company will continue to pursue its long-term IR plan.

Key elements of the OEB's 2007 rate decision are set out below in the section titled "Rate Regulation - 2007 and 2006 Rates". A copy of the OEB's decision is available at www.oeb.gov.on.ca.

Equity Injection by Parent Company

On August 3, 2007, the Company's parent company subscribed for and was issued an additional 4,853,023 common shares for proceeds of $87.5 million, which were utilized by the Company to repay commercial paper borrowings. The equity injection helped, in part, to rebalance the Company's capital structure to be in alignment with the new deemed equity ratio of 36%.

Open Bill Access

On February 13, 2007, the OEB approved a settlement agreement between the Company and its stakeholders, which permits the Company to bill for services and collect payments on behalf of other entities in the energy services industry. Subsequently, on April 1, 2007, the Company entered into an agreement with Direct Energy Marketing Limited (Direct Energy), effective retroactively to January 1, 2007, which replaced existing billing agreements among the Company, Direct Energy and CustomerWorks Limited Partnership. Based on the decision of the OEB, variances in net revenues from agreed upon estimates will be refunded to or collected from customers. A shareholder incentive allows the Company to earn commissions subject to OEB guidelines. On a net earnings basis, there is minimal impact to the Company's earnings as a result of the Open Bill Access program. The Company has since entered into similar arrangements with additional entities in the energy services industry.

Customer Care and CIS Agreements

In April 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. The total cost of the contracts is approximately $274.0 million over the five-year term.

The Company is working toward implementing a new CIS by July 2009, at an estimated cost of $119.0 million, in order to meet regulatory requirements and to meet the need for a more robust and technologically up-to-date system.

The OEB has approved a six-year rate recovery arrangement for customer care services and a ten-year recovery of the $119.0 million to be invested in the new CIS.

Permit Fees

In December 2006, the Ontario government enacted a regulation that enabled municipalities to charge permit fees to natural gas utilities for work on municipal roadways. The Company believed that the permit fees should not apply to natural gas utilities in Ontario and made submissions to the government requesting that the regulation be repealed; however, the government allowed the regulation to stand. Commencing in 2008, the OEB allowed the Company to establish a deferral account for recovery from customers permit fees paid to municipalities in excess of prescribed threshold amounts. Disposition of the amounts recorded in the account is subject to OEB approval.

STRATEGY

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

- achieve top decile safety performance;
- enhance operational and financial governance effectiveness;
- deliver shareholder value;
- maintain a healthy and productive work environment; and
- enhance customer and stakeholder relationships.

One of the Company's major strategic initiatives is to continue to enhance the effectiveness of the business operations under IR, including rationalizing capital investment and increasing productivity.

In addition, the Company will seek new growth opportunities, including growth in its core natural gas distribution business, investment in new infrastructure for power generation and fuel switching, development and delivery of energy efficiency programs and billing services for third parties, as well as the development of new natural gas storage space.

To successfully pursue these strategies, the Company must mitigate certain business risks. These risks, and the Company's strategies for managing them, are described in the "Risk Factors and Risk Management" section later in this document.

RESULTS OF OPERATIONS

(millions of dollars, except for operating statistics)	**Year ended December 31, 2008**	Year ended December 31, 2007	Year ended December 31, 2006
Gas distribution margin	**$1,010.6**	$ 984.7	$ 869.7
Other revenue	**93.9**	81.4	58.5
Operation and maintenance expenses	**(373.5)**	(367.0)	(357.3)
Amortization	**(239.0)**	(228.0)	(212.8)
Municipal and other taxes	**(47.3)**	(55.1)	(47.9)
Earnings sharing	**(5.8)**	-	-
Affiliate financing income	**62.7**	62.7	62.7
Interest expense	**(200.8)**	(210.3)	(202.9)
Income taxes	**(89.4)**	(78.5)	(42.8)
Earnings	**$211.4**	$ 189.9	$ 127.2
Earnings applicable to common shares	**$206.5**	$ 185.0	$ 122.3
Selected operating statistics			
Return on equity*	**11.4%**	10.9%	7.6%
Total distribution volume *(million cubic metres)*	**12,252**	12,452	11,550
Degree day deficiency**			
Actual	**3,802**	3,659	3,355
Forecast based on normal weather	**3,543**	3,617	3,745
New customer additions***	**41,297**	43,160	47,622
Number of active customers***	**1,898,229**	1,860,857	1,819,765

* *Return on equity data relates to the consolidated entity.*

** *Degree day deficiency is a measure of coldness that is indicative of volumetric requirements of natural gas utilized for heating purposes in the Company's franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius equals 18 degree days. The figures given are those accumulated in the Greater Toronto Area.*

*** *New customer additions relate to new service lines installed during the year. Active customers relate to the count of natural gas consuming customers at the end of the year.*

Earnings Applicable to Common Shares

Earnings applicable to common shares for the year ended December 31, 2008 increased by $21.5 million compared with the year ended December 31, 2007. The increase was primarily due to colder weather, customer growth, higher other revenue and lower borrowing costs, partially offset by higher amortization.

Earnings applicable to common shares for the year ended December 31, 2008, excluding the effect of weather, were higher by $12.6 million compared with the year ended December 31, 2007. The increase was primarily due to customer growth, higher other revenue and lower borrowing costs, partially offset by higher amortization.

Earnings applicable to common shares for the year ended December 31, 2007 increased by $62.7 million, compared with the year ended December 31, 2006. The increase was primarily due to higher gas distribution margin, partially offset by higher amortization and interest expense.

Earnings applicable to common shares for the year ended December 31, 2007, excluding the effect of weather, were higher by $11.6 million compared with the year ended December 31, 2006. The increase was primarily due to customer growth, higher rates from an increased rate base, and a higher deemed equity component of the rate base for regulatory purposes, partially offset by higher amortization and interest expense.

Gas Distribution Margin

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 (December 31, 2007 – $22.3 million).

Gas distribution margin for the year ended December 31, 2007 increased by $115.0 million, compared with the year ended December 31, 2006. The increase primarily resulted from higher volumes distributed as a result of colder weather, customer growth, and higher rates from an increased rate base.

Weather, measured in degree days, was 3,659 degree days for the year ended December 31, 2007 compared with 3,355 degree days for the year ended December 31, 2006. The degree days reported in 2007 were 42 degree days colder compared with forecast degree days. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2007 would have been lower by approximately $22.3 million (December 31, 2006 – higher by $57.8 million).

Other Revenue

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: (a) higher revenue from the sale of oil, recovered as a byproduct from the Company's natural gas storage operations, as a result of higher oil prices; (b) new revenue relating to the management of fee-for-service energy efficiency initiatives for external parties; and (c) higher shared savings mechanism (SSM) revenue. SSM revenue results from the delivery of energy efficiency programs that result in customers using natural gas in a more efficient manner.

Other revenue for the year ended December 31, 2007 increased by $22.9 million compared with the year ended December 31, 2006. The increase was primarily due to revenues generated from the new Open Bill Access program and due to SSM revenue, which was absent in the prior year.

Operation and Maintenance

Operation and maintenance 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 demand side management (DSM) costs incurred on promotion of energy efficient use of natural gas by customers as per the OEB approved DSM plan, partially offset by lower rate hearing costs and lower customer support related costs.

Operation and maintenance costs for the year ended December 31, 2007 increased by $9.7 million compared with the year ended December 31, 2006. The increase was primarily due to costs incurred on the new Open Bill Access program, higher employee related costs, and higher DSM costs incurred on promotion of energy efficient use of natural gas by customers, partially offset by lower customer support related costs as a result of the new customer care contract.

Amortization

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.

Amortization charge for the year ended December 31, 2007 increased by $15.2 million compared with the year ended December 31, 2006. 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, 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. Refer to the "Contingencies" section later in this document for a more detailed discussion.

Municipal and other taxes for the year ended December 31, 2007 increased by $7.2 million compared with the year ended December 31, 2006. The increase was primarily due to amounts relating to the GST overpayment. Refer to the "Contingencies" section later in this document for a more detailed discussion.

Earnings Sharing

The earnings sharing mechanism results in the return of revenue of $5.8 million to customers. Refer to the "Rate Regulation – 2008 Rates" section later in this document for a detailed discussion of the earnings sharing mechanism that forms part of the IR methodology. For the comparative years, the Company's earnings were not subject to an earnings sharing mechanism.

Interest Expense

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.

Interest expense for the year ended December 31, 2007 increased by $7.4 million compared with the year ended December 31, 2006. The increase was primarily due to higher long-term borrowings relating to higher capital employed and higher short-term borrowing rates.

Income Taxes

(millions of dollars)	**Year ended December 31, 2008**	Year ended December 31, 2007	Year ended December 31, 2006
Earnings before income taxes	**$300.8**	$ 268.4	$ 170.0
Income tax expense	**89.4**	78.5	42.8
Effective tax rate (%)	**29.7%**	29.2%	25.2%

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 prior year, partially offset by a reduction in the statutory income tax rate for 2008.

The effective tax rate for the year ended December 31, 2007 was higher compared with the year ended December 31, 2006. The increase was primarily due to a lower reduction of the effective tax rate relating to deductions utilized in the calculation of taxable income given higher earnings before income taxes and due to income tax rate differences between current and future taxes on amounts to be refunded to customers.

RATE REGULATION

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

Rate Regulation - Incentive Regulation

Improving the regulatory environment is a key strategic thrust to provide greater operational and organizational flexibility. In 2008, the Company moved to an IR methodology, with 2007 as the base year for a five-year plan. Under IR, the distribution revenue requirement is based on a formulaic approach, using the prior year as the starting point.

The objectives of the IR plan are as follows:

- reduce regulatory costs with less time required;
- provide incentive for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates.

2009 Rate Adjustment Application

On September 26, 2008, the Company filed an application with the OEB to adjust rates for 2009 pursuant to the 2008 approved IR formula and to seek approval for specific changes to the Rate Handbook. Subject to OEB approval, the rate adjustment would be effective January 1, 2009.

A settlement agreement containing all applied for aspects of the formulaic component of the IR rate setting process was approved by the OEB on December 18, 2008.

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, and will be adjusted by 55% in 2009 - 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.

[*] 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.

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 result from new regulatory orders and/or changes in statutory obligations.

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 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 NROE.

The Company received a fiscal 2008 final rate order from the OEB on May 15, 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.

2007 and 2006 Rates

The Company's rates for 2007 and 2006 were set under a Cost of Service methodology that allowed the revenues to be set to recover the Company's forecast costs. Forecast costs included natural gas commodity and transportation, operation and maintenance, amortization, municipal taxes, income taxes and the debt and equity costs of financing the rate base. The rate base is the Company's investment in all assets used in natural gas distribution, storage and transmission and an allowance for working capital. A requested increase in rates to recover forecast costs reflects a revenue deficiency, while a reduction in rates reflects a revenue sufficiency. Under Cost of Service, it was the responsibility of the Company to demonstrate to the OEB the prudence of the costs it incurred or the activities it undertook. For those customers who purchase their natural gas supply from the Company, the cost of the natural gas commodity is passed on to such customers as a flow-through; the Company does not earn a margin on commodity sales.

Key elements of the OEB's 2007 rate decision, including issues previously settled and approved by the OEB, and a previous decision are summarized below:

Regulatory year ended	Approved December 31, 2007	Approved December 31, 2006
Rate base (millions)	$3,745.7	$3,633.6
Rate of return on rate base	7.58%	7.74%
Deemed common equity for regulatory purposes	36.00%	35.00%
Rate of return on common equity	8.39%	8.74%

For 2007, the Company was granted a 1% increase in the equity component of its deemed capital structure. The 36% deemed equity level is a better reflection of changes in the Company's current business and financial risk relative to the earlier deemed equity level of 35%.

2007 Approved Regulatory Capital Structure

	Capital Structure*			Rate of Return
	Millions	Component	Rate**	on Rate Base
	$	%	%	%
Medium and long-term debt	2,234.4	59.65	7.31	4.36
Short-term debt	62.9	1.68	4.12	0.07
Preference shares	99.9	2.67	5.00	0.13
Common shareholders' equity	1,348.5	36.00	8.39	3.02
Total capitalization	3,745.7	100.00		7.58

* *The capital structure reflects the average capital to be employed during the year in the regulated Ontario utility operations.*

** *The rate on debt and preference shares reflects the weighted average rate, while the rate on common equity represents the requested cost of capital for the shareholder.*

Impact of Rate Regulation

The Company follows 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 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, *Disclosures by Entities Subject to Rate Regulation (AcG-19),* 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 entity's consolidated financial statements. Detailed disclosure on rate regulation is included in Note 3 to the 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 price of natural gas approved by the Regulators and the actual cost of natural gas purchased is the most significant such example. The refund or recovery of the difference 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 cost of natural gas and the related revenue, rather than the actual cost of natural gas 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 Company does not record future income taxes on its regulated operations as the taxes payable method is prescribed by the Regulators for rate-making purposes and it is probable that all such future taxes will be recovered through rates when they become payable. The deferral of differences between amounts included in regulated rates and the Company's actual experience is based on the expectation that the Regulators will approve the refund to or recovery from customers of the deferred balance, normally in the following year. Future income taxes recorded primarily relate to such deferrals and to the non-regulated operations of the Company. The Accounting Standards Board announced during 2007 that future income taxes must be recorded for rate regulated entities commencing in 2009. Refer to the "Change in Accounting Policies" section later in this document for a more detailed discussion.

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.

Regulatory and Associated Developments

Gas Distribution Access Rule (GDAR)
The OEB, pursuant to the Energy Competition Act, undertook the development of a GDAR. The stated purpose of the GDAR is to establish rules governing natural gas distributors' conduct in relation to natural gas marketers and to establish conditions of access to distribution services. Despite the Company's arguments with respect to the GDAR's position on customer mobility and billing options, the GDAR mandates that distributors, including the Company, provide natural gas marketers with the option to consolidate the natural gas distribution charges to consumers on the marketers' own bill (referred to as Vendor Consolidated Billing), forcing the distributor to appoint the marketer as its billing agent. The Company will have to undertake extensive system changes and negotiate new contractual arrangements in order to effect the GDAR directives. The Company's court challenges to the GDAR were unsuccessful.

Initial implementation adjustments were required to be implemented by June 1, 2007. These initial adjustments were implemented by the Company on schedule. The more complex adjustments to the billing systems were to be implemented by January 1, 2008. On August 18, 2006, the Company requested relief from the January 1, 2008 implementation requirement in view of the Company's development of a new CIS, which is expected to be in service by July 2009. On December 11, 2007, the OEB adopted its Notice of Proposal of July 16, 2007 in which the OEB proposed to amend the GDAR to eliminate the need for natural gas distributors to accommodate bill-ready distributor-consolidated billing (DCB) as of January 1, 2008. The OEB indicated that a single, industry-wide set of electronic business transaction (EBT) standards should be developed in relation to bill-ready DCB as and when a request is made for that option by a natural gas marketer. Implementation timelines will be addressed by natural gas marketers, natural gas utilities and the OEB, if necessary, at that time in order to ensure that the EBT standards are developed, implemented and tested within a reasonable time frame.

Should natural gas marketers elect to consolidate distribution charges on their own bill (Vendor Consolidated Billing), the Company may lose some of the revenue it earns by providing billing services; however, this is not expected to have a significant impact on earnings.

LIQUIDITY AND CAPITAL RESOURCES

The Company's primary sources of liquidity and capital resources are funds generated from operations, short-term financing through the issuance of short-term commercial paper or drawing on bank credit facilities, and longer term debt, which includes debentures and medium-term notes (MTNs). These sources are used to satisfy the Company's capital resource requirements, which include the financing of receivables and gas inventory, capital expenditures, servicing and repayment of debt, other investing activities and dividends.

The Company currently has a $1.0 billion commercial paper program limit that is backstopped by committed lines of credit of $1.0 billion. The 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 Company's MTN program provides for the continuous offering of unsecured MTNs under a shelf prospectus. Proceeds from MTN borrowings are used for general corporate and working capital requirements, to finance additions to property, plant and equipment or for retirement of debt.

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, 2008, this ratio was 2.78 (December 31, 2007 – 2.48). 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.

At December 31, 2008, the Company's investment in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc. was $825.0 million at a weighted average dividend yield of 7.60%; the borrowing from IPL System Inc. was $375.0 million ($200.0 million at 6.85% and $175.0 million at 7.50%).

Disruption of Functioning of Capital Markets

Multiple events during 2008 involving numerous financial institutions have restricted liquidity in the capital markets. Despite efforts by government agencies to provide liquidity to the financial sector, capital markets currently remain constrained. Given the Company's current and future growth and related funding requirements, these events and market conditions pose potential challenges. The Company's strong, predictable, internally generated cash flows and access to adequate committed credit facilities from diversified sources assist in mitigating these challenges. Maintaining the Company's investment grade credit rating may also support continued access to capital markets and debt refinancing at reasonable terms, if required.

The fair value of the Company's registered pension plan holdings declined significantly during the year. Despite the decline, the pension plan continued to remain in a surplus position at the measurement date of September 30, 2008 and at the fiscal year-end of December 31, 2008. As a result, the Company will not be required to make contributions to the plan.

Financing Arrangements

During the year ended December 31, 2008, the Company had the following financing arrangements in place:

- A $750.0 million shelf prospectus filed in February 2006 expired during the first quarter. A new $600.0 million shelf prospectus was filed in May 2008 and will be effective for a 25-month period. In November 2008, the Company issued $200.0 million of new MTNs at an interest rate of 5.57%.
- Committed lines of credit from banks in the amount of $1.0 billion at December 31, 2008 (December 31, 2007 – $1.0 billion). At December 31, 2008, $872.0 million, net of an unamortized discount of $2.5 million, was drawn or used to backstop commercial paper (December 31, 2007 – $545.6 million, net of an unamortized discount of $1.4 million). The Company has uncommitted lines of credit in the amount of $6.1 million (December 31, 2007 - $4.9 million), against which the Company borrowed $2.5 million as at December 31, 2008 (December 31, 2007 - $0.6 million).

On July 9, 2007, the Company redeemed all $100.0 million of its outstanding 10.60% debentures maturing July 6, 2012 for a price of 101.67% of the principal amount plus accrued interest. The repayment was funded with short-term borrowings. In conformity with regulatory requirements, net savings on borrowing costs realized from this transaction in 2007 were refunded to customers.

The Company believes that it will be able to meet its short-term and long-term liquidity needs. In order to strengthen the Company's financial position and its ability to access the long-term debt market to finance rate base growth, as part of its 2007 rate application, the Company requested an increase in the equity component of its deemed capital structure from 35% to 38% and received approval for a 1% increase from 35% to 36%.

On August 3, 2007, the Company's parent company subscribed for and was issued an additional 4,853,023 common shares for proceeds of $87.5 million, which were utilized by the Company to repay commercial paper borrowings. The equity injection helped, in part, to rebalance the Company's capital structure to be in alignment with the new deemed equity ratio of 36%.

Due to the seasonal nature of the Company's business and continuing growth in rate base, cash receipts do not typically match the Company's requirements for capital expenditures, dividends, long-term debt retirement and inventory replenishment. Any 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.

Long-term funding is supported by the 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.

CASH FLOWS

(millions of dollars)	**Year ended December 31, 2008**	Year ended December 31, 2007	Year ended December 31, 2006
Bank overdraft, beginning of the year	**$ (4.8)**	$ (14.6)	$ (15.5)
Cash flow from (used in):			
Operating activities	**367.7**	528.7	464.9
Investing activities	**(405.8)**	(368.6)	(420.0)
Financing activities	**98.3**	(150.3)	(44.0)
Increase in cash	**60.2**	9.8	0.9
Cash and cash equivalents (bank overdraft), end of the year	**$ 55.4**	$ (4.8)	$ (14.6)

Operating Activities
Operating activities, after changes in non-cash working capital, provided cash of $367.7 million for the year ended December 31, 2008, compared with $528.7 million for the year ended December 31, 2007. The decrease was primarily due to a net outflow in non-cash working capital as opposed to a net inflow in the prior year. This was partially offset by higher earnings in the current year, primarily due to colder weather.

The net outflow from changes in working capital, compared to the net inflow in the prior year, is primarily the result of the Company investing more in working capital during the current year due to fluctuations in the market price of natural gas.

Operating activities, after changes in non-cash working capital, provided cash of $528.7 million for the year ended December 31, 2007, compared with $464.9 million for the year ended December 31, 2006. The increase resulted from higher earnings in the current year primarily due to colder weather, partially offset by a lower net inflow from changes in non-cash working capital.

The lower net inflow from changes in non-cash working capital primarily resulted from an increase in accounts receivable, compared with a decrease in the prior year, as a result of relatively colder weather during the concluding billing periods in the year. This was partially offset by an increase in payables compared to a decrease in the prior year, primarily relating to higher purchases of natural gas than the prior year and a greater decrease in gas inventories primarily relating to a reduction in the price of natural gas and as a result of lower volumes in storage due to colder weather.

Cash flows from operating activities are subject to significant fluctuations due to potentially erratic weather patterns impacting consumption and also from potentially volatile natural gas prices. The Company has adequate financing arrangements in place to meet the increased liquidity needs arising from such fluctuations. These arrangements are described in the section "Liquidity and Capital Resources".

Investing Activities
Cash used for investing activities was $405.8 million for the year ended December 31, 2008 compared with $368.6 million for the year ended December 31, 2007. The increase in cash used was primarily due to higher net additions to property, plant and equipment. In addition, there was a significant increase in

capital accruals in the prior year, compared to a decrease in the current year, due to the timing of capital expenditures.

Following are the significant components of capital expenditures:

(millions of dollars)	**Year ended December 31, 2008**	Year ended December 31, 2007	Year ended December 31, 2006
System expansion	**$120.3**	$ 135.6	$ 134.9
System improvements and upgrades	**154.3**	153.6	176.7
Computers and communication equipment	**64.6**	50.0	30.2
Unregulated storage	**28.2**	8.3	-
Other	**43.8**	37.7	51.1
Total capital expenditures	**$411.2**	$ 385.2	$ 392.9

Higher capital expenditures during the year primarily resulted from increased spending on unregulated storage projects and computers and communication equipment.

Cash used for investing activities was $368.6 million for the year ended December 31, 2007 compared with $420.0 million for the year ended December 31, 2006. The decrease in cash used was primarily due to lower net additions to property, plant and equipment and due to the prior year impact of the class action lawsuit settlement recoverable. In addition, there was a significantly larger increase in capital accruals in the current year, compared to the prior year, due to the timing of capital expenditures.

Financing Activities
Cash provided by financing activities was $98.3 million for the year ended December 31, 2008, compared with cash used of $150.3 million for the year ended December 31, 2007. The transition from cash used to cash provided was primarily the result of an increase in short-term borrowings due to the impact of higher commodity prices on accounts receivable and gas inventories. This was partially offset by an increase in dividends paid and net repayment of long-term borrowings.

Cash used for financing activities was $150.3 million for the year ended December 31, 2007, compared with cash used of $44.0 million for the year ended December 31, 2006. The increase in cash used was primarily due to lower proceeds realized from the issue of new long-term debt, partially offset by a reduction in dividends paid, lower net repayments of short-term borrowings, and the issuance of common shares to help rebalance the Company's capital structure.

Expected Capital Expenditures
The Company's existing distribution network consists of more than 34,000 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required. Annual capital expenditures in recent years have averaged approximately $378.0 million per year, but are expected to decrease in 2009 due to the completion of the new CIS, which will be fully operational by July 2009, the completion of unregulated storage projects in early 2009, and as a result of reduced requirements for fleet, tools and equipment.

Contractual Commitments

Following is a summary of the significant long-term contractual obligations the Company is party to:

(millions of dollars)

Nature of commitment	**Less than 1 year**	**1-3 years**	**3-5 years**	**After 5 years**	**Total**
Long-term debt maturities	100.0	300.0	-	1,888.6	**2,288.6**
Long-term debt interest obligations	148.9	267.0	224.7	1,311.8	**1,952.4**
Loans from affiliate company*	-	-	-	375.0	**375.0**
Consulting contract**	12.0	16.2	13.6	3.4	**45.2**
Customer care service contracts	55.9	113.4	14.6	-	**183.9**
CIS contracts	25.0	14.2	1.2	-	**40.4**
Gas transportation	312.7	362.2	282.4	150.8	**1,108.1**
Post-employment benefits	31.6	67.5	73.6	213.3	**386.0**
Total	**686.1**	**1,140.5**	**610.1**	**3,942.9**	**6,379.6**

* *See Note 15 to the Company's consolidated financial statements for details of these loans, excluding annual interest payments of $26.8 million.*

** *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, 2008, $93.7 million (December 31, 2007 - $82.2 million) of such costs were included in gas mains, which are amortized over the average service life of 25 years.*

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, 2007.

Consolidated statements of financial position category	**Increase (Decrease)** *(millions of dollars)*	**Explanation**
Cash and cash equivalents	100.0	Due to a short-term investment held over year-end as a result of the timing of cash requirements.
Accounts receivable	62.5	Primarily due to higher commodity prices and customer growth.
Gas inventories	62.7	Primarily due to higher commodity prices, partially offset by lower commodity volumes in storage as a result of colder weather.
Property, plant and equipment	174.4	Primarily due to capital additions relating to customer growth and system improvements, partially offset by amortization.
Loans and notes payable	330.6	Primarily as a result of higher working capital requirements due to higher commodity prices, partially offset by net repayments of long-term debt.
Long-term debt (including current portion)	(66.5)	Primarily due to the $270.0 million repayment of medium-term notes, partially offset by the issuance of $200.0 million in medium-term notes, net of issuance costs.

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.

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 the end use consumer.

At December 31, 2008, $175.9 million worth of natural gas was held on behalf of transportation service customers (December 31, 2007 - $187.0 million). These transactions have no impact on the Company's consolidated earnings, cash flows or financial position.

Financial Instruments

Pursuant to the OEB's directive of July 2007, the Company no longer utilizes derivative and non-derivative instruments to manage changes in commodity prices. However, the OEB decision does not impact the natural gas commodity risk program at St. Lawrence.

Hedge settlements resulting from the use of natural gas financial derivatives at St. Lawrence form part of the total cost of natural gas incurred by St. Lawrence and are recoverable from, or refundable to, customers, once approved by the NYSPSC; thus, they do not impact St. Lawrence's earnings.

Please refer to Notes 9 and 10 of the consolidated financial statements for additional information.

At December 31, 2008, the fair value the Company would be required to pay on termination of such derivative contracts was $0.6 million (December 31, 2007 – $1.0 million) related to St. Lawrence.

The Company also utilizes interest rate swaps to manage its exposure to fluctuations in interest rates. These financial instruments used for hedging purposes are employed only in connection with an underlying liability or anticipated transaction and are only transacted with counterparties with investment grade credit ratings.

CONTINGENCIES

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 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 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 and 2008 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

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

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

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. The Company expects that it will recover the overpayment from the CRA during 2009.

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 $22.0 million settlement, as a result of the class action lawsuit regarding late payment penalties. On February 4, 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.

In May 2008, the representative plaintiff in the class action made a petition to the 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.

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 on April 24, 2003. On October 25, 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice. The appeal is scheduled to be heard by the Court during November 2009. The maximum possible fine upon conviction would not result in any 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.

Harper Gardens Incident
On February 14, 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A natural gas contractor working in the home at the time of the explosion was seriously injured. Several public authorities commenced investigations in connection with the incident. The Company has also been named as a defendant in civil actions related to the incident, but does not expect these actions to result in any material financial impact.

RISK FACTORS AND RISK MANAGEMENT

The Company's business activities are subject to financing, regulatory, forecast, market price, operational and legal risks. The Company has formal risk management policies, processes and systems designed to mitigate these risks.

The current economic conditions have not caused the Company to change any risk management practices. The existing philosophy and framework was designed to be applied in all market conditions. The Company continues to closely measure and monitor risks using best practice methodologies and manage exposures within the risk constraints of approved policies.

Financing Risk
The Company's financing risk relates to the interest rate volatility and the ability to raise debt to finance capital expenditures and refinance existing debt maturities. This risk arises from market factors given that Canadian debt market conditions can change dramatically, thereby affecting capital availability.

To address this risk, the Company ensures that it can more quickly access the Canadian public capital markets by typically maintaining a current shelf prospectus with the securities regulator. In addition, the Company has access to sufficient liquidity through committed credit facilities with banking institutions, which would enable the Company to fund anticipated requirements.

Refer also to the "Liquidity and Capital Resources" section earlier in this document.

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

The Settlement allows certain Y and Z factors (which represent specific categories of expense, added at Cost of Service base amounts, 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 end the IR plan and return to Cost of Service 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 the natural gas commodity 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 commodity cost differential.

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

Forecast Risks
Volumes
Since customers are billed 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.

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 follows:

Factor	Incremental change	Approximate incremental impact
Weather	17 degree days	1 billion cubic feet
Volume	1 billion cubic feet	$1.4 million (after-tax)

However, in recent years, weather has impacted earnings by a larger magnitude than the above sensitivities would suggest. This results from the unusual 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.

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 to partially mitigate the impact of higher natural gas commodity prices further contribute to the decline in annual average consumption.

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 return on equity 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 use of appropriate forecasting models and through 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 is still at distribution volume risk for contract customers.

Market Price Risk

The Company's earnings are subject to movements in interest rates, foreign exchange rates and other price risks. The Company is also exposed to credit risk and liquidity risk. Portions of these risks are borne by customers through certain regulatory mechanisms. 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 is exposed to interest rate fluctuations in the form of cash flow interest rate risk and fair value interest rate risk. Cash flows are impacted by changes in market interest rates on impending variable rate debt (primarily commercial paper) and fixed rate debt issuances. The fair value of fixed rate long-term debt is also impacted by changes in market interest rates. Floating to fixed interest rate swaps, collars and forward rate agreements may be used to mitigate cash flow volatility due to the effect of future interest rate movements on existing debt instruments. The Company is also exposed to cash flow interest rate risk on fluctuations in market interest rates ahead of anticipated fixed rate debt issuances. The Company may enter into interest rate derivatives such as bond forwards and treasury locks to fix a portion of the interest payments of these future debt issuances. The Company does not typically manage the fair value risk of its debt instruments.

Based on variable rate debt outstanding through the year ended December 31, 2008, a 1.0% change in interest rates would have had a $nil impact on earnings.

Information about the debt portfolio is included in Note 6 to the consolidated financial statements.

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 entirely borne by the customers.

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 US dollars and as a result there is exposure to fluctuations of the US 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.

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. In addition, security deposits are collected from certain high risk customers and can be applied against these accounts in the event of default.

Liquidity Risk
Refer to the "Liquidity and Capital Resources" section earlier in this document for a detailed discussion.

Fair Values of Financial Instruments
Information about the financial instruments outstanding at year-end is included in Note 10 to the consolidated financial statements.

Operational 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 pipelines 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. Further, the Company disseminates information relating to industry best practices and encourages contractors to adopt those practices to minimize the occurrence of incidents. 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 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 or releases of natural gas 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. Compliance with future environmental laws and regulations, which are likely to become more stringent over time, may impose additional capital costs and financial expenditures, which could adversely affect operating results and profitability.

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 shareholders, 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. Current environmental protection requirements applicable to the Company are not expected to affect the Company's competitive position, capital expenditure program or level of earnings.

Approximately 36% of the Company's workforce is represented either by the Communications, Energy and Paperworkers Union, Local 975 (CEPU) or the International Brotherhood of Electrical Workers (IBEW), Local 97. The current collective agreement for CEPU expired in December 2008 and a new collective agreement is being negotiated. The terms of the prior agreement remain in force until the new agreement is ratified by the union members. The current collective agreement for IBEW expires February 2009.

Legal Risks

The Company, through the normal course of its business, is occasionally named as a defendant in various claims and legal proceedings. The nature of these claims is usually related to personal injury, environmental issues and billings. Exposure to these claims is mitigated through levels of insurance coverage considered appropriate by management. Refer to the "Contingencies" section earlier in this document.

CRITICAL ACCOUNTING ESTIMATES

The following critical accounting estimates have been used in the generation of the consolidated financial statements:

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.

Amortization

Amortization of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2008 of $3,660.7 million (December 31, 2007 - $3,486.3 million), or 58.2% of total assets (December 31, 2007 – 58.9%), is provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. Amortization expense includes a provision for future removal and site restoration costs at rates approved by the Regulators. Actual removal and site restoration costs incurred are charged to accumulated amortization in accordance with regulatory treatment.

These amortization rates are reviewed through periodic amortization 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 amortization 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 amortization study. The last such study was completed in 2006.

Regulatory Assets and Liabilities

The Regulators exercise statutory authority over matters such as construction, rates and underlying accounting practices and rate-making 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 what would otherwise be expected under 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, 2008, the Company's regulatory assets totaled $54.9 million (December 31, 2007 - $76.1 million) and regulatory liabilities totaled $97.9 million (December 31, 2007 - $156.5 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 from those recorded. Refer to the "Rate Regulation – Impact of Rate Regulation" section earlier in this document for a more detailed discussion.

Bad Debt Provision
The provision for bad debt is evaluated and established based on historical patterns of collection. Adequacy of the provision is reviewed on a periodic basis.

Post-employment Benefits
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 recovery of such costs in rates.

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 also expensed as paid, consistent with the recovery of such costs in rates.

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.

If the Company used the accrual method of accounting for post-employment benefits, actual results that differ from assumptions, which are amortized over future periods, could materially affect the expense recognized and the recorded obligation in future periods.

The decline in the capital markets has reduced the current market value of the plan assets; however, an increase in the discount rate resulted in a lower expected benefit obligation, substantially offsetting the decline in the plan assets. The Company's plan remains in a surplus position thus precluding any contribution requirements. Please refer to Note 13 to the consolidated financial statements for additional disclosures.

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 disclosed in Note 16 of the consolidated financial statements.

REGULATORY GOVERNANCE

Certain aspects of the Company's business, such as affiliate financing and investments, which are not regulated, are subject to governance by the OEB by means of Undertakings and an Affiliate Relationships Code for Gas Utilities published by the OEB.

Undertakings
Enbridge Inc. and the Company have entered into undertakings with the Government of Ontario committing Enbridge Inc. and the Company to certain obligations relating to the maintenance of common equity, as well as a restriction 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 applied to the OEB and has approval to carry on the Natural Gas Vehicle Program, Agent Billing and Collection Program, and the Gas Sales and Oil Production activity.

In August 2006, the Government of Ontario approved changes to the undertakings in order to assist the government to achieve its energy conservation goals. The changes will allow the Company, without prior approval of the OEB, 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 will be allowed to engage in activities and provide services related to the local distribution of steam, hot and cold water in a Markham District Energy Inc. initiative, and the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

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 level agreements must be prepared and transfer pricing guidelines.

TRANSACTIONS WITH RELATED PARTIES

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, 2008 were $25.9 million (December 31, 2007 - $21.9 million) with an outstanding payable balance of $1.9 million at December 31, 2008 (December 31, 2007 – receivable of $7.6 million).

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, 2008, the investment of $825.0 million resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2008, dividends received amounted to $62.7 million (December 31, 2007 - $62.7 million) with an outstanding receivable balance of $5.3 million at December 31, 2008 (December 31, 2007 - $5.0 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 preference shares of the Company. For the year ended December 31, 2008, interest paid amounted to $26.8 million (December 31, 2007 - $26.8 million) with an outstanding payable balance of $2.3 million at December 31, 2008 (December 31, 2007 - $2.1 million).

CustomerWorks Limited Partnership, a related entity jointly controlled by an affiliated company under common control, provided customer care services. The Company was charged market prices for these services. Effective April 1, 2007, the Company transferred, pursuant to an OEB approved agreement, its customer care services from CustomerWorks Limited Partnership to a third party service provider. Total charges for the year ended December 31, 2008 were $nil (December 31, 2007 - $26.3 million) with an outstanding receivable of $nil at December 31, 2008 (December 31, 2007 – $0.1 million).

Enbridge Operational Services Inc., an affiliated company under common control, managed the Company's gas control functions. The activity included monitoring the distribution system and the pressures and flows of natural gas through the Company's distribution system. Effective January 1, 2008, the Company manages these services internally. Total charges for the year ended December 31, 2008 were $nil (December 31, 2007 - $2.5 million) with an outstanding payable of $nil at December 31, 2008 (December 31, 2007 - $0.1 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, 2008 were $23.6 million (December 31, 2007 - $21.3 million) with an outstanding payable of $nil at December 31, 2008 (December 31, 2007 – $nil).

Alliance Pipeline LP (US), 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, 2008 were $17.1 million (December 31, 2007 - $15.1 million) with an outstanding payable of $nil at December 31, 2008 (December 31, 2007 – $nil).

Vector Pipeline LP, 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, 2008 were $27.0 million (December 31, 2007 - $25.0 million) with an outstanding payable of $nil at December 31, 2008 (December 31, 2007 - $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, 2008 were $47.2 million (December 31, 2007 - $48.6 million) with an outstanding receivable of $9.3 million at December 31, 2008 (December 31, 2007 - $8.1 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, 2008 were $3.4 million (December 31, 2007 - $2.7 million) with an outstanding payable of $0.2 million at December 31, 2008 (December 31, 2007 - $0.6 million).

CHANGE IN ACCOUNTING POLICIES

Capital Disclosures and Financial Instruments – Disclosure and Presentation

Effective January 1, 2008, the Company adopted The Canadian Institute of Chartered Accountants (CICA) Handbook Section 1535, Capital Disclosures, Section 3862, Financial Instruments - Disclosure and Section 3863, Financial Instruments – Presentation. While the new standards did not change the Company's accounting policies, they resulted in additional disclosures.

Under Section 1535, the Company disclosed its objectives, policies and procedures for managing capital, any summary quantitative data about what the Company manages as capital, whether the Company has complied with any externally imposed capital requirements and, if the Company has not complied, any consequences of non-compliance with these capital requirements. Please refer to Notes 2 and 11 of the Company's consolidated financial statements for additional information.

Sections 3862 and 3863 replaced Section 3861, Financial Instruments – Disclosure and Presentation. Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements have expanded disclosure about the significance of financial instruments for the Company's financial position and performance, the nature and extent of risks arising from financial instruments to which the entity is exposed during the year and at the consolidated statement of financial position date, and how the entity manages those risks. Please refer to Notes 2, 9 and 10 of the Company's consolidated financial statements for additional information.

The adoption of these new accounting standards had no impact on the recognition or measurement of the Company's assets, liabilities, revenues or expenses.

Inventories

Effective January 1, 2008, the Company adopted CICA Handbook Section 3031, Inventories, which aligns accounting for inventories under GAAP with International Financial Reporting Standards and provides additional guidance on the measurement and disclosure requirements for inventories. The adoption of this accounting standard did not materially impact the Company's consolidated financial statements.

Financial Instruments, Hedging Relationships and Other Comprehensive Income

Effective January 1, 2007, the Company adopted new accounting standards for Financial Instruments - Recognition and Measurement, Financial Instruments - Disclosure and Presentation, Comprehensive Income and Hedges. These policies were adopted prospectively and, accordingly, the prior years were not restated. However, the Company's foreign currency translation losses on St. Lawrence are now included in accumulated other comprehensive loss. Furthermore, the unamortized deferred financing fees of $25.2 million as at January 1, 2007 were reclassified from deferred charges and other assets to long-term debt.

The adoption of the new standards did not impact the Company's earnings or cash flows.

The new standards required that all financial assets and liabilities be recorded at fair value, except loans and receivables and certain instruments held to maturity or those that do not have a quoted market price in an active market. Loans and receivables and certain instruments that are held to maturity are measured at amortized cost. For instruments measured at fair value, unrealized changes in fair value are recognized in earnings, unless the instrument is an available-for-sale asset or is designated an effective cash flow hedging instrument, in which case the unrealized changes are recorded in other comprehensive income (OCI).

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the Company did not change the valuation of other financial instruments.

The Company uses derivatives and non-derivative financial instruments to manage changes in commodity prices, foreign currency exchange rates and interest rates. Hedge accounting is optional and applying 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. Ordinarily, the effective portion of the change in the fair value of the cash flow hedging instrument is recorded in OCI and reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset or liability. Any hedge ineffectiveness is recorded in the current period earnings.

The majority of St. Lawrence's cash flow hedges have been for purchases of natural gas. 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. Pursuant to the OEB's final decision issued on July 5, 2007, the Company no longer utilizes derivative and non-derivative instruments to manage changes in commodity prices, effective July 2007. However, the OEB decision does not impact the natural gas commodity risk program at St. Lawrence.

Please refer to Notes 1 and 2 of the Company's consolidated financial statements for additional information.

Future Accounting Policy Changes

Accounting for the Effects of Rate Regulation
Effective for the Company beginning January 1, 2009, the CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. As a result, the Company will recognize the post-employment benefit assets and liabilities for the amount of post-employment benefits expected to be included in future rates and recovered from, or paid to, customers. It is also anticipated that the Company will recognize a separate and offsetting regulatory asset or liability related to the post-employment benefits. As disclosed in Note 13 of the Company's consolidated financial statements, the net pension asset balance was $199.5 million and the net other post-employment benefit liability was $63.6 million.

The CICA has also issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate and offsetting regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers. The future income tax liabilities related to the regulated operations were $150.7 million at December 31, 2008. Please refer to Note 12 of the Company's consolidated financial statements.

These recommendations will be applied prospectively.

Goodwill and Intangible Assets
The CICA implemented revisions to standards dealing with goodwill and intangible assets effective for fiscal years beginning on or after October 1, 2008. Section 3064, Goodwill and Intangible Assets, which replaced Section 3062, Goodwill and Other Intangible Assets, gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. Section 3450, Research and Development Costs, will be withdrawn. This standard is not expected to materially impact the Company's consolidated financial statements.

International Financial Reporting Standards
The Canadian Accounting Standards Board confirmed in February 2008 that publicly accountable entities will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual consolidated financial statements effective January 1, 2011.

Enbridge Inc. has established an IFRS governance structure to monitor the progress of the transition. This group is comprised of senior management from finance, treasury, tax and Enbridge Inc.'s business units, among others. The Audit, Finance & Risk Committee of Enbridge Inc.'s Board of Directors receives regular reports on the advancement of the IFRS transition plan. In addition, the Company has trained internal IFRS team members and has hired a public accounting firm to assist with project management and technical accounting advice, as needed.

The Company has a multi-year transition plan, which includes four phases: diagnostic, project planning, policy design and implementation. In 2008, the Company completed the diagnostic phase and has identified the relevant differences between current GAAP and IFRS. The Company is in the policy design stage and is also assessing the impact of policy alternatives on its consolidated financial statements, systems, processes and controls. As the transition progresses, the Company will provide increased clarity into the anticipated consequences of accounting policy changes. The Company is in the process of developing a detailed project plan for 2009 and 2010, which will include staff communications, a training plan and an external stakeholders communication plan. Policy design will be completed in 2009 and implementation will begin during 2009 and will be completed by the end of 2010.

Changes in accounting policies and processes and collection of additional information for disclosure will require modifications to the Company's information technology systems and processes as well as its system of internal controls. The identified information technology system alterations are being incorporated into the detailed project plan to allow time to modify and test the systems before implementation during 2010. The impact on internal controls over financial reporting and disclosure controls and procedures will be determined during the policy design and implementation phases.

SELECTED HISTORICAL QUARTERLY FINANCIAL INFORMATION

The following table presents selected historical financial information.

	Quarter ended							
(millions of dollars)	Dec. 31, 2008	Sept. 30, 2008	June 30, 2008	Mar. 31, 2008	Dec. 31, 2007	Sept. 30, 2007	June 30, 2007	Mar. 31, 2007
Total revenue	1,068.6	376.0	465.9	1,194.4	861.5	304.7	524.7	1,263.0
Earnings (loss) applicable to common shares	73.9	(3.9)	22.5	114.0	64.8	(15.0)	33.0	102.2

Total revenue includes amounts billed to customers for natural gas, which varies with fluctuations in the commodity price. Therefore, higher natural gas commodity 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 erratic weather patterns. More 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 change in customer billing, to increase the fixed charge portion and decrease the per unit volumetric charge, 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 2008 HIGHLIGHTS

Earnings applicable to common shares were $73.9 million for the three months ended December 31, 2008, compared with $64.8 million for the three months ended December 31, 2007. The increase of $9.1 million was primarily due to higher volumes distributed as a result of colder weather and customer growth. Earnings applicable to common shares for the three months ended December 31, 2008, excluding the effect of weather, were consistent with the prior year.

Additional information relating to the Company, including the Annual Information Form, is available at www.sedar.com.

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiary, including management's assessment of the Company's 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. 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,; anticipated in-service dates and weather.

The Company's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, exchange rates, interest rates and commodity prices, 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.

Management's Report

To the Shareholders of Enbridge Gas Distribution Inc.

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 judgement and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management has established systems of internal control that provide reasonable assurance that assets are safeguarded from loss or unauthorized use and produce reliable accounting records for the preparation of financial information. The internal control system includes an internal audit function and an established code of business conduct.

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 for ensuring that management fulfills its responsibility 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.

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

J. Holder
President

W. G. Ross
Vice President,
Finance & Information Technology

February 11, 2009

PRICEWATERHOUSECOOPERS

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February 11, 2009

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, 2008 and 2007 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, 2008. 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, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants, Licensed Public Accountants

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars)		
Year ended December 31,	**2008**	2007
Gas commodity and distribution revenue	**2,506.2**	2,372.3
Transportation of gas for customers	**504.8**	500.2
	3,011.0	2,872.5
Gas commodity and distribution costs excluding amortization (Note 15)	**2,000.4**	1,887.8
Gas distribution margin	**1,010.6**	984.7
Other revenue	**93.9**	81.4
	1,104.5	1,066.1
Expenses		
Operation and maintenance (Notes 8 and 15)	**373.5**	367.0
Amortization	**239.0**	228.0
Municipal and other taxes	**47.3**	55.1
Earnings sharing (Note 3)	**5.8**	-
	665.6	650.1
	438.9	416.0
Affiliate financing income (Note 15)	**62.7**	62.7
Interest expense (Notes 6 and 15)	**(200.8)**	(210.3)
Earnings before income taxes	**300.8**	268.4
Income taxes (Note 12)		
Current	**68.2**	72.8
Future	**21.2**	5.7
Income taxes	**89.4**	78.5
Earnings	**211.4**	189.9
Dividends on preference shares (Note 7)	**4.9**	4.9
Earnings applicable to common shares	**206.5**	185.0

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

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars) Year ended December 31,	**2008**	2007
Earnings	**211.4**	189.9
Other comprehensive income (loss)		
Change in net unrealized losses on cash flow hedges, net of tax	**-**	(0.2)
Change in foreign currency translation adjustment	**4.1**	(3.0)
Other comprehensive income (loss)	**4.1**	(3.2)
Comprehensive income (Note 2)	**215.5**	186.7

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

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(millions of Canadian dollars) Year ended December 31,	**2008**	2007
Preference shares (Note 7)	**100.0**	100.0
Common shares (Note 7)	**1,070.7**	1,070.7
Contributed surplus	**202.5**	202.5
Retained earnings		
Balance at beginning of year	**518.3**	421.7
Earnings	**211.4**	189.9
Preference share dividends	**(4.9)**	(4.9)
Common share dividends	**(158.2)**	(88.4)
Balance at end of year	**566.6**	518.3
Accumulated other comprehensive loss (Note 2)		
Balance at beginning of year	**(6.2)**	(3.0)
Other comprehensive income (loss)	**4.1**	(3.2)
Balance at end of year	**(2.1)**	(6.2)
Total shareholders' equity	**1,937.7**	1,885.3

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

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars) Year ended December 31,	**2008**	2007
Operating activities		
Earnings	**211.4**	189.9
Charges not affecting cash and cash equivalents		
Amortization	**239.0**	228.0
Earnings sharing (Note 3)	**5.8**	-
Future income taxes	**21.2**	5.7
Non-cash interest	**2.7**	2.9
Other	**4.1**	(3.6)
	484.2	422.9
Change in non-cash working capital (Note 14)	**(121.2)**	105.8
Settlement recoverable (Notes 3, 5 and 16)	**4.7**	-
	367.7	528.7
Investing activities		
Additions to property, plant and equipment, net	**(411.2)**	(385.2)
Other, net	**9.5**	(13.4)
Change in non-cash working capital (Note 14)	**(4.1)**	30.0
	(405.8)	(368.6)
Financing activities		
Loans and notes payable, net	**328.9**	(262.3)
Issue of note payable to parent (Note 15)	**5.3**	2.8
Repayment of note payable to parent (Note 15)	**(3.6)**	(5.9)
Issue of long-term debt	**200.0**	200.0
Long-term debt repayments	**(270.0)**	(101.3)
Issue of common shares to parent (Note 7)	**-**	87.5
Dividends paid, preference shares	**(4.9)**	(4.9)
Dividends paid, common shares	**(158.2)**	(65.2)
Other, net	**0.8**	(1.0)
	98.3	(150.3)
Increase in cash and cash equivalents during the year	**60.2**	9.8
Bank overdraft at beginning of year	**(4.8)**	(14.6)
Cash and cash equivalents (bank overdraft) at end of year	**55.4**	(4.8)
Cash and cash equivalents[1] (Notes 10 and 11)	**100.0**	-
Bank overdraft (Notes 10 and 11)	**(44.6)**	(4.8)
	55.4	(4.8)

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

[1] Cash and cash equivalents consists of $nil (2007 - $nil) of cash and $100.0 million (2007 - $nil) of short-term investments.

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(millions of Canadian dollars) December 31,	**2008**	2007
Assets		
Current assets		
Cash and cash equivalents (Notes 10 and 11)	**100.0**	-
Accounts receivable (Notes 2, 3, 9, 10 and 15)	**980.3**	917.8
Gas inventories	**656.3**	593.6
Other current assets	**7.5**	10.1
Future income taxes (Note 12)	**15.3**	36.4
	1,759.4	1,557.9
Property, plant and equipment (Note 4)	**3,660.7**	3,486.3
Investment in affiliate company (Notes 10 and 15)	**825.0**	825.0
Deferred charges and other (Notes 2, 3, 5 and 16)	**40.0**	51.9
	6,285.1	5,921.1
Liabilities and Shareholders' Equity		
Current liabilities		
Bank overdraft (Notes 10 and 11)	**44.6**	4.8
Accounts payable (Notes 2, 3, 10 and 15)	**677.1**	706.1
Loans and notes payable (Notes 10, 11 and 15)	**881.6**	551.0
Other current liabilities (Notes 3 and 10)	**88.1**	61.6
Current portion of long-term debt (Notes 6, 10 and 11)	**100.0**	270.0
	1,791.4	1,593.5
Long-term debt (Notes 2, 6, 10 and 11)	**2,167.1**	2,063.6
Other long-term liabilities	**10.9**	1.2
Future income taxes (Note 12)	**3.0**	2.5
Loans from affiliate company (Notes 10, 11 and 15)	**375.0**	375.0
	4,347.4	4,035.8
Shareholders' equity		
Share capital (Note 7)		
Preference shares	**100.0**	100.0
Common shares	**1,070.7**	1,070.7
Contributed surplus	**202.5**	202.5
Retained earnings	**566.6**	518.3
Accumulated other comprehensive loss (Note 2)	**(2.1)**	(6.2)
	1,937.7	1,885.3
Commitments and contingencies (Notes 15 and 16)		
	6,285.1	5,921.1

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

Approved by the Board of Directors:

J. Richard Bird
Director

Stephen J. J. Letwin
Director

ENBRIDGE GAS DISTRIBUTION INC.

Notes to the Consolidated Financial Statements
(Tabular amounts expressed in millions of Canadian dollars, except shares and volumes)

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (GAAP). The preparation of consolidated financial statements in conformity with 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. Actual results could differ from those estimates.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries. Investments in entities, which are not subsidiaries, or where the Company does not have the ability to exercise significant influence, are accounted for using the cost method.

Regulation

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

The Regulators exercise statutory authority over matters such as construction, rates and underlying accounting practices and rate-making 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 what would otherwise be expected under 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 of 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 as either held-for-trading, available-for-sale, held-to-maturity, or loans and receivables. The Company classifies financial liabilities as either held-for-trading or other financial liabilities.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(CONTINUED)*

Financial assets and liabilities that are held-for-trading are measured at fair value with changes in fair value recognized in earnings, except for derivatives that are designated as, and determined to be, effective hedging instruments, whose change in fair value is recorded in other comprehensive income (OCI).

Financial assets that are available-for-sale are measured at fair value with changes in those fair values recorded in OCI. Financial assets that are held-to-maturity or loans and receivables and financial liabilities that are other financial liabilities are measured at amortized cost using the effective interest rate method of amortization.

Cash and cash equivalents, bank overdraft, and current derivatives payable are designated as held-for-trading and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Investment in affiliate company is designated as available-for-sale. Accounts receivable are designated as loans and receivables. Loans and notes payable, accounts payable, other current liabilities, long-term debt and loans from affiliate company are designated as other financial liabilities.

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 and are recorded as interest expense in the consolidated statement of earnings.

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.

Hedges
The Company uses derivatives and non-derivative financial instruments to manage changes in commodity prices, foreign currency exchange rates and interest rates. Hedge accounting is optional and applying 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.

Cash Flow Hedges
The Company uses cash flow hedges to manage changes in commodity prices, foreign currency exchange rates and interest rates. Ordinarily, the effective portion of the change in the fair value of the cash flow hedging instrument is recorded in OCI and reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset or liability. Any hedge ineffectiveness is recorded in the current period earnings.

The majority of St. Lawrence's cash flow hedges are for purchases of natural gas. 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.

Pursuant to the OEB's final decision issued on July 5, 2007, the Company no longer utilizes derivative and non-derivative instruments to manage changes in commodity prices, effective July 2007. However, the OEB decision does not impact the natural gas commodity risk program at St. Lawrence.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(CONTINUED)*

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 they occur.

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 and the Company does not record future income tax assets or liabilities related to these differences. The Company expects that all unrecorded future income taxes will be recovered in rates when they become payable.

For all other operations, 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.

Foreign Currency Translation
The functional currency of the Company's only foreign operation, St. Lawrence, is the US 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, with revenues and expenses translated using average rates for the period. Gains and losses arising on translation of this operation are included in the foreign currency translation adjustment component of accumulated other comprehensive loss (AOCL).

Cash and Cash Equivalents
Cash and cash equivalents include short-term investments, with Canadian chartered banks, with a term to maturity of three months or less when purchased.

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. 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 the end use consumer.

At December 31, 2008, $175.9 million worth of natural gas was held on behalf of transportation service customers (December 31, 2007 - $187.0 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 and removal costs, net of any proceeds, are charged to accumulated amortization. Upon retirement or sale of major items of utility property, any gain or loss is included in earnings.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(CONTINUED)*

Amortization

Amortization 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.

Amortization expense includes a provision for future removal and site restoration costs at rates approved by the Regulators. Actual removal and site restoration costs incurred are charged to accumulated amortization in accordance with regulatory treatment.

Deferred Charges

Certain costs, as required or permitted by the Regulators, have been deferred to be recovered through future revenues. Certain other regulatory deferrals are subject to future decisions by the Regulators who will determine the treatment to be given to the various items. Refer to Note 5.

Asset Retirement Obligations

Asset retirement obligations (AROs) represent the fair value of a liability relating to the retirement of the long-lived assets in the period in which such liability is incurred, if a reasonable estimate of fair value of the liability can be determined. AROs are added to the carrying value of the associated asset and amortized over the asset's useful life. The corresponding liability is accreted over the estimated useful life of the asset through charges to earnings.

The Company's natural gas distribution network is comprised of mains, service lines, measuring and regulating equipment and storage facilities. The Company estimates that it does not have a material legal retirement obligation on its distribution network.

Post-employment Benefits

The Company maintains non-contributory defined benefit pension plans (the Plans), of which the largest plan has a defined contribution pension component. Contributions made to the Plans are expensed as paid, consistent with the recovery of such costs in rates. The Company also provides post-employment benefits other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is expensed as paid, consistent with the recovery of such costs in rates.

The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2008.

Comparative Amounts

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

2. CHANGES IN ACCOUNTING POLICIES

Capital Disclosures and Financial Instruments – Disclosure and Presentation
Effective January 1, 2008, the Company adopted The Canadian Institute of Chartered Accountants (CICA) Handbook Section 1535, Capital Disclosures, Section 3862, Financial Instruments - Disclosure and Section 3863, Financial Instruments – Presentation. While the new standards did not change the Company's accounting policies, they resulted in additional disclosures.

Under Section 1535, the Company discloses its objectives, policies and procedures for managing capital, any summary quantitative data about what the Company manages as capital, whether the Company has complied with any externally imposed capital requirements and, if the Company has not complied, any consequences of non-compliance with these capital requirements. The additional disclosure required under this standard has been incorporated in Note 11.

Sections 3862 and 3863 replaced Section 3861, Financial Instruments – Disclosure and Presentation. Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements have expanded disclosure about the significance of financial instruments for the Company's financial position and performance, the nature and extent of risks arising from financial instruments to which the entity is exposed during the year and at the consolidated statement of financial position date, and how the entity manages those risks. The additional disclosures required under these standards have been included in Notes 9 and 10.

The adoption of these new accounting standards had no impact on the recognition or measurement of the Company's assets, liabilities, revenues or expenses.

Inventories
Effective January 1, 2008, the Company adopted CICA Handbook Section 3031, Inventories, which aligns accounting for inventories under GAAP with International Financial Reporting Standards and provides additional guidance on the measurement and disclosure requirements for inventories. The adoption of this accounting standard did not materially impact the Company's consolidated financial statements.

Financial Instruments, Comprehensive Income and Hedging Relationships
Effective January 1, 2007, the Company adopted CICA Handbook Section 1530, Comprehensive Income, Section 3251, Equity, Section 3855, Financial Instruments – Recognition and Measurement, Section 3861, Financial Instruments – Disclosure and Presentation and Section 3865, Hedges. In accordance with the transitional provisions in these new standards, these policies were adopted prospectively and accordingly, the prior periods were not restated, however prior period unrealized gains and losses related to the Company's foreign currency translation adjustments are now included in AOCL.

The adoption of the new standards did not impact the Company's earnings or cash flows.

Comprehensive Income and Equity
The new standards introduced comprehensive income, which consists of earnings and OCI. The Company's consolidated financial statements now include a Consolidated Statement of Comprehensive Income. The Company's OCI is currently comprised of the effective portion of changes in unrealized gains and losses related to cash flow hedges and unrealized foreign exchange gains and losses related to the Company's wholly owned self-sustaining foreign operation, St. Lawrence.

The Company now presents a Consolidated Statement of Shareholders' Equity, which includes the change for each component of shareholders' equity. The cumulative changes in OCI are recorded in AOCL, a separate component of shareholders' equity. The cumulative translation adjustment, previously presented as a separate component of shareholders' equity, is now presented as a component of AOCL.

2. CHANGES IN ACCOUNTING POLICIES *(CONTINUED)*

Financial Instruments
CICA Handbook Section 3855 establishes recognition and measurement criteria for financial instruments and requires that, generally, all financial instruments be recorded at fair value on initial recognition. Subsequent measurement depends on whether the instrument has been classified as held-to-maturity, held-for-trading, available-for-sale, or loans and receivables as defined by Section 3855.

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the value of the Company's financial instruments did not change upon adoption. The methods by which the Company determines the fair value of its financial instruments also did not change as a result of adopting this standard.

Impact on Adoption
The adoption of the new standards resulted in the following adjustments on January 1, 2007:

(millions of dollars) Increase (Decrease)	Assets	Liabilities and Equity
Accounts receivable[1]	23.4	-
Accounts payable[1]	-	23.4
Deferred charges and other[2]	(25.2)	-
Long-term debt[2]	-	(25.2)
	(1.8)	(1.8)

1. The Company recognized a liability of $23.4 million to counterparties for unrealized losses related to natural gas purchase hedges at January 1, 2007, and a receivable of $23.4 million from customers.
2. On January 1, 2007, the Company reclassified unamortized deferred financing fees of $25.2 million from deferred charges and other to long-term debt as a result of adoption of CICA Handbook Section 3855 Financial Instruments – Recognition and Measurement.

Future Accounting Policy Changes

Accounting for the Effects of Rate Regulation
Effective for the Company beginning January 1, 2009, the CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. As a result, the Company will recognize the post-employment benefit assets and liabilities for the amount of post-employment benefits expected to be included in future rates and recovered from, or paid to, customers. It is also anticipated that the Company will recognize a separate and offsetting regulatory asset or liability related to the post-employment benefits. As disclosed in Note 13, the net pension asset balance was $199.5 million and the net other post-employment benefit liability was $63.6 million.

The CICA has also issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate and offsetting regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers. The future income tax liabilities related to the regulated operations were $150.7 million at December 31, 2008. Please refer to Note 12.

These recommendations will be applied prospectively.

2. CHANGES IN ACCOUNTING POLICIES *(CONTINUED)*

Goodwill and Intangible Assets
The CICA implemented revisions to standards dealing with goodwill and intangible assets effective for fiscal years beginning on or after October 1, 2008. Section 3064, Goodwill and Intangible Assets, which replaced Section 3062, Goodwill and Other Intangible Assets, gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. Section 3450, Research and Development Costs, will be withdrawn. This standard is not expected to materially impact the Company's consolidated financial statements.

International Financial Reporting Standards (IFRS)
In February 2008, the Canadian Accounting Standards Board confirmed the mandatory changeover date from GAAP to IFRS. The change will take effect January 1, 2011. The Company will prepare IFRS compliant financial information beginning January 1, 2010 to produce comparable information for the first IFRS consolidated financial statements published in 2011.

The Company has completed the diagnostic phase of its transition plan and major differences identified which may have the most significant impact on the Company are rate regulated accounting, development of opening balances in the consolidated statement of financial position, measurement of property, plant and equipment, pension costs and obligations and taxes. The impact of these differences and the complete conversion to IFRS are currently being evaluated by the Company, but are not reasonably determinable at this 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 any resulting required adjustment to rates, and relies on an annual process to forecast volume and customer additions. Unlike the cost of service (COS) methodology utilized in prior years, the concepts of rate base and return on rate base are not relevant within the formulaic component of the setting of rates, but are still utilized for the purpose of measuring actual financial results. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The cost of the natural gas commodity is passed on to customers as a flow-through.

St. Lawrence’s rates for each year are set using a COS methodology that allows the revenues to be set to recover forecasted costs and to earn a rate of return on common equity. Forecasted costs include natural gas commodity and transportation, operation and maintenance, 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 Regulators the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken. The cost of the natural gas commodity is passed on to customers as a flow-through.

Approved Rates

Enbridge Gas Distribution

For 2008, Enbridge Gas Distribution’s rate of return on common equity embedded in rates was 8.39% (2007 – 8.39%) based on a 36% (2007 – 36%) deemed common equity 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 on February 11, 2008. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive). To the extent the actual utility return on the approved equity level represented by normalized earnings (i.e., excluding the effects of weather) (ROE) exceeds the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings are shared with customers. The 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.

St. Lawrence

For 2008, St. Lawrence’s approved rate of return on its rate base was 7.8% (2007 – 7.8%). Its approved rate of return on common equity was 9.6% (2007 – 9.6%) based on a 51.5% (2007 – 51.5%) deemed common equity component for regulatory purposes. Any earnings above a return on equity of 9.6% (2007 – 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, 2008.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION *(CONTINUED)*

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 Regulator

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, GAAP would not permit the recognition of 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 charges and other, whereas current regulatory assets are recorded in accounts receivable. Regulatory liabilities are recorded in accounts payable and other current liabilities.

Regulatory assets and liabilities are set up with the approval of the Regulators for purposes of deferral of costs or credits to a future period. Deferral of costs is monitored by two broad categories of accounts, “regulatory deferral accounts” and “regulatory variance accounts”. Regulatory deferral accounts track those items that are viewed as not forming part of an original rate application, since the occurrence and/or quantum of such costs could not be established at the time of the rate application. Regulatory variance accounts, on the other hand, track variances for those cost elements that formed part of a COS application using the best estimates available at the time of the application and/or which are considered to be embedded within ongoing rates within Enbridge Gas Distribution’s IR period. To the extent actual amounts for these cost elements are over or under the estimates filed in the rate application, such variations, subject to regulatory approval, are captured in the regulatory variance account. Regulatory deferral and variance accounts accrue interest on balances therein, in accordance with the Regulators’ approval, and are flowed through to customers, usually through one-time billing adjustments.

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.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION *(CONTINUED)*

The following is a list of Enbridge Gas Distribution's and St. Lawrence's regulatory assets and liabilities that have been recognized solely as a result of the effects of rate regulation:

					Earnings Impact* (After-tax)**	
(millions of dollars) **December 31,**	**2008**	**2007**	**Estimated Recovery / Settlement Period (Years)**	**Inclusion in Consolidated Statement of Financial Position****	**2008**	**2007**
Regulatory Assets (Liabilities)						
Enbridge Gas Distribution						
Ontario hearing costs[1]	**5.3**	8.1	Up to 2 years	AR/DC	**(1.8)**	(0.7)
Demand side management variance[2]	**(0.9)**	0.4	2 – 4 years	AR/(AP)	**(0.8)**	(1.8)
Shared savings mechanism[3]	**8.2**	8.4	*	AR	**-**	-
Purchased gas variance[4]	**(75.2)**	(141.1)	*	(AP)	**43.8**	(8.8)
Unaccounted for gas variance[5]	**0.6**	6.1	*	AR	**(3.6)**	11.4
Transactional services deferral[6]	**(6.5)**	(8.8)	*	AP	**-**	-
Union Gas regulatory deferral[7]	**(1.9)**	3.4	*	AR/(AP)	**(3.5)**	4.0
Deferred rebate deferral[8]	**2.1**	0.5	*	AR	**-**	-
Class action lawsuit settlement deferral[9]	**20.1**	22.0	4 years	AR/DC	**(1.2)**	-
Gas distribution access rule deferral[10]	**0.8**	7.2	*	AR	**(4.3)**	(0.8)
EnergyLink deferral[11]	**-**	4.6	Not applicable	DC	**(3.1)**	2.9
Interest savings on early debt redemption deferral[12]	**-**	(2.6)	Not applicable	AP	**-**	-
Customer care procurement costs[13]	**3.9**	4.9	4 years	DC	**(0.7)**	3.1
Customer Information System procurement and selection costs[14]	**4.1**	-	4 years	DC	**2.7**	
Earnings sharing deferral[15]	**(5.8)**	-	*	AP	**-**	-
Tax rate and rule change variance[16]	**1.8**	-	*	AR	**1.2**	-
Average use true-up variance[17]	**(2.7)**	-	*	AP	**(1.8)**	-
Other regulatory assets and liabilities	**2.9**	4.7	*	AR/DC	**(1.2)**	-
St. Lawrence						
Pensions and OPEB variances[18]	**2.7**	2.8	Deferred until next rate case	DC	**-**	(0.2)
Gas Adjustment Clause[19]	**(2.6)**	0.4	*	AR/(AP)	**(2.0)**	(1.4)
Kamine / Natural Dam deferred revenue[20]	**(1.2)**	(1.5)	Expires 2011	OCL	**0.2**	0.5
Other regulatory assets and liabilities	**1.3**	0.1	*	AR/DC	**0.8**	-

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION *(CONTINUED)*

* *Up to one year after approval*
** *AR – represents accounts receivable*
DC – represents deferred charges and other under non-current assets
AP – represents accounts payable
OCL – represents other current liabilities
*** *Represents the increase (decrease) reflected in the Company's consolidated after-tax 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.*

[1] *Ontario hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has historically been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, GAAP would require these costs to be expensed in the year incurred.*

[2] *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 for the recovery of 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, GAAP would require the excess costs to be expensed in the year incurred.*

[3] *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 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, GAAP would require the amount to be included in earnings in the year of approval.*

[4] *Purchased gas variance is the difference between the actual and estimated cost of natural gas purchased by Enbridge Gas Distribution. The estimated cost of natural gas is approved by the OEB and is reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval for recovery or refund of this variance within a year. In the absence of rate regulation, GAAP would require the actual cost of natural gas to be included in cost of sales, resulting in the variance amount being recognized in earnings in the year incurred.*

[5] *Unaccounted for gas variance represents the difference between the amount of 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. Based on approval from the OEB, Enbridge Gas Distribution has deferred unaccounted for natural gas and has historically been granted approval for recovery or refund of this amount in the subsequent year. In the absence of rate regulation, GAAP would require the variance to be included in cost of sales, impacting 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 by the OEB to refund the amount outstanding to customers in the following year. The GAAP treatment of this item is the same as that under rate regulation.*

[7] *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 forecasted 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, GAAP would require the variance to be included in earnings in the year incurred.*

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION *(CONTINUED)*

[8] Deferred rebate deferral represents an accumulation of amounts required by the OEB to be recovered from or refunded to customers of Enbridge Gas Distribution, but remain pending due to the inability to locate certain customers. This amount will be cleared to customers in the subsequent year. The GAAP treatment of this item is the same as that under rate regulation.

[9] Class action lawsuit settlement deferral represents the amounts that have been paid toward the settlement of the class action lawsuit related to late payment penalties. Pursuant to an OEB decision issued on February 4, 2008, these amounts will be recovered from customers over a five-year period commencing in 2008. In the absence of rate regulation, GAAP would require these costs to be expensed in the year incurred. Further details on the class action lawsuit are provided in Note 16.

[10] 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, GAAP would require these costs to be expensed in the year incurred.

[11] 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 recovery of amounts already incurred, completely in 2008. In the absence of rate regulation, GAAP would require these costs to be expensed in the year incurred.

[12] Interest savings on early debt redemption deferral represents amounts relating to interest savings realized on an early debt redemption, which occurred in 2007. The interest savings are payable to customers and represent the difference between the interest cost embedded in rates in 2007 in relation to the debt redeemed and the cost of refinancing. The GAAP treatment of this item is the same as that under rate regulation.

[13] 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 the next five years. In the absence of rate regulation, GAAP would require the amounts to be expensed in the year incurred.

[14] Customer Information System (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 the next five years. The related costs in this account will be drawn down over the same five-year period in recognition of the rate recovery. In the absence of rate regulation, GAAP would require the amounts to be expensed in the year incurred.

[15] 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 GAAP treatment of this item is the same as that under rate regulation.

[16] 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, GAAP would require the amounts to be expensed in the year incurred.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION *(CONTINUED)*

[17] *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 incorporated into earnings in the year incurred.*

[18] *Pensions 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 incorporated into earnings in the year incurred.*

[19] *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, GAAP would require the actual cost of natural gas be included in cost of sales in the year incurred, resulting in the variance amount being recognized in earnings in the year incurred.*

[20] *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 have included the impact of this amortization.*

Other Items Affected by Rate Regulation

The following are specific financial statement policies or items affected by rate regulation and descriptions of their accounting effects:

Revenue Recognition

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. Refer to Note 1 – “Revenue Recognition” for further information.

Future Income Taxes

Refer to Note 1 – “Income Taxes” for a discussion of the impact of rate regulation on the accounting treatment of income taxes for the Company. Refer to Note 12 for the consolidated financial statement impacts of income taxes and the accumulated future income taxes payable related to rate-regulated operations that have not been recorded.

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 amortization on such capitalized costs in future years. In the absence of accounting for the effects of rate regulation, such operating costs would be charged to earnings in the period incurred.

The Company entered into a consulting contract relating to services provided with respect to work and asset management initiatives. The majority of the related costs, primarily consulting fees, are being capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2008, $93.7 million (December 31, 2007 - $82.2 million) was included in gas mains, which are amortized over the average service life of 25 years. In the absence of rate regulation, the majority of these costs would be recognized in earnings in the period incurred.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION *(CONTINUED)*

Post-employment Benefits
Refer to Notes 1 and 13 – “Post-employment Benefits” for a discussion of the impact of rate regulation and additional information on reporting of post-employment benefits.

In the absence of rate regulation, GAAP would require pension costs to be determined using the projected benefit method and to be charged to earnings as services are rendered. Had pension costs and obligations been recognized, the net pension asset would have been $199.5 million at December 31, 2008 (December 31, 2007 - $173.5 million) and the impact on after-tax earnings would have been an increase of $16.8 million for the year ended December 31, 2008 (December 31, 2007 - increase of $14.0 million).

In the absence of rate regulation, GAAP would require the cost of post-employment benefits other than pensions to be accrued during the years employees render service and to be charged to earnings as costs are accrued. Had these other post-employment benefit (OPEB) costs been accrued, the net OPEB liability would have been $63.6 million at December 31, 2008 (December 31, 2007 - $55.7 million) and the impact on after-tax earnings would have been a decrease of $5.2 million for the year ended December 31, 2008 (December 31, 2007 - decrease of $5.3 million).

Property, Plant and Equipment
Refer to Note 1 – “Property, Plant and Equipment” for a discussion of the impact of rate regulation on 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 and removal costs, net of proceeds, would be recorded as a loss on the sale of assets in earnings in the period of retirement.

The Company entered into contracts relating to CIS integration services, software maintenance and support. The costs will be capitalized to computer technology under property, plant and equipment in accordance with regulatory treatment. At December 31, 2008, $78.7 million (December 31, 2007 - $32.2 million) was included in construction-in-progress. In the absence of rate regulation, certain of these costs would be expensed in the period incurred.

Amortization
Refer to Note 1 – “Amortization” for a discussion of the impact of rate regulation on amortization. In the absence of rate regulation, amortization rates would not have included an estimate of future removal and site restoration costs and such actual costs would have been included in the determination of gain or loss on disposition of the relevant asset.

Gas Inventories
Refer to Note 1 – “Gas Inventories” for a discussion of the impact of rate regulation on gas inventories. 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, 2008 is $36.8 million (December 31, 2007 - $30.8 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.

4. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars) December 31, 2008	**Weighted Average Amortization Rate**	**Cost**	**Accumulated Amortization**	**Net Book Value**
Gas mains	**4.2%**	**2,309.6**	**800.3**	**1,509.3**
Gas services	**4.5%**	**1,892.7**	**772.6**	**1,120.1**
Regulating and metering equipment	**3.7%**	**650.5**	**230.9**	**419.6**
Storage	**2.7%**	**266.7**	**89.6**	**177.1**
Computer technology	**21.1%**	**167.0**	**78.9**	**88.1**
Other	**3.7%**	**366.6**	**83.3**	**283.3**
Subtotal		**5,653.1**	**2,055.6**	**3,597.5**
Unregulated storage		**36.5**	**-**	**36.5**
Construction materials inventory		**26.7**	**-**	**26.7**
Total		**5,716.3**	**2,055.6**	**3,660.7**

(millions of dollars) December 31, 2007	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net Book Value
Gas mains	4.3%	2,168.1	723.4	1,444.7
Gas services	4.6%	1,838.5	724.5	1,114.0
Regulating and metering equipment	3.7%	616.4	212.2	404.2
Storage	2.7%	260.5	83.8	176.7
Computer technology	18.8%	198.5	106.9	91.6
Other	4.7%	291.5	76.8	214.7
Subtotal		5,373.5	1,927.6	3,445.9
Unregulated Storage		8.3	-	8.3
Construction materials inventory		32.1	-	32.1
Total		5,413.9	1,927.6	3,486.3

Property, plant and equipment include $190.0 million of construction-in-progress (December 31, 2007 - $143.1 million) for which no amortization has been provided.

5. DEFERRED CHARGES AND OTHER

(millions of dollars) December 31,	**2008**	2007
Settlement recoverable (Notes 3 and 16)	**14.1**	22.0
Deferred rate hearing costs	**3.0**	5.6
Customer care procurement costs	**3.9**	4.9
Customer Information System procurement and selection costs	**4.1**	-
EnergyLink	**-**	4.6
Other assets	**14.9**	14.8
	40.0	51.9

The settlement recoverable relates to the settlement of a class action lawsuit regarding late payment penalties, fully described in Note 16.

6. DEBT

(millions of dollars) December 31,	Weighted Average Interest Rate	Maturity	**2008**	2007
Debentures	11.2%	2009 – 2024	**485.0**	485.0
Medium-term notes	5.9%	2014 – 2036	**1,795.0**	1,865.0
Other	5.7%		**8.6**	6.9
Unamortized deferred financing fees			**(21.5)**	(23.3)
Total debt			**2,267.1**	2,333.6
Current maturities			**(100.0)**	(270.0)
Long-term debt			**2,167.1**	2,063.6

For the year ended December 31, 2008, the effective interest rate of long-term debt, after giving effect to the interest rate swap agreements (Note 9) and all related issue costs, was 6.9% (2007 – 7.3%). The Company issued $200.0 million of new medium-term notes during the year (2007 - $200.0 million).

The following tables summarize expected cash outflows to settle both the principal and the interest payments associated with the long-term debt. The interest obligations table is exclusive of interest rate swap impacts.

Long-term Debt Maturities

(millions of dollars) **December 31, 2008**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**After 5 years**	**Total**
Debentures	100.0	300.0	–	85.0	**485.0**
Medium-term notes	–	–	–	1,795.0	**1,795.0**
Other	–	–	–	8.6	**8.6**
	100.0	**300.0**	**–**	**1,888.6**	**2,288.6**

Interest Obligations[1]

(millions of dollars) **December 31, 2008**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**After 5 years**	**Total**
Interest payments on debentures	48.1	59.0	16.7	92.1	**215.9**
Interest payments on medium-term notes	100.3	207.0	207.0	1,219.2	**1,733.5**
Interest payments on other	0.5	1.0	1.0	0.5	**3.0**
	148.9	**267.0**	**224.7**	**1,311.8**	**1,952.4**

1) The above table excludes the annual interest obligations of $26.8 million related to the loans from affiliate company.

Credit Facilities

The Company currently has a $1.0 billion commercial paper program limit (December 31, 2007 – $1.0 billion) that is backstopped by committed lines of credit of $1.0 billion (December 31, 2007 – $1.0 billion). The commercial paper issued under this program may not exceed one year. The committed lines of credit comprise a revolving 364-day unsecured credit facility that has a one-year term-out option at the Company's option. The credit facility carries a standby fee of 0.07% (2007 – weighted average standby fee of 0.062%) per annum on the unused portion and drawdowns bear interest at market rates.

6. DEBT *(CONTINUED)*

At December 31, 2008, $872.0 million, net of an unamortized discount of $2.5 million, was drawn or used to backstop commercial paper (December 31, 2007 – $545.6 million, net of an unamortized discount of $1.4 million) with interest cost ranging between 2.35% to 4.15% and the latest maturity in March 2009. The Company has uncommitted lines of credit in the amount of $6.1 million (December 31, 2007 - $4.9 million), against which the Company borrowed $2.5 million as at December 31, 2008 (December 31, 2007 - $0.6 million).

Total loans and notes payable at December 31, 2008 is $881.6 million (December 31, 2007 - $551.0 million), including the $7.1 million short-term note payable to Enbridge Inc. outstanding at December 31, 2008 (December 31, 2007 - $5.4 million).

Interest Expense

(millions of dollars) Year ended December 31,	**2008**	2007
Long-term debt	**161.8**	158.8
Loans and notes payable to affiliate company	**26.8**	26.8
Other interest and finance costs	**17.3**	28.0
Capitalized	**(5.1)**	(3.3)
	200.8	210.3

7. SHARE CAPITAL

Common Shares
Authorized: Unlimited
Issued and Outstanding:

December 31,	**2008**		2007	
	Number of Shares	**Amount *(millions of dollars)***	Number of Shares	Amount *(millions of dollars)*
Balance at beginning of year	**140,732,747**	**1,070.7**	135,879,724	983.2
Common shares issued	**-**	**-**	4,853,023	87.5
Balance at end of year	**140,732,747**	**1,070.7**	140,732,747	1,070.7

In August 2007, the Company's parent company subscribed for and was issued an additional 4,853,023 common shares for proceeds of $87.5 million.

Preference Shares

December 31, 2008 and 2007	**Authorized**	**Issued and Outstanding**	**Amount** *(millions of dollars)*
Group 1	**176,435**	**Nil**	**-**
Group 2, Series A - C, Cumulative Redeemable Retractable	**6,000,000**	**Nil**	**-**
Group 2, Series D, Cumulative Redeemable Convertible	**4,000,000**	**Nil**	**-**
Group 3, Series A - C, Cumulative Redeemable Retractable	**6,000,000**	**Nil**	**-**
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	**4,000,000**	**4,000,000**	**100.0**
Group 4	**10,000,000**	**Nil**	**-**
Group 5	**10,000,000**	**Nil**	**-**
			100.0

Cumulative cash dividends on the Group 3, Series D preference shares are payable at a fixed yield rate of 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends would be payable at 80% of the prime rate. On or after July 1, 2009, the Company has the option to redeem the shares for $25.50 per share if, after July 4, 2009, the preference 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, 2009, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period. The Group 2, Series D preference shares can be redeemed, at the Company's option, at $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

8. STOCK-OPTION AND STOCK UNIT PLANS

Certain employees and senior officers of the Company are granted stock-based compensation from Enbridge Inc., the Company's ultimate parent, through its three plans for mid to long-term incentive compensation: 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 equivalent to one Enbridge Inc. common share and are payable in cash.

Incentive Stock Options

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

During the year ended December 31, 2008, 220,600 stock options (2007 – 132,500 options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $40.42 in 2008 (2007 - $38.26) and a grant date fair value of $6.20 (2007 - $6.16).

Performance Stock Units

Enbridge Inc. has a PSU Plan for the Company's senior officers under which 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 Inc.'s weighted average common share price and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge Inc.'s performance fails to meet threshold performance levels, to a maximum of two, if Enbridge Inc. performs within the highest range of its performance targets. The performance multiplier for the 2006 grant was determined by Enbridge Inc.'s total shareholder return over the three-year performance period relative to a specified peer group of companies. The PSU plan covering the 2007 and 2008 grants derives the performance multiplier through a calculation of Enbridge Inc.'s price/earnings ratio relative to a specified peer group of companies and Enbridge Inc.'s growth in earnings per share relative to targets established at the time of the grant.

During the year ended December 31, 2008, 6,700 PSUs (2007 – 8,900 PSUs) were issued to employees of the Company.

Restricted Stock Units

Enbridge Inc. has an RSU plan where cash awards are granted to certain non-executive employees of the Company. After the thirty-five month vesting period, RSU holders receive cash equal to Enbridge Inc.'s weighted average share price for each RSU held.

During the year ended December 31, 2008, Enbridge Inc. granted 52,000 RSUs (2007 – 41,050 RSUs) to certain employees of the Company.

Stock-based Compensation Expense

The Company is charged an expense for stock-based compensation that includes a direct charge for ISOs, PSUs and RSUs issued to the employees of the Company and an allocation of such costs with respect to employees of Enbridge Inc. For the year ended December 31, 2008, the direct charge totalled $4.2 million (2007 – $2.4 million) and the allocation totalled $3.4 million (2007 – $1.5 million). These costs are included in operation and maintenance.

9. RISK MANAGEMENT

Market Price Risk

The Company's earnings are subject to movements in interest rates, foreign exchange rates and other price risks. The Company is also exposed to credit risk and liquidity 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 is exposed to interest rate fluctuations in the form of cash flow interest rate risk and fair value interest rate risk. Cash flows are impacted by changes in market interest rates on impending variable rate debt (primarily commercial paper) and fixed rate debt issuances. The fair value of fixed rate long-term debt is also impacted by changes in market interest rates. Floating to fixed interest rate swaps, collars and forward rate agreements may be used to mitigate cash flow volatility due to the effect of future interest rate movements on existing debt instruments. The Company is also exposed to cash flow interest rate risk on fluctuations in market interest rates ahead of anticipated fixed rate debt issuances. The Company may enter into interest rate derivatives such as bond forwards and treasury locks to fix a portion of the interest payments of these future debt issuances. The Company does not typically manage the fair value risk of its debt instruments.

Based on variable rate debt outstanding through the year ended December 31, 2008, a 1.0% change in interest rates would have had a $nil impact on earnings.

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 entirely borne by the customers.

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 US dollars and as a result there is exposure to fluctuations of the US 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.

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. In addition, security deposits are collected from certain high risk customers and can be applied against these accounts in the event of default. The maximum exposure to credit risk is the carrying value of the financial assets as disclosed in Note 10.

9. RISK MANAGEMENT *(CONTINUED)*

The change in the allowance for doubtful accounts in respect of accounts receivable for the year-ended December 31, 2008 is detailed below:

Allowance for Doubtful Accounts

(millions of dollars) Year ended December 31,	**2008**	2007
Opening balance	**(47.0)**	(42.4)
Additional allowance	**(26.4)**	(23.1)
Amounts used	**22.2**	18.5
Amounts reversed	**0.9**	-
Closing balance	**(50.3)**	(47.0)

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 give rise 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 high investment grade credit ratings. Credit risk relating to derivative counterparties is also mitigated by credit exposure limits and netting arrangements. The Company has no significant concentration with any single counterparty.

Liquidity Risk
Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. In order to manage this risk, the Company forecasts the cash requirements over the near and long-term to determine the availability of sufficient funds. The Company's primary sources of liquidity and capital resources are funds generated from operations, short-term financing through the issuance of short-term commercial paper or drawing on bank credit facilities, and longer term debt, which includes debentures and medium-term notes. The Company can more quickly access the Canadian public capital markets by typically maintaining a current shelf prospectus with the securities regulator. In addition, the Company has access to sufficient liquidity through committed credit facilities with banking institutions, which would enable the Company to fund anticipated requirements. The Company expects to generate sufficient cash from operations and debt issuances to fund liabilities as they become due, finance budgeted investing activity, and pay common and preference share dividends throughout the year.

Maturities of Financial Liabilities
The Company generally has no financial liabilities maturing beyond one year with the exception of its long-term debt. Refer to Note 6 – "Debt" for a summary of long-term debt maturities and interest obligations.

9. RISK MANAGEMENT *(CONTINUED)*

Summary of Derivative Instruments used for Risk Management
Pursuant to the OEB's directive of July 2007, the Company no longer utilizes derivative and non-derivative instruments to manage changes in commodity prices. However, the OEB decision does not impact the natural gas commodity risk program at St. Lawrence. The majority of St. Lawrence's cash flow hedges are for purchases of natural gas. Ordinarily, the effective portion of the change in fair value of the cash flow hedging instrument is recorded in OCI and reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in the current period earnings. However, given that St. Lawrence is subject to rate regulation, the effective portion of changes in the fair value of these natural gas purchase hedges are 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.

At December 31, 2008, the Company recognized a payable of $0.6 million to counterparties for unrealized losses related to natural gas purchase hedges (December 31, 2007 - $1.0 million) and a receivable of $0.6 million from customers (December 31, 2007 - $1.0 million). Natural gas purchase hedges typically expire within one year of the effective date of the hedge.

Total Derivative Instruments

	December 31, 2008			December 31, 2007		
	Notional Principal ($) or Quantity ($10^6 m^3$)	**Fair Value Payable *(millions of dollars)***	**Maturity**	Notional Principal ($) or Quantity ($10^6 m^3$)	Fair Value Payable *(millions of dollars)*	Maturity
Natural gas supply management	**43**	**0.6**	**2009**	15	1.0	2008
Interest rate swaps	**$8.6**	**0.2**	**2009**	$7.0	0.2	2008

The fair values of financial derivative instruments have been estimated using period-end market information. This market information includes observable inputs such as published market prices for commodities and interest rate yield curves. When possible, financial instruments are valued using quoted market prices.

The Company estimates that $0.2 million of accumulated other comprehensive loss related to cash flow hedges will be reclassified to earnings in the next twelve months.

As at December 31, 2008, the Company does not have any fair value hedges or non-hedging derivative instruments.

10. FINANCIAL INSTRUMENTS

(millions of dollars)	**December 31, 2008** Carrying Value	Fair Value	December 31, 2007 Carrying Value	Fair Value
Financial Assets				
Cash and cash equivalents	**100.0**	**100.0**	-	-
Accounts receivable[1]	**955.5**	**955.5**	881.8	881.8
Investment in affiliate company[2]	**825.0**	**N/A**	825.0	N/A
Financial Liabilities				
Bank overdraft	**44.6**	**44.6**	4.8	4.8
Accounts payable[1]	**583.0**	**583.0**	550.1	550.1
Current derivatives payable[1]	**0.8**	**0.8**	1.2	1.2
Loans and notes payable	**881.6**	**881.6**	551.0	551.0
Other current liabilities	**88.1**	**88.1**	61.6	61.6
Long-term debt (including current portion)	**2,267.1**	**2,253.0**	2,333.6	2,576.5
Loans from affiliate company[3]	**375.0**	**N/A**	375.0	N/A

1) Accounts receivable as at December 31, 2008 excludes $24.8 million of regulatory assets that do not meet the definition of a financial instrument (December 31, 2007 - $36.0 million). Accounts payable as at December 31, 2008 exclude $93.3 million of regulatory liabilities that do not meet the definition of a financial instrument (December 31, 2007 - $154.8 million). Accounts payable as at December 31, 2008 also exclude $0.8 million of current derivatives payable, which is disclosed separately (December 31, 2007 - $1.2 million).

2) 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.

3) 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 preference 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 values of financial instruments reflect 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. 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 values of cash and cash equivalents, bank overdraft, and loans and notes payable approximate 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.

10. FINANCIAL INSTRUMENTS *(CONTINUED)*

The fair value of other financial assets and liabilities approximate their carrying value due to the short period to maturity. The change in the fair value of the short-term derivatives held for trading is due solely to fluctuations in interest rates and commodity prices, as well as time value. The Company has not incurred any fair value changes due to credit risk.

The recovery of interest through regulated distribution rates is subsumed within the incentive regulation rate formula for the years 2008 through 2012.

11. CAPITAL DISCLOSURES

The Company defines capital as bank overdraft, loans and notes payable, long-term debt (including intercompany debt, excluding transaction costs), and shareholders' equity (excluding accumulated other comprehensive loss) less cash and cash equivalents.

The Company's capital is calculated as follows:

(millions of dollars)	**December 31, 2008**	December 31, 2007
Bank overdraft	**44.6**	4.8
Loans and notes payable	**881.6**	551.0
Long-term debt, including current portion	**2,288.6**	2,356.9
Loans from affiliate company	**375.0**	375.0
Shareholders' equity	**1,939.8**	1,891.5
Cash and cash equivalents	**(100.0)**	-
	5,429.6	5,179.2

The Company's policies with respect to the management of capital have not changed significantly during the year.

The Company's objectives when managing capital are to maintain flexibility between:

- 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 the 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 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 GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of 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, 2007 and December 31, 2008, the Company was in compliance with these covenants.

12. INCOME TAXES

Income Tax Rate Reconciliation

(millions of dollars) Year ended December 31,	**2008**	2007
Earnings before income taxes	**300.8**	268.4
Combined statutory income tax rate	**33.5%**	36.1%
Income taxes at statutory rate	**100.8**	96.9
Increase (decrease) resulting from:		
Non-taxable dividend income from affiliated companies	**(21.0)**	(22.7)
Unrecorded future income taxes related to regulated operations	**10.8**	5.4
Other	**(1.2)**	(1.1)
Income taxes	**89.4**	78.5
Effective income tax rate	**29.7%**	29.2%

The future income taxes recorded in current assets of $15.3 million (2007 - $36.4 million) arise primarily from temporary differences related to regulatory deferral accounts.

Accumulated future income tax liabilities related to rate-regulated operations, which have not been recorded, amounted to $150.7 million at December 31, 2008 (December 31, 2007 - $161.9 million). Had the liability method been prescribed by the regulatory authorities for rate-making purposes, such amounts would have been recorded and recovered in revenues to date.

13. 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 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.

The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2008. 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

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.

Had the Company used the accrual method of accounting for post-employment benefits, a transitional asset and obligation would be 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 other post-employment benefits and is equal to the accrued benefit obligation at October 1, 2000, amortized over 15 years.

The disclosures reflect the following post-employment benefit policies:

- The cost of pensions and other post-employment benefits 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.

13. POST-EMPLOYMENT BENEFITS *(CONTINUED)*

The following table details the changes in the benefit obligation, the fair value of plan assets and the unrecorded asset or liability for the Company's defined benefit pension plan, defined contribution pension plan, and OPEB plan had the accrual method been used.

	OPEB		Pension Benefit	
(millions of dollars)	**2008**	2007	**2008**	2007
Change in accrued benefit obligation				
Benefit obligation	**99.5**	99.4	**639.8**	650.3
Service cost	**1.5**	1.7	**15.9**	14.9
Interest cost	**5.6**	5.3	**35.9**	33.8
Transfer to the defined contribution component	-	-	**(1.3)**	(1.3)
Net transfer out	-	-	**(4.8)**	-
Adjustment due to change in measurement date	**0.2**	-	-	-
Actuarial gain	**(20.3)**	(3.9)	**(78.9)**	(31.8)
Benefits paid	**(3.3)**	(3.0)	**(27.7)**	(26.1)
Benefit obligation	**83.2**	99.5	**578.9**	639.8
Change in plan assets				
Fair value of plan assets	-	-	**831.7**	792.9
Transfer to the defined contribution component	-	-	**(1.3)**	(1.3)
Actual return (loss) on plan assets	-	-	**(96.2)**	65.6
Employer contributions	**3.3**	2.9	**0.6**	0.6
Benefits paid	**(3.3)**	(2.9)	**(27.7)**	(26.1)
Net transfer out	-	-	**(6.7)**	-
Fair value of plan assets	-	-	**700.4**	831.7
Funded Status				
Benefit obligation	**(83.2)**	(99.5)	**(578.9)**	(639.8)
Fair value of plan assets	-	-	**700.4**	831.7
Overfunded (underfunded) status	**(83.2)**	(99.5)	**121.5**	191.9
Employer contributions during period from measurement date to fiscal year-end date	**0.8**	0.7	**0.1**	-
Unamortized net actuarial loss (gain)	**(2.4)**	18.9	**191.2**	118.7
Unamortized prior service cost (credit)	**(0.6)**	(0.7)	**6.1**	7.4
Unamortized transitional asset	-	-	**(119.4)**	(144.5)
Unamortized transitional obligation	**21.8**	24.9	-	-
Net unrecorded accrued benefit asset (liability)	**(63.6)**	(55.7)	**199.5**	173.5

Major Categories of Plan Assets

(millions of dollars)		OPEB			Pension Benefit	
December 31,	**%**	**2008**	2007	**%**	**2008**	2007
Equity securities	**-**	**-**	**-**	**49**	**341.8**	487.8
Fixed income securities	**-**	**-**	**-**	**46**	**325.3**	310.8
Other	**-**	**-**	**-**	**5**	**33.3**	33.1
Total assets	**-**	**-**	**-**	**100**	**700.4**	831.7

13. POST-EMPLOYMENT BENEFITS *(CONTINUED)*

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 below table reflects both the target allocation percentage for each of the categories presented at the end of the period, as well as the expected long-term rate of return on assets, both on a weighted average basis. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and fixed income securities based on long-term expectations.

Expected Rate of Return on Plan Assets

		OPEB			Pension Benefit	
Year ended December 31,	**%**	**2008**	2007		**2008**	2007
Equity securities	**-**	**-**	**-**	60%	**8.75%**	8.75%
Fixed income securities	**-**	**-**	**-**	40%	**5.00%**	5.00%
	-	**-**	**-**	100%	**7.25%**	7.25%

Plan Contributions by the Company

(millions of dollars)	OPEB		Pension Benefit	
Year ended December 31,	**2008**	2007	**2008**	2007
Total contributions	**3.3**	2.9	**0.7**	0.6
Contributions expected to be paid in 2009	**3.5**		**0.5**	

The table below summarizes the expense that would have been recorded under accrual accounting related to the defined benefit plans had regulatory accounting not been followed.

Pension Plan and OPEB Costs on an Accrual Basis

(millions of dollars)	OPEB		Pension Benefit	
Year ended December 31,	**2008**	2007	**2008**	2007
Benefits earned during the year	**1.5**	1.7	**15.9**	14.9
Interest cost on projected benefit obligations	**5.6**	5.3	**35.9**	33.8
Actual return (loss) on plan assets	**-**	-	**96.2**	(65.6)
Actuarial gain	**(20.3)**	(3.9)	**(78.9)**	(31.8)
Costs arising in the year	**(13.2)**	3.1	**69.1**	(48.7)
Differences between costs arising in the year and costs recognized in the year:				
Return (loss) on plan assets	**-**	-	**(154.6)**	10.0
Past service costs (credits)	**(0.1)**	(0.1)	**1.3**	1.2
Actuarial gains	**21.3**	5.1	**83.8**	40.7
Transitional obligation (asset)	**3.1**	3.1	**(25.1)**	(25.1)
Costs (credits) on an accrual basis	**11.1**	11.2	**(25.5)**	(21.9)

13. POST-EMPLOYMENT BENEFITS *(CONTINUED)*

Pension Plan and OPEB Costs Recognized on a Cash Basis

The table below reflects the pension and OPEB costs for all of the Company's benefit plans on a cash basis, which corresponds to the amount expensed, reflecting its ability to recover employee benefit costs from customers.

(millions of dollars) Year ended December 31,	**2008**	2007
Pension	**2.4**	2.3
OPEB	**3.3**	2.9
Total costs recognized on a cash basis	**5.7**	5.2

Economic Assumptions

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

(millions of dollars)	**OPEB**		**Pension Benefit**	
Year ended December 31,	**2008**	2007	**2008**	2007
Discount rate	**5.60%**	5.20%	**5.60%**	5.20%
Average rate of salary increases	**5.00%**	5.00%	**5.00%**	5.00%
Average rate of return on pension plan assets	**-**	-	**7.25%**	7.25%

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

	OPEB		**Pension Benefit**	
December 31,	**2008**	2007	**2008**	2007
Discount rate	**6.70%**	5.60%	**6.70%**	5.60%
Average rate of salary increases	**5.00%**	5.00%	**5.00%**	5.00%

Medical Cost Trend Rates

The assumed medical cost trend rates for the next year used to measure the expected cost of benefits and the ultimate trend rate and the year in which the ultimate trend rate is assumed to be achieved 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	**10.00%**	**5.00%**	**2017**
Other medical and dental	**5.00%**	**5.00%**	**2017**

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $10.8 million in the accumulated post-employment benefit obligations and an increase of $1.1 million in OPEB cost. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $8.8 million in the accumulated post-employment benefit obligations and a decrease of $0.9 million in OPEB cost.

14. STATEMENT OF CASH FLOWS – ADDITIONAL INFORMATION

Change in Non-cash Working Capital

(millions of dollars) Year ended December 31,	**2008**	2007
Accounts receivable	**(66.6)**	(123.6)
Gas inventories	**(62.7)**	178.8
Other current assets	**2.6**	13.7
Accounts payable	**(25.1)**	63.0
Other current liabilities (excluding impact of dividends payable)	**26.5**	3.9
	(125.3)	135.8

Change in Non-cash Working Capital by Activity

(millions of dollars) Year ended December 31,	**2008**	2007
Operating activities	**(121.2)**	105.8
Investing activities	**(4.1)**	30.0
	(125.3)	135.8

Changes in non-cash working capital related to investing activities represent changes in capital asset accruals.

Cash Receipts (Payments)

(millions of dollars) Year ended December 31,	**2008**	2007
Interest received from third parties	**2.1**	1.5
Interest paid to third parties	**(179.2)**	(185.4)
Income taxes paid	**(43.1)**	(77.8)
Interest paid to affiliated companies	**(26.8)**	(27.0)
Dividends received from affiliate company	**62.7**	63.0

15. RELATED PARTY TRANSACTIONS

(millions of dollars) Year ended December 31,	**2008**	2007
Parent Company		
Enbridge Inc., ultimate parent company		
Purchase of treasury and other management services	**25.9**	21.9
Related Parties		
Enbridge Commercial Services Inc.		
Purchase of information services	**3.4**	2.7
CustomerWorks Limited Partnership		
Purchase of customer care services	**-**	26.3
Enbridge Operational Services Inc.		
Purchase of gas control services	**-**	2.5
Alliance Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**23.6**	21.3
Alliance Pipeline LP (US)		
Purchase of gas transportation services	**17.1**	15.1
Vector Pipeline LP		
Purchase of gas transportation services	**27.0**	25.0
Gazifère Inc.		
Revenue from wholesale service, including gas sales and transportation services	**47.2**	48.6
IPL System Inc.		
Dividend income	**62.7**	62.7
Interest expense	**26.8**	26.8

The Company had related party balances as follows:

As at December 31,	**2008**	2007
Note payable to parent company		
Enbridge Inc.	**7.1**	5.4
Investment in affiliate company		
IPL System Inc.	**825.0**	825.0
Dividend receivable	**5.3**	5.0
Loans from affiliated company		
IPL System Inc.	**375.0**	375.0
Interest payable	**2.3**	2.1
Trade receivables (payables)		
Enbridge Inc.	**(1.9)**	7.6
Gazifère Inc.	**9.3**	8.1
CustomerWorks Limited Partnership	**-**	0.1

15. RELATED PARTY TRANSACTIONS *(CONTINUED)*

Financing Transactions
The note payable to the Company's ultimate parent company, Enbridge Inc., bears interest at the banker's acceptance rate plus 0.325%, and is payable on demand. The note receivable from Enbridge Inc., when outstanding, bears interest at the banker's acceptance rate plus 0.325%, 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, 2008, the Company's total investment of $825.0 million (December 31, 2007 - $825.0 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2008, 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 preference shares of the Company. For the year ended December 31, 2008, interest paid amounted to $26.8 million (year ended December 31, 2007 - $26.8 million).

Treasury and Other Management Services
Enbridge Inc. 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.

Customer Care
The Company formerly received its customer care services from CustomerWorks Limited Partnership, a related entity jointly controlled by an affiliate under common control, and was charged market prices for these services. Effective April 1, 2007, the Company transferred, pursuant to an OEB approved agreement, its customer care services from CustomerWorks Limited Partnership to a third party service provider.

Gas Control Services
The Company's gas control functions were formally managed by Enbridge Operational Services Inc., an affiliate under common control, based on contracted rates under a service level agreement. The activity included monitoring the distribution system and the pressures and flows of natural gas through the Company's distribution system. Effective January 1, 2008, the Company manages these services internally.

Gas Transportation Services
The Company has contracted for natural gas transportation services from Alliance Pipeline Limited Partnership (Canadian), Alliance Pipeline LP (US) and Vector Pipeline Limited Partnership, related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2009 - $74.4 million, 2010 to 2011 - $143.9 million, 2012 to 2013 - $142.3 million and thereafter - $121.7 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.

15. RELATED PARTY TRANSACTIONS *(CONTINUED)*

Trade Receivables and Payables

The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge Inc., the ultimate parent company. 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.

16. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

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

(millions of dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
Consulting contract[1]	12.0	9.4	6.8	6.8	6.8	3.4	**45.2**
Customer care service contracts[2]	55.9	56.1	57.3	14.6	-	-	**183.9**
CIS contracts[3]	25.0	7.5	6.7	1.2	-	-	**40.4**
	92.9	**73.0**	**70.8**	**22.6**	**6.8**	**3.4**	**269.5**

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 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 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).

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[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 April 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.

16. COMMITMENTS AND CONTINGENCIES *(CONTINUED)*

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 and 2008 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

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

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

Goods and 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 is approximately $40 million and is included in accounts receivable. The Company expects that it will recover the overpayment from the CRA during 2009.

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 $22.0 million settlement, as a result of the class action lawsuit regarding late payment penalties. On February 4, 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. Refer to Notes 3 and 5.

16. COMMITMENTS AND CONTINGENCIES *(CONTINUED)*

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.

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 on April 24, 2003. On October 25, 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice. The appeal is scheduled to be heard by the Court during November 2009. The maximum possible fine upon conviction would not result in any 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.

Harper Gardens Incident

On February 14, 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A natural gas contractor working in the home at the time of the explosion was seriously injured. Several public authorities commenced investigations in connection with the incident. The Company has also been named as a defendant in civil actions related to the incident, but does not expect these actions to result in any material financial impact.

Other Litigation

The Company is subject to various other legal actions and proceedings that arise in the normal course of business. 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%, 11.15% 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 Preference 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 seven (7) members, three (3) 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
R. W. Martin
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 5, 2008), which is incorporated herein by reference.